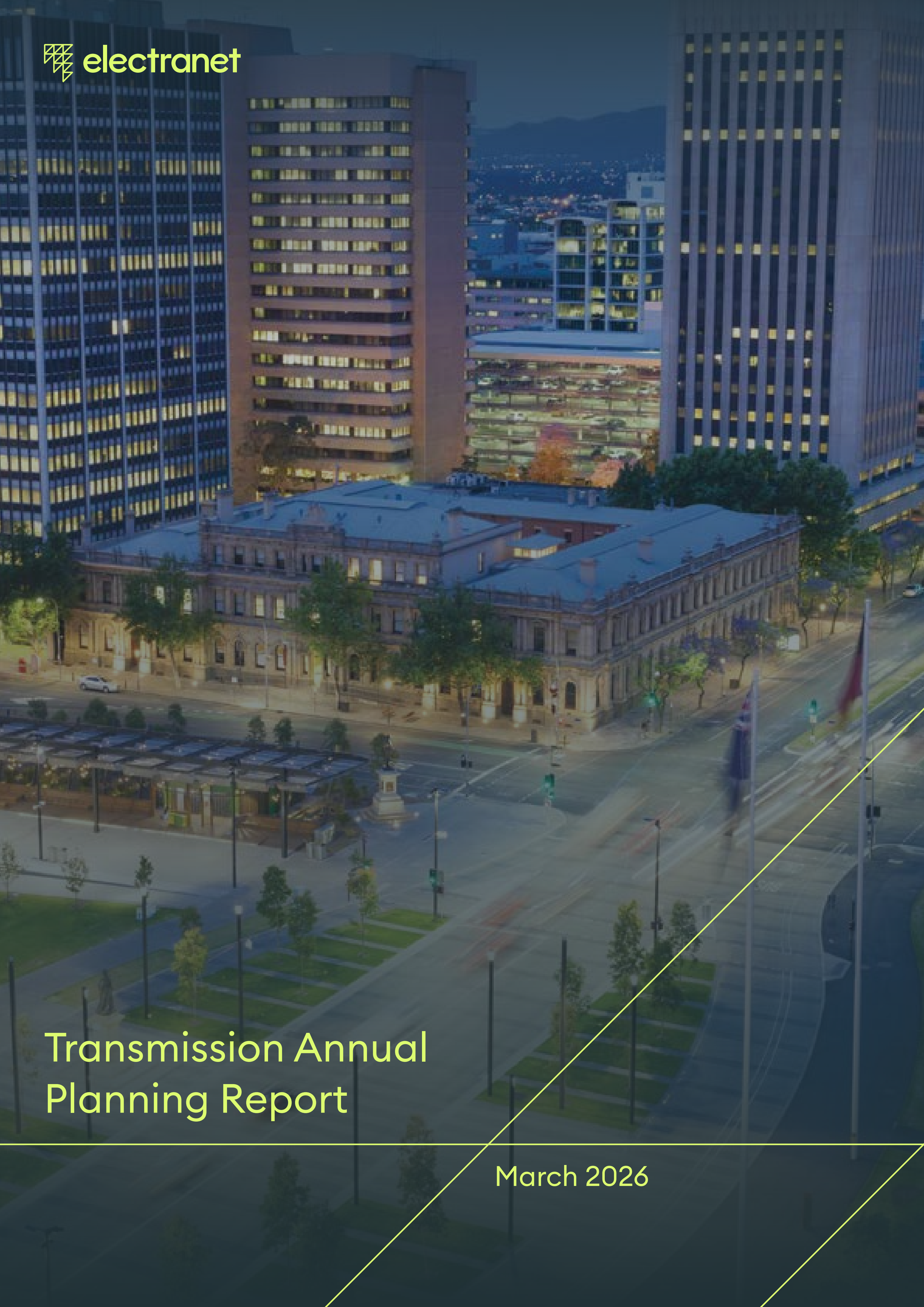


electranet

Transmission Annual Planning Report

March 2026

Acknowledgement of Country

In the spirit of reconciliation, ElectraNet acknowledges the Traditional Owners throughout South Australia and their ongoing connections to land, sea and community.

ElectraNet's transmission network operates across many traditional lands, and we value the opportunity this provides to build positive relationships with the communities.

We pay our respect to Elders past and present and extend that respect to all Aboriginal and Torres Strait Islander peoples.

Artwork by Kaurna, Ngarrindjeri, Narungga, Wirangu artist Gabriel Stengle

Prominent Hill
Roxby Downs
Olympic Dam North
Olympic Dam West
Leigh Creek
Leigh Creek Coalfield
Leigh Creek South
Upper North Region
Woomera
Pimba
Pernatty
Mount Gunson
Mount Gunson South
Neuroodla
Port Augusta
Emeroo
Davenport
Corraberra Hill
Eyre Region
Mid North Region
Stony Point
Cultana
Whyalla Central
Whyalla Terminal
Baroota
Mount Lock
Wudinna
Middleback
Port Pirie
Bungama
Belalie
Canowie
Willalo
Hookota
Redhill
Mount Millar
Yadnarie
Brinkworth
Snowtown
Blyth West
Clare North
Mintaro
Bundey
Riverland Region
Kadina East
North West Bend
Hummocks
Waterloo
Robertstown
Monash
Murraylink
Berri
Ardrossan West
Templers
Dorrien
Roseworthy
Munno Para
Port Lincoln
Sleaford
Para
Dalrymple North
Adelaide
Dalrymple
Magill
Tungkillo
Mannum
Mobilong
Morphett Vale East
Mount Barker
Tailem Bend
Cherry Gardens
Eastern Hills Region
Metropolitan Region
South East Region
ENLARGEMENT AREA
Pelican Point
Metropolitan Region
Adelaide
Keith
Black Range
Kincraig
Penola West
Snuggery
Mayurra
South East
Blanche
Mount Gambier
Heywood
NEW SOUTH WALES
SOUTH AUSTRALIA
VICTORIA
South Australia Transmission Network
Wind Farm
Solar Farm
Battery Energy Storage System
Power Station
Synchronous Condenser
Connections under construction
330 kV Substation
275 kV Substation
132 kV Substation
< 66 kV Substation
Pump Station
330 kV Project Energy Connect
275 kV
275 kV OWNED BY OTHERS
132 kV
132 kV OWNED BY OTHERS
De-Energised line
DC Cable
electranet
0 30 60 90km
© ElectraNet Pty Ltd. South Australia's Electricity Transmission Network, March 2026.

Contents

Appendices

About ElectraNet

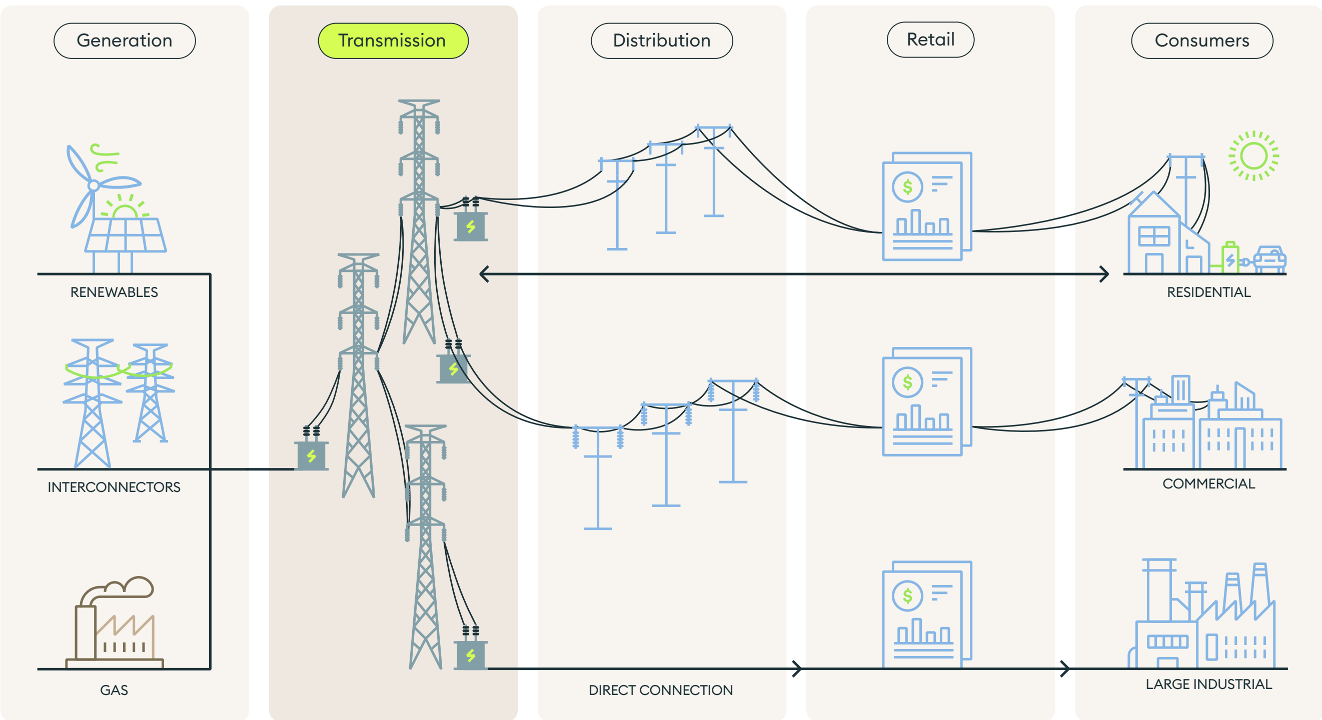
We're enabling the transition to a clean energy future for South Australia

Today, with the majority of our state's electricity coming from renewable sources, and with a South Australian Government target of 100% net renewable energy by 2027, we're leading the world in the green energy transition and doing things many wouldn't have thought possible.

ElectraNet is the owner and operator of South Australia's electricity transmission network, which transports energy from local and distant generation sources to where it is needed to serve electricity consumers. We play a critical role in enabling South Australia to be a leader in the global energy transformation. The electricity transmission network powers homes, businesses and communities, enabling the transition to a clean energy future.

As the state's principal electricity Transmission Network Service Provider (TNSP) we also provide system services, such as system strength and inertia to support the growth in renewable energy, and connection services to customers and generators wanting to connect to the transmission network.

We are committed to navigating this transition with our customers and stakeholders while maintaining affordable, reliable and sustainable electricity supply.



Generation	Transmission	Distribution	Retail	Consumers
Electricity is generated from traditional and renewable energy sources such as wind, solar, gas and coal.	Electricity enters ElectraNet's network where it is converted to higher voltages for efficient long-distance transport to cities and towns around South Australia. The voltage is then lowered so it can enter the distribution network or be supplied directly to some large industrial customers.	The distribution network, operated in South Australia by SA Power Networks, transports low-voltage electricity to residential and commercial customers.	Retailers are the primary point of contact for residential and commercial customers. They coordinate connections and manage billing and payments.	The traditional flow of electricity supply is changing. Over one in two South Australian homes now combines the electricity they draw from the network with power generated by rooftop solar panels. They also contribute surplus electricity back to the network.

Our Vision

Energising South Australia's clean energy future

Our Purpose

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

Our Strategy

To deliver on our Vision, ElectraNet has developed a Network Transition Strategy to provide a pathway and framework for working with our customers and stakeholders to manage the challenges and opportunities of the energy transition. The strategy is guided by our asset management objectives and is underpinned by three key themes to ensure we continue to develop and implement solutions to enable the energy transition.

Priorities

Safety | **Affordability** | **Reliability** | **Sustainability**

Energy reliability

Plan and deliver timely and efficient transmission infrastructure to connect customer loads with renewable energy and storage and maintain reliability of supply.

Power system security and resilience

Deliver system services and protection and emergency control schemes to maintain power system security and resilience during the energy transition.

Operability

Uplift network planning and operations capabilities, systems and tools to manage the increasing complexity and risk of the power system.

Purpose of the Transmission Annual Planning Report

Each year, ElectraNet reviews the capability of South Australia's electricity transmission network and regulated connection points to ensure they are able to meet the ongoing and increasing demand for electricity transmission services, under a wide variety of forecast operating scenarios.

ElectraNet undertakes joint planning with SA Power Networks (SAPN), which is responsible for the electricity distribution network throughout South Australia, and with the Australian Energy Market Operator (AEMO) as the National Transmission Planner, to complete the review. ElectraNet also provides input to and considers the findings of AEMO's Integrated System Plan and the outcomes of joint planning with AEMO in its role as Victorian Transmission Planner, along with interstate TNSPs such as Powerlink in Queensland, TransGrid in New South Wales and AusNet Services in Victoria (Appendix A).

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 to June 2035 and identifies potential network capability limitations and possible solution options. Significant changes from the 2025 Transmission Annual Planning Report are presented in Appendix J.

We also publish supporting data for our Transmission Annual Planning Reports on our website.[1] We will publish the supporting data for this Transmission Annual Planning Report later in 2026.

The Transmission Annual Planning Report (TAPR) provides deep insight across several key focus areas:

- the state of the transmission network and the drivers behind increasing demand (chapter 1)
- evolving electricity demand, particularly the rise of large industrial load and the impact of rooftop solar output (chapter 2)
- connection opportunities for both load and generation customers, alongside technical advice for new entrants (chapter 3)
- ElectraNet's approach to sustainability and community engagement (chapter 4)
- network constraints and ongoing development projects (chapter 5)
- challenges of maintaining security, system strength, and resilience in a rapidly changing operating environment (chapter 6).

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

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

We invite feedback on any aspect of this report. Your feedback will help us to serve you better and ensure we can continue to provide reliable and affordable electricity transmission services.

Comments and suggestions can be directed to:

consultation@electranet.com.au

Phone: +61 8 8404 7966
electranet.com.au

[1] ElectraNet | Transmission Annual Planning Report

Message from the Chief Executive Officer

South Australia leads the world in the transition to net zero and the closer we get to 100% net renewable, the closer we are to realising the once-in-a-generation economic opportunity it presents.

This is a remarkable feat given that the State relied almost entirely on fossil fuels in 2007. Fast forward to 2026 and South Australia regularly generates 100 per cent of its electricity needs from renewables and is expected to reach 100 per cent net renewables on an annual basis by next year.

The State has abundant renewable energy, world-class sun and wind resources, and access to valuable minerals, such as copper and magnetite iron ore. As industries such as mining, steelmaking, defence and data centres expand to take advantage of the State's natural resources, the demand for electricity in the State is set to grow significantly.

The transmission network is a critical enabler of the energy transition and the key to unlocking economic growth across South Australia and the thousands of jobs that come with it.

To realise the opportunity this new era of economic growth and increased electricity demand represents, we need timely investment in transmission infrastructure.

Knowing what infrastructure is needed, and when, will be critical to unlock the untapped renewables needed to power both new and existing industries. As constraints on the existing network grow, strategic investment will be key to ease congestion and provide the essential systems and services required to underpin the economic growth that will create jobs for future generations.

South Australia's future remains bright, but smart and timely decisions will be needed to keep energy affordable, reliable and sustainable for customers and consumers, so the whole State can realise a truly unique growth opportunity.

Electranet stands ready to play its part in realising this potential. This TAPR details our plan for South Australia's transmission network.

Simon Emms
Chief Executive Officer
ElectraNet

Executive Summary

The South Australia economy is witnessing its greatest opportunity in decades – new industries emerging, existing industries expanding and job opportunities developing.

These new industries are emerging at clearly defined hot spots, including the greater Adelaide region, the Upper Spencer Gulf, around the mid-north of South Australia and Mt Gambier. These hot spots will require substantial electricity demand.

Plentiful and affordable renewable energy unpins this opportunity, with significant investment in renewables seen across the SA electricity system in the past two decades. In 2025, 75% of supply was renewable and 100% net renewables by the end 2027. Wind, centred on the State's Mid-North, is supplying the majority of renewable electricity, and this will continue, complemented by transmission and distribution connected solar generation.

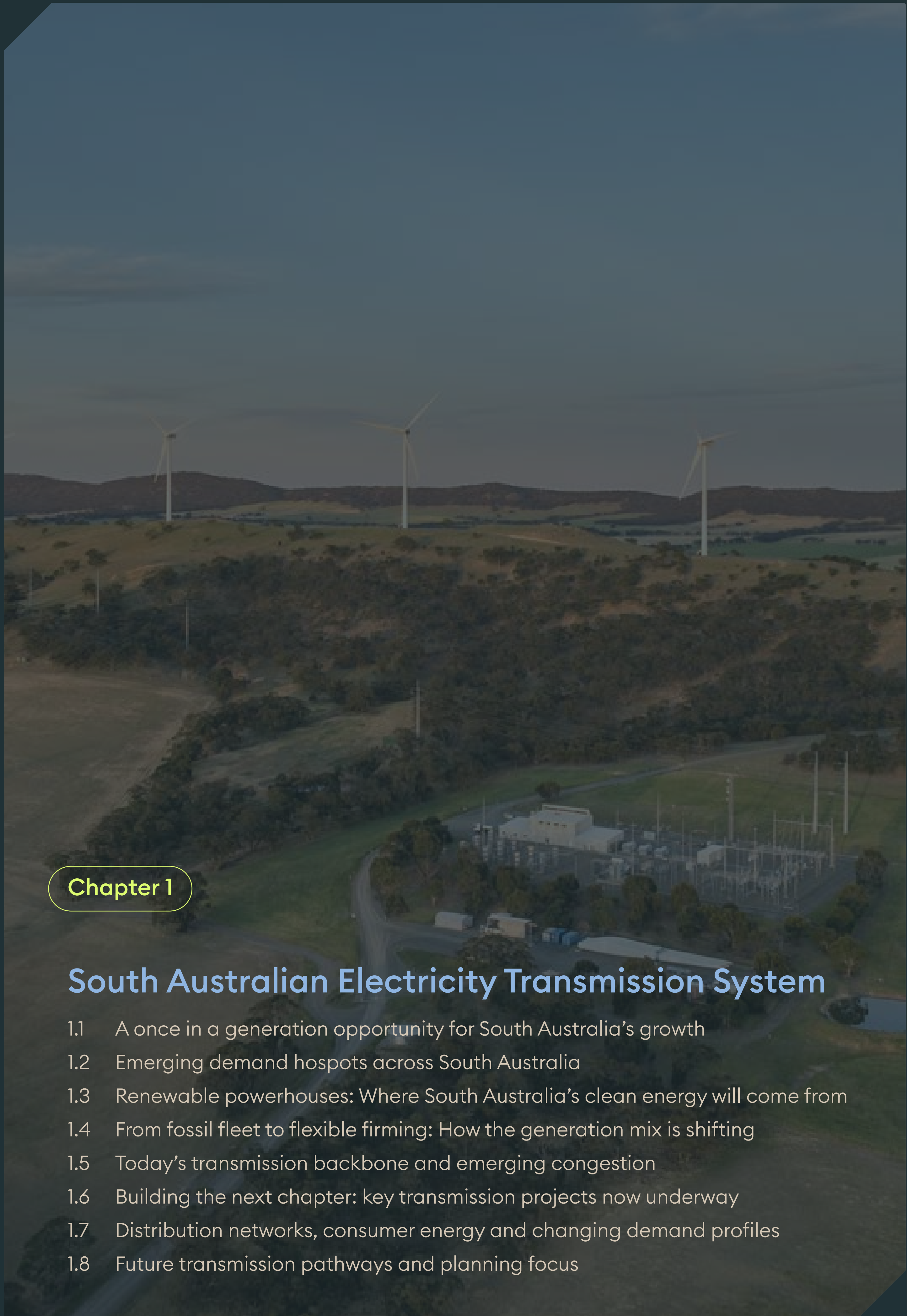
Having supported the State until now, conventional assets are retiring from the Adelaide metro region, including the Torrens Island Power Stations, and being rapidly replaced by Batteries in areas to the north of Adelaide. The next two decades will see these trends continuing, supported by the South Australian Government's Renewable Release Areas.

The ElectraNet network has played a crucial role to-date in bringing these areas together, but the scale of the opportunity means that existing infrastructure is increasingly congested. ElectraNet has plans in place to ensure that the States needs are met in the most cost-effective way for South Australia, including:

- The Eyre Peninsula Upgrade to strengthen the network between Port Augusta and Whyalla
- The Northern Transmission project supply demand growth specifically at Adelaide, mid-north around Bundey and Whyalla with renewables connections centred on Bundey
- The Upper South East augmentation to strengthen the connection between Tailem Bend and Mount Barker, for which we are using this TAPR to commence the RIT-T process
- Avoiding high-cost system strength remedies by pursuing innovative new solutions.

There continues to be major shifts in South Australian residential consumption patterns. Underpinned by factors including government support, high rates of rooftop PV installations continue, now totalling over 3GW. Increasing battery storage complimented this, with over 500MWh installed in the second half of 2025 alone. The resulting hollowing out of mid-day demand continues to create transmission and distribution operational network complexity, especially when overlaid with increasing maximum demand in many areas.

Upgrading and augmenting the South Australian electricity network has never been more challenging and important to meeting customers expectations of affordability and reliability. ElectraNet is working closely with the SA Government, SA Power Networks, and others to deliver the required capacity the State and its people need in the coming decades to realise the economic opportunity of a generation. This 2026 Transmission Annual Planning Report details the changes and needs, both existing and emerging, across the State. It sets out the where, why and how of these, the challenges they present and the breadth of ElectraNet's planning and progress to account for these, put into context through time and across the National Electricity Market.



Chapter 1

South Australian Electricity Transmission System

South Australian Electricity Transmission System

The South Australian energy system is moving into a crucial period in the energy transition. South Australia will become a 100% net renewable electricity system by 2027. Additionally, South Australia is on the cusp of a generationally significant increase in electricity demand associated with economic development and electrification.

Electricity transmission services play a vital role in enabling the energy transition, which is occurring at an ever-accelerating pace. Having been at the forefront of the transition globally, the South Australian Electricity Transmission System is characterised by very high levels of renewable generation, a rapidly changing nature of dispatchable capacity and extraordinary levels of forecast demand.

ElectraNet plays a central role in delivering South Australia's electrical needs. We are enabling the energy transition at increasing scale and speed. The complexity of evolving the state's electricity network, while also continuing to ensure energy reliability and security, cannot be overstated. In the face of this challenge, ElectraNet continues to build on its considerable track record of delivering efficient and timely network solutions in one of the world's most rapidly evolving energy systems.

ElectraNet owns and operates the statewide high voltage network spanning about 7,000 km of transmission lines and approximately 100 substations. This network connects widely distributed renewable energy zones to South Australia's population and industrial centres. The electricity system is characterised by highly concentrated demand in Greater Adelaide yet also dispersed across a large, sparsely populated geography. Over the past five years, ElectraNet has delivered more than 1,000 km of new transmission lines and major system strength projects on time and budget, reflecting the pace of change already underway.

The 2026 ElectraNet Transmission Annual Planning Report (TAPR) outlines the tremendous opportunity and challenge the South Australian electricity system faces, how the electricity system is changing, why the transmission network must continue to evolve, and how ElectraNet is responding through targeted investments and considered operational capability uplift.

1.1 A once in a generation opportunity for South Australia's growth

South Australia is at the forefront of the global clean energy transition, having rapidly advanced from a grid dominated by fossil fuels to one that now regularly operates beyond 100% variable renewable energy (VRE) penetration.

In the early 2000s, over 90% of the State's electricity was supplied by coal and gas generation. Today, South Australia has more than 3,400 MW of grid scale wind and solar generators installed as well as over 3,000 MW of rooftop solar PV. For context these developments have occurred in a system with an average operational demand of roughly 1,400 MW and a historical peak demand of around 3,300 MW. In October 2021, South Australia became the first major jurisdiction to have its local demand entirely met by renewable sources, and these intervals have since been achieved more frequently and for longer durations. In 2025, renewables (wind, solar and rooftop PV) supplied over 75% of South Australia's annual electricity consumption (net of imports/exports), driving toward the State's legislated target of 100% net renewable electricity by 2027.

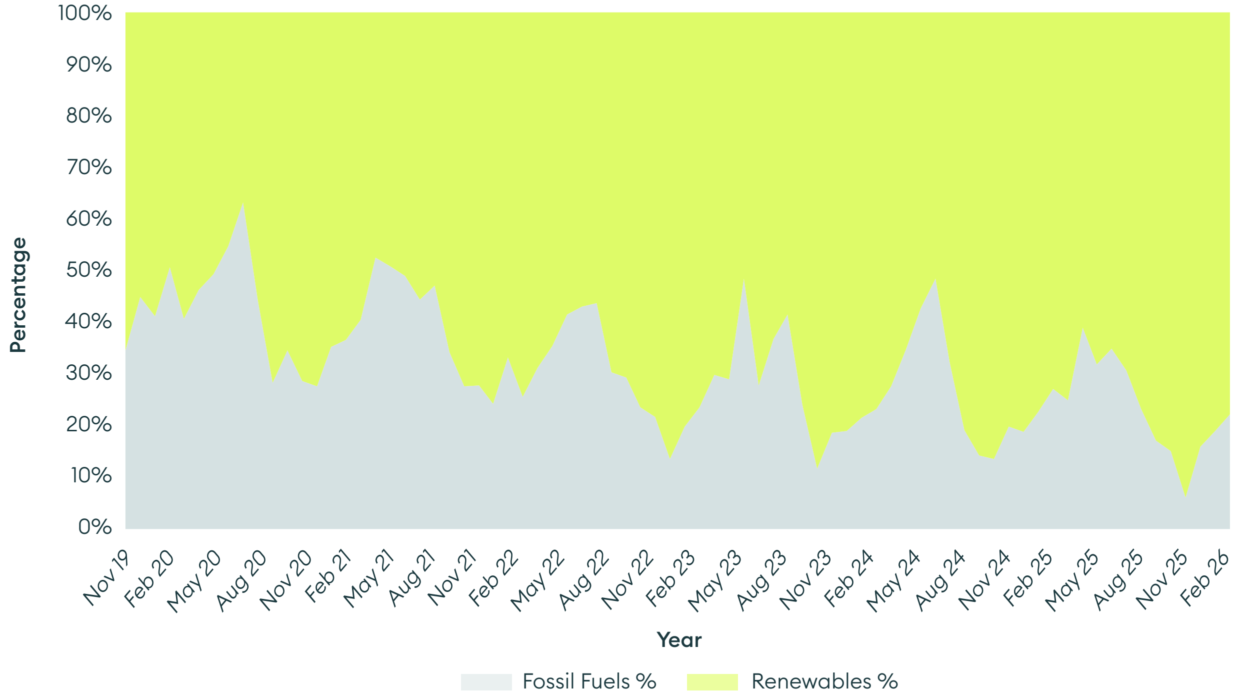


Figure 1: South Australian Fossil Fuel and Renewable Generation – Historical

This system transformation is now intersecting with a new and consequential driver: South Australia is on the cusp of a substantial increase in electricity demand associated with economic development and electrification. Policy settings at both State and Federal levels are oriented toward decarbonisation and industrial transformation. There is significant and growing interest in locating new electricity-intensive activity in South Australia to take advantage of the State's renewable resource potential and mineral endowment. This emerging "growth phase" is expected to include a mix of regional and metropolitan developments spanning minerals processing, green metals and manufacturing, water infrastructure, digital infrastructure, including data centres, and defence precinct expansion. These developments are expected to be geographically diverse and, in many cases, large and discrete in timing, creating "step changes" in load as facilities reach energisation.

ElectraNet's role as South Australia's principal Transmission Network Service Provider is central to enabling this opportunity while delivering reliability and affordability. ElectraNet owns and operates the statewide high voltage network spanning about 7,000 km of transmission lines and approximately 100 substations. This network connects widely distributed renewable energy zones to South Australia's population and industrial centres, highly concentrated in Greater Adelaide yet dispersed across a large, sparsely populated geography. Over the past five years, ElectraNet has delivered more than 1,000 km of new transmission lines and major system strength projects, reflecting the pace of change already underway.

At a system level, South Australia's next stage of decarbonisation and economic development is increasingly a transmission challenge. The State's best renewable resources are not co-located with its largest and growing load centres, and the retirement of thermal generation within the metropolitan area will increase reliance on power delivered from outside Adelaide. Building a resilient, high-capacity transmission backbone, supported by system strength, modern protection and enhanced operational tools, will be essential to translate South Australia's renewable advantage into secure, low cost electricity supply for households, businesses and new industry in the future.

1.2 Emerging demand hotspots across South Australia

South Australia's forecast demand growth is expected to be both material and geographically diverse.

This matters for transmission planning because the network must be developed in a way that aligns with where demand is emerging, the scale and timing of customer commitments, and the characteristics of new loads, including their reliability requirements and flexibility potential. Planning must be sufficiently forward looking to avoid a lag between demand growth and deliverable network capability, while also remaining staged and prudent given the uncertainty inherent in prospective projects.

Figure 2 illustrates the electricity consumption forecast to more than double over the period though to 2041, from ~12 TWh to over 25 TWh. Interest in connecting to the SA transmission network is at the highest level in decades, if not ever. ElectraNet presently has over 50 individual opportunities in detailed discussions as to how, when and where they are able to secure connection. This surge reflects the convergence of decarbonisation, digitalisation, and re-industrialisation.

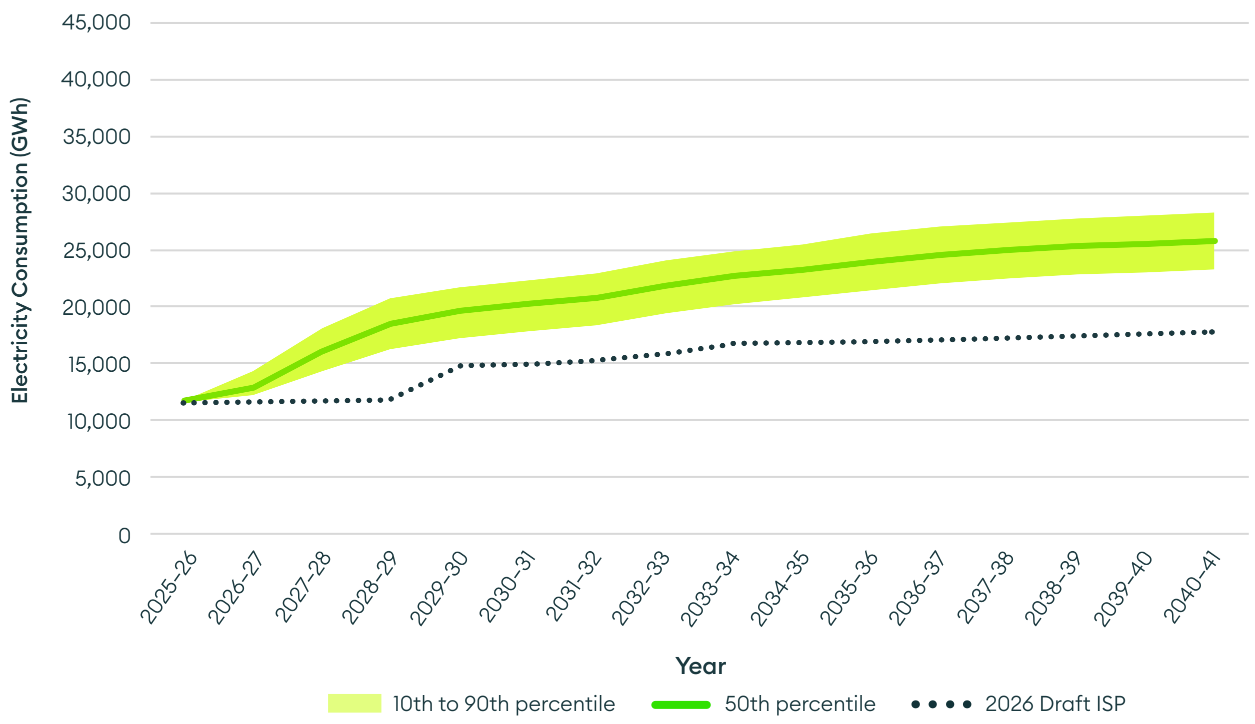


Figure 2: South Australian forecast operational demand – *Step Change* scenario

Emerging Hotspots

Several demand hotspots are evident across current planning and engagement. These hotspots include already significant load centres, which will need to expand further, whilst others are seeing a step change in their associated load profile. This has a material impact on requirements for transmission infrastructure to ensure reliable energy supply in a highly complex and decentralised renewable energy system.

The geographic diversity of prospective developments increases the importance of a network plan that can move energy efficiently and reliably between resource rich zones, the principal Adelaide load centre, and emerging significant new demand centres.

Greater Adelaide

Greater Adelaide is South Australia's largest load centre and is projected to increase by 30–40% over the next 10–15 years. The growth is driven primarily by new energy intensive industrial connections, such as data centres. Defence sector growth is also expected to concentrate major activity in Adelaide, including ongoing expansion at key precincts.

Eyre Peninsula and the Upper Spencer Gulf regions

The Eyre Peninsula and Upper Spencer Gulf regions are expected to experience large, discrete load growth associated with industrial transformation, including green metals and minerals processing, desalination and other infrastructure. There is significant new load connection interest concentrated in the Upper Spencer Gulf and surrounding regions, with implications for the scale and location of required transmission development. Additionally, the region is emerging as a renewable development region, supported by strengthened transmission capability following delivery of the Eyre Peninsula Link and the expectation of the Eyre Peninsula Upgrade. The potential for new large loads and associated economic development in the west of the State reinforces the need for a transmission pathway that can accommodate staged growth and support efficient connection outcomes.

Mid North and South East

Both the Mid North and South East regions are also expected to host material new activity, including a mix of renewable generation development, storage, and emerging large loads, including data centres. The geographic diversity of prospective developments increases the importance of a network plan that can move energy efficiently between resource rich zones, the principal Adelaide load centre, and new regional demand hubs.

The varied nature of demand

These demand hotspots are not uniform in their load profiles. Some emerging loads such as data centres and certain industrial processes have stricter requirements and different reliability needs. Contrary to this, other load types may be able to operate flexibly in response to renewable generation availability. Accounting for this diversity is important as it influences both the optimal network development pathway and the way system operability, resilience and security services must evolve as demand increases.

Historically, connecting singular, large industrial loads to the network was suitably enabled in a reactive way. Investment in the transmission network was modest and able to be achieved in a timely manner, as ElectraNet was able to leverage a system with significant capacity. However, this approach is no longer sustainable, as system complexity has significantly increased and system capacity is increasingly locally constrained. The need to appropriately and adequately manage the risk to the network, existing customers, and the customers seeking to be connected is a key focus for future transmission network development by ElectraNet. The rapidly evolving and complex environment demands a more proactive and system wide approach, with robust planning and investment required in the immediate future.

Chapter 2 sets out the detail of the state of forecast demand growth in SA, the drivers of the growth and ElectraNet's work on ensuring that the national planning framework accounts for the unique position and nature of South Australia.

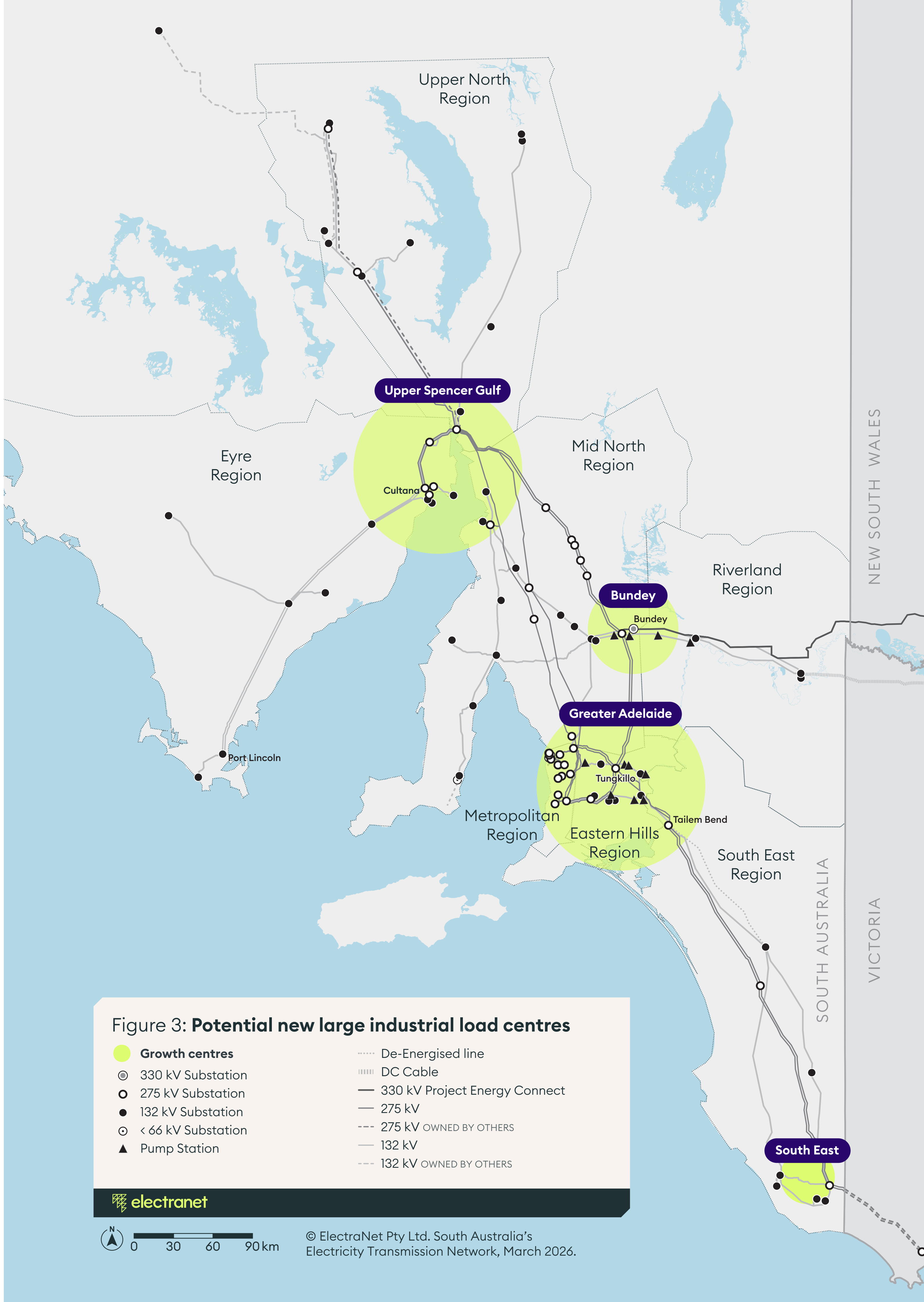


Figure 3: **Potential new large industrial load centres**

1.3 Renewable powerhouses: Where South Australia's clean energy will come from

South Australia's economic development opportunity is closely linked to renewable energy generation.

Meeting decarbonisation targets and supplying growing demand at lowest long-run cost requires continued development of high-quality wind and solar resources, coupled with storage and complementary firming solutions. The geographic distribution of South Australia's best renewable resources and the location of feasible development areas mean that a large share of new generation will continue to connect outside Greater Adelaide, placing greater weight on the transmission network's ability to deliver energy to load centres and to facilitate exports during periods of surplus renewable output.

Regional Renewable Focus Areas

There are three regions with large and growing renewable generation capacity that are particularly important in the current planning context, including South Australia's Mid North, Eyre Peninsula and the South East. ElectraNet considers generation and transmission infrastructure diversity as an important factor to energy affordability and security.

Mid North

The Mid North is already the powerhouse of South Australia's renewable fleet with industrial scale wind generators harnessing globally leading wind resources. Further, the region hosts a growing portfolio of grid-scale batteries and utility scale solar. Wind generation supplies 49% of the State's total energy demand and the Mid-North contributes around 73% of this.

The Mid North is serviced by the state's main 275 kV transmission infrastructure, linking Adelaide to Port Augusta (Davenport). Much of the State's renewable output is delivered through this corridor to supply Adelaide, other demand centres and export excess renewable energy to Victoria. The existing mid-north transmission corridor was designed to transmit coal power into Adelaide, with coal generation peaking at around 780 MW[2] in 2016. Market-led renewable and storage investments have vastly exceeded this capacity at 1,850 MW, with over 860 MW more wind anticipated to be connected in the mid-north within 5 years, along with over 2,300 MW of BESS[3], representing 65% of the State's battery storage capacity.

The Mid North also connects South Australia to Victoria via the Murraylink DC interconnector and via the new Project EnergyConnect interconnector to New South Wales.

The continued expansion of renewables and storage in the Mid North underpins the need for network reinforcement to reduce increasing congestion, and thus temporary generation and dispatch curtailment, to enable efficient utilisation of high quality renewable energy resources.

Eyre Peninsula

The Eyre Peninsula is emerging as a significant renewable and industrial development region, with prospective development around the Whyalla and Davenport area and the announced renewable release areas to the West around the Gawler Ranges. The latter, which are underpinned by the Hydrogen and Renewable Energy Act (2023), could see significant new renewable electricity supply introduced in the coming years.

Historically the Eyre Peninsula was serviced by lower reliability radial supply arrangements. In 2023, ElectraNet commissioned the Eyre Peninsula Link, replacing ageing assets and materially improving reliability while unlocking capacity for further growth. The addition of the Eyre Peninsula Upgrade is expected to further enable the connection of significant new load and new generation connections in the region.

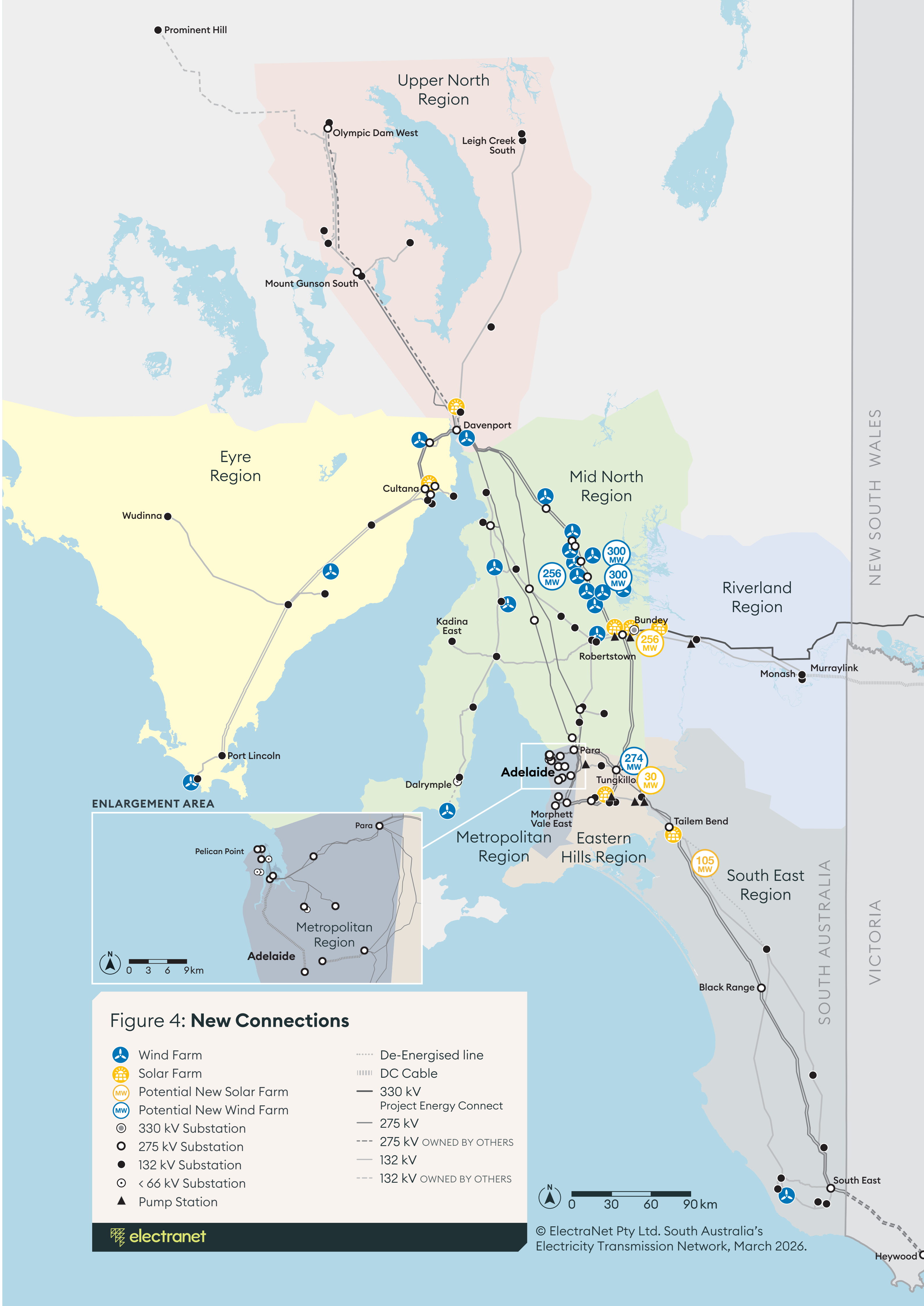


Figure 4: **New Connections**

© ElectraNet Pty Ltd. South Australia's Electricity Transmission Network, March 2026.

[2] Northern (540 MW) and Playford (240 MW) Power Stations

[3] AEMO | Generator Information

Stronger transmission capability on the Eyre Peninsula will support new wind, solar and storage projects as well as new industrial loads, further diversifying South Australia's world class energy system. The Eyre Peninsula will contribute to broadening South Australian supply and enable exporting surplus energy when system conditions permit.

South East

The South East also plays a dual role: it hosts renewable development potential and has historically provided the only AC interconnection pathway to Victoria through the Heywood interconnector. Strengthening the transfer capability from the South East toward Adelaide and the Mid North improves the ability to utilise renewable output, enhances flexibility in routing power flows, and supports more resilient operation during high transfer periods and outages.

The central planning implication is that South Australia's future renewable supply will increasingly be characterised by geographically dispersed, inverter based resources. The system value of this supply is maximised when the transmission network can:

- Connect new renewable generation and storage at efficient locations
- Move energy to growing load centres at low loss and with sufficient security margins
- Facilitate exports to neighbouring regions when local demand is met-reducing curtailment and improving overall system efficiency.

Extending and strengthening transmission is imperative to enable the optimal mix of renewable generation and storage to be developed to meet South Australia's needs as dispatchable capacity retires and industrial activity grows.

1.4 From fossil fleet to flexible firming: How the generation mix is shifting

South Australia's rapid renewable build-out has occurred alongside the progressive exit of traditional synchronous generation and the entry of new forms of firm capacity and storage.

South Australia's last coalfired power stations were shuttered by 2016, and since then gas fired generation, concentrated around Torrens Island and Osborne, has served as the primary dispatchable capacity. This conventional fleet is now ageing and exiting, most recently with the retirement of the Torrens Island A steam turbines in 2022. Further anticipated retirements include:

- Osborne CCGT by 2027 (175 MW combined cycle gas turbine)
- Torrens Island B by 2028 (800 MW steam plant)
- Pelican Point CCGT) by 2037 (478 MW combined cycle gas turbine)
- Dry Creek in 2030 (156 MW open-cycle gas turbine).[4]

The Greater Adelaide area will therefore see a major reduction in local firm generation over the coming years.

As metropolitan gas units retire, replacing their energy and, critically, their system services requires a portfolio response. Grid-scale batteries are already playing a growing role in firming and essential system services. Recent and committed storage developments include multiple large battery projects such as Carmody's Hill and Goyder BESSs, and additional battery capacity has been supported through national policy programs. In parallel, new dispatchable resources are being considered at strategic locations where electricity and gas transmission infrastructure intersect. This is consistent with the defined future role for fast start dispatchable plant to support reliability and operability under high renewable penetration.

This transition has direct implications for power flows and congestion. As high-quality renewable resources develop in the Mid North, Eyre Peninsula and other regions, and as local synchronous generation within the city declines, Adelaide becomes increasingly reliant on transmission imports. At the same time, the system must manage greater variability in net demand and renewable output, including large intraday swings, including significant periods of negative demands. For example, the South Australian system can move from renewable generation exceeding demand to a single digit proportional share within hours, driving steep ramping requirements for firming, storage and interconnection. A cited example over 3–4 October 2025 shows wind and solar supplying 91% of demand at midday, falling to 6% by early evening, then rising again to 107% several hours later. These operating conditions reinforce the importance of both network capacity and operability capability as the generation mix continues to shift.

South Australia is moving from a system where significant dispatchable supply was collocated with the main load centre, to one where energy, capacity and system services are increasingly provided by a combination of remote renewables, storage and targeted firming solutions. Transmission capability and resilience, supported by system strength and modern protection and control, are therefore foundational requirements for maintaining reliability and affordability through this transition.

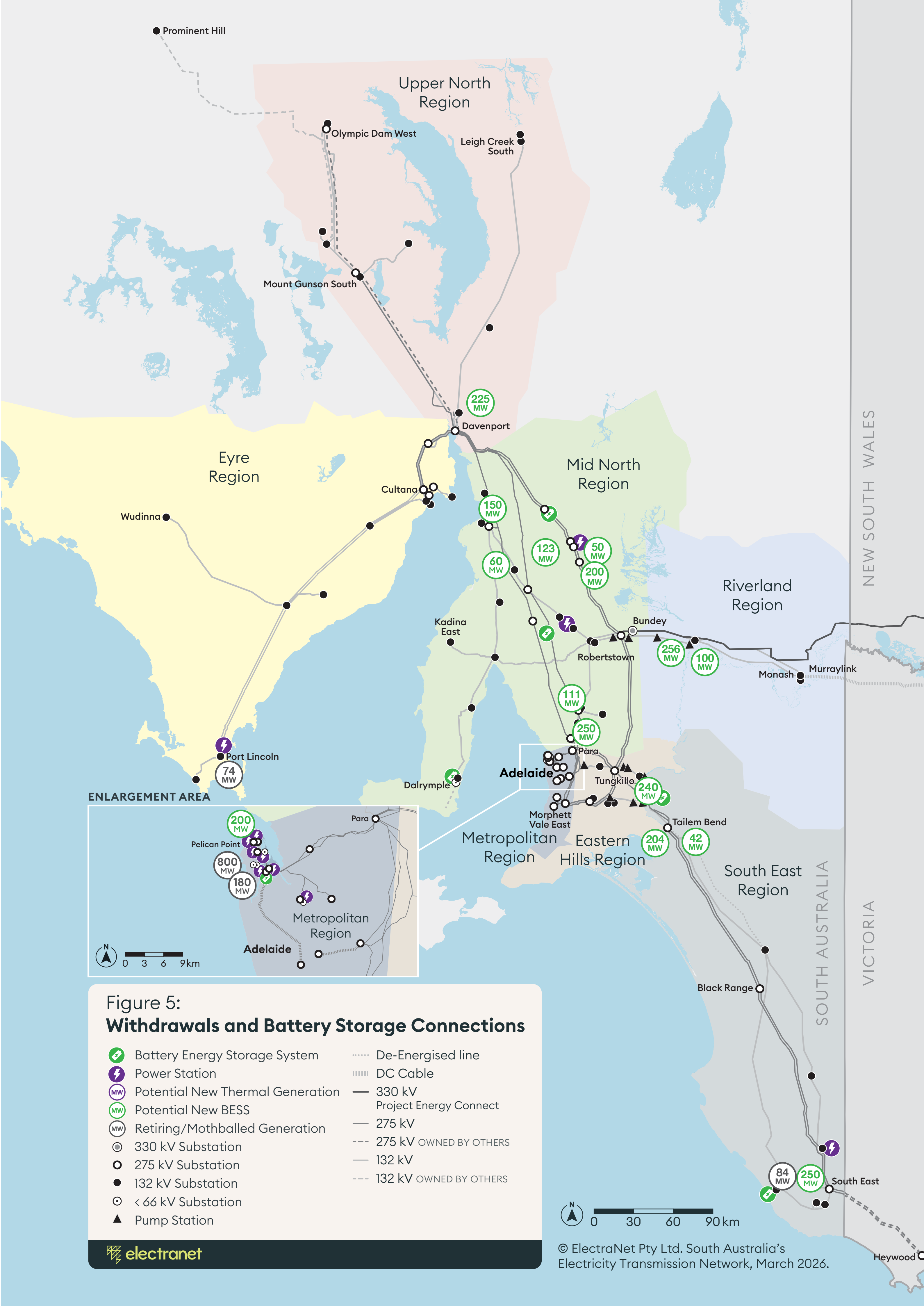


Figure 5:
Withdrawals and Battery Storage Connections

[4] AEMO Retirements

1.5 Today's transmission backbone and emerging congestion

South Australia's transmission network is evolving under the combined pressures of geographically diverse renewable development, changing power flows and emerging load growth.

The existing 275 kV network was not designed for the current and forecast conditions of sustained high renewable penetration, material two way flows and large new loads in regional areas. As a result, congestion is increasingly structural, reflecting the physics and security requirements of the network, rather than a limited number of isolated constraint events. This increasing congestion results in restrictions on the most efficient and lowest-cost combination of supply feeding into demand centres, such as Greater Adelaide. If this dynamic persists it will drive higher wholesale and retail prices for consumers across South Australia.

A practical indication of current capability is provided by current transfer limits. Practical transfer capability into Greater Adelaide maxes out at 1,470 MW, and averages closer to 1,100MW, while practical transfer capability into the Upper Spencer Gulf (Whyalla) is around 450 MW. These practical limits are constrained by a combination of thermal limits and system security requirements, including stability and system strength constraints. As northern variable renewable output and regional loads rise, these limits become binding more frequently and for longer durations.

The principal 275 kV corridor running from Davenport (near Port Augusta) to Adelaide is the backbone of the South Australian grid, linking resource rich northern regions to the load rich south. Four parallel 275 kV lines connect the Mid North region to metropolitan Adelaide. During periods of high wind and solar output in the north, these lines can reach capacity and require renewable output to be curtailed to maintain system security. As local dispatchable generation retires within Adelaide, the corridor will shoulder more of Adelaide's supply, increasing the severity and consequences of congestion unless new capacity and alternative pathways are developed. Under central planning scenarios, studies indicate a tipping point around 2030 beyond which congestion hours on key interfaces into Adelaide increase materially; without augmentation, this will restrict access to lower cost renewable supply and increase the risk of higher wholesale prices and reduced reliability margins.

Constraints are also emerging in the northern regions. While the northern terminus of the main 275 kV system is at Davenport, sub-transmission networks extend to key regions such as the Eyre Peninsula and Olympic Dam. These arrangements are not designed to support the scale of new industrial demand and additional dispatchable capacity signalled in the Upper Spencer Gulf and adjacent regions, nor to support the efficient integration of new renewable supply at the scale anticipated under high growth pathways. Addressing this requires a step change in transmission capability that can both supply new loads and provide efficient and reliable pathways for renewable energy to reach the relevant demand centres.

In addition to internal constraints, interconnector and interface limitations can become binding as South Australia's renewable surplus grows. While detailed treatment of interconnector interface constraints is addressed through national planning processes, South Australia's internal upgrades are complementary to interconnector capability. Internal transmission must be sufficiently strong to allow South Australia to export when surplus low-cost renewable energy is available and to import when needed, without internal bottlenecks undermining the value of interconnection.

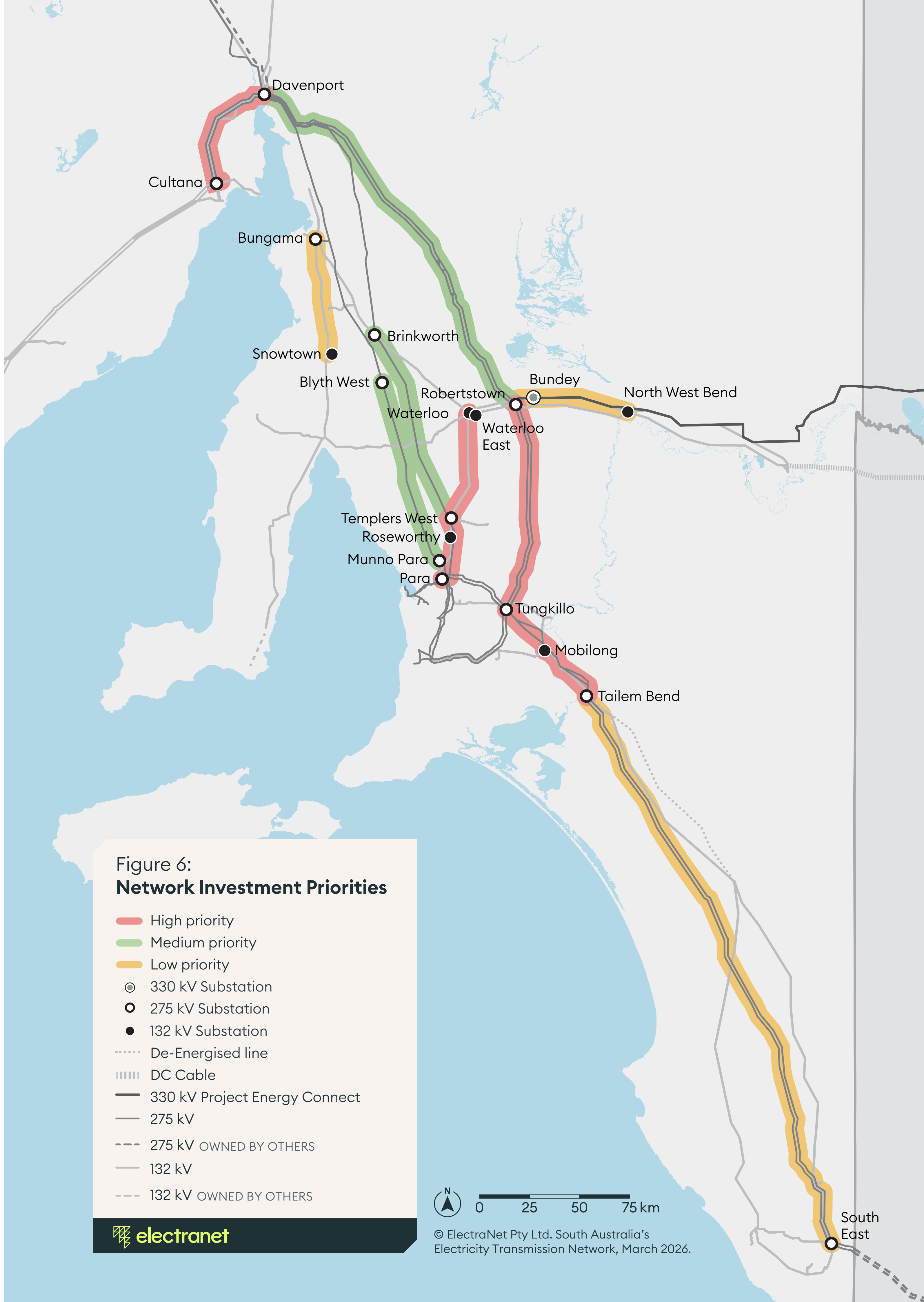


Figure 6: **Network Investment Priorities**

1.6 Building the next chapter: key transmission projects now underway

ElectraNet is progressing a coordinated portfolio of transmission augmentations and enabling investments to address emerging constraints, connect new load and generation, and strengthen the network's resilience and operability.

These investments are designed to deliver consumer benefits through improved reliability and reduced long run costs by enabling access to high quality renewable supply and efficient connection pathways for new demand. Investments include the Eyre Peninsula Upgrade, Northern Transmission Project, South East Expansion and crucial targeted augmentation works.

Eyre Peninsula Upgrade

Over the coming years, South Australia's Eyre Peninsula is expected to experience high levels of economic activity and associated growth in electricity demand, with energy intensive industries such as mining, data centres and green steel processing seeking connection to the transmission network. The Eyre Peninsula includes, and is close to, resources that are crucial in supporting this expected growth, including high quality renewable energy sites such as the release areas being opened up in the Upper Eyre Peninsula, Gawler Ranges and Upper Spencer Gulf region.

The Eyre Peninsula Link was commissioned in 2023 and replaced ageing assets with a higher capacity connection to the Eyre Peninsula. As a function of that project the 132kV double circuit line from Cultana to Yadnarie was designed and built with the option to upgrade it to 275kV if required by future load development. The Eyre Peninsula Upgrade is expected to both enable the connection of significant new load and new generation connections in the Eyre Peninsula and deliver on reliability requirements in doing so.

Northern Transmission Project (NTx)

NTx was identified as an actionable project in AEMO's 2024 Integrated System Plan. It comprises a new high capacity transmission line in two stages: NTx South from Adelaide to the Mid North (Bundey near Robertstown), and NTx North from Bundey to the Upper Spencer Gulf (near Whyalla/Cultana). NTx would create a 2,000 MW+ north-south "electricity highway", materially increasing transfer capability.

NTx is intended to:

- Support Adelaide's growing demand with low-cost generation from the north
- Provide a geographically distinct pathway into Greater Adelaide to improve resilience to bushfire and extreme weather risks
- Enable mining and industrial growth in the north by delivering high capacity supply
- Reduce generation curtailment by relieving binding constraints on key corridors.

ElectraNet has progressed planning and engagement activities and has identified the importance of maintaining actionable status to support efficient sequencing of analysis, early works and timely deliverability.

South East Expansion (Stage 1)

The South East Expansion is a targeted reinforcement that strings a second 275 kV circuit on the Tailem Bend–Tungkillo corridor. This upgrade increases transfer capability between the South East, Mid North and Adelaide regions, improves flexibility in routing power flows, and supports more robust utilisation of South East renewable output and interconnector flows through Heywood under a broader range of operating conditions.

Crucial works to support augmentation

Network augmentations are complemented by enabling investments in system strength, protection and control, and operational capability. Work such as the recent RIT-T on system strength requirements, which identified low-cost, high impact means of maintaining system security, demonstrate the multifaceted nature and requirements of the system-wide planning exercise.

Across the breadth of system strength, protection and control, and operational capability, ElectraNet has already:

- Delivered four synchronous condensers commissioned in 2021 to provide inertia and voltage support
- Upgraded the System Integrity Protection Scheme into a Wide Area Protection Scheme (WAPS)
- Implemented automated voltage control schemes at key nodes
- Delivered monitoring and control centre upgrades to improve observability and control in a high renewables operating environment.

These measures have supported improvements in operating envelopes, including agreement in late 2025 to reduce the minimum number of synchronous gas units required online from two to one under certain conditions, contributing to downward pressures on wholesale electricity prices. ElectraNet's system strength approach is deliberately technology-agnostic and is intended to evolve with the power system, combining network assets, contracted services and emerging inverter based solutions as required.

ElectraNet's focus on advancing economically efficient transmission projects is key to ensuring that connection to the transmission network is well-planned, timely and efficient, optimising the long-term cost to all users. These projects will address current and emerging constraints, unlock capacity for new and existing customer demand, and build generation connection capability. These projects are further detailed in section 5.2.

1.7 Distribution networks, consumer energy and changing demand profiles

South Australia's transition is occurring from both ends of the system.

While large industrial loads and utility scale renewables shape the bulk transmission outlook, consumer energy resources (CER), including rooftop PV, behind-the-meter batteries and electric vehicles, are reshaping demand profiles and power flows at the distribution-transmission interface. The transmission network must increasingly accommodate more dynamic and two way power flows and coordinate with distribution planning to ensure reliability and efficient investment outcomes.

Household and Commercial Electrification

As the Australian economy decarbonises, we are seeing the electrification of all sectors, with transport, industry, and the built environment leading the way. As awareness grows and government incentives expand, demand for electric solutions is expected to surge as households increasingly adopt CER in the form of electric heating, hot water and other household appliances, particularly as gas-fired replacements.

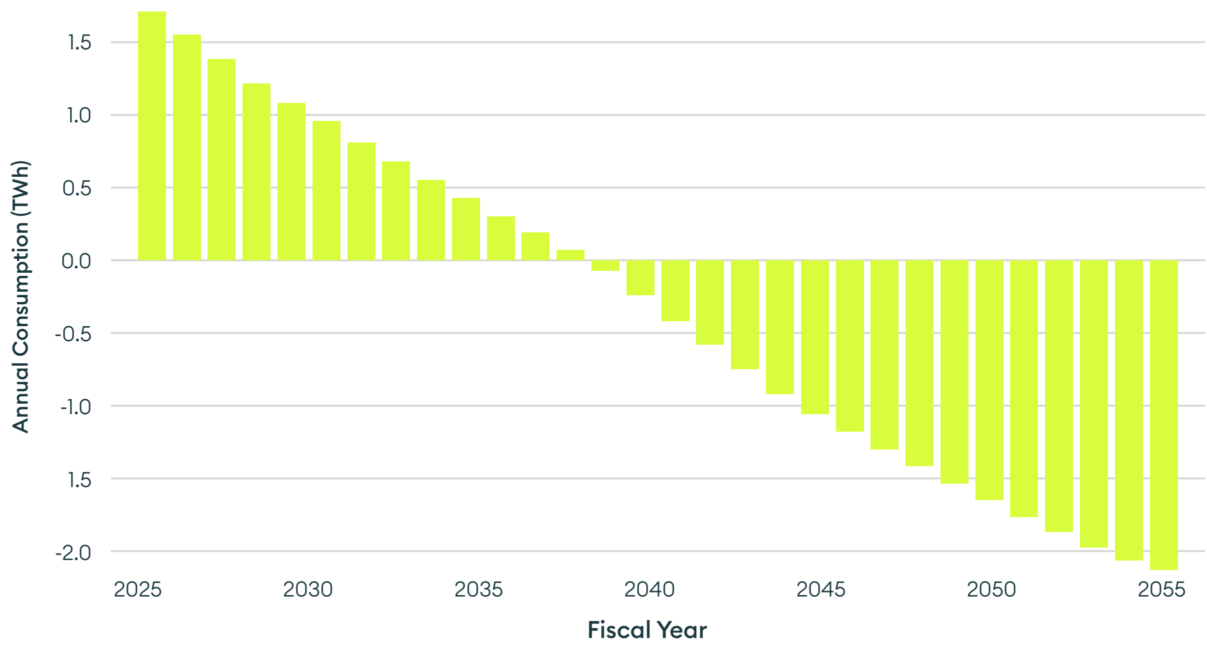


Figure 7: South Australian residential operational demand – 2025 ESOO ***Step Change*** scenario

A key element of this dynamic is the duality of increasing maximum demand in Greater Adelaide and falling net residential consumption.

- Rooftop PV has "hollowed out" daytime operational demand
- Evening peaks and maximum demand events have remained high – amplified by electrification
- Growth of behind-the-meter storage adds a further layer of complexity and opportunity

As a result, there are a number of connection points that are at risk of breaching capacity limits before 2040, despite falling net consumption across the residential customers.

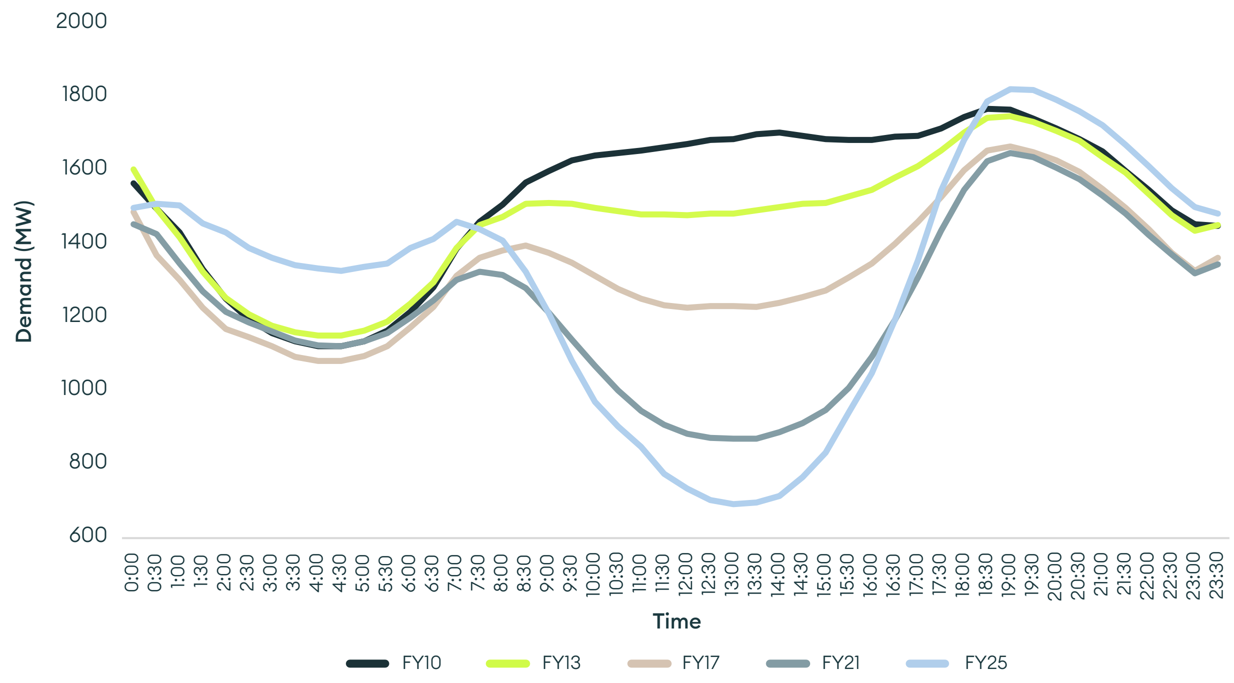


Figure 8: Changes in South Australia's average daily demand curve 2010–2025

Growing Demand Maximums

Through updated demand forecasting approaches and detailed planning studies, ElectraNet has identified that there are a growing number of, currently 17, distribution connection points that are within 10–15% of the maximum demand forecast before they require augmentation. Forecasts highlight that:

- Mount Gambier and Blache connection points will require upgrade in 2030 due to the connection of a new industrial load in the region
- Tailem Bend and Baroota connection points will require upgrade in 2034, based on our analysis of current maximum demand forecasts
- Several connection points are currently projected to required upgrades later in the 2030s or 2040s but could be required in 2034 or earlier if significant potential new industrial loads connect to the distribution network or load forecasts are increased by 10-15% in the future. These include Mount Barker South, Davenport West, Southern Suburbs, Western Suburbs, and Yadnarie.

ElectraNet is actively working with SA Power Networks (SAPN) to manage the implications and potential impacts of constraints across the transmission-distribution boundary, defining various solutions to account for the differing needs.

The Power of Rooftops and Garages

Rooftop PV uptake has been world leading and is a defining feature of South Australia's demand profile. The combined 439,664 installed rooftop systems, as shown in Figure 9, total to a combined capacity of 3 GW, and uptake is continuing at pace, with the number and size of systems increasing with each passing year.

Rooftop PV has "hollowed out" daytime operational demand while evening peaks remain high, increasing ramping requirements and altering voltage and power flow conditions across the system. Extended periods of low or negative net load can challenge voltage management and protection adequacy (including minimum fault levels) and increase reliance on effective system strength arrangements and control schemes. These dynamics are expected to continue as CER uptake grows and as electrification alters household and business demand.

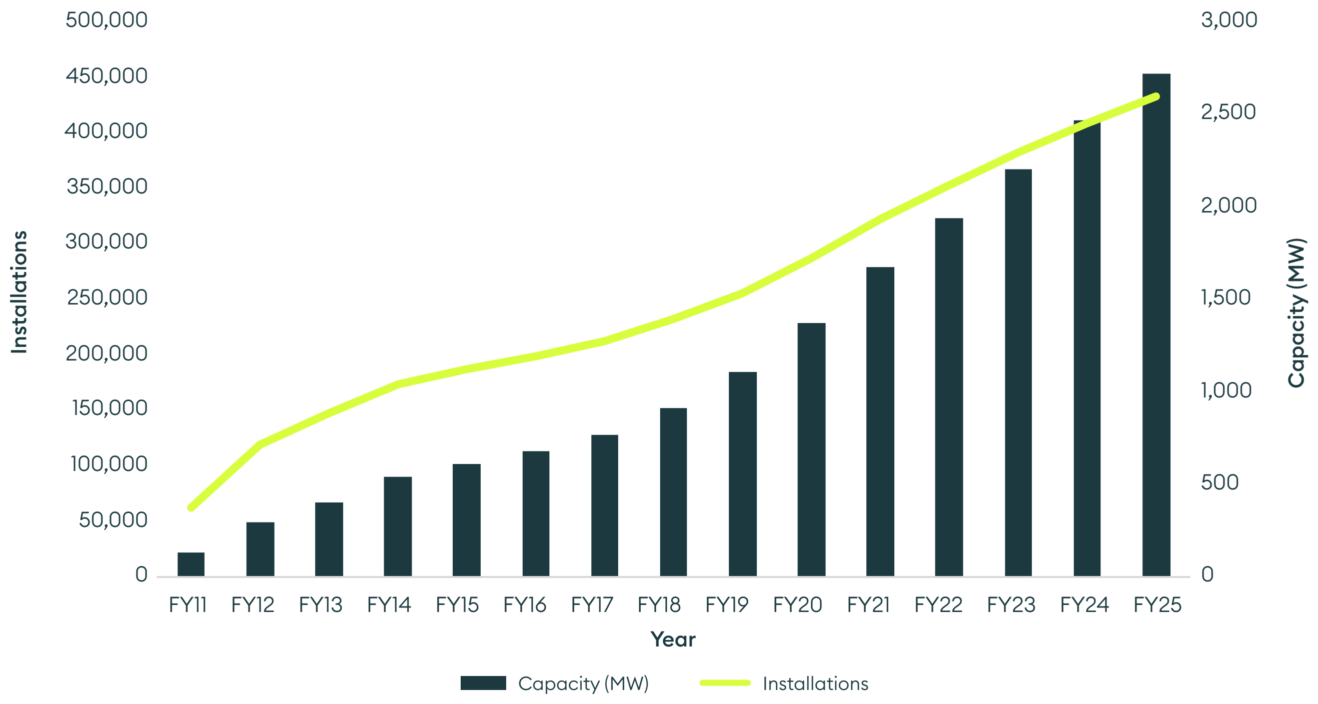


Figure 9: South Australian Rooftop PV Installations and Capacity

The growth of behind-the-meter (BTM) storage adds a further layer of complexity and opportunity. Figure 10 shows the significant growth in storage installations as a result of the Federal Government's Cheaper Home Batteries Program. Between July and December 2025, 23,587 batteries with a combined capacity of 527 MWh were installed in SA. This compares to 26,674 installed in total over the ten years between 2015–2024.[5]

As distributed batteries expand, the timing and location of net demand becomes more uncertain: batteries can reduce evening peaks by discharging locally, and they can also increase midday consumption if charging responds to price signals or operational settings. This introduces planning challenges as well as potential nonnetwork opportunities if distributed resources can be orchestrated to support peak reduction and provide system services. ElectraNet and SAPN are progressively developing coordination mechanisms, including operational visibility, dynamic operating envelopes and service procurement approaches, to support secure operation and efficient utilisation of distributed flexibility.

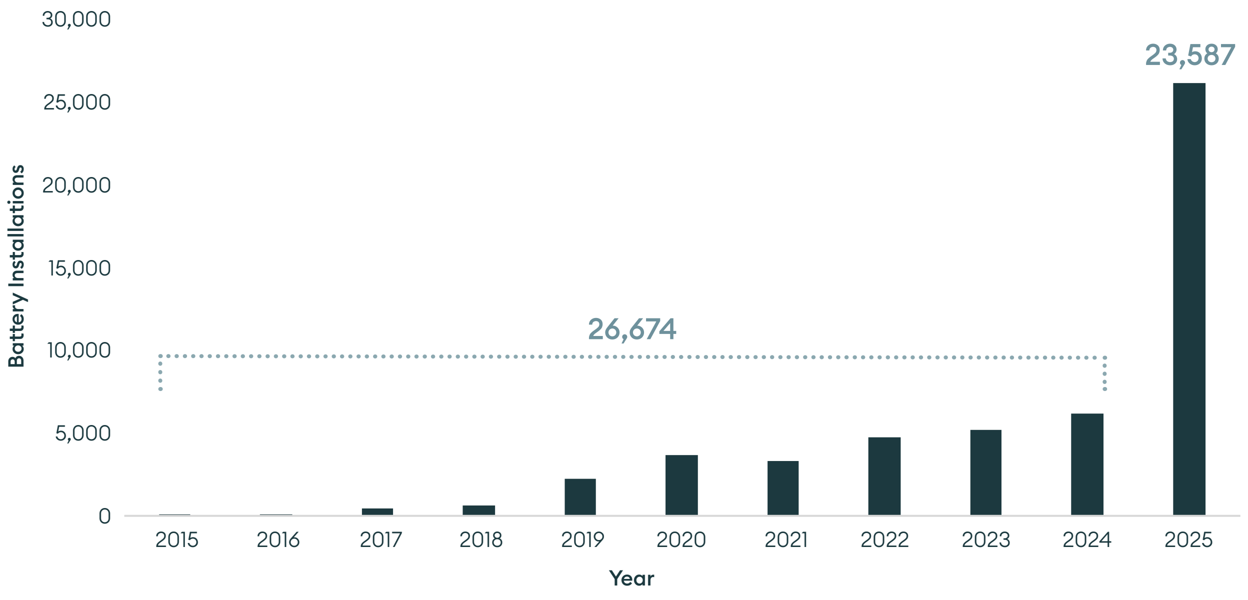


Figure 10: South Australian Behind-the-Meter Battery Installations

For Greater Adelaide in particular, the interaction between declining local synchronous generation, changing net demand profiles and increasing reliance on transmission imports underscores the importance of close transmission-distribution coordination.
As demand grows through electrification and new commercial loads, and as CER continues to change load shapes, the transmission network must be capable of managing both high import requirements during low renewable output and reverse flows during low demand, high rooftop PV conditions. The overall system outcome depends on coordinated planning and staged investment across both transmission and distribution.

[5] Clean Energy Regulator | Small-scale installation postcode data

1.8 Future transmission pathways and planning focus

South Australia is moving toward an era of sustained ultra-high renewable penetration, and ultimately toward secure operation under conditions where synchronous generation is absent.

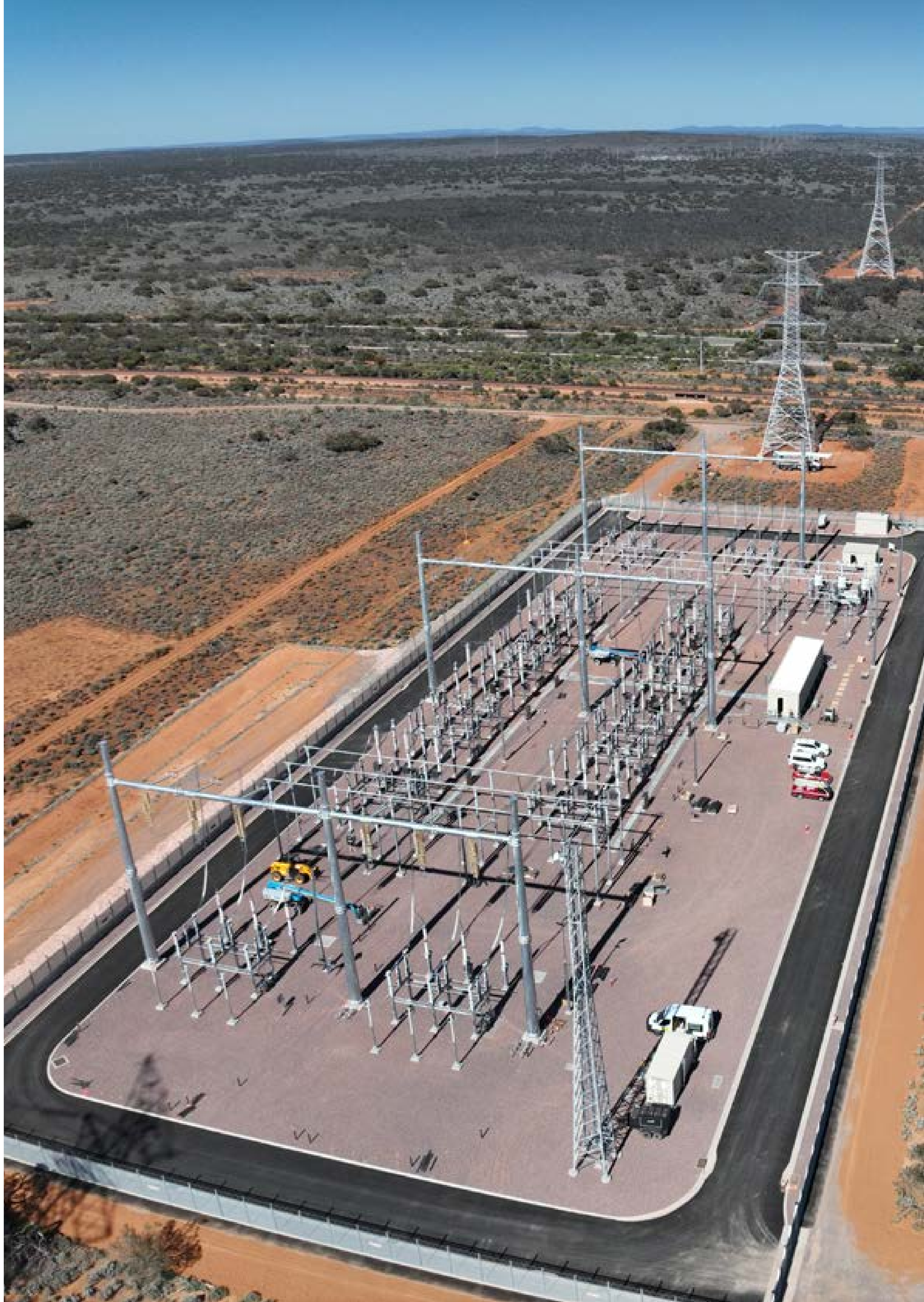
This final stage of the transition will occur alongside the prospect of substantial new load growth, increasing the importance of timely, least regrets transmission development and a step change in operating capability. In this environment, a system-wide planning focus must account for long asset lead times, asymmetric risks associated with underbuilding the network, and the need to retain flexibility as demand and policy conditions evolve.

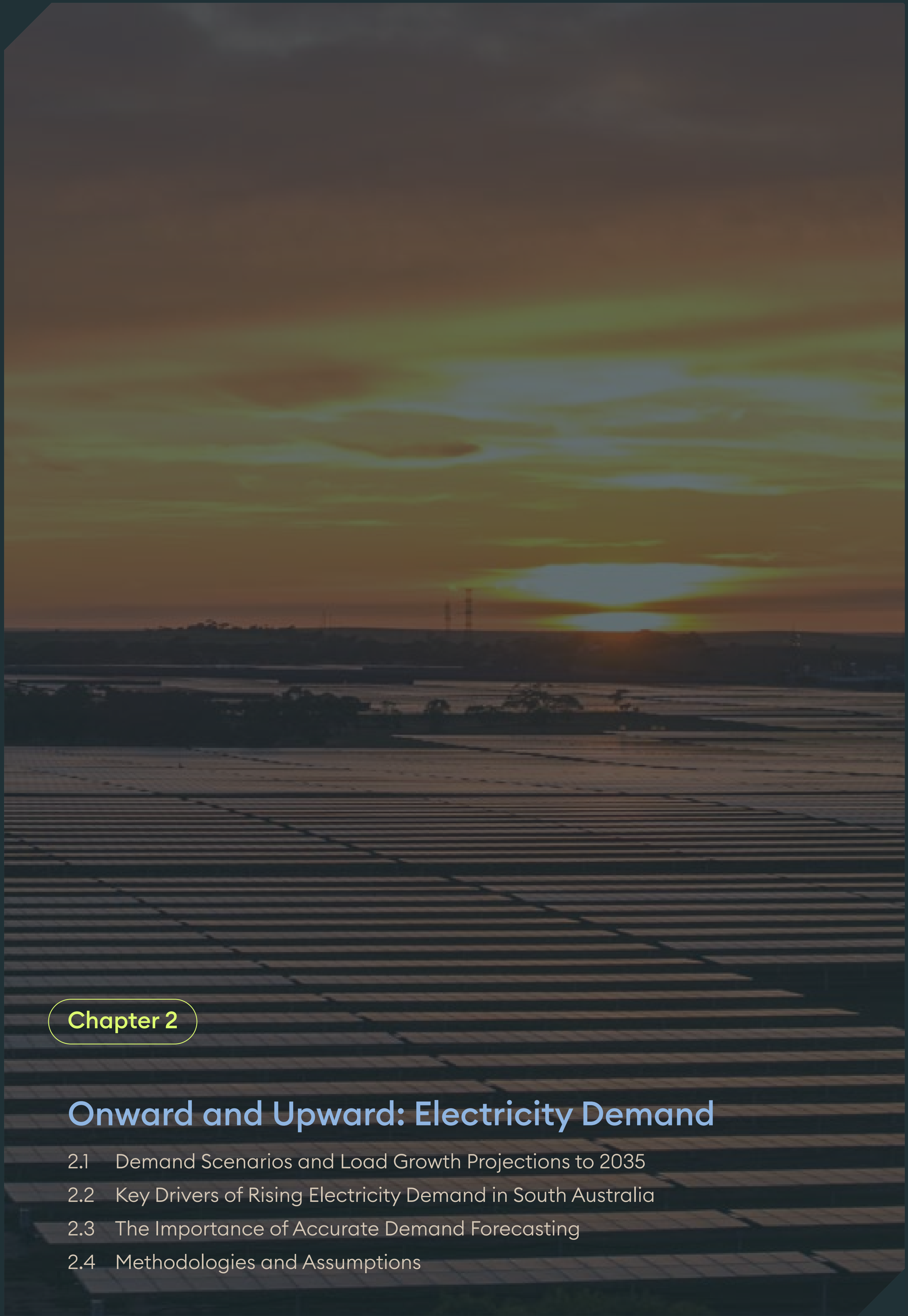
In this context, several priorities become central to enabling and sustaining periods beyond 100% VRE whilst enabling the connection of new industrial loads reliably and affordably:

1. **Staged reinforcement of the Mid North to Adelaide supply** as congestion increases and the metropolitan generation mix shifts. This includes refining augmentation options and trigger points as demand and connection commitments firm, and ensuring that network development supports efficient utilisation of high-quality renewable resources and storage located in the Mid North.
2. **Supplying emerging regional industrial hubs**, particularly in the Upper Spencer Gulf, Eyre Peninsula and other northern regions, through a backbone that can match credible load growth while maintaining reliability and security for existing customers.
3. **Strengthening complementary pathways and interfaces**, including the South East corridor and the ability to utilise interconnector capability when available, recognising that internal constraints can otherwise limit the value of exports and imports.
4. **Operability uplift for a high-IBR system**, including continued evolution of system strength arrangements, wider deployment of advanced protection and control schemes, enhanced monitoring and real time operational tools, and monitoring of the application and capabilities of grid forming technologies and new approaches to frequency and voltage management.
5. **Improved demand forecasting and spatial planning inputs**, given the increasing materiality of large industrial loads, the diversity of new load profiles, and the growing influence of CER on demand shapes and system conditions. This includes incorporating updated information on prospective loads and generator development pipelines, and ensuring that planning inputs remain aligned with observed connections activity and realistic delivery trajectories.

Time is of the essence – major transmission investments commonly require multiyear development lead times, and the cost of delayed delivery can be high: higher wholesale prices, increased curtailment of low cost renewables, tighter reliability margins, and reduced ability to accommodate new industrial and community demand at least cost. South Australia's progress to date demonstrates that operating and planning a high renewables power system is achievable, but it requires an adaptable, robust transmission backbone and a sustained focus on system strength, resilience and operability.

The remainder of the TAPR provides the detailed analysis underpinning these messages, including demand and generation outlooks, emerging network constraints and the project pathways intended to address them.





Chapter 2

Onward and Upward: Electricity Demand

Onward and Upward: Electricity Demand

South Australia is entering a period of exceptional electricity demand growth after decades of relatively flat demand, a dramatic reversal of the trend for over a decade.

Per ElectraNet's 2025 TAPR, the growth in demand is driven by a significant uptick in industrial activity, underpinned by supportive government policies, and set against the backdrop of a high VRE system. As such, ElectraNet is experiencing historically unprecedented levels of enquiry for network connection from prospective generators, prospective electricity users, and from existing businesses seeking to shift their processes to electricity. Securely, reliably and safely connect this growing demand with supply from renewable generation is the challenge and opportunity for ElectraNet over the next 25 years.

2.1 Demand Scenarios and Load Growth Projections to 2035

To plan for an uncertain future, ElectraNet and AEMO use scenario analysis to capture a range of plausible outcomes for electricity demand through 2035 and beyond.

Ensuring that the State is best placed and well informed from a planning perspective is instituting a rigorous demand forecasting approach. ElectraNet is working to ensure the many and varied inputs are understood, the risks of both under and over scoping are captured and managed, and the continued reliability and affordability of electricity in SA is maintained.

2.1.1 The ISP and South Australia

The AEMO Integrated System Plan (ISP) provides a comprehensive road map for the NEM and seeks to facilitate the efficient development and connection of renewable energy zones across it. The ISP models pathways to delivering the least-cost way to supply electricity to homes and businesses through to, predicated on:

- Generation being renewable
- connected with transmission and distribution
- firmed with storage
- backed up by gas-powered generation.

In doing so it identifies an Optimal Development Path (ODP) for development of the NEM, which will see existing fossil fuelled generators replaced with renewables, the addition of energy storage and other new forms of firming capacity, and reconfiguration of the grid to support two-way energy flow. The 2026 ISP defines several scenarios for the National Electricity Market, including South Australia:

- ***Step Change* (46% weighting – Most Likely)**: A rapid but structured transition with significant electrification and clean energy build-out, roughly aligned with current policies. This is treated as the "most likely" or central scenario in many planning processes.
- ***Accelerated Transition* (27% weighting)**: An ambitious scenario with very high electrification, faster economic growth (particularly in clean industries), and strong policy support, leading to substantially higher electricity demand – this reflects an upper bound or "high demand" future for SA.
- ***Slower Growth* (27% weighting)**: A slower-paced transition with more modest economic growth and slower technology adoption (yielding lower electricity demand growth).

By modelling different scenarios, AEMO can assess the impact of key uncertainties on the power system and identify the investments needed to ensure reliability, affordability, and sustainability in each case. This in turn informs key decisions about infrastructure, market design, and policy direction in the transition.

Since the 2024 ISP, AEMO through stakeholder consultation has made several changes, including:

- Renaming the *Green Energy Exports* scenario *Accelerated Transition* and increasing the weighting of this scenario to 27% from 15%
- Renaming the Progressive Change scenario *Slower Growth* and decreasing its weighting to 27% from 42%
- Increasing the weighting of the *Step Change* scenario to 46% from 43%.

The weightings attached to the scenarios continue to understate South Australia's expected economic development, advanced position in the energy transition, and significant interest in connecting new large industrial loads. For these reasons, ElectraNet does not see the Slower Growth scenario as relevant for investment planning and network development in South Australia.

2.1.2 Demand Scenarios in South Australia

In reality, trends suggest that South Australia's demand might be trending closer to a high-growth trajectory. Driven by the "once-in-a-generation" industrial expansion now underway, the state's electricity consumption could far exceed what earlier official forecasts assumed. ElectraNet's analysis, informed by current connection enquiries, shows a plausible pathway where annual energy consumption grows from roughly 12 TWh in 2025 to on the order of 30 TWh by 2040 under a central outlook – this is approximately 40% higher than AEMO's Step Change forecast for SA. In an even more accelerated case (if many major projects proceed), consumption could approach 50 TWh by 2040, roughly a fourfold increase of today's levels.

Per Figure 11, our projections to 2041 show significant demand growth in all but the most pessimistic scenario. Under a high industrial growth scenario, South Australia's total electricity consumption could realistically double or even triple compared to the mid-2020s, and peak demand could likewise soar to levels never before seen. For instance, ElectraNet's high-end estimates indicate a potential peak demand of around 7 GW by the late 2030s, up from -3.3 GW today, if multiple large industrial loads materialise. Even under more conservative outlooks, the direction is clearly upward – a stark change from historical trends where energy efficiency and rooftop solar growth once kept net demand growth low or negative.

Such an increase in load would also require the connection of commensurate levels of renewable generation to supply this load and maintain South Australia's 100% renewables target. ElectraNet would need to undertake substantial network augmentation and development to service this level of demand and generation growth. Most importantly, lead times for network development are generally longer than for load and generation development, underlining the importance of a sufficiently forward-looking approach to demand to support timely transmission planning and development.

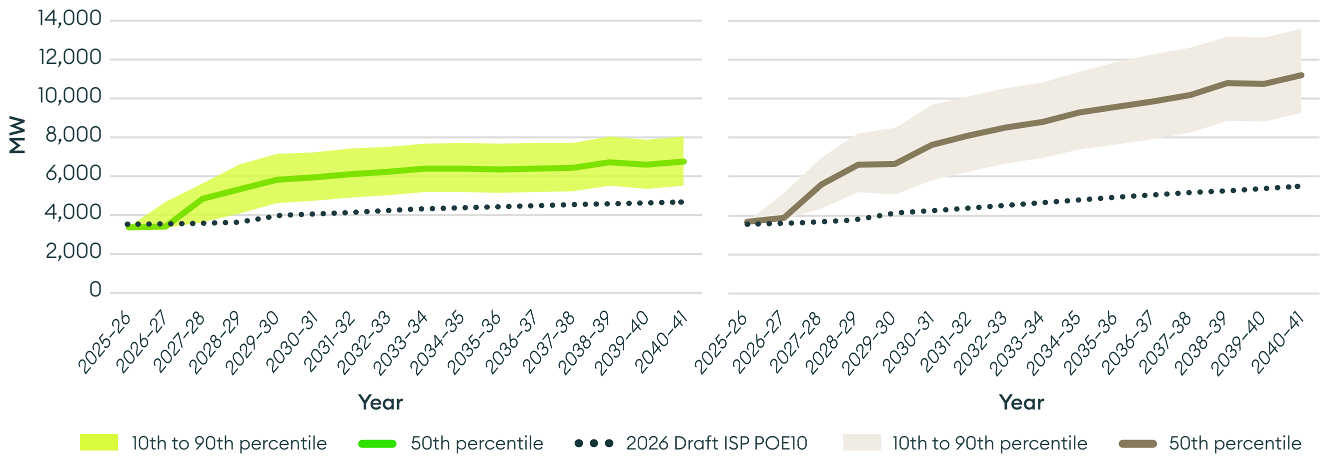


Figure 11: South Australian maximum demand and operational demand forecasts

It is worth noting that AEMO's scenarios include one called *Slower Growth*, which envisages sluggish economic conditions and minimal new large loads. In that scenario, South Australia's electricity consumption could remain relatively flat or even decline slightly in the long term. However, given the level of government commitment and private investment currently observed in SA, most stakeholders view a no-growth scenario as increasingly unlikely. Indeed, as of early 2026, the evidence points to robust growth: the South Australian government has publicly emphasized the alignment of its economic development agenda with net-zero, and many projects are already moving beyond the proposal stage. For planning purposes, therefore, ElectraNet places greater emphasis on the *Step Change* and high-growth (Accelerated) scenarios, while treating a stagnant demand future as lower probability. The next sections discuss what is driving this new demand, and how ElectraNet is refining its forecasting approach to ensure the transmission network is prepared for the range of outcomes.

In an environment of growing demand and rapid change it is critical that demand forecasts and scenario plans are sufficiently flexible to capture expected load growth, given the need to ensure timely and efficient transmission development to deliver the transition to net zero at least cost to consumers. Chapter 2 of this Report addresses demand considerations in greater detail.

2.2 Key Drivers of Rising Electricity Demand in South Australia

The dramatic upswing in projected demand is rooted in several converging trends.

The primary drivers of load growth in South Australia are linked to multiple factors, including the State's economic and energy transformation and the impacts of decarbonisation. The exact trajectory of both is uncertain but, as the nature of change in the electricity sector over the past 20 years has shown, fundamental change is not only possible but likely, and managing this risk is paramount.

The impact of the demand growth is expected to impact the scale and operation of the grid in different ways due to geographical, temporal, and economic factors. The below details how these factors pertain to each unique source of load.

2.2.1 Industrial Load Growth

South Australia is experiencing surging interest from large industrial customers to connect to the grid. The state's unique advantages, including world-class wind and solar resources and abundant mineral reserves, are attracting industries that seek low-cost clean energy for operations. Transmission-connected large industrial load (LIL) consumption is by far the single largest factor in South Australia impacting the nature of electricity demand. Its impact must be fully accounted for in determining required transmission infrastructure investments across the state, in both the immediate future and over the longer term.

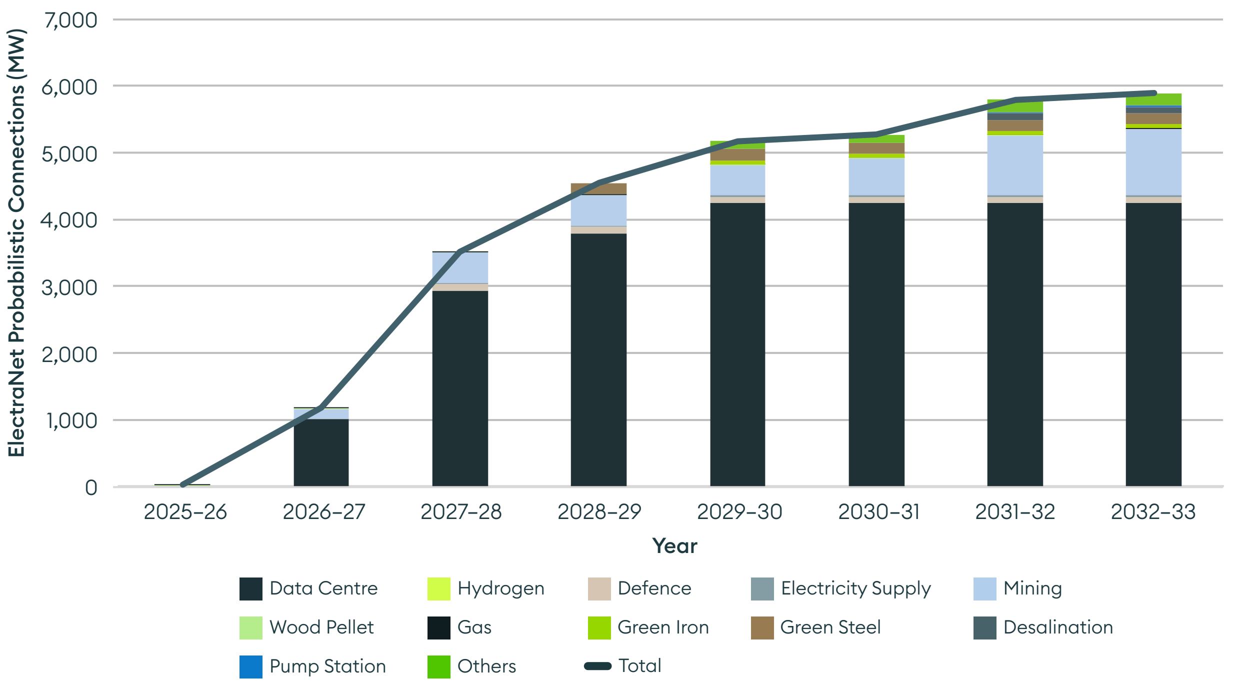


Figure 12: Cumulative prospective new customer connections – 2026 Draft ISP *Accelerated Transition* scenario

LIL consumption was once relatively modest in South Australia, making up less than 9% of the state's total load in 2009–10, but with its consistent growth this segment has increased its share of the pie, today (2024–25) representing 18% of electricity consumption.

The following highlights the industrial and economic drivers that are having the most material impact on consumption across the State.

Minerals processing for high tech industries

SA's geological endowment of critical minerals, including copper, graphite, rare earths, and magnetite, positions the state to expand value-adding processing powered by renewables. Government programs and geoscience initiatives are targeting discovery and processing capability to move exports up the value chain, with explicit links to decarbonisation of global supply chains.[6] As processing steps shift onshore, electricity intensity rises. The growing pipeline of rare earth exploration illustrates that, if developed with modern separation and solvent-extraction trains, a need for reliable power supply and process heat, reinforcing the likelihood of further electricity-intensive facilities in SA over the medium term.

Data centres and computational power

SA's digital economy is scaling quickly with Adelaide now hosting data centres designed for AI and high-density workloads. These centres can serve government, defence, space, health and mining clients, anchoring continuous, high load demand profiles that compound with AI adoption. As further needs emerge, aggregate loads can multiply, with redundancy requirements influencing local network planning. Market-wide, AEMO's outlook highlights data centres as a leading driver of rising electricity consumption over the next decade,[7] an early signal for SA that sustained growth in ICT loads will intersect with other industrial demand.

Steel production reinvigoration

The proposed transformation of the steel-making facilities at Whyalla, away from coal based steelmaking toward an electric arc furnace (EAF), coupled with a proposed direct reduction (DRI) plant, is pivotal to the future economic viability of the area in a low-carbon world.[8] The transformation will have materially higher electricity requirements and grid integration needs and is based on a strategic case for minimising gas lock-in and leveraging SA's renewable resource to underpin genuinely low emissions iron and steel, pointing to expanded, reliable power supply as a prerequisite for investment certainty.

Defence industry development

The Osborne Naval Shipyard precinct is entering a multi-year expansion phase to deliver Hunter class frigates and prepare for AUKUS submarine construction.[9] New production facilities, training academies, and advanced manufacturing lines will add steady industrial loads and specialised reliability requirements. Defence sector strategies project thousands of highly skilled jobs and long-duration programs, implying persistent electricity demand from shipyard operations and supply-chain SMEs across the metropolitan north-west, all depending on resilient, secure electricity and digital infrastructure.

Water management and desalination

The Northern Water Project is a $5 billion+ strategic infrastructure initiative in South Australia, proposing a large-scale desalination plant on the Spencer Gulf and a ~600 km pipeline to deliver water to the state's north.[10] The project addresses water scarcity in arid regions and underpins South Australia's green industrialisation strategy. The facility will be powered by renewable energy, requiring integration with new transmission assets.

Energy carriers and renewable energy transportability

SA's Upper Spencer Gulf is being positioned as a hydrogen export hub, with electrolytic hydrogen being fundamentally an electricity-derived energy carrier.[11] If the hydrogen sector develops, particularly with the state ambition being ~1.8 Mt by 2030, the increase in electricity demand associated will be significant and require investment in support infrastructure, including in the network.

The cumulative effect of these developments is extraordinary. Current connection enquiries with ElectraNet have reached an unprecedented scale. As of early 2026, over 75 prospective projects across 41 proponents are in discussions to connect to the SA transmission network, representing multiple times the state's current peak demand in potential new load by the 2030s. By comparison, in the decade between 2012 and 2022, only one new large industrial load of ~50 MW connected to the grid. Even if only a fraction of these materialises, the impact will be enormous: for context, adding just 1,500-3,000 MW of new industrial demand would raise SA's peak load by 50–100% over the 2024–25 peak of ~3,300 MW. Put another way, South Australia's total maximum demand (~3.3 GW) is much smaller than that of larger states like New South Wales (~13 GW). Thus, a handful of big industrial connections in SA can shift the demand trajectory far more dramatically in percentage terms than would be the case elsewhere.

[6] Energy & Mining | Green Iron and Steel Strategy
[7] Oxford Economics Australia | Data Centre Energy Demand Final Report
[8] Energy & Mining | South Australia's Green iron and steel strategy
[9] Department of State Development | Defence
[10] Northern Water | Project Overview
[11] Energy & Mining | Port Bonython Hydrogen Hub

2.3 The Importance of Accurate Demand Forecasting

Accurate electricity demand forecasting is critically important in the planning of transmission infrastructure.

Over-forecasting can lead to over-investment in capacity that isn't needed, burdening customers with unnecessary costs. Under-forecasting, on the other hand, risks the network being caught short, resulting in bottlenecks, reliability shortfalls, and the need for expensive last-minute solutions. In South Australia's current context, with its highly dynamic and fast-changing outlook, traditional forecasting methods have shown some limitations.

Timely and precise forecasting is essential to ensure the reliability and security of the grid on an ongoing basis in a world of demand growth. Without it, delays in connecting new industrial loads, generation, and storage projects could place upward pressure on costs and jeopardise the achievement of State and Federal policy objectives. ElectraNet continues to advocate for reforms to scenario modelling. These are needed urgently to support efficient infrastructure delivery and unlock the full potential of South Australia's clean energy future.

2.3.1 Limitations of Current Forecasting Models

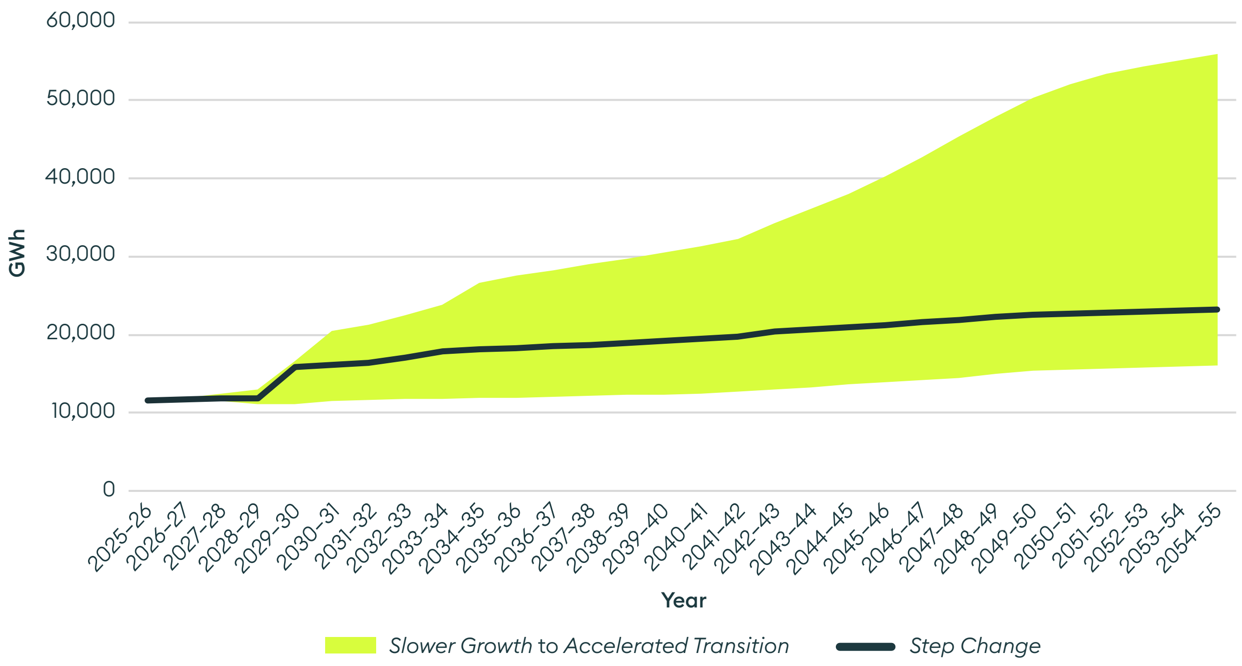


Figure 13: The range of AEMO operational demand forecast – Slower Growth through Accelerated Transition

ElectraNet's view on AEMO's official forecasts and ISP modelling is that whilst fairly comprehensive they have historically been conservative in reflecting the step-change in SA's economic transition and electrification. Their review of their approach to demand forecasting, as incorporated initially in the 2025 Electricity Statement of Opportunities (ESOO), has made progress on several fronts, including broadening the inclusion of anticipated loads and specific approaches for large emerging sources of industrial load, picking up some of the recommendations made in the 2025 ElectraNet TAPR. These changes will result in demand forecasts at the National level closing the gap on our state-level forecasts and planning activities, but more needs to be done.

While AEMO's updated methodology incorporates some recommendations and represents an advancement in forecasting practice, the residual methodological discrepancies highlight ongoing limitations. These limitations include:

- Too narrow a scope and a lack of flexibility of load inclusion
- Alignment of forecasts with diverse planning needs
- Detail and applicability of spatial resolution
- Tracking of emerging demand sectors.

Amongst and above all these is the pace at which forecast demand changes and prospective loads emerge, given the prospective load interest ElectraNet is receiving. Given our role in SA, ElectraNet has significantly more up-to-date information on the interest in connection, which is translating into major differences between forecast represented in the ISP and ElectraNet's planning processes. Addressing these limitations will be critical to enhancing the robustness, responsiveness, and practical utility of electricity demand forecasts in the evolving energy landscape.

Accurate and adaptive forecasting is more important than ever. South Australia's experience, where official forecasts have had to be repeatedly revised upward as industrial plans solidify, shows the perils of anchoring on business-as-usual in a time of transformation. The ISP, as a strategic plan, must err on the side of least regrets when dealing with deep uncertainty, which, in this case, means preparing for high demand growth and ensuring SA is not left with insufficient network capacity. AEMO has been receptive to these concerns through joint planning discussions, and we will continue to work for uplift to forecasting processes that better reflect South Australia's situation.

2.4 Methodologies and Assumptions

To capture the drivers described above and to mitigate the shortcomings in external forecasts, ElectraNet employs a comprehensive, evidence-based demand forecasting methodology for the planning purposes.

Our approach is designed to ensure that the transmission development program is robust under a range of futures and that it triggers investment at the right time – neither too early such that assets sit underutilised, nor too late such that they cannot meet urgent needs.

ElectraNet's methodology combines:

- The demand forecasts of the three scenarios produced by AEMO for their ISP modelling, minus the inclusion of large industrial loads per AEMO's methodology
- Assessment of anticipated large industrial loads seeking connection to the ElectraNet network
- Probabilistic forecast of longer-term demand growth.

This approach provides a comprehensive view of future demand, accounting for both committed and probable developments.

2.4.1 Data Sources and Collaboration

ElectraNet's demand forecasting process integrates data and insights from multiple sources to produce robust, actionable forecasts. The methodology is designed to support timely and efficient transmission development, minimising risks to customers and communities.

Integration of Multiple Data Sources

We combine insights from AEMO, SAPN, and our own customer interactions:

- AEMO's state-wide demand forecasts for South Australia serve as a foundation for each scenario, ensuring consistency with the broader NEM-wide context. From these, we subtract out AEMO's embedded assumptions about new large industrial loads, to avoid double counting, especially now that AEMO's 2025 ESOO includes some anticipated and proposed LILs in South Australia.
- We then add our independent assessment of additional large industrial loads based on the extensive pipeline of connection enquiries we are tracking. This involves assigning each prospective project a likelihood of progressing (e.g. certain, likely, possible) informed by its development status, government support, and proponent engagement.
- Finally, we overlay a probabilistic long-term growth outlook to capture the potential for further load increases (or decreases) beyond known projects – effectively bracketing the high end of demand if many more opportunities emerge or, conversely, if some expected projects falter.

Collaboration with SA Power Networks and Other Stakeholders

As a significant portion of demand growth and CER uptake manifests in the distribution network, we collaborate closely with SAPN, who produce detailed 20-year connection point forecasts for substations across SA. These forecasts reflect local trends like housing development, small business growth, and distributed generation. These are initially derived from AEMO's state-level forecasts, often aligned with AEMO's Step Change scenario, and then adjusted for rooftop PV and other factors at the distribution level. ElectraNet works with SAPN to ensure that our top-down state forecasts are reconciled with bottom-up distribution forecasts, accounting for differences such as embedded generator output and any major loads that might be connected to the lower-voltage network.

We also engage with large customers and project developers directly to gather the latest information on their plans and timelines, and we maintain open channels with the SA Government's energy and economic development agencies to incorporate relevant policy-driven insights, for example, expected timing of government-supported projects such as the Northern Water initiative.

This collaborative approach ensures our forecasts are grounded in the most current and granular information available, rather than relying solely on high-level economic trends.

2.4.2 Integration with AEMO Forecasts

ElectraNet's forecasting methodology is closely aligned with AEMO forecasts but with adaptations to ensure that the demand forecasts published here are specific to the unique nature of South Australia and inclusive of our insights into connections activity. In August 2025, AEMO published state-level forecasts for maximum and minimum electricity demand in South Australia as part of the 2025 ESOO, split across the three scenarios – *Slower Growth*, *Step Change* and *Accelerated Transition*.

ElectraNet's methodology is broadly aligned with AEMO's scenario framework in that we use the same scenario definitions, e.g. Step Change, etc., and core assumptions about macroeconomic drivers, population, national policy, etc., for consistency. However, we introduce key differences to better reflect the SA context:

- We include a larger and more probable set of new large industrial loads than AEMO's base forecasts. As discussed, AEMO's 2025 ESOO began incorporating proposed LILs but still excludes many projects that haven't reached the formal connection application stage. ElectraNet's view is that the probability-adjusted sum of likely new industrial developments is much higher than what AEMO has in its Step Change and Accelerated Transition scenarios for South Australia. We therefore explicitly add these to our forecasts, effectively creating a more aggressive demand trajectory for SA.
- We apply a probabilistic weighting to potential LIL connections based on criteria similar to, but broader than, AEMO's. For example, if a project has secured financing and permits for an expansion, we may treat that as a high-probability addition, whereas a speculative project in early concept stage might be included under a lower probability or only in the high scenario. This approach acknowledges uncertainty but avoids the pitfall of waiting for absolute certainty before acknowledging a load in the forecast, a wait that could leave the network underprepared.

The below highlights how ElectraNet models several demand scenarios off the AEMO core scenarios to capture a range of future possibilities:

1. **Baseline Scenario (*Step Change*)**
    a. The baseline scenario is derived from AEMO's Step Change scenario
    b. Includes anticipated large industrial loads meeting defined commitment criteria
    c. Additionally incorporates a probabilistic forecast of longer-term demand growth
2. **High-Growth Scenario (*Accelerated Transition*)**
    a. Derived from AEMOs Accelerated Transition scenario
    b. Includes all anticipated projects on a probabilistic basis
        i. Projects with government support or high likelihood of development are included at a higher probability
        ii. Hydrogen hubs are included at a low probability (~10%), resulting in a wide range of possible outcomes
3. **Low-Growth Scenario (*Slower Growth*)**
    a. Derived from AEMOs Slower Growth scenario
    b. Includes only the large industrial loads that meet the committed or anticipated criteria, per the AEMO Electricity Demand Forecasting Methodology released in August 2025.
    c. Reflects conservative assumptions about future demand growth

As a result of the ElectraNet approach, the core demand forecasts only include the potential for near to medium-term large industrial load customers with a high probability of connection. The higher-growth scenario included all anticipated projects, scaling all on a probabilistic basis.

Scenario Probabilities

The probabilistic approach to long-term load forecasting is done by assessing the weighted probability of connection success for proposed large industrial loads seeking connection with ElectraNet. The assessed weighted probability indicates the likelihood of a LIL completing the connection process and achieving energisation.

The assessment is based on information and data provided by the proponent during the connection process, supplemented by publicly available data. The assessment ranks each load against criteria such as government policy support, progress through the formal connections process and demonstration of commercial and financial strength. The assessment does not take into consideration detailed market analysis of historic or forecast commodity pricing, demand patterns, or supply volatility, which could affect project viability.

The weighted probability is calculated by scoring the proposed LIL project against each criteria and the resulting outcome will be used to build the load forecast and inform our proposed load register.

2.4.3 Forecast Revision and Application

ElectraNet updates its demand forecasts annually as part of the TAPR process, incorporating the latest information from all sources. The forecast used in this 2026 TAPR leverages the AEMO Draft 2026 ISP data, which already reflects some methodological improvements, such as including proposed LILs to a degree. Additionally, we factored in several new large connection enquiries received in late 2025/early 2026 that were not included in AEMO's data, given our confidence in their eventual progression.

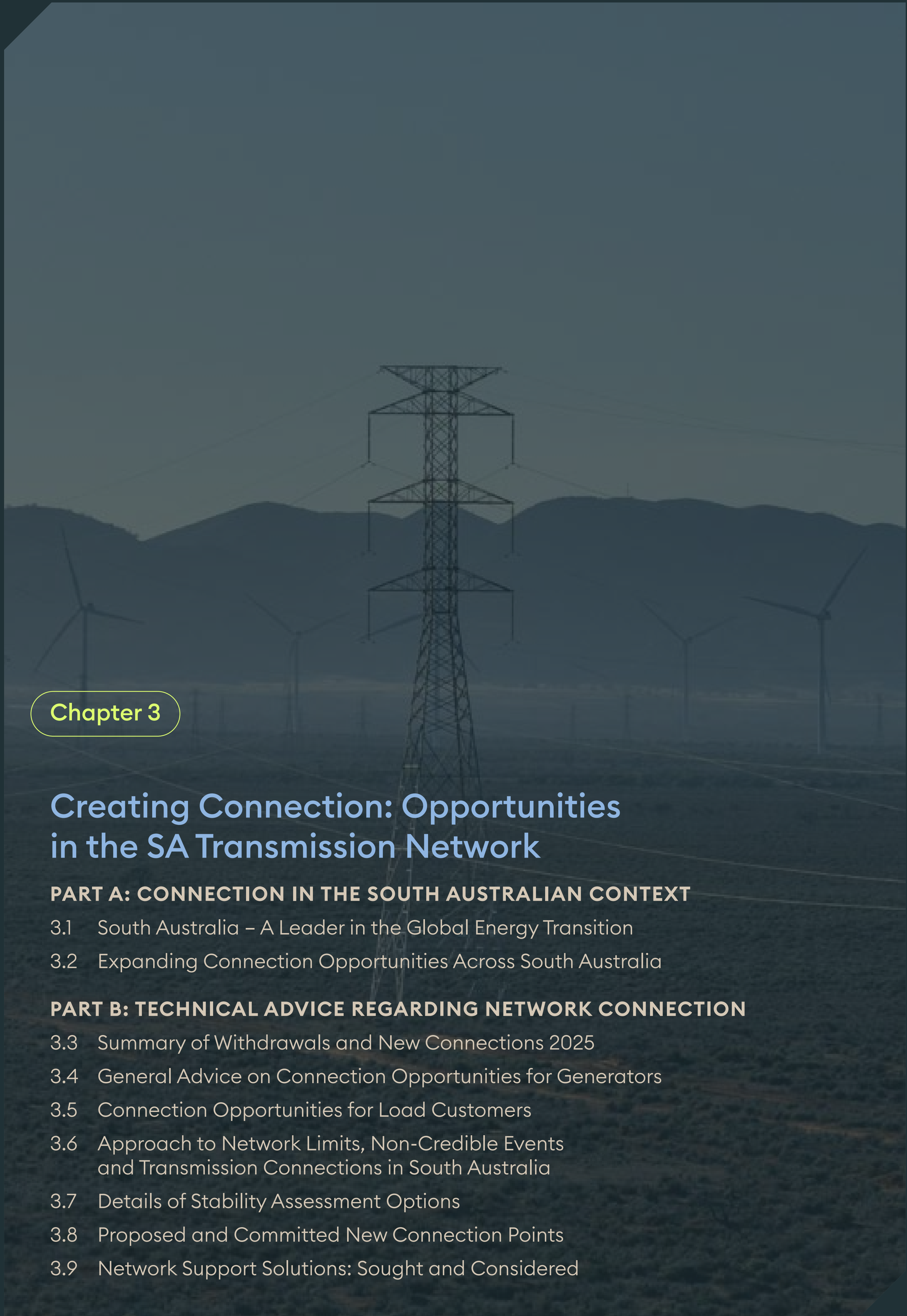
Once the TAPR is published, we continue to collaborate with AEMO, providing them our insights and data for consideration in their final 2026 ISP. In turn, when AEMO releases the Final ISP, expected in mid-2026, we will review and potentially update our plans if new material information arises. In this way, forecasting is an iterative, continuous process, not a one-off exercise. The outputs directly inform project timing, e.g., when we expect network limits to be reached under each scenario, regulatory applications for project approvals, which require demonstrating need under forecast conditions, and the design of non-network solutions or operational measures that might defer or complement network investments.

2.4.4 Principles and Assumptions Underpinning the Forecast

Our forecasting approach is underpinned by clear principles. We adopt a neutral base-case outlook that incorporates current policy settings, e.g., the renewable targets and electrification initiatives in place, and known committed projects. Upon that foundation, we layer scenario-specific assumptions:

- **Economic growth and policy**: We assume the successful implementation of announced policies like the State Prosperity Project initiatives in the Step Change and high scenarios, driving substantial industrial demand (with variations in timing and scale between scenarios). In the Slower Growth case, we assume delays or failures in some of these initiatives, leading to fewer new loads.
- **Large industrial loads**: For each identified potential LIL project, we make an assumption on its timing (earliest feasible connection year) and eventual demand (in MW and energy). In Step Change, we include only those with a high likelihood, e.g., meeting several of AEMO's commitment criteria or having government backing. In Accelerated Transition, we include a greater number of projects (assuming more optimistic economic conditions and technology readiness), capturing the upper range of interest, e.g. hydrogen projects, multiple new mines and processing plants. We avoid assumptions that all such projects proceed, but we do assume more than AEMO's central case, given the policy environment. Our probabilistic methods then create a distribution of outcomes around these core assumptions.
- **Scenario consistency and commitment criteria**: Loads included in multiple scenarios retain the same probability across those scenarios and only LILs meeting AEMO's commitment criteria (classified as anticipated or committed) are included in short-term forecast.

By adhering to these principles and assumptions, ElectraNet's demand forecasting aims to present a realistic and transparent picture of South Australia's electricity future, one that is directly tied to the planning and decision-making for new infrastructure. We continually refine this approach, for instance, lessons from the 2025 TAPR, which highlighted the need for improved demand forecasting at the national level, have been used to further enhance this 2026 TAPR's analysis. The outcome is a set of forecasts that we believe properly reflect the magnitude of the coming "electrification wave" in South Australia, ensuring that our Transmission Annual Planning Report remains a robust guide for investment in the safe, reliable, and efficient development of the South Australian electricity transmission system in the decade ahead.



Chapter 3

Creating Connection: Opportunities in the SA Transmission Network

3.1 South Australia – A Leader in the Global Energy Transition

As the owner and operator of South Australia's electricity transmission network, ElectraNet is playing a central role in the provision of novel network engineering solutions to meet the 'once in a generation' challenges and opportunities presented by the energy transition.

ElectraNet has decades of experience delivering connections within the NEM and confidently provides clients with high voltage electricity transmission services, facilitates new connections and provides highly reliable electricity transmission services to customers.

South Australia has one of the most advanced electricity networks in the world, regularly achieving 100% instantaneous variable renewable energy, driven by its world-leading uptake of grid scale renewable energy resources and rooftop solar PV.

The Government of South Australia has set an ambitious agenda aimed at meeting its net 100% renewables target by 2027; decarbonising the state's economy; developing new sources of renewable generation linked to Renewable Energy Zones (REZ); and enabling development of green industries proximate to, and supported by, renewable generation. The Hydrogen & Renewable Energy Act 2023 is being used to open new parts of the state for renewable energy project development, with the Government of South Australia recently consulting on the Gawler Ranges East and Whyalla West proposed release areas, which span approximately 5,200 km² and 6,500 km² respectively on the Upper Eyre Peninsula.

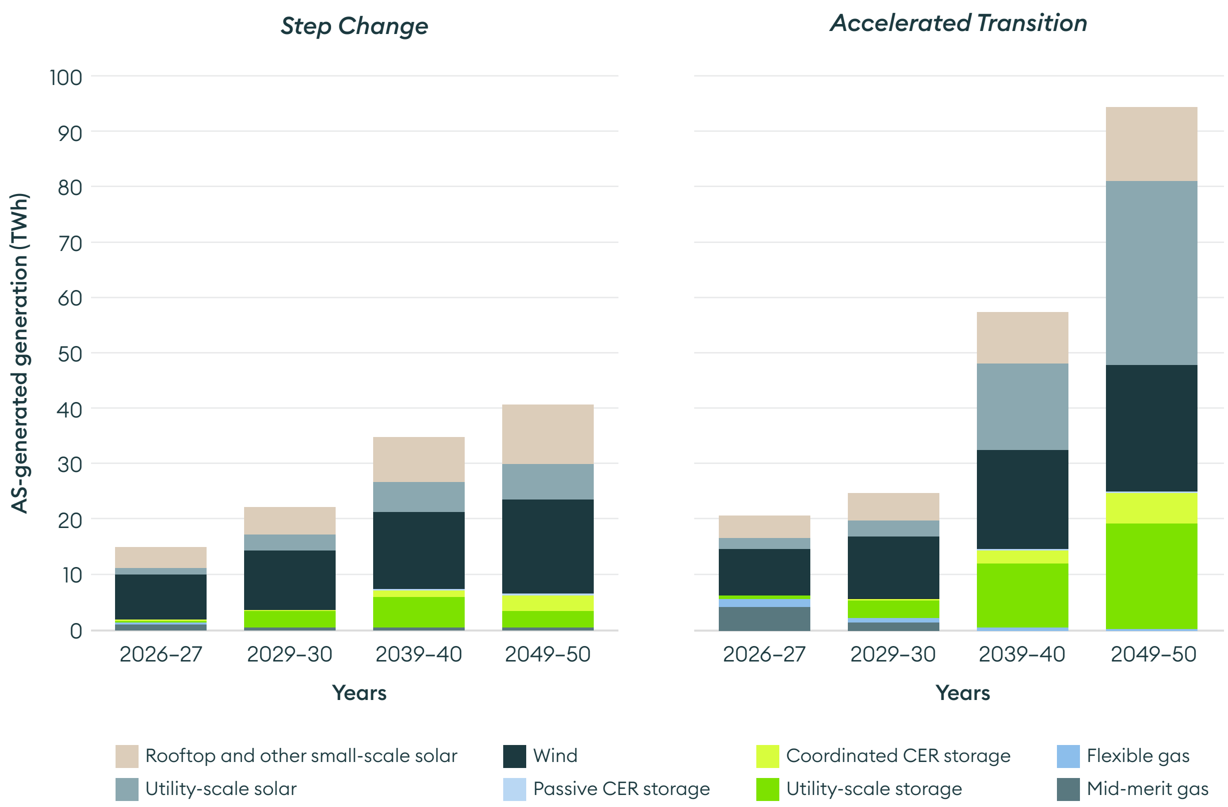


Figure 14: Comparison of future generation outlooks in the 2026 Draft ISP *Step Change* and *Accelerated Transition* scenarios

Recognising the need for forward planning, to coordinate connection of new generation and new loads to the transmission network, ElectraNet seeks to work collaboratively with customers to ensure efficient and timely connection to the transmission network.

We encourage proponents to engage with ElectraNet early from the project's inception to ensure ElectraNet can adequately plan the network to deliver the best outcomes for the community and maximise utilisation of the proponent's plant.

ElectraNet welcomes connection inquiries and encourages interested parties to contact its Corporate Development Team: connection@electranet.com.au

Further detail about the connection services ElectraNet offers can be found on the website.[12]

[12] ElectraNet | Connection Capabilities

3.2 Expanding Connection Opportunities Across South Australia

ElectraNet's Network Transition Strategy is focused on the timely and efficient development of transmission infrastructure to support South Australia's energy transition.

New transmission is essential to connect renewable generation and storage to existing customer demand, and to meet increasing demand from electrification and emerging industrial loads. Through this strategy, ElectraNet identifies key geographic regions where the best opportunities for transmission network connection are available, encouraging proponents to consider locations that align with their project needs.

Riverland Region
Project EnergyConnect (PEC)

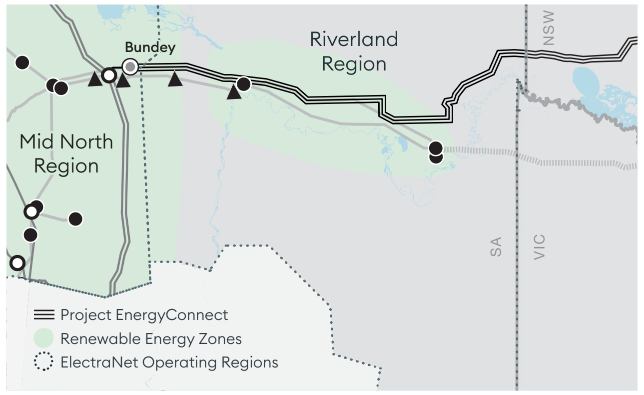


Figure 15: Project EnergyConnect

Project EnergyConnect (PEC) is a transformative interconnector between South Australia and New South Wales, with full capacity release expected in 2027. The South Australian component of PEC enhances system security and resilience, while enabling increased renewable energy development and export opportunities.

A key milestone in PEC's delivery is the completion of Bundey substation – South Australia's first 330 kV substation. Bundey facilitates interstate power exchange and serves as a central hub for future renewable integration. It houses the State's largest electricity transformers, critical for managing power flows across this new energy corridor.

Potential Connection Types:

- **Generation**: Utility-scale solar and wind farms, battery energy storage systems (BESS).
- **Load**: Agricultural processing, regional manufacturing, interconnector support infrastructure.

Eyre Region
Eyre Peninsula Upgrade

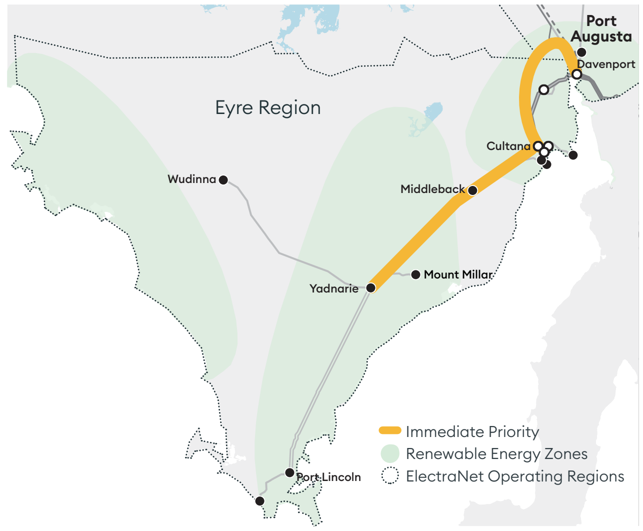


Figure 16: Eyre Peninsula Upgrade

The completion of the Eyre Peninsula Link in 2023 significantly increased capacity for new connections in the region. It enables renewable energy projects to connect to the network and lays the foundation for future expansion.

The upcoming Eyre Peninsula Upgrade, which could be delivered as soon as 2028, will further enhance transmission capacity by enabling the Cultana–Yadnarie lines to operate at 275 kV (up from 132 kV). This upgrade will support additional loads and generators, making the Eyre Peninsula a key area for new energy developments.

Potential Connection Types:

- **Generation**: Wind farms, solar farms.
- **Load**: Mining operations, remote communities, agricultural processing.

Mid North Region
Northern Transmission Project (NTx)

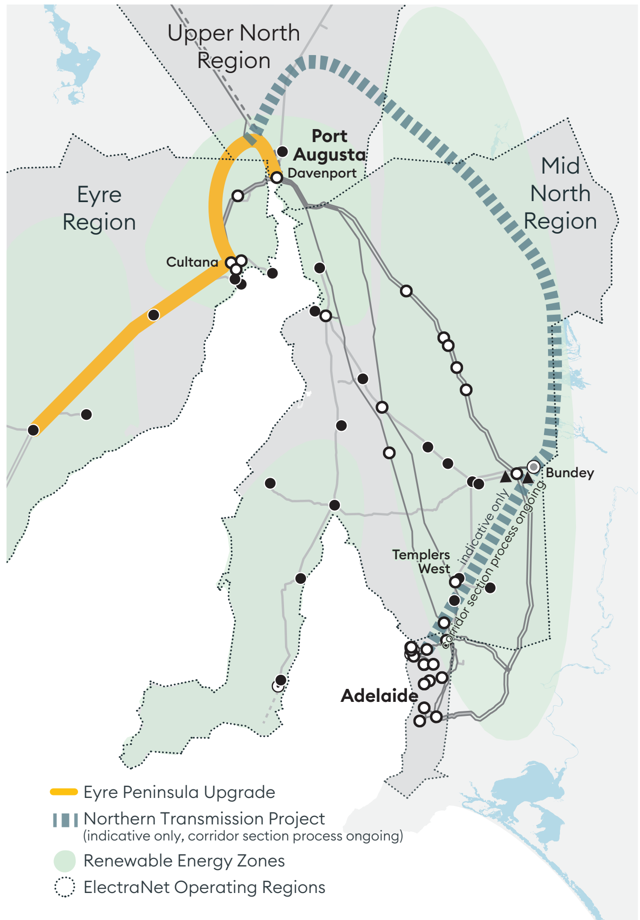


Figure 17: Northern Transmission Project

The Northern Transmission Project (NTx) is designed to extend the transmission network's footprint and capability across the northern and eastern parts of South Australia. This region is experiencing significant growth in mining, renewable generation, green iron and steel production, and other industrial developments. NTx will unlock access to these resources and support projected demand growth.

The southern component of NTx will also enable higher transfers of electricity to Adelaide, enhancing supply security through a diverse transmission path as the city's energy mix becomes increasingly reliant on remote generation sources.

Potential Connection Types:

- **Generation**: Large-scale solar farms, wind farms, and hybrid renewable projects.
- **Load**: Mining operations, green hydrogen and steel manufacturing, industrial precincts.

South East Region
South East Expansion

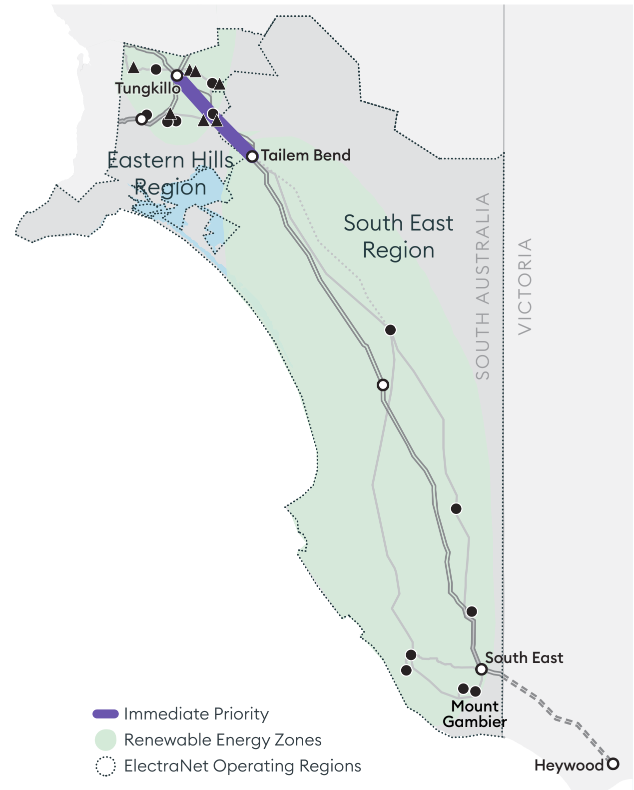


Figure 18: South East Expansion

ElectraNet's analysis of the South East Expansion has identified substantial benefits for the region. This initiative aims to improve access to the transmission network and support future energy developments. ElectraNet is planning to initiate a stand-alone Regulatory Investment Test for Transmission (RIT-T) to progress this project, reinforcing its commitment to strategic network growth in the South East.

Potential Connection Types:

- **Generation**: Biomass, wind energy, and distributed energy resources.
- **Load**: Timber processing, food manufacturing, regional industrial hubs.

Part B: Technical Advice Regarding Network Connection

ElectraNet is committed to providing timely and accurate advice to customers and stakeholders regarding connection opportunities to the transmission network.

The South Australian network is subject to jurisdiction-specific operating requirements that proponents should understand when considering connection.

ElectraNet aims to provide advice to proponents so that they understand underlying factors relevant to generation and load connection in South Australia; and to ensure that their connection decisions are informed by best-available technical information.

Considerations relating to connection to ElectraNet's transmission network are set out in greater detail below.

This section provides advice on the following:

- Withdrawals and new connections
- Connection opportunities for generators
- Connection opportunities for load customers
- Approach to network limits, non-credible events and transmission connections in South Australia
- Changes to ElectraNet's stability assessment process
- Proposed and committed new connection points
- Projects for which network support solutions are being sought or considered.

Network Capacity for Connections Reports

ElectraNet released the first in a series of Network Capacity for Connections Reports in 2025, setting out connection opportunities on a region-by-region basis. These reports replace the extensive technical data that has previously been provided via the 'Summary of Connection Opportunities' section in previous TAPRs. The first report of the series, focusing on the Mid North providing an update of hosting capacity in that part of the state, is publicly available on the ElectraNet website.[13]

[13] ElectraNet | Assessment of Network Capacity for Connections Report 2029

3.3 Summary of Withdrawals and New Connections 2025

ElectraNet provides a summary of South Australian generator connections, generator withdrawals, commitments to connect, and announcements of intention to withdraw (Tables 1–3).

This summary provides an update on data and advice on changes that have occurred since release of the 2024 TAPR.

A full accounting of expected retirements and connection status is available on AEMO's website.[14]

Table 1: Critical Generator Retirements

Generators	Type	Size	Closure date
Torrens Island B	Turbine – Steam Sub Critical	800 MW	Unit 1 – June 2026 Unit 2/3/4– June 2028
Osborne	Turbine -- CCGT	180 MW	December 2027
Port Lincoln GT	Turbine – OCGT	74 MW	January 2028
Snuggery	Turbine – OCGT	84 MW	January 2028
Pelican Point	Turbine – CCGT	522 MW	2037

Table 2: Potential dispatchable generator withdrawal

Generators	Type	Size	Potential Closure date
Dalrymple BESS	BESS	30 MW	2030
Dry Creek	Turbine – OCGT	156 MW	2030
Mintaro	Turbine – OCGT	90 MW	2030
Lake Bonney BESS	BESS	25 MW	2034
Ladbroke Grove	Turbine – OCGT	80 MW	2035

Table 3: Potential renewable generator withdrawal

Generators	Type	Size	Potential Closure date
Cathedral Rocks	Wind	62 MW	2030
Wattle Point	Wind	90 MW	2031
Snowtown	Wind	98 MW	2033
Canunda	Wind	46 MW	2035
Hallett Stage 2 Hallett Hill	Wind	71 MW	2035
Lake Bonney 1	Wind	80 MW	2035

[14] AEMO | Generation information

Table 4: Generators that have connected since June 2025 or have entered service, are committed or anticipated to connect in future

Generators	Type	Size	Status/ Status Date
Lincoln Gap BESS	Battery – Storage	10 MW 10 MWh	Committed Mar 2026
Bungama Solar	Storage – Battery	150 MW 300 MWh	Committed May 2026
Clements Gap – BESS	Storage – Battery	60 MW 120 MWh	Committed CIS SA-VIC tender May 2026
Summerfield BESS	Storage – Battery	240 MW 960 MWh	Committed Nov 2026
Tailem Bend Stage 3	Storage – Battery	204 MW 408 MWh	Committed Apr 2027
Pelican Point BESS	Storage – Battery	200 MW 400 MWh	Committed July 2027
Carmody's Hill Wind Farm	Wind	247 MW	Committed CIS Tender 4 Jan 2029
Lindley BESS	Storage – Battery	100 MW	Anticipated Jun 2027
Hallett BESS	Storage – Battery	50 MW 200 MWh	Anticipated CIS SA-VIC tender Jun 2027
Solar River	Solar Storage – Battery	255 MW 256 MW 650 MWh	Anticipated CIS SA-VIC tender Nov 2027
Reeves Plains	Storage – Battery	250 MW 1000 MWh	Anticipated CIS Tender 3 Feb 2028
Goyder BESS	Storage – Battery	300 MW 800 MWh	Anticipated May 2028
Emeroo BESS	Storage – Battery	225 MW 212 MWh	Anticipated Dec 2028
Goyder North Wind Farm	Wind	600 MW	Anticipated CIS Tender 1
Carmody's Hill BESS	Storage – Battery	118 MW 247 MWh	Anticipated Jan 2030
Mannum Solar Farm 2	Solar	30 MW	In commissioning
Mannum BESS	Storage – Battery	100 MW 200 MWh	In Service Sep 2025
Templers BESS	Storage – Battery	111 MW 291 MWh	In Commissioning
Palmer Wind Farm	Wind	274 MW	CIS tender 1

Table 4: Generators that have connected since June 2025 or have entered service, are committed or anticipated to connect in future (cont.)

Generators	Type	Size	Status/ Status Date
Limestone Coast West BESS	Storage – Battery	250 MW 750 MWh	CIS SA-VIC tender
Koolunga BESS	Storage – Battery	200 MW 800 MWh	CIS Tender 3 June 2026
Bundey BESS and Solar	Solar Storage	475 MW 300 MW 1200 MWh	CIS Tender 4
Willogoleche 2 Wind Farm	Wind	108 MW	CIS Tender 4

3.4 General Advice on 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).

Location-Specific Advice

Generators should note the following advice applicable to connections in the locations listed below:

- Connections on the Davenport – Bungama – Blyth West – Munno Para – Para 275 kV lines will be subject to constraints or forced outages under N-1 conditions, and may become increasingly subject to constraints at times of high aggregate generation output under system normal conditions.
- Connections on the Davenport – Brinkworth – Templers West– Para 275 kV lines will be subject to constraints or forced outages under N-1 conditions.
- Connections on the Davenport – Robertstown 275 kV lines may become subject to constraints under N-1 conditions.
- Connections on the Torrens Island – Le Fevre – Pelican Point – Parafield Gardens West – Para 275 kV lines may be subject to constraints under N-1 conditions and may become subject to constraints at times of high aggregate generation output under system normal conditions.
- Generation connected anywhere from Tungkillo through to Tailem Bend and South East may be subject to co-optimised dispatch with the Heywood interconnector, due to its potential impact on the ability to import power from Victoria and the rest of the NEM.
- Connection between Tailem Bend and South East is complicated by series compensation at Black Range and may not be cost effective. We are examining whether alternative network configurations may be able to address these complications.
- 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. For Robertstown and Cultana respectively, Bundey and Cultana East are suitable sites for proponents to connect. With regards to Davenport, the potential development of the Narcoona substation will provide opportunities for proponents to connect.
- At times of coincident high wind generation output and high solar generation output, including from distributed rooftop solar PV, generation constraints can be significantly more onerous than presented in section 3.5 (below), constrained by SA's export capability. Conversely, such conditions could be favourable for energy storage proposals. 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. Existing maximum fault levels are also 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.

Technical Considerations for New Connections

Technical considerations that apply to new connections in South Australia are provided in Appendix E of this report.

3.5 Connection Opportunities for Load Customers

ElectraNet advises that almost any point in the proximity of the Main Grid 275 kV transmission system and the 132 kV sub-transmission system should be suitable for a new load to connections. Substantial load connections may require coordination with deep network augmentation and this may come at a cost to the proponent.

An under-voltage load shedding scheme is 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.

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

3.6 Approach to Network Limits, Non-Credible Events and Transmission Connections in South Australia

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

TNSPs make extensive efforts to ensure that their network will withstand stress conditions in accordance with obligations under the Rules alongside upholding stringent electricity industry standards as a matter of operational practice.

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

A credible contingency event is defined in clause 4.2.3(b) of the Rules as an event which AEMO considers reasonably possible in the surrounding circumstances, such as the unexpected loss of either one generating unit in South Australia or a single item of transmission plant such as a single circuit of a transmission line.

The power system is generally designed to withstand these events without disruption to customers.

A non-credible contingency event is defined in clause 4.2.3(e) of the Rules as a contingency event that is not a credible contingency event, therefore an event that AEMO does not consider reasonably possible.

The example given in the Rules includes the simultaneous failure of multiple elements. The power system is not necessarily designed to withstand these without disruption but there is an expectation that emergency controls such as load or generation shedding will reduce but not eliminate the probability of cascading failure following this type of event. It would be prohibitively expensive to design and build a transmission system that can withstand any and all non-credible contingencies.

To date, ElectraNet has planned and operated the power system to withstand the loss of the single largest generating unit in South Australia without disruption. Historically, that was a Northern Power Station generating unit at 273 MW.

In practice, therefore, ElectraNet has sought to ensure that South Australia's electricity transmission network could continue to operate securely even if 273 MW of generation was lost unexpectedly.

More recently the Snowtown 2 wind farm and Port Augusta Renewable Energy Park have been connected which are now the equal largest credible contingencies in South Australia at 273 MW each.

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

Accordingly, ElectraNet's approach to managing the network has become to identify the maximum amount of generation or load that could be lost and the network maintained without disrupting others (i.e. without activating load or generation shedding schemes).

The focus has been on the total load or generation quantity whose loss could be sustained without disruption. This then defines the largest credible contingency.

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

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

Recent ElectraNet studies have shown that the maximum allowable generation loss under a credible contingency event is limited to:

- 270 MW in Adelaide and the South East
- Up to 400 MW in the Mid North

ElectraNet and AEMO (as the market advisory body for connections) work with connecting parties to ensure that their plant design incorporates the ability to maintain the single largest contingency at the value currently defined within South Australia.

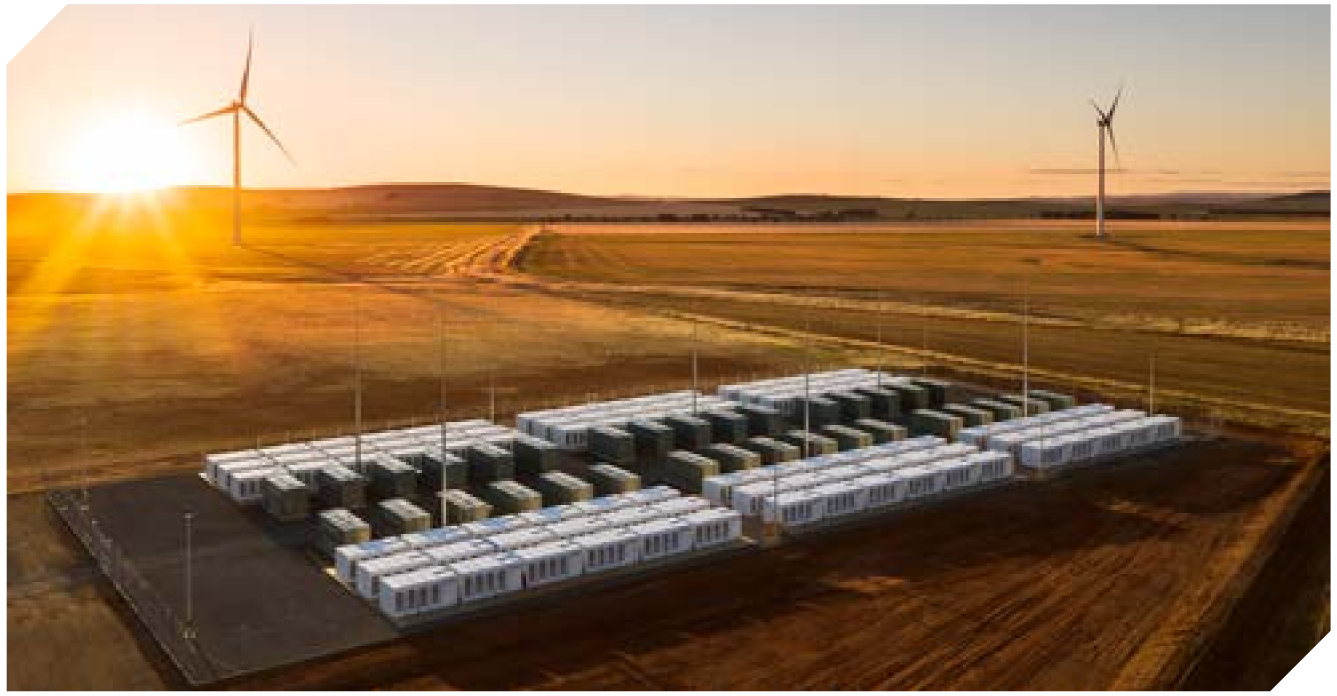
The South Australian Interconnector Trip Remedial Action Scheme (SAIT RAS) is being designed for the total loss of either the PEC or Heywood interconnector corridor. This is expected to be as high as 800 MW for system normal conditions, representing an increase in the largest non-credible contingency event from the current multiple generation loss of up to 500 MW in South Australia.

SAIT RAS may not be effective for a single non-credible contingency within South Australia that exceeds 800 MW. Any proposed generator connections exceeding 800 MW in capacity are therefore likely to be constrained to prevent them exceeding that level in practice to meet power system security and stability requirements.

ElectraNet's analysis shows that all generator connections made after 2010 ride through the non-credible loss of the Heywood Interconnector.

ElectraNet has already received multiple connection enquiries that are exploring the 400 MW limit.

More detail about the SAIT RAS is provided at 6.3.3.



3.7 Details of stability assessment options

The South Australian energy transformation has created two key challenges in relation to the stability assessment process:

- **Network complexity**: South Australia is the most globally advanced variable renewable penetration network which has created new challenges and network complexities due to the variability of electricity generation and usage patterns which require innovative solutions
- **High connection demand**: our world-leading reputation has resulted in unprecedented levels of interest in connecting to the South Australian electricity network.

As it currently stands, ElectraNet can only undertake about eight stability assessments per year. We are constrained in part by computing capacity, but more so by access to the specialised skills required to complete and review these assessments.

Given the unprecedented interest in connecting to the network ElectraNet are currently exploring all options to increase the number of stability assessments able to be undertaken at any one time. Every part of ElectraNet's stability assessment approach has been reviewed including processes, resourcing and use of technology.

From April, ElectraNet has commenced a trial which will increase the stability assessment options available to customers. These options will allow ElectraNet to undertake up to six stability assessments at any one time, up from the current maximum of two.

ElectraNet will continue to run its established process for stability assessment, with two stability assessments run by ElectraNet at any one time.

A new option will be introduced for customers under a 'start when ready' approach, with up to four projects having their stability assessment completed by an external provider. Following the successful completion of a stability assessment the project will be integrated into ElectraNet's network models.

A high-level overview of these approaches is included in Figure 19:

- **Traditional**: Utilises the base model to assess all committed project and system variables.
- **Start When Ready**: Utilises a parallel model to assess most committed project and system variables to gain comfort of stability. Conditional TCA offered and committed status while waiting for final assessment and integration to the base model.

The successful completion of both approaches will result in the issuance of a 5.3.4 A/B letter from AEMO and subsequent offer to connect from ElectraNet.

Additional options will be available under special circumstances with heavily provisioned offers to enable customers' specific business goals while decreasing their risk materially.

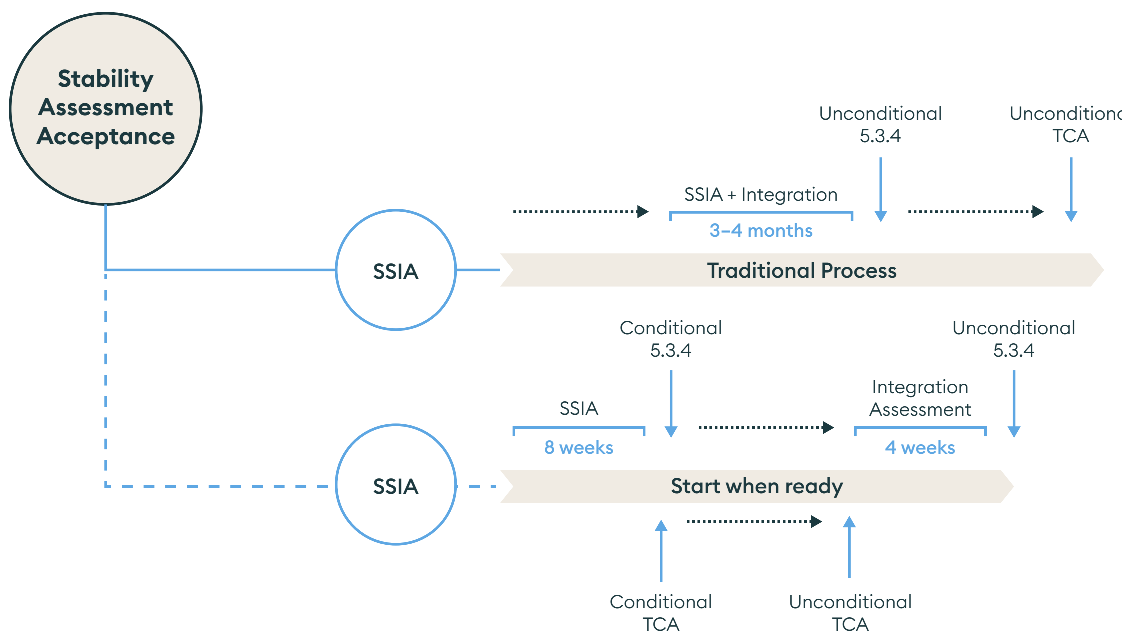


Figure 19: Stability Assessment Acceptance – Comparing traditional and Start-when-ready processes

3.7.1 Details of Stability Assessment Options

ElectraNet conducts system strength impact assessments in line with clause 4.6.6 of the Rules and AEMO's System Strength Impact Assessment Guidelines.[15]

The assessment utilises models supplied by the customer and maintained by the Network Service Provider in a wide area (typically across the whole of South Australia).

Traditional assessment process

The traditional assessment process utilises the current base model to build and operate a set of scenarios against all the committed and considered projects on the transmission network. These assessments are the primary pathway to be assessed against the network. This pathway is limited to two projects at a time to ensure separation and identification of issues or responses during the assessment process.

This overall assessment ensures a minimum level of risk and issues to be included in either a 5.3.4 letter or TCA.

Start When Ready assessment process

Differing from the traditional assessment process, the "Start When Ready" assessment process utilises a parallel model to the traditional process, being built to operate a similar set of scenarios against most committed and considered projects on the transmission network. These assessments are the secondary pathway which will require additional assessment against the primary model later. This pathway is limited to four projects at a time to ensure the complexity can be managed and any issues can be identified during the assessment process.

This overall assessment ensures an understanding of the performance and interactions to minimise the customer risk, allowing the issue of a conditional 5.3.4 letter and a conditional TCA.

A subsequent assessment is required as soon as practical (as defined by ElectraNet) to integrate this parallel model into the base model, ensuring a full assessment has been conducted and allowing the issue of an unconditional 5.3.4 letter and TCA.

Other assessment processes

Additional options will be available under special circumstances with heavily provisioned offers to enable customers' specific business goals while increasing their risk materially.

[15] AEMO | System Strength Impact Assessment Guidelines

3.8 Proposed and Committed New Connection Points

New connection sites that have recently been energised, committed, or are proposed to enable the connection of new generators or loads are listed below in Table 5.

Table 5: Projects for which ElectraNet is seeking proposals for non-network solutions

Connection Point	Planning Region	Project Year	Connection Voltage	Scope of work
Clements Gap North	Mid North	2025	132 kV	Establish Clements Gap North switching station to enable the connection of Clements Gap BESS
Roopena	Eyre Peninsula	2025	275 kV	Part of Whyalla Industrial Link - establish Roopena switching station to facilitate new customer connections
Cultana East	Eyre Peninsula	2025	275 kV	Part of Whyalla Industrial Link - establish Cultana East switching station to facilitate new customer connections
Narridy	Mid North	2028	275 kV	Establish Narridy switching station to enable the connection of Carmodys Hill Wind Farm
Tepko	Mid North	2026	275 kV	Establish Tepko switching station to enable the connection of Summerfield BESS

3.9 Network Support Solutions: Sought and Considered

There is one planned and one current consultation for forecast limitations for which we plan to seek proposals for network support solutions (Table 6).

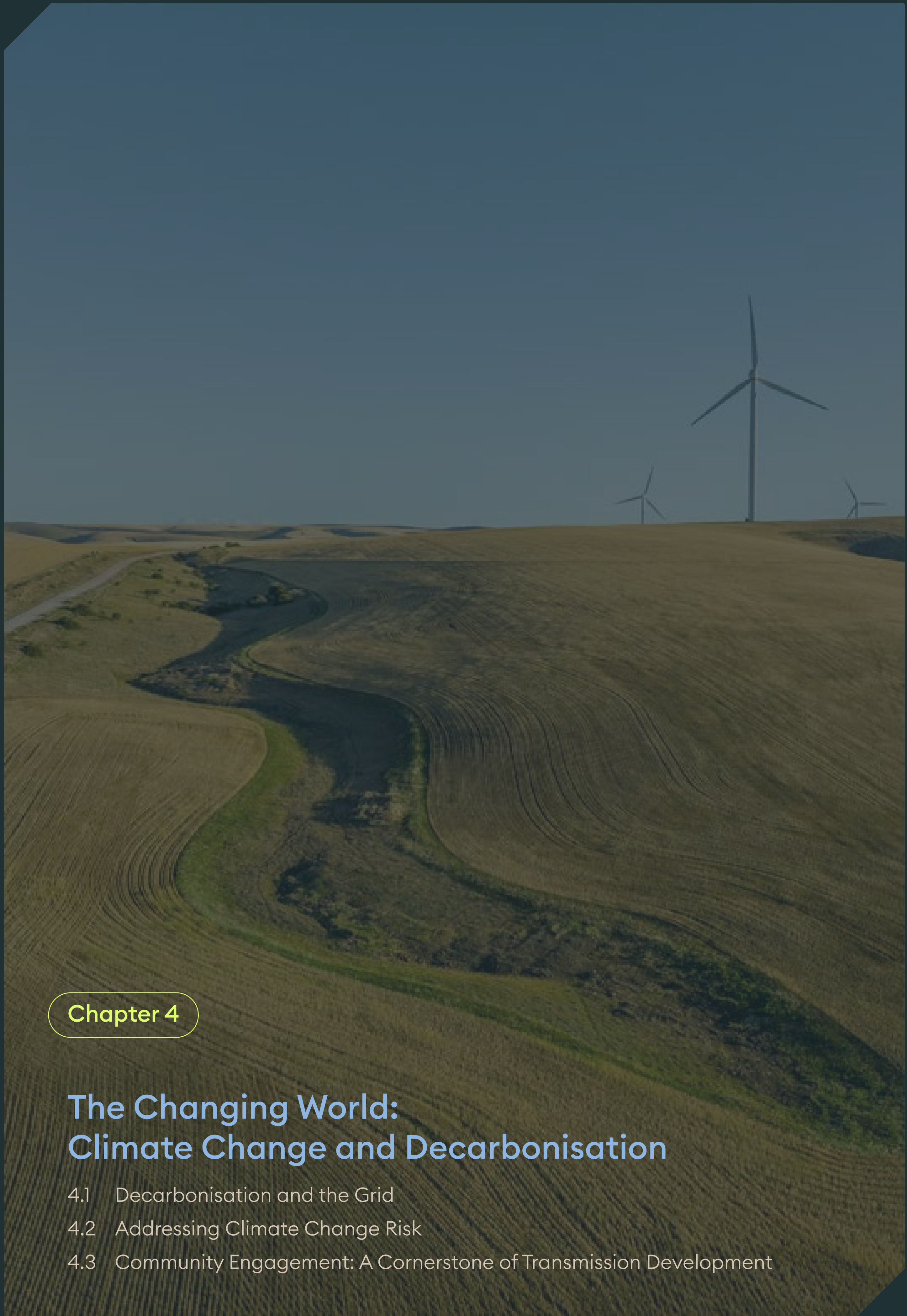
Future dates are indicative only. Reports will be published on ElectraNet's website,[16] with a summary on AEMO's website.[17]

ElectraNet also liaises with AEMO to notify interested parties when we publish new Regulatory Investment Test for Transmission (RIT-T) reports through the "AEMO Communications" email notifications.

Table 6: Projects for which ElectraNet is seeking proposals for non-network solutions

RIT-T	Expected project commitment date	Consultation status
Meeting System Strength in SA	N/A	ElectraNet published the PACR in December 2025, with the preferred option having been identified as contracting with future non-network proponents who can add mechanical clutches to synchronous generators such that can operate as synchronous condensers. It is a prudent low cost and 'low regret' insurance against the need to provide additional system strength in South Australia. In concluding the RIT-T, and avoided the need for investment, the South Australian Government has adopted the proposed solution and has mandated its need, via the Office of the Technical Regulator updating its Generator Development Approval Procedure. ElectraNet will review the situation over the coming years to ensure the system has sufficient system strength services and this may require further action in the future. We will not be seeking network support agreements for the provision or use of this service.
NTx	2026	The RIT-T on this project was initiated when AEMO's 2024 ISP declared the project formerly known as the Mid North SA REZ Expansion to be an actionable project. ElectraNet plans to publish the PADR during the second quarter of 2026.
South East Expansion (Stage 1)	2026	ElectraNet has commenced a stand-alone RIT-T for this project – please see Appendix F for the Project Specification Consultation Report.
Lower South East Upgrade (Blanche)	2026	ElectraNet has commenced a stand-alone RIT-T for this project – please see Appendix F for the Project Specification Consultation Report.

[16] ElectraNet | Reports & Publications
[17] AEMO | Current and closed consultations



Chapter 4

The Changing World: Climate Change and Decarbonisation

The Changing World: Climate Change and Decarbonisation

Operating sustainably is integral to ElectraNet's role in South Australia's clean energy future.

This means developing, operating and maintaining the transmission network in ways that create opportunities for both people and nature to thrive. Guided by internationally recognised frameworks, ElectraNet is committed to setting clear targets, monitoring and reporting on Environmental, Social and Governance (ESG) performance, and building resilience to climate and other ESG-related risks.

This chapter sets out the sustainability principles and climate resilience approaches that are embedded in ElectraNet's network planning approach. These principles and approaches are consistent with nationally and state-endorsed frameworks and mandatory climate-related disclosure requirements under the Australian Sustainability Reporting Standards (ASRS).

Our sustainability focus areas ensure we operate responsibly, support South Australia's energy transition, and create lasting value for our stakeholders. These include:

- Greenhouse Gas Emissions
- Understanding and Managing Climate Risk
- Health and safety
- Diversity, Equity and Inclusion
- Reconciliation and Engagement with Traditional Owners
- Engagement with Landholders and Communities
- Governance, Compliance and Ethical Conduct.

In a context of rapid energy system transformation and increasing climate uncertainty, ElectraNet's sustainability approach is underpinned by a least-regrets planning philosophy. This recognises the asymmetry of risk facing South Australia: under-investment in transmission capacity, resilience and optionality carries significantly higher long-term economic, reliability and emissions costs than prudent, staged investment that preserves flexibility.

Sustainability considerations are therefore embedded alongside reliability and affordability objectives, ensuring that network planning decisions support South Australia's decarbonisation pathway while maintaining system security and community outcomes under a wide range of plausible futures.

4.1 Decarbonisation and the Grid

Achieving the South Australian Net Zero target by 2050 relies heavily on the electricity sector, including generation, transmission and storage, as a critical enabler of these targets. Being able to meet the underlying goal of 100% renewable electricity generation by 2027 is dependent on transmission infrastructure accelerating renewable energy development, integrating energy storage and firming, supporting demand management technologies, and maintaining system security as the generation mix continues to change.

South Australia's Net Zero Strategy and Statewide Climate Risk Context

South Australia's Net Zero Strategy[18] is crucial to the government's response to the climate emergency declared in May 2022. It outlines objectives, policies, and actions to reduce greenhouse gas emissions, enhance prosperity, and improve wellbeing. The strategy aims to meet interim emissions targets, targeting a reduction in net greenhouse gas emissions by at least 60% by 2030, and achieving net zero emissions by 2050.

South Australia's first statewide Climate Change Risk Assessment highlights both risks and opportunities for or the electricity sector.[19] It details that the state is becoming warmer and drier, with increasing frequency and severity of extreme weather events such as heatwaves, drought, bushfire weather, intense rainfall and damaging winds. It notes that climate change increases physical risks to energy infrastructure and operations, while also reinforcing the importance of grid modernisation, transmission investment and system flexibility to support renewable energy integration and a reliable energy transition. The assessment also emphasises that climate risks are often compounding and interconnected, with impacts in one system, such as transport or communications, potentially amplifying risks to energy supply and emergency response. Strengthening transmission infrastructure is therefore both a decarbonisation enabler and a key adaptation response to escalating physical climate risks.

ElectraNet's Role in South Australian Net-Zero

In this context, ElectraNet's transmission planning must respond not only to energy transition drivers, but also to a changing climate risk profile. Planning decisions increasingly account for long term physical climate risks alongside demand growth, generation development and policy settings. The Net Zero Strategy and statewide climate risk assessment together reinforce the importance of timely, resilient and flexible transmission investment to support South Australia's transition to a net zero, renewable dominated electricity system while maintaining reliability and system security. These network development pathways are progressed in partnership with customers, communities and Traditional Owners to maintain social licence and to optimise corridor selection and design, with due regard to cultural heritage, biodiversity and land use considerations.

ElectraNet Emissions Reduction Plan

In addition to enabling South Australia's transition to a net zero economy, ElectraNet has committed to reducing its own operational emissions. Progress toward ElectraNet's emissions reduction targets is guided by its Emissions Reduction Plan, which outlines initiatives to reduce emissions associated with SF_6 management, transmission line losses, electricity consumption across occupied sites, and value chain activities, per Figure 20. Under the plan, ElectraNet has set targets to achieve a 50 per cent reduction in Scope 1 and Scope 2 emissions by 2030 and net zero emissions by 2040. ElectraNet's emissions inventory covers Scope 1 emissions (including sulphur hexafluoride (SF_6) and vehicle fuels) and Scope 2 emissions (including transmission line losses and purchased electricity). Material Scope 3 emissions are progressively identified and refined as data quality and supplier reporting improves Accordingly, network planning and asset design seek to minimise operational emissions where practicable, including through efficient corridor selection, modern equipment choices and initiatives to reduce transmission losses and SF_6 use.

18 Department for Environment and Water | South Australia's Net Zero Strategy 2024–2030

19 Department for Environment and Water | Statewide Climate Change Risk and Opportunity Assessment

SF_6

SF_6 leakage from transmission assets is a key source of ElectraNet's Scope 1 emissions. To reduce this, ElectraNet is increasing maintenance to repair leaking equipment and replacing end-of-life SF_6 assets with non-SF_6 alternatives, as part of its SF_6 Maintenance and Reduction Strategy.

Electrification

ElectraNet operates a fleet of around 50 vehicles, mostly 4WD diesels, and is transitioning to electric alternatives through a phased approach. Small vehicles are targeted for replacement by 2027, with larger vehicles to follow. Due to limited charging infrastructure and the remote location of many assets, ElectraNet will rely on private investment in South Australia's public and private fast-charging network support this shift. Where gaps remain strategically placed charging stations will be considered.

Renewable Connections

Transmission line losses are a key source of ElectraNet's Scope 2 emissions. As renewable energy increases on the grid, these emissions are expected to decline. To support this transition, ElectraNet is enabling timely connections of renewable generators and ensuring the grid is designed and managed to avoid delays caused by network constraints or system strength issues.

Value Chain Collaboration

A substantial share of ElectraNet's total emissions originates from its supply chain. To address this, ElectraNet is actively collaborating with key suppliers to better understand Scope 3 emissions and identify opportunities for reduction. This includes working together to improve data transparency, encourage low-emission materials and practices, and support suppliers in adopting more sustainable operations across their own value chains.

Decarbonisation

ElectraNet has established Scope 1 and Scope 2 emissions targets to track progress toward decarbonisation. It acknowledges the complexities of reducing SF_6-related emissions, given the technical challenges and uncertainties surrounding the development and availability of viable alternatives.

Figure 20: ElectraNet Emissions Reduction Plan (ERP) Priority Areas

This approach ensures that transmission development supports South Australia's energy transition while maintaining a clear focus on operational efficiency and emissions reduction within ElectraNet's direct control.

4.2 Addressing Climate Change Risk

Climate change is materially altering the operating environment for electricity transmission networks. To support informed planning and proactive risk management, ElectraNet has undertaken a climate resilience assessment aligned with the Electricity Sector Climate Information (ESCI) framework and informed by the Australian Climate Service's National Climate Risk Assessment (NCRA).[20] This assessment helps illustrate any future risk associated with climate change and increased exposure of assets to climate hazards such as bushfire, flood, wind, extreme heat and severe storms. Such hazards pose systemic risks to reliability, asset performance and community resilience. ElectraNet uses a climate risk methodology combining hazard, exposure, and vulnerability or our assets to evaluate climate-related physical risks across eight ElectraNet asset typologies, per Figure 21, and is evaluated over 5, 20 and 50 year timeframes.

Climate hazard data (for extreme heat, bushfire, wind, flood, and drought) is sourced from a range of national datasets and analysed across two IPCC-aligned future climate scenarios (SSP2-4.5 and SSP3-7.0) and three timeframes (2030, 2045, 2075) aligned with ElectraNet's regulatory cycle, strategic planning framework, and asset lifecycle.

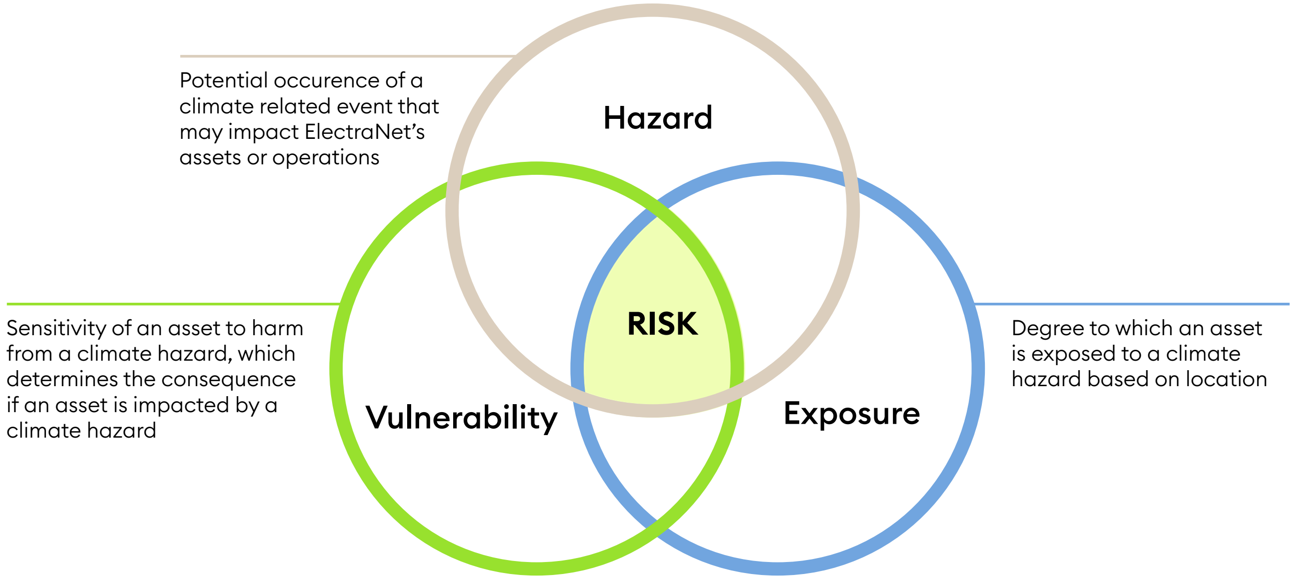


Figure 21: ElectraNet Climate Hazard Methodology

[20] Australian Climate Service | National Climate Risk Assessment

Alignment With AEMO ISP And Climate Modelling

ElectraNet's climate resilience assessment has been developed to complement the scenario framework applied by the Australian Energy Market Operator (AEMO) in the Integrated System Plan (ISP).

AEMO's ISP scenarios explore a range of plausible energy transition pathways, reflecting different assumptions about demand, generation mix, storage, transmission development and emissions.[21] These scenarios are used to inform efficient development pathways for the National Electricity Market and to assess the risks of under- and over-investment in transmission infrastructure.

ElectraNet's climate resilience modelling focuses on physical climate risks to transmission assets, assessing how hazards such as bushfire, extreme heat, wind, drought and flooding may affect asset performance and reliability over time. The modelling applies IPCC-aligned climate scenarios across multiple time horizons aligned to regulatory periods, strategic planning horizons and asset lifecycles.

While addressing different dimensions of risk, both approaches apply scenario-based planning under uncertainty. ISP scenarios test alternative transition pathways, while ElectraNet's modelling examines a range of physical climate futures that could occur under those pathways. Climate resilience insights are used to inform and stress-test ISP-aligned transmission planning outcomes, supporting a least-regrets approach to long-lived infrastructure investment.

Table 7: ElectraNet's Future Climate Scenarios

	Low Warming World	Moderate Warming World	High Warming World
Temperature Pathway	1.5°C above pre-industrial levels	2.5° C above pre-industrial levels	3.6° C +above pre-industrial levels
AEMO ISP	*Accelerated Transition* *Step Change*	*Slower Growth*	
RCP/SSP Scenario	SSP1 – 1.9 / 2.6[22]	SSP2 – 4.5	SSP3 – 7.0
Narrative	Policies are introduced early and become gradually more stringent. Early investment in infrastructure is required for business resilience. Physical risks are present but less pronounced.	Global climate action is uneven and slower, leading to fragmented policies and moderate electrification. Physical risks like heatwaves, bushfires, and storms intensify, increasing resilience and repair costs. Transition risks remain but investment shifts toward maintaining reliability rather than growth	Climate action stalls globally, with minimal policy support and slow decarbonisation. Physical risks escalate to extreme levels, causing frequent asset damage and costly adaptations, while transition risks and opportunities remain low. ElectraNet prioritises resilience spending over innovation amid rising operational challenges.
What it means for ElectraNet	Hosting capacity, system strength and inertia portfolios, voltage control for very low demand, and early engagement to optimise routes.	Staged augmentation, corridor diversification, and uplift of operational controls to maintain security and affordability.	Hardening and redundancy, emergency access and bypass options, and contingency portfolios to maintain reliability. Investment timing is calibrated to minimise regret while preserving flexibility to respond to emerging loads and policy shifts

[21] AEMO | 2025 Input Assumptions and Scenarios Report

[22] Physical climate risk modelling is based on SSP2-4.5 and SSP3-7.0 only. Lower-warming scenarios are included for contextual comparison.

Key Results from ElectraNet's Climate Resilience Assessment

The ElectraNet assessment used climate scenario analysis to understand how physical climate hazards may affect the reliability and performance of transmission assets over time. The assessment considered a range of future climate conditions and time horizons aligned to regulatory, strategic planning and asset lifecycles.

Key findings from the assessment include:

- Drought emerges as a major risk driver for overhead transmission lines, increasing the likelihood of insulation degradation, faults and bushfire ignition.
- Bushfire presents widespread risk across most asset types, driven by increasing fire weather severity and exposure across the network.
- Wind poses significant risk to overhead lines and structures through increased mechanical loading, vibration and vegetation interaction.
- Extreme heat becomes a more material risk in the longer term, particularly for network assets, affecting performance and operational reliability.
- Flooding is generally a lower-order, network-wide risk, but remains important for specific, flood-sensitive assets such as substations, buildings and underground cables in certain locations.

Overall, the analysis shows that climate risk is expected to escalate between now and mid-century and beyond, reinforcing the importance of considering climate resilience alongside economic and system planning. These insights are being used to inform ElectraNet's transmission planning, asset management and risk management processes, supporting a least-regrets approach to long-lived infrastructure investment.

Use Of Climate Insights in Transmission Planning

Outputs from ElectraNet's climate resilience assessment are being progressively integrated into transmission planning and project scoping, options analysis and asset management decision-making. These insights help identify where climate risks may materially influence network performance over the life of assets and inform the selection of prudent, least-regrets responses.

Examples of how climate insights are being applied include:

- Use of targeted risk mitigation measures, such as enhanced vegetation management to reduce bushfire ignition risk and design responses for flood-prone locations, including elevated platforms or embankments as is being scoped for a potential Bolivar substation in the coming years.
- Transmission corridor diversification and staged adaptation, such as is the case with the NTx development program, supporting security of supply and affordability while managing exposure to higher-risk areas over time.
- Climate-aware asset renewal and design, incorporating appropriate redundancy, emergency bypass provisions and monitoring capabilities to improve preparedness for extreme weather events.

Climate-related insights are expected to continue to evolve as new assets are commissioned and climate datasets are refined. At present, however, the availability of consistent, high-resolution data for certain hazards, particularly severe storms, flooding and high winds, remains limited in some regions. This constrains the precision of long-term assessments and reinforces the need for adaptive planning approaches that can be updated as improved information becomes available.

4.3 Community Engagement: A Cornerstone of Transmission Development

Meaningful, early and ongoing community engagement continues |to be central to ElectraNet's ability to deliver the transmission infrastructure required to support South Australia's energy future.

Transmission infrastructure is long-lived, highly visible, and often located across privately owned land or within areas of environmental and cultural sensitivity. For these reasons, community engagement remains integral to our day-to-day operations and essential for earning and maintaining social and community acceptance to plan, build, operate and maintain the transmission network and support South Australia's transition to net zero.

ElectraNet's approach to community engagement is aligned with industry best practice and has regard to:

- South Australian Planning Commission's Community Engagement Charter
- International Association for Public Participation (IAP2)
- Energy Charter – Better Practice Social Licence Guideline
- National Guidelines for Community Engagement and Benefits for Electricity Transmission Projects
- Australian Energy Infrastructure Commissioner – observations and recommendations
- Department for Energy and Mining – Principles for Engagement with Communities and Stakeholders
- South Australian Chamber of Mines and Energy – Land Access Engagement Guidelines
- Australian Energy Regulator – Regulatory Investment Test for Transmission Guidelines.

4.3.1 Our Foundations for Engagement

Clear, Accurate and Timely

Comprehensive forward planning and accurate and timely communication are essential.

Accessible and Inclusive

Ensure that every member of the community is included, well informed and listened to.

Transparent

Communicating the same information to the same people at the same time avoids confusion and misunderstandings.

Measurable

We are committed to monitoring our community engagement strategy and building in feedback loops.

Figure 22: ElectraNet's Principles for Community Engagement

ElectraNet's approach is guided by principles that support transparency, inclusive participation, accessible information and timely communication. We commit to presenting clear and accurate information, monitoring and evaluating our engagement activities, and embedding feedback loops that ensure community perspectives and insights are reflected in our planning and delivery processes.

Project Snapshot: Community Engagement

ElectraNet is embedding early, continuous and transparent community engagement at the centre of development for the Northern Transmission Project, ensuring the perspectives of landholders, Traditional Owners, local communities and stakeholders are reflected in project decisions. Insights gathered throughout planning are directly informing the refinement of potential transmission corridors, identification of environmental and agricultural sensitivities, and consideration of broader social, visual and economic impacts. This approach enables local priorities to be recognised early, supports balanced assessment of risks and opportunities, and helps shape a project pathway that minimises disruption while ensuring the transmission network can continue to meet South Australia's evolving energy needs.

4.3.2 Engagement in Practice

Engagement begins early in the planning process and continues throughout the lifecycle of a project. ElectraNet works collaboratively with landholders, Traditional Owners, councils, community groups and local and regional stakeholders to understand local values, priorities and concerns. Our approach includes providing clear explanations of why new infrastructure is needed, how route options are identified and assessed, and what considerations guide planning decisions.

For landholders, engagement focuses on early visibility of proposals, clear communication regarding easements and access requirements, and support to minimise disruption to productive land and farming operations. Dedicated teams maintain ongoing relationships and remain available to respond to questions throughout planning, construction and reinstatement.

Engagement with Traditional Owners is grounded in respect for cultural knowledge, connection to Country and cultural heritage responsibilities. This includes undertaking cultural heritage surveys, collaborating on approaches to avoid or minimise impacts, and supporting ongoing dialogue to ensure cultural values are appropriately considered in planning and decision-making.

Across all communities, ElectraNet provides accessible and inclusive opportunities to participate in engagement activities, utilising a range of communication methods and formats to ensure information is easy to understand. Feedback received through engagement helps shape project refinements, inform route selection, guide environmental and cultural considerations, and support the development of appropriate mitigation and management measures.

4.3.3 Delivering Long-Term Value

By prioritising open dialogue, transparency and inclusion, ElectraNet aims to ensure that transmission development delivers not only the energy system benefits required for South Australia's future, but also lasting value for the communities that host this critical infrastructure.

Chapter 5

Where to from here: Network Development

Where to from here: Network Development

The planning and implementation of projects is a key capability for ElectraNet in consistently and continually improving our network.

Delivery of timely and effective transmission infrastructure enables efficient connection of customer loads with renewable energy and storage and the continual reliability of supply.

This chapter details the four key projects outlined in chapter 1 that aim to ensure the South Australian electricity transmission grid will continue to provide adequate capability and capacity for future new customers and generators. It will also provide a high-level summary of significant projects ElectraNet have recently completed, committed to or have become anticipated over the last year.

ElectraNet is also addressing constraints on the transmission system, as well as forecasting emerging constraints that could impact future efficacy of the transmission system, without proposed network development.

In the planning and delivery of these projects, ElectraNet recognises the importance of effectively engaging with community stakeholders in a manner that aims be respectful, inclusive, transparent, genuine, accountable and flexible (Section 4.3). Further to this, ElectraNet continually strives to understand and respect Traditional culture, underpinned by a commitment to the protection of sites of cultural significance and provision of support in the preservation of them for current and future generations.

5.1 Constraints

The South Australian electricity network is already witnessing the impact of the very high levels of variable renewable energy, including increasing constraints between areas of high generation and the major load centres.

These constraints can impact energy reliability and the price of electricity, as AEMO uses constraint equations to manage system security and market pricing. The current state of the network and its constraints is instigating ElectraNet to proactively plan efficient and cost-effective future projects – both on-grid development and off-grid solutions with third parties and customers. This will ensure South Australian homes and businesses aren't impacted by a reactive approach that comes too late and can result in higher prices. The below covers the formation of constraints, their impact on supply and pricing and what ElectraNet is doing to ensure there are solutions being implemented to manage these issues.

5.1.1 Constraints Currently Binding

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

AEMO publishes the marginal value of a constraint when it binds. The marginal value indicates its impact on market prices, but this measure is only an approximation and can be misleading in some instances. At times, constraints that have a relatively small impact can report large marginal values due to interactions between the network limitation, price at the time and the bids of generators affected by the constraint. As a result, ElectraNet also considers the hours of the year a constraint impacts on the market. Together, these two metrics provide insights into the market benefits that may be achieved by alleviating the constraint.

The binding constraints reflecting the top 10 constraints by impact in 2025 are presented below (Table 8). Alleviating, or un-binding, these constraints are predominantly reliant on the next phases of the current MurrayLink, EnergyConnect (Project EnergyConnect, PEC) and Northern Transmission (NTx) projects. Some constraints have contributed to the identification and planning of ElectraNet's key potential developments for the SA South Australian transmission network in 2026.

Table 8: Constraint equations, descriptions, and impact in 2025

Network limitation	Binding impact in 2025 [$]	Binding duration in 2025 [hours]	Comments, with proposed and implemented actions
S>NIL_MHNW1_MHNW2 Avoid overload of Monash – North West Bend #2 132kV line if the Monash – North West Bend #1 132kV line was to trip	4,829,272.2	1623.7	This constraint will be alleviated when project EC.15175 Increase Murraylink Transfer Capacity upgrades the existing runback control scheme to include bi-directionality and allow it to run forward if required.
S>NIL_HUWT_STBG3 Limit Snowtown WF generation to avoid overload of Snowtown – Bungama 132 kV line if the Hummocks – Waterloo 132 kV line was to trip, if Wattle Point WF generating <60 MW	2,009,955.3	237.2	ElectraNet is monitoring this constraint and considering whether there are economic and equitable options to alleviate it. This constraint will be further alleviated by EC.15424 Northern Transmission Project.
S-NIL_WTPT_SC+INV_2 Limit output of Wattle Point WF based on Wattle Point statcom status & the number of Dalrymple battery inverters that are in-service, if the number of Dalrymple battery inverters is < 10	739,614.9	73.2	This constraint is applied to manage system security during STATCOM unavailability at Wattle Point Wind Farm.

Table 8: Constraint equations, descriptions, and impact in 2025 (cont.)

Network limitation	Binding impact in 2025 [$]	Binding duration in 2025 [hours]	Comments, with proposed and implemented actions
S^NIL_SA_NORTH Manage the risk of voltage collapse in northern SA for the trip of one 275kV line between Davenport – Para or Davenport – Tungkillo if at least one synchronous condenser is in service at both Davenport and Robertstown	473,832.9	127.4	This constraint will be alleviated by EC.15424 Northern Transmission Project.
S>NIL_NWRB2_NWRB1 Avoid overload of North West Bend – Robertstown #1 132kV line if the North West Bend – Robertstown #2 132kV line was to trip	367,045.0	231.1	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_TBTX4_TBMO_1 Avoid overload of Tailem Bend to Mobilong #1 132kV line if the Tailem Bend 275/132kV (#4) transformer was to trip	237,655.1	34.6	ElectraNet is investigating whether Project EC.11011 South East Expansion or the installation of a second 275/132 kV transformer at Tailem Bend would best alleviate this constraint.
VS_600_TEST Vic to SA on Heywood limit of 600 MW, limit for testing of Heywood interconnection upgrade	233,921.0	293.6	Full commissioning of Stage 2 of Project EnergyConnect will alleviate this constraint.
S-NIL_WTPT_SC+INV_1 Limit output of Wattle Point windfarm based on Wattle Point windfarm STATCOM status and the number of in-service Dalrymple battery inverters (Note: constraint only applies when the number of in-service Dalrymple battery inverters is 10 or more)	225,182.9	18.3	This constraint is applied to manage system security during STATCOM unavailability at Wattle Point Wind Farm.
V_S_HEYWOOD_UFLS Limit Heywood flows when South Australian under frequency load shedding (UFLS) is insufficient (i.e. when UFLS blocks in SA	165,668.9	163.8	Market impacts expected to be alleviated by fully operational Project EnergyConnect.
SVML^NIL_MH-CAP_ON SA to Vic on Murraylink upper transfer limit to avoid voltage collapse at Monash (Note: applies when capacitor banks at Monash are available and in-service for switching)	149,085.9	548.8	Proposed project EC.15175 Increase Murraylink transfer capacity will alleviate this constraint.
S>>NIL_RBTX_RBTX_1 Avoid overload of one Robertstown 275/132kV transformer if the other Robertstown 275/132kV transformer was to trip	145,260.9	188.3	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. This constraint will be further alleviated by EC.15424 Northern Transmission Project. Replacement of a single transformer with a larger will also partially alleviate this constraint.
S>NIL_BWMP_RHBR-T Avoid overload of Redhill – Brinkworth tee 132 kV line if the Blyth West – Munno Para 275 kV line was to trip	109,540.7	23.3	ElectraNet is monitoring this constraint and considering whether there are economic and equitable options to alleviate it. EC.15424 Northern Transmission Project will contribute to alleviating this constraint.

5.2 Emerging Network Limitations

5.2.1 Emerging and Future Constraints

Significant expansion in renewable energy generation and anticipated growth in large industrial loads in the state is expected to lead to substantial changes in power flows on the network. Added to this is the already changing dispatch patterns of existing generators due to the establishment of Project EnergyConnect between South Australia and New South Wales. The combination of these factors will materially alter flows and constraints on the network over the coming decades.

ElectraNet's most recent forecast of congestion focuses on rating limitations as the primary future constraint priority facing South Australia. ElectraNet have based assessment of the thermal limitations in South Australia on the existing 3-band operational ratings. When considering new builds, some non-network options are selected to avoid network congestion. As a consequence, the congestion in this forecast may be underestimated. The 275 kV corridors where congestion is potentially underestimated include Davenport to Cultana, Tailem Bend to Tungkillo, and Robertstown to Tungkillo. Thermal limitations are also forecast across interconnectors PEC, MurrayLink and the Heywood Interconnector.

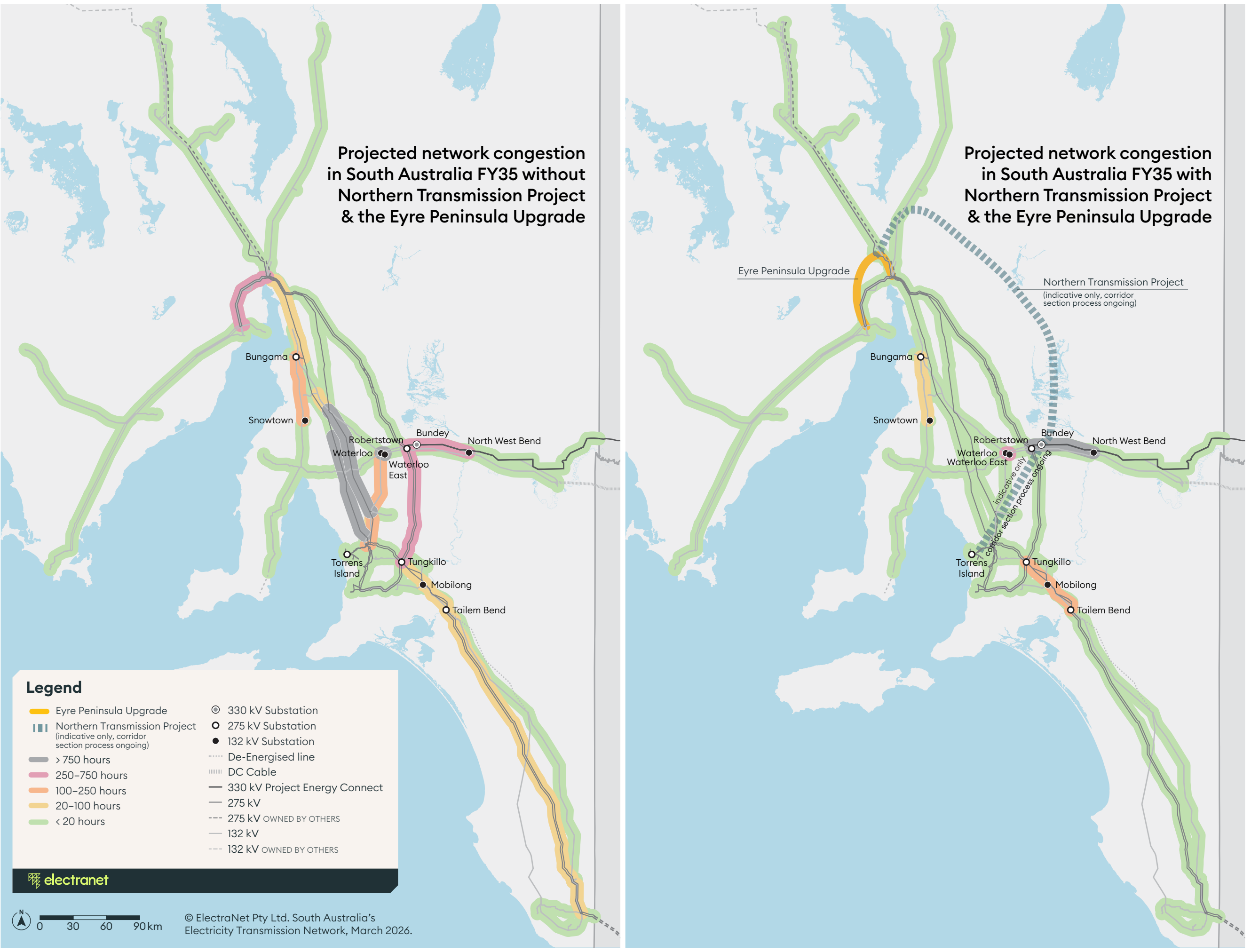


Figure 23: Projected network congestions in South Australia

A high-level summary of this modelling, including thermal limitations, is represented in the table below (Table 9).

Table 9: Emerging network constraints, descriptions, and links to major projects

Network limitation	Comments, with proposed and implemented actions	Link to Major Project
S>NIL_NWRB2_NWRB1 Out= NIL, avoid O/L North West Bend – Robertstown #1 132kV line on trip of North West Bend – Robertstown #2 132kV line (this trips MWP1-3 SFs)	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.	Project EnergyConnect
S>>NIL_RBTU_WEWT Avoid overload Waterloo East – Waterloo 132 kV line on trip of Robertstown – Tungkillo 275 kV line	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 Northern Transmission Project (Southern).	Northern Transmission Project (NTx)
S>NIL_RBMWP3_RBNW1 Out= Nil, avoid O/L Robertstown – North West Bend #1 132kV line on trip of Robertstown – Morgan Pipeline 3 – Morgan Pipeline 2 – Morgan Pipeline 1 – North West Bend 132kV #2 line	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.	Project EnergyConnect
S>>NIL_SETB_SETB_1 Out= Nil, avoid O/L one South East – Tailem Bend 275kV on trip of other South East – Tailem Bend 275kV line	This constraint will be alleviated when project EC.15470 constructs 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.	South East Expansion (Stage 2)
S>>NIL_RBTX_RBTX_1 Avoid overload of one Robertstown 275/132 kV transformer if the other Robertstown 275/132 kV transformer was to trip	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.	NTx
S>>NIL_TBTU_TBTU_1 Avoid overload of one Tailem Bend – Tungkillo 275 kV of the other Tailem Bend – Tungkillo 275 kV line was to trip	This constraint will be alleviated when Project EC.11011 strings the vacant third 275 kV circuit between Tailem Bend and Tungkillo and installs static and dynamic reactive compensation if needed to increase transfer capability between the South East and the Adelaide metropolitan area, and between the Mid North and the Heywood interconnector.	South East Augmentation
S>NIL_MHNW1_MHNW2 Avoid overload of Monash – North West Bend #2 132 kV line if the Monash – North West Bend #1 132kV line was to trip	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.	Project EnergyConnect
S>>NIL_RBTU_RBTU Out= NIL, avoid O/L Robertstown – Tungkillo 275kV line 1 or 2 on trip of parallel Robertstown – Tungkillo 275kV line 2 or 1	This constraint would be alleviated by the new high capacity lines and increased transfer capacity between Bundey and the Adelaide metropolitan load centre, as part of EC.15424 Northern Transmission Project.	NTx
S>>NIL_TBTU_TBMO_1 Out= NIL, avoid O/L Tailem Bend – Mobilong 132kV line on trip of one Tailem Bend – Tungkillo 275kV line	This N-1 rating should be improved when Project EC.11011 strings the vacant third 275 kV circuit between Tailem Bend and Tungkillo and installs static and dynamic reactive compensation if needed to increase transfer capability between the South East and the Adelaide metropolitan area, and between the Mid North and the Heywood interconnector.	Upper South East Augmentation
S>>NIL_BRTW_WTTP Out= Nil, avoid O/L Waterloo – Templers 132kV on trip of Brinkworth – Templers West 275kV line	This constraint would be alleviated by the installation of a second 275/132 kV transformer at Templers West as part of EC.15424 Northern Transmission Project and reconfiguration of the Mid North 132 kV system and further future augmentation may be required as part of the EC.15424 – Mid North REZ Expansion project.	NTx

Table 9: Emerging network constraints, descriptions, and links to major projects (cont.)

Network limitation	Comments, with proposed and implemented actions	Link to Major Project
S>>NIL_RBTU_WTTP Out= Nil, avoid O/L Waterloo – Templers 132kV on trip of one Robertstown – Tungkillo 275kV line	This constraint would be alleviated by the installation of a second 275/132 kV transformer at Templers West and reconfiguration of the Mid North 132 kV system as part of the EC.15424 – Mid North REZ Expansion project.	NTx
S>>NIL_TWPA_TPRS Avoid overload of Templers – Roseworthy 132 kV line if the Templers West – Para 275kV line was to trip	This constraint would be alleviated by the installation of a second 275/132 kV transformer at Templers West and reconfiguration of the Mid North 132 kV system as part of the EC.15424 Northern Transmission Project (confirm if disconnecting Roseworthy – Para is in scope of NTx). Further augmentation may be required in the 2040s through the mid-north Reinforcement.	NTx
S>>NIL_BWMP_WTTP Avoid overload of the Waterloo – Templers 132 kV line if the Blyth West – Munno Para 275 kV line was to trip	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 Northern Transmission Project.	NTx

5.3 Projects

5.3.1 Key Proposed Developments

To ensure the South Australian energy transmission grid will continue to provide adequate and efficient capability and capacity for future new customers and generators, ElectraNet has four key projects that are being prioritised for the coming five years. These projects will address current and emerging constraints, unlock capacity for new and existing customer demand, and build capability for new generator connection with the transition to renewable energy.

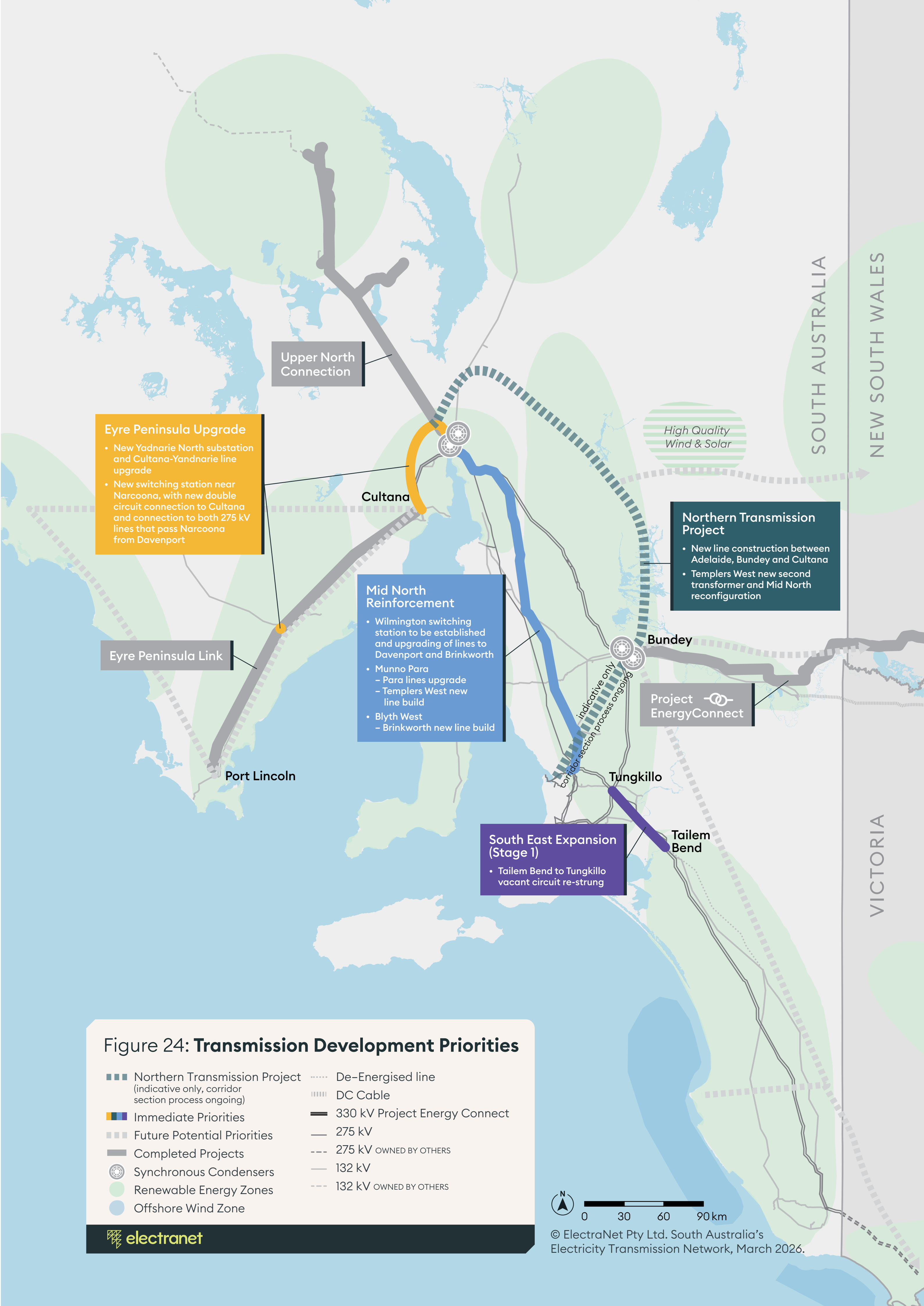


Figure 24: **Transmission Development Priorities**

Eyre Peninsula Upgrade

The Eyre Peninsula region spans from Sleaford in the South, to Wudinna in the West and Davenport in the North East. Key projects in the region, shown in Figure 25 include a new Yadnarie North substation adjacent to Yadnarie, works at Cultana to enable the Cultana – Yadnarie lines to be operated at 275 kV, and if required by future large industrial load connections a new switching station near Narcoona with new connections to Cultana East and the Davenport lines.

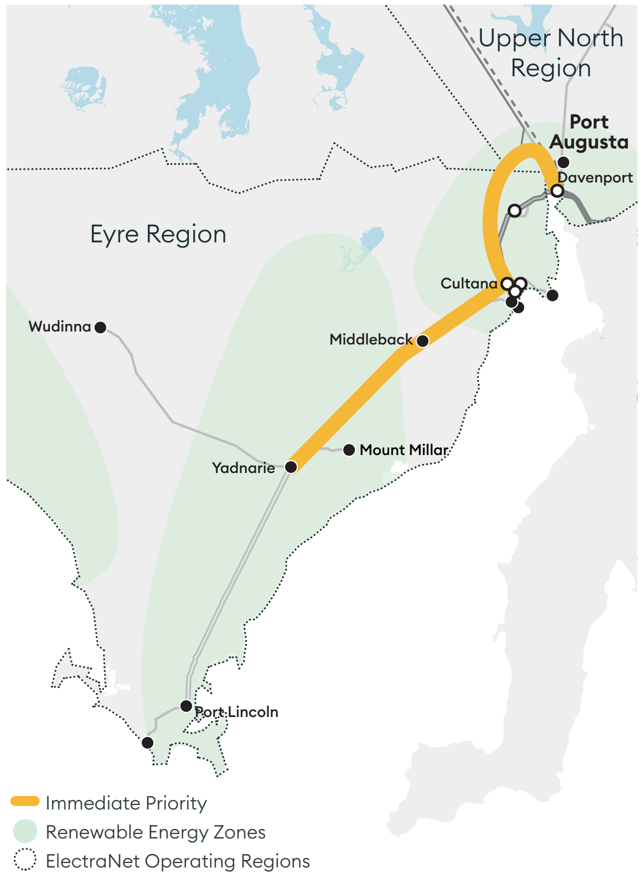


Figure 25: Eyre Peninsula upgrade

Yadnarie North Substation:

- Establish a new 275/132 kV Yadnarie North Substation
- Upgrade the Cultana-Yadnarie lines from 132 kV to 275 kV operation

Narcoona Substation:

- Establish a new substation near Narcoona, 30km north of Davenport.
- Build a new double circuit 275 kV lines from Davenport to Narcoona
- Build a new double circuit 275 kV lines from Cultana East to Narcoona

UNLOCKING

- Increased low-cost renewable energy connection in the Eastern Eyre Peninsula REZ, due to an increase in the capacity to supply large new loads to the region.
- Increased ability for Eyre Peninsula renewable generation to supply potential large industrial loads located in the upper Spencer Gulf.
- Potential to support future westward expansion of the transmission network to unlock solar energy that is time-shifted from the rest of the NEM.

NEXT STEPS

- The PACR published on the ElectraNet website on 18 December 2025 concluded that the preferred solution is to upgrade operation of the Cultana to Yadnarie double circuit lines from 132 kV to 275 kV by performing 275 kV works at Cultana and establishing a new 275/132 kV substation at Yadnarie North. It also identified that if sufficient new customer load connections become committed, then construction of new double circuit 275 kV lines between Narcoona and Cultana should also form part of the preferred solution.
- With the commitment of sufficient additional load on the Eyre Peninsula, ElectraNet will apply to the AER for funding of the Eyre Peninsula Upgrade contingent project that was included in the 2023–24 to 2027–28 revenue determination.

Northern Transmission Project (NTx)

AEMO's 2024 ISP declared the expansion of South Australia's Mid North REZ, now titled the NTx by ElectraNet, as an actionable project with a tentative completion date by July 2029. The identified need formulated by AEMO for the project is to increase power system capability of the transmission network in the region, Figure 26. This is with a view to support the expected increase in generation north of Adelaide that will be required to meet the growing demand in Adelaide, ensure adequate network capacity for large industrial loads, and alleviate congestion of renewables from the Mid North to the rest of the NEM.[23]

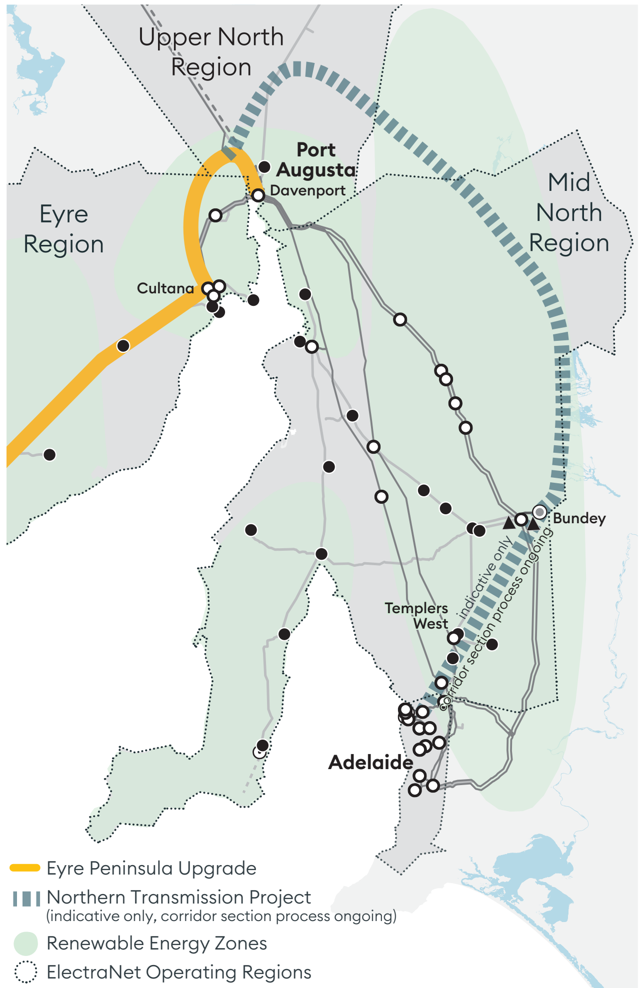


Figure 26: Northern Transmission Project

Adelaide New Line Construction:

- Build new lines between Adelaide, Bundey and Narcoona. Lines to be constructed as high-capacity 275 kV, 330 kV or 500 kV lines.

Mid North System Reconfiguration:

- Install a second 275/132 kV transformer at Templers West
- Reconfigure the 132 kV system in the Mid North to alleviate constraints caused by the parallel operation of the 275 kV and 132 kV systems.

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- Growth of low-cost generation to the Adelaide metropolitan load centre, due to the new high-capacity transmission path from the Mid North, Riverland and Northern SA REZs.
- Improved security of Adelaide metropolitan electricity supply, due to increased geographical diversification of transmission corridors mitigating risk of climate change impacts, such as bushfire risks to transmission corridors in the Adelaide Hills.
- Increased renewable catchment area of the Mid North REZ by expanding further northeast.
- Enablement of large industrial load connections north of Adelaide, such as future mining, green steel, data centres and other potential developments.

NEXT STEPS

- ElectraNet is progressing the options analysis as part of the RIT-T process and expect to publish the PADR in the second quarter of 2026.
- If found to deliver net market benefits, ElectraNet will seek full contingent project funding in accordance with the process for ISP projects.

[23] Northern Transmission Project | website for more information

South East Expansion (stage 1)

The South East Region, spanning from Mt Gambier to Tailem Bend Figure 27, relies significantly on its strength of transmission to the SA Mid North REZ and the Heywood interconnector. This one key project could significantly impact the growth and security of the South East REZ, as well as the capacity and capability of the Mid North REZ and Heywood interconnector.

Figure 27: South East Expansion (Stage 1)

Additional Tailem Bend to Tungkillo Circuit:

- String the vacant circuit that exists on one of the Tailem Bend-Tungkillo 275 kV lines.
- There are no other comparable options

UNLOCKING

- Increased connection of low-cost renewables near Tailem Bend, due to an increase in transfer capacity between the South East REZ and the rest of South Australia.
- Increasing capacity for new renewable generation in the Mid North REZ, due to increase in transfer capacity between the South East REZ and the rest of the NEM via the Heywood interconnector.
- Improve firmness of South East REZ's Heywood interconnector limit to 750 MW.

NEXT STEPS

- Based on modelling undertaken by ElectraNet, given the demand outlook this project would deliver substantial net market benefits.
- ElectraNet has initiated a standalone RIT-T to progress the project.

Mid North Reinforcement

Currently beyond scope of the actionable NTx, ElectraNet have identified further incremental opportunity across the Mid North REZ that could further enhance the efficiency, strength and security of the region's transmission network (Figure 28).

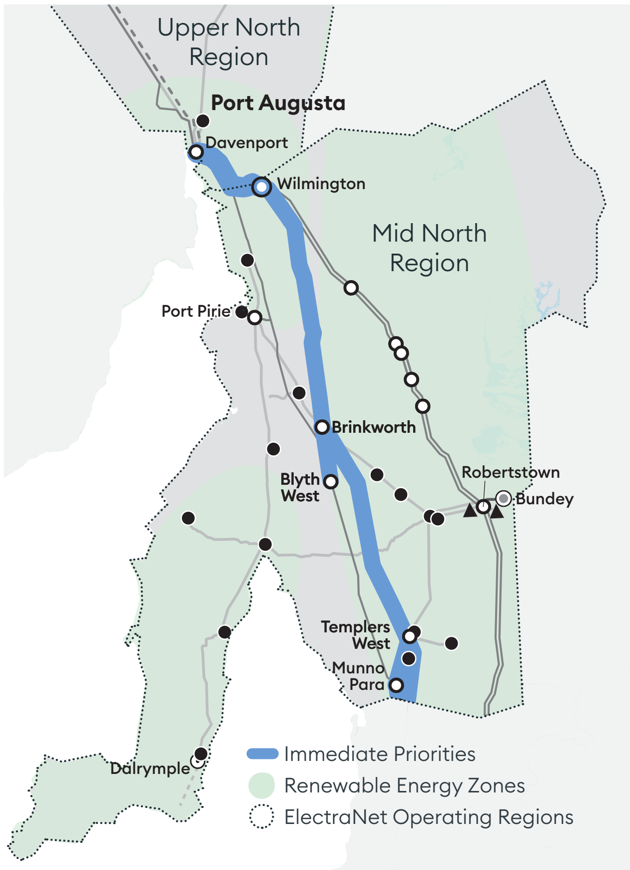


Figure 28: Mid North Reinforcement

Wilmington Switching Station:

- Establish a 275 kV switching station in Wilmington, where the Davenport to Brinkworth, Mt Lock and Belalie 275 kV lines converge.
- Rebuild all Davenport-Wilmington 275 kV lines as high-capacity 275 kV lines.
- Rebuild the Wilmington – Brinkworth – Templers West – Para 275 kV lines as high-capacity double circuit 275 kV lines.

New Mid North Lines:

- Rebuild Para-Munno Para 275 kV line as a high-capacity double circuit 275 kV line.
- Construct new single circuit 275 kV line between Munno Para and Templers West
- Construct new single circuit 275 kV line between Blyth West and Brinkworth

UNLOCKING

- Increased access for new low-cost renewable generation in the Mid North that, in the current state, would need to connect in locations that don't optimally utilise the existing transmission network.

NEXT STEPS

- ElectraNet are currently liaising with AEMO to provide scope and capacity benefit details for consideration in the 2026 ISP.

5.3.2 Committed Developments

ElectraNet is committed to the following projects, having completed the RIT-T (where required) and received ElectraNet Board approval. These projects predominantly address asset condition and performance, security, stability, with some power quality and market benefit impact (Table 10).

Table 10: Committed projects

Project Description	Region	Constraint Driver and Investment Type	Planned Asset in Service
EC.14171 PEC: 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): 150 MW transfer capacity released in April 2025 Stage 2 (Buronga to Wagga Wagga): 500 MW expected by June 2027. Full transfer capacity expected to be released by June 2028
EC.14131 Motorised Isolator Layer of Protection Analysis 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 LOPA.	Various	Safety Asset renewal	August 2026
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	November 2026
EC.14032 Instrument Transformer Unit Asset Replacement Replace instrument transformers at 19 substations which are at the end of their technical lives, due to an increased risk of failure which may result in an increasing rate of explosive asset failure.	Various	Asset condition and performance Asset renewal	November 2026
EC.14034 Isolator Unit Asset Replacement 2018–2023 Remove, and replace where required, approximately 73 isolators at 18 substations that no longer have original manufacturer support and create inventory spares to support the ongoing maintenance of ElectraNet's ageing isolator fleet.	Various	Asset condition and performance Asset renewal	November 2026
EC.14176 Surge Arrestor Unit Asset Replacement 2018–2023 Replace porcelain surge arrestors and arcing horns at 18 substations that are at the end of their technical and economic lives due to their increasing risk of failure and potential to cause injury to personnel and collateral damage to other plant within the substation as a result of an explosive failure.	Various	Asset condition and performance Asset renewal	November 2026
EC.15272 Wide Area Monitoring Scheme (WAMS) 2023–2028 Expand the existing WAMS by installing phasor measurement units (PMUs) as required by AEMO at candidate sites across the SA transmission network.	All	Stability Operational	September 2026

Table 10: Committed projects (cont.)

Project Description	Region	Constraint Driver and Investment Type	Planned Asset in Service
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	June 2026
EC.11645 Transmission Network Voltage Control Install of two 50 Mvar 275 reactors, three 60 Mvar 275 kV reactors around the Adelaide metropolitan region and a single 50 Mvar 275 kV reactor at South East. These and other reactive and voltage control devices on the main 275 kV transmission network will be upgraded to enable coordinated automatic switching of existing and planned reactive power devices. This will require the installation and modification of secondary plant items for monitoring, control and protection covering multiple substation sites including automating Onload Tap Changer operation at SAPN connection points.	Main Grid	Reactive support Augmentation	Installation of five 275 kV reactors by end of 2027 Automated switching by 2030
EC.14084 Line Conductor and Earthwire Refurbishment 2019 to 2023 Program to replace transmission line conductors and earthwire to extend the life of seven 132 kV transmission lines in the Mid North and Riverland regions.	Mid North and Riverland	Asset condition and performance Asset renewal	October 2027
EC.15279 Emergency Unit Asset Replacement 2023–24 to 2027–28 Emergency replacement of individual assets is undertaken for assets that fail unexpectedly, to meet reliability standards.	Various	Asset condition and performance Asset renewal	June 2028
EC.15568 Northfield Transformer 8, 9 and 10 Interface Connection Requirement SAPN are planning to replace their aging/failing 66kV Gas Insulated Switchgear (GIS) switchgear at Northfield substation with a new Air Insulated Switchgear (AIS) 66kV switchyard. To support this replacement, we will need to upgrade the 66 kV GIS to AIS connection points to transformer #9 and will be replacing our two aging GIS transformers (#7 and #8) with two new AIS transformers (#1 and #2) at Northfield substation.	Metropolitan	Asset condition and performance Asset renewal	Connection of transformer #9 by April 2026 Connection of transformer #1 by September 2026 Connection of transformer #2 by July 2030
EC.14077 Mannum Transformer #1 and Secondary System Replacement Replace transformer #1 and secondary systems at Mannum substation that has been assessed to be at the end of their technical lives with a corresponding high risk of failure, with a new 25 MVA 132/33 kV transformers (nearest ElectraNet standard size). Note that Mannum transformer #2 was replaced in 2021 when the transformer failed.	Eastern Hills	Asset condition and performance Asset renewal	Transformer#1 replaced by October 2025 Secondary Systems replaced by June 2029
EC.14182 South East SVC Computer Control System Replacement Replace the computer control system for the SVC 1 and SVC 2 at South East substation that has been assessed as being end of its life cycle, requiring replacement during the 2024–2028 regulatory control period. We published a PACR on 16 November 2023, concluding the RIT T for this project.	South East	Asset condition and performance Asset renewal	December 2027

Table 10: Committed projects (cont.)

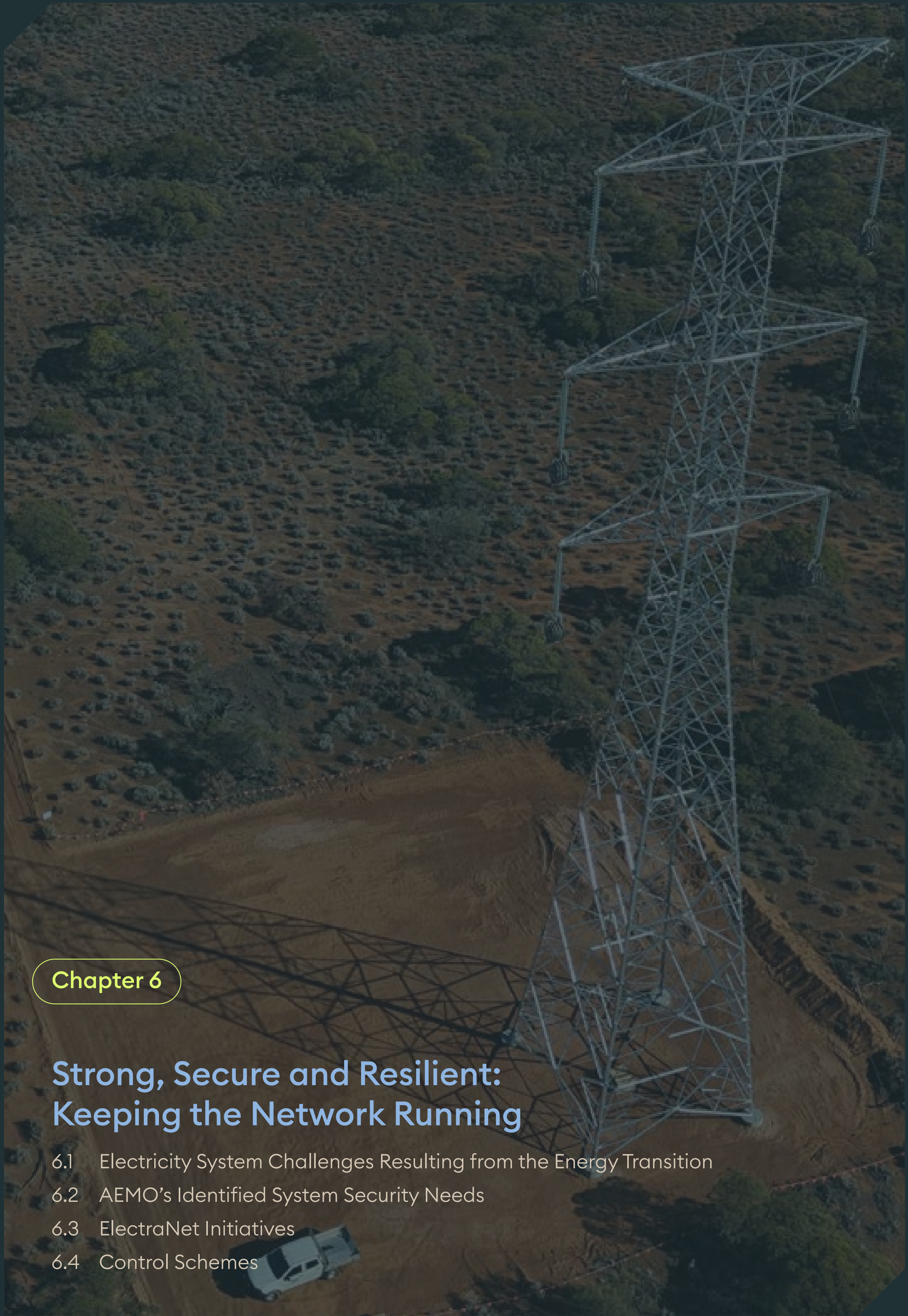
Project Description	Region	Constraint Driver and Investment Type	Planned Asset in Service
EC.15321 TIPS IMB300 CT Replacement Urgent removal and replacement of 38 sets of current transformers at TIPS A and B switchyards that have been identified as high risk of failure.	Metro	Asset condition and performance Asset renewal	June 2026
EC.15449 IMB300 CT Hazard Mitigation Replace 56 sets of current transformers at six substations that have been identified as high risk of failure, based on failure of similar of current transformers that were of same make, model and age.	Various	Asset condition and performance Asset renewal	October 2026
EC.14081 Line Insulator Systems Refurbishment 2018–2023 Program to refurbish transmission line support systems and extend the life of 18 transmission lines by renewing line asset components.	Various	Asset condition and performance Asset renewal	November 2026
EC.14046 AC Board Replacement 2018–2023 Replace and improve AC auxiliary supply equipment, switchboards and cabling at 23 substations that are at the end of technical life.	Various	Asset condition and safety Asset renewal	April 2026
EC.15171 NCIPAP Davenport to Cultana line uprating 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	September 2026
EG.01011 / EC.15571 Transmission Line Rating Improvement 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.	All	Market benefits (NCIPAP) Augmentation	June 2026
EC.15175 Increase Murraylink Transfer Capacity This project is included in our 2023–24 to 2027–28 NCIPAP Alleviate forecast congestion on the Murraylink interconnector at times of high export by installing a 132 kV capacitor bank Monash and upgrade the existing runback control scheme to include bi-directionality and allow it to run forward if required.	Riverland	Market benefits (NCIPAP) Augmentation	June 2027

5.3.3 Recently Completed Developments

ElectraNet has completed several significant projects to remove network limitations, address asset condition, and increase capacity and capability of the South Australian Transmission Network (Table 11).

Table 11: Recently completed developments

Project Description	Region	Constraint Driver and Investment Type	Planned Asset in Service
EC.14033 Circuit Breaker Unit Asset Replacement 2018–2023 Replace 15 circuit breakers located in six substations that are at the end of their technical lives and require replacement based on their condition due to an increasing risk of catastrophic failure.	Various	Asset condition and performance Asset renewal	February 2025
EC.14047 Transformer Bushing Unit Asset Replacement 2018–2023 Replace transformer bushings fitted on 20 power transformers located in nine substations that are at the end of their technical lives and require replacement based on their condition, due to an increasing risk of failure that may result in safety and reliability issues, or in the worst case, catastrophic failure of the transformer and the resultant loss and associated damage.	Various	Asset condition and performance Asset renewal	April 2025
EC.15474 Tailem Bend to South East High-Risk Tower Foundation Replacements Replace foundations on 12 high-risk towers along the Tailem Bend to South-East 275 kV double circuit interconnector, following an incident on 22 November 2022 when a tower foundation failed on this transmission line.	South East	Asset condition and performance Asset renewal	July 2025
EC.14236 Capacitor Bank Infrastructure Safety Improvement Improve the safety of personnel accessing enclosed high voltage areas having low height high voltage equipment at 18 substations, so far as is reasonably practicable, by: • upgrading fences on low height high voltage equipment to current standards • improving earthling of high voltage equipment within enclosures • upgrading entry points to current standards.	Various	Safety Asset renewal	February 2025
EC.15179 Robertstown to Tungkillo Line Uprating *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 100°C to 120°C design clearances. This will increase the average line ratings by 90 MVA. ElectraNet envisages that this project will impact intra-regional transfer, but not inter-regional transfer.	Mid North	Market benefits (NCIPAP) Augmentation	October 2025
EC.15503 F1813 Davenport – Leigh Creek Damage Section Replacement 2024 Replace 19 structures, conductors and earth-wire systems between Davenport and Leigh Creek substations that were damaged in the storm event on 17th October 2024.	Upper North	Asset condition and performance Asset renewal	February 2025
EC.11646 Eyre Peninsula and Upper North Voltage Control Scheme Implement automated voltage control scheme to ensure the complex voltage interactions at Mount Gunson and Wudinna are managed.	Eyre Peninsula and Upper North	Power Quality Operational	November 2025



Chapter 6

Strong, Secure and Resilient: Keeping the Network Running

Strong, Secure and Resilient: Keeping the Network Running

As South Australia's sole TNSP, ElectraNet ensures a strong, resilient and secure transmission network in the state in accordance with the Rules.

The change to South Australia's electricity system due to the ongoing energy transition has been steep. In less than 20 years the state's electricity system has gone from being made up of 90% fossil fuels and 10% renewables to a system today where all coal fired generation has been retired, and 75% of South Australian generation is from renewables with gas and diesel providing the balance and continuing to drop (Figure 29).

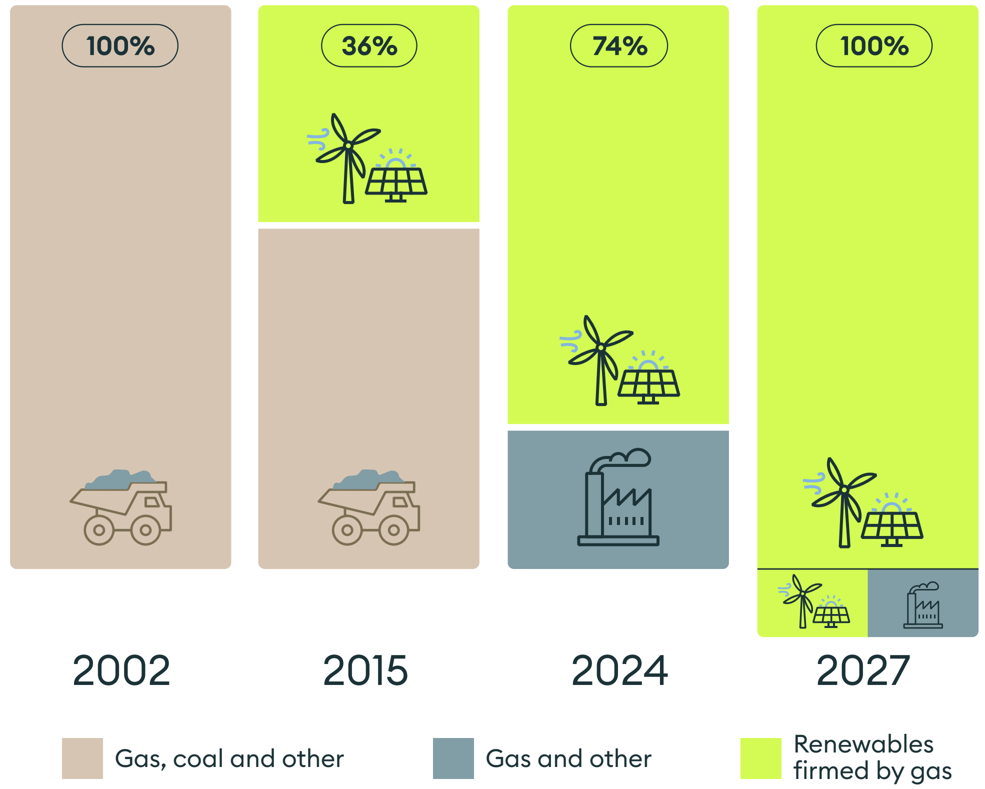


Figure 29: The transition to 100% variable renewable energy in South Australia

It is important to understand that the scale and speed of South Australia's energy transition is achieved by the corresponding ability of the electricity network to accommodate it and relies on ElectraNet working closely with AEMO to continually monitor the impact on the network, forecast potential challenges and invest appropriately to address them. ElectraNet is doing just that, dedicating its expertise and prudent resource management to ensure that emerging challenges from the transition don't negatively impact customers.

This chapter explores the challenges facing the network as a result of South Australia's energy transition, the findings and guidance from AEMO on how to address these challenges, and the work that ElectraNet is doing to both manage existing change and prepare for the future.

6.1 Electricity System Challenges Resulting from the Energy Transition

The success South Australia has had in decarbonising its network brings significant and varying challenges to the network.

For example, the variability of wind and solar energy resources leads to an increasing rate of change of power flows on the network. This needs to be managed appropriately to maintain a secure and reliable supply. For example, on 3rd Oct 2025, wind and solar supplied 91% of SA demand at midday, fell to 6% six hours later, and rebounded to 107% several hours after that – illustrating the operational volatility that must be routinely managed.

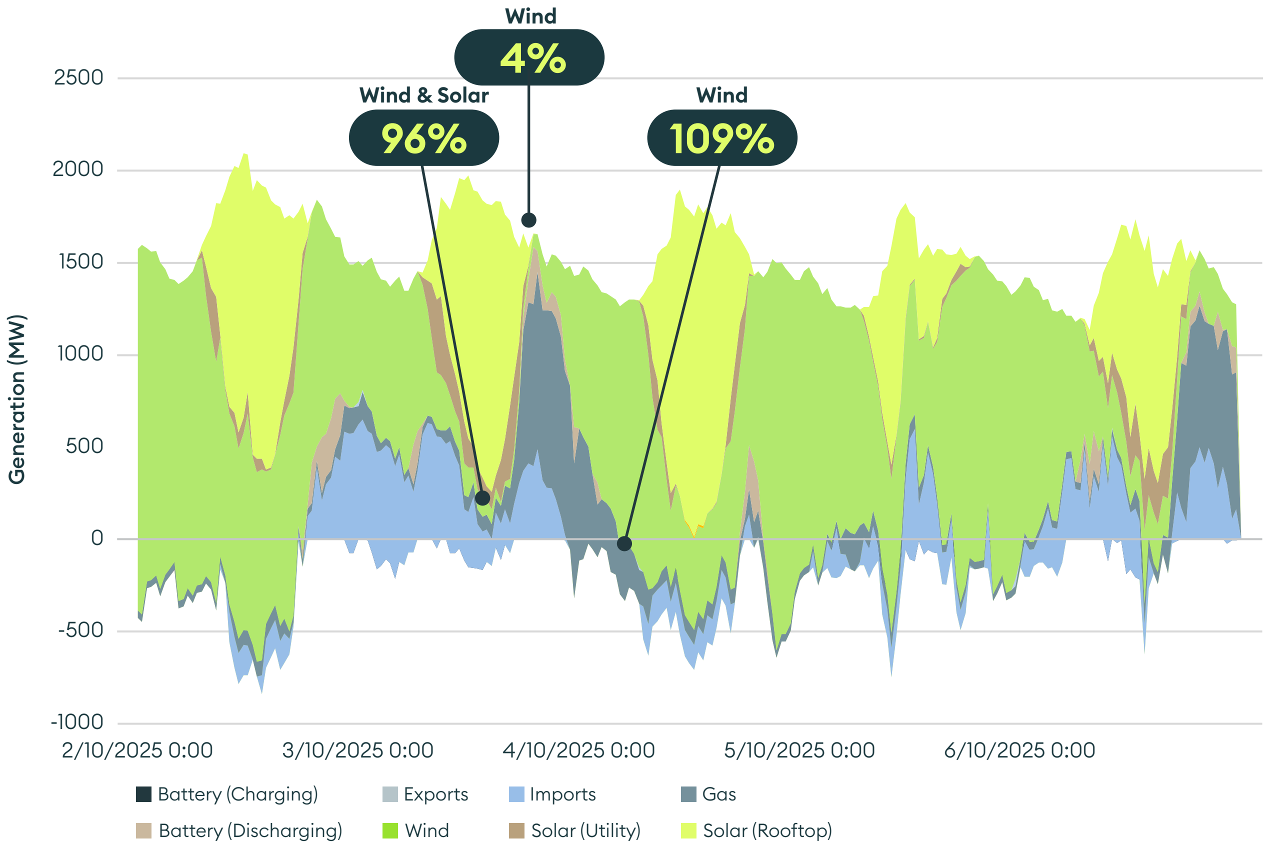


Figure 30: Variability in South Australian generation, October 2025

Managing this volatility of generation across the day and through the seasons requires new approaches and capabilities. One mechanism introduced by the SA Government to support these efforts is the Firm Energy Reliability Mechanism (FERM).[24] The FERM will tender for firming capacity, whereby long duration firm capacity generators annually tender for contracts to meet a rolling five-year Firm Energy Target, to maintain reliability of the system under conditions of high variability. This firming capacity can be provided by technologies such as conventional generation or storage such as batteries or pumped hydro.

The South Australian Electricity Development Plan calculates that the combined capacity required to meet this challenge through to 2030–31 is 2,300 MW of long duration firming capacity (generators that are over 30 MW and are capable of being dispatched for a minimum of eight hours). This will support the reliability and resilience of the network while also preventing barriers to investment for large, energy intensive industries. The development of the network will need to accommodate different locations and capacity of firming generation as the deployment of the FERM progresses.

[24] Energy & Mining | Firm Energy Reliability Mechanism (FERM)

The key challenges facing South Australia's electricity system and how the energy transition can impact each of them, and hence the network, are outlined in Table 12.

Table 12: Key challenges facing South Australia's electricity system

Challenge	Description	Impact of Energy Transition
System strength	The ability of an electricity system to maintain stable voltage waveform[25] at any given location in the network when subjected to disturbances, such as faults, sudden changes in power flows, and maintaining sufficient fault levels for protection systems to operate correctly during contingencies.	Synchronous generation in the form of coal and gas fuelled generators has traditionally supplied system strength. The energy transition has however seen these rapidly replaced by inverter-based resources (IBR) creating the potential for supply interruptions to end consumers.
System security	The ability of an electricity system to operate reliably under both normal and abnormal conditions.	Shortfalls in frequency control, system strength and inertia services, historically provided by synchronous generators.
Resilience	The ability of a high VRE electricity system to recover from major disruptions, including extreme weather or widespread blackouts.	As the frequency and severity of extreme weather events increase, the power system requires improved resilience measures, including rapid restoration capabilities, emergency response, islanding capability and enhanced grid flexibility.
Inertia	The ability of an electricity system to withstand disturbances while maintaining stable system frequency.	Traditionally provided by synchronous generators, inertia is now reduced due to the transition to IBRs, requiring alternative solutions such as fast frequency response mechanisms.
Voltage control	The ability to maintain voltages throughout an electricity system within stable and safe limits.	Increasing penetration of IBR reduces minimum demand and creates changes in customer load characteristics leading to increasing reactive power and voltage control challenges.
Frequency control	The ability to maintain the frequency of the power system within stable limits.	Traditional frequency control utilised inertia as a natural buffer, preventing rapid frequency swings when generation or demand fluctuated. IBRs don't inherently provide inertia and hence managing rapid frequency changes or peaks and troughs in frequency requires new solutions. New developments are however enabling IBRs to provide inertia with the right controls.
Protection adequacy	The ability of the electricity system's fault detection and protection systems to operate correctly under evolving grid conditions.	Fault currents were more predictable when the system was dominated by synchronous generators. Changing requirements require more frequent review, including for minimum fault level conditions from IBR generation and bi-directional power flows from rooftop solar PV. Faster voltage swings also require protection systems that can react instantly.
Increasing system complexity and risk	As the electricity network becomes more decentralised, its complexity has increased, requiring different approaches to operation and planning.	More distributed energy resources, renewable generation, and increased interconnection between markets have created a wider range of operating conditions with more frequent stress points, and higher variability including zero and negative minimum demand conditions.

[25] AEMO | System Strength Requirements Methodology, page 20

Table 12: Key challenges facing South Australia's electricity system (cont.)

Challenge	Description	Impact of Energy Transition
Extreme events	Extreme weather events such as storms, heatwaves, bushfires and flooding, all pose significant risks to the electricity system's stability and resilience.	Increased risk to the system has created a greater reliance on complex special protection schemes to manage risk and maximise power transfer capability.
Harnessing customer energy resources	CER refers to small-scale, distributed energy assets owned by households and businesses, including rooftop solar PV, batteries and electric vehicles.	Integrating millions of individual CER to manage excess generation while delivering lowest cost outcomes and addressing system security risks.

6.2 AEMO's Identified System Security Needs

Previously, AEMO had published three reports relating to system security, most recently in December 2024:

- The Transition Plan for System Security
- System Strength Report
- Inertia Report
- Network Support and Control Ancillary Services (NSCAS) Report.

As of 1 December 2025, AEMO has combined all four system security reports as the Transition Plan for System Security (TPSS).

The TPSS is an annual report focusing on maintaining power system security as the National Electricity Market (NEM) transitions towards lower emissions. It provides a structured approach for the energy sector to navigate key upcoming transition points – events that require material changes in the operational approach to managing power system security – over at least the next 10 years.

The following set out the finding from the 2025 TPSS with regards to South Australia.

6.2.1 System Strength

From December 2, 2025, a new system strength framework began operation under the NER under which ElectraNet is required to deliver system strength services for South Australia on a forward-looking basis, based on IBR forecasts from AEMO.

The new framework goes beyond ensuring that 'shortfalls' are met and instead seeks to ensure that system strength is met in full throughout the year through a portfolio of solutions. The new framework is designed to ensure that solutions are put in place that achieve economies of scale, while also preserving the option for new entrants to bring their own solutions.

This approach will ensure that competition drives not only the best solution, but lowest long run costs to the consumer, and is biased towards early procurement of services rather than late procurement.

The system strength framework identifies a minimum requirement and a higher efficient level of services. AEMO's 2025 forecasts indicates that the minimum requirement in South Australia will continue to be met, and no further action is required by ElectraNet for the foreseeable future to address this.

The efficient level must also be met by ElectraNet to ensure system strength is in place to enable the more rapid connection of IBR such as solar and wind. The efficient level is however based on AEMO's forecast of IBR as presented in AEMOs Draft 2026 ISP modelling. In South Australia, this delivers a forecast of around 4,400 MW of IBR (including existing transmission connected IBR, but excluding distribution connected IBR).

ElectraNet has undertaken a RIT-T on system strength requirements in SA. The associated PSCR , PADR and PACR were developed to define our response to maintain sufficient system strength for hosting IBR connections forecast under the 2024 ISP *Step Change* scenario. ElectraNet have identified the preferred option as contracting with future non-network proponents who can add mechanical clutches to synchronous generators within the next five years. This is envisaged to be done as part of the initial build costs, reflecting the incremental costs of the auxiliary systems and the cost of operation (including energy losses) as a synchronous condenser. Geographically, and considering the long-term trend of varying quality of fault levels, the 275 kV nodes of the Metropolitan region or the Eyre Peninsula are the preferred locations for new synchronous generators with integrated mechanical clutches. ElectraNet considers that the preferred option at this stage satisfies the RIT-T.

6.2.2 Inertia

AEMO's 2025 TPSS provides an outline of the inertia requirements for the coming 10-year period for the NEM. This report includes an assessment of the minimum inertia requirements, a "secure inertia level" and the likelihood of each region becoming islanded from the remainder of the NEM – with the aim of ensuring all regions have adequate frequency control services in place to operate securely and independently, when needed. ElectraNet is required to ensure sufficient supplies are available to meet its inertial sub-network allocation from 2 December 2027.

The minimum or 'satisfactory' level of inertia required to be maintained in South Australia was determined to be 4,100 MW and the secure operating level is 5,600 MW.

Table 13: South Australian inertia requirements from 2 December 2024 to 1 December 2034

Quantity	Value
Assumed level of 1-second FCAS	403 MW
Satisfactory inertia level	4,100 MWs
Secure inertia level	5,600 MWs
Inertia sub-network allocation	4,300 MWs
Minimum regional interconnected inertia level	1,800 MWs
Likelihood of islanding	Likely

Source: AEMO's 2025 TPSS.

In addition, AEMO does not consider the islanding of South Australia to be sufficiently likely following the expected commissioning of PEC Stage 2. This includes the necessary emergency control schemes being in place to manage the non-credible loss of Project Energy Connect itself or the Heywood interconnector.

Furthermore, AEMO has determined that no inertia shortfalls for South Australia over the three-year investment horizon, noting that an earlier inertia shortfall has been addressed by ElectraNet's deliberate intervention in the form of synchronous condensers installed in 2021, along with additional registrations in the 1-second Frequency Control Ancillary Services (FCAS) market.

Given South Australia's increasing energy demand ElectraNet will continue to work with AEMO to monitor whether the state's relative share of demand increases as a proportion of the NEM, as this may alter the inertia requirements necessary to maintain the required inertia levels.

6.2.3 Network Support and Control Ancillary Services (NSCAS)

AEMO's 2024 NSCAS Report released in December 2024 has identified new system security needs across the NEM over the coming five years. Across the NEM, AEMO reports declining minimum operational demand, reduced operation of synchronous generators, and rapid uptake of variable renewable energy have combined to create an increased need for essential power system services.

In this year's report AEMO has confirmed that in addition to not identifying any system strength or inertia shortfalls in South Australia, that the magnitude and timing of the voltage control gap that was first declared in the 2023 NSCAS Report has improved.

In December 2023, AEMO declared an ongoing Reliability and Security Ancillary Service (RSAS) gap of 200 MVAr during periods when South Australian demand is below 600 MW, and South Australia is not islanded or at credible risk of islanding. ElectraNet has addressed this gap through a RIT-T process, with additional shunt reactors to be installed in the Adelaide metropolitan region (3x60 MVAr and 2x50 MVAr) and South East (1x50 MVAr). These reactors will be deployed progressively by 2026, with three already in service, 2x50 MVAr in the Adelaide metropolitan area and 1x50 MVAr in the South East, and the remaining three to be in service by October 2027.

Post the introduction of new conditions in SA that the system could operate down to a single synchronous unit, AEMO has identified that under night-time conditions there exists a risk of growing capacitive demand exacerbating voltage control issues. As a function of the NSCAS analysis in the TPSS, AEMO indicates that there is no voltage management risk under current assumptions. None-the-less this is an emerging risk and ElectraNet will continue to work with AEMO to track trends in reactive demand over time.

6.2.4 General Power System Risk Review (GPSRR)

In addition to the three reports just discussed, AEMO published the final report for the 2025 GPSRR, in July 2025. The GPSRR is intended to help AEMO, NSPs and other market participants to better understand the nature of new risks and monitor them over time.

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

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

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

As part of the 2025 GPSRR, AEMO considered the following priority risks:

- Minimum system load (MSL)
- Unexpected operation or interaction of protection systems and control schemes
- Increasing risks of non-credible contingencies
- Inverter-based resources (IBR) response to remote frequency events.

Recommendations and findings related to South Australia

As the growth of distributed PV and other CER continues, the lack of emergency backstop mechanisms is contributing to operational risk during MSL conditions. In the 2025 GPSRR AEMO recommends all TNSPs in the NEM to:

- Develop TNSP operating procedures for the use of emergency backstop
- Analyse transmission system needs in low demand periods.

The NEM is seeing changing fault levels, new transmission topologies, and varying power flow paths as the energy transition progresses. As a result, many of the assumptions underpinning power system protection designs are subject to change. In addition, new generation projects are increasingly observed to propose remedial action schemes (RASs) to manage non-credible contingencies.

Considering RASs, there are both challenges and benefits to their implementation. On the downside, the schemes add complexity to the network but conversely, they also deliver benefits by minimising costs and deferring the need for further investment in primary plant that would otherwise be required. To manage the increase in complexity and changing system conditions, the risk of unexpected operation of protection systems and control schemes requires increased consideration.

To understand these impacts in more detail the GPSRR recommends that AEMO leads a project with input from industry to investigate and implement explicit requirements related to RASs in the NEM. ElectraNet will be collaborating with AEMO to further understand and mitigate unexpected operation or interaction of protection systems and control schemes in South Australia.

On the changing topology of the power system, this has the potential to increase the risk of non-credible contingencies, as the number and size of potential non-credible contingencies increase. Continued assessment of the risk of these events will become increasingly important as the potential impacts become more significant, testing the resilience of the power system.

As the installed capacity of BESS increases in SA, there is a potential for interconnector instability. This is due to the aggregate response of BESSs for a remote generation contingency during SA export conditions, and for a remote load contingency during SA import conditions. However, AEMO analysis identified that existing and planned BESS facilities in the NEM are sufficiently distributed to mitigate the risk of excessive BESS frequency response in the short and medium term. AEMO recommends that all NSPs:

- Continue monitoring the location, control settings, and timelines of expected BESS or other fast-acting IBR connections in their respective networks or regions
- Continue sharing any changes in concentration of IBR in regions or sub-regions that could affect power system stability.

ElectraNet continues to collaborate with AEMO and other TNSPs in relation to the recommendations from previous iterations of the GPSRR. Key areas of focus include:

- Reviewing the effectiveness of the OFGS and modify it as required, to include additional generation in the scheme
- Evaluating current and emerging operational capability gaps, encompassing online tools, systems and training.

Managing risks associated with lightning trips in SA, including:

- Investigating SA transmission tower earthing and lightning protection based on recent contingency events to identify or rule-out any existing design weaknesses
- Investigate the suitability of a RAS to prevent South Australia intra-regional separation.

6.3 ElectraNet Initiatives

To continue to appropriately address the changes to the network from the energy transition in South Australia and maintain the stability of the power system, ElectraNet is pursuing a range of solutions that are designed to not only address the evolving requirements of the system; but also ensure an efficient approach to delivering the benefits needed for the investment required.

A full list of projects is included in Appendix F.6.

These solutions include as a priority initiatives addressing the following six areas:

- System Strength
- System Security
- Resilience
- Voltage Control
- Control Schemes
- Operability.

6.3.1 System Strength

In 2021, ElectraNet installed and began operating the state's first large synchronous condenser: a large motor that spins freely without fuel combustion or power generation. South Australia now has four synchronous condensers: two at Davenport, near Port Augusta; and two at Robertstown, north of Adelaide. Together, this infrastructure provides increased reactive power to the grid – enabling it to better meet system strength and inertia requirements, to maintain grid stability.

AEMO's 2022, 2023 and 2024 System Strength Reports indicated that 'minimum level' system strength requirements are forecast to be sufficient within a three-year period in South Australia without intervention by ElectraNet or AEMO. Further, ElectraNet is not forecasting a shortfall beyond that horizon.

Modern wind farms, solar farms, and BESSs are based on voltage inverter technology and are known collectively as inverter-based resources (IBR). ElectraNet's analysis of AEMO's System Strength Reports identified that there may be a need for ElectraNet to provide additional system strength services to meet the 'efficient level' system strength requirements based on forecast volumes of IBR.

In late 2023 we commenced a RIT-T with the publication of the PSCR specifying an identified need.

Subsequently, we assessed the requirements with detailed modelling and published the PADR in April 2025. Detailed modelling completed by ElectraNet has shown that the existing network, including the infrastructure outlined above and following the commissioning of Project Energy Connect stage 2 (330kV double circuit line between Bundey, Buronga and Wagga-Wagga to be operational in 2027), will have sufficient system strength to meet the efficient level required under the NER.

There are some uncertainties with this analysis, including:

- the rate of growth in IBR investments
- the rate at which IBR generators will improve and contribute to satisfying system strength services
- the assumed representation of the forecast generation included in the PSCAD models more than three years ahead.

As a result, ElectraNet does not consider there to be a requirement for large capital expenditure on additional synchronous condensers at this point under the ISP Step Change scenario. This position differs from that in the PSCR and is due to changes in the IBR forecasts since the PSCR was published, as well as the more refined methodology we have applied at the PADR stage.

Looking to the 2024 ISP Step Change scenario after December 2029, ElectraNet considers it prudent to identify low-cost generic system strength services as a low regret back up. ElectraNet also recognises that AEMO's forecast on IBR volume under the Green Energy Exports scenario exceeds 11 GW of wind, solar and batteries over the next 10 years (section 3.2).

The interest in new large industrial load connections to the transmission network also raises the potential for a much more rapid increase in IBR connections than forecast in the Step Change scenario. This would require a significant increase in the efficient level of system strength.

ElectraNet considers the Green Energy Exports, now Accelerated Transition, scenario is a useful proxy for the potential connection of large industrial loads. If this scenario unfolds, and no action is taken to meet the efficient level, there could potentially be significant and rapid investment in further system strength services requirements. It may not be possible to deliver this investment sufficiently quickly, due to the long lead times for some of these investments, which could result in insufficient system strength. Alternatively, while it may be possible to deliver an urgent investment in time, it could come at a significant cost to customers.

Proactively preparing the network with low-cost mechanical clutches to new synchronous generators, enabling them to operate as synchronous condensers, may partially or completely avoid the need for any such 'emergency investment' (as well as any reliability implications for customers).

Based on submissions to the PSCR and the Government of South Australia's development of a FERM, ElectraNet considers it likely that new synchronous generators will develop in the next few years.

The use of clutches provides an opportunistic, low cost and 'low regret' insurance against the need to provide additional system strength in South Australia due to a greater volume of IBR connecting (e.g. through large industrial load connections) in the next three to five years.

Specifically, while these solutions would ultimately be provided by non-network proponents (the costs of which would be recovered via network support contracts with ElectraNet), the incremental capital cost of fitting clutches during construction is estimated to cost in the order of $5 million.

The addition of clutches to new synchronous generators provides prudent insurance against needing to provide additional higher-cost system strength services in the future, and these contracts should be considered the basis of the preferred option for the ongoing provision of an efficient level of system strength. ElectraNet considers this conclusion to be consistent with the recent AER guidance on managing uncertainty beyond the compliance years (i.e. that System Strength Service Providers may procure system strength solutions for beyond the next three years if they demonstrate net economic benefits).

6.3.2 System Security

As the South Australian generation mix changes and ElectraNet's transmission network expands to deliver the energy from existing and proposed energy projects in the state's REZs, it will be important to ensure that diversity is maintained in the network to avoid disruption. This is particularly the case when seeking to manage the risk in areas prone to bushfire, high wind speeds or other climate related events that have the potential to impact on the electricity network are increasing in frequency and intensity.

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 in 2019–20, such as Hospers Mountain (Hawkesbury), Green Wattle Creek (Wollondilly) and Currowan (Shoalhaven) each burnt areas of more than 200,000 hectares.

ElectraNet is pursuing two investments to mitigate the risks posed by bushfire or high winds, building increased system security as the network grows. The NTx project includes a proposed southern circuit from Bundey to Adelaide, with a route that avoids the existing transmission line through the bush fire prone Adelaide Hills. Also being included as part of the scope of NTx is a northern circuit from Bundey to the Upper Spencer Gulf, with a route that avoids the region south of Port Augusta where high winds have previously damaged multiple existing lines (such as in the system black event of 2016).

6.3.3 Resilience

A RAS is an advanced grid protection system designed to automatically detect and respond to abnormal conditions on the electricity network. A RAS is designed to monitor the grid at a holistic level, taking coordinated actions to maintain stability and prevent cascading failures.

RAS systems are today being used across the NEM to prevent minor disturbances from escalating into major system failures. As South Australia continues its transition to more renewables, RAS systems are becoming even more essential in managing the increased risk of destabilisation, due to the unpredictable fluctuation of generation, and increasingly frequent extreme weather events.

As part of PEC, ElectraNet is developing the SAIT RAS. SAIT RAS is designed to detect the non-credible loss of either the Heywood Interconnector or PEC, and will take remedial action to prevent the remaining interconnector from tripping due to power system instability. SAIT RAS is important for building greater resilience in the network, ensuring that it is easier and quicker to restore load – compared to what would be possible if recovering from a system black state.

The SAIT RAS comprises three main components, planned for commissioning in Q2 2026:

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

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

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

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

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

In addition to RASs, ElectraNet is responsible for ensuring that all network planning and design is conducted to ensure the network withstands stress conditions. This is covered in more detail in section 3.7.

6.3.4 Voltage Control

ElectraNet is working closely with SAPN to enhance voltage control across South Australia's electricity network. Part of this approach involves pursuing a range of cost-effective voltage control enhancements that reduce peak demand in the evenings and facilitate increased solar energy exports during peak generation times. This approach enables the deferral of large investments in the transmission network by instead accessing ex ante project funding; including through the Demand Management Innovation Allowance Mechanism that promotes innovative demand management projects.

A challenge experienced with this approach to reduce cost has been the simultaneous increase of project costs, resulting in a reduced ability of ElectraNet to deliver the network changes required. One option to address this would be to enable Ex Ante funding to be indexed to enable project cost increases to be absorbed more effectively, and in doing so enable greater benefits to flow through to consumers from efficient energy management projects.

6.3.5 Operability

The significant changes to South Australia's energy system necessitates improvements and changes to the way the network is operated. To address this ElectraNet is developing and implementing network planning and operations capabilities to manage power system changes in an increasingly complex and volatile environment. Changes required to ElectraNet's systems, people and processes have been identified, ensuring the right capabilities are in place, and are flexible enough to allow continued support for operational changes into the future. Complementing this, ElectraNet is also working with AEMO and other transmission providers to develop a future capability framework that guides technology investments and the capability uplift required.

Regarding our specific technical uplifts, ElectraNet is upgrading its Electricity Management System (EMS), deploying the foundational capability to support future network operational needs. In addition, we are embarking on establishing a Network Model Management Solution (NMMS) as a centralised, trusted grid network model that supports the entire asset lifecycle, from planning and design through commissioning and operations. The NMMS is foundational for ElectraNet to prepare for increasing network and operational complexity, combined with a higher volume of network changes.

In future the NMMS will enhance the ability to create and maintain accurate, accessible and timely network information to support improved network planning and operations, such as:

- Improved integration with the EMS – importing network augmentations by utilising a standards-based model exchange.
- Outage coordination – Deliver a concise view of known outages and enable flexible and responsive action, including modelling and decision support for outages, as well as end-to-end digitisation of outage processes.
- Protection adequacy – standards-based integration with a device configuration management system to improve regular protection reviews and coordination.

6.4 Control Schemes

ElectraNet has implemented, continues to implement and is planning for a range of different control schemes designed to allow the energy system to adapt to variable generation, changing demand patterns and evolving technical challenges.

These control schemes maximise the efficiency, reliability and security of the existing network, utilising existing capacity rather than requiring major new infrastructure investments.

6.4.1 Frequency Control Schemes

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

- a distributed automatic UFLS scheme
- a distributed automatic OFGS scheme
- Emergency Control Schemes.

Automatic UFLS

South Australia's existing UFLS scheme is designed to return system frequency to normal following an event that leads to South Australia separating from the rest of the NEM while importing across the Heywood interconnector.

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

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

- 700 MW, or
- 60% of operational demand.

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

ElectraNet has worked with transmission network direct-connect customers to ensure UFLS arrangements for each customer comply with Rules obligations. SAPN met targets to roll out "dynamic arming" of UFLS relays (relays designed to dynamically disarm if the circuit is in reverse flows), by September 2024. Over 700 MW of BESS are either committed or in commissioning in South Australia, which will significantly increase the amount of BESS headroom that will be typically available to provide emergency frequency response.

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

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

Automatic OFGS

The purpose of OFGS is to manage the frequency performance during islanding events resulting from non-credible or multiple contingencies during high export to Victoria. The South Australia OFGS operates in the frequency range of 51 to 52 Hz. Generation to be tripped is split into eight blocks, each with around 150 MW of wind generation, set to trip between 51 Hz and 52 Hz.

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

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

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

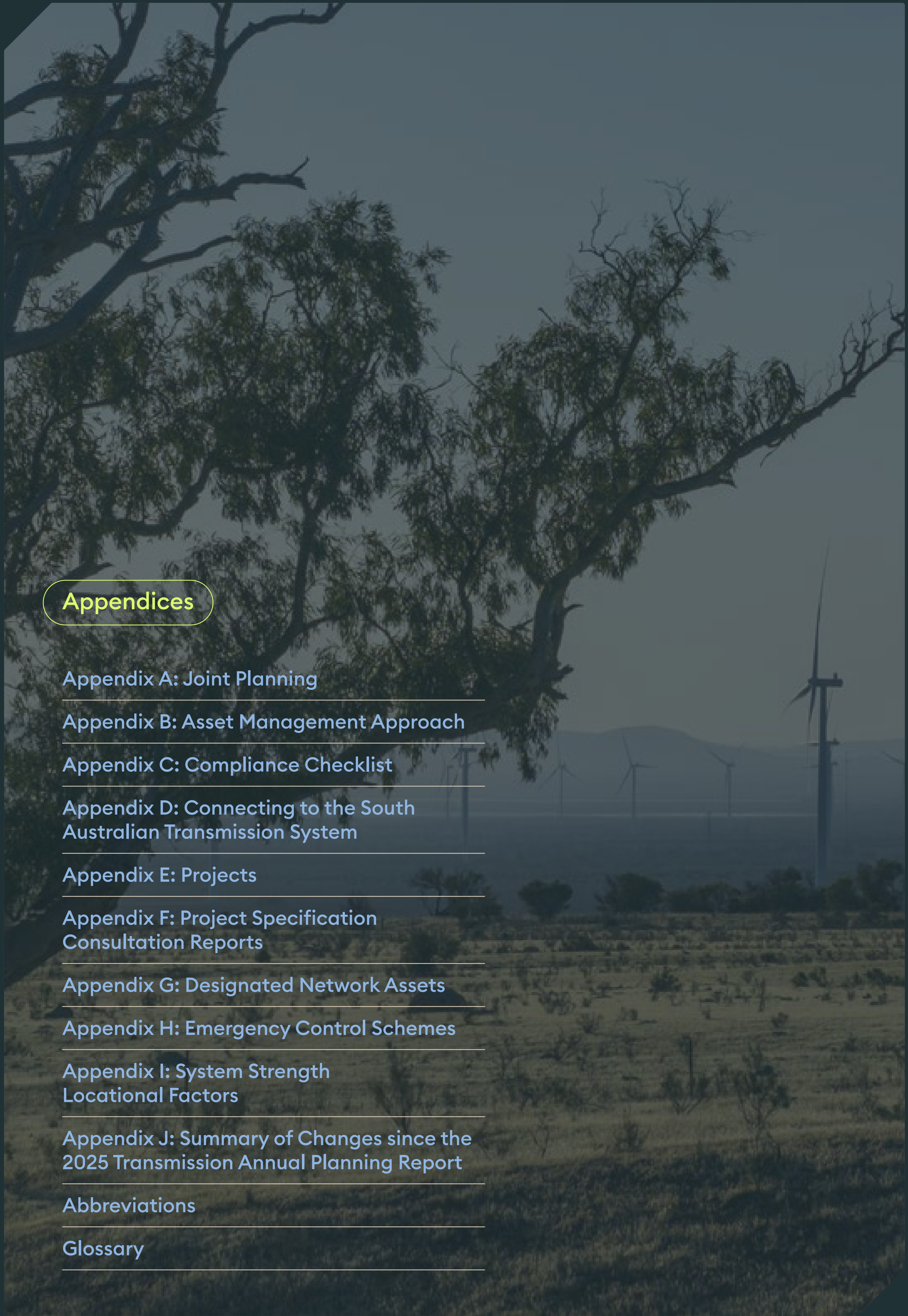
6.4.2 Emergency Control Schemes

With increasing complexity in South Australia's electricity network emergency control schemes are becoming an increasingly important part of the system. These schemes are automated or manual systems designed to maintain the stability and security of the electricity network during unexpected or extreme events. They kick in when normal operations are threatened and are often thought of as the network's emergency breaks. This includes a sudden loss of a generator or major transmission line, and natural disaster or equipment failure.

However, if designed appropriately emergency control schemes can play a more strategic role, enabling system security, while also maximising the capability of the network, without the need for significant capital investment to augment the system.

It is important to ensure that putting in place an emergency control scheme doesn't trigger the very event they were designed to prevent. To avoid this, ElectraNet ensures that it monitors potential interactions between different emergency control schemes to avoid conflicting actions, prevent cascading failures and preserve system integrity.

A list of emergency control schemes that are in development, or being considered, in South Australia is provided in Appendix H.



Appendices

Appendix A
Joint Planning

We undertake a wide range of joint planning activities with both transmission and distribution entities on a regular and as-needed basis, and through a range of forums. This includes working closely with SA Power Networks to ensure optimal solutions for South Australian customers are identified and implemented.

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

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

A.1 National transmission planning working groups

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

- Executive Joint Planning Committee
- Joint Planning Committee
- Operational Transition Planning Working Group
- Future Transition Points Working Group
- Regulatory Working Group
- Market Modelling Reference Group
- Forecasting Reference Group
- Power System Modelling Reference Group
- System Strength Service Providers Working Group
- ENA[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.

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.

Operational Transition Planning Working Group

The Operational Transition Planning Working Group identifies and assesses operational transition points from today to two years ahead, to facilitate preparation for when they materialise within the NEM.

Future Transition Points Working Group

The Future Transition Points Working Group identifies and assesses potential upcoming operational transition points in the planning timeframe (from 2-5 years ahead), to enable sufficient preparation for when they materialise within the NEM. The Future Transition Points Working Group coordinates with the Operational Transition Planning Working Group for potential transition points in the timeframe from today to two years ahead.

[1] Energy Networks Australia

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.

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.

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.

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.

System Strength Service Providers Working Group

The System Strength Service Providers Working Group is a regular working group with AEMO and each of the five system strength service providers. It is intended to support collaboration, consultation, and coordination between system strength service providers on implementing the System Strength Framework. The group is intended to workshop ideas, encourage consistent practices, and facilitate joint planning across regions.

A.2 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.

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.

A.3 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.

A.4 Joint Planning Projects

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

Integrated System Plan development

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 2024 ISP.

Project EnergyConnect

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 Project EnergyConnect into the NEM.

Northern Transmission Project

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

Northfield Transformer Replacement

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

Appendix B
Asset Management Approach

B.1 ElectraNet's asset management strategy

Our Asset Management Objectives guide our asset management plans and activities (Figure 31).

Safety

Ensure the safety of staff, contractors, and the public.

Affordability

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.

Reliability

Maintain the reliability of transmission services and the security and resilience of the network while balancing risk and service outcomes.

Sustainability

Operate our network in a way that enables people and nature to thrive.

Figure 31: ElectraNet's Asset Management Objectives

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 [2].

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.

[2] AEMC | National Electricity Rules clauses 6.5.6(a), 6.5.7(a), 6A.6.6 and 6A.6.7

Our asset management strategic planning framework is designed to deliver a safe and reliable network at an efficient cost (Table 14). Further detailed information is provided in the later sections of this appendix.

Table 14: How ElectraNet ensures efficient and prudent capital expenditure forecasts

Inputs and analysis	Our approach
Demand forecasts and reliability	Forecast demand is an important driver of reliability capital expenditure. We use estimates of the Value of Customer Reliability (VCR)[3] and Value of Network Resilience (VNR)[4] as determined by the AER. Adopting these independent values provides confidence in these inputs The demand forecasts are compared against the ability of the transmission system to meet the reliability standard set by the Electricity Transmission Code (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

[3] AER | Values of customer reliability final decision

[4] AER | Value of Network Resilience 2024

B.2 Capital expenditure

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

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

Transmission licence and ETC

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 the Essential Service Commission of South Australia (ESCOSA).[5]

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[6]
- 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.

[5] ESOCSA | ElectraNet transmission licence as currently in force (last varied 16 October 2019)

[6] AEMC | National Electricity Rules, Schedule 5.1

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 (Table 15).

Table 15: Connection point reliability categories

<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>

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.

The full version of the ETC version TC/09.4 is available at ESCOSA Codes.

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 Distribution Network Service Providers (DNSPs) and other TNSPs whose networks can impact the South Australian transmission network
- provide information to registered participants and interested parties on projected network limitations and the required timeframes for action
- 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.

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.

B.3 Capital expenditure categories

We apply a range of categories to our capital expenditure. For each category, we also identify the AER's reporting category as indicated in their TAPR Guideline (Table 16).[7]

Table 16: 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 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 to maintain reliability of supply. Replacement projects are generally undertaken due to the increased risk of plant failure due to 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

[7] Australia Energy Regulator | Transmission Annual Planning Report Guidelines

B.4 Expenditure forecasting methodology

Our capital expenditure forecasting methodology is outlined below.

Customer and stakeholder requirements

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

Planning process

The planning process operates within a strategic framework informed by our Network Transition Strategy, and industry planning documents prepared by AEMO such as the ISP. The planning process also relies on inputs such as demand forecasts and connection applications.

Assessment of network limitations

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

- Load and market benefit driven network investment requirements are identified through modelling of future power system capability and analysis of network constraints
- Non-load and non-market benefit driven network investment requirements are determined in accordance with our asset management framework, which takes a risk-based approach to the replacement or refurbishment of assets based on assessed risk, condition and performance.

Options analysis

A range of solutions (including both network and non-network options) are considered to address identified network limitations, and to efficiently defer the need for major capital investments for as long as possible, while maintaining safety, security, reliability and resilience, following a risk-based approach.

Economic analysis and risk assessment techniques are applied to investigate the potential options. The preferred solution must be technically and economically feasible, be deliverable in the timeframe required and minimise long-run total costs.

Scope and estimate

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

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

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

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

B.5 Key inputs and assumptions

The key inputs and assumptions underlying the network expenditure forecast comprise:

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

These are discussed in turn below.

Demand forecasts

Refer to chapter 2 in this report for information on how we develop and use demand forecasts.

Asset health and condition assessments

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

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

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

Planning and design standards

Our planning standards are derived from the Rules and the ETC, and are presented in more detail in appendix C.2. The ETC establishes the specific reliability standards that apply to each exit point on the transmission network. Connection point power factor requirements are reflected in customer connection agreements.

We have developed and maintain a comprehensive set of design and construction standards in order to comply with the requirements of our SRMTMP. This plan is required by section 15 of the Electricity Act 1996 (SA) to demonstrate that our infrastructure complies with good electricity industry practice and the standards referred to in the Act.

Network modelling

We use the Siemens Power Technologies International PSS/E suite of power system analysis programs as the platform for identifying both operational and future network limitations, as is the case for most other Australian TNSPs, DNSPs and AEMO. Our network model is provided to AEMO and is, therefore, subject to regular scrutiny by independent power industry experts.

Plant data is based on primary sources such as transmission line impedance tests, generator commissioning and compliance tests, power transformer test certificates and on secondary sources such as line impedances calculated from first principles.

Economic assessments

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

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

Inputs considered in these assessments include:

- capital and operating costs of alternative options
- reliability benefits – where unserved energy is measured by the VCR and VNR estimates published by the AER
- cost savings – for example avoided maintenance costs
- risk reduction – as measured by the quantified value of the risk reduced or avoided through the project (for example avoided environmental contamination)
- standard discount rate assumptions – based on a range of estimates including commercial rates and the prevailing regulated rate of return
- optimal timing – including the potential for deferral of an investment to a subsequent regulatory period.

Sensitivity testing is also conducted to determine the robustness and level of confidence in the outcomes of these economic assessments.

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

Non-network alternatives

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

Risk assessments

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

This risk analysis considers:

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

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

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

Project cost estimation

Project cost estimates are derived as described earlier in appendix C.4.

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.

B.6 Further information on ElectraNet's asset management strategy and methodology

Further information can be obtained from:

consultation@electranet.com.au

Appendix C Compliance Checklist

This appendix sets out a compliance checklist which demonstrates the compliance of ElectraNet's 2025 Transmission Annual Planning Report with the requirements of clause 5.12.2(c) of version 243 of the Rules (the latest version at time of writing).

Summary of Requirements		Section
The Transmission Annual Planning Report must be consistent with the TAPR Guidelines 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* from the previous year which are significantly different from the actual outcome;	Chapter 2, and our Transmission Annual Planning Report web page[8]
(1A)	for all *network* asset retirements, and for all *network* asset de-ratings that would result in a *network constraint*, that are planned over the minimum planning period specified in clause 5.12.1(c), the following information in sufficient detail relative to the size or significance of the asset: i. A description of the *network* asset, including location; ii. The reasons, including methodologies and assumptions used by the *Transmission Network Service Provider* for deciding that it is necessary or prudent for the network asset to be retired or de-rated, taking into account factors such as the condition of the *network* asset; iii. The date from which the *Transmission Network Service Provider* proposes that the *network* asset will be retired or *de-rated*; and iv. If the date to retire or *de-rate* the *network* asset has changed since the previous *Transmission Annual Planning Report*, an explanation of why this has occurred;	Appendix E.5, and our Transmission Annual Planning Report web page[8]
(1B)	For the purposes of subparagraph (1A), where two or more *network* assets are: i. Of the same type; ii. To be retired or *de-rated* across more than one location; iii. To be retired or *de-rated* in the same calendar year; and iv. Each expected to have a replacement cost less than $200,000 (as varied by a cost *threshold determination*, Those assets can be reported together by setting out in the *Transmission Annual Planning Report*: v. A description of the *network* assets, including a summarized description of their locations; vi. The reasons, including methodologies and assumptions used by the *Transmission Network Service Provider*, for deciding that it is necessary or prudent for the *network* assets to be retired or *de-rated*, taking into account factors such as the condition of the *network* assets; vii. The date from which the *Transmission Network Service Provider* proposes that the *network* assets will be retired or *de-rated*; and viii. If the calendar year to retire or *de-rate* the *network* assets has changed since the previous *Transmission Annual Planning Report*, an explanation of why this has occurred;	Appendix E, and our Transmission Annual Planning Report web page[8]
(2)	Planning proposals for future *connection points*;	Section 3.8

[8] ElectraNet | Transmission Annual Planning Report

	Summary of Requirements	Section
(3)	A forecast of constraints and inability to meet the *network* performance requirements set out in schedule 5.1 or relevant legislation or regulations of a *participating jurisdiction* over 1, 3 and 5 years, including at least: i. A description of the *constraints* and their causes; ii. The timing and likelihood of the *constraints*; iii. A brief discussion of the types of planned future projects that may address the *constraints* over the next 5 years, if such projects are required; and iv. Sufficient information to enable an understanding of the *constraints* and how such forecasts were developed;	Section 5.1
(4)	In respect of information required by subparagraph (3), where an estimated reduction in forecast *load* would defer a forecast *constraint* for a period of 12 months, include: i. The year and months in which a *constraint* is forecast to occur; ii. The relevant *connection points* at which the estimated reduction in forecast *load* may occur; iii. The estimated reduction in forecast *load* in MW needed; and iv. A statement of whether the *Transmission Network Service Provider* plans to issue a request for proposals for *augmentation*, replacement of *network* assets, or a *non-network* option identified by the annual planning review conducted under clause 5.12.1(b) and if so, the expected date the request will be issued;	Appendix E, and our Transmission Annual Planning Report web page[9]
(5)	For all proposed *augmentations* to the *network* and proposed replacements of *network* assets the following information, in sufficient detail relative to the size or significance of the project and the proposed operational date of the project: i. Project/asset name and the month and year in which it is proposed that the asset will become operational; ii. The reason for the actual or potential *constraint*, if any, or inability, if any, to meet the *network* performance requirements set out in schedule 5.1 or relevant legislation or regulations of a *participating jurisdiction*, including *load* forecasts and all assumptions used; iii. The proposed solution to the *constraint* or inability to meet the network performance requirements identified in subparagraph (ii), if any; iv. Total cost of the proposed solution; v. Whether the proposed solution will have a *material inter-network impact*. In assessing whether an *augmentation* to the *network* will have a *material inter-network* impact a *Transmission Network Service Provider* must have regard to the objective set of criteria *published* by *AEMO* in accordance with clause 5.21 (if any such criteria have been published by *AEMO*); and vi. Other reasonably *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 reasonably *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*;	Section 5, Appendix E, and our Transmission Annual Planning Report web page[9]
(6)	The manner in which the proposed augmentations and proposed replacements of *network assets* relate to the most recent *Integrated System Plan*;	Section 5
(6A)	for proposed new or modified *emergency frequency control schemes*; the manner in which the project relates to the most recent general *power system risk review*;	Section 6.3, Appendix G
(6B)	information about which parts of its *transmission network* are *designated network assets* and the identities of the owners of those *designated network assets*;	Appendix F

[9] ElectraNet | Transmission Annual Planning Report

	Summary of Requirements	Section
(7)	information on the *Transmission Network Service Provider's* asset management approach, including: i. A summary of any asset management strategy employed by the *Transmission Network Service Provider*; ii. A summary of any issues that may impact on the system *constraints* identified in the *Transmission Annual Planning Report* that has been identified through carrying out *asset management*; and iii. Information about where further information on the *asset management* strategy and methodology adopted by the *Transmission Network Service Provider* may be obtained.	Appendix B
(8)	Any information required to be included in a *Transmission Annual Planning Report* under: i. Clauses 5.16.3(c) and 5.16A.3 in relation to a *network* investment which is determined to be required to address an urgent and unforeseen *network* issue; or ii. Clauses 5.20B.4(h) and (i) and clauses 5.20C.3(f) and (g) in relation to *network* investment and other activities to: a. Provide *inertia network services* or *inertia support activities*; or b. Meet the standard in clause S5.1.14 in relation to a *system strength node*;	ElectraNet has not made any network investments that were determined to be required to address an urgent and unforeseen network issue Section 6.3
(9)	Emergency controls in place under clause S5.1.8, including the *Network Service Provider's* assessment of the need for new or altered emergency controls under that clause;	Appendix G
(9A)	the analysis of the operation of, and any known or potential interactions between: i. Any *emergency frequency control schemes*, or emergency controls in place under clause S5.1.8, on its *network*; and ii. *Protection systems* or *control systems* or *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 6.4
(10)	Facilities in place under clause S5.1.10;	Appendix G
(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 J
(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; and	Appendix A
(13)	The *system strength locational factor* for each *system strength connection point* for which it is the Network Service Provider and the corresponding *system strength node*.	Appendix H

Appendix D
Connecting to the South Australian Transmission System

D.1 Implications of South Australian system strength requirements for generators

ElectraNet installed synchronous condensers at Davenport and Robertstown in 2021, bolstering system reliability; and addressing a shortfall in system strength and inertia.

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 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 at this new increased level now that the four synchronous condensers have been installed.

Other constraints such as for thermal capacity, stability or voltage limitations, and interconnector transfer capacity are likely to bind at times so as to limit non-synchronous generation at levels below the non-synchronous generation system strength constraint.

The successful completion of a system strength Full Impact Assessment conducted for a proposed non-synchronous generator in accordance with clause 5.3.4B of the National Energy 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.

ElectraNet has assessed the anticipated impact that the full implementation of Project EnergyConnect will have on the amount of non-synchronous generation that can be dispatched at times of minimum conventional generation in South Australia. We have taken the results of that assessment into account as we prepared the PACR for our System Strength Requirements in South Australia RIT-T, which we published in December 2025.

D.2 Opportunities to connect to Project EnergyConnect

Project EnergyConnect, the transmission interlink with NSW and Victoria, comprises two stages:

- Stage 1 – construction of the first 700 km double circuit and release of 150 MW which was completed in March 2025
- Stage 2 – release of 800 MW, scheduled to be completed in 2027.

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

We advise that a staged approach for progressing connections to Project EnergyConnect has been adopted, taking into account Project EnergyConnect's stated May 2027 timeframe for completion.

A Connections Framework which outlines pre-requisites for each connection project phase relative to Project EnergyConnect milestones is available on the Project EnergyConnect website.[10]

[10] Project Energy Connect | Resources

For proponents interested in connecting to Project EnergyConnect, in many cases the connection process will be similar to the current process for connection to the transmission network.

However, proponents interested in connecting to certain sections of Project EnergyConnect in NSW will need to take into account access arrangements relating to the South-West Renewable Energy Zone.

The update provided in April 2024 confirms that Project EnergyConnect models have reached sufficient maturity to be used for planning purposes.

Project EnergyConnect models are now available to proponents via the AEMO Data Request process.[11]

Further details can be found the Project EnergyConnect website.[12]

New cut-in connections along Project EnergyConnect

While connection enquiries and connection applications for proposed connections directly to Project EnergyConnect (cut-ins) can be lodged and processed utilising available information, connections can only be physically facilitated once 500 MW of transfer capacity has been released across Project EnergyConnect.

This is anticipated to occur in 2027, following successful completion of hold point testing under the Inter-Network Test Plan.

ElectraNet encourages interested parties to submit connection enquiries and applications for proposed connections directly to Project EnergyConnect.

South Australian Interconnector Trip Remedial Action Scheme (SAIT RAS)

SAIT RAS is a special protection scheme developed by ElectraNet to cater for a non-credible trip of either the Project EnergyConnect interconnector or the Heywood interconnector under high power transfer conditions so as to prevent separation of South Australia from the NEM.

It is the largest and most complex protection scheme in the NEM and aims to ensure that South Australia can continue to progress the energy transition at pace.

ElectraNet advises that any cut-in along Project EnergyConnect will likely require a significant amount of analysis and consequential redesign of the SAIT RAS.

NSW South-West Renewable Energy Zone Access Arrangements

Proponents seeking a connection to the Project EnergyConnect network infrastructure in NSW will need to consider access arrangements for the South-West REZ.

This may affect the proponent's ability to submit a connection enquiry, apply to connect, or receive an offer to connect to Project Energy Connect network infrastructure both within and outside the South-West REZ.

ElectraNet advises that proponents seeking a connection should familiarise themselves with the regulatory and access arrangements for the South-West REZ.[13]

D.3 Impact of generation connection on power quality

To support 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.

As such, ElectraNet requires generators to submit a site-specific power quality model for use in the PowerFactory simulation tool per Section 4.6 of the AEMO Power System Model Guidelines; and a power quality design report that incorporates sufficient supporting studies and assessment results per the submission requirements under 5.3.4A(b2) of the National Electricity Rules.

[11] AEMO | Policy on provision of network data
[12] Project Energy Connect
[13] EnergyCo | South West Renewable Energy Zone

Appendix E Projects

E.1 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 wider area monitoring and protection schemes (Table 17).

These projects have either been identified by AEMO in an ISP or GPSRR, or we will be working with AEMO to enable assessment of these projects in future ISPs or GPSRRs.

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

Project Description	Region	Constraint driver and investment type	Asset in service
EC.14171 Project EnergyConnect: New interconnector between South Australia and New South Wales **Estimated cost: $500–520 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. We envisage that this project will impact inter-regional transfer.	Main Grid	Market benefit Augmentation	Stage 1 (Robertstown to Buronga): 150 MW transfer capacity released in April 2025 Stage 2 (Buronga to Wagga Wagga): 500 MW expected by June 2027 Full transfer capacity expected to be released by June 2028
EC.15272 Wide Area Monitoring Scheme 2023–2028 **Estimated cost: $15–18 million** **Status: Committed** Expand the existing WAMS by installing phasor measurement units (PMUs) as required by AEMO at candidate sites across the SA transmission network. The scope of works includes installing hardware and software to integrate new PMUs to existing systems and deploy associated software application analytical tools that will be used to analyse the data collected. The candidate sites cover a range of network locations listed below: • Main transmission network (incremental to existing PMU network) – will monitor the performance of the main transmission network and identify emerging power system challenges • Generator/BESS sites – will monitor the dynamic response of major generators and batteries • Regional Load sites at the periphery of the system – monitoring will help understanding of load dynamics for benchmarking power system models and identification of emerging challenges in the power system • Metro Loads incorporating significant 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	AEMO data requirement was completed by August 2024 Remaining site data by September 2026

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

Project Description	Region	Constraint driver and investment type	Asset in service
EC.15466 South East Interconnection **Estimated cost: To be determined** **Status: Proposed option for future development** Develop a new AC interconnector between the South East of South Australia and Heywood in Victoria. This project option would increase transfer capability between South Australia and Victoria to unlock cheaper energy sources, enabling access for South East SA wind-powered generation to Victoria and the rest of the NEM. This project would impact inter-regional transfer.	Main Grid	Market benefit Augmentation	Subject to if or when shown to deliver benefit to customers
EC.15467 Mid North Interconnection **Estimated cost: To be determined** **Status: Proposed option for future development** Develop a new 500 kV AC interconnector between the Mid North of South Australia at New South Wales. This project option would increase transfer capability between South Australia and New South Wales to unlock cheaper energy sources, enabling access for South Australian wind- and solar-powered generation to New South Wales and the rest of the NEM. This project will impact inter-regional transfer.	Main Grid	Market benefit Augmentation	Subject to if or when shown to deliver benefit to customers
EC.15826 Wide Area Monitoring System Upgrade **Estimated cost: to be determined** **Status: Proposed for the 2029–33 revenue control period** Upgrade and expand the existing wide area monitoring system (WAMS). The upgrade is required to keep up with the changing network (more connections). The WAMS provides a real time view of system dynamics including oscillations and damping, providing the control room with visibility of emerging risks due to IBR and Inverter connector loads such as data centers. WAMS also provides historical data to support investigations, model verification, and projects to improve system damping.	Main Grid	Stability Operational	2029–2033
EC.15827 South Australia Intra-Area Separation Prevention Scheme **Estimated cost: to be determined** **Status: Proposed for the 2029-33 revenue control period** Develop a new control scheme to deal with the non-credible loss of multiple lines (i.e. N-2) within the mid north region to avoid cascade tripping and minimise the extent of any outage.	Mid North	Stability Operational	2029–2033
EC.15832 South Australia Interconnector Trip Remedial Action Scheme Modification **Estimated cost: to be determined** **Status: Proposed for the 2029-33 revenue control period** Review and modify the existing South Australia Interconnector Trip Remedial Action Scheme (SAIT RAS) to accommodate the impact of changes occurring elsewhere in the NEM (e.g. VNI West, Hume Link, NSW South West REZ). SAIT RAS will need to undergo extensive review and modifications to ensure the scheme remains fit for purpose.	Main Grid	Stability Operational	2029–2033

E.2 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 (Table 18).

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.[14]

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

Project Description	Region	Constraint driver and investment type	Asset in service
EC.11645 Transmission Network Voltage Control **Estimated cost: $90–105 million** **Status: Committed** Install three 60 MVAr 275 kV reactors around the Adelaide metropolitan region, one at Magill and two at Torrens Island Power Station, and install two 50 MVAr 275 kV reactors around the Adelaide metropolitan region, one at Cherry Gardens and another at Para substation, and a single 50 MVAr 275 kV reactor at South East. The installations will include associated works for reactor connection and switching, monitoring and control, system protection, and site civil works. These and other reactive and voltage control devices on the main 275 kV transmission network will be upgraded to enable coordinated automatic switching of existing and planned reactive power devices. This will require the installation and modification of secondary plant items for monitoring, control and protection covering multiple substation sites including automating Onload Tap Changer operation at SA Power Networks connection points. The RIT-T for this project was completed in June 2024. ElectraNet does not envisage that this project will impact inter-regional transfer.	Main Grid	Reactive support Augmentation	Cherry Gardens reactor installed September 2023 Para reactor installed December 2024 Installation of remainder of 275 kV reactors by end of 2027 Automated switching by 2030
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)
EG.10052 Main Grid System Strength Support 2024–2028 **Estimated cost: About $5 million per clutch on each new generator** **Status: Planned** Procure prudent levels of additional system strength services to satisfy future system strength requirements at System Strength Nodes in South Australia. We published the PACR in December 2025. ElectraNet does not envisage that this project will impact inter-regional transfer.	Main Grid	Compliance Augmentation	2026–2029 (depending upon solution)

[14] ElectraNet | Transmission Annual Planning Report

Table 18: Projects proposed to maintain or enhance system security or power quality (cont.)

Project Description	Region	Constraint driver and investment type	Asset in service
EC.15829 South East SSR and SSCI Mitigation **Estimated cost: to be determined** **Status: Proposed as a contingent project for the 2029–33 revenue control period** Install passive damping filters to the existing fixed series capacitor (FSC) at Black Range to mitigate sub-synchronous resonance (SSR) and sub-synchronous control integration (SSCI) between Black Range Series Capacitor and new generation sources proposed to be connected to the Tailem Bend – South East lines.	South East	Capacity Augmentation	2029–2033
EC.15821 Power Quality Monitoring Installation 2029–2033 **Estimated cost: to be determined** **Status: Proposed for the 2029–33 revenue control period** To support the ongoing identification of non-compliances with NER obligations on the transmission system. We propose to retrofit Capacitive Voltage Transformers (CVTs) to be used for power quality measurement with harmonic compensation in the form of PQ Sensors and where required install new power quality meters to ensure accurate harmonic distortion measurement of the complete harmonic spectrum. As well as upgrades to measurement power quality software and servers to support the above.	Various	Compliance Augmentation	2029–2033
EC.15822 Transmission Network Voltage Control Enhancement 2029–2033 **Estimated cost: to be determined** **Status: Proposed for the 2029–33 revenue control period** Install an additional two capacitor banks and one reactor to maintain grid voltages to within their acceptable operating margins. Will also ensure that the users of the grid including those that maintain and operate the grid are working in a safe environment.	Main Grid	Reactive support Augmentation	2029–2033
EC.15912 Eyre Peninsula Grid Forming STATCOM **Estimated cost: to be determined** **Status: Proposed for the 2029–33 revenue control period** Install a grid forming STATCOM to increase system strength and manage voltage flicker within the Eyre Peninsula region.	Eyre Peninsula	Compliance Augmentation	2029–2033
EC.15946 Protection Adequacy Upgrade **Estimated cost: to be determined** **Status: Proposed for the 2029–33 revenue control period** Upgrade protection adequacy to ensure compliance to TNSP network security obligations.	Various	Compliance Asset renewal	2029–2033

E.3 Capacity and Renewable Energy Zone development

We have identified potential projects to provide capability for future new customers and generators (Table 19 and Figure 32).

ElectraNet annually compares connection capability against forecast connection point demand, considering the redundancy requirements specified for each connection point in the South Australian Electricity Transmission Code (ETC, redundancy requirements summarised in Appendix B.2). This is coordinated through joint planning with SA Power Networks, in which connection point projects are considered, proposed, and planned (Appendix A.2).

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

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

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

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

- There is a potential need for a new connection point at Kingsford in the 2030s if potential new residential developments connect to the distribution network in that area
- Mount Gambier and Blache connection points will require upgrade in 2030 due to the connection of a new industrial load in the region
- Tailem Bend and Baroota connection points will require upgrade in 2034, based on our analysis of current maximum demand forecasts.
- Several connection points are currently projected to required upgrades later in the 2030s or 2040s but could be required in 2034 or earlier if significant potential new industrial loads connect to the distribution network or load forecasts are increased by 10-15% in the future. These include the following connection points:
  - Mount Barker South
  - Davenport West
  - Southern Suburbs
  - Western Suburbs
  - Yadnarie.

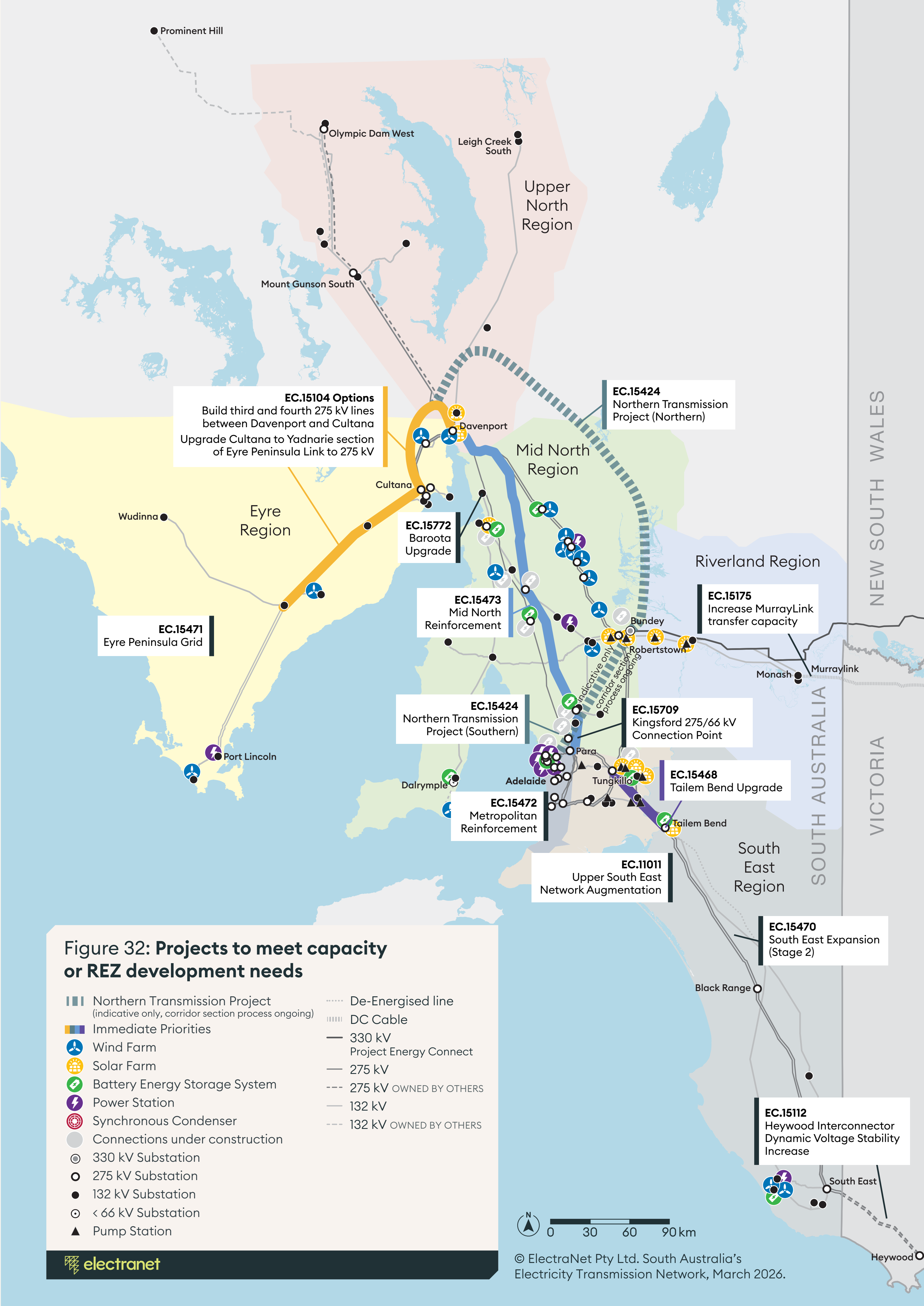


Figure 32: **Projects to meet capacity or REZ development needs**

Table 19: Projects to meet capacity or REZ development needs

Project Description	Region	Constraint driver and investment type	Asset in service
EC.15104 Eyre Peninsula Upgrade **Estimated cost: $160–350 million (depending upon solution)** **Status: Planned** Establish a new 275/132 kV Yadnarie North substation, and upgrade the operating voltage of the Cultana to Yadnarie lines from 132 kV to 275 kV. If potential large loads connect on the Eyre Peninsula, construct additional double circuit 275 kV line between Davenport and Cultana, via a new substation at Narcoona. We published the PACR in December 2025. ElectraNet does not envisage that this project will impact inter-regional transfer.	Eyre Peninsula	Capacity Augmentation	2027–2030 (depending on solution)
EC.11011 Upper South East Network Augmentation **Estimated cost: $80–90 million** **Status: Proposed for the 2029–33 revenue control period** 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, and between the Mid North and the Heywood interconnector. We are progressing this project as a stand-alone RIT-T, and have included the PSCR as part of this Transmission Annual Planning Report. ElectraNet envisages that this project may impact inter-regional transfer.	Eastern Hills	Market benefits Augmentation	2029
EC.15424 Northern Transmission Project (NTx) **Estimated cost: $750–3,500 million** **Status: Planned** The project has been identified as an actionable project in AEMO 2024 ISP report. The project will explore the benefits of increased transfer capacity between Bundey and the Adelaide metropolitan load centre, and Bundey and the anticipated Cultana load centre. We have commenced the RIT-T process and are planning to publish the PADR by the end of April 2026. Project options are included in Chapter 5. We envisage that this project may impact inter-regional transfer.	Mid North	Market benefits Augmentation	2029–2033 (depending on solution)
EC.15473 Mid North Reinforcement **Estimated cost: to be determined** **Status: Proposed option for future development** Rebuild the Davenport – Brinkworth – Templers West – Para 275 kV line, and the Para – Munno Para 275 kV line, as high-capacity double circuit lines, with new connecting lines between Munno Para and Templers West and between Bungama and Brinkworth. Additional potential details are included in Chapter 5. 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. ElectraNet does not envisage that this project will impact inter-regional transfer.	Main Grid	Capacity and Market benefits Augmentation	2030s (subject to demonstrating benefits to customers)

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

Project Description	Region	Constraint driver and investment type	Asset in service
EC.15112 Heywood Interconnector Dynamic Voltage Stability Increase **Estimated cost: $30–60 million** **Status: Proposed option for future development** 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	2030s (subject to demonstrating benefits to customers)
EC.15709 Kingsford 275/66kV Connection Point **Estimated cost: $35–60 million** **Status: Proposed as a contingent project for the 2029-33 revenue control period** Cut into the Para to Templers West 275 kV line and create a 66 kV connection point with two 275/66 kV transformers.	Mid North	Capacity Augmentation	2030s (depending on local load growth)
EC.15471 Eyre Peninsula Grid **Estimated cost: to be determined** **Status: Proposed option for future development** This project would support development of REZs and Hydrogen and Renewable Energy Act release areas on the Eyre Peninsula to support large renewable generation projects near Whyalla, Port Bonython, and Cape Hardy, unlocking potential for increased connection of low-cost renewables to supply increasing demand. ElectraNet does not envisage that this project will impact inter-regional transfer.	Eyre Peninsula	Capacity and Market benefits Augmentation	2030s (depending on local load growth)
EC.15468 Tailem Bend 132-33kV Transformer Upgrade **Estimated cost: $12–15 million** **Status: Proposed for the 2029–33 revenue control period** Replace the two existing 25 MVA 132/33 kV transformers at Tailem Bend with two 60 MVA units. SA Power Networks' draft 2024 connection point report is forecasting the need for this project in 2034. We plan to commence the RIT-T process in 2028. ElectraNet does not envisage that this project will impact inter-regional transfer.	South East	Capacity Augmentation	2034 A 10% higher load forecast would require this project in 2028
EC.15772 Baroota Substation Upgrade **Estimated cost: $30–50 million** **Status: Proposed for the 2029–33 revenue control period** Rebuild connection point with two 25 MVA 132/33 kV transformers. ElectraNet does not envisage that this project will impact inter-regional transfer.	Mid North	Capacity Augmentation	2034
EC.15773 Mount Barker South Substation Reinforcement **Estimated cost: $10–20 million** **Status: Proposed option for future development** Install a second 225 MVA 275/66 kV transformer at Mount Barker South and retire ElectraNet assets at Mount Barker. ElectraNet does not envisage that this project will impact inter-regional transfer.	Eastern Hills	Capacity Augmentation	2038 A 10% higher load forecast would require this project in 2035 A 15% higher load forecast would require this project in 2033

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

Project Description	Region	Constraint driver and investment type	Asset in service
EC.15774 Davenport West Reinforcement **Estimated cost: $15–30 million** **Status: Proposed option for future development** Replace existing two 60 MVA 132/33 kV transformers with two 120 MVA 132/33 kV transformers. ElectraNet does not envisage that this project will impact inter-regional transfer.	Upper North	Capacity Augmentation	A 15% higher load forecast would require this project in 2043
EC.15708 Lower South East Upgrade **Estimated cost: $35–50 million** **Status: Proposed for the 2029–33 revenue control period** Options: • Option 1 – Replace the existing 25 MVA 132/33 kV transformer at Mount Gambier with a second 60 MVA 132/33 kV transformer and transfer load from Blanche to Mount Gambier - consider rebuilding Mount Gambier connection point at a nearby site; • Option 2 – Replace the existing 132/33 kV transformers at Blanche connection point with two 120 MVA 132/33 kV transformers and transfer load from Mt Gambier to Blanche. Option 1 is currently the preferred option. We are progressing this project as a stand-alone RIT-T, and have included the PSCR as part of this Transmission Annual Planning Report. ElectraNet does not envisage that this project will impact inter-regional transfer.	South East	Capacity Augmentation	Required from 2029/30 based on SAPN forecast
EC.15472 Metropolitan Reinforcement **Estimated cost: to be determined** **Status: Proposed 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. ElectraNet does not envisage that this project will impact inter-regional transfer.	Metropolitan	Capacity Augmentation	2040s (depending on local load growth)
EC.15730 Southern Suburbs Reinforcement **Estimated cost: $30–$50 million** **Status: Proposed option for future development** Install a third 225 MVA 275/66 kV transformer at Morphett Vale East or replace the existing two 225 MVA 275/66 kV transformers at Morphett Vale East with two 300 MVA 275/66 kV transformers. ElectraNet does not envisage that this project will impact inter-regional transfer.	Metropolitan	Capacity Augmentation	2041 A 10% higher load forecast would require this project in 2037 A 15% higher load forecast would require this project in 2034

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

Project Description	Region	Constraint driver and investment type	Asset in service
EC.15729 Western Suburbs Reinforcement **Estimated cost: $20–60 million, depending on option** **Status: Proposed option for future development** Options: • Replace the existing two 150 MVA 275/66 kV transformers at Torrens Island with two 225 MVA 275/66 kV transformers • Install a second 225 MVA 275/66 kV transformer at Kilburn ElectraNet does not envisage that this project will impact inter-regional transfer.	Metropolitan	Capacity Augmentation	2041 A 10% higher load forecast would require this project in 2037 A 15% higher load forecast would require this project in 2034
EC.15776 Northern Suburbs Reinforcement **Estimated cost: $15–100 million, depending on option** **Status: Proposed option for future development** Options: • Replace existing 180 MVA 275/66 kV transformer at Parafield Gardens West with a 225 MVA or 300 MVA 275/66 kV transformer • Install second 225 MVA 275/66 kV transformer at Munno Para and rebuild the Para – Munno Para 275 kV line as double circuit. ElectraNet does not envisage that this project will impact inter-regional transfer.	Metropolitan	Capacity Augmentation	A 10% higher load forecast would require this project in 2042 A 15% higher load forecast would require this project in 2040 A 120 MW spot load increase would require this project from 2035
EC.15777 Whyalla Central Substation Upgrade **Estimated cost: to be determined** **Status: Proposed option for future development** Rebuild the Cultana to Whyalla 132 kV lines with larger conductors and apply cyclic ratings to Whyalla Central 132/33 kV transformers. ElectraNet does not envisage that this project will impact inter-regional transfer.	Eyre Peninsula	Capacity Augmentation	A 10% higher load forecast would require this project in 2043 A 15% higher load forecast would require this project in 2040
EC.15778 Mobilong Substation Upgrade **Estimated cost: to be determined** **Status: Proposed option for future development** Replace existing two 60 MVA 132/33 kV transformers with two 120 MVA 132/33 kV transformers. Consider rebuilding Mobilong connection point or building an additional connection point at a nearby site. ElectraNet does not envisage that this project will impact inter-regional transfer.	Eastern Hills	Capacity Augmentation	A 15% higher load forecast would require this project in 2038
EC.15771 Angas Creek Substation Upgrade **Estimated cost: to be determined** **Status: Proposed option for future development** Replace existing two 25 MVA 132/33 kV transformers with two 60 MVA 132/33 kV transformers and build a new 132 kV bus. ElectraNet does not envisage that this project will impact inter-regional transfer.	Eastern Hills	Capacity Augmentation	A 15% higher load forecast would require this project in 2042

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

Project Description	Region	Constraint driver and investment type	Asset in service
EC.15779 Berri/Monash Substation Upgrade **Estimated cost: to be determined** **Status: Proposed option for future development** Install two 120 MVA 132/66 kV transformers at Monash, and remove the existing two 50 MVA 132/66 kV transformers at Berri and the 60 MVA 132/66 kV transformer at Monash. Convert the two Monash to Berri 132 kV lines to 66 kV operation. ElectraNet does not envisage that this project will impact inter-regional transfer.	Riverland	Capacity Augmentation	A 15% higher load forecast would require this project in 2042
EC.15780 Kanmantoo Substation Upgrade **Estimated cost: to be determined** **Status: Proposed option for future development** Transfer connection point from 11 kV tertiary winding to 33 kV secondary winding of existing 132/33/11 kV transformer. ElectraNet does not envisage that this project will impact inter-regional transfer.	Eastern Hills	Capacity Augmentation	A 15% higher load forecast would require this project in 2042
EC.15781 Mannum Substation Upgrade **Estimated cost: to be determined** **Status: Proposed option for future development** Replace existing 33 kV transformer cables and cyclically rate the existing 25 MVA 132/33 kV transformers. ElectraNet does not envisage that this project will impact inter-regional transfer.	Eastern Hills	Capacity Augmentation	A 15% higher load forecast would require this project in 2042
EC.15782 Kincraig Substation Upgrade **Estimated cost: to be determined** **Status: Proposed option for future development** Replace existing two 25 MVA 132/33 kV transformers with two 60 MVA 132/33 kV transformers. ElectraNet does not envisage that this project will impact inter-regional transfer.	South East	Capacity Augmentation	A 15% higher load forecast would require this project in 2044
EC.15783 Eastern Suburbs Reinforcement **Estimated cost: to be determined** **Status: Proposed option for future development** Potential solution to be determined. ElectraNet does not envisage that this project will impact inter-regional transfer.	Metropolitan	Capacity Augmentation	A 15% higher load forecast would require this project in 2044
EC.15470 South East Expansion (Stage 2) **Estimated cost: to be determined** **Status: Proposed 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 would 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. ElectraNet envisages that this project may impact inter-regional transfer.	Main Grid	Market benefits Augmentation	Subject to demonstrating benefits to customers

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

Project Description	Region	Constraint driver and investment type	Asset in service
EC.15839 Line Rating Remediation 2029-2033 **Estimated cost: to be determined** **Status: Proposed for the 2029–33 revenue control period** Perform remediation works (interplant conductor augmentations & secondary system alterations etc) to address previously unidentified rating constraints to enable line ratings for about 60 lines to be returned to their historic operational levels.	Various	Capacity Augmentation	2029–2033
EC.15841 - Yorke Peninsula Reinforcement **Estimated cost: to be determined** **Status: Proposed as a contingent project for the 2029–33 revenue control period** Construct new twin circuit 275 kV line from Blyth West-Hummocks to meet expected load growth that is forecast to exceed the ETC requirements for supply from 132 kV, specifically Waterloo-Hummocks, Snowtown-Hummocks transmission lines.	Yorke	Capacity Augmentation	2029–2033 (subject to customer load driving augmentation)
EC.15843 Tailem Bend 2nd 275/132 kV Transformer **Estimated cost: $25–35 million** **Status: Proposed for the 2029–33 revenue control period** Connect existing spare 275/132 kV 150 MVA transformer as 2nd transformer at Tailem Bend substation and populate existing benched diameter with additional 275 kV CB.	South East	Capacity, reliability Augmentation	2029–2033
EC.15899 Brinkworth Second 275/132kV Transformer **Estimated cost: to be determined** **Status: Proposed for the 2029–33 revenue control period** Under contingent conditions, the existing 200 MVA 275/132kV TF3 at Brinkworth substation may be overloaded during peak demand or periods of high generation dispatch on the 132kV or 275kV network. The installation of a second transformer will prevent this. Additionally, this transformer may be required to reconfigure the 132 kV network to increase 275 kV transfer capacity.	Mid North	Capacity Augmentation	2029–2033
• **EC.15901 Bungama Second 275/132 kV Transformer** • **Estimated cost: to be determined** • **Status: Proposed for the 2029–33 revenue control period** • Under contingent conditions, the existing 200 MVA 275/132kV TF3 at Bungama substation may be overloaded during peak demand or periods of high generation dispatch on the 132kV or 275kV network. The installation of a second transformer will prevent this. Additionally, this transformer may be required to reconfigure the 132 kV network to increase 275 kV transfer capacity.	Mid North	Capacity Augmentation	2029–2033
• **EC.15906 Mid North 132kV system Modification** • **Estimated cost: to be determined** • **Status: Proposed option for future development** • Undertake 132kV line works and construct new double circuit 132 kV line between Redhill – Brinkworth to Hummocks to enable existing 132kV ring (Waterloo – Hummocks - Bungama – Brinkworth – Waterloo) to be split into two discrete 132kV rings to increase the 275 kV transfer capacity.	Mid North	Capacity Augmentation	2034–2038

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

Project Description	Region	Constraint driver and investment type	Asset in service
EC.15907 Munno Para New 275kV Line **Estimated cost: to be determined** **Status: Proposed for the 2029–33 revenue control period** Build a second 275kV line between Para and Munno Para, approximately 12 km long, to prevent the need to trip the Munno Para 275/66kV transformer to mitigate overload of SAPN's 66kV network following loss of the existing Para – Munno Para line.	Metro	Capacity, reliability Augmentation	2029–2033
EC.15909 Para Second 275/132 kV Transformer **Estimated cost: to be determined** **Status: Proposed for the 2029–33 revenue control period** Install a second 275/132 kV 160 MVA transformer at Para substation to reduce outage and generation constraints, firming the 132 kV supply to the Adelaide load centre.	Metro	Capacity, reliability Augmentation	2029–2033
EC.15209 Second Templers West Transformer **Estimated cost: to be determined** **Status: Proposed for the 2029–33 revenue control period** Install 2nd Templers West 275/132 kV transformer and reconfigure the Mid North 132 kV network by: 1. Disconnecting Templers-Waterloo 132 kV 2. Connecting Templers - Templers West 132 kV This will increase transfer capacity between the north of South Australia and the metropolitan load centre to cater for new generation in the north of SA and generation retirements in the metropolitan area.	Mid North	Capacity Augmentation	2029–2033
EC.15900 Establish Globe Derby Switching Station **Estimated cost: to be determined** **Status: Proposed for the 202–33 revenue control period** Establish Globe Derby switching station and tie-in three 275 kV lines to mitigate a number of N-1 and N-1-1 line constraints as well as forecast line overloads from 2029 under certain conditions.	Metro	Capacity Augmentation	2029–2033
EC.15831 Bundey System Strength Improvement **Estimated cost: to be determined** **Status: Proposed for the 2029–33 revenue control period** Manage the security risks posed by the scale of forecast new generation connection at Bundey and maintain network stability and ensure NER compliance. Options: • Expand the Bundey Generation Inter-Trip Scheme, a new RAS • Establish a new double circuit line from Bundey to Robertstown.	Riverland	Stability Augmentation	2029–2033

E.4 Market benefit opportunities

ElectraNet monitors congestion on the South Australian transmission system (Section 5.1). We also consider information regarding future probable generator and load connections, along with AEMO's ISP, to predict new constraints that may develop in future years.

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

Table 20: Projects to address market benefit opportunities

Project Description	Region	Constraint driver and investment type	Asset in service
EC.15179 Robertstown to Tungkillo Line Uprating **Estimated cost: $1–2 million** **Status: Complete** This project is included in our 2023–2024 to 2027–2028 NCIPAP. Alleviate forecast constraints between Robertstown and Para, and Robertstown to Tungkillo by uprating the lines from 100°C to 120°C design clearances. This will increase the average line ratings by 90 MVA. ElectraNet envisages that this project will impact intra-regional transfer, but not inter-regional transfer.	Mid North	Market benefits (NCIPAP) Augmentation	October 2025
EC.15171 NCIPAP Davenport to Cultana line uprating **Estimated cost: $1–2 million** **Status: Committed** This project is included in our 2023–2024 to 2027–2028 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	September 2026
EG.01011 / EC.15571 Transmission Line Rating Improvement **Estimated cost: $5–7 million** **Status: Committed** This project is included in our 2023–2024 to 2027–2028 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 envisages that this project will impact intra-regional transfer and inter-regional transfer.	All	Market benefits (NCIPAP) Augmentation	June 2026
EC.15175 Increase Murraylink Transfer Capacity **Estimated cost: $4–6 million** **Status: Committed** This project is included in our 2023–2024 to 2027–2028 NCIPAP. Alleviate forecast congestion on the Murraylink interconnector at times of high export by installing a 132 kV capacitor bank Monash and upgrade the existing runback control scheme to include bi-directionality and allow it to run forward if required. ElectraNet envisages that this project will impact inter-regional transfer.	Riverland	Market benefits (NCIPAP) Augmentation	June 2027

E.5 Network asset retirements and retirements

Electranet carries out projects that address needs that arise from planned retirements or de-ratings of assets, for example due to condition (Table 21).

Table 21: Projects to address planned asset retirements

Project Description	Region	Constraint driver and investment type	Asset in service
EC.14084 Line Conductor and Earthwire Refurbishment 2019–2023 **Estimated cost: $24–28 million** **Status: Committed** 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. We published a PACR on 1 June 2023, concluding the RIT-T for this project.	Mid North and Riverland	Asset condition and performance Asset renewal	October 2027
EC.14077 Mannum Transformer #1 and Secondary System Replacement **Estimated cost: $13–15 million** **Status: Committed** Replace transformer #1 and secondary systems at Mannum substation that has been assessed to be at the end of their technical lives with a corresponding high risk of failure, with a new 25 MVA 132/33 kV transformers (nearest ElectraNet standard size). Note that Mannum transformer #2 was replaced in 2021 when the transformer failed.	Eastern Hills	Asset condition and performance Asset renewal	Replace transformer #1 by October 2025 Replace the Secondary Systems by June 2029
EC.14032 Instrument Transformer Unit Asset Replacement 2019–2023 **Estimated cost: $16–18 million** **Status: Committed** Replace 55 voltage transformers and 121 current transformers across the South Australian electricity transmission system that have reached the end of their technical or economic lives and have an increased likelihood of catastrophic explosion.	Various	Asset condition and performance Asset renewal	November 2026
EC.14031 Protection Systems Unit Asset Replacement 2019–2023 **Estimated cost: $45–50 million** **Status: Committed** Replace protection scheme relays across the South Australian electricity transmission system that have reached the end of their technical or economic lives. We concluded the RIT T for this program of work on 6 December 2019.	Various	Asset condition and performance Asset renewal	November 2026

Table 21: Projects to address planned asset retirements (cont.)

Project Description	Region	Constraint driver and investment type	Asset in service
EC.14034 Isolator Unit Asset Replacement 2019–2023 **Estimated cost: $18–20 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 2018–2019 to 2022–2023 regulatory period. We concluded the RIT-T for this program of work on 18 November 2019.	Various	Asset condition and performance Asset renewal	November 2026
EC.14176 Surge Arrestor Unit Asset Replacement 2018–2023 **Estimated cost: $8–10 million** **Status: Committed** Replace porcelain surge arrestors and arcing horns at 18 substations that are at the end of their technical and economic lives due to their increasing risk of failure and potential to cause injury to personnel and collateral damage to other plant within the substation as a result of an explosive failure.	Various	Asset condition and performance Asset renewal	November 2026
EC.15321 TIPS IMB300 CT Replacement **Estimated Cost: $16–18 million** **Status: Committed** Urgent removal and replacement of 38 sets of current transformers at TIPS A and B switchyards that have been identified as high risk of failure. We published a PACR on 16 January 2025, concluding the RIT-T for this project.	Metro	Asset condition and performance Asset renewal	June 2026
EC.14182 South East SVC Computer Control System Replacement **Estimated cost: $7–10 million** **Status: Committed** Replace the computer control system for the SVC 1 and SVC 2 at South East substation that has been assessed as being end of its life cycle, requiring replacement during the 2024–2028 regulatory control period. We published a PACR on 16 November 2023, concluding the RIT-T for this project.	South East	Asset condition and performance Asset renewal	December 2027
EC.15449 IMB300 CT Hazard Mitigation **Estimated cost: $18–20 million** **Status: Committed** Replace 56 sets of current transformers at six substations that have been identified as high risk of failure, based on failure of similar of current transformers that were of same make, model and age. We published a PACR on 16 January 2025, concluding the RIT-T for this project.[15]	Various	Asset condition and performance Asset renewal	October 2026

[15] ElectraNet | Managing the Risk of 275 kV Current Transformer Failures 2024–2028

Table 21: Projects to address planned asset retirements (cont.)

Project Description	Region	Constraint driver and investment type	Asset in service
EC.15568 Northfield Transformer #8, #9 and #10 Interface Connection Requirement **Estimated Cost: $60–65 million** **Status: Committed** SAPN are planning to replace their aging/failing 66kV Gas Insulated Switchgear (GIS) switchgear at Northfield substation with a new Air Insulated Switchgear (AIS) 66kV switchyard. To support this replacement, we will need to upgrade the 66 kV GIS to AIS connection points to transformer #9 and will be replacing our two aging GIS transformers (#7 and #8) with two new AIS transformers (#1 and #2) at Northfield substation. SA Power Networks published the final RIT-D document for Ensuring Reliable Supply for Adelaide's Eastern Suburbs in December 2022.	Metropolitan	Asset condition and performance Asset renewal	Connection of transformer #9 by April 2026 Connection of transformer #1 by September 2026 Connection of transformer #2 by July 2030
EC.15427 High Crossing Tower Climbing System Replacement **Estimated cost: $6–8 million** **Status: Planned** 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	May 2030
EC.15239 F1803 Hummocks – Ardrossan West 132 kV Line Renewal **Estimated cost: $35–38 million** **Status: Pending** Replace the Hummocks to Ardrossan West 132 kV line in its entirety as a majority of the line components have been assessed to be at end-of-life. We published a PACR on 5 December 2024, concluding the RIT-T for this project.	Mid North	Asset condition and performance Asset renewal	January 2030
EC.15481 Metro Unit Asset Replacement 2024–2028 **Estimated cost: $25–30 million** **Status: Pending** Replace circuit breakers, instrument transformers, disconnectors and surge arrestors at nine substations across the Metropolitan Region that has been assessed to be at the end of their technical and economic lives during the 2024–2028 regulatory control period.[16]	Metropolitan	Asset condition and performance Asset renewal	October 2031

[16] For efficiency, we are delivering the 2024–2028 Asset Based Replacement projects, that were included in the 2025 TAPR via regional based 2024–2028 Asset Replacement projects. Where applicable, RIT-Ts have been completed for the 2024–2028 Asset Replacement projects*.
- EC.15060 Circuit Breakers Unit Asset Replacement 2024–2028*
- EC.15120 Instrument Transformer Unit Asset Replacement 2024–2028*
- EC.15189 Protection Relay Unit Asset Replacement 2024–2028*
- EC.15237 Surge Arrestor Unit Asset Replacement 2024–2028*
- EC.15397 Isolator Unit Asset Replacement 2024–2028*

Table 21: Projects to address planned asset retirements (cont.)

Project Description	Region	Constraint driver and investment type	Asset in service
EC.15482 Eastern Hills Unit Asset Replacement 2024–2028 **Estimated cost: $4–6 million** **Status: Pending** Replace circuit breakers, instrument transformers, surge arrestors and protection relays at three substations across the Eastern Hills Region that have been assessed to be at the end of their technical and economic lives during the 2024–2028 regulatory control period.[15]	Eastern Hills	Asset condition and performance Asset renewal	July 2027
EC.15483 Mid North Unit Asset Replacement 2024–2028 **Estimated cost: $4–6 million** **Status: Pending** Replace circuit breakers, instrument transformers and surge arrestors at three substations across the Mid North Region that have been assessed to be at the end of their technical and economic lives during the 2024–2028 regulatory control period.[15]	Mid North	Asset condition and performance Asset renewal	November 2029
EC.15484 Riverland Unit Asset Replacement 2024–2028 **Estimated cost: $5–7 million** **Status: Pending** Replace circuit breakers, instrument transformers and surge arrestors at two substations across the Riverland Region that have been assessed to be at the end of their technical and economic lives during the 2024–2028 regulatory control period.[15]	Riverland	Asset condition and performance Asset renewal	October 2028
EC.15485 South East Unit Asset Replacement 2024–2028 **Estimated cost: $16–18 million** **Status: Pending** Replace surge arrestors and instrument transformers, disconnectors and protection relays at six substations across the South East Region that have been assessed to be at the end of their technical and economic lives during the 2024–2028 regulatory control period.[15]	South East	Asset condition and performance Asset renewal	December 2029
EC.15486 Eyre Peninsula Unit Asset Replacement 2024–2028 **Estimated cost: $8–10 million** **Status: Pending** Replace circuit breakers, instrument transformers, disconnectors and protection relays at six substations across the Eyre Peninsula Region that have been assessed to be at the end of their technical and economic lives during the 2024-2028 regulatory control period.[15]	Eyre Peninsula	Asset condition and performance Asset renewal	April 2028
EC.15487 Upper North Unit Asset Replacement 2024–2028 **Estimated cost: $7–9 million** **Status: Pending** Replace circuit breakers, instrument transformers and surge arrestors at two substations across the Upper North Region that have been assessed to be at the end of their technical and economic lives during the 2024–2028 regulatory control period.[15]	Upper North	Asset condition and performance Asset renewal	March 2030

Table 21: Projects to address planned asset retirements (cont.)

Project Description	Region	Constraint driver and investment type	Asset in service
EC.15512 Metro Unit Asset Replacement 2024–2028 DSE Sites **Estimated cost: $7–9 million** **Status: Pending** Replace circuit breakers, instrument transformers, disconnectors and surge arrestors at two substations across the Metropolitan Region that have been assessed to be at the end of their technical and economic lives during the 2024–2028 regulatory control period.[15]	Metropolitan	Asset condition and performance Asset renewal	July 2028
EC.15279 Emergency Unit Asset Replacement 2024–2028 **Estimated cost: $8–12 million** **Status: Committed** Emergency replacement of individual assets is undertaken for assets that fail unexpectedly, to meet reliability standards.	Various	Asset condition and performance Asset renewal	June 2028
EC.15233 Transmission Line Insulation System Replacement 2024–2028 **Estimated cost: $38–40 million** **Status: Pending** Implement a program to replace about 2775 insulator strings on 779 structures with equivalent insulation and associated hardware on 14 transmission lines across the network that have been assessed to be at end-of-life during the 2024–2028 regulatory control period, to renew line asset components and extend line life. We published a PACR on 24 October 2024, concluding the RIT-T for this project.[17]	Various	Asset condition and performance Asset renewal	November 2029
EC.15242 Transformer Bushing Unit Asset Replacement 2024–2028 **Estimated cost: $14–16million** **Status: Pending** Replace individual transformer bushings on 15 high voltage transformers at 13 substations across the South Australian electricity transmission system that have been assessed to be at end-of-life during the 2024–2028 regulatory control period. We published a PACR on 23 October 2024, concluding the RIT-T for this project.[18]	Various	Asset condition and performance Asset renewal	August 2028
EC.15394 Invensys C50 RTU Upgrades **Estimated cost: $6–8 million** **Status: Planned** 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	July 2029
EC.15432 F1802 Bungama – Port Pirie 132kV Line Refurbishment **Estimated cost: $5–10 million** **Status: Proposed for the 2029–2033 revenue control period** Decommission the existing Port Pirie to Bungama 132 kV line, which has been assessed to be at end-of-life during the 2029–2033 regulatory control period, and replace with a new 132 kV line alongside the existing easement. We plan to initiate a RIT-T prior to commitment.	Mid North	Asset condition and performance Asset renewal	2029–2033

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

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

Table 21: Projects to address planned asset retirements (cont.)

Project Description	Region	Constraint driver and investment type	Asset in service
EC.14090 Mount Gambier Transformer 1 Replacement **Estimated cost: $10–15 million** **Status: Proposed for the 2029–2033 revenue control period** 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 60 MVA transformer. A size of 60 MVA has been selected to provide additional capacity to meet the forecast demand at Mount Gambier connection point. We plan to initiate a RIT-T prior to commitment.	South East	Asset condition and performance Asset renewal	2029–2033
EC.15069 Circuit Breakers Unit Asset Replacement 2029 to 2033 **Estimated cost: $6–10 million** **Status: Proposed for the 2029–2033 revenue control period** Replace and improve circuit breakers across the South Australian electricity transmission system that will be assessed to be at the end of their technical and economic lives during the 2029–2033 regulatory control period. We plan to initiate a RIT-T prior to commitment.	Various	Asset condition and performance Asset renewal	2029–2033
EC.15042 AC Board Unit Asset Replacement 2029 to 2033 **Estimated cost: $18–24 million** **Status: Proposed for the 2029–2033 revenue control period** Replace and improve AC auxiliary supply equipment, switch boards and cabling at 23 substations across the South Australian electricity transmission system that will be assessed to be at the end of their technical and economic lives during the 2029–2033 regulatory control period. We plan to initiate a RIT-T prior to commitment.	Various	Asset condition and performance Asset renewal	2029–2033
EC.15123 Instrument Transformer Unit Asset Replacement 2029 to 2033 **Estimated cost: $50–60 million** **Status: Proposed for the 2029–2033 revenue control period** Replace voltage transformers and current transformers across the South Australian electricity transmission system that have reached the end of their technical or economic lives and have an increased likelihood of catastrophic explosion. This project will include the replacement of assets which will be determined based on asset needs. We plan to initiate a RIT-T prior to commitment.	Various	Asset condition and performance Asset renewal	2029–2033
EC.15244 Transformer Bushing Unit Asset Replacement 2029 to 2033 **Estimated cost: $5–10 million** **Status: Proposed for the 2029–2033 revenue control period** Replace individual transformer bushings that will be assessed to be at the end of their technical or economic lives during the 2029–2033 regulatory control period. This project will include the replacement of assets which will be determined based on asset needs. We plan to initiate a RIT-T prior to commitment.	Various	Asset condition and performance Asset renewal	2029–2033

Table 21: Projects to address planned asset retirements (cont.)

Project Description	Region	Constraint driver and investment type	Asset in service
EC.15211 Protection Relays Unit Asset Replacement 2029 to 2033 **Estimated cost: $8–15 million** **Status: Proposed for the 2029–2033 revenue control period** Replace protection relays and control schemes across the South Australian electricity transmission system that will be assessed to be at the end of their technical and economic lives during the 2029–2033 regulatory control period. We plan to initiate a RIT-T prior to commitment.	Various	Asset condition and performance Asset renewal	2029–2033
EC.15251 Transmission Line Insulation Unit Asset Replacement 2029 to 2033 **Estimated cost: $12–20 million** **Status: Proposed for the 2029–2033 revenue control period** Refurbish transmission line insulator systems across the network that will be assessed to be at end-of-life during the 2029–2033 regulatory control period, to renew line asset components and extend line life. We plan to initiate a RIT-T prior to commitment.	Various	Asset condition and performance Asset renewal	2029–2033
EC.15253 Transmission Line Conductor Unit Asset Replacement 2029 to 2033 **Estimated cost: $12–20 million** **Status: Proposed for the 2029–2033 revenue control period** Replace transmission line conductor and earthwire components that will be assessed to be at end-of-life during the 2029–2033 regulatory control period, to renew line asset components and extend line life. We plan to initiate a RIT-T prior to commitment.	Various	Asset condition and performance Asset renewal	2029–2033
EC.15295 Emergency Unit Asset Replacement 2029 to 2033 **Estimated cost: $14–18 million** **Status: Proposed for the 2029–2033 revenue control period** 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 $3 million.	Various	Asset condition and performance Asset renewal	2029–2033
EC.15660 Hummocks Substation Replacement 2029–2033 **Estimated cost: $50–60 million** **Status: Proposed for the 2029–2033 revenue control period** Full replacement of Hummocks substation except for the retention of the two transformers. The replacement of the substation is required to address operational issues and substation assets that have been identified at end of their technical life and require replacement in the 2029–2033 period. We plan to initiate a RIT-T prior to commitment.	Mid North	Asset condition and performance Asset renewal	2029–2033

Table 21: Projects to address planned asset retirements (cont.)

Project Description	Region	Constraint driver and investment type	Asset in service
EC.15737 Robertstown 275/132 kV Transformer 1 Replacement **Estimated cost: $15–20 million** **Status: Proposed for the 2029–2033 revenue control period** Replace Robertstown 275/132 kV transformer 1 that has been identified at end of life, in the 2029-2033 period. The replacement will include auxiliary equipment, such as the OLTC Control Relay, 132kV surge arrestors, gantry and transformer foundation and bund. We plan to initiate a RIT-T prior to commitment.	Mid North	Asset condition and performance Asset renewal	2029–2033
EC.15748 Berri 132/66 kV Transformer 1 and 2 Replacement **Estimated cost: $15–20 million** **Status: Proposed for the 2029–2033 revenue control period** Replace Berri transformers 1 and 2 that have been identified at end of their technical life by 2032. The replacement will include auxiliary equipment, such as the 66kV gantries, 132kV and 66kV surge arrestors, foundations, bunds, fire walls and associated civil works. We plan to initiate a RIT-T prior to commitment.	Riverland	Asset condition and performance Asset renewal	2029–2033
EC.15655 Cherry Gardens Substation Transformer 1 Replacement **Estimated cost: $10–15 million** **Status: Proposed for the 2029–2033 revenue control period** Replace Cherry Gardens 275/132 kV transformer 1 that has been identified at end of life, in the 2029–2033 period. The replacement will include bund and oil containment improvement works, replacement of the OLTC Control Relay, transformer 1 and Cherry Gardens protection systems. We plan to initiate a RIT-T prior to commitment.	Metro	Asset condition and performance Asset renewal	2029–2033
EC.15755 Control Scheme Replacements 2029–2033 **Estimated cost: $10–15 million** **Status: Proposed for the 2029–2033 revenue control period** Replace all the automatic control schemes such as voltage control (AVRs), breaker control (Point on wave, Sync check, etc.), reactive plant switching, as well as remedial action schemes across the network whose equipment is approaching end of technical life and can no longer be maintained. We plan to initiate a RIT-T prior to commitment.	Various	Asset condition and performance Asset renewal	2029–2033

E.6 Security and compliance

There are a range of committed and planned projects that relate to the maintenance of our security and compliance for which planned expenditure exceeds $8 million (Table 22).

Table 22: Projects to maintain security and compliance

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	August 2026
EC.15401 Happy Valley Site Drainage Replacement **Estimated cost: $14–18 million** **Status: Planned** 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.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	September 2029
EC.11828 Substation Perimeter Intrusion and Motion Detection Security System **Estimated cost: $14–16 million** **Status: Planned** Upgrade substation security systems across 35 ElectraNet substations by installing external motion detection and CCTV systems with built-in analytics reporting back to a networked video management system. These external motion detection and CCTV systems will supplement the “deter and delay” primary control measures such as fences and signage with a proactive and responsive secondary system, responding to potential unauthorised presence inside the security fence.	Various	Safety Operational	June 2029
EC.15220 Substation Security Fencing Replacement 2024–2028 **Estimated cost: $10–12 million** **Status: Planned** Replace high voltage security fencing and gates located at eleven substations that have been assessed to be at the end of their technical and/or economic lives and require replacement to prevent unauthorised access	Various	Safety Asset renewal	April 2030

Table 22: Projects to maintain security and compliance (cont.)

Project Description	Region	Constraint driver and investment type	Asset in service
EC.15235 Transmission Line Anti-Climb Installation 2024–2028 **Estimated cost: $20–25 million** **Status: Planned** Install climbing deterrent devices and warning signage on 1,986 transmission towers located on 42 high voltage transmission lines that have been assessed as highly vulnerable to unauthorised access.	Various	Safety Asset renewal	January 2031
EC.15496 Substation LAN Replacement and Cybersecurity Uplift 2028–2033 **Estimated cost: $8–12 million** **Status: Proposed for the 2029–33 revenue control period** Replace and upgrade substation technology assets identified as being susceptible to cyber-attack breaches by replacing relevant equipment as well and uplifting cyber security of network and intelligent devices at 19 substations. This cyber-security uplift continues the work undertaken in 2024–2028 period.	Various	Security Asset Renewal	2029–2033
EC.15231 Transmission Line Anti-Climb 2029–2033 **Estimated cost: $30–40 million** **Status: Proposed for the 2029–2033 revenue control period** 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.15419 Oil Containment Systems Improvement **Estimated cost: $16–18 million** **Status: Planned** Addresses environmental hazards with existing oil containment systems at seven substations in 2024–2028 period. By upgrading existing transformer bunds, underground tank and oil water separator systems that are not performing to EPA standards and the installation of monitoring systems for water tables for pollutants. Plus, the installation of additional oil containment systems for sites with large containment requirements.	Various	Compliance Asset renewal	November 2030
EC.15564 Oil Containment System Improvement 2029–2033 **Estimated cost: $30–40 million** **Status: Proposed for the 2029–2033 revenue control period** Addresses environmental hazards with existing oil containment systems at various ElectraNet substations in 2029–2033 period. By replacing lining of low integrity transformer bunds, upgrading / replacing underground tank oil water separator systems that are not performing to EPA standards and the installation of monitoring systems for water tables for pollutants. Plus, the installation of additional oil containment systems for sites with large containment requirements.	Various	Compliance Asset renewal	2029–2033
EC.15916 Live Line Training and Trial Facility **Estimated cost: to be determined** **Status: Proposed for the 2029-33 revenue control period** Establish a purpose-built facility comprising of replicated but de-energised transmission line sections to facilitate practice of both de-energised and live works work procedures and techniques. Increased outage constraints necessitate more live line work, which requires significant further training. The facility will also be used for training for rapid deployment of Lindsey structures to restore service following storm events.	Metro	Operational Operational	2029–2033

E.7 Contingent projects

Table 23: Contingent projects for the 2024–2028 revenue control period

Project	Trigger[19]	Current Status	Reference
Eyre Peninsula Upgrade Upgrade of the 132 kV Eyre Peninsula Link between Cultana and Yadnarie to 275 kV and/or augmentation of power transfer capacity between Davenport and Cultana and/or Cultana and Whyalla and/or Cultana and Stony Point	Commitment for additional load from one or more customers to connect to the transmission network with aggregate load sufficient to cause the: a. Cultana 275/132 kV transformers to exceed their thermal limit of 200 MVA; or b. Whyalla Central 132/33 kV transformers to exceed their thermal limit of 120 MVA; or c. Whyalla Central to Cultana 132 kV lines to exceed their thermal limit of 117 MVA; or d. Cultana to Stony Point 132 kV line to exceed its thermal limit of 144 MVA; or e. Davenport to Cultana 275 kV lines to exceed their thermal limit of 597 MVA. causing a need for the 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 Stony Point. Successful completion of a RIT-T, including an assessment of credible options, showing the 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 between Cultana and Whyalla and/or between Cultana and Stony Point is the preferred option: a. Demonstrating positive net market benefits; and/or b. Addressing a reliability corrective action.	We published a PACR for this project in December 2025	Appendix F.3
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 Rules 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 Rules 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. Successful completion of a RIT-T that demonstrates that the proposed network investment is the most efficient option to ensure that voltage waveform distortion planning levels at the sites at which voltage harmonics exceeded specifications as referred to above are not exceeded.	Not yet triggered	Appendix F.2

[19] In addition, the following trigger condition applies to each of the projects listed:

- ElectraNet Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.

Appendix F Project Specification Consultation Reports

F.1 Managing the risk of thermal overloading of the 132 kV network between Tailem Bend and Tungkillo

Executive summary

This Project Specification Consultation Report (PSCR) relates to the risk of thermal overloading of the 275 kV and 132 kV network in the transmission corridor between Tailem Bend and Tungkillo under the credible contingency of a trip on one of the two 275 kV lines.

The transmission corridor between Tailem Bend and Tungkillo currently comprises two 275 kV transmission lines in parallel with an underlying 132 kV network. Under the credible contingency of a trip on one of the two 275 kV lines, the remaining 275 kV and/or 132 kV line will be restricted by thermal overloading limit thereby restricting power flow across the Heywood interconnector below its nominal maximum transfer limitations.

This risk is exacerbated by the connection of new solar and battery energy storage systems (BESS) at Tailem Bend and is expected to become more extreme as additional renewable generation is established near the Tailem Bend area. The risk is currently managed through pre-contingent constraints on renewable generation and interconnector flows, particularly during times of high import demand. The current configuration also severely restricts maintenance windows for the existing 275 kV circuits.

The proposed augmentation is to complete a third 275 kV circuit by leveraging committed developments, including establishment of the Tepko Substation (attached to the Summerfield BESS project) and the stringing of the vacant circuit from Tungkillo to Tepko. Stringing the remainder of the vacant circuit from Tepko to Tailem Bend would complete the third circuit through the entire corridor. This is intended to alleviate the 275 kV and 132 kV overload risk, reduce pre-contingent constraints, and enable necessary maintenance access.

Introduction

Purpose of this report

This PSCR has been prepared as the consultation report required to set out prescribed information about the proposed transmission investment, including the identified need, the assumptions used, the technical characteristics a non-network option would be required to deliver, and a description of credible options and specified information for each credible option.

This Regulatory Investment Test for Transmission (RIT-T) Project Specification Consultation Report (PSCR) represents the first step in the application of the RIT-T to addressing the risk of thermal overloading of the 275 kV and 132kV network in the transmission corridor between Tailem Bend and Tungkillo under the credible contingency of a trip on one of the two 275 kV lines.

This report:

- Describes the identified need that we are seeking to address, together with the assumptions used in identifying this need
- Sets out the technical characteristics that a non-network option would be required to deliver to address this identified need
- Outlines the credible option that we consider addresses the identified need.

Why we consider this RIT-T is necessary

The National Electricity Rules (NER) require the application of the RIT-T to replacement capital expenditure where the estimated capital cost of at least one credible option exceeds $8 million.[20]

Accordingly, we have initiated this RIT-T to consult on proposed expenditure related to stringing the vacant side of the existing line from Tepko to Tailem Bend to complete the third circuit between Tungkillo and Tailem Bend, noting that none of the exemptions listed in NER clause 5.16.3(a) apply.

[20] NER clause 5.15A.1(c) states that the purpose of the RIT–T is to: identify the credible option that maximises the present value of net economic benefit to all those who produce, consume and transport electricity in the market (the preferred option). For the avoidance of doubt, a preferred option may, in the relevant circumstances, have a negative net economic benefit (that is a net economic cost) to the extent the identified need is for reliability corrective action or the provision of inertia network services required under clause 5.20B.4 or the provision of system strength services required under clause 5.20C.3.

The credible option discussed in this PSCR has not been foreshadowed in AEMO's 2024 Integrated System Plan (ISP).

Submissions and next steps

We welcome written submissions on this PSCR. Submissions are due on or before Tuesday, 30 June 2026. Submissions should be emailed to consultation@electranet.com.au.

Submissions will be published on the ElectraNet website. If you do not want your submission to be published, please clearly specify this at the time it. Subject to submissions received on this PSCR, a Project Assessment Conclusions Report (PACR) is expected to be published in due course.

Further details in relation to this project can be obtained from: consultation@electranet.com.au

Identified need

Background and context

The corridor connecting Tailem Bend and Tungkillo is a critical backbone for the South Australian transmission network and currently comprises two operational 275 kV circuits and a parallel 132 kV sub-transmission network.

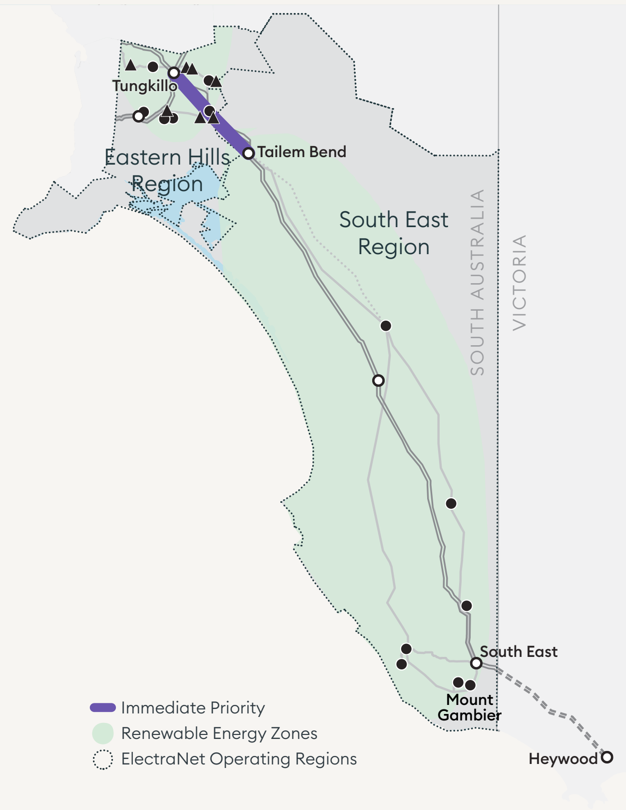


Figure 33: South East Priority

Committed developments in the region include establishment of the Tepko Substation (attached to the Summerfield BESS) and the stringing of the vacant circuit from Tungkillo to Tepko, providing a "partial" third circuit along the corridor prior to the proposed works described in this PSCR.

Description of the identified need

The identified need for this project is to continue to provide electricity transmission services in South Australia at a prudent and efficient cost. Specifically, the identified need for this RIT-T is to efficiently manage the risk of thermal overloading of the 132kV network in the transmission corridor between Tailem Bend and Tungkillo under the credible contingency of a trip on one of the two 275 kV lines.

Key Challenges

The current network configuration, which relies on two 275 kV circuits supported by a limited 132 kV network, presents significant operational and security challenges. These challenges are intensifying due to the growth of renewable generation in the region and include:

- **Network Security (N-1 Overloads)**: The primary security challenge exists during the credible event of a trip on one of the two existing 275 kV lines. At times of high load, the remaining 275 kV circuit and 132 kV circuit rapidly reaches thermal limits. As this overload would occur immediately following a fault, the network must be operated with strict pre-contingent constraints to ensure flows remain within safe limits, specifically during periods of high import demand. This is referred to as operating in a secure operating state within the NER.[21]
- **Renewable Integration and Constraints**: The region has seen significant uptake in renewable energy, including solar and BESS projects connecting at Tailem Bend. During periods of high Heywood Interconnector imports, the addition of this local generation exacerbates the loading issues described above. This situation is set to become more extreme as further renewable generation is established near the Tailem Bend area. Without network augmentation, ElectraNet will be forced to apply increasingly severe pre-contingent constraints to these renewable generators, further limiting their output and the overall efficiency of the market.
- **Maintenance Constraints**: There are extremely limited windows available to perform maintenance on either of the existing 275 kV circuits. Taking one circuit out of service for planned work places the network in a single-circuit risk state, where the next credible contingency would instantaneously overload the 132 kV network.

To attempt to manage this, maintenance is often required to be performed overnight, which is operationally inefficient and costly, or at times during the day when conditions are expected to be favourable. These outages cannot be planned with confidence in advance as they require a precise balance of load, solar, and wind resources to proceed safely. As a result, planned outages may need to be cancelled or moved at late notice, leading to deferred maintenance and increased asset risk.

Assumptions used in identifying the identified need

The following assumptions underpin the assessment of the need and potential options:

- The corridor comprises two 275 kV circuits operating in parallel with an underlying 132 kV network.
- The relevant credible contingency is the trip of one of the two 275 kV lines.
- The risk is most acute during high import conditions/ high import demand.
- Current operational mitigation includes pre-contingent constraints on renewable generation and interconnector flows.
- New solar and BESS connections at Tailem Bend exacerbate the limitation, with increasing severity expected as further renewables connect near Tailem Bend.
- Committed developments include Tepko Substation (attached to Summerfield BESS) and stringing the vacant circuit from Tungkillo to Tepko prior to this project.

Technical characteristics required of non-network options

A non-network option would need to prevent post-contingent thermal overloading of the 275 kV and 132 kV network following the loss of one 275 kV circuit under high import conditions, and to reduce reliance on pre-contingent constraints on renewable generation and interconnector flows while enabling practicable maintenance access for the existing 275 kV circuits.

Credible options

ElectraNet consider there to be one technically feasible option – stringing the vacant side of the existing line from Tepko to Tailem Bend to complete the third circuit. The work to establish the Tepko connection point and string the vacant circuit from Tungkillo to Tepko is scheduled to be completed prior to this proposed project to complete the 275 kV circuit and will provide a "partial" third circuit along the corridor. By stringing the remainder of the vacant circuit from Tepko to Tailem Bend. This extension will effectively link the radial BESS connection into a fully interconnected third transmission circuit between Tungkillo and Tailem Bend via Tepko.

String Vacant Circuit (Tepko–Tailem Bend) Technical characteristics

Functional requirement

Establish a 275 kV transmission circuit between Tepko Substation and Tailem Bend by stringing the vacant side of existing double-circuit structures south of Tepko and establishing the switching bays to integrate the new line.

Primary systems

- Tepko Substation: populate one 275 kV bay within the ElectraNet yard (attached to the Summerfield BESS yard) to facilitate the line exit to Tailem Bend; install circuit breakers, disconnectors, and associated primary plant.
- Tailem Bend Substation: install one 275 kV circuit breaker bay into the vacant bay of the existing SE2 diameter (one-and-a-half breaker configuration) to accommodate the new line entry; install one 275 kV transformer circuit breaker bays for the existing 275/132 kV transformer; install one 275 kV motorised isolator with earth switch for the existing SE1 entry diameter.
- No works required at Tungkillo Substation.

Secondary systems

- Tepko Substation: install protection and control panels for the Tailem Bend line exit; integrate the new bay into SCADA and protection systems.
- Tailem Bend Substation: utilise existing HMI (stated as an assumption); install one feeder protection panel (differential/distance); integrate new protection into existing buszone protection and SCADA systems.

[21] Per NER clause 4.2.4

Transmission lines

The primary scope is stringing the vacant position of the existing line between Tepko and Tailem Bend:

- Engineering/design review to confirm tower loading meets current standards
- String the vacant side of the existing double-circuit line from Tepko to Tailem Bend (length to be confirmed).
- New line connection at Tailem Bend (~700–800 m)
- Connection at Tepko substation gantry
- Establish and acquire easements where new connection sections depart the existing easement
- Preferred conductor: Twin Olive (2 × 54/7/3.5 ACSR/AZ) designed for 100°C; fallback conductor arrangements specified subject to structural analysis
- Structures: utilise existing double-circuit steel lattice towers; new connections to use single-circuit twin conductor steel lattice towers (examples stated).

Telecommunications

- 48-core OPGW required between Tailem Bend and Tepko.
- Assumed integration into existing telecommunications network, assuming OPGW will be strung as part of the Tungkillo–Tepko works.

Material inter-regional impact

We have considered whether the credible option will have a material inter-regional impact and the credible option outlined above does not have a material inter-regional impact as it does not have the potential to increase maximum power transfer capabilities. This option may reduce constraints on the network between Tailem Bend and Tungkillo and could potentially reduce the time that transfer limits along the Heywood interconnection corridor are constrained below nominal. This reduction in constraints is expected to be time constrained under the nominal capacity of the Heywood interconnector rather than improving the nominal limit directly.

By reference to AEMO's screening test for an inter-network impact, a material inter-regional impact arises if the option:

- Involves a series capacitor or modification near an existing series capacitor
- Is expected to result in a change in power transfer capability between South Australia and neighbouring transmission networks or
- Is expected to increase fault levels at any substation in another TNSP's network.

None of these criteria are satisfied for the project discussed here.[22]

Market benefit classes unlikely to be material (and reasons)

The requirements of a PSCR include stating whether any of the classes of market benefits are unlikely the be material. At this stage of the RIT-T, ElectraNet does not consider there a reason for any classes to be ruled out as immaterial, and subsequent stages of the process all classes will be assessed.

Estimated construction timetable and commissioning date

Required start date: 01/07/2028.

Required completion date: 30/06/2033.

Total indicative capital and maintenance costs

Project estimated cost: $81 million.

[22] In accordance with NER clause 5.16.4(b)(6)(ii).

Compliance checklist

NER Clause	Requirement	Where addressed
5.16.4(b)	A RIT-T proponent must prepare a report (the project specification consultation report), which must include:	
	(1) a description of the identified need	Section 2
	(2) the assumptions used in identifying the identified need (including, in the case of proposed reliability corrective action, why the RIT-T proponent considers reliability corrective action is necessary)	Section 2.3
	(3) the technical characteristics of the identified need that a non-network option would be required to deliver, such as: (i) the size of load reduction or additional supply; (ii) location; and (iii) operating profile;	Section 3
	(4) if applicable, reference to any discussion on the description of the identified need or the credible options in respect of that identified need in the most recent Integrated System Plan;	Why we consider this RIT-T necessary
	(5) a description of all credible options of which the RIT-T proponent is aware that address the identified need, which may include, without limitation, alternative transmission options, interconnectors, generation, system strength services, demand side management, market network services or other network options;	Section 4
	(6) for each credible option identified in accordance with subparagraph (5), information about: (i) the technical characteristics of the credible option; (ii) whether the credible option is reasonably likely to have a material inter-network impact; (iii) the classes of market benefits that the RIT-T proponent considers are likely not to be material in accordance with clause 5.15A.2(b)(6), together with reasons of why the RIT-T proponent considers that these classes of market benefits are not likely to be material; (iv) the estimated construction timetable and commissioning date; and (v) to the extent practicable, the total indicative capital and operating and maintenance costs.	Sections 4.1

F.2 Lower South East Upgrade

Executive summary

This Project Specification Consultation Report (PSCR) relates to the identified need to maintain sufficient transformation capacity in the Lower South East supply area. This need is driven by forecast demand at the Blanche connection points and associated obligations under the Electricity Transmission Code (ETC).

SA Power Networks has advised update demand forecasts in December 2025. Based on adding these to current forecasts, there is an overload of the transformers at Blanche as early as 2029.

There is considered to be a single technically and economically credible option:

- Transfer approximately 13 MVA of SAPN load (Mount Gambier West 33/11 kV zone substation) from Blanche to Mount Gambier (SAPN switching), and augment Mount Gambier by replacing the existing 25 MVA 132/33 kV transformer (TF2) with a 60 MVA transformer, alongside associated refurbishment / replacement works at Mount Gambier.

Introduction

Purpose of this report

This PSCR has been prepared as the consultation report required to set out prescribed information about the proposed transmission investment, including the identified need, the assumptions used, the technical characteristics a non-network option would be required to deliver, and a description of credible options and specified information for each credible option.

This Regulatory Investment Test for Transmission (RIT-T) Project Specification Consultation Report (PSCR) represents the first step in the application of the RIT-T to addressing the risk of overload at the Blanche connection point due to forecast increasing customer load due by 2030.

This report:

- Describes the identified need that we are seeking to address, together with the assumptions used in identifying this need
- Sets out the technical characteristics that a non-network option would be required to deliver to address this identified need
- Outlines the credible option that we consider addresses the identified need.

Why we consider this RIT-T is necessary

The National Electricity Rules (NER) require the application of the RIT-T to replacement capital expenditure where the estimated capital cost of at least one credible option exceeds $7 million.[23]

Accordingly, we have initiated this RIT-T to consult on proposed expenditure related meeting the obligations of the South Australian Electricity Transmission Code, noting that none of the exemptions listed in NER clause 5.16.3(a) apply.

The credible option discussed in this PSCR has not been foreshadowed in AEMO's 2024 Integrated System Plan (ISP).

Submissions and next steps

We welcome written submissions on this PSCR. Submissions are due on or before Tuesday, 30 June 2026. Submissions should be emailed to consultation@electranet.com.au.

Submissions will be published on the ElectraNet website. If you do not want your submission to be published, please clearly specify this at the time it. Subject to submissions received on this PSCR, a Project Assessment Draft Report (PADR) is expected to be published in due course.

Further details in relation to this project can be obtained from: consultation@electranet.com.au

[23] NER clause 5.15A.1(c) states that the purpose of the RIT–T is to: identify the credible option that maximises the present value of net economic benefit to all those who produce, consume and transport electricity in the market (the preferred option). For the avoidance of doubt, a preferred option may, in the relevant circumstances, have a negative net economic benefit (that is a net economic cost) to the extent the identified need is for reliability corrective action or the provision of inertia network services required under clause 5.20B.4 or the provision of system strength services required under clause 5.20C.3.

Identified need

Background and context

SA Power Network have forecast distribution load increases that will require an increase to the agreed maximum demand at the Blanche connection point.

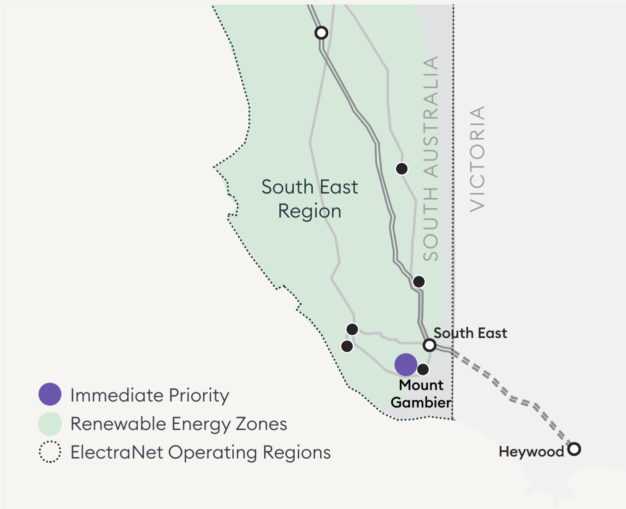


Figure 34: Lower South East Upgrade

Description of the identified need

The identified need for this project is to continue to provide electricity transmission services in South Australia at a prudent and efficient cost. Specifically, the identified need for this RIT-T is to is to efficiently manage the risk of overload at the Blanche connection point due to forecast increasing distribution load by 2030.

Based on current maximum demand forecasts, the capacity of Blanche connection point would need to be upgraded before summer 2030/31.

Reliability corrective action

This RIT-T is a reliability corrective action as defined NER 5.10.2, as the objective is to meet the regulatory obligations and service standards contained in schedule 5.1 of the NER and within the applicable regulatory instrument of the Essential Services Commission of South Australia's (ESCOSA) Electricity Transmission Code (ETC).

Assumptions used in identifying the identified need and potential options

The following assumptions underpin the assessment of the need and potential options:

- SA Power Networks demand forecasts received December 2025
- Daily peak demands occur for 6 hours between 4 pm and 10 pm with a further margin of 2 hours
- SAPN have the ability to switch ~13 MVA of load (Mount Gambier West 33/11 kV zone substation) from Blanche connection point to Mt Gambier connection point. No capital cost to them to do so – switching only.

Technical characteristics required of non-network options

A non-network option would need to prevent overload at the Blanche connection point due to forecast increasing customer load due by 2030. Any proposal would need to have the following minimum requirements:

- Demonstrate operation that reduces the power flows over the transformers at Blanche by at least 5 MW and for the duration of at least 8 hours
- Be capable of receiving an automated instruction to operate and cease operation
- Demonstrate 24/7 operation to receive telephone connections from the ElectraNet control room
- Be capable of full and complete operation by 31 October 2030.

Credible options

ElectraNet consider there to be one technically and economically credible option - Transfer approximately 13 MVA of SAPN load from Blanche to Mount Gambier (SAPN switching), and augment Mount Gambier by replacing the existing 25 MVA 132/33 kV transformer with a 60 MVA transformer, alongside associated refurbishment / replacement works at Mount Gambier.

Option 1: Transfer SAPN load and augment Mount Gambier Technical characteristics

Implementing the transfer of load from Blanche to Mt Gambier would enable ElectraNet to provide capacity for the growing load by upgrading Mt Gambier connection point and would avoid the need to upgrade Blanche as well as Mt Gambier.

Functional Requirement

To augment Mount Gambier and Blanche capacity to supply 10–20 years of forecast load growth including spot loads. The Option outlined below describes implementing SA Power Networks switching load from the Blanche substation to the Mount Gambier substation and then augmenting the latter to account for the increased load.

Mount Gambier substation overview

Replace the existing 25 MVA 132/33 kV TF2 at Mt Gambier with a new 60 MVA 132/33 kV transformer, and perform required refurbishment and replacement works at Mt Gambier. A single line diagram of Mount Gambier substation is shown in Figure 1, and an overhead view of the substation is shown in Figure 2. The transformer being replaced is highlighted on both figures.

Primary scope of works

1. Decommission and remove existing 25 MVA 132/33 kV TF2.
2. Install a new 60 MVA 132/33 kV transformer (design, supply, install, and commissioning) in the same bay:
   - Integrate suitable bunding SOW with Project EC.15564 Oil Containment System Improvements 2028–33
   - Integrate oil containment SOW with Project EC.15564 Oil Containment System Improvements 2028–33
   - Integrate earth formed evaporation pond SOW with Project EC.15564 Oil Containment System Improvements 2028–33.
   - Earthing
   - Trenching
   - Larger footings due to increased TF size
   - Primary connections
   - Move gantry to potentially avoid larger bz̀ushings. Modification to 33 kV connection
   - New 132 kV CVT for TF2 HV side (sync check)
   - New 33 kV VT for TF2 LV side (Revenue Metering and sync check)

Secondary systems

- New Transformer Set 1 and Set 2 protection scheme
- New CBM schemes for CB6088 and CB6009
- New TF LVCB scheme for 4523
- New SAPN interface trip scheme
- SCADA updates to include new IEDs and install a new WAMS IED.

Transmission lines / telecommunications

- Transmission lines: N/A
- Telecommunications: update telco switches to include new IEDs.

Switching – SA Power Networks

- SA Power Networks switches approximately 13 MVA of load (Mount Gambier West 33/11 kV zone substation) from Blanche to Mount Gambier (switching only).

Material inter-regional impact

We have considered whether the credible option will have a material inter-regional impact.[24]

By reference to AEMO's screening test for an inter-network impact, a material inter-regional impact arises if the option:

- Involves a series capacitor or modification near an existing series capacitor
- Is expected to result in a change in power transfer capability between South Australia and neighbouring transmission networks or
- Is expected to increase fault levels at any substation in another TNSP's network.

None of these criteria are satisfied for the project discussed here. Therefore, ElectraNet does not consider there are any associated material inter-network impacts.

[24] In accordance with NER clause 5.16.4(b)(6)(ii).

Market benefit classes unlikely to be material (and reasons)

The requirements of a PSCR include stating whether any of the classes of market benefits are unlikely the be material. At this stage of the RIT-T, ElectraNet does not consider there a reason for any classes to be ruled out as immaterial except changes in ancillary services costs and competition benefits.

Estimated construction timetable and commissioning date

Start date: 01/07/2028.

Required completion date: 31/10/2030.

Total indicative capital and maintenance costs

Project estimated cost: $12 million.

Compliance Checklist

NER Clause	Requirement	Where addressed
5.16.4(b)	A RIT-T proponent must prepare a report (the project specification consultation report), which must include:	–
	(1) a description of the identified need	Section 2
	(2) the assumptions used in identifying the identified need (including, in the case of proposed reliability corrective action, why the RIT-T proponent considers reliability corrective action is necessary)	Section 2.3
	(3) the technical characteristics of the identified need that a non-network option would be required to deliver, such as: (i) the size of load reduction or additional supply; (ii) location; and (iii) operating profile;	Section 3
	(4) if applicable, reference to any discussion on the description of the identified need or the credible options in respect of that identified need in the most recent Integrated System Plan;	Why we consider this RIT-T necessary
	(5) a description of all credible options of which the RIT-T proponent is aware that address the identified need, which may include, without limitation, alternative transmission options, interconnectors, generation, system strength services, demand side management, market network services or other network options;	Section 4
	(6) for each credible option identified in accordance with subparagraph (5), information about: (i) the technical characteristics of the credible option; (ii) whether the credible option is reasonably likely to have a material inter-network impact; (iii) the classes of market benefits that the RIT-T proponent considers are likely not to be material in accordance with clause 5.15A.2(b)(6), together with reasons of why the RIT-T proponent considers that these classes of market benefits are not likely to be material; (iv) the estimated construction timetable and commissioning date; and (v) to the extent practicable, the total indicative capital and operating and maintenance costs.	Sections 4.1

Appendix G
Designated Network Assets

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

There is one designated network asset in South Australia, as shown in the following table. There are several other assets that are expected under construction and to be commissioned as Designated Network Assets, but these are not yet in service.

Table 24: Designated Network Assets in South Australia

Designated network asset	Connection point to shared transmission network	Owner
Clements Gap DNA	Redhill 132 kV	ElectraNet

Appendix H
Emergency Control Schemes

H.1 List of existing control schemes

There are a wide range of control schemes that are used to enhance the capability, security and resilience of the South Australian transmission system (Table 25).

Table 25: Existing control schemes

Scheme Name	Scheme Type	Functionality
South Australian Interconnector Trip Remedial Action Scheme	Transient Stability	Rapidly detect the non-credible loss of either Heywood Interconnector or South Australia New South Wales Interconnector and will take remedial action to prevent the tripping of the remaining interconnector due to power system stability. The scheme is currently in the detailed design phase and planned to be commissioned in October 2026.
Wide Area Protection Scheme	Transient Stability	Rapidly identify conditions that could otherwise result in a loss of synchronism between South Australia and Victoria and correct those conditions by rapidly injecting power or shedding load in South Australia to avoid this loss of synchronism. The scheme will be decommissioned following the implementation of SAIT RAS.
PEC Stage 1 Inter-trip Scheme	Transient Stability	Trip South Australia – New South Wales Interconnector in the event of trip of Heywood Interconnector. The scheme will be decommissioned following the implementation of SAIT RAS.
South East Loss of Synchronism Protection	Transient Stability	Trip the Heywood interconnector for loss of synchronism between South Australia and Victoria.
Tailem Bend 132 kV Tripping Scheme	Transient Stability and Thermal Loading	Trip the underlying 132 kV network in the event of a 275 kV double circuit outage between South East and Tailem Bend or Tailem Bend and Tungkillo.
Murraylink Automated Control Scheme	Anti-Islanding/ Thermal Loading	Reduce Murraylink flow to prevent overload of transmission elements (Robertstown – Northwest Bend lines 1 and 2, Northwest Bend – Monash 1 &2, Robertstown 275/132 kV transformers). If Murraylink is connected to an islanded section of SA, trip the circuit breakers CB 6152, 6153, 6154 at Monash, isolating the Murraylink from South Australia.
Hallett Power Station Islanding Scheme	Anti-islanding	Armed when Canowie is radially fed to trip Hallett Power Station and Hallett 2 WF on next contingency to prevent islanded generation.
Wattle point Tripping Scheme	Voltage Stability	Prevent voltage instability caused by the trip of Hummocks – Waterloo or Hummocks – Snowtown-Bungama lines when Wattle point wind generation is above 60 MW, by tripping the Wattle Point wind farm.

Table 25: Existing control schemes (cont.)

Scheme Name	Scheme Type	Functionality
Waterloo Runback Scheme	Thermal Loading	Runback or trip to Waterloo wind farm on overloading of following transmission lines or transformers. Waterloo East – MWP4 132 kV line MWP4 – Robertstown 132 kV line Waterloo – Templers 132 kV line Robertstown 275/132kV transformer 1 & 2
AMCOR runback Scheme	Thermal Loading	Runback or trip AMCOR load following the loss of Para – Roseworthy line.
South East Control Scheme	Thermal Loading	Runback or trip to Lake Bonney wind farm generation on overload of Southeast transformers or the Southeast - Snuggery / Mayurra 132kV line.
Black Range Fixed Series Capacitors Bypass Control Scheme	Asset Protection	Detect Sub-synchronous Oscillation / Sub-synchronous Control Interaction and bypass the Black Range Fixed Series Capacitor.
Bungala solar farm Runback and Sever Scheme	Thermal Loading/ Anti-Islanding	Runback or trip Bungala Solar Farm on overload of Davenport 275/132 kV transformers. Prevent islanding of Bungala Solar Farm with 132 kV load for trip of both 275/132 kV transformers at Davenport, by tripping the solar farms.
Hornsdale Wind Farm 3 Inter-trip Scheme	System Strength	For loss of Mount Lock – Canowie, Mount Lock - Davenport, or Canowie – Robertstown lines, trip turbines in Hornsdale Wind Farm Stage 3 to manage system strength.
Blyth West Control Scheme	Thermal loading, System Strength	Trip Blyth West -Snowtown 2 line following a loss of one of the line sections of the Para – Munno Para – Blyth West – Bungama – Davenport 275kV line.
Upper North Voltage Management Emergency Control Scheme	Voltage Stability	Prevent voltage collapse and/or unacceptable voltages at Davenport and Prominent Hill following multiple contingency events.
Dalrymple BESS Islanding Detection Scheme	Islanding	This system detects if Dalrymple Substation has been islanded due to an upstream event. With the IDS in AUTO and if it detects an islanding condition, the BESS & IDS will island Dalrymple Substation, Dalrymple Nth and SAPN load onto a micro-grid.
Under Voltage Load Shedding schemes	Voltage Stability	Prevent voltage collapse and or line overloading at high system loads during a contingency. UVLS is installed in following sites: • Mannum Adelaide Pump Station 1, 2 and 3 • Murray Bridge Pump Station 1, 2 and 3 • Keith.
Eyre Peninsula Anti Islanding Scheme	Anti-islanding	Inter-trip Eyre Peninsula generators when an island is formed in Eyre Peninsula (due to the loss of double circuits/ loss of single circuit during a planned outage of the other circuit between Cultana and Port Lincoln).
TIPS66 – TINS Islanding Sever Trip Scheme	Anti-islanding	Intertrip Quarantine Power Station Generator Circuit Breakers if TIPS - TINS 66 kV line breakers are opened at TIPS and Quarantine Power Station generators are islanded.
Lake Bonney Inter-trip Scheme	System Strength	Intertrip Lake Bonney Wind Farm Stage 1, 2 and 3 for loss of double circuits between Moorabool – South East.

H.2 Potential new control schemes and modifications

ElectraNet is evaluating additional remedial action schemes to fulfill NER S5.1.8 requirements and optimise network capacity utilisation (Table 26).

Table 26: New Control Schemes Under Consideration

Scheme Name	Scheme Type	Functionality
Mid North (West) Remedial Action Scheme	Thermal Loading, system strength under outage conditions	Manage current and future generation in the Para – Muno Para – Blyth West – Bungama – Davenport corridor under outage conditions.
Mid North (East) Remedial Action Scheme	Thermal Loading, system strength under outage conditions	Manage future generation in the Para – Templers West – Brinkworth – Davenport corridor under outage conditions.
Riverland North Remedial Action Scheme	System strength under outage conditions	Manage future generation connected to the Bundey substation under prior outage condition/non-credible loss of Bundey – Robertstown double circuit.
Eyre Peninsula Anti-Islanding Scheme	Anti-islanding Scheme	Expansion of the existing anti-islanding scheme to include upper Eyre Peninsula area and future generation in the region.
Mid North 132 kV Remedial Action Scheme	Thermal Loading, system strength under outage conditions	Manage future generation in the Eastern Hill 132 kV network under prior outage conditions.
South Australia Intra regional Separation Prevention Scheme	Transient Stability	Manage transient stability within the South Australian system and prevent system separation between the upper north region and metro regions due to non-credible loss of multiple circuit in the mid north region.
Upgrade of Murraylink Control Scheme	Thermal Loading and islanding	Upgrade to Murraylink control scheme considering the future generation in the mid north and riverland networks.

Appendix I
System Strength Locational Factors

System strength locational factors quantify how a connection point's location affects its impact on the overall stability and strength of the electrical grid.

It is calculated by AEMO based on the electrical distance between the connection point and the nearest system strength node; and is used to determine the relative impact on system strength at different locations within the transmission network.

The greater the electrical distance (or impedance) of a connecting generator from a node, the greater its impacts on system strength.

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

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

We publish system strength locational factors for committed or connected facilities where the proponent has elected to pay the system strength charge where applicable (Table 27).

Table 27: System strength locational factors

System Strength Connection Point	Status	System Strength Node	System Strength Locational Factor
Palmer Wind Farm	Committed	Para	1.0063
Pelican Point BESS	Committed	Para	1.0046
Carmody's Hill Wind Farm	Committed	N/A	N/A*
Solar River BESS	Committed	Robertstown	1.0027

*This connection pre-dates system strength requirements. It is included here for visibility as the TCA was signed during the preceding 12 month period.

Appendix J
Summary of Changes since the 2025 Transmission Annual Planning Report

System Strength Requirements in SA

ElectraNet published the PACR in December 2025, with the preferred option having been identified as contracting with future non-network proponents who can add mechanical clutches to synchronous generators such that can operate as synchronous condensers.

While this investment is not strictly required to meet either the 'minimum' or 'efficient level' system strength requirements under the Step Change scenario, it is a prudent low cost and 'low regret' insurance against the need to provide additional system strength in South Australia.

In concluding the RIT-T, and avoided the need for investment, the South Australian Government has adopted the proposed solution and has mandated its need, via the Office of the Technical Regulator updating its Generator Development Approval Procedure.

ElectraNet will review the situation over the coming years to ensure the system has sufficient system strength services and this may require further action in the future. We will not be seeking network support agreements for the provision or use of this service.

Eyre Peninsula Upgrade

ElectraNet published the PACR for the Eyre Peninsula Upgrade RIT-T in December 2025.

The preferred solution identified in the PACR is to upgrade operation of the Cultana to Yadnarie double circuit lines from 132 kV to 275 kV by performing 275 kV works at Cultana and establishing a new 275/132 kV substation at Yadnarie North.

The PACR also identifies that if sufficient new customer load connections become committed, then the construction of new double circuit 275 kV lines between Narcoona, Davenport and Cultana East should also form part of the preferred solution.

South East Region RIT-T Processes

ElectraNet is commencing two separate RIT-T processes in this TAPR by publishing two Project Specification Consultation Reports – one related to the network between Tepko and Tailem Bend in the Upper South East and one related to the Blanche substation in the Lower South East.

Both reports are included in Appendix F of this document and outline why we consider the RIT-T necessary, the identified need at each location, the requirements of any potential non-network solution, the credible option detailed for each, and the associated timing and costs.

The consultation period for each will conclude on 30 June 2026.

Abbreviations

Abbreviation	Definition
°C	Degrees Celsius
AC	Alternating Current
AI	Artificial Intelligence
AIS	Gas Insulated Switchgear
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMD	Agreed maximum demand
ASRS	Australian Sustainability Reporting Standards
AUKUS	Australia, United Kingdom and United State (Security pact)
BESS	Battery energy storage system
BTM	Behind-the-meter
CBD	Central business district
CCGT	Combined Cycle Gas Turbine
CER	Consumer Energy Resources
CIS	Capacity Investment Scheme
cm	A unit of distance, equivalent to one hundredth of a metre
CO2-e	Carbon dioxide equivalent
DNSP	Distribution Network Service Provider
DRI	Direct Reduced Iron
EAF	Electric Arc Furnace
EDC	Event-driven component, one of the three components of the SAIT RAS
EMS	Emergency Management System
ESCI	Electricity Sector Climate Information
ESCOSA	Essential Services Commission of South Australia
ESG	Environmental, social and governance
ESOO	Electricity Statement of Opportunities, published by AEMO
ETC	Electricity Transmission Code, published by ESCOSA
EV	Electric Vehicle
FAPR	Fast active power response
FERM	Firm Energy Reliability Mechanism
FCAS	Frequency control ancillary services
GPSRR	General Power System Risk Review, published by AEMO
GIS	Gas Insulated Switchgear
GW	Giga-Watt, a unit of active power equivalent to 1,000 MW
GWh	Giga-Watt-hours, a unit of energy equivalent to 1,000,000 Watt-hours
HRE Act	South Australian Hydrogen and Renewable Energy Act
Hz	Herz, a unit of frequency
IASR	Inputs, Assumptions and Scenarios Report, published by AEMO
IBR	Inverter based resources

Abbreviations (cont.)

Abbreviation	Definition
ICT	Information and communications technology
ISP	Integrated System Plan, published by AEMO
km	Kilometres
kV	kilo-Volts, a unit of electrical potential equivalent to 1,000 Volts
LIL	Large industrial load
LOPA	Layer of protection analysis
ML	Mega-litres, a unit of volume equivalent to 1,000,000 litres
MSL	Minimum System Load
Mt	Mega-tonnes, a unit of mass equivalent to 1,000 tonnes
MVA	Mega-Volt-Ampere, a unit of apparent power
MVAr	Mega-MAr, a unit of reactive power
MW	Mega-Watt, a unit of active power equivalent to 1,000 Watts
NCIPAP	Network Capability Incentive Parameter Action Plan
NCRA	National Climate Risk Assessment
NEM	National Electricity Market
NER/Rules	National Electricity Rules
NMMS	Network Model Management Solution
NOTE	Network Operational Technology Enhancements program
NSCAS	Network Support and Control Ancillary Services report, published by AEMO
NSP	Network Service Provider
NTx	Northern Transmission Project
OCGT	Open-Cycle Gas Turbine
ODP	Optimal development plan
OFGS	Over frequency generator shedding
OTR	Office of the Technical Regulator
PACR	Project Assessment Conclusions Report, the final report in the RIT-T process
PADR	Project Assessment Draft Report, the second report (if required) in the RIT-T process
PEC	Project EnergyConnect
PMU	Phasor measurement unit
PSCAD	Power Systems Computer Aided Design
PSCR	Project Specification Consultation Report, the first report in the RIT-T process
PV	Photovoltaic
RAS	Remedial action scheme
RCC	Resource controller component, one of the three components of the SAIT RAS
RDC	Response-driven component, one of the three components of the SAIT RAS
RETA	Renewable Energy Transformation Agreement
REZ	Renewable Energy Zone
RoCoF	Rate of change of frequency
RIT-T	Regulatory Investment Test for Transmission
RSAS	Reliability and Security Ancillary Service

Abbreviations (cont.)

Abbreviation	Definition
SAIT RAS	South Australian Interconnector Trip Remedial Action Scheme
SF_6	Sulphur hexafluoride
SRMTMP	Safety, Reliability, Maintenance and Technical Management Plan
STATCOM	Static Compensator
SVC	Static Var Compensator
TAPR	Transmission Annual Planning Report
TCA	Transmission Connection Agreement
TNSP	Transmission Network Service Provider
TPSS	Transition Plan for System Security
TUoS	Transmission Use of Service
TWh	Tera-Watt-hours, a unit of energy equivalent to 1,000 GWh
UFLS	Under frequency load shedding
VCR	Value of customer reliability
VNR	Value of network resilience
VRE	Variable renewable energy
WAPS	Wide area protection system

Glossary

Term	Description
10% PoE	10% probability of exceedance. This is used to indicate a forecast value that is expected to be exceeded once in every 10 years, on average.
90% PoE	90% probability of exceedance. This is used to indicate a forecast value that is ex-pected to be exceeded nine times in every 10 years, on average.
Constraint	A limitation on the capability of a network, load or a generating unit that prevents it from either transferring, consuming or generating the level of electrical power which would otherwise be available if the limitation was removed.
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 stabilize system frequency from the first few seconds after a frequency disturbance, while regulation FCAS rase 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 three interconnectors and seven regional networks in South Australia.
Maximum demand	The highest amount of electricity drawn from the network within a given time period.
Metropolitan	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, will all network elements in-service.
N-1	One network element out of service, with all other network elements in-service.
National Electricity 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	Options which address a network that don't include regulated network infrastructure, such as generation, market network services and demand-side management initiatives.
Over frequency generator shedding	A scheme that trips generators based on a pre-determined schedule 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.
STATCOM	A power electronic device based on IGBT technology that can rapidly adjust its level of reactive power contribution.
SVC	A power electronic device based on thyristor technology that can rapidly adjust its level of reactive power contribution.
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 feasible power transfer through a transmission or distribution limit.
Under frequency load shedding	A scheme that trips loads based on a pre-determined schedule when the system frequency decreases due to demand exceeding supply.

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