TasNetworks Annual Planning Report 2026



TasNetworks | Powering a Bright Future



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Executive summary

Tasmanian Networks Pty Ltd (TasNetworks) presents its 2026 Annual Planning Report (APR) prepared in accordance with the National Electricity Rules (the Rules) and Tasmanian jurisdictional requirements. We are a Transmission and Distribution Network Service Provider within the Tasmanian jurisdiction of the National Electricity Market (NEM) and have been appointed by the Minister as the Jurisdictional Planning Body. As such, in accordance with the Rules, we are also the System Strength Service Provider and Inertia Service Provider and have been appointed as the Coordinating Network Service Provider to allocate the aggregate annual revenue requirement for prescribed transmission services.

This combined transmission and distribution APR provides information on our planning activities over a 10-year planning period through to 2036. Some aspects are based on shorter planning time frames. In particular, our distribution line loads are based on a 2- year planning horizon. The following key objectives continue to provide us with guidance for our planning activities:

- development of new large-scale load connections;
- supporting generation and Pumped Hydro Energy Storage (**PHES**) initiatives;
- supporting the Australian Energy Market Operator's (**AEMO**) 2026 Integrated System Plan (**ISP**); and
- meeting reliability and security obligations.

We assess both network and non-network options to address emerging limitations and asset management issues. The intention is that our APR provides existing and potential customers and non-network solution providers with information to prompt discussion on:

- opportunities to address identified network limitations;
- locations that would benefit from supply capability improvements or network support initiatives; and
- locations where new loads or generation could be readily connected.

As a provider of monopoly electricity transmission and distribution network services, we commenced preparation of our regulatory proposal for the 2029-2034 period to be submitted for determination by the Australian Energy Regulator (**AER**). Regulatory Proposals are submitted every five years and detail capital and operational expenditure requirements to build, operate, and maintain Tasmania's electricity networks.

Renewable energy development

Our network planning strategies consider and support the objectives of the Tasmanian Government to utilise renewable energy as a key economic driver in Tasmania. The Tasmanian Renewable Energy Target (**TRET**)[1], was passed into legislation in late 2020 with the objective to grow Tasmania's renewable electricity generation with the aim, by the end of 2040, to double Tasmania's 2020 baseline of 10,500 GWh of renewable generation per year.

The TRET defines an increase of 3,000 MW of new renewable generation capacity within Tasmania to meet the 20 year energy production targets. In this regard, the current pipeline of on-island projects at various stages of development total nearly 7,000 MW of wind farms, 800 MW of large scale solar-photovoltaics (**PVs**), 750 MW of Pumped Hydro Energy Storage (**PHES**), and 700 MW of Battery Energy Storage Systems (**BESS**).

In terms of the network today, there is currently near 3,400 MW of on-island generation covering hydro, gas, wind, and large-scale PVs in Tasmania.

1 Part 1A – Renewable Energy, Energy Co-ordination and Planning Act 1995, Tasmania



The integration of such large quantities of variable renewable energy (**VRE**) into the Tasmanian electricity system will involve significant developments and augmentation to the transmission network. The TRET's continued function is to drive strategic planning and investment coordination activities.

Renewable energy zones

AEMO previously identified four candidate Tasmanian Renewable Energy Zones (**REZ**); being:

- North East Tasmania REZ;
- North West Tasmania REZ;
- Central Highlands REZ; and
- North Tasmania Coastal REZ.

Hosting capacity of each REZ depends on a number of factors, such as thermal capacity of the network, system strength limitations, and the distance of new generation developments from the existing network. We take the view that the REZ concept does not restrict the development and connection of any new generation outside of these nominated areas.

Marinus Link and North West Transmission Developments

Project Marinus is the combination of Marinus Link and within Tasmania the supporting North West Transmission Developments (**NWTD**). The AER published its final decisions on construction costs for Stages 1 of Marinus Link and the NWTD confirming analysis that Tasmanians and Victorians will be better off with investment in these national infrastructure projects.

Marinus Link will be a 1,500 MW capacity electricity interconnector between Tasmania and Victoria comprising two 750 MW staged cables along with advanced converter technology required to interface with the grid. Marinus Link Pty Ltd shareholders made a Final Investment Decision to proceed with Stage 1 of Marinus Link.

The first stage of the NWTD includes 129 kilometres of new and upgraded double circuit transmission lines between Palmerston, Sheffield and Burnie and an interim tee connection to Heybridge to connect the first 750 MW stage of Marinus Link.

TasNetworks commenced construction of the NWTD after reaching financial close and obtaining all regulatory approvals.

Basslink

Basslink is a HVDC interconnector connecting the 220 kV Tasmanian transmission network at George Town Substation with the 500 kV Victorian transmission network at Loy Yang Substation. Following the AER's approval, Basslink converted from a market network service to a prescribed transmission service from 1 July 2026.

With Basslink converted to a regulated interconnector, TasNetworks was appointed as the Coordinating Network Service Provider for Tasmania. This means we will be required to recover a portion of Basslink's regulated revenue from Tasmanian customers.

Basslink settlement residues are allocated as interregional settlement residues (**IRSRs**) to two new regulated notional interconnectors VIC➜TAS for imports into Tasmania and TAS➜VIC for imports into Victoria. The VIC➜TAS IRSRs are distributed via AEMO's Settlement Residue Auction (**SRA**) framework to TasNetworks to offset locational transmission charges.

Large-scale load connections

We monitor the impacts of national and international influences on the operations of Tasmanian industry to understand potential impacts on transmission and distribution services. We are also in discussions with customers with the view to providing connection services that support their operational plans.

AI factories

Australian AI infrastructure developer Firmus Technologies commenced construction of Project Southgate, a series of AI factories. Stage 1 of the project has contracted a 104 MW supply at St Leonards, near Launceston with a further 288 MW at Bell Bay and 52 MW at Wesley Vale. These AI factories will provide a new digital baseload to support the growth of Tasmania's renewable energy sector and enable sustainable expansion in AI infrastructure. Included with these new developments are planned upgrades to the supporting communications infrastructure, such as additional subsea fibre data cables.

Renewable hydrogen

The Australian Renewable Energy Agency (**ARENA**) shortlisted projects for Round 2 of the Hydrogen Headstart Program. Two Tasmanian based projects, Bell Bay Powerfuels and HIF Tasmania, were selected to progress to the next stage in the application process being some of the most advanced large-scale renewable hydrogen proposals in the country.

Integrated System Plan

AEMO published the 2026 ISP being a roadmap for the transition of the NEM. The ISP's optimal development path sets out the needed generation, storage, and network investments to transition to net zero by 2050.

The 2026 ISP identified two Tasmanian projects on the optimal development path—both as actionable ISP projects for which development should be either continued or commenced immediately. These projects are:

- **Tasmanian REZ expansion** through implementing either:
  - the ISP candidate option being NWTD stage 2: Burnie to Hampshire Hills component; or
  - the alternative option being Waddamana to Palmerston transfer capability upgrade.
- **Project Marinus stage 2**.

Project Marinus Stage 1 progressed to committed or anticipated status and is therefore no longer evaluated through the ISP.

Waddamana to Palmerston transfer capability upgrade

In AEMO's 2026 ISP, the Waddamana to Palmerston transfer capability upgrade was replaced as an actionable ISP project by the Tasmanian REZ Expansion project. TasNetworks discontinued work on the Waddamana to Palmerston transfer capability upgrade Regulatory Investment Test for Transmission (**RIT-T**). A separate RIT-T will commence that considers options for meeting the identified need for the new Tasmania REZ Expansion project.

Evolving customer expectations

Electric Vehicles

Our vision is to be an enabler of electric vehicle (**EV**) uptake and for our customers to easily connect to our network. We continue to engage with external stakeholders including councils and EV Charge Point Operators (**CPO**), to better understand their needs and what new capabilities they require from the distribution network. We have published a network capacity map, sharing distribution asset location and estimated capacity of distribution low voltage substations.

Consumer Energy Resources

The distribution network continued to experience growth in small-scale rooftop photovoltaic (**PV**) installations with aggregate installed rooftop PV capacity increasing to 415 MW.

Residential battery uptake also increased significantly following the commencement of the Federal battery rebate program with 6,185 registered residential batteries. Operational observations indicate that residential battery systems are contributing positively to network performance under Tasmania's winter-peaking demand conditions.

Community Batteries

Community batteries are emerging as an innovative solution to enhance distribution networks' ability to manage a growing PV penetration, while providing an energy storage solution that can benefit local customers under various community benefit schemes.

TasNetworks with funding through the Australian Government's Community Batteries for Household Solar program commissioned batteries in Shorewell Park, in the north-west of the State, and Glebe Hill, in the south. With funding support from the Australian Renewable Energy Agency's Advancing Renewables Program, six additional community batteries will be installed across Tasmania in early 2027.

Regulatory changes

The Australian Energy Market Commission (**AEMC**) progressed a Rule change to amend the existing distribution annual planning report framework and replace it with a longer-term network development plan. The changes aim to improve transparency and consistency of long-term plans to help consumers to understand how the distribution network is expected to change in future.

The AEMC completed two Rule changes to improve the technical requirements for connection to the NEM. Package 1 aims to make the NEM access standards fit for purpose in a world where inverter-based resources (**IBR**) are becoming more prevalent. It also adds more prescription and clarity to the access standards.

Package 2 of the rule change focused on the access standards for large, inverter-based loads, such as AI factories, and hydrogen electrolysers. The changes facilitate the planning and design of large loads in a way that supports future power system security.

System strength and inertia

Tasmania continues to be in a situation where it is theoretically possible to meet 100% of Tasmania's operational demand from inverter-based resources, predominantly comprising wind farm generation and Basslink import. As more non-synchronous generation is introduced into the network, careful management of power system security continues to be a high priority.

Contractual arrangements to address existing shortfalls in inertia and system strength are currently in place until June 2029. TasNetworks will consider solutions for providing system strength beyond 2029 in a future RIT-T.

Operational impacts

We note two key developments with regards to the load and generation balance in Tasmania during 2025 and into 2026;

(1) The finalised closure of Liberty Bell Bay smelter at George Town, resulting in a reduction of approximately 100 MW of major industrial load from the system; and

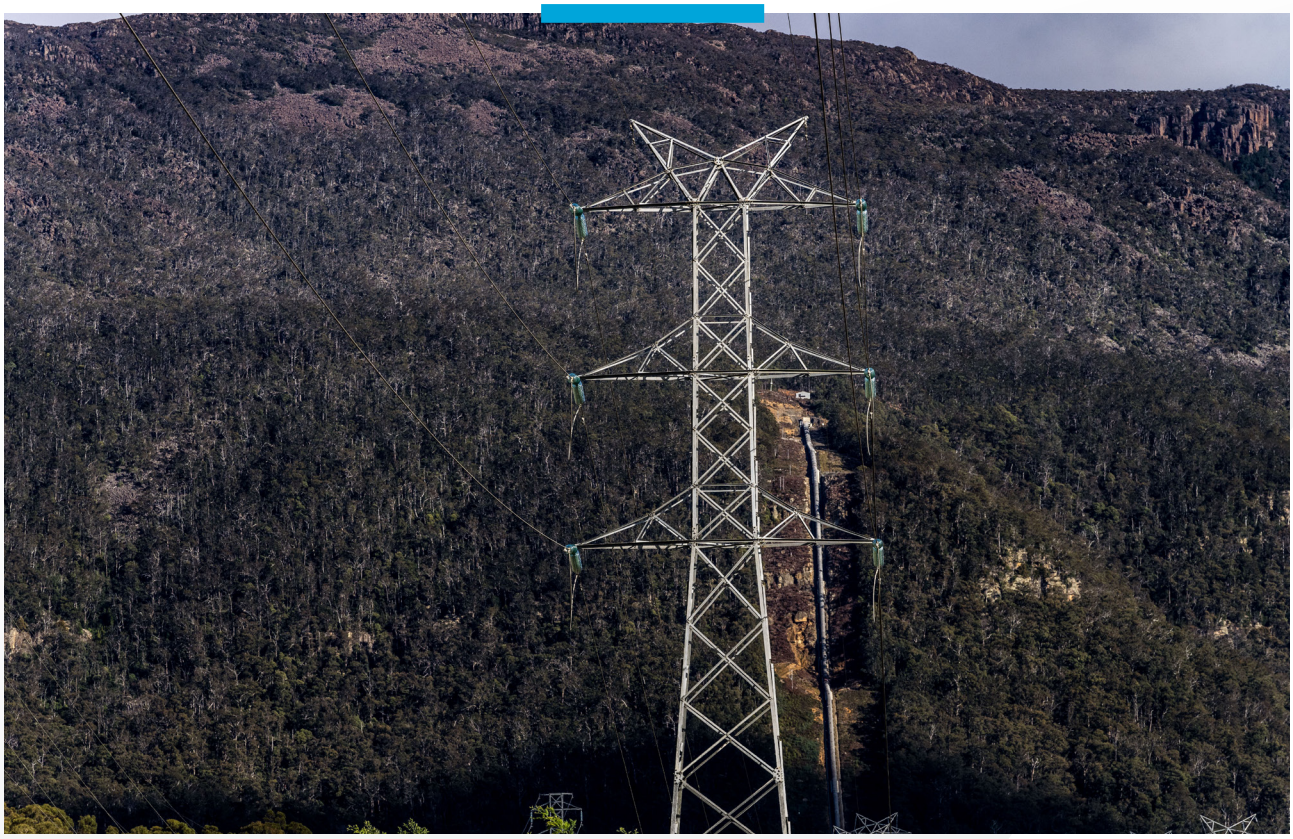
(2) In early September 2026, a fire occured at Tungatinah power station, resulting in destruction of the building and electrical plant. As a result 142 MW of generation capacity was lost from the system.

The medium to long term impacts of these changes will continue to be assessed and incorporated into ongoing and future planning strategies.

We welcome feedback

TasNetworks welcomes feedback and enquiries on our APR, particularly from anyone interested in discussing opportunities for alternative solutions to those identified in this APR. Please send feedback and enquiries to: planning.enquiries@tasnetworks.com.au

Potential demand management solution providers can also register with us via our Industry Engagement Register on our website at: www.tasnetworks.com.au/forms/Industry-Engagement-Register/Industry-Engagement



Chapter 1

Tasmanian network planning environment

- As Tasmania's provider of electricity transmission and distribution services, we are committed to providing our customers with electricity at the lowest possible price and helping Australia transition to cleaner energy sources.
- We commenced the preparation and consultation process of our regulatory proposal for submission to the Australian Energy Regulator (**AER**) detailing our plans to build, operate and maintain Tasmania's electricity network for the period 2029–2034.
- Interest continues in the development of large-scale renewable energy proposals.
- Interest in development of AI factories increased, with the initiation of new facility connections at multiple locations across the State.
- Marinus Link Pty Ltd (**MLPL**) commenced construction of Marinus Link Stage 1.
- TasNetworks commenced construction of North West Transmission Developments (**NWTD**) Stage 1.
- The Basslink interconnector commenced operation as a prescribed regulated transmission service on 1 July 2026.
- The Australian Energy Market Operator (**AEMO**) published the 2026 Integrated System Plan (**ISP**).

Chapter 2

Tasmanian power system

- During 2025, Tasmanian generation (hydro, wind, gas, and embedded generation) provided approximately 88% of the State total energy requirements, with 12% (or approximately 1,290 GWh) of electrical energy imported into Tasmania over Basslink.
- Our transmission–connected customers, dominated by four major industrial sites, were responsible for 40% of the network's maximum demand and consuming 55% of the total energy delivered through the transmission network in 2025.
- The Australian Energy Market Operator (**AEMO**) has significantly revised down their hydrogen projections and included only modest projections for AI factory loads in the 2025 Electricity Statement of Opportunities (**ESOO**), published in August 2025. TasNetworks has included the impact of recently committed and anticipated AI factory projects in the step change forecasts for demand and energy.

Chapter 3

Transmission Network Developments

- Tasmanian transmission network planning activities examine the intra-regional transfer of electricity from generation sources to Tasmanian load centres as well as supporting inter-regional power flows to and from the mainland via interconnection with Victoria.
- The Australian Energy Market Operator (**AEMO**) published the 2026 Integrated System Plan (**ISP**) identifying Tasmanian Renewable Energy Zone (**REZ**) expansion plans as an actionable ISP project to support significant projected new Variable Renewable Energy (**VRE**) generation in Tasmania.
- TasNetworks and Marinus Link Pty Ltd (**MLPL**) commenced construction of their respective parts of Stage 1 of Project Marinus.
- We progressed a Regulatory Investment Test for Transmission (**RIT-T**) for augmentations at George Town Substation triggered by an initial tranche of new load, such as hydrogen or AI factories.
- We initiated a new Network Capability Incentive Parameter Action Plan (**NCIPAP**) project to upgrade the corridor capacity between Liapootah and Waddamana, to be delivered in the 2024-2029 regulatory period.

Chapter 4

Area planning constraints and developments

- Four geographic planning areas are considered: North West and West Coast, Northern, Central, and Southern.
- Details of planned augmentations and replacements are provided by planning area.
- Targeted reliability improvement projects continue for specific reliability communities.
- Exemptions from jurisdictional planning requirements are retained for three locations, with a new five year exemption of the Farrell-Savage River-Waratah transmission line in the North West and West Coast planning area.
- Feedback is welcomed on prospective alternative solutions to our augmentation and asset retirement and replacement plans.

Chapter 5

Network security performance

- Tasmania continues to be in a situation where it is theoretically possible to meet 100% of Tasmania's operational demand from inverter-based resources (**IBR**), predominantly comprising wind farm generation and Basslink import. As more non-synchronous generation is introduced into the network in the future, careful management of power system security continues to be a high priority.
- Modelling associated with Australian Energy Market Operator's (**AEMO**) 2026 Integrated System Plan (**ISP**) forecasts ongoing shortfalls for both *system strength* and *inertia network services* in the Tasmanian region. Contractual arrangements to address existing shortfalls are currently in place until June 2029.
- The National Electricity Rules (**the Rules**) framework for managing system strength introduced significant new obligations for System Strength Service Providers (**SSSP**) which commenced on 2 December 2025. TasNetworks is the SSSP for the Tasmanian region of the National Electricity Market (**NEM**). This framework introduced a new approach for the procurement and payment of *system strength services*, including proactive planning obligations for SSSPs which now form part of the *System Standards* within the Rules.
- We published the Project Assessment Conclusions Report (**PACR**) to address system strength requirements in Tasmania from 2 December 2025 confirming that the preferred option is to contract with existing owners of synchronous condensers and generation assets. Contractual agreements will meet the system strength requirements until June 2029.

Chapter 6

- In 2025, transmission system performance remained within target for transformer and capacitor circuit fault outage rate metrics but was outside target for the transmission line fault outage rate.
- Transmission Loss of Supply (**LOS**) event count was outside target for events greater than 0.1 system minutes and on target for events greater than 1.0 system minute. The average outage duration of all LOS events remained within target.
- Distribution system performance for 2025-26 was outside the Tasmanian Electricity Code's (**the Code**) System Average Interruption Duration Index (**SAIDI**) standards for Urban and Regional Centres category.
- Distribution system performance for 2025-26 was outside the Australian Energy Regulator's (**AER**) Service Target Performance Incentive Scheme (**STPIS**), System Average Interruption Frequency Index (**SAIFI**) standards for Critical Infrastructure, High Density Commercial, High Density Rural and Lower Density Rural categories and outside the SAIDI standards for Critical Infrastructure, High Density Rural and Lower Density Rural categories.
- Distributed Energy Resource (**DER**) systems reached over 60,000 with a total installed capacity of 415 MW, a 15% increase over the course of 2025-26.

Chapter 1

Tasmanian network planning environment

- As Tasmania's provider of electricity transmission and distribution services, we are committed to providing our customers with electricity at the lowest possible price and helping Australia transition to cleaner energy sources.
- We commenced the preparation and consultation process of our regulatory proposal for submission to the Australian Energy Regulator (**AER**) detailing our plans to build, operate and maintain Tasmania's electricity network for the period 2029–2034.
- Interest continues in the development of large-scale renewable energy proposals.
- Interest in development of AI factories increased, with the initiation of new facility connections at multiple locations across the State.
- Marinus Link Pty Ltd (**MLPL**) commenced construction of Marinus Link Stage 1.
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- The Australian Energy Market Operator (**AEMO**) published the 2026 Integrated System Plan (**ISP**).

1. Introduction

1.1 Introduction

Tasmanian Networks Pty Ltd (**TasNetworks**) presents its 2026 Annual Planning Report (**APR**) prepared in accordance with the National Electricity Rules (**the Rules**) and Tasmanian jurisdictional requirements. We are a Transmission and Distribution Network Service Provider within the Tasmanian jurisdiction of the National Electricity Market (**NEM**) and have been appointed by the Minister as the Jurisdictional Planning Body. As such, in accordance with the Rules, we are also the System Strength Service Provider and Inertia Service Provider and have been appointed as the Coordinating Network Service Provider to allocate the aggregate annual revenue requirement for prescribed transmission services.

As a key business activity, we continuously review the adequacy of the Tasmanian electricity networks for both current and future needs. The capabilities of the existing transmission and distribution networks are analysed for their abilities to accommodate changes to electricity load and generation, as well as understanding limitations to meeting the required performance standards. The APR combines our obligations to publish by 31 October each year a Transmission Annual Planning Report in accordance with clause 5.12.2 of the Rules, and a Distribution Annual Planning Report in accordance with clauses 5.13.2 of the Rules and 8.3.2 of the Tasmanian Electricity Code (**the Code**).

We assess both network and non-network options to address any emerging limitations and asset management issues. The intention is that our APR provides existing and potential customers and non-network solution providers with information to prompt discussion on:

- opportunities to address identified network limitations;
- locations that would benefit from supply capability improvements or network support initiatives; and
- locations where new loads or generation could be readily connected.

The APR provides information on our planning activities over a 10-year planning period through to 2036. Some aspects are based on shorter planning time frames. In particular, our distribution line loads are based on a 2- year planning horizon.

This Chapter outlines:

- what we do;
- our strategy;
- externalities that guide our planning;
- TasNetworks' customers and our interactions with them;
- current consultations on major projects; and
- concludes with a description of significant changes and developments since our 2025 APR.

1.2 What we do

We own, operate, and maintain the electricity transmission and distribution networks in Tasmania to deliver a safe, cost-effective, and reliable electricity supply to more than 300,000 residential, commercial and industrial customers. We also provide telecommunications and technology services. We are owned by the State of Tasmania and operate as a commercial business through both monopoly and competitive electricity supply services with assets of $3.5 billion.

Tasmania is part of the NEM's eastern Australian power system, which extends from north Queensland to South Australia. Tasmanian large-scale electricity generation is provided by hydro, wind, and thermal (gas-fired) generators located throughout the network. A number of other small generators are connected within the distribution network, termed 'embedded generation', including small hydro and rooftop solar-photovoltaics (**PVs**). We facilitate the transfer of electricity between Victoria and Tasmania via Basslink, the sub-sea electricity interconnector. The components of the Tasmanian power system are presented in Figure 1-1. The role of TasNetworks is highlighted in blue.

Our responsibilities include:

- keeping our people and our customers safe;
- Tasmanian jurisdictional planner in the NEM;
- maintaining and replacing network infrastructure to ensure a reliable service for our customers;
- connecting new customers to the network (including small and large-scale generators);
- investing in the network to support capacity growth;
- operating the network on a day-to-day basis, including all power outage restoration;
- maintaining the public lighting system;
- recording and providing regulated meter data to retailers; and
- providing telecommunications, data centre and information technology services to customers, including those in the Tasmanian electricity supply industry.

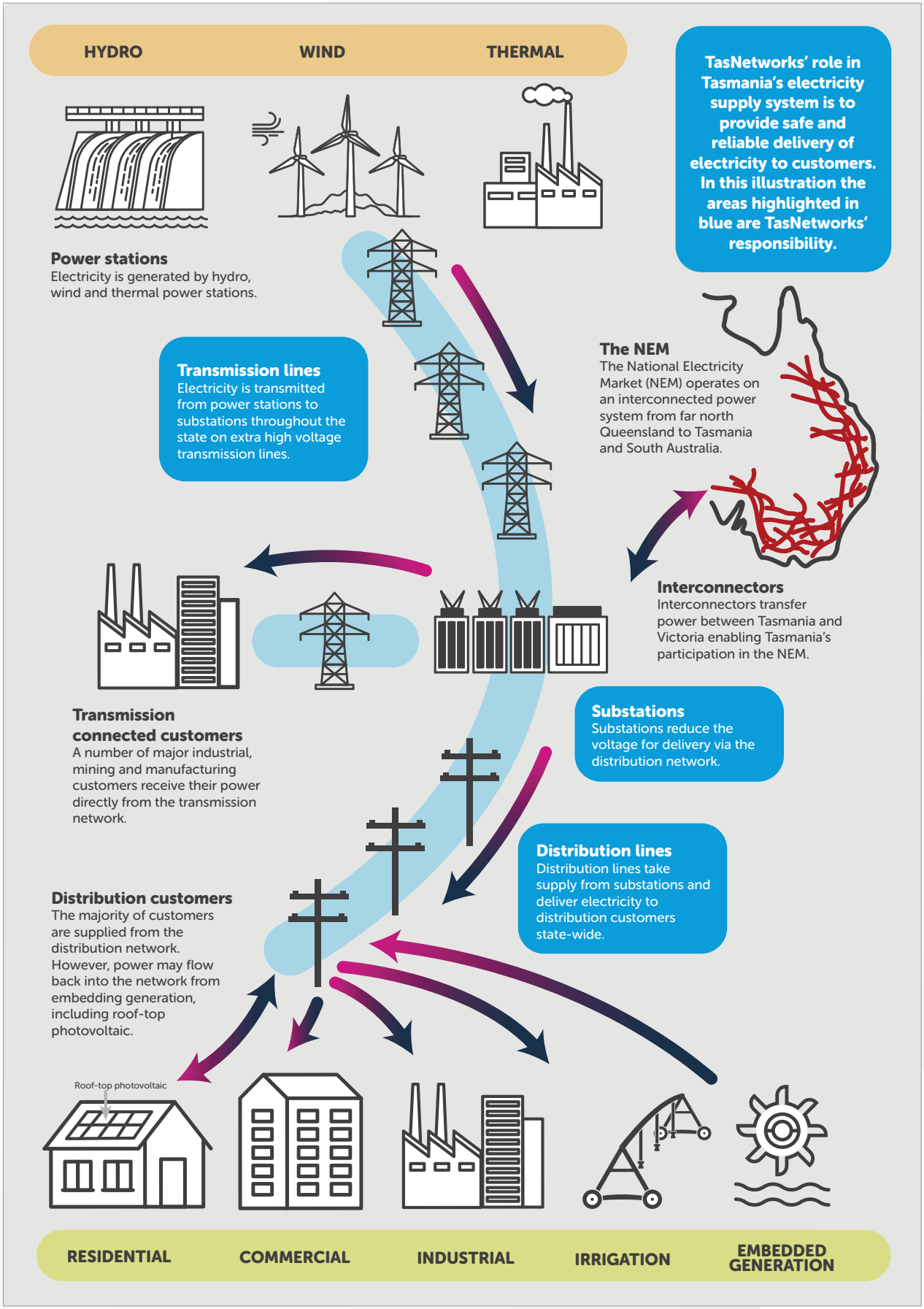


Figure 1-1: Tasmania's power system

1.2.1 Transmission and distribution networks

We charge for our electricity transport services through a component of prices paid by electricity end-users who purchase either from retailers or directly from the centrally controlled wholesale energy market. The transmission network transfers bulk power from generators, often in remote areas, to transmission-distribution connection points (substations) near load centres throughout Tasmania, and to large customers directly connected to the transmission network. The distribution network distributes electricity to smaller industrial and commercial users, as well as irrigation and residential customers.

As a provider of monopoly electricity transmission and distribution network services in Tasmania, TasNetworks is required to submit a regulatory proposal to the AER every five years, detailing our plans to build, operate and maintain Tasmania's electricity network. This process is known as a 'revenue reset' and is one of the AER's key mechanisms to ensure our customers pay no more than necessary for safe and reliable power. At the end of this process, the AER releases a final determination that sets out the revenue we can recover in the new regulatory period, which starts on 1 July 2029 and runs until to 30 June 2034.[2]

Underpinned by a comprehensive customer and stakeholder engagement program, the development of each regulatory proposal includes financial forecasting, asset planning, price and tariff modelling, and reviews of existing services and policies.

Engagement commenced in 2025 and will continue through to 2028 and April 2029 when the AER makes its Final Decision on TasNetworks' Revised Proposal. These conversations help us to better understand what matters most to our customers creating a more efficient regulatory process for all stakeholders. This is detailed in the AER's "Better Resets Handbook, Towards Consumer Centric Network Proposals".[3] Prominent identified emerging needs and potential network augmentations of the transmission network are outlined in Chapter 3.

1.2.2 Telecommunications network

The telecommunications network supports the operation of our electricity network interfacing protection, control and data, telephone handsets, and mobile radio transceivers. It also serves customers in the electricity supply industry and is utilised by other parties under commercial agreements.

In support of our telecommunications network, a number of telecommunications circuits are provided via a third-party network. This is generally outside our network's coverage area and includes all interstate services.

1.2.3 Subsidiary business functions

The subsidiaries of Tasmanian Networks Pty Ltd are TasNetworks Holdings Pty Ltd (non-trading subsidiary) and Fortytwo 24 Pty Ltd (42-24).

Our subsidiary 42-24 provides telecommunications, information technology, and data centre services to customers. These are non-electricity services that are legally separated from our regulated distribution and transmission businesses.

2 https://talkwith.tasnetworks.com.au/tasnetworks-2029-34-revenue-reset

3 https://www.aer.gov.au/industry/registers/resources/guidelines/better-resets-handbook-towards-consumer-centric-network-proposals [aer.gov.au]

1.3 TasNetworks' strategy

Our company strategy (**Strategy**) focuses on our core business – to deliver safe and sustainable essential services while maximising value for all of Tasmania.

Our Strategy enables us to deliver on our purpose and achieve our key business objectives. It contains pillars and priorities that reflect the strategic choices we have made, and outlines what we are focussed on to ensure we serve our customers and communities. It considers external market trends that influence our business and clearly identifies what we need to do to deliver meaningful and sustainable change.

Our key business objectives are to:

Enhance the safety and wellbeing of our people

We do not compromise the safety and wellbeing of our people, our customers, our communities, or the environment. Our focus is on ensuring physical, psychological, and environmental wellbeing.

Deliver value for our customers

We deliver value for our customers and strive to meet their expectations in every action we take. Our focus is on the quality of customers' and stakeholders' experiences with us and how we perform against their needs and expectations.

Supply reliable essential services

We deliver and enable reliable and sustainable essential services and we recognise our role to serve and create value for the benefit of Tasmanians. Our focus is on proactively delivering reliable and sustainable electricity supply for the Tasmanian community.

Provide a sustainable financial return

We seek to be an affordable service, while providing sustainable profits back to our shareholders, the Tasmanian Government. Our focus is on delivering efficient operations, so our profits can be reinvested to benefit the Tasmanian community.

Our three strategic pillars are:

Understand and respond to our customers and communities

By better understanding what is important to our customers and the Tasmanian community, we will deepen our strong relationships with them, be better positioned to tailor our services, and build their trust in us.

Deliver operational excellence

Through our continued commitment to improve the way we do things, we remain focused on getting the foundations right to keep our people, the community, and the environment safe, and operating efficiently to keep our cost to serve as low as possible.

Innovate in a targeted way

We are specifically targeting areas of our network and ways of working to improve our performance and keep prices as low as possible for customers. We will respond to shifts in the energy industry and adapt to changing customer needs through innovation.

We have included climate change as a key business risk and we are uplifting our sustainability reporting to align with the new Australian Government Climate Financial Risk Disclosure legislation. We continue to support the lowering of greenhouse gas emissions within the NEM through our support for Marinus Link, projects like NWTD and our own direct emissions reduction activities.

1.4 Strategic planning environment

As the jurisdictional planner in Tasmania, our planning activities are undertaken within the Rules' framework. Our network planning strategies consider and support the objectives of the Tasmanian Government to utilise renewable energy as a key economic driver in Tasmania. The following key objectives continue to provide us with guidance for our planning activities:

- development of new large-scale load connections;
- supporting generation and Pumped Hydro Energy Storage (**PHES**) initiatives;
- supporting the ISP[4]; and
- meeting reliability and security obligations.

The Tasmanian Renewable Energy Target (**TRET**)[5], was passed into legislation in late 2020 with the objective to grow Tasmania's renewable electricity generation with the aim, by the end of 2040, to double Tasmania's 2020 baseline of 10,500 GWh of renewable generation per year.

The TRET defines an increase of 3,000 MW of new renewable generation capacity within Tasmania to meet the 20 year energy production targets. In this regard, the current pipeline of on-island projects at various stages of development total nearly 7,000 MW of wind farms, 800 MW of large scale solar-photovoltaics (**PVs**), 750 MW of Pumped Hydro Energy Storage (**PHES**), and 700 MW of Battery Energy Storage Systems (**BESS**).

The integration of such large quantities of variable renewable energy (**VRE**) into the Tasmanian electricity system will involve significant developments and augmentation to the transmission network.

1.4.1 Integrated System Plan

AEMO published the 2026 ISP in June 2026 being a roadmap for the transition of the NEM, with a clear plan for essential infrastructure that will meet future energy needs. The ISP's optimal development path sets out the needed generation, storage, and network investments to transition to net zero by 2050 through current policy settings and deliver significant net market benefits for consumers.

The 2026 ISP identified two Tasmanian projects on the optimal development path—both as actionable ISP projects for which development should be either continued or commenced immediately. These projects are:

- **Tasmanian Renewable Energy Zone (REZ) expansion:** transmission network expansion to support the expected increase in renewable generation in Tasmania through implementing either:
  - the ISP candidate option being **NWTD stage 2: Burnie to Hampshire Hills component:** advancing a portion of NWTD Stage 2 to support renewable energy development in the North West Tasmania REZ; or
  - the alternative option being **Waddamana to Palmerston transfer capability upgrade:** an alternative option of a third 220 kV transmission circuit in the Waddamana–Palmerston 220 kV transmission corridor, to increase the transmission capacity for new VRE generation in the Central Highlands REZ.
- **Project Marinus stage 2:** the development of the second 750 MW Marinus Link between Tasmanian and Victoria, and NWTD Stage 2 comprising Staverton–Burnie 220 kV transmission line via Hampshire Hills and a new Staverton Switching Station.

Project Marinus Stage 1 progressed to committed status and is therefore no longer evaluated through the ISP.

4 https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp

5 Part 1A – Renewable Energy, Energy Co-ordination and Planning Act 1995, Tasmania

1.4.2 Large-scale load connections

We monitor the impacts of national and international influences on the operations of Tasmanian industry to understand potential impacts on transmission and distribution services. We are also in discussions with customers with the view to providing connection services that support their operational plans.

1.4.2.1 AI factories

The Tasmanian Government established an AI Factory Zone at St Leonards in northern Tasmania.[6] This supported Australian AI infrastructure developer Firmus Technologies to commence construction of Project Southgate, a series of AI factories. Stage 1 of the project has contracted a 104 MW supply at St Leonards, near Launceston with a further 288 MW at Bell Bay and 52 MW at Wesley Vale. These AI factories will provide a new baseload to support the growth of Tasmania's renewable energy sector and enable sustainable expansion in AI infrastructure.[7]

Included with these new AI factory developments are planned upgrades to the supporting communications infrastructure, such as additional subsea fibre data cables. Two active proposals are:

- Firmus Technologies and submarine cable operator SUBCO announced plans to build Bernacchi-1 a new subsea fibre connection between Tasmania and mainland Australia connecting Tasmania into SUBCO's Sydney – Melbourne – Adelaide – Perth cable system. In addition to a route to Melbourne, Bernacchi-1 will provide Tasmania with a direct connection to Sydney for the first time.[8]
- Energy Estate Digital is developing state of the art subsea data cable networks between Australia and New Zealand and key global hubs.[9] They propose two landing points in Tasmania at Bell Bay and close to Burnie.

1.4.2.2 Renewable hydrogen

The Australian Renewable Energy Agency (**ARENA**) shortlisted projects for Round 2 of the Hydrogen Headstart Program. Two Tasmanian based projects were selected to progress to the next stage in the application process being some of the most advanced large-scale renewable hydrogen proposals in the country.[10]

As the provisional proponent for the Tasmanian Green Hydrogen Hub Project at Bell Bay;[11] Bell Bay Powerfuels[12] progressed the establishment of industrial scale green hydrogen production. The project involves a green hydrogen and green methanol production facility.

HIF Tasmania plans to develop Australia's first commercial-scale e-fuels facility, investigating locations at / near Burnie. The proposed 255 MW facility would harness renewable energy to power their electrolysers helping to underpin the further growth of renewable energy in Tasmania.[13]

TasPorts and the H2U Group signed a memorandum of understanding (**MoU**) to investigate the feasibility of developing a large-scale green hydrogen and ammonia production and export facility within the Bell Bay port precinct. TasPorts and the H2U Group are expected to assess the technical, economic, environmental, and social feasibility of the project.[14]

6 https://tas.liberal.org.au/news/2025/07/01/transformational-industry-coming-northern-tasmania [tas.liberal.org.au]
7 https://firmus.co/newsroom/tasmanian-world-first-ai-factory-zone-clears-path-for-firmus-project-southgate [firmus.com]
8 https://firmus.co/newsroom/firmus-and-subco-to-build-bernacchi-1
9 https://www.energyestate.com/energy-estate-digital-announces-tasmanian-data-center-hubs-and-digital-infrastructure-plans [energyestate.com]
10 https://arena.gov.au/news/arena-shortlists-major-projects-to-scale-australias-renewable-hydrogen-industry/ [arena.gov.au]
11 https://recfit.tas.gov.au/what_is_recfit/energy_vision/green_hydrogen_hub_vision [recfit.tas.gov.au]
12 https://bellbaypowerfuels.com.au [bellbaypowerfuels.com.au]
13 https://hifglobal.com/locations/tasmania [hifglobal.com]
14 https://tasports.com.au/news/tasports-and-the-h2u-group-explore-green-hydrogen-and-ammonia-production-at-bell-bay [tasports.com.au]

1.4.3 Marinus Link and North West Transmission Developments

Project Marinus is the combination of Marinus Link and within Tasmania the supporting NWTD. Marinus Link will be a 1,500 MW capacity electricity interconnector between Tasmania and Victoria comprising two 750 MW staged cables along with advanced converter technology required to interface with the grid.[15] Marinus Link Pty Ltd (**MLPL**) is responsible for progressing the Marinus Link and is jointly owned by the Commonwealth of Australia, the State of Tasmania and the State of Victoria.

The first stage of the NWTD includes 129 kilometres of new and upgraded double circuit transmission lines between Palmerston, Sheffield and Burnie, as well as new substations and an interim tee connection to Heybridge to connect the first 750 MW stage of Marinus Link.[16] TasNetworks is responsible for the delivery of NWTD.

To proceed as a regulated investment, Project Marinus successfully completed a Regulatory Investment Test – Transmission (**RIT-T**) in 2021[17] concluding that Project Marinus provides benefits to the NEM. In July 2025 a further update of the RIT-T confirmed that the preferred option remained unchanged from the RIT-T update in April 2024.

Subsequently, the AER published its final decisions on construction costs for Stages 1 of Marinus Link and the NWTD confirming analysis that Tasmanians and Victorians will be better off with investment in these national infrastructure projects.[18]

MLPL shareholders made a Final Investment Decision to proceed with Stage 1 of Marinus Link noting that financial close had been achieved with the project's debt financier, the Clean Energy Finance Corporation. The Marinus Link Stage 1 is now fully funded, has primary Commonwealth and Victorian environmental approvals, a regulatory decision, and issued notices to proceed for its high-voltage direct current (**HVDC**) cable and converter technology suppliers, Prysmian Powerlink and Hitachi Energy.[19]

TasNetworks reached financial close for the NWTD with project financing requirements in place for the $1.317 billion NWTD Stage 1 works.

The project has approvals under the Environment Protection and Biodiversity Conservation Act from the Commonwealth Government, subject to conditions. Full construction commenced when the Tasmanian Planning Commission's permit conditions were satisfied and proceedings before the Tasmanian Civil and Administrative Tribunal were resolved. Our head contractor, the GenusPlus Group,[20] progressed site mobilisation. We present more information on the progress of Marinus Link and NWTD in Chapter 3 of the APR, as well as on our website.[21]

15 https://www.marinuslink.com.au/about-us/ [marinuslink.com.au]

16 https://www.tasnetworks.com.au/Planning-and-projects/Major-projects/North-West-Transmission-Developments

17 https://www.marinuslink.com.au/rit-t-process/ [marinuslink.com.au]

18 https://www.aer.gov.au/industry/registers/determinations/marinus-link-intending-transmission-network-application/final-decision [aer.gov.au]

19 https://www.marinuslink.com.au/wp-content/uploads/2025/09/FACT-SHEET-Marinus-Link-Financial-Close-Notices-to-Proceed.pdf [marinuslink.com.au]

20 https://www.genus.com.au [genus.com.au]

21 https://www.tasnetworks.com.au/Poles-and-wires/Planning-and-developments/North-West-Transmission-Developments-and-Marinus-L

1.4.4 Basslink

Basslink is a HVDC interconnector connecting the 220 kV Tasmanian transmission network at George Town Substation with the 500 kV Victorian transmission network at Loy Yang Substation. Basslink also has a number of fibre optic assets that carry high speed bandwidth services.

In 2025, the AER approved APA Group's application to convert the Basslink interconnector from a market network service to a prescribed transmission service from 1 July 2026.[22] Following on from this, Basslink sought a revenue determination from the AER. On 27 February 2026, the AER made its final decision on the revenue that Basslink can recover for the 2026–30 period.

With Basslink converted to a regulated interconnector, TasNetworks was appointed as the Coordinating Network Service Provider for Tasmania. This means we will be required to recover a portion of Basslink's regulated revenue from Tasmanian customers. Basslink will determine the allocation of its regulated transmission charges between Victoria and Tasmania based on the use of the interconnector unless the Tasmanian and Victorian Governments enter into an interconnector cost allocation agreement. The current proposed cost split is 25 per cent for Tasmanian customers and 75 per cent for Victorian customers.

In the event that differences in pool prices across Basslink occur the associated settlement residues are allocated as interregional settlement residues (**IRSRs**) to two new regulated notional interconnectors, being VIC➜TAS for flows from Victoria and TAS➜VIC for flows from Tasmania. The IRSRs are distributed via AEMO's Settlement Residue Auction (**SRA**) framework.

SRA proceeds for the VIC➜TAS IRSRs and unsold IRSRs are allocated to TasNetworks to offset locational transmission charges. In the case of negative VIC➜AS IRSRs TasNetworks recovers them from customers.

1.4.5 TasNetworks 2029-2034 revenue submission Network investments

As outlined in section 1.2.1, TasNetworks commenced preparations of the regulatory proposal to for the 2029-2034 period, detailing our plans to build, operate and maintain Tasmania's electricity network. The identified emerging needs are significantly influenced by the emergence of major industrial scale load, such as AI factories and hydrogen developments, and changes to the utilisation of the network in support of new renewable energy developments across the network.

The candidate augmentations being progressed includes:

- voltage stability and network security support in the southern Tasmanian network, driven by demand growth in the region;
- voltage stability and network capacity support in the northern Tasmanian network, driven by demand growth in the region; and
- alleviation of corridor constraints in the west coast region.

The details of these candidate projects, including the technical triggers and proposed solutions are outlined in section 3.6.

22 Final decision: Basslink conversion | Australian Energy Regulator (AER)

1.5 Our customers

Our customers are at the centre of Tasmania's renewable energy transformation. Electricity plays an essential role in homes, businesses, industries, and communities across the State, and customers are increasingly interacting with the energy network through new technologies and energy choices.

Traditionally, customers relied on the network primarily as consumers of electricity. Today, many are also generating, storing, and managing their own energy through technologies such as rooftop PV, battery storage, and electric vehicles (**EVs**). As adoption of these technologies continues to grow, customers are becoming more active participants in the energy system and are seeking greater choice, flexibility and control over how they use energy.

While customer expectations are evolving, the fundamentals remain unchanged. Customers continue to place a high value on a safe, sustainable electricity supply at the lowest possible price, underpinned by a network that is resilient and responsive. This is particularly important as severe weather events become more frequent and disruptive. Customers expect timely information and communication during outages, efficient restoration of supply, and ongoing investment in network resilience to help withstand changing environmental conditions. Customers also expect the network to support Tasmania's renewable energy future by enabling the connection of renewable generation, facilitating emerging technologies, and ensuring the benefits of the energy transition are delivered in a way that remains affordable and equitable.

To ensure we continue to understand and respond to these evolving expectations, we engage with customers and stakeholders through a range of channels, including advisory and focus groups, customer and community engagement activities, and Voice of Customer programs. We complement these insights with operational and market data, customer segmentation, and analysis of emerging energy trends. Together, these insights inform our planning and investment decisions, helping ensure the initiatives and investments outlined in this plan reflect customer priorities and continue to deliver value through our network to support Tasmania's energy future.

1.5.1 Industry Engagement Strategy and Industry Engagement Register

When the capacity of our network approaches a limit, TasNetworks can either increase the available capacity or pursue alternatives such as – but not limited to – Stand Alone Power Systems (**SAPS**) and/or demand management to address asset and peak demand issues. Different types of solutions apply to the transmission and distribution networks given the functions of each.

Reducing peak demand is called demand management. Typically, this can be achieved by:

- shifting the demand of certain load segments from peak time to an off-peak time (for example, off-peak heating);
- shedding non-critical loads;
- reducing the electricity used by appliances for short periods (such as hot water load control);
- operating generators within a customer's installation; and
- installing energy storage (e.g. batteries) and using some of the battery capacity to address peak demand issues (including customer-owned batteries).

Long power lines that traverse difficult terrain to serve remote customers must be maintained to the same standard as all other lines in our network. The ongoing cost required to keep such lines operational may be higher than the cost involved in constructing and maintaining a SAPS that provides an off-grid supply.

Our objective is to work with our customers to identify cost-effective non-network and SAPS solutions that allow us to defer or avoid the need for network investment and reduce the long-term costs of our network. Financial incentives may be offered under specific schemes, rewarding solutions that provide network benefits. Our current process for assessing these solutions is outlined in Appendix A.6.

Network support payments are available to our customers, or a third party contracted by us to provide network support services. This is subject to our network having an identified limitation and a formal agreement with the customer or provider.

To deliver solutions for our distribution network, we follow our Industry Engagement Strategy that explains how we will engage and consult with our customers and suppliers. We encourage providers to register with us on our website:

https://www.tasnetworks.com.au/Forms/Demand-Management-Industry-Engagement-Register

1.5.2 Electric vehicles (EV)

Our vision is to be an enabler of EV uptake and for our customers to easily connect to our network. We continue to engage with external stakeholders including councils and EV Charge Point Operators (**CPO**), to better understand their needs and what new capabilities they require from the distribution network. One key area of development has been the sharing of the location and capacity of low voltage assets so developers and councils can better target sites for EV charger rollout. To support the selection by charger operators of appropriate sites we published a network capacity map that shares distribution asset location and estimated capacity of distribution low voltage substations. We are also engaging with local councils to enable asset sharing models and the installation of private chargers on our power poles. To support this, we have engaged with councils and CPOs to understand barriers to the installation of private chargers on electricity poles and are investigating possible solutions to streamline this process.

At this stage, residential charging of EVs has not materially impacted the network – we continue to monitor local utilisation, supported by smart meter data, and will be investigating charging behaviours as EV penetration grows.

1.5.3 CER (Consumer Energy Resources) penetration

The distribution network continued to experience growth in small-scale rooftop **PV** installations during the reporting period, driven by both new customer installations and upgrades or replacement of existing systems. A total of 4,783 installation applications were approved, with aggregate installed rooftop PV capacity increasing from 311 MW to 415 MW over the 2025 calendar year.

Residential battery uptake also increased significantly following the commencement of the Federal battery rebate program in July 2025. The number of registered residential batteries increased from 2,773 in 2025 to 6,185 by the end of the reporting period.

At present, residential battery systems in Tasmania are generally not orchestrated or centrally coordinated. There are currently no active Virtual Power Plant programs operating in the jurisdiction, and only one retailer offers customers a form of wholesale market exposure, with very limited participation due to its small market share. As a result, residential batteries are generally not exporting energy back to the network.

Operational observations indicate that residential battery systems are contributing positively to network performance under Tasmania's winter-peaking demand conditions. In particular, batteries appear to be complementing lower winter solar generation through off-peak grid charging and are providing support during evening peak demand periods by reducing customer reliance on grid-supplied energy during those times.

TasNetworks will continue to monitor the impact of CER on network operations and planning outcomes, including the future availability and uptake of more dynamic retail products and orchestration arrangements. These developments may support more active management of CER growth and enhance the ability of distributed resources to deliver broader network and customer benefits.

1.5.4 Community batteries

Community batteries are emerging as an innovative solution to enhance distribution networks' ability to manage a growing PV penetration, while providing an energy storage solution that can benefit local customers under various community benefit schemes. These shared energy storage systems allow communities to store excess PV power generated during the day and use it during peak demand periods or at night. By doing so, they help reduce electricity costs, lower carbon emissions, and improve grid stability. Community batteries also facilitate greater participation in renewable energy initiatives, offering a practical way for communities to collectively manage and optimise their energy resources. Community batteries may also support reliability and resilience outcomes, in addition to their core function of supporting network operation with a higher solar penetration.

TasNetworks successfully acquired funding for two community batteries through the Australian Government's Community Batteries for Household Solar program.[23] The batteries have been commissioned in Shorewell Park, in the north-west of the State, and Glebe Hill, in the south. Each is rated at 120 kW with 258 kWh energy storage capacity. TasNetworks will be delivering six additional community batteries across Tasmania in early 2027 with funding support from the Australian Renewable Energy Agency's Advancing Renewables Program. These community batteries will build on lessons learned from the Shorewell Park and Glebe Hill in maintaining supply to a community centre during outages.

1.6 Project consultations

We undertake Regulatory Investment Tests (**RITs**) for both transmission (**RIT-T**) and distribution (**RIT- D**) network investments that exceed the cost threshold of $8 million and $7 million respectively. Projects required to address an urgent and unforeseen network issue and would otherwise be subject to an RIT, are reported in the APR. We did not have any urgent or unforeseen network issues arising in the past year.

A key part of the RIT process is to undertake consultations in accordance with the provisions of the Rules. We welcome feedback and enquiries on this APR including any listed projects, not only those subject to a RIT. Since the 2025 APR, we completed the following RIT-Ts:

Table 1-1: Summary of completed RIT-Ts

RIT-T Investment	Identified Need
Sheffield Substation T1 Transformer Replacement	Address escalating risk costs associated with an aging transformer at Sheffield Substation.
Rosebery Substation T1 & T2 and 44kV switchgear replacement	Address escalating risk costs associated with the aging transformers and switchgear at Rosebery Substation.

A summary of current and proposed RIT-Ts are presented in Table 1-2. We currently do not plan to initiate any RIT-Ds.

Table 1-2: Summary of proposed and current RIT-Ts

RIT-T Investment	Identified Need	RIT process Timing
Meeting network planning requirements at George Town	Address minimum network performance requirements following connection of new load at George Town Substation.	Project Assessment Draft Report published May 2026 Project Assessment Conclusions Report published late 2026
Tasmania REZ Expansion (actionable ISP project)	Support additional renewable energy growth in Tasmania	Project Assessment Draft Report expected by June 2028
System Strength	Address TasNetworks' system strength obligations	Project Specification Consultation Report expected in 2026

23 https://www.dcceew.gov.au/energy/renewable/community-batteries

1.7 What has changed since 2025

1.7.1 North West Transmission Developments

In May 2026, the TasNetworks Board determined to proceed with the construction of the $1.317 billion Stage 1 of the NWTD. This decision was made following the achievement of several key milestones in early 2026 including a construction phase revenue determination from the Australian Energy Regulator, securing concessional project financing from the Clean Energy Finance Corporation and the Tasmanian Government (as Shareholders of TasNetworks), and obtaining the necessary planning and environmental approvals.

Full construction activities began when the Tasmanian Planning Commission's permit conditions were satisfied and proceedings before the Tasmanian Civil and Administrative Tribunal were resolved. Our head contractor, Genus Infrastructure (NSW) Pty Ltd,[24] progressed contractor involvement and site mobilisation activities in the first half of 2026.

More information on this project is provided in Chapter 3.

1.7.2 Waddamana to Palmerston transfer capability upgrade

Following publication of the AEMO's Final 2024 ISP, TasNetworks commenced the RIT-T process to determine the least cost investment that increase power system capability of the transmission network to support the expected increase in renewable generation in the Central Highlands REZ.

TasNetworks undertook several activities to progress development of the RIT-T including:

- technical analysis to determine credible network options;
- schedule and cost estimate development;
- electricity market modelling to assess wholesale electricity market benefits of each option; and
- stakeholder engagement activities.

In AEMO's 2026 ISP, the Waddamana to Palmerston transfer capability upgrade was replaced as an actionable ISP project by the Tasmanian REZ Expansion project. As a result, TasNetworks discontinued work on the Waddamana to Palmerston transfer capability upgrade RIT-T. A separate RIT-T will commence that considers options for meeting the identified need for the new Tasmania REZ Expansion project.

As part of the Tasmanian REZ Expansion analysis, TasNetworks will assess some of the options previously considered as part of the Waddamana to Palmerston transfer capability upgrade RIT-T.

More information on the Tasmanian REZ expansion project is provided in section 3.4.3.

24 https://www.genus.com.au [genus.com.au]

1.7.3 Load forecasts

For the 2026 APR, TasNetworks prepared a 20-year energy and maximum demand forecast for the existing customer base. Transmission-connected customers (excluding Basslink) account for a large portion of the demand within Tasmania, currently over 50% of on-island energy consumption (refer Section 2.1.1). For the distribution network, maximum demand is temperature sensitive, with increased heating load observed at times of low ambient temperatures.

TasNetworks' forecasting methodology uses a top-down approach, utilising AEMO's state-level forecast as a basis for developing individual connection point forecasts. AEMO, through its annual Electricity Statement Of Opportunities (**ESOO**) publication, provides maximum demand forecasts for all regions in the NEM. The state-level forecast referred to as the native demand forecast, comprises distribution total demand, major industrial transmission customers demand, and transmission losses.

The key scenarios used by AEMO for forecasting in the ESOO are the Slow Change, Step Change, and Accelerated change. For each of these scenarios, 10%, 50% and 90% probability of exceedance (**POE**) forecasts are utilised.

We note that AEMO's 2025 ESOO scenarios do not include any material impacts from new AI factory connections. To account for recently committed and, anticipated connection of these new loads , TasNetworks has included a forecast sensitivity to illustrate the expected increase to peak demand and the energy transfer requirements across the transmission network.

Tasmania's state-level forecast prepared previously for the 2025 APR is also included for comparison.

1.7.4 Enhancing distribution network planning and reporting

The Australian Energy Market Commission (**AEMC**) progressed a Rule change in response to a request to amend the existing distribution annual planning report framework and replace it with a longer-term network development plan. The changes aim to improve transparency and consistency of the long term plans that Distribution Network Service Providers prepare for their networks. The AEMC consider that this would help consumers understand how the distribution network is expected to change in future. They would then be better placed to make informed and efficient investments in CER.

1.7.5 NEM Access Standards

The AEMC completed two Rule changes to improve the technical requirements for connection to the NEM. Package 1 of the rule change[25] was finalised in May 2025 and aims to make the NEM access standards fit for purpose in a world where inverter-based resources (**IBR**) are becoming more prevalent. It also adds more prescription and clarity to the access standards helping to reduce costs and time for connecting parties, TasNetworks, and AEMO in negotiations undertaken when connecting plant.

Package 2 of the rule change[26] was finalised in 2026 and focuses on the access standards for large, inverter-based loads, such as AI factories, and hydrogen electrolysers. The AEMC's determination proposed amendments to facilitate the planning and design of large loads in a way that supports future power system security.

25 Improving the NEM access standards – Package 1 | AEMC

26 Improving the NEM access standards – Package 2 | AEMC

1.7.6 Inertia and system strength

Tasmania continues to be in a situation where it is theoretically possible to meet 100% of Tasmania's operational demand from IBR, predominantly comprising wind farm generation and Basslink import. As more non-synchronous generation is introduced into the network in the future, careful management of power system security continues to be a high priority.

Contractual arrangements to address existing shortfalls in inertia and system strength are currently in place until June 2029. TasNetworks will consider solutions for providing system strength beyond 2029 in a future RIT-T, when there is less uncertainty regarding the volume of new connecting IBR. More information and details relating to system strength is provided in Chapter 5.

1.7.7 Planned investments and forecast limitations

Material differences between planned investments and forecast limitations from those reported in our 2025 APR are summarised in Table 1-3. The table also provides references to the relevant sections of this APR where we present the actual investment or forecast limitation.

Table 1-3: Differences in planned investments and forecast limitations reported in 2025 APR

Location	Summary of change	APR Reference
Now completed		
Wesley Vale	Wesley Vale Substation 110 kV disconnectors	Table 4-9
Sorell	Sorell Substation 22 kV switchgear	Table 4-9
Savage River	Savage River Substation 110 kV disconnectors and gantry	Table 4-9
St Mary's	St Mary's Substation transformers	Table 4-8
Chapel St	Chapel St Substation 11 kV switchgear	Table 4-9
George Town	George Town Substation 220 kV disconnectors	Table 4-9
Now committed		
Sheffield	Sheffield Substation 220 kV disconnectors and current transformers	Table 4-9
Sheffield	Sheffield Substation 110 kV disconnectors	Table 4-9
Sheffield/Burnie	Sheffield Substation T1 replacement/Burnie T3 relocation	Table 4-8
Rosebery	Rosebery T1 and T2 and 44 kV switchgear replacement	Table 4-8
Bridgewater	Bridgewater Substation 110 kV circuit breakers	Table 4-9
Statewide	Statewide protection relays	Table 4-10
Statewide	Statewide SCADA scheme (part replacements Gateway RTU only)	Table 4-10
Waddamana	Liapootah-Waddamana 220kV transmission line corridor upgrade	Section 3.3.2
Palmerston	Palmerston-Hadspen 220kV transmission circuit upgrade	Section 3.3.2

Chapter 2

Tasmanian power system

- During 2025, Tasmanian generation (hydro, wind, gas, and embedded generation) provided approximately 88% of the State total energy requirements, with 12% (or approximately 1,290 GWh) of electrical energy imported into Tasmania over Basslink.
- Our transmission–connected customers, dominated by four major industrial sites, were responsible for 40% of the network's maximum demand and consuming 55% of the total energy delivered to the transmission network in 2025.
- The Australian Energy Market Operator (**AEMO**) has significantly revised down their hydrogen projections and included only minor contributions for AI factory loads in the 2025 Electricity Statement of Opportunities (**ESOO**), published in August 2025. TasNetworks has included the impact of recently committed and anticipated AI factory projects in the step change forecasts for demand and energy.

2.1 Load and generation characteristics

2.1.1 Load characteristics

The Tasmanian transmission network conveys electricity to Tasmanian customers and to the rest of the National Electricity Market (**NEM**) via Basslink.

Tasmania has a small load demand compared to other NEM regions, ranging between approximately 728 – 1,645 MW in 2025. The load duration characteristic for Tasmanian customers and total network (including Basslink export) during 2025 is presented in Table 2-1.

Table 2-1: Tasmanian load duration characteristic for 2025

Duration / operating point	Total Tasmanian customer demand (MW)[27]	Total network demand[28] (MW)
Maximum	1,645	2,003
25th percentile	1,217	1,487
50th percentile	1,117	1,330
75th percentile	1,035	1,152
Minimum (99.9th percentile)	728	728

The active power maximum demand on the transmission network during 2025 to supply Tasmanian customers was 1,645 MW, with the total network maximum demand of 2,003 MW including power transfers across Basslink. This presents a notable reduction since 2024, attributed to the recent closure of Liberty Bell Bay smelter in the north of the State.

Peak demand in Tasmania occurs during winter, driven by heating load. Figure 2-1 presents the transmission network demand duration curves for supply of Tasmanian customers, as well as total network demand inclusive of Basslink exports.

27 Total Tasmanian customer demand is presented as the demand met through scheduled / semi-scheduled generating units, interconnector import flows and non scheduled generation above 30MW, classified as "operational demand" by AEMO

28 Total network demand describesoperating scenarios where Tasmanian generation contributions supply all demand in Tasmania, and surplus generation is exported through Basslink

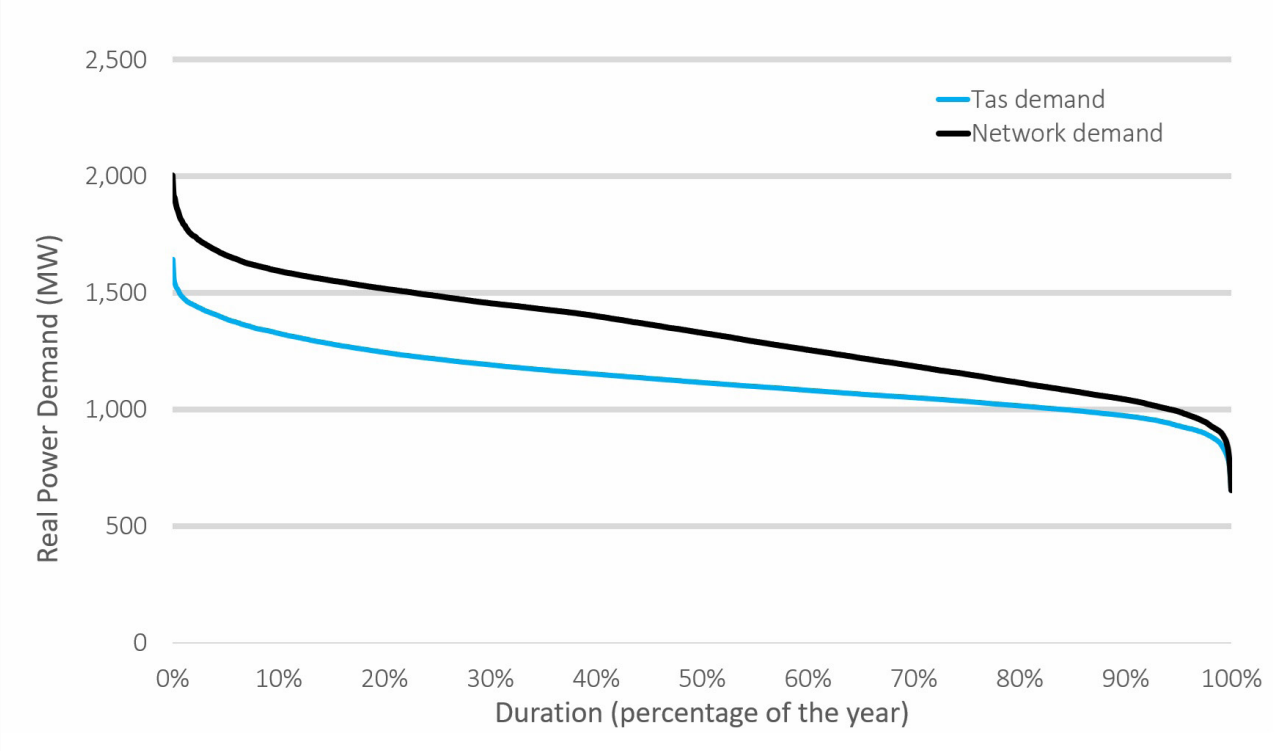


Figure 2-1: Transmission network active power demand duration curves 2025

In 2025, a continued trend of reduction in the reactive power demand was observed for Tasmanian customers, as measured at their connection points. This is being partially attributed to the progressive uptake of energy efficient loads, including those interfaced through 'smart' power electronics, that tend to operate much closer to unity power factor. The 5-year reactive power demand duration characteristic, inclusive of customer and broader transmission network needs is presented in Figure 2-2.

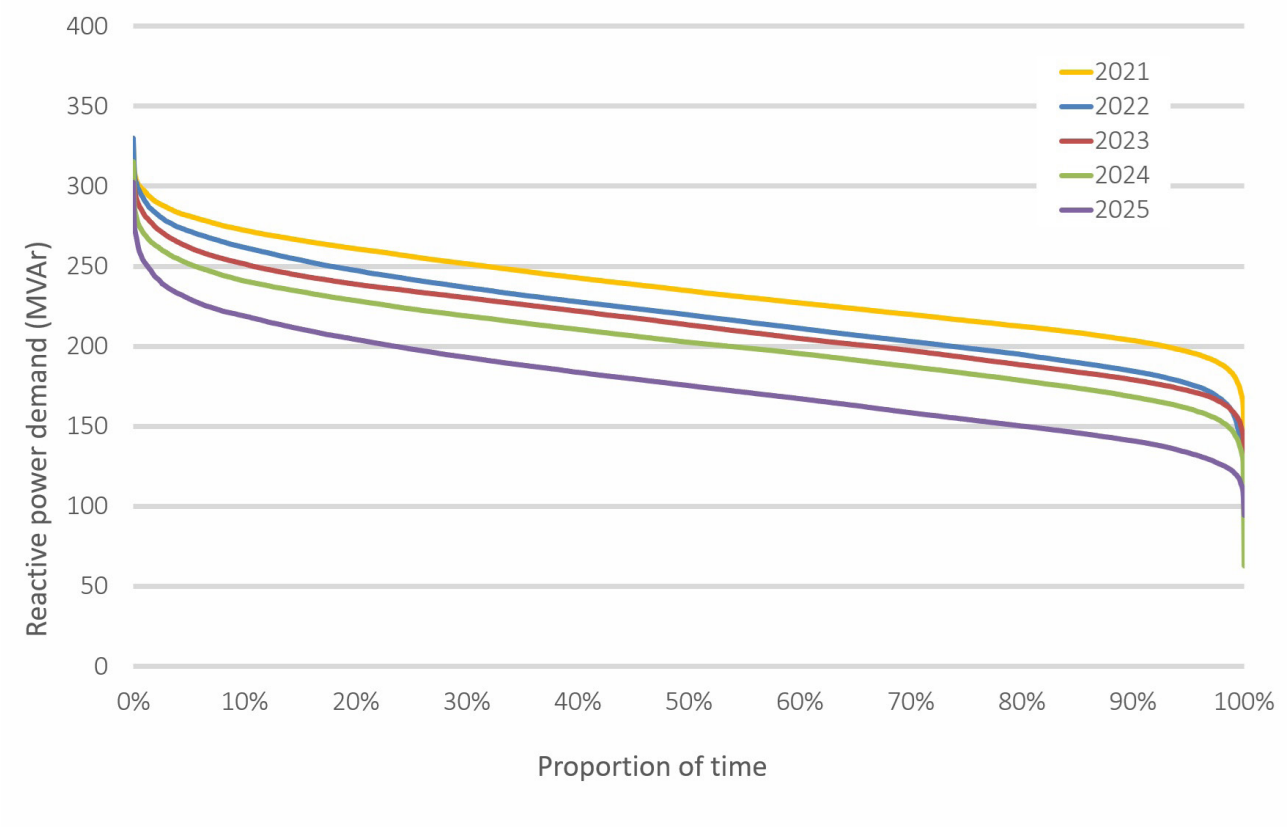


Figure 2-2: Total network reactive power demand duration curves 2021-2025

2.1.2 Energy Consumption characteristics

In Tasmania, the annual energy consumption is apportioned approximately equally between transmission and distribution connected customers. The vast majority of transmission consumption is due to major industrial customers, with a small remaining portion attributed to remaining transmission customers. Distribution consumption is comparably divided between commercial and residential customers. The 2025 energy consumption profile for Tasmania is presented in Figure 2-3.

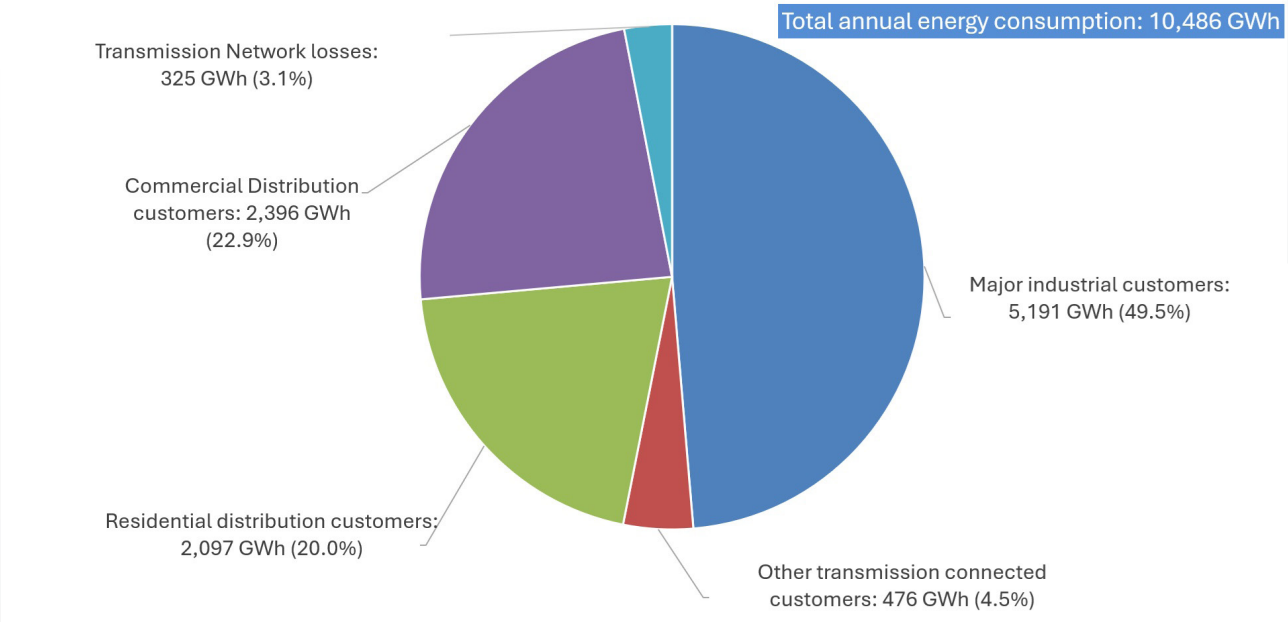


Figure 2-3: Annual Tasmanian energy consumption in 2025

In 2025, major industrial customers consumed 5,191 GWh or 49.5% of the State total, with the remaining transmission customers consuming 476 GWh (4.5%). Residential distribution customers accounted for 2,097 GWh (20%) and commercial customers accounted for 2,396 GWh (22.9%).

Transmission network losses accounted for approximately 325 GWh, or 3.1% of the State total per annum.

2.1.3 Generation characteristics

Table 2-2 presents the total existing generation capacity connected to the transmission network, including Basslink import. The impact of embedded generation in the distribution network is reflected as a reduction in connection point demand and is outlined in Chapter 6.

Table 2-2: Existing generation capacity

Generation type	Number of sites	Total nameplate rating (MW)	Proportion of installed capacity (%)	Contribution to Tasmanian network energy demand (%)
Hydro	25	2,125[29]	56.0	62.9
Wind	5	568	14.0	18.2
Gas	1	386	9.5	1.4
Embedded generation[30]	64,646	415	8.7	5.2
Interconnector net energy flow (import)	1	479	11.8	12.3

The generation mix in Tasmania over the past five years is presented in Figure 2-4. This includes generation within Tasmania and net interconnector flows.

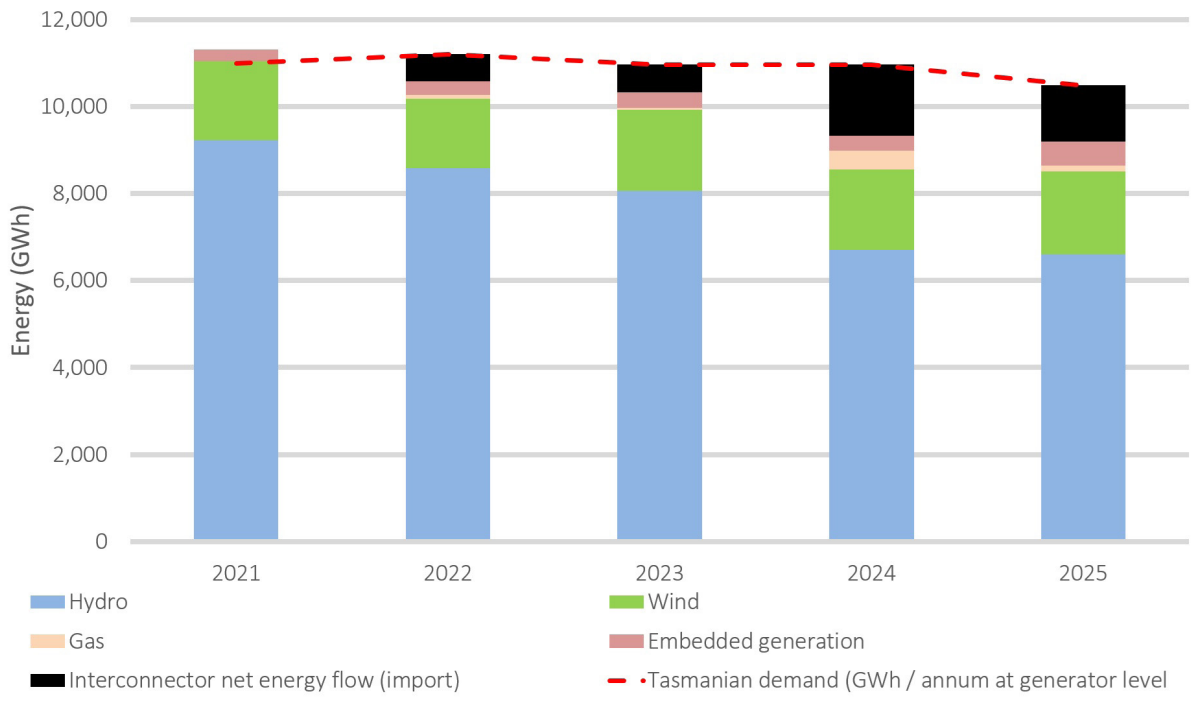


Figure 2-4: Supply contribution by type: 2021 to 2025

29 Total nameplate capacity in Tasmania has been reduced following the recent damage to Tungatinah power station

30 Generation capacity is predominantly Solar PV installations

In 2025, overall energy demand in Tasmania was approximately 10,401 GWh, a 5% reduction to the previous year. Wind energy contributions were largely consistent with the previous year at approximately 1,963 GWh and embedded generation increased by 33% to 461 GWh.

The energy supply contributions from hydro generation in Tasmania was approximately 6,597 GWh, also largely consistent with the previous year. The balance of the annual energy demand in the State was met by lower gas generation (145 GWh, a 66% reduction), and Basslink imported energy (1,291 GWh, a 21% reduction).

2.2 Energy and maximum demand forecasts

2.2.1 Introduction

This section presents the Tasmanian energy and maximum demand forecast for the transmission and distribution networks, as measured at the network entry points. Transmission network demand is determined by the sum of on-island generation and Basslink import into Tasmania. Distribution network demand is measured at the interfaces with the transmission network.

Forecasts provide both an indication of the future energy requirements within Tasmania and the increased demand on the transmission and distribution networks to support energy transfer.

For the 2026 Annual Planning Report (**APR**), TasNetworks prepared a 20-year energy and maximum demand forecast for the existing customer base. Transmission-connected customers (excluding Basslink) account for more than half of the maximum demand. For the distribution network, maximum demand is temperature sensitive, with increased load observed at times of low ambient temperatures.

For planning activities, we apply a 50% probability of exceedance (**POE**) maximum demand forecast. Temperature sensitivity is not as acute as other NEM regions that experience maximum demands during extreme summer temperatures.

Substations, zone substations, feeder maximum demand forecasts and substation load profiles are available as downloadable appendices to this APR on our website: **www.tasnetworks.com.au/apr**

2.2.2 Forecast scenarios

AEMO, through its annual ESOO,[31] provides maximum demand forecasts for all regions in the NEM. Three key scenarios used by AEMO and adopted by TasNetworks for forecasting are the Slower Growth, Step Change and Accelerated Transition. Table 2-3 presents an overview of forecast scenarios.

TasNetworks' forecasting methodology comprises a top-down approach, utilising AEMO's state-level forecast as the basis for developing individual connection point forecasts.

Table 2-3: Forecast scenarios

Scenario	Description
Slower Growth	The Slower Growth scenario meets Australia's current Paris Agreement commitment of 43% emissions reduction by 2030 and other State and Federal government policies to support energy transition. In this scenario consumers and commercial businesses face greater investment challenges and the industrial sector faces greater risks of closures.
Step Change	The Step Change scenario achieves a scale of energy transformation that supports Federal government policies. This scenario assumes moderate economic conditions, noting that recent economic challenges and current economic conditions affect the starting conditions. Consumers continue to provide a strong foundation for the transformation, with significant continued investments in Consumer Energy Resources (**CERs**), including electrification of the transportation sector. Data centres, such as AI factories and the electrification of business are expected to materially contribute to new electricity consumption across the NEM.
Accelerated Transition	The Accelerated Transition scenario reflects very strong decarbonisation activities domestically, rapidly transforming Australia's energy sectors, resulting in strong use of electrification.

The distribution component is extracted from Tasmania's state-level demand forecast and aligned with historical actual demands. This is then used to model individual transmission-distribution connection point demand projections.

Due to the review and publication cycle for annual reporting, TasNetworks used the 2025 ESOO energy and demand forecasts as its basis for the 2026 APR.

31 2025-electricity-statement-of-opportunities.pdf

2.2.3 Annual energy forecast

Figure 2-5 presents the historical actuals and forecast Tasmanian energy requirements on the transmission network over the next 20 years to 2046. Forecasts are presented for the distribution network and whole-of-state. Forecasts from our 2025 APR are included for comparison.

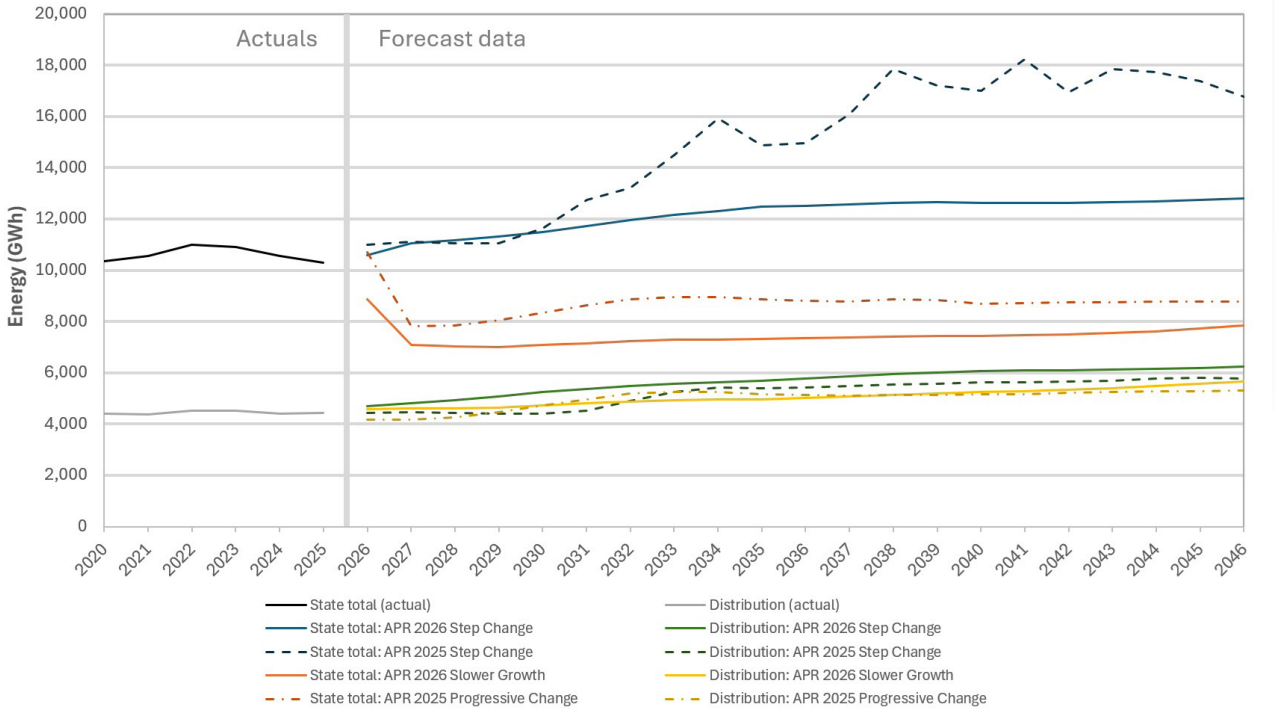


Figure 2-5: Annual energy forecast

The key insights across the Step Change and Slower Growth forecasting scenarios are as follows:

Scenario	Description
Step change	In the Step Change scenario, the total energy consumption growth is considerably lower over the forecast period compared against the previous year, due to a reduction in the expected hydrogen developments. Electrification (across business and residential customers) is the primary contributor to energy consumption growth, gradually increasing to just over 12,000 GWh by 2046. Distribution energy consumption increases moderately driven by electric vehicles (**EV**) uptake and electrification, and moderated by energy efficiency savings.
Slower Growth	In the Slower Growth scenario, potential major industrial (**MI**) closure risk continues to be explored, which brings State total energy consumption down by approx. 43% in 2027. This initial drop is gradually offset by a moderate business electrification uptake. Distribution energy consumption increases moderately driven by EV uptake and electrification at a slower rate of uptake compared with the Step Change scenario. Energy efficiency savings are expected to provide similar levels of moderation.

In addition to the baseline energy consumption growth attributed to AI factory development, TasNetworks has received multiple connection enquiries from developers actively progressing AI factory projects at various locations across the network. TasNetworks reasonably expects the commitment of a number of these projects over the next 24 months. Once committed, these projects have the capability to increase the annual energy consumption by up to 30% by 2030.

Figure 2-6 provides a breakdown of each energy consumption category over the forecast planning period under the Step Change scenario, with the projected additional AI factory driven energy requirements.

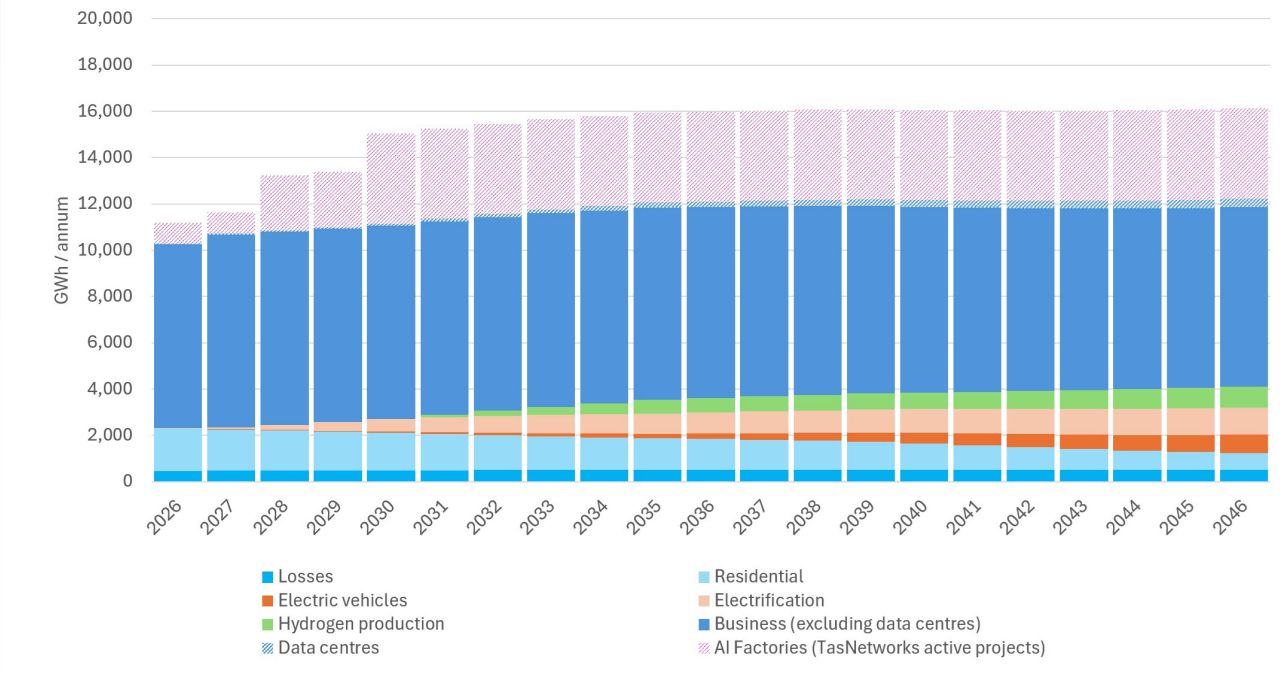


Figure 2-6: Tasmanian annual energy forecast-consumption by category-Step Change scenario

The annual energy supply and demand balance for Tasmania is impacted from upcoming AI factory connections due to the short time frames for these facilities to come online compared with new generation. Over the short-medium term, annual energy consumption is forecast to return to early 2025 levels that prevailed prior to the shutdown of existing large industrial load, with continued increases to 16,000 GWh as new load tranches are connected.

2.2.4 Annual maximum demand forecast

Figure 2-7 presents the historical actuals and forecast peak demand at 50% POE for the whole-of-state and distribution network over the next 20 years to 2046. As with the energy forecasts, the previous year's state-level demand forecast is included for comparison, including the impact of recently committed and anticipated AI factory connections, expected to be in full operation by 2030.

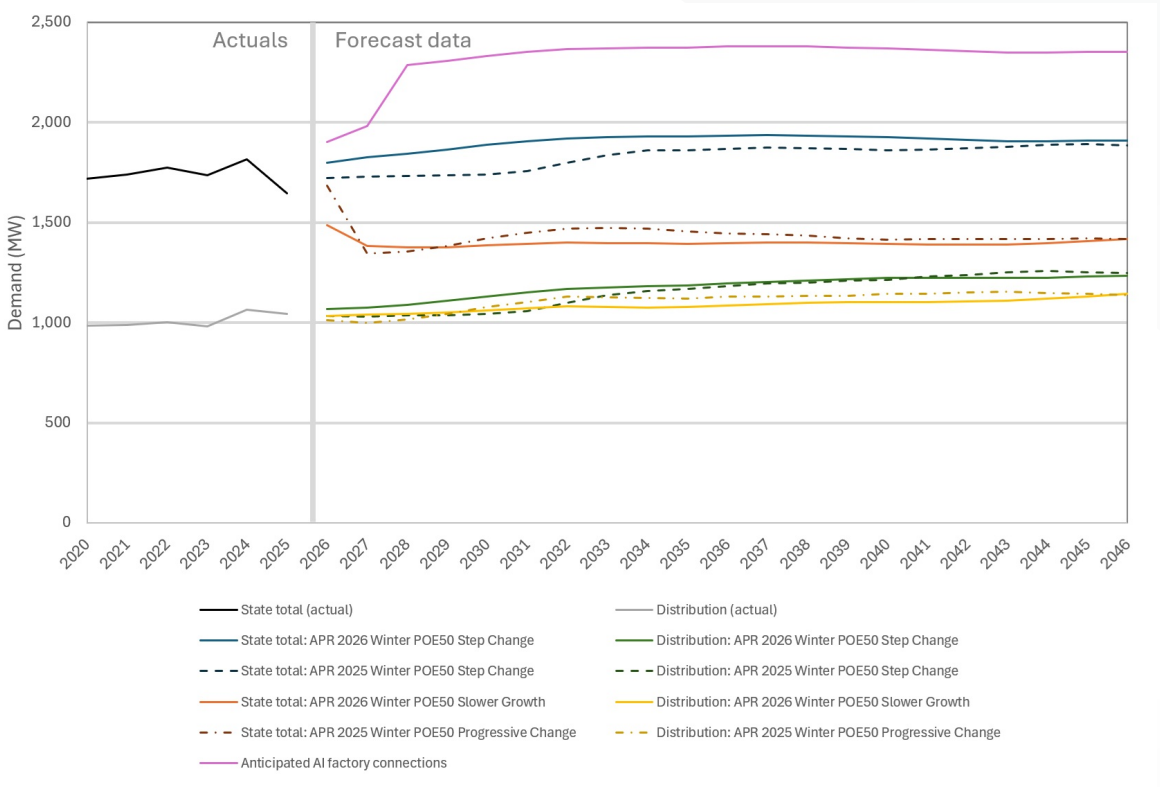


Figure 2-7: Maximum Demand forecast

It is noted that no hydrogen-related components are included in this maximum demand forecast. Additionally, distributed solar-photovoltaic (**PV**) generally has a lower impact on maximum demand as peak demand is in the winter in Tasmania with fewer daylight hours. The key insights across the Step Change and Slower Growth scenarios are as follows:

Timeframe	Description
1-10 Years	Maximum native demand forecast (50% POE) is projected to be higher than the previous year's outlook in the Step Change scenario. This results from a modest growth of EV uptake and small to medium business loads, complemented by reductions in the pace of electrification investment. In Slower Growth scenario, a large industrial load closure risk is continued to be included, dropping the state maximum demand by approximately 26% in 2027. State total maximum demand is then forecast to slightly recover due to electrification uptake, at a lower level to last year.
10-20 Years	Maximum native demand is forecast to remain relatively flat in all scenarios as a result of slower pace of electrification and increasing but low EV adoption, offset by a slight drop in large industrial loads in the middle of this decade.

As discussed in the previous section for the annual energy consumption forecast, the recently committed and anticipated AI factory developments will increase demand via a series of successive step changes over the next 24 months. With these projects included, the maximum demand is forecast to increase by more than approximately 400 MW, reaching a total of 2,300 MW by 2036.

The step increases in load from these new connections introduce emerging issues on the transmission network. These issues include:

- Voltage stability in the George Town area, which results in constraints on Basslink export and potential non-compliance with mandated minimum limits under the National Electricty Rules (**the Rules**).
- Load at risk and potential unserved energy levels that exceed the Tasmanian Electricity Supply Industry (**ESI**) network planning requirements for the transmission network.

As outlined in Chapter 3, we anticipate that a series of contingent projects will be put forward in our upcoming 2029-2034 revenue submission to meet the forecast identified needs that could arise from new load connections over the forward planning period.

2.3 Transmission network

The Tasmanian transmission network comprises:

- a 220 kV, and some parallel 110 kV, bulk transmission network that provides corridors for transferring power from several major generation centres to major load centres and Basslink;
- a peripheral 110 kV transmission network that connects smaller load centres and generators to the bulk transmission network; and
- substations that form interconnections within the 110 kV and 220 kV transmission network and provide transmission connection points for the distribution network and transmission connected customers.

Most customer connections are concentrated in the north and south-east of the State. Bulk 220 kV supply points are located at Burnie and Sheffield (supplying the north-west), George Town and Hadspen (supplying Launceston and the north-east), and Chapel Street and Lindisfarne (supplying Hobart and the south-east). Smaller load centres are supplied via the 110 kV transmission network on the periphery.

Our transmission network map is presented in Figure 2-8, and a summary of the transmission network infrastructure is provided in Table 2-4.

Table 2-4: Transmission infrastructure

Asset	Quantity
Substations	49
Switching stations	8
Circuit kilometres of transmission lines	3,311
Route kilometres of transmission lines	2,220.6
Circuit kilometres of transmission cable	25.2
Transmission line support structures (towers and poles)	7,048
Easement area (Hectares)	11,176

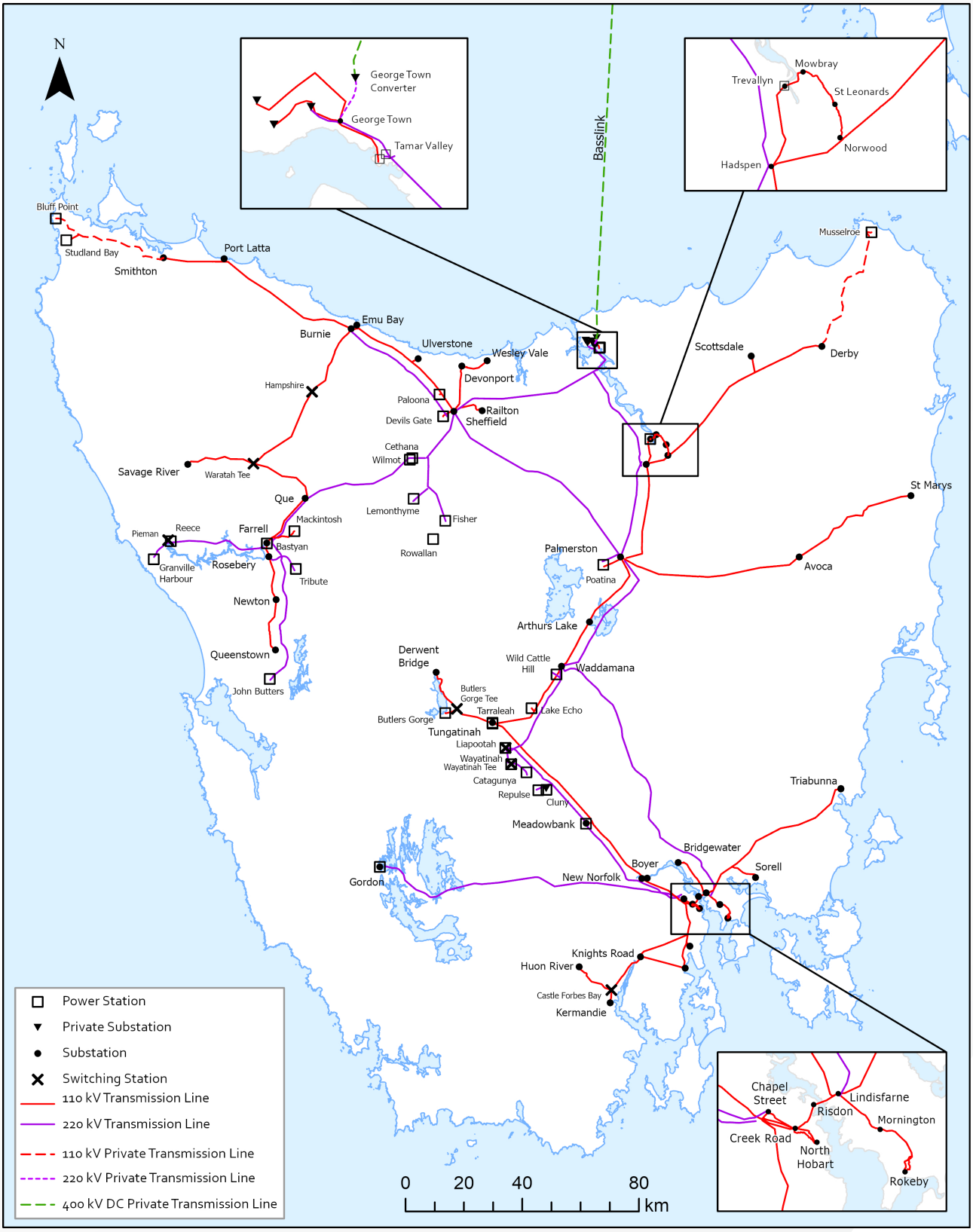


Figure 2-8: Tasmania's electricity transmission network

2.4 Distribution network

TasNetworks is responsible for delivering electricity to homes and businesses on mainland Tasmania. Our distribution network provides power to more than 295,000 residential, commercial, and industrial customers comprising:

- a sub-transmission network in the greater Hobart area, including Kingston, and one sub-transmission line on the West Coast that, in addition to transmission-distribution connection points, provide supply to the high voltage distribution network;
- a high voltage network of distribution lines that distribute electricity from transmission-distribution connection points and zone substations to the low voltage network and a small number of customers connected directly to the high voltage network; and
- distribution substations and low voltage circuits providing supply to the majority of Tasmanian customers.

Figure 2-9 presents our distribution network map by voltage.

Distribution lines are classified as supplying either rural or urban areas, and these tend to have different characteristics. Urban areas are outlined in the figure and exist in the surrounds of greater Hobart, Launceston, and the north-west of Tasmania; all other areas are classified as rural.

Rural areas generally have low load demand, low customer connection density, and smaller rural population centres remote from major supply points. Distribution lines supplying rural areas tend to cover wide geographic areas and can have a total route length of between 50 km and 500 km. This significant route length creates a high exposure to external influences such as storm damage, interactions with trees and tree branches, as well as lightning. Additionally, rural lines are generally radial in nature, with limited ability to interconnect with alternative supply options. These characteristics tend to result in more frequent and longer duration interruptions for rural customers.

Urban areas have higher load and customer connection density. Distribution lines supplying urban areas are generally much shorter than rural lines. They tend to have more underground assets and more interconnections with other supply points. Restoration following supply interruptions is usually quicker than in rural areas.

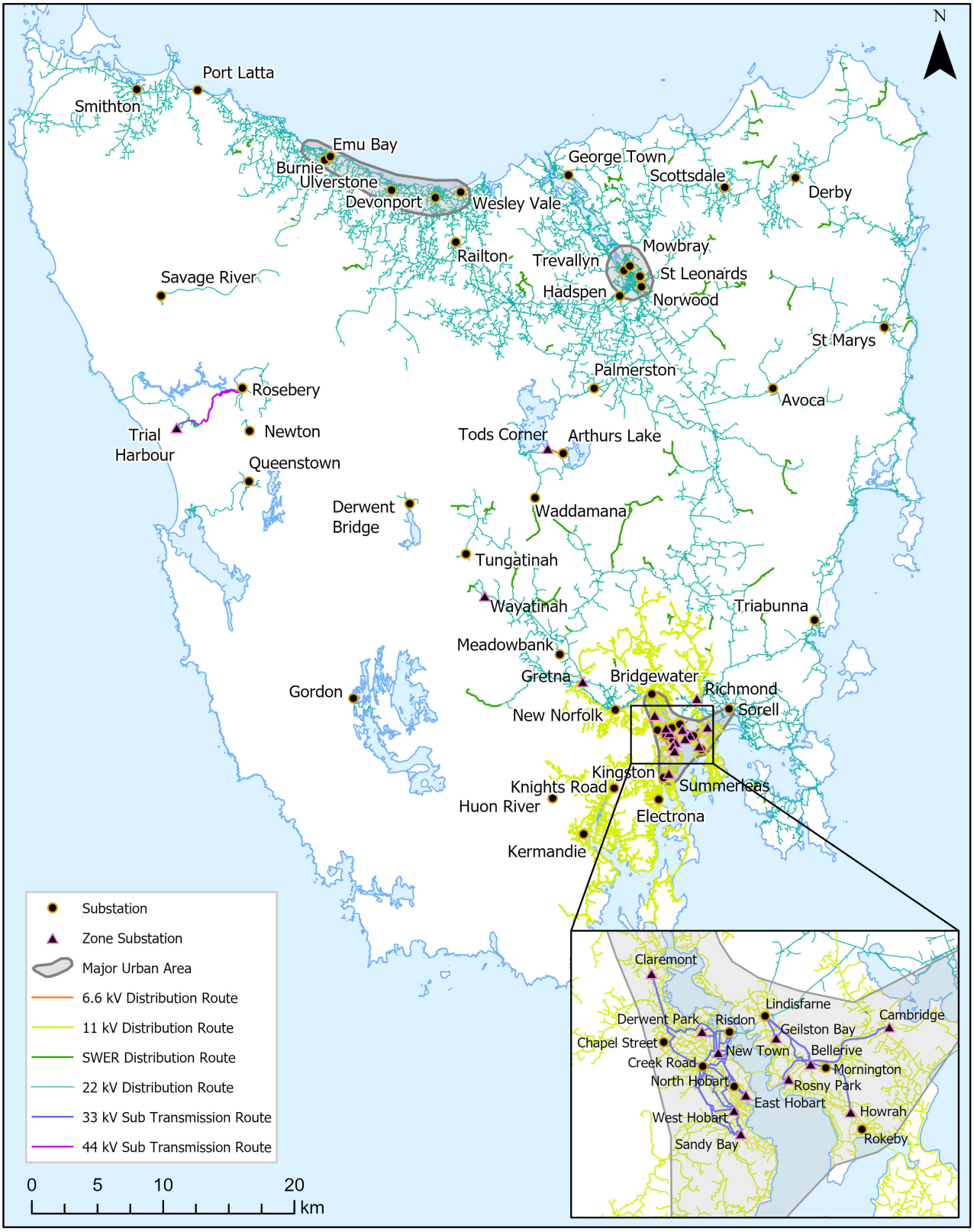


Figure 2-9: Tasmanian distribution voltage areas

A summary of our distribution network infrastructure is presented Table 2-5.

Table 2-5: Distribution network infrastructure

Infrastructure	Voltage (kV)	Quantity
Connection points		
Sites	44, 33, 22, 11, and 6.6	46
Sub-transmission lines	44, 33, and 22	27
Minor zone substation source lines[32]	22 and 11	7
Distribution lines	22, 11, and 6.6	247
Zone substations		
Major zone substations	44, 33, and 22	13
Major zone distribution lines	22 and 11	123
Minor zone substations	22 and 11	4
Minor zone distribution lines	22 and 11	8
Distribution substations		
Overhead		30,789
Ground mounted		2,296
Route data		
High-voltage overhead (km)	6.6 to 44	15,415
High-voltage underground (km)		1,314
Low-voltage overhead (km)[33]	0.4	4,562
Low-voltage underground (km)[30]		1,545
Poles	All voltages	231,643

32 Includes minor zone alternate-supply lines

33 Excludes customer service lines



Chapter 3

Transmission network developments

- Tasmanian transmission network planning activities examine the intra-regional transfer of electricity from generation sources to Tasmanian load centres as well as support inter-regional power flows to and from the mainland via interconnection with Victoria.
- The Australian Energy Market Operator (**AEMO**) published the 2026 Integrated System Plan (ISP) identifying Tasmanian Renewable Enery Zone (**REZ**) expansion plans as an actionable ISP project to support significant projected new Variable Renewable Energy (VRE) generation in Tasmania.
- TasNetworks and Marinus Link Pty Ltd (**MLPL**) commenced construction of their respective parts of Stage 1 of Project Marinus.
- We initiated a Regulatory Investment Test for Transmission (**RIT-T**) for augmentations at George Town Substation triggered by an initial tranche of new load, such as hydrogen or AI factories.
- We initiated a new Network Capability Incentive Parameter Action Plan (**NCIPAP**) project to upgrade the corridor capacity between Liapootah and Waddamana, to be delivered in the 2024-2029 regulatory period.

3.1 Introduction

This Chapter provides information on our plans to develop the Tasmanian backbone transmission system that comprises a 220 kV network, with some parallel 110 kV transmission assets. Its role is to facilitate the intra-regional transfer of electricity from generation sources to Tasmanian load centres as well as support inter-regional power flows to and from the mainland via interconnection with Victoria.

The main considerations when planning the backbone transmission network are the technical requirements of the National Electricity Rules (**the Rules**) as outlined in Appendix A and opportunities for development that deliver market benefits to customers. The Rules set how we determine the technical envelope within which the power system must be operated. Market benefits may be delivered by increasing access to lower-cost generation or by reducing the risk of unserved energy to customers. Our jurisdictional network planning requirements are also considered, with further details available in Appendix A.3.3.

Our plans are informed by a combination of enquiries from renewable energy generators, upgrades to existing power stations, enquiries from AI factory developers, integration of energy "firming" facilities such as battery energy storage systems (**BESS**) and pumped hydro energy storage (**PHES**), as well as sustained interest from export-scale hydrogen developers.

The presence of new large scale loads will impact the Tasmanian network in a number of ways, such as:

- changes in network utilisation and available capacity;
- the overall energy balance that can be achieved in Tasmania;
- access to sufficient levels of firming capacity, supplied within Tasmania and through interconnection; and
- changes to power system security and operational resilience.

3.2 Renewable energy zones and proponent generation interest

Candidate renewable energy zones (**REZs**) are "high renewable resource areas" identified by AEMO due to their renewable energy resource quality, existing land uses, and proximity to grid infrastructure. They are considered areas best suited for the development of new renewable energy resources to support the NEM transition away from fossil fuel-based generation.

AEMO's 2026 ISP identifies 44 candidate REZs across the National Electricity Market (**NEM**), of which Tasmania has four. The wind resource quality of the Tasmanian REZs is amongst the highest across the NEM.[34] The locations of the four Tasmanian REZs are presented in Figure 3-1. The figure also shows the combined generation and integrated resource (i.e. battery energy storage system (**BESS**)) connection interest by technology for each REZ.[35] There is no active connection interest in the offshore North Tasmania Coast REZ.

New VRE generation may utilise a variety of natural resources. In Tasmania, wind is the projected dominant new energy source, though with some large grid-connected solar-photovoltaic (**PV**) also proposed. We take the view that the REZ concept does not restrict the development and connection of any new generation outside of these nominated areas.

34 2026 ISP, Appendix A3: https://www.aemo.com.au/-/media/files/major-publications/isp/2026/appendices/a3-renewable-energy-zones.pdf?rev=6bb2ea22f0244c04a87cf3b2139be152&sc_lang=en

35 Connection interest sourced from AEMO NEM Generation Information Apr 2026, connection status of publicly announced or anticipated, with last survey update within 2 years

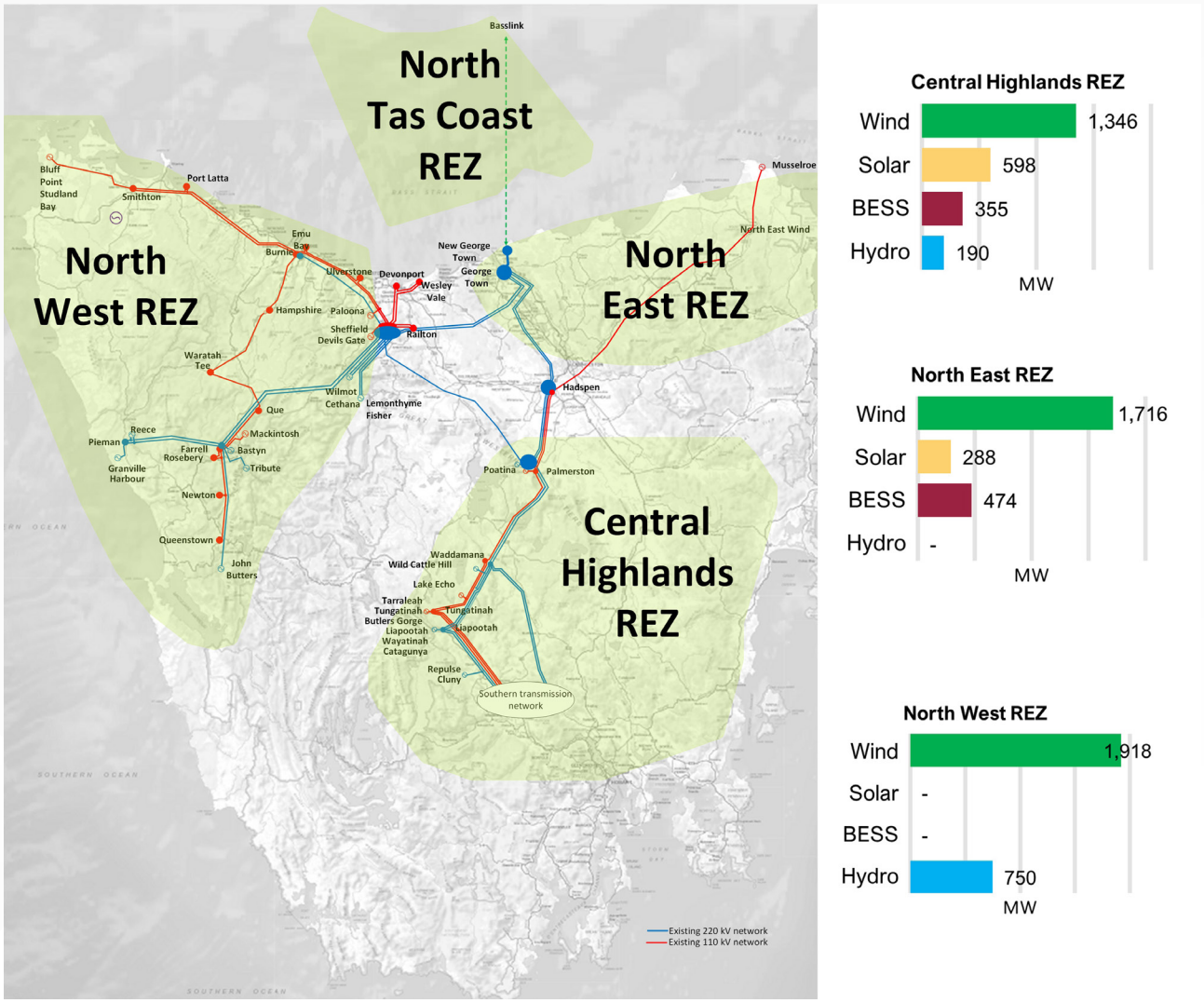


Figure 3-1: Tasmanian candidate renewable energy zones and proponent generation interest

3.3 Committed and completed projects

3.3.1 Project Marinus

Project Marinus is proposed to be a two stage, 1,500 MW interconnection with Victoria being a combination of Marinus Link (itself a transmission network service provider) and the North West Transmission Developments (**NWTD**). Project Marinus will create a transmission pathway significantly increasing energy transfer capabilities between Tasmania and the rest of the NEM and potential new renewable generation and storage projects in North West Tasmania and Central Highlands REZs.

The 750 MW Stage 1 of Marinus Link and the first stage of NWTD, are now committed projects and under construction.

Marinus Link will be a subsea and land interconnection to Victoria comprising a High Voltage Direct Current (**HVDC**) transmission system using voltage source converter (**VSC**) technology. Converter stations will be located at Heybridge (Tasmania) and Hazelwood (Victoria).

The NWTD comprises a new, high capacity 220 kV double circuit transmission network in north-west Tasmania and reinforcement of the Sheffield–Palmerston transmission corridor. It will support the increased power flows to and from Marinus Link and potential new renewable generation and storage projects in North West Tasmania and Central Highlands REZs. NWTD stage 1 scope comprises:

- **New 220 kV switching station:** at Heybridge;
- **Substation upgrade works:** at Palmerston, Sheffield and Burnie substations;
- **New 220 kV double-circuit transmission lines:** Palmerston–Sheffield and Sheffield–Heybridge–Burnie; and
- **Decommission:** existing single-circuit Palmerston–Sheffield and Sheffield–Burnie 220 kV transmission lines.

The proposed arrangement for NWTD is outlined in Figure 3-2.

More information on NWTD is available from the TasNetworks website at:

https://www.tasnetworks.com.au/Poles-and-wires/Planning-and-developments/North-West-Transmission-Developments

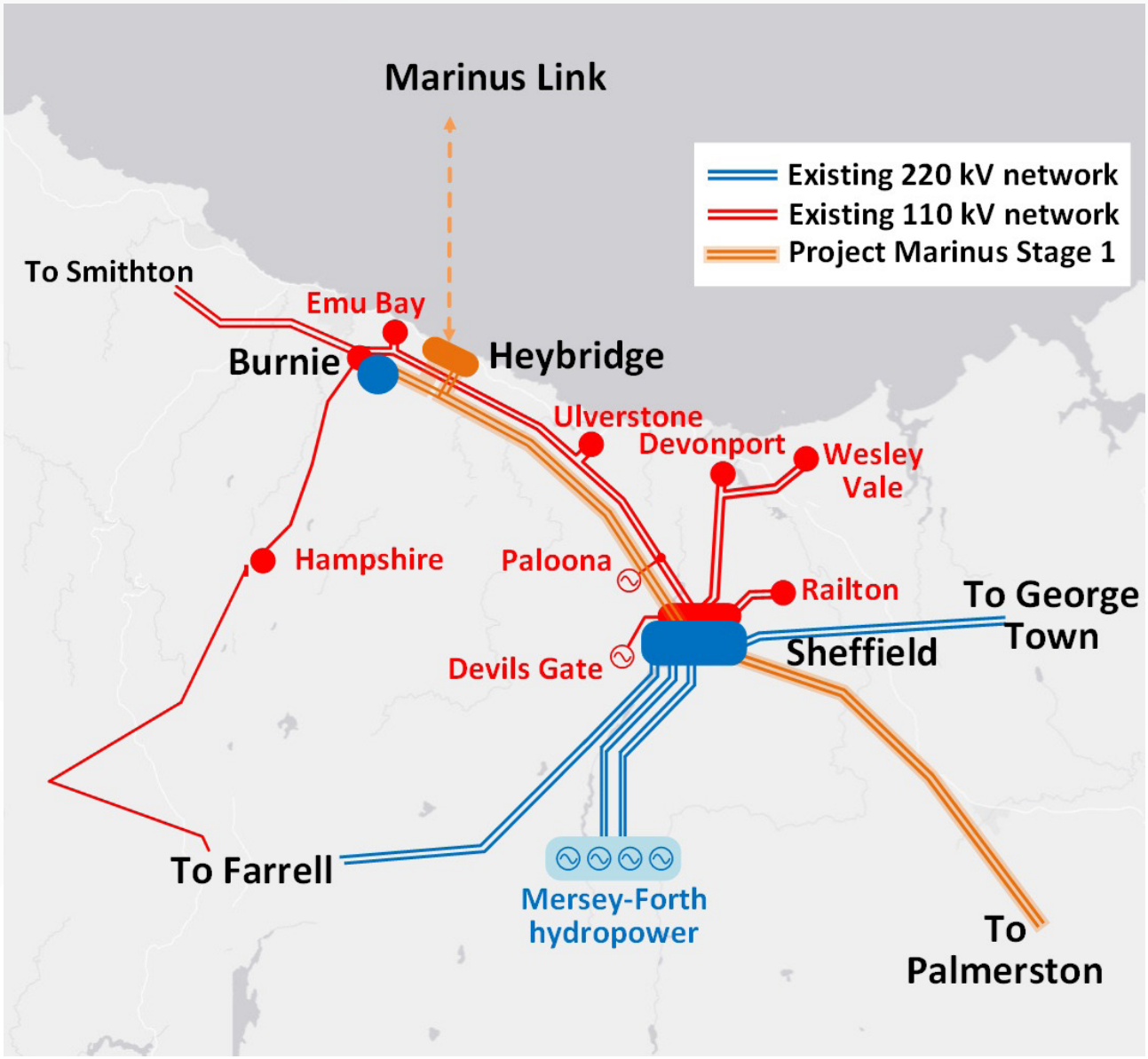


Figure 3-2: Project Marinus Stage 1 North West Tasmania transmission network

3.3.2 Central Highlands renewable energy zone capacity upgrades

TasNetworks is undertaking a series of upgrades to increase thermal capacity of the transmission network in the Central Highlands REZ and beyond. This increase is in addition to the NWTD and will support projected new VRE development in the Central Highlands REZ and subsequent increased power transfers through these corridors.

The Central Highlands REZ network comprises 220 kV and 110 kV transmission networks providing connectivity between the northern and southern supply regions of Tasmania. Liapootah, Tungatinah and Palmerston substations provide connections for hydro generation, with Wild Cattle Hill wind farm connected close to Waddamana Substation. The general overview of the Central Highland REZ transmission network is provided in Figure 3-3 , with the proposed augmentations.

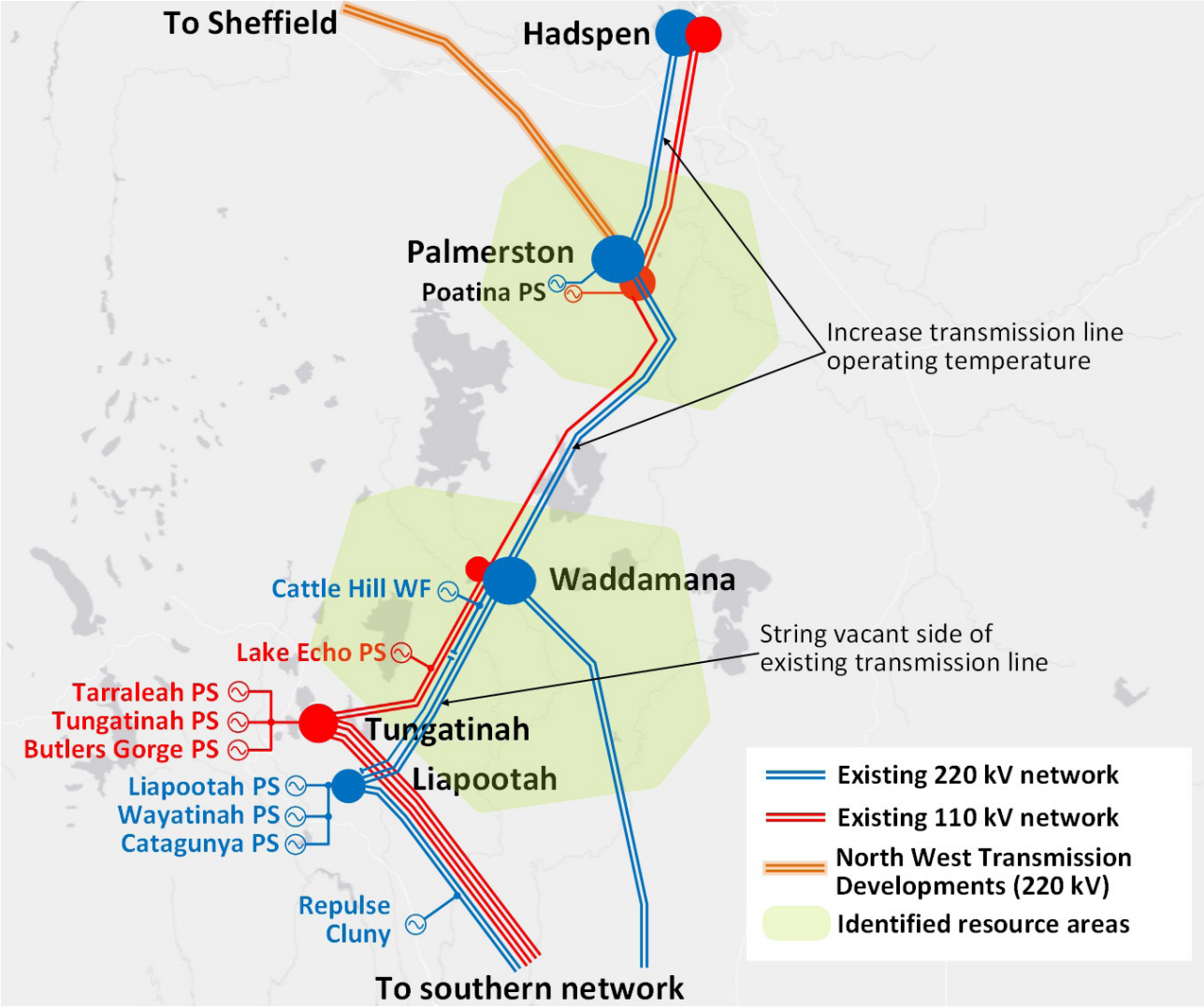


Figure 3-3: Central Highlands REZ and operational transmission upgrades

The operational upgrades to the Central Highlands REZ transmission network comprise:

- stringing the vacant side of the double-circuit Liapootah–Waddamana 220 kV transmission line, increasing circuit rating from 376 MVA to 501 MVA. This initiative has been progressed as a Network Capability Incentive Parameter Action Plan (NCIPAP) project
- implementing an increase from 75°C to 90°C in operating temperature of the Waddamana–Palmerston 220 kV transmission line (line identified to already have this capability), increasing circuit ratings from 501 MVA to 570 MVA; and
- increasing the operating temperature of Palmerston–Hadspen 220 kV transmission circuit from 75°C to 90°C through minor ground clearance upgrades, increasing circuit ratings from 333 MVA to 376 MVA.

These upgrades are expected to be completed by June 2027.

3.4 Integrated System Plan

AEMO publishes an ISP every two years. The ISP defines an optimal development path for the build of new generation (predominantly VRE), transmission, and storage across the NEM to meet future energy needs as existing thermal generation sources (coal and gas) retires over coming years. The ISP projects out to 2050, projecting VRE build by REZ and by type, and new transmission developments as actionable and future ISP projects on the optimal development path (**ODP**). Actionable ISP projects should commence development immediately to ensure they can meet their required in-service date. The 2026 ISP was published on 25 June 2026.

The ISP includes international and government energy commitments across all scenarios. In Tasmania, this includes the Tasmanian Government's Tasmanian Renewable Energy Target (**TRET**) to increase Tasmania's 2020 renewable energy generation production by half by 2030, and to double by 2040. The TRET and ISP modelling incorporate new renewable generation at utility-scale, embedded generation in the distribution network, and network-connected consumer energy resources (**CER**) including rooftop PV.

The 2026 ISP identified two Tasmanian projects on the optimal development path—both as actionable ISP projects for which development should be continued, or commenced immediately. These projects are:

- **Project Marinus stage 2:** Actionable for 2034–35, development of the second 750 MW Marinus Link interconnector between Tasmanian and Victoria, and the NWTD Stage 2.
- **Tasmanian REZ expansion:** transmission network expansion to support the expected increase in renewable generation in Tasmania. The ISP identifies this could be achieved through implementing either:
  - the ISP candidate option being **NWTD Stage 2: Burnie to Hampshire Hills component:** Actionable for 2030–31 advancing a portion of NWTD Stage 2 to support renewable energy development in the North West Tasmania REZ. It is advanced from future project status in ODP of the 2024 ISP or
  - the alternative option being **Waddamana to Palmerston transfer capability upgrade:** Actionable for 2030–31 provision of a third 220 kV transmission circuit in the Waddamana–Palmerston 220 kV transmission corridor increasing transmission capacity for new VRE generation in the Central Highlands REZ. This was an actionable ISP project in the 2024 ISP ODP.

3.4.1 Renewable energy projections

In the Step Change scenario, outlined in Chapter 2, 1,180 MW of new wind generation and 873 MW of new grid-connected PV generation is projected in Tasmania by 2032 to meet the TRET 2030 target and mainland Tasmania energy requirements. This generation is supported by utilising transmission capacity realised by Project Marinus and further new transmission network development.[36] In the following decade to 2040, projected new wind build increases to 1,600 MW across Tasmania, while there is no increase in new utility-scale PV.

Table 3-1 presents the 2026 ISP projections for new utility / large–scale VRE by technology and REZ by 2032 and 2040 under the Step Change and Accelerated Transition scenarios. This includes anticipated and government-funded projects[37] and ISP modelling projections but excludes existing VRE. There is no VRE projection for North Tasmania Coast offshore REZ under any scenario.

36 This generation, and as presented in Table 3-1, is with the ODP, Step Change scenario and NWTD Stage 2: Burnie to Hampshire as the actionable project for Tasmanian REZ expansion. Under the Accelerated Transition scenario, the Waddamana to Palmerston transfer capability upgrade project is also required to facilitate the additional generation requirements in the Central Highlands REZ

37 These projects are as included as 'given' in the ISP, assessed by AEMO to meet anticipated (or committed) status under the project commitment criteria, and government funding for projects such as the Australian Government capacity investment scheme

Table 3-1: 2026 ISP VRE projections (MW)

		Step Change scenario		Accelerated scenario	
REZ	**Technology**	**2032**	**2040**	**2032**	**2040**
North East Tasmania	Wind	228	228	228	228
	PV	413	413	314	314
North West Tasmania	Wind	319	590	320	884
	PV	150	150	150	150
Central Highlands	Wind	637	797	660	900
	PV	310	310	400	400
Total	**Wind**	**1,183**	**1,615**	**1,207**	**2,012**
	PV	**873**	**873**	**864**	**864**

3.4.2 Project Marinus Stage 2

Project Marinus Stage 2, shown in Figure 3-4, remains an actionable ISP project in the 2026 ISP. Stage 2 will enable theoretical full 1,500 MW export and import capability of Marinus Link. The second stage of NWTD will enable the requisite power transfer to Marinus Link via a second 220 kV transmission route from Sheffield Substation, with a secondary benefit of providing connection capability for new VRE generation in the North West Tasmania REZ.

The NWTD Stage 2 component of Project Marinus Stage 2 comprises:

- new Staverton Switching Station;
- intersecting existing 220 kV transmission circuits into Staverton Switching Station and upgrade capacity; and
- new Staverton–Burnie 220 kV transmission line, via Hampshire Hills.[38]

The estimated cost of NWTD Stage 2 works is $525 million and is actionable for 2034–35. It was included as part of the broader RIT–T for both stages of Project Marinus.[39]

Marinus Link Pty Ltd will deliver the Marinus Link interconnector component of Project Marinus Stage 2.

38 Burnie–Hampshire Hill 220 kV transmission line section may already be delivered through the Tasmania REZ expansion actionable project, with renewable energy development in the North West Tasmania REZ (refer Section 3.5.2). The estimated cost presented is for the full scope of NWTD Stage 2

39 https://www.marinuslink.com.au/rit-t-process/

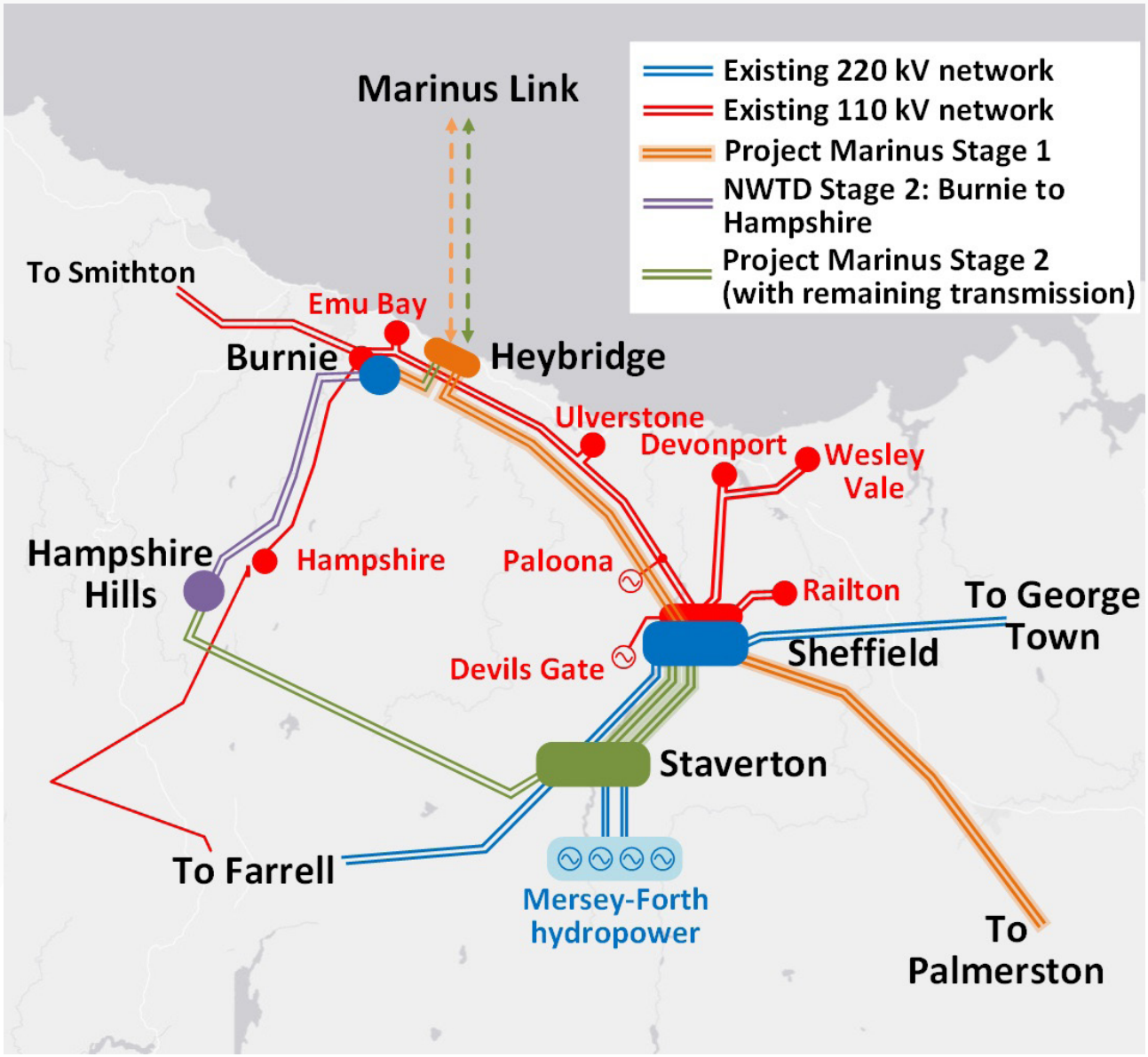


Figure 3-4: Project Marinus Stage 2 with other staged development in North West Tasmania

3.4.3 Tasmanian REZ expansion

The 2026 ISP identifies Tasmanian REZ expansion as an actionable ISP project to support significant projected new VRE generation in Tasmania.

It identifies the ISP candidate option as:

- new VRE and transmission development in the North West Tasmania REZ,
- coupled with VRE development in the Central Highlands REZ within existing network capability.

However; it also acknowledges the benefit of the Waddamana to Palmerston transfer capability upgrade (an actionable ISP project in 2024 ISP) and identifies it as an alternative option to the ISP candidate option.

TasNetworks is assessing both options (and others) as part the RIT-T for the Tasmanian REZ expansion. The assessment will consider developer interest, updated cost estimates for both options, and other local factors difficult to capture in the ISP model.

AEMO has undertaken a call for non-network options,[40] with responses to be considered in the RIT-T. The RIT-T will assess the relative cost and benefits of each credible option, and the preferred solution which maximises net benefit to consumers. The project assessment draft report (**PADR**) is the next stage of the RIT-T and will be published by 25 June 2028.

3.4.3.1 ISP candidate option: NWTD Stage 2: Burnie to Hampshire Hills component

The Tasmania REZ expansion ISP candidate option is to develop a new Burnie–Hampshire Hills 220 kV transmission line and Hampshire Hills Switching Station (in the Hampshire locality) as a collector node for new VRE resources, The Burnie–Hampshire Hills 220 kV transmission line is a 'bring forward' component of NWTD Stage 2, known as NWTD Stage 2: Burnie to Hampshire Hills component. Figure 3-5 presents this option with Project Marinus Stage 1 and the broader transmission network in north-west Tasmania.

This option provides efficiency by advancing an element of NWTD Stage 2 (itself an actionable ISP project as part of Project Marinus Stage 2), rather than develop a separate transmission augmentation in addition to NWTD Stage 2. This allows development of VRE in the North West Tasmania REZ (projected 740 MW across wind and PV farms[41]), while a substantial amount of VRE is still developed in the Central Highlands REZ (projected 1,100 MW across wind and PV farms) taking advantage of existing transmission network capacity.

The estimated cost of NWTD Stage 2: Burnie to Hampshire is $245 million and is actionable for 2030–31.

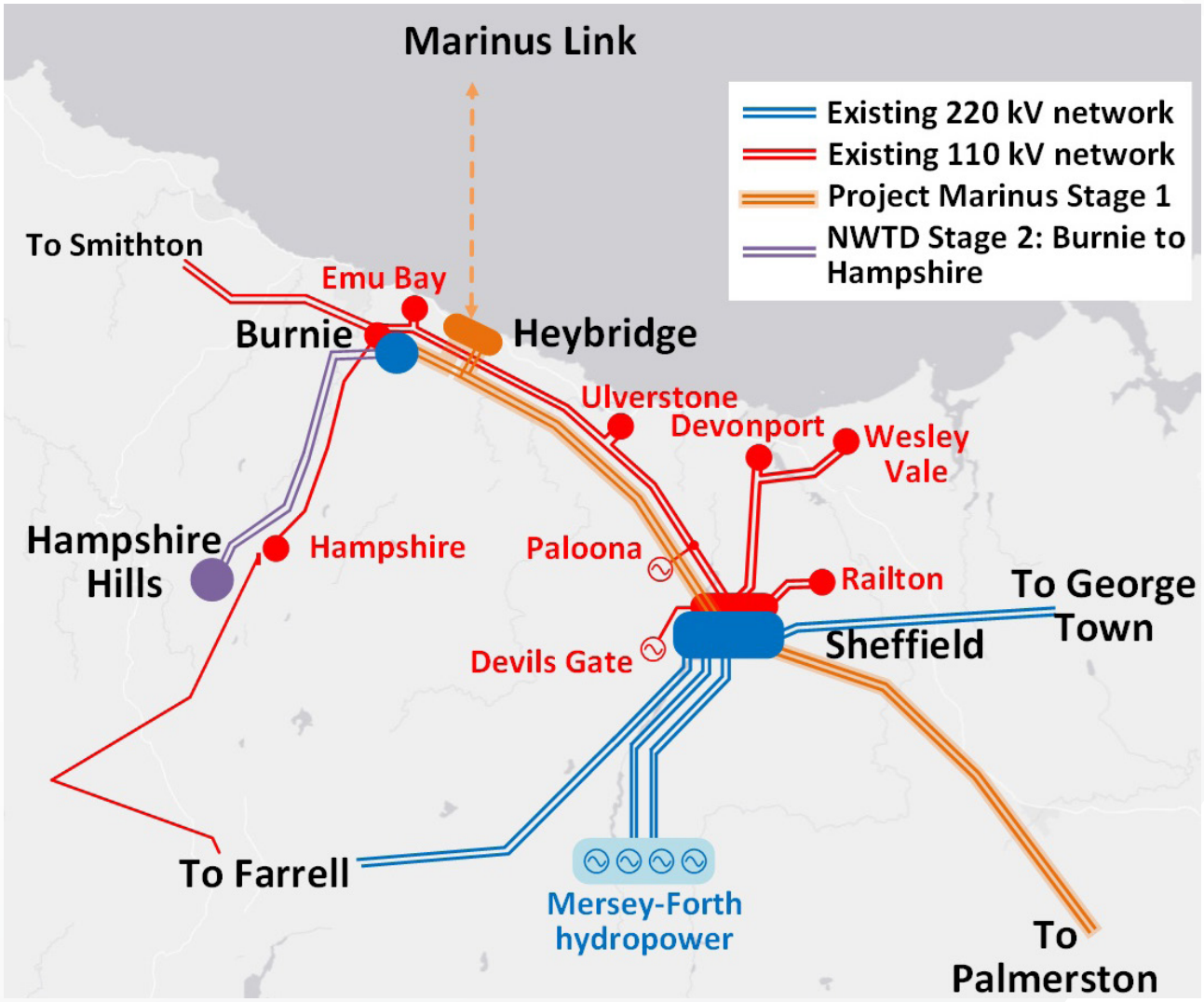


Figure 3-5: NWTD Stage 2: Burnie to Hampshire Hills component

40 2026 ISP, Appendix A5, Network Investments, section A5.3.6

41 This option will be capable of supporting 800 MW of new VRE at the Hampshire Hills VRE collector station—740 MW is the projected build in the 2026 ISP ODP Step Change scenario by 2040. The VRE hosting capability will further increase with the additional transmission from the remainder of NWTD Stage 2

3.4.3.2 ISP alternative option: Waddamana to Palmerston transfer capability upgrade

The 2026 ISP includes an alternative option for Tasmanian REZ expansion being the Waddamana to Palmerston transfer capability upgrade, Figure 3-6. This option was an actionable ISP project in the 2024 ISP. It will allow further development of new VRE in the Central Highlands REZ (in addition to existing network capability, including operational upgrades identified in Section 3.3.2) instead of development in the North West Tasmania REZ. Under this option, Project Marinus Stage 2 remains its own actionable ISP project.

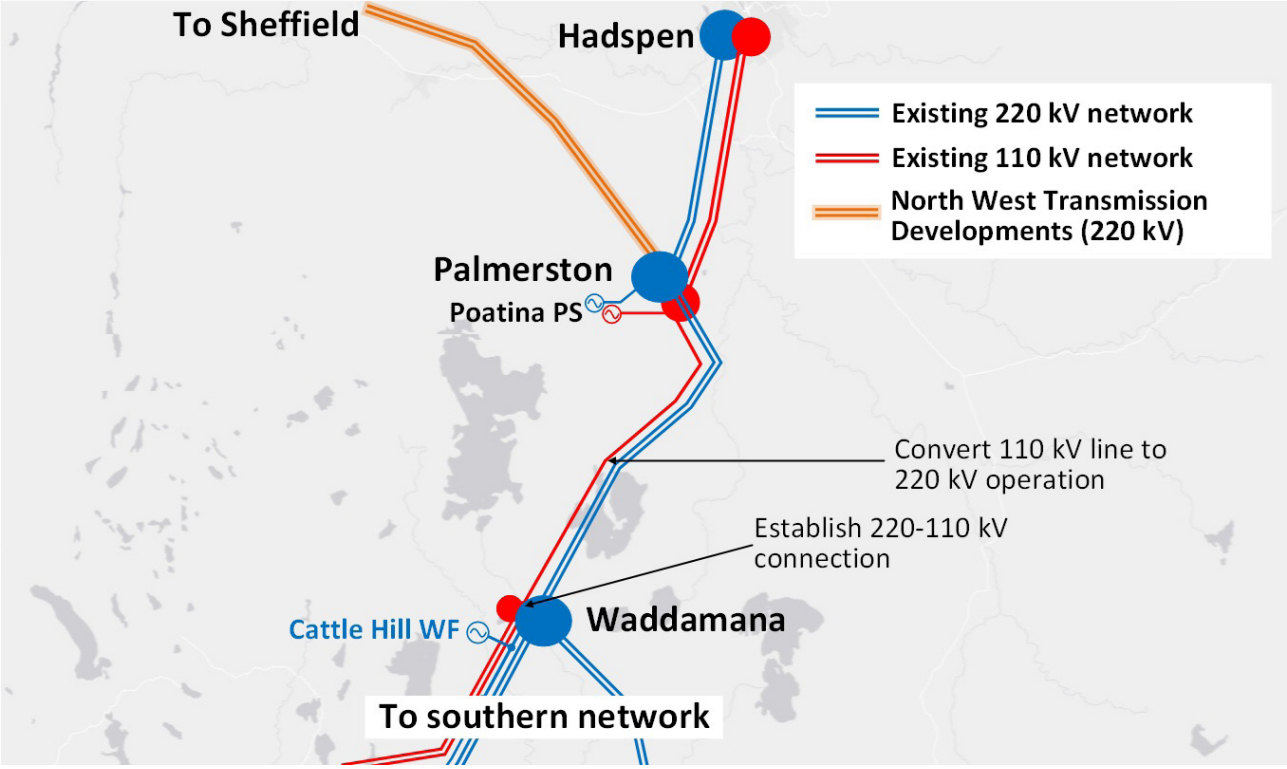


Figure 3-6: Central Highlands transmission network with Waddamana to Palmerston transfer capability upgrade

The scope of Waddamana to Palmerston transfer capability upgrade comprises:

- Upgrades to the Waddamana–Palmerston 110 kV transmission line to 220 kV operation (the line operated previously at 220 kV), including select structure replacement;
- reconductoring the transmission line with high temperature-low sag conductor providing increased transfer capability;
- installation of a 220/110 kV network transformer at Waddamana Substation, to maintain north-south 110 kV power flows with conversion of existing 110 kV circuit to 220 kV operation; and
- augmentation of Palmerston and Waddamana Substations to accommodate the upgraded transmission line and new network transformer.

The estimated cost of Waddamana to Palmerston transfer capability upgrade is $224 million and would be delivered by 2030–31.

3.5 Large-scale load development

Large-scale load development remains credible in Tasmania. Lead candidate industries are across AI factories, hydrogen and alternative fuel production, and electrification of existing loads. Associated with this, we also consider the future operation of existing major industrial loads. Potential for large-scale load development is presented in Section 1.4.2.

An important factor in large-scale loads from new and emerging industries (aforementioned AI factories andhydrogen electrolysers) is their ability to operate as a responsive load. This means the load can rapidly alter its demandfollowing a network contingency or system disturbance to maintain power system security and reliability. This means there is less requirement for new transmission infrastructure (particularly new transmission lines) as new large-scale load is developed.

However; there will points at which the requirements of the load or power system operation will necessitate transmission network augmentation. Any transmission augmentations required to support new load will be identified through regulated process (unless funded externally), including being identified in our Annual Planning Report, revenue reset, and regulated investment test process.

3.6 Network investments

In addition to the ISP nominated projects, there are further planned investments proposed to the backbone transmission network in Tasmania. These investments are to:

- support large-scale load growth in the Bell Bay industrial area supplied from George Town Substation and surrounds;
- alleviation of west coast generation constraints; and
- Improve efficiency of transmission network operation through reducing losses in the Upper Derwent 110 kV transmission network.

These investments are contingent on specific technical triggers being met, as well as successful completion of RIT-Ts. Some investments have been previously identified and accounted for in the current 2024-2029 revenue period, with others as candidates in the upcoming 2029-2034 revenue submission.

3.6.1 Meeting network planning requirements at George Town

TasNetworks has initiated on behalf of the Tasmanian Government a RIT-T for network augmentations at George Town Substation that support the establishment of new major loads. At the time the project was initiated in 2022, the RIT-T was focussed on the combined interest from developers to establish industrial scale hydrogen production in Tasmania. Two main issues arise in the network following new load connection directly at George Town. Both issues are related to the minimum network performance requirements in the Network Planning Requirements (**NPR**)[42] and the Rules.

Compliance with NPR: Single contingency size

George Town is dominated by major industrial loads with a largely flat consumption profile throughout the year. The addition of 300[43] MW or more of new load at George Town will at times equal or exceed 60% of the total State load.

A NPR compliance breach could arise from a single asset failure, such as a catastrophic failure of one of the network transformers or 220 kV bus at George Town Substation, resulting in an outage of the entire substation. If 60% or more of the State demand is lost, this is classified as a system black condition.

Demand reduction or network augmentation is likely to be required to allow new loads to connect to maintain compliance with this NPR requirement.

42 https://www.legislation.tas.gov.au/view/whole/html/inforce/current/sr-2018-002

43 The original technical trigger level at the commencement of the RIT-T was identified as 210 MW, based on the total loading of George Town and the overall network. Since the closure of Liberty Bell Bay, this trigger level has increased by approximately 90 MW

Compliance with NPR and the Rules: Voltage stability

As the load increases at George Town, the stability of the voltage waveform is more severely impacted by fault events, potentially leading to undamped oscillations and cascading failure of the network—a system black event. To ensure that acceptable voltage stability is maintained in accordance with Schedules S5.1 and S5.1a of the Rules, constraints are applied to Basslink export and Tasmanian generation to manage the reactive power margin requirements defined under Chapter 5 of the Rules.

Such constraints can restrict the amount of energy from marginal generators, resulting in an increase in NEM energy spot prices.

Following the connection of additional load at George Town, the network is exposed to increased periods of stability risks. Network constraints are a function of Basslink export and local Tasmanian generator dispatch, and at a certain point may no longer be effective to manage the risk.

A single credible network option was identified to address the needs, comprising:

- establishment of a new air insulated switchgear substation;
- installation of 550 Mvar of reactive support in the new substation; and
- reconfiguration of the 220 kV switchyard at the existing George Town substation.

This project was included as a contingent project in our revenue proposal for the 2024-2029 regulatory control period at a cost of $370.6 million.

Further information on the RIT-T can be found on our website:

https://www.tasnetworks.com.au/planning-and-projects/regulatory-investment-test-projects

Treatment of locational sensitivities for new load connections

In addition to the forward forecasts, newly anticipated load connections have emerged, including projects connecting in the northern network and in close proximity to George Town. These are of sufficient magnitude to affect the voltage stability, but not necessarily impacting network security in a manner that would trigger the current RIT-T. To accommodate these new load connections, an alternative investment is considered to provide reactive support at / close to George Town, scaled according to the magnitude of new load. The technical trigger for this investment is the point at which Basslink export constraints are insufficient to maintain voltage stability in compliance with the NER.

For higher magnitudes of load connections, or successive increases in loading at / close to George Town over the forward planning period, a higher tier technical trigger emerges due to thermal limits and voltage stability. The proposed solution to address these limitations is to install additional reactive support and to augment the northern transmission network.

These investments are intended to form part of TasNetworks upcoming 2029-2034 revenue submission.

3.6.2 Reducing losses in Upper Derwent 110 kV transmission network

We have identified an opportunity to significantly reduce transmission losses in the Upper Derwent 110 kV transmission network. There is 250 MW of generation capacity connected to Tungatinah Substation, which is transmitted via 110 kV assets to Palmerston and New Norfolk Substations. Providing a local interconnection between the 110 kV and 220 kV networks will allow for a more efficient transfer of power into the higher capacity 220 kV network, thereby reducing network losses.

We have assessed a number of options for the location and timing of this network augmentation to provide access for Upper Derwent 110 kV generation into the 220 kV network.

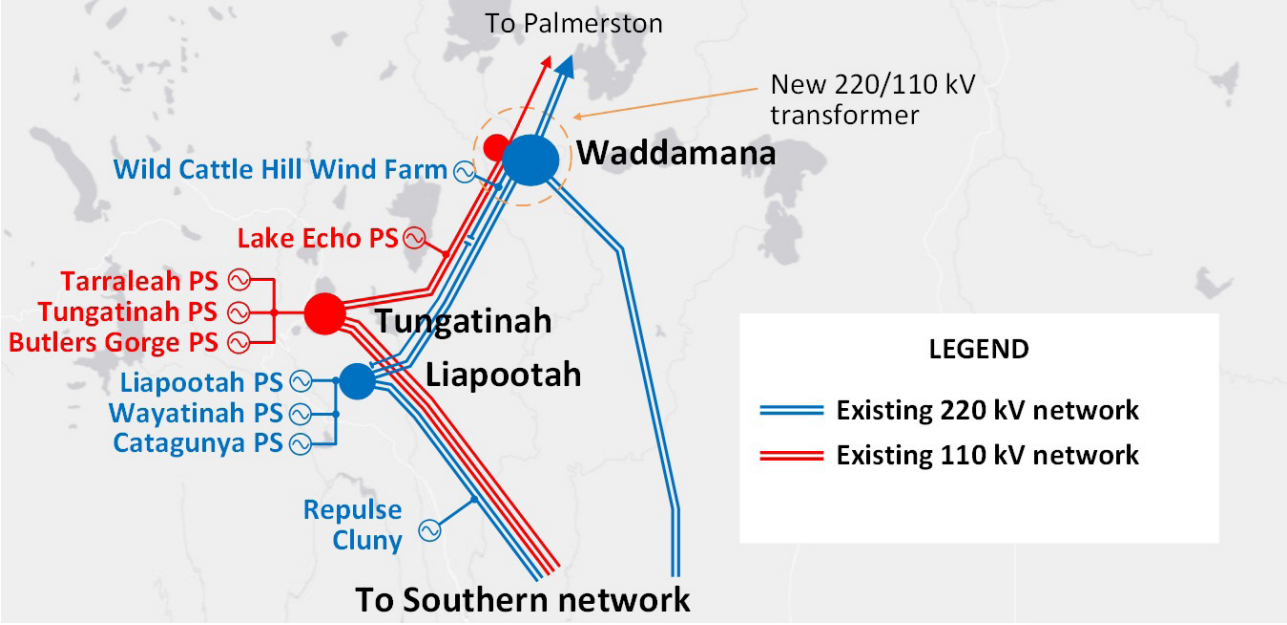


Figure 3-7: Reducing losses in Upper Derwent 110 kV transmission network

Our preferred option to reduce losses in the Upper Derwent 110 kV transmission network is to install a 220/110 kV network transformer at Waddamana Substation, as presented in Figure 3-7. It is a relatively simple solution and is economically justified through the savings in reduced network losses being greater than the cost of installing the transformer.

This project is estimated to cost $10.9 million and is scheduled to be completed by 2029.

3.6.3 Addressing southern Tasmania voltage stability

The following regulatory investment has been identified to address emerging issues relating to the future demand profile in southern Tasmania.

As the load increases in the southern Tasmanian network to a certain level, the post-contingency reactive margin level at critical connection points in this region of the network is no longer compliant with the voltage stability criteria required in the clause S5.1.8 of the NER. According to the latest demand forecast, the total load in the southern Tasmania will likely cause voltage stability issue and a risk of voltage collapse and cascaded failures in the network, especially following a credible contingency.w

A network study established the reactive margin requirements at critical connection points across the southern area under an intact system and after a credible contingency. To maintain healthy voltage performance and comply with the NER, TasNetworks has proposed to install two 40 Mvar capacitor banks at one or two 110 kV substations in the Greater Hobart area. The project costs and finalised scope will be developed as part of the upcoming 2029-2034 revenue submission.

3.6.4 Addressing Farrell-Sheffield transient stability constraint

Farrell Substation functions as the connection interface between the west coast hydro and wind generation and supplies load customers in the west coast region.

Farrell Substation is connected via a double circuit 220 kV transmission line to Sheffield substation, through which up to 760 MW of combined generation contributions from the West Coast are distributed through the broader network. The transmission line is approximately 85 km in length.

The size and concentration of generation, connected via this long radial transmission line exposes the network to the risk of transient and oscillatory instability, which can occur following network faults involving a loss of one of the Farrell-Sheffield transmission circuits.

As a result, TasNetworks provided limit advice to AEMO that places constraints on the maximum generation contribution at Farrell Substation (and therefore transmission corridor flows from Farrell-Sheffield). The constraint depends on factors such as the generation contribution of individual generation units in the West Coast, the aggregate regional load, and behaviour of wider network conditions, such as total network generation, demand and Basslink interconnector flows.

There has been developer interest in the west coast region to connect additional generation and in the area that forms part of the North West REZ.

Increases to the generation connected out of Farrell Substation will exacerbate the existing transient stability constraint on the Farrell-Shefield corridor, restricting the amount of generation that can be provided from the west coast region.

The conditions where this constraint binds already exist resulting in restrictions on power flows through the Farrell-Sheffield corridor, subsequently limiting the dispatch for west coast generators. Restricted generation, that would otherwise add to the market settlement results in negative outcomes for the NEM in the form of higher spot prices. Additional generation connecting to the West Coast will exacerbate the duration of binding intervals of this constraint and the quantity of undelivered energy (spill) to the market.

The trigger level for additional generation that corresponds to a positive market benefit ranges from 100 MW – 150MW, depending on the sample year.

In order to mitigate against the transient and oscillatory instability, the severity of fault events affecting the Farrell-Sheffield transmission line can be reduced by splitting the transmission line into separate segments, so that faults and outages of individual segments result in a lesser impact to the network (a smaller change to network impedance).

Tasmanian network upgrades, such as Marinus Link and the supporting NWTD, unlock access for new customers. It is probable that at least 100 MW of generation projects will progress, specifically out of the West Coast, to meet this increased demand during the 2029–34 regulatory control period.

The Farrell-Sheffield corridor augmentation was not included as a candidate augmentation in the 2026 ISP. The inclusion of this augmentation as a contingent project in the upcoming regulatory control period of 2029-2034 provides the means to initiate the project prior to the 2028 ISP. If the project is classified as an actionable ISP project in the 2028 ISP, then the project would be progressed through the ISP pathway.

3.6.5 Addressing the southern Tasmania transmission reliability risk

The Waddamana–Palmerston transmission corridor, comprising 220 kV and 110 kV transmission lines, provides connectivity between the southern and northern Tasmanian electricity networks. It is a critical part of the network, supporting the load-generation balance between regions and maintaining the integrity and stability of the overall power system. The corridor contains a double-circuit 220 kV transmission line and a single-circuit 110 kV transmission line.

The most severe contingency event affecting this corridor is a 220 kV double circuit transmission line outage. At times of high north-to-south power flows, a loss of both 220 kV circuits network (and subsequent loss of the 110 kV circuit due to its inability to carry the resultant power flow) would result in the separation of network. Following separation, the network is exposed to severe voltage instability and cascading outages, with the potential to lead to a system black event the southern region.

This risk is expected to become more prevalent in the future, with forecast increases to the southern demand, combined with increased frequency of reduced southern hydro generation through increased imports through Basslink and Marinus Link interconnectors.

The Electricity Supply Industry NPR specify a series of minimum performance requirements. These requirements include a limit to the maximum quantity of load that is capable of being interrupted by a single asset failure.

Clause 5(1)(ii) states:

"in respect of an intact transmission system, no more than 850 MW of load is to be capable of being interrupted by a single asset failure"

The definition of 'single asset' includes a double-circuit transmission line. In the context of the north-south separation event and loss of the southern system, when the southern load exceeds 850 MW TasNetworks will not meet this network planning requirement.

The demand forecast for TasNetworks 2029–34 revenue submission has been developed from AEMO's 2025 Electricity Statement of Opportunities (**ESOO**) load forecast. Under the Step Change scenario, southern area maximum demand is forecast to reach 830 MW by 2034.

Boyer Paper Mill is a large industrial load in southern Tasmania. It is seeking to replace its coal-fired boiler with a new electrode boiler. The electrode boiler is proposed as a 60 MW unit, and connection for the late 2020s. The project has grant funding from the Australian Government.[44] It is expected that the new boiler load will be coincident with maximum demand in southern Tasmania, colder temperatures which drive maximum demand also driving peak boiler requirement.

If this project proceeds, southern area maximum demand will exceed 850 MW in 2030—within the 2029–34 regulatory period. At this point, action must be taken to meet the network performance requirements.

The solution seeks to maintain north-south connection and southern voltage stability following single asset failure of the double-circuit Waddamana–Palmerston 220 kV transmission line. The indicative solution to this is to provide additional 220 kV circuits between Waddamana and Palmerston Substations. The project costs and finalised scope will be developed as part of the upcoming 2029-2034 revenue submission.

44 https://www.boyercorporation.au/projects

Chapter 4

Area planning constraints and development

- Four geographic planning areas are considered: North West and West Coast, Northern, Central, and Southern.
- Details of planned augmentations and replacements are provided by planning area.
- Targeted reliability improvement projects continue for specific reliability communities.
- Exemptions from jurisdictional planning requirements are retained for three locations, with a new five year exemption of the Farrell-Savage River-Waratah transmission line in the North West and West Coast planning area.
- Feedback is welcomed on prospective alternative solutions to our augmentation and asset retirement and replacement plans.

4.1 Background to area planning

In conjunction with our assessment of the backbone transmission network, we plan local transmission and distribution networks in accordance with regulatory requirements as outlined in Appendix A. In doing so, we address integrated planning considerations and technical analysis methodologies. Our plans are based on four geographical planning areas being:

- North West and West Coast planning area;
- Northern planning area;
- Central planning area; and
- Southern planning area.

This Chapter provides information on both the transmission and distribution networks within each planning area, including:

- availability to connect to the network;
- network limitations and constraints;
- completed and committed projects;
- future connection points;
- actions to address poor performing reliability communities; and
- deferred or averted limitations.

It also presents our asset retirement and replacement programs and our proposed investments in operational support systems and the telecommunications network. These programs and investments are presented on a whole-of-state basis, by asset class.

While the network maximum demand in Tasmania remains below its historic peak, the Australian Energy Market Operator's (**AEMO**) Step Change scenario forecasts ongoing growth for the decade, largely driven by electrification and expansion of large industrial load consumption in the later years.

Many of these prospective large scale load developments are concentrated at specific connection points in the network and will trigger augmentations to the backbone transmission network.

At a locality level, the network remains largely adequate to meet supply reliability requirements over the next 10 years, with a focus largely on distribution network asset management and reliability of supply issues at specific locations.

4.2 Planning areas

The planning areas are defined by the core transmission network connecting major supply points, and the geographical coverage of the distribution network across the State. Figure 4-1 shows the geographic planning areas and the following sections provide brief descriptions of each.

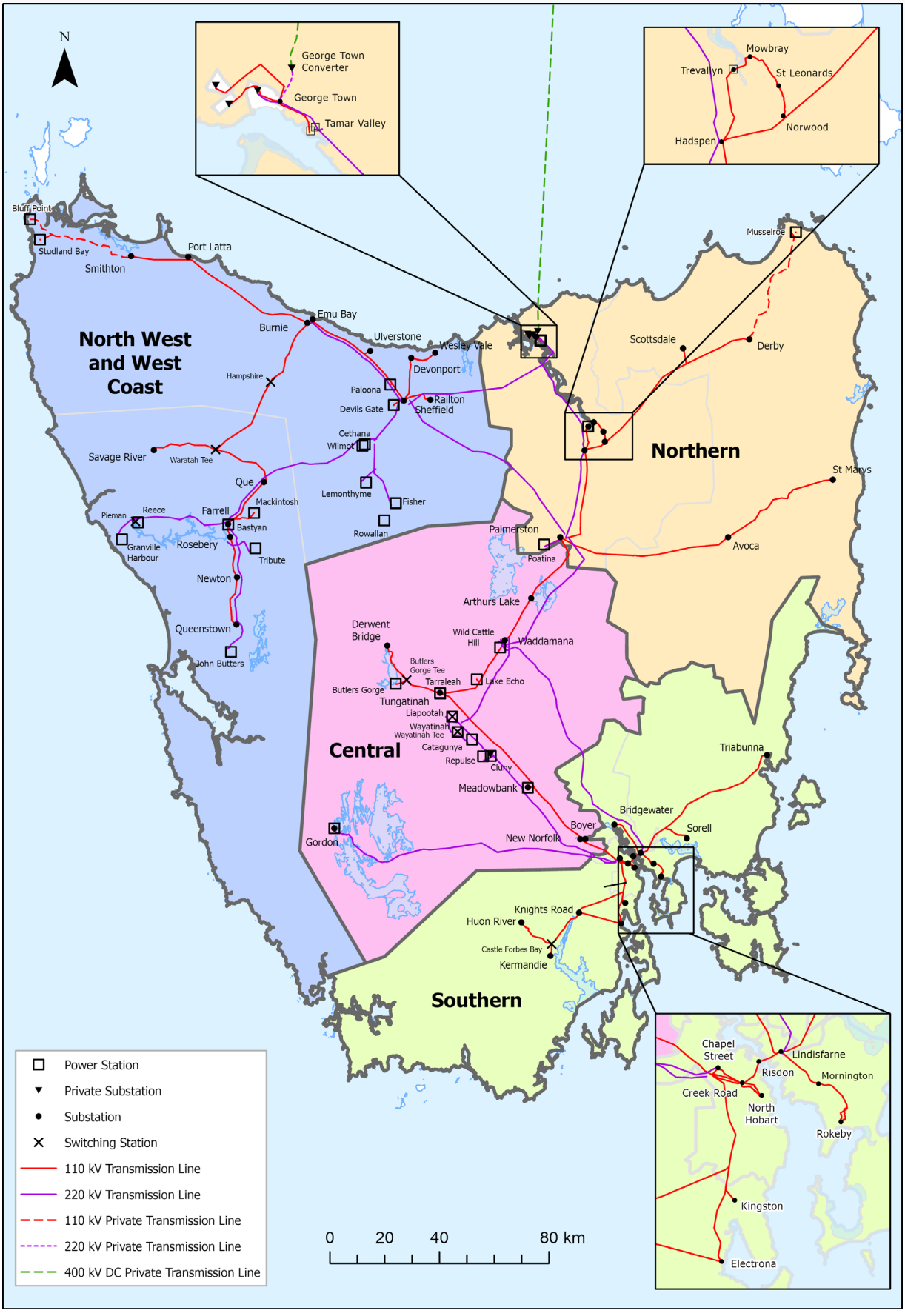


Figure 4-1: Geographical planning areas

4.2.1 North West and West Coast planning area

The North West planning area extends from Deloraine and Port Sorell, to Smithton and the far north-west. This area is supplied from the 220 kV backbone network at Burnie and Sheffield Substations. The West Coast planning area covers the network area supplied from Farrell Substation.

Customers comprise residential, commercial, and small to medium scale industries. There are two customers connected directly to the transmission network. Emu Bay Substation supplies part of the Burnie central business district and is the only 11 kV network in the area. The rest of the distribution network operates at 22 kV.

The West Coast planning area is characterised by mining loads, supplied from both the transmission and distribution networks, and tourism and aquaculture businesses. The area is supplied from the main transmission network at 110 kV from Farrell Substation (near Tullah), with a 110 kV transmission circuit from Burnie Substation available as an alternative supply. Rosebery Substation is supplied by two transmission circuits, with other substations radially supplied. Distribution feeders in the area are supplied from four substations and one zone substation, with no interconnection between substation supply areas.

There is a significant amount of transmission-connected generation in the North West and West Coast planning area. These include the Pieman and King-Yolande (through Farrell Substation) and Mersey-Forth (through Sheffield Substation) hydropower schemes, and wind farms in both the far north-west (Bluff Point and Studland Bay wind farms) and the west coast (Granville Harbour Wind Farm) of Tasmania.

4.2.2 Northern planning area

The Northern planning area is diverse, with urban and commercial centres in and around Greater Launceston and the Tamar, industrial load in and around George Town including major energy users connected directly to the transmission network, and large rural areas of the northern midlands, the north-east, and east coast of Tasmania.

The area is supplied from the backbone 220 kV transmission network at Hadspen, George Town, and Palmerston Substations. Hadspen Substation also provides a 110 kV supply to Launceston and north-east Tasmania, while Palmerston Substation provides supply to the northern midlands and east coast. George Town Substation predominantly supplies the industrial loads in the area and also provides the connection point for the Basslink HVDC interconnector.

Musselroe Wind Farm is connected to Derby Substation via a private 110 kV transmission line. Tamar Valley, Trevallyn, and Poatina Power Stations provide generation directly into the network at George Town, Trevallyn, and Palmerston Substations respectively.

4.2.3 Central planning area

The Central planning area covers the Central Highlands and Derwent Valley and includes a supply point at Strathgordon. The area is generally supplied from the 110 kV network between New Norfolk, Tungatinah (near Tarraleah), and Waddamana Substations.

The Central planning area supplies the Boyer paper mill (supplied directly from the transmission network) and the majority of the distribution-connected load in the New Norfolk township. The remaining substations supply low load density areas in the Central Highlands with limited, if any, transfer capability between feeders and substations.

The transmission-connected generation in the Central planning area is critical to supplying southern Tasmanian load, which includes the Derwent hydropower scheme connecting into both the 110 kV and 220 kV networks, as well as Gordon Power Station, which also connects at 220 kV. Wild Cattle Hill Wind Farm connects to Waddamana Substation.

4.2.4 Southern planning area

The Southern planning area covers the Greater Hobart region and the southern parts of Tasmania. The Greater Hobart area is mostly urban, with rural supplies to the outer southern reaches. Load in the Greater Hobart area is a mixture of commercial, major industrial, and urban residential loads.

The Southern planning area is supplied from three 220 kV connections emanating from Gordon, Liapootah, and Waddamana Substations which connect to Chapel Street and Lindisfarne Substations located on the outskirts of Hobart. Major 110 kV substations in the Hobart area include Creek Road and Risdon.

The Southern planning area is characterised by a substantial 33 kV sub-transmission network, along with zone substations that supply areas to the north, south, and east of Hobart. Urban areas are supplied through a highly interconnected 11 kV distribution network. This allows load transfers between substations in outage and emergency situations. Rural areas are generally supplied via long 11 kV feeders with limited interconnection; however, Sorell, and Triabunna Substations provide supply at 22 kV.

Areas to the east of Greater Hobart are supplied via the peripheral 110 kV network from Lindisfarne Substation. Areas to the south of Greater Hobart are supplied from the 110 kV network from Chapel Street Substation.

The southern part of Tasmania covers the area from Kingston to Southport, including Bruny Island and the Huon Valley. This area is supplied through a 110 kV double-circuit transmission line from Chapel Street Substation. The area contains a mix of coastal, rural, and urban townships as well as moderate agriculture and aquaculture commercial precinct developments.

4.3 Availability to connect to network

Table 4-1 provides the available firm headroom to accommodate new load at the time of Annual Planning Report (**APR**) forecast substation maximum demands at each connection point substation and sub-transmission substation. Substation capacity headroom is based on the 2026 forecast year for network demand, including contracted capacity and committed load developments, with applicable asset ratings applied. Hosting capacity depends on factors that include the rating of equipment at each connection point and upstream network, network stability, security, and reliability considerations.

The table (ordered by available capacity by planning area) also provides the total and firm capacity of each substation. For single-transformer substations and substations where existing demand already exceeds the firm capacity, the available headroom is zero.

Table 4-1: Substation available headroom by planning area.

Planning Area	Substation Name	Substation Voltage (kV)	Installed capacity (MVA) Total	Installed capacity (MVA) Firm	2026 Maximum demand (MVA)	Available headroom (MVA) Firm
North West and West Coast	Emu Bay	110/22	76	38	9	29
	Queenstown (22 kV)	110/22	50	25	5	20*
	Rosebery (44 kV)	110/44	102	66	47	19
	Wesley Vale	110/22	50	25	11	14***
	Ulverstone	110/22	90	45	31	14
	Smithton	110/22	70	35	22	13
	Queenstown (11 kV)	110/11	50	25	15	10*
	Trial Harbour Zone	44/22	40	20	12	8*
	Rosebery (22 kV)	44/22	16	6	2	4
	Port Latta	110/22	50	25	22	3
	Devonport	110/22	110	60	58	2
	Burnie	110/22	120	60	62	0
	Railton	110/22	100	50	55	0
	Savage River	110/22	45	22.5	23	0*
	Que	110/22	50	0	5	0*
	Sheffield	110/22	25	0	6	0
	Newton	110/22	22.5	0	4	0*
Northern	George Town	110/22	96	48	19	29
	St Leonards	110/22	120	60	32	28***
	Trevallyn	110/22	150	100	74	26
	Norwood	110/22	100	50	31	19
	Scottsdale	110/22	63	31.5	13	19
	Mowbray	110/22	100	50	38	12
	Palmerston	110/22	50	25	14	11
	St Marys	110/22	50	25	16	9
	Hadspen	110/22	100	50	57	0
	Avoca	110/22	17	0	10	0*
	Derby	110/22	25	0	6	0*
Central	New Norfolk	110/22	60	30	18	12
	Arthurs Lake	110/6.6	25	0	6	0*
	Meadowbank	110/22	25	0	8	0
	Derwent Bridge	110/22	6	0	<1	0*
	Tungatinah	110/22	13	0	<1	0
	Waddamana	110/22	4	0	<1	0

Planning Area	Substation Name	Voltage (kV)	Installed capacity (MVA) Total	Firm	2026 Maximum demand (MVA)	Available headroom (MVA) Firm
Southern	Kingston (33 kV)	110/33	120	60	13	47
	Creek Road	110/33	180	120	84	36
	Risdon	110/33	150	100	67	33
	Lindisfarne	110/33	120	60	33	27
	Sorell	110/22	120	60	35	25
	Chapel Street	110/11	120	60	37	23
	Sandy Bay Zone	33/11	90	60	29	21**
	West Hobart Zone	33/11	90	60	33	17**
	Triabunna	110/22	50	25	7	18
	Mornington	110/33	120	60	43	17
	Kermandie	110/11	50	25	9	16
	East Hobart Zone	33/11	90	60	27	16**
	Rokeby	110/11	70	35	23	12
	Bellerive Zone	33/11	45	22.5	10	10**
	North Hobart	110/11	90	45	34	11
	Electrona	110/11	50	25	15	10
	Kingston (11 kV)	110/11	70	35	26	9
	Howrah Zone	33/11	50	25	17	8**
	Geilston Bay Zone	33/11	45	22.5	18	4**
	Cambridge Zone	33/11	40	20	16	2**
	Claremont Zone	33/11	50	25	21	0**
	Knights Road	110/11	40	20	20	0*
	Bridgewater	110/11	70	35	36	0*
	Derwent Park Zone	33/11	45	22.5	19	0**
	New Town Zone	33/11	45	22.5	21	0**
	Rosny Park Zone	33/11	25	0	16	0*
	Huon River	110/11	25	0	1	0*
	Summerleas Zone	33/11	25	0	12	0*

* Non-firm transmission or sub-transmission network connection

** Headroom due to an applied sub-transmission network constraint

*** Not available until 2028 due to interim load connection

4.4 Completed and committed projects

Table 4-2 presents the material network projects that are committed or that have been completed since our 2025 APR for each planning area. Our definition of 'committed' is as used in the Regulatory Investment Test (**RIT**). We will report on the progress of our committed projects in future APRs.

Table 4-2: Completed and committed projects

Planning Area	Project and description
Completed	
North West and West Coast	Zeehan reliability improvement (44 kV sub-transmission line switching augmentation).
Committed	
North West and West Coast	Emu Bay Substation new 22 kV distribution line.
Northern	Palmerston Substation new 22 kV distribution line.
Southern	Knights Road to Huonville (North)-Ranelagh-Judbury-Lonnavale 22 kV distribution line.

4.5 Network limitations and developments

The network limitations and development section provides details of our proposed augmentation projects over the next ten years which address forecast network limitations. Network limitations are identified under the Step Change scenario of the load forecast (refer Section 2.2.). We identify points on the network that are unable to meet forecast generation or demand due to limited thermal capacity, a jurisdictional network planning requirement or other technical limits. Reliability planning criteria are presented in Appendices A.3.3 (transmission) and A.3.4 (distribution).

Table 4-3 provides information on the type of limitation and our preferred network solution, with estimated timing and cost. We also identify other potential solutions wherever practical. We identify the opportunity for demand management solutions where a controlled reduction in load or improvement in power factor may defer the need for expenditure. None of our proposed network developments will have a material inter-network impact.

We provide additional information on all connection point and transmission line limitations as supplementary information published as 'Transmission annual planning report data' and 'Distribution system limitations report'. These reports are required as part of publishing the APR and provide additional information on identified limitations, including geographic location, energy and demand requirements, identifying load at risk, and deferral value of projects, among others. The reports are provided to enable consistency of information for readers when comparing APRs of different transmission and distribution network service providers across the National Electricity Market (**NEM**).

The reports are available as a downloadable appendix from our website: www.tasnetworks.com.au/apr

Table 4-3: Network limitations and proposed solutions

Planning Area	Limitation	Deferral requirement (MVA)		Proposed solution or options considered	Timing	Cost ($M)
		1 year	5 years			
Northern	**Palmerston–Avoca 110 kV transmission line** From 2031, loss of Palmerston–Avoca 110 kV transmission line may result in 25 MW load interruption to Avoca and St Marys substations. This will not meet the jurisdictional network planning requirements.	0.6	1.4	Distribution solutions to unload St Marys Substation and reduce the load at risk. Non-network solutions to reduce load interruption following contingency events. Transmission augmentation option not credible given low level of load at risk.	2031	N/A
North West and West Coast	**Sheffield–Devonport–110 kV transmission line** From 2028 with forecast new industry load growth, loss of double-circuit Sheffield—Devonport 110 kV transmission line may result in 3,000 MWh of unserved energy from Devonport and Wesley Vale Substations. This will not meet the jurisdictional network planning requirements.	33	37	Due to nature of the new industry load growth, exemption from the jurisdictional network planning requirements may be appropriate. Transmission augmentation to provide alternative suppl path through third 110 kV circuit to supply area.	2028 2031	No cost 56
	Sheffield 220/110 kV network transformers From 2031 with forecast new industry load growth, loss of one 220/110 kV network transformer at Sheffield Substation may exceed the rating of the remaining unit and result in 25 MW load interruption. This will not meet the jurisdictional network planning requirements.	15	30	Install a third 220/110 kV network transformer at Sheffield Substation.	2031	12

Planning Area	Limitation	Deferral requirement (MVA)		Proposed solution or options considered	Timing	Cost ($M)
		1 year	5 years			
North West and West Coast	**Farrell–Rosebery 110 kV transmission line and Farrell–Rosebery–Newton–Queenstown 110 kV transmission circuit** By 2029, forecast mining load increases at Rosebery and Queenstown Substations will mean: loss of double-circuit Farrell–Rosebery 110 kV transmission line will result in 3,000 MWh of unserved energy from Rosebery, Newton and Queenstown Substations. loss of Farrell–Rosebery–Newton–Queenstown 110 kV transmission circuit will interrupt 25 MW of load from Newton and Queenstown Substations. This will not meet the jurisdictional network planning requirements.	Not practical due to nature of network and load		Transmission network augmentation solutions to increase supply diversity. Due to nature of mining load, and that increases are from existing customers, exemption from the jurisdictional network planning requirements may be appropriate.	TBD	TBD
Southern	**Southern area voltage stability** From 2033, voltage stability is at risk when southern transmission area load reaches 825 MW.	5	25	Install 2 x 40 Mvar capacitor banks in southern area	2033	10

4.6 Future connection points

We consider future transmission-distribution connection point requirements over the planning period for each planning area. Presently, we are not forecasting any future connection points; however, we would include the location and description of future connection points, along with future loading levels and estimated timing and costs.

4.7 Targeted reliability corrective action

We undertake large individual targeted reliability improvement projects that may require significant investment. Currently we are continuing to progress the Zeehan community reliability project.

Programs associated with distribution reliability community performance, compliance, and corrective action are presented in Chapter 6.

Table 4-4: Targeted reliability corrective action

Reliability community	Description
Zeehan	Zeehan reliability community is supplied from a single 22 kV distribution line from Trial Harbour Zone Substation, with that site being supplied via a single 35 km, 44 kV sub-transmission line from Rosebery Substation. Alternative supply is only available on the sub-transmission line for the first 10 km up to Renison Bell. We are continuing to undertake a program of works to improve supply reliability to meet the standard. In recent years we completed the installation of additional mobile generation support and have installed additional switching capability between the 44 kV sub-transmission lines. We propose one further initiative to improve supply reliability, comprising the installation of a semi-permanent diesel micro-grid for back-up supply for loss of the 44 kV sub-transmission line or 22 kV distribution line. The project is forecast for completion by June 2028 and is estimated to cost $3.8 million.

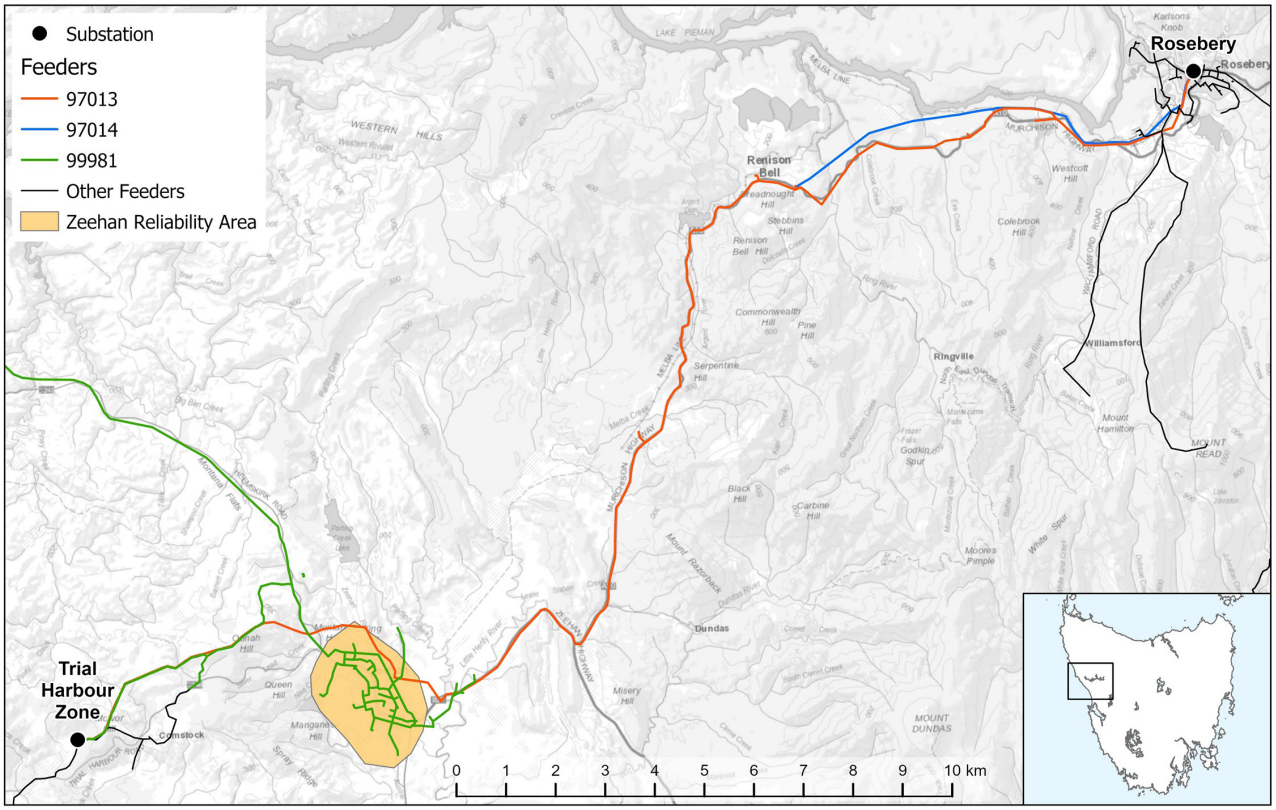


Figure 4-2: Zeehan reliability community

4.8 Deferred or averted limitations

4.8.1 Exemptions under jurisdictional network planning requirements

We have exemption agreements with affected customers permitted under the jurisdictional planning requirements. All relate to radial transmission supplies, where loss of the circuit may result in more than 300 MWh of unserved energy, and/or loss of 25 MW of load. Table 4-5 presents the assets for which we have agreed exemptions.

Table 4-5: Jurisdictional network planning requirement exemptions

Planning area	Asset	Location of affected customers	Performance requirement	Exemption ceases
North West and West Coast	Farrell–Rosebery–Newton–Queenstown 110 kV transmission circuit	Newton and Queenstown Substations	Loss of circuit may exceed 300 MWh of unserved energy.	Previous exemption under renewal
	Newton Substation supply transformer	Newton Substation	Loss of supply transformer may exceed 300 MWh of unserved energy.	Previous exemption under renewal
	Waratah–Savage River 110 kV transmission circuit section	Savage River Substation	Loss of circuit section may cause loss of 25 MW of load and may exceed 300 MWh of unserved energy.	2028
	Farrell–Que–Hampshire–Savage River 110 kV transmission circuit	Que and Savage River Substations	Loss of circuit may cause loss of 25 MW of load and may exceed 300 MWh of unserved energy.	2028

Our agreements exist on the basis that the affected customers have agreed there is insufficient benefit for a network augmentation solution to address these limitations. We are thus exempt under clause 8(4) of the network planning requirements from planning the network to meet this requirement. The exemption will cease by the dates identified in Table 4-5, or when an affected customer considers remedial action has sufficient benefit, or circumstances have materially changed. We do not consider that the circumstances have materially changed since the exemption period commenced and will consult the relevant customers at the time the current agreement ends.

4.8.2 Chapel Street–Kingston 110 kV transmission line limitation

Our 2025 APR identified a limitation on the Chapel Street–Kingston 110 kV transmission line, where from 2031 loss of the double-circuit line would result in more than 3,000 MWh of unserved energy—in excess of our jurisdictional network planning requirements. Under the load forecast used in this 2026 APR, this limitation is deferred past the 10 year planning period and is no longer reported in the APR. We will continue to monitor the potential limitation into the future.

4.9 Other factors affecting the network

4.9.1 Fault levels

Network fault level is defined in terms of apparent power (mega-volt ampere (**MVA**)) or electrical current (usually expressed in kilo-amperes (**kA**)). The short-circuit fault current, defined at a given point in the network, is the current that flows if a solid fault occurs at that particular location. Determining the maximum fault currents within our network is important for the appropriate selection of equipment such as circuit breakers, switchgear, cables, and busbars.

This equipment is designed to withstand the thermal and mechanical stresses experienced due to the high currents that occur during short circuit conditions.

We require new connecting circuit breakers to meet a minimum fault clearance capability. For all voltage levels, circuit breakers require a minimum symmetrical three-phase fault current withstand capability of 25 kA for 1 second for connection to our transmission network. For the high-voltage side of our distribution network, it is 16 kA for 1 second.

Fault level data, a technical description of fault level quantities and our calculation methodology, are provided as a downloadable appendix and are available on our website:

www.tasnetworks.com.au/apr

Fault level data includes the existing maximum and minimum three-phase and single-phase fault levels, and positive, negative, and zero sequence impedances, at all transmission substation busbars.

4.9.1.1 Connection point fault levels

Within our network, the maximum allowable fault current contribution at transmission-distribution connection points has historically been 13 kA. This has been determined on the assumption that the distribution network design fault current limit is 16 kA, with a 3 kA contribution margin allowed from any embedded generation that is not explicitly accounted for in network studies. We have a number of connection points where the maximum fault current contribution from the transmission network exceeds 13 kA, listed in Table 4-8. These sites are managed through appropriate operational strategies that we review as network changes occur.

Additional fault level constraints exist at two connection points. At Smithton Substation, a distribution earthing issue has required the fault level to be reduced until corrective action can be implemented. There is also a fault level limitation at Port Latta Substation to comply with a customer connection agreement.

Table 4-6 presents the operational procedures in place to manage the fault level issues at these connection points in the meantime.

Table 4-6: Transmission-distribution connection points with open bus coupler

Substation (voltage [kV])	Issue	Management strategy
Bridgewater (11)	Fault level exceeds 13 kA	11 kV bus coupler operated normally open with auto-close scheme to immediately restore supply to the other busbar following a supply transformer contingency.
Chapel Street (11)		
Kingston (11)		
Rokeby (11)		
Electrona (11)		
Smithton (22)	Distribution earthing issue	Bus coupler operated normally-open until a corrective action can be implemented.
Creek Road (33)	Fault level exceeds 13 kA	Supply transformer incoming circuit breaker opened when fault current exceeds 13 kA, with auto-close scheme to re-connect transformer following a contingency involving one of the other supply transformers.
Trevallyn (22)		
Port Latta (22)	Customer connection agreement	22 kV Port Latta bus coupler operated normally-open due to the rating of a 3.3 kV customer switchboard and at least one circuit breaker.

4.9.1.2 System strength

MVA fault levels are used as a proxy to define the strength of the power system during normal operation. Minimum fault levels may be used to determine the appropriateness of a connection point to accommodate a new load, or for planned switching considering impacts on voltage transients and power quality. Connection points with higher fault levels experience lower levels of voltage flicker for load switching events, compared to those with low fault levels.

Conventional high voltage direct current (**HVDC**) interconnection and inverter- based resources (**IBR**) such as wind and solar-photovoltaic (**PV**) farms require a certain level of system strength at their connection point. Basslink and the existing wind farms in Tasmania have 'absorbed' much of the available system strength in their locality.

Under the National Electricity Rules (**the Rules**), AEMO publishes a forecast of future system strength requirements, based on a projection of new IBR in the system. TasNetworks as the designated System Strength Service Provider (**SSSP**) is now responsible for addressing these future requirements.

Details of the system strength framework are outlined in Chapter 5.

4.9.2 Voltage management

Maintaining voltages within target ranges ensures the safety of our people and equipment, contributes to the efficient and secure operation the power system, and quality of supply to our customers. Exceeding the upper voltage limit may result in insulation breakdown and subsequent equipment damage. Operating below the lower limit impacts on power quality and could cause fuses to blow or equipment to trip.

We have a number of constraint equations to ensure transmission voltages are maintained within target ranges. Details of constraint equation performance is provided in Chapter 5.

Voltage management is a critical component of power quality, impacting all our customers. Voltage management in our distribution network is considered part of power quality. The network-wide and localised voltage limitations due to PV installations are detailed in Appendix A.7.

Schedules 5.1a (System Standards) and 5.1 (Network Performance Requirements to be provided or Coordinated by Network Service Providers) of the Rules describe the planning, design, and operating criteria applied to our transmission network for power quality. The quality of supply standards relevant to the distribution network are detailed in AS/NZS 61000 Electromagnetic compatibility (**EMC**), and Chapter 8 of the Tasmanian Electricity Code (**the Code**). Our published planning limits are available via the Power Quality Planning Levels document on the TasNetworks website at:

https://www.tasnetworks.com.au/Poles-and-wires/Planning-and-developments/Planning-our-network

4.9.3 Ageing and potentially unreliable assets

There are many ageing assets within our network and we undertake routine maintenance to reduce the probability of equipment failure. Factors that may impact on ageing and potentially unreliable assets are:

- location (whether the assets are located indoors or outdoors);
- operation (load utilisation, frequency of use, and load profiles); and
- condition.

These are managed as part of our asset management strategy and are discussed in Appendix A.4.

4.10 Network asset retirements and replacements

This section presents our forecast network asset retirements over the next 10 years. Almost all retirements are due to assets reaching their end of service life based on condition. These are identified through our asset management process, outlined in Appendix A.4.

Following asset retirement, investment is almost always needed to maintain service levels. When investment is required, we present the proposed solution, with forecast timing and cost, along with any other potential solutions considered. We welcome feedback on prospective alternative solutions.

We do not have any planned de-rating of network assets over the next 10 years.

Table 4-7: Network asset retirements and replacements – overhead lines and cables

Proposed	Timing	Cost ($M)
George Town–Temco 110 kV transmission line retirement	2027	Nil[45]
Risdon–East Hobart 33 kV sub-transmission cable	2027	3.0
Creek Road–Claremont 33 kV sub-transmission cable	2030	3.1
Risdon–New Town 33 kV sub-transmission cable	2031	2.2
Creek Road–Sandy Bay 33 kV sub-transmission cable	2032	1.7
Lindisfarne–Bellerive 33 kV sub-transmission cable	2032	2.7

Table 4-8: Network asset retirements and replacements – power transformers

Completed		
St Marys Substation supply transformers		
Proposed	**Timing**	**Cost ($M)**
Transmission substations		
Sheffield Substation network transformer T1	2027	10.7
Rosebery Substation supply transformers and associated asset replacement	2028	17.5
Boyer Substation		
Supply transformers T13 and T14	2030	10.0
Supply transformer T2	2030	3.0
Savage River Substation supply transformers	2032	8.0
Burnie Substation supply transformers	2033	10.0
Wesley Vale Substation supply transformers	2033	8.0
Zone substations		
Derwent Park Zone Substation supply transformers	2030	3.5
Bellerive Zone Substation supply transformers	2031	3.5
Geilston Bay Zone Substation supply transformers	2033	3.5

45 Nil capital expenditure—some operational expenditure will be incurred in retiring the transmission line.

Table 4-9: Network asset retirements and replacements – switchgear and instrument transformers

Completed		
George Town Substation 220 kV disconnectors		
Wesley Vale Substation 110 kV disconnectors		
Sorell Substation 22 kV switchgear		
Chapel Street Substation 11 kV switchgear		
Savage River Substation 110 kV disconnectors and gantry		
Committed		
Rosebery Substation 44 kV switchgear		
Sheffield Substation 220 kV disconnectors and current transformers		
Sheffield Substation 110 kV disconnectors		
Bridgewater Substation 110 kV circuit breakers		
Proposed	**Timing**	**Cost ($M)**
Boyer Substation 6.6 kV switchgear	2030	7.0
Kingston Substation 110 kV circuit breakers	2033	4.5
Knights Road Substation 11 kV switchgear	2032	5.5

Table 4-10: Network asset retirements and replacements – protection and SCADA

Completed		
Statewide SCADA Gateway RTU program planned for FY2025		
Statewide protection relay program planned FY2025		
Planned protection upgrade with primary asset replacements FY2025		
Committed		
Statewide SCADA scheme (part replacements Gateway RTU only) FY2026 to FY2029		
Statewide protection relay replacement program FY2026 to FY2029		
Protection upgrade with statewide primary asset replacement program FY2026 to FY2029		
Proposed	**Timing**	**Cost ($M)**
Protection spares replenishments	2025–29	7.1
SCADA replacements	2025–29	13.9

Table 4-11 presents our investments in state-wide asset programs classified by network and asset class over the planning period to 2035. These investments are predominantly replacement programs for assets we have identified to be retired due to reaching end of life because of asset condition, economics, obsolescence, and other factors defined in our asset management strategies. For these assets, our proposed solution is to replace the asset like-for-like with new, modern equivalents. No other credible potential options have been identified. This forecast is currently under review as part of our 2029-34 revenue reset process.

Table 4-11: State-wide asset investment programs (cost in $M)

Network, asset class and description	2025–26	2026–27	2027–28	2028–29	2029–30	2030–31	2031–32	2032–33	2033–34	2034-35
Distribution Network										
Distribution Overhead										
Asset replacement and refurbishment	28.5	29.5	30.6	30.5	30.9	30.9	30.9	30.9	30.9	30.9
Initiatives to limit the potential of assets initiating bushfires	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Innovations and equipment trials	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Threatened bird species fatality mitigation	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
High Voltage Regulators										
Asset replacement and refurbishment	0.9	0.3	0.9	0.3	0.9	0.3	0.9	0.3	0.9	0.9
Safety and environmental programs	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
High Voltage and Low Voltage Cables										
Asset replacement	1.5	2.5	2.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Ground Substations										
Asset replacement and refurbishment	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2
Safety and environmental programs	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Low Voltage Services										
New and replacement of assets to customer installations	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
New and replacement of public lighting assets	3.5	3.5	3.9	3.9	1.6	1.6	1.6	1.6	1.6	1.6
Meter panel replacement	1.5	1.5	0.4	0	0	0	0	0	0	0
Transmission Network										
Transmission Lines										
Asset replacement and refurbishment	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3
Substandard clearance rectification	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Transmission Substations										
Asset replacement and refurbishment	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8
Protection and Control (distribution and transmission)										
Asset replacement	4.0	4.0	4.2	4.4	8.0	16.0	16.0	16.0	16.0	16.0
Network Control Systems (distribution and transmission)										
Asset replacement	0.4	0.4	0	0.4	0.4	0	0.4	0.4	0.0	0.0

4.11 Investments in operational support systems and telecommunication systems

4.11.1 Operational support system programs

Operational support system programs are critical in enabling us to improve our performance, efficiencies, and effectiveness in asset management and network operation. Operational support systems comprise network operational control systems (**NOCS**) and asset management systems (**AMS**). Elements of focus for successful information system programs are people, processes, data, and technology. The objectives of the AMS program are:

- to manage risk of asset failure;
- to enhance network performance;
- compliance with regulatory and governance requirements;
- effective collection and management of asset knowledge;
- effective resource utilisation;
- optimum infrastructure investment; and
- understanding risk at an individual asset level and asset portfolio level.

We are continuing to build a network digital twin service to provide spatial, situational, and temporal network data across the transmission and distribution networks, funded through increased productivity and cost savings realised across the transmission and distribution capital and operating programs.

Investment within the NOCS is required to ensure that we can:

- operate the Tasmanian transmission system on a standalone basis, should the provision for Residual Power System Security (**RPSS**) be invoked;
- provide operating and market interfaces between AEMO and Tasmanian market participants; and
- provide a suite of online network modelling tools to assist us in ensuring the network is operated within its technical envelope.

This section details our investments in regulated operational support system programs in the transmission and distribution networks.

Our regulated investments in operational support system programs in 2025-26 are summarised in Table 4-12:

Table 4-12: Regulated investment in operational support systems in the past year

Completed Projects	Description	Investment ($M)
Enterprise geographical information system strategy implementation	Consolidation and modernisation of the geographical information system and capability.	0.4
Asset risk management	Develop and enhance systems and models to assess asset criticality and failure probabilities, improving life-cycle management of network assets. It will enable key information about assets to be analysed and presented quantitatively.	1.1
Advanced Distribution Management System	Implementation of the fully integrated OSI Monarch Outage Management System to replace existing legacy systems. Delivery of real time integration between the Distribution Management System and Outage Management System and implementation of low-voltage Connectivity Model to manage customer outages.	1.35
Energy management system and distribution management system upgrade	Upgrade of the real-time system to current versions to provide new capability, improve cyber-security and resolve product defects.	0.29

Our planned investments in operational support system programs in the forward planning period to 2035-36 are summarised in the Table 4-13.

Table 4-13: Operational support systems expected investment forward planning period

Project	Description	Investment ($M)
Enterprise geographical information system strategy implementation	Consolidation and modernisation of the geographical information system and capability.	6.0
Advanced Distribution Management System	Implementation of the fully integrated OSI Monarch Outage Management System to replace existing legacy systems. Delivery of real time integration between the Distribution Management System and Outage Management System and implementation of low-voltage Connectivity Model to manage customer outages.	5.65
Asset risk management	Develop and enhance systems and models to assess asset criticality and failure probabilities, improving life-cycle management of network assets. It will enable key information about assets to be analysed and presented quantitatively.	5.2
Energy management system and distribution management systems	Upgrade and enhancement of the real-time systems to current versions to provide new capability, improve cyber-security, and resolve product defects.	31

4.11.2 Telecommunications systems

The telecommunications network supports operation of the electricity network through interfacing protection, control and data, telephone handsets, and mobile radio transceivers. It also serves customers in the electricity supply industry and is utilised by other parties under commercial agreements. The telecommunications assets comprise communications rooms and associated ancillary equipment within substations and administrative buildings, optical fibre on transmission and distribution lines, underground optical fibre, digital microwave radios and associated repeater stations.

This section details our investments in regulated telecommunications systems programs in the distribution and transmission networks.

Our regulated investments in telecommunications systems programs in 2025–26 are summarised in Table 4-14:

Table 4-14: Regulated investment in telecommunications systems in the past year

Project	Description	Investment ($M)
Infrastructure	Telecommunication sites	0.5
Bearer and management systems	Backbone bearers and Network Management Systems	0.3
Multiplexer systems	Multiplexer systems in the networks	0.4
Ethernet systems	Ethernet systems within the network	0.2

Our planned regulated investments in telecommunications systems programs in the forward planning period to 2035–36 are summarised in Table 4-15. The majority of these are ongoing programs, with the investment commitment over the duration of the program.

Table 4-15: Regulated investment in telecommunications systems in the forward planning period

Project	Description	Investment ($M)
Infrastructure	Telecommunication sites	4.1
Bearer and management systems	Backbone bearers and Network Management Systems	14.2
Multiplexer systems	Multiplexer systems in the networks	0.3
Ethernet systems	Ethernet systems within the network	3.4



Chapter 5

Network security performance

- Tasmania continues to be in a situation where it is theoretically possible to meet 100% of Tasmania's operational demand from inverter-based resources (**IBR**), predominantly comprising wind farm generation and Basslink import. As more non-synchronous generation is introduced into the network in the future, careful management of power system security continues to be a high priority.
- Modelling associated with Australian Energy Market Operator's (**AEMO**) 2026 Integrated System Plan (ISP) forecasts ongoing shortfalls for both system strength and inertia network services in the Tasmanian region. Contractual arrangements to address existing shortfalls are currently in place until June 2029.
- The National Electricity Rules (**the Rules**) framework for managing system strength introduced significant new obligations for System Strength Service Providers (SSSP) which commenced on 2 December 2025. TasNetworks is the SSSP for the Tasmanian region of the National Electricity Market (**NEM**). This framework introduced a new approach for the procurement and payment of system strength services, including proactive planning obligations for SSSPs which now form part of the System Standards within the Rules.
- We published the Project Assessment Conclusions Report (**PACR**) to address system strength requirements in Tasmania from 2 December 2025 confirming that the preferred option is to contract with existing owners of synchronous condensers and generation assets. Contractual agreements will meet the system strength requirements until June 2029.

5.1 Introduction

Power system security involves the continuous, safe scheduling, operation, and management of the power system according to the guidelines outlined in Chapter 4 of the Rules. An increasingly significant factor affecting power system security is the displacement of synchronous generation on account of rising penetration of Inverter Based Resources (**IBR**), which include wind and solar-photovoltaic (**PV**) power, along with power transfers via High Voltage Direct Current (**HVDC**) interconnectors. The decline in the dispatch of synchronous generation occasionally leads to very low levels of inertia and system strength over expanding areas of the NEM.

In Tasmania, the installed capacity of IBR sources, mainly wind and imports through the Basslink HVDC interconnector, can sometimes meet a large proportion of the State's operational demand,[46] resulting in limited dispatch of synchronous generation. This issue is particularly relevant in Tasmania, where hydroelectric power is predominant. Unlike large thermal plants that are not ideal for load cycling or quick shutdowns and restarts, hydroelectric generation is relatively flexible. This flexibility, as shown in Figure 5-1, allows for water conservation when IBR sources are available and cost-effective. However; it also presents challenges because the inherent system security services provided by large synchronous hydro units are reduced when these units are withdrawn from the grid.

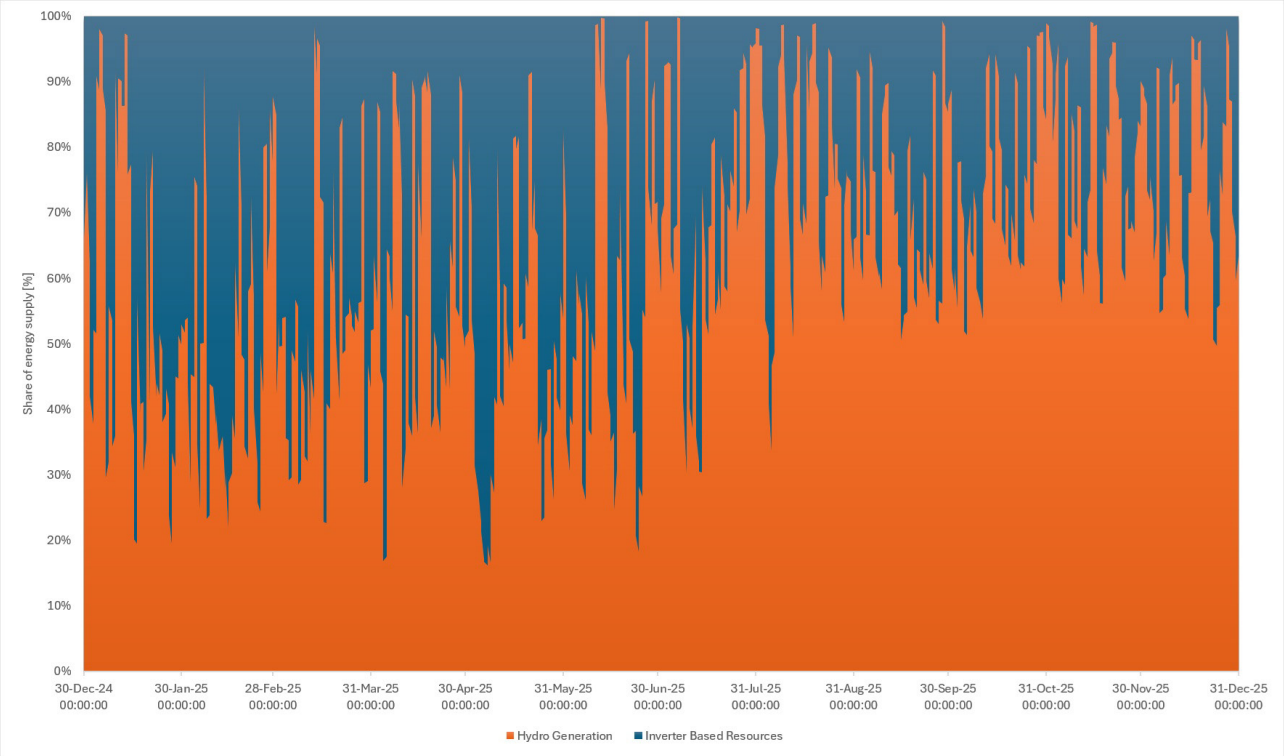


Figure 5-1 Tasmanian Electricity supply mix for the year 2025

TasNetworks remains focused on the ongoing management of power system security, addressing the impacts of a changing generation mix. The following discussions highlight the outcomes and observations from the past year and offer insights into planned and current work programs.

46 Operational Demand - https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/data-nem/operational-demand-data

5.2 Updates on operational activities and specific events

5.2.1 System non-synchronous penetration ratio

TasNetworks employs the System Non-Synchronous Penetration (**SNSP**) ratio as a key metric to assess and manage challenging network operating conditions. This ratio indicates the extent to which Tasmania's operational demand is met by wind generation and imports through Basslink, as compared with synchronous generation. As the SNSP ratio increases, there is a greater likelihood that real-time operator actions will be necessary to address issues such as low inertia and system strength. Consequently, contracted services may be required to ensure the security of the power system, as elaborated in later sections of this Chapter.

A summary of key SNSP statistics over the last three financial years are provided below in Table 5-1.

Table 5-1: SNSP statistics using system measurements having a 5-minute data resolution

Measure	2023–24	2024-25	2025-26
Peak SNSP recorded	88.7%	93.7%	77.9%
99th Percentile	80.9%	80.9%	68.1%
95th Percentile	73.4%	73.4%	55.0%
50th Percentile	40.2%	44.6%	25.1%

This year's SNSP statistics saw a significant reduction when compared to previous years due to the voluntary administration of one of Tasmania's largest loads, Liberty Bell Bay, and Basslink's status then as an unregulated Market Network Service Provider (**MNSP**), affecting its import and export operation (refer to section 5.5). This trend; however, is not set to continue due to the reclassification of Basslink as a regulated Transmission Network Service Provider (**TNSP**) from 1 July 2026.[47] Additionally, as more wind and PV power becomes integrated into Tasmania's energy mix in the coming years, and with the integration of Marinus Link in early 2030, the likelihood of encountering higher SNSP conditions will inevitably rise. In coordination with various initiatives across the NEM, we are actively exploring what is necessary to eventually allow the Tasmanian power system to operate at 100% instantaneous IBR.

5.2.2 AEMO Engineering Roadmap to 100% Renewables

Since 2021, TasNetworks has been actively involved in the NEM Engineering Framework Review.[48] This NEM-wide initiative was launched in response to projections indicating that *"the instantaneous penetration of renewables is increasing rapidly and, with proper preparation, could occasionally reach up to 100% by 2025."* In crafting their initial roadmap, AEMO highlighted that *"urgent and extensive industry collaboration and effort are required to engineer the power system to adapt to these new conditions in a timely and orderly manner, prioritizing positive consumer outcomes in all decision-making."*

AEMO's latest update, titled *"Engineering Roadmap to 100% Renewables – FY2026 Priority Actions,"* [49] outlines the activities AEMO plans to undertake in the 2025–26 financial year (FY2026) to help advance the operational capability of the NEM for times of high renewables contribution. We are collaborating closely with AEMO on this initiative and have published the report *"100% Inverter Based Resource Generation Study – Tasmania Region."*[50] This document outlines the results of an extensive study that identifies key system security and reliability challenges when operating the Tasmanian network without synchronous generation.

The summary of our report indicates that maintaining network frequency control—encompassing both primary frequency regulation and contingency service management—will be challenging in a future energy mix that may at times lack synchronous generation. Additionally, managing the rate of change of frequency (**ROCOF**) poses challenges, as TasNetworks currently lacks a mechanism to request inertia above the secure inertia level of 3,800 MW.s. As we look ahead, the potential system security enhancements from large-scale Battery Energy Storage Systems (**BESS**) and the Marinus Link are under consideration in these investigations.

47 https://www.aemo.com.au/initiatives/major-programs/nem-reform-program/nem-reform-program-initiatives/basslink-determination-participant-support-arrangements

48 Details available at: www.aemo.com.au/en/initiatives/major-programs/engineering-framework

49 engineering-roadmap-fy2026-priority-actions-report.pdf

50 https://aemo.com.au/-/media/files/initiatives/engineering-framework/2023/tasmania-100-percent-ibr-generation-study.pdf?la=en

This effort is closely aligned with the State's goals to double its renewable energy generation by 2040, as outlined in the Tasmanian Renewable Energy Target (**TRET**). Given that the TRET is expected to be fulfilled by a mix of new wind and PV generation, understanding the engineering required to achieve these practical outcomes is essential.

5.3 Important changes to power system security management

5.3.1 Rules framework for managing system strength

On 21st October, 2021, the AEMC finalised a Rule change determination for the *"Efficient Management of System Strength on the Power System."*[51] The new Rules established a System Standard and essentially a transmission network planning standard to govern the provision of system strength across the NEM. This Rule change imposed a proactive obligation on each SSSP to plan for and ensure there is sufficient system strength available to support anticipated levels of IBR connecting to the power system. TasNetworks is the SSSP for the Tasmanian region of the NEM.

A key aspect of the framework is the requirement for SSSPs to guarantee that both the defined minimum and *efficient levels of system strength* are met independently of any coincidental system strength services provided by generators while operating in the energy market. As a result, SSSPs are mandated to procure the entire amount of system strength necessary to meet the standard.

Figure 5-2 illustrates the practical implications of the Rule change. Under this framework, TasNetworks is accountable for securing the full volume of system strength needed to achieve both the minimum three-phase fault level requirement and the *efficient level of system strength* simultaneously. Previously, regulatory arrangements only required procurement of the shortfall volume as identified by AEMO.

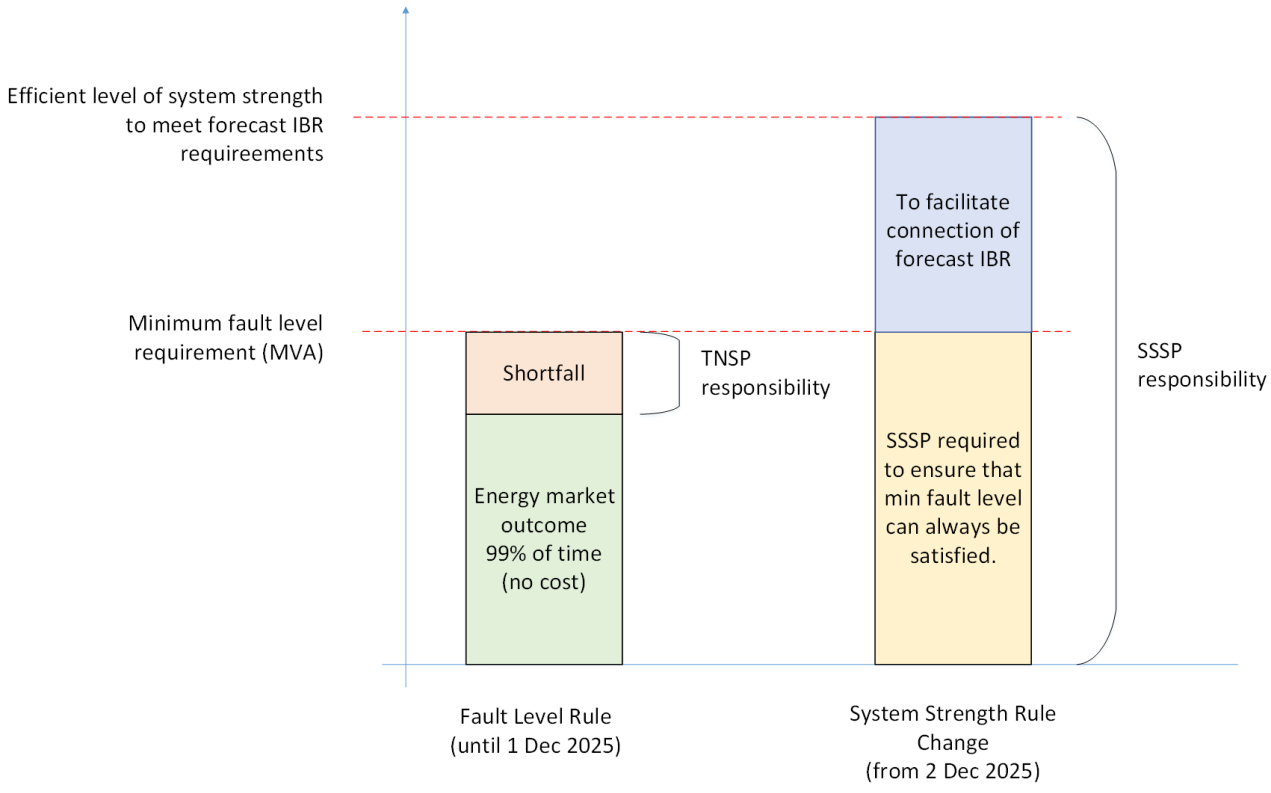


Figure 5-2: Comparison of system strength Rule frameworks

To enhance system security as the NEM transitions towards a low emissions power system, the AEMC introduced the Improving Security Frameworks (**ISF**) Rule in March 2024. The ISF does not take away responsibility from SSSPs to procure the entire system strength requirements as illustrated above but has enhanced frameworks for the management of system strength and inertia. This is discussed further in section 5.3.3.

51 Available at https://www.aemc.gov.au/rule-changes/efficient-management-system-strength-power-system

5.3.2 Regulatory changes impacting System Strength and Inertia reporting

The "National Electricity Amendment (Improving security frameworks for the energy transition) Rule 2024" (ISF Rule), published by the AEMC in March 2024, aims to enhance system security frameworks and equip AEMO with new tools to manage power system security during the energy transition in the NEM. Effective from 1 December 2024, the ISF Rule included inertia network services and system strength services under the Network Support and Control Ancillary Services (NSCAS) framework, providing a regulated procurement mechanism for these needs. Transmission Network Service Providers (TNSPs) have three years to deliver any forecast requirements for inertia or system strength, with AEMO able to declare and procure shortfall services if requirements change within this period.

The rule also enhances existing power system security procurement frameworks to address system security issues during the energy transition, aiming to reduce the inefficient use of directions and incentivise long-term investments in system security. It increases transparency of current system security needs and outlines how AEMO plans to manage security as the power system transitions to low- or zero-emissions. The rule evolves existing frameworks to ensure sufficient security services are provided as the system integrates more IBRs, allows AEMO to procure and enable necessary security services in operational timeframes, supports trials of new security methods, and requires AEMO to report on its security management plans.

5.3.3 Transition plan for System Security

AEMO published its first annual Transition Plan for System Security[52] to address new obligations from the ISF Rule change in March 2024. This plan aims to maintain power system security in the NEM during the transition to a low-emissions power system. It complements AEMO's Integrated System Plan (**ISP**), System Security reports, and the Engineering Roadmap program.[53] The Transition Plan outlines a structured approach to navigate key transition points and defines the capabilities needed to achieve system security in a low-emissions environment, specifying the required services and technologies.

The plan introduces a new Transitional Services procurement framework to meet the Transitional Services Objective. This includes "Type 1" contracts for essential services that cannot be provided through existing frameworks and "Type 2" contracts to trial new security services or applications of existing technologies. AEMO has also released a Transitional Services Guideline to develop a procurement approach for these services, ensuring they complement but do not replace other security services.

To maintain system security throughout the energy transition, the Transition Plan details planning processes over short-term, medium-term, and long-term horizons.

Horizon 1 focuses on operational planning for known transition points over the next two years using current assets and technology.

Horizon 2 identifies potential future transition points within two to five years, enabling early preparation and defining required security capabilities.

Horizon 3 involves understanding all elements of a low- or zero-emissions power system and initiating long lead-time activities (5+ years) to prepare for emerging needs.

Immediate actions are required across all horizons to support the longer-term energy transition.

5.3.4 Security framework enhancement Rules change

In November 2025, AEMO submitted a Rules change request to provide better management of system strength and inertia shortfalls.[54] The Rules change request came in response to the increasing closure of non-renewable synchronous plants across the NEM, without sufficient time to replace the inertia and system strength services these plants provide. Unlike the rest of the NEM, Tasmania does not suffer from such a significant change due to its existing hydro fleet, which is expected to support the network and provide these services into the future.

52 https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/transition-planning

53 https://aemo.com.au/initiatives/major-programs/engineering-roadmap

54 Security framework enhancements | AEMC

The Rules change aims to address the inertia and system strength shortfalls via making changes to the system strength, inertia and NSCAS frameworks. The changes would first provide greater certainty of the future requirements, with a better foresight of asset commissioning and retirement timeframes. This would allow for sufficient time to procure any new resources required to manage these shortfalls, with the option of contracting these services if required. Additionally, the regulatory investment test for transmission (**RIT-T**) process is to be streamlined, and will allow more flexibility to meet the network demands and reduce the likelihood of a late delivery of resources. The Rules change status is currently open, with further updates expected for late 2026.

5.4 Meeting our power system security obligations

5.4.1 An overview of inertia and system strength

Inertia and frequency control are closely linked in a power system. After a disturbance that disrupts the balance between generation and demand, power systems with high inertia can better withstand rapid frequency changes, limiting the ROCOF. Conversely, systems with lower inertia are more prone to rapid frequency shifts, which can have harmful effects if not properly managed.

System strength encompasses various specific technical issues, but the key components are:

- Ensuring sufficient short circuit current is consistently available for the proper functioning of network protection systems, including those in downstream distribution networks and protection systems within customer premises, including generating systems.
- Guaranteeing stable voltage control throughout the network, both under normal conditions and following network contingency events and switching actions (like transformer and capacitor energisation). This is required even in areas far from devices capable of providing dynamic reactive power control, such as generators and Flexible Alternating Current Transmission System (**FACTS**) devices.
- Ensuring that the voltage at the connection points of grid-following IBRs remains robust enough to support their continuous, uninterrupted operation during network faults and other credible disturbances.

Synchronous generators have historically provided much of the capability in maintaining system strength in Tasmania's power system, an arrangement which will change as more IBR is integrated into the network. While IBR technology offers numerous advantages in terms of configurability and rapid response, it operates differently to synchronous machines. These differences must be carefully integrated into the design and operation of the power system.

5.4.2 Latest shortfall declarations

As a Tasmanian TNSP and Jurisdictional Planning Body, TasNetworks is both the *Inertia Service Provider* and *SSSP* for the Tasmanian region. As a result, we are responsible for providing sufficient capabilities to AEMO under the rules to ensure that the operational limits listed in Table 5-2 and Table 5-3 can be satisfied on a continuous basis.

Table 5-2: System inertia requirements

Rules term	Minimum requirement (MW.seconds)
Secure operating level of inertia	3,800
Minimum threshold level of inertia	3,200

Table 5-3: Minimum fault level requirements (intact network)

Fault Level Node	Minimum three-phase fault level (MVA)
George Town 220 kV	1,450
Waddamana 220 kV	1,400
Burnie 110 kV	750[55]
Risdon 110 kV	1,330

55 Minimum pre-contingent three-phase fault level requirement reduced from 850MVA to 750MA on account of commissioning of 2x STATCOMs at Port Latta

Prior to 1 December 2025, Tasmania's system strength and inertia requirements were fulfilled via existing contracts with Hydro Tasmania. Following TasNetworks' RIT-T process (refer to section 5.4.3.6), which concluded with the Project Assessment Conclusions Report (**PACR**), contracting with existing generators to provide system strength services will meet Tasmania's system strength obligations until June 2029. Therefore, there has been no shortfall in system strength identified up until June 2029. The 2026 ISP[56] published by AEMO reports system strength shortfalls post 2030 as summarised in Table 5-4. These shortfalls are to be addressed in TasNetworks' next RIT-T post June 2029.

AEMO's 2026 ISP identified shortfalls for inertia as presented in Table 5-5. These shortfalls are predicted to carry low level risk due to the progression of TasNetworks' inertia remediation measures and inertia contracting to meet these requirements up until 2029. Post 2029, a new RIT-T will be commenced to address the future network requirements.

Table 5-4: Forecast system strength shortfalls

	Indicative deficits against minimum requirements (MVA)		
System Strength Node	**2026-2029**	**2030-2032**	**2032-2036**
George Town 220 kV	0	1320	1320
Waddamana 220 kV	0	1264	1264
Burnie 110 kV	0	629	629
Risdon 110 kV	0	1192	1192

Table 5-5: Forecast inertia shortfalls

	2026-2028	**2029-2030**	**2031-2032**	**2032-2036**
Secure inertia level (MWs)	3,800	3,800	3,800	3,800
Inertia available 99.87% of the time (MWs)	3,800	180	180	180
Calculated inertia deficit (MWs)	0	3,620	3,620	3,620

5.4.3 Longer term management of inertia and system strength

As discussed in Section 5.3.2, TasNetworks has an obligation to assess the forward-looking requirements for inertia and system strength and considering the need for future investments necessary to satisfy our responsibilities under the Rules.

5.4.3.1 System strength nodes

Since 2 December 2025, locations previously referred to as *fault level nodes* for the purposes of managing fault level shortfalls, have transitioned to *system strength nodes* (**SSN**) under the new Rules framework. In consultation with AEMO, the declared SSNs in the Tasmanian region are as listed in Table 5-6 and will serve the primary functions as indicated.

Table 5-6: System Strength Nodes (SSN) in the Tasmanian transmission network

System Strength Node	**Minimum three-phase fault level (MVA)**	**Purposes / Intention**
George Town 220 kV	1,450	Reference SSN for North East Tasmania REZ (T1)
Waddamana 220 kV	1,400	Reference SSN for Central Highlands REZ (T3)
Burnie 110 kV	750	Reference SSN for North West Tasmania REZ (T2) – 110 kV
Risdon 110 kV	1,330	To maintain network security in southern Tasmania.
Proposed future SSN		
Hampshire Hills 220 kV	To be confirmed	Reference SSN for North West Tasmania REZ (T2) – 220 kV

56 AEMO-2026-Integrated-System-Plan-Appendix7

The future proposed SSN at the Hampshire Hills 220 kV Switching Station is currently under evaluation and will ultimately be influenced by the timing of the North West Transmission Developments (**NWTD**). If this switching station is not built before a need arises in the north-west region—triggered by either the Marinus Link or the establishment of 220 kV connection points for wind farm projects—an alternative SSN could be located at Burnie 220 kV Substation. The distance between the two locations is approximately 29.6 km, which is not deemed significant considering the planned design of the interconnecting circuits. Nonetheless, once the new 220 kV SSN is established and made operational in the north-west, the necessity for the existing Burnie 110 kV SSN will be reassessed.

5.4.3.2 System strength locational factors

TasNetworks is obliged under Rules Clause 5.12.2(c)(13) to publish the *system strength locational factor* for each *system strength connection point* in the Tasmanian region. A *system strength connection point* is a *connection point* for IBR plant or equipment that has elected to pay the *system strength charge* and therefore relies upon centrally provided *system strength services* as opposed to self-mitigation.

Currently, TasNetworks has no registered *system strength connection points* in its transmission or distribution networks. As a result, no locational factors are considered in this Annual Planning Report (**APR**).

5.4.3.3 Forecast IBR installations and efficient levels of system strength

Since 2nd December 2025, TasNetworks has been obligated to provide adequate *system strength* services to meet two specific technical criteria:

- ensuring the minimum *three-phase fault level* specified by AEMO is maintained at each SSN; and
- providing sufficient system strength services to support the forecast IBR expected to connect to the network, referenced to each SSN, to achieve stable voltage waveforms across the network without the imposition of network constraints.

Both criteria are defined in terms of operating an intact network, but must take into account the effects of *credible contingency events* and *protected events*. Management of previous outage conditions—such as planned network outages or extended forced outages—may involve implementing network constraints to ensure power system security, as providing the required levels of system strength for unrestricted operation of all IBR under these circumstances may not be economically feasible.

The 10 year IBR forecast for Tasmania, including wind, PV and BESS projects is presented in Table 5-7. This forecast is based on AEMO's 2025 Transition Plan for System Security (**TPSS**),[57] proposed future generator connections, and AEMO's 2026 ISP. It is important to note that all future IBR projects for the Burnie-Hampshire Hills region are currently allocated to Burnie. This is to follow AEMO's approach in not allocating IBR forecasts to SSNs that are not yet formally declared. Changes in IBR forecasts with respect to last year's APR is shown in Table 5-8.

Table 5-7: Forecast IBR developments (installed MW capacity) referenced to each Tasmanian SSN

Reference SSN	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Burnie 110 kV	0	0	21	21	171	171	471	471	471	471	471
George Town 220 kV	0	0	0	288	625	625	625	625	625	625	625
Waddamana 220 kV	0	0	610	901	1269	1269	1269	1269	1269	1269	1269
Risdon 110 kV	0	0	0	0	0	0	0	0	0	0	0
Aggregate (MW)	**0**	**0**	**631**	**1210**	**2065**	**2065**	**2365**	**2365**	**2365**	**2365**	**2365**

Table 5-8: Change in IBR forecast with reference to 2025 APR.

Reference SSN	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Burnie 110 kV	0%	-100%	250%	40%	1040%	1040%	251%	232%	232%	22%
George Town 220 kV	0%	-100%	-100%	19%	158%	158%	56%	56%	56%	56%
Waddamana 220 kV	0%	-100%	2%	41%	-3%	-3%	-8%	-9%	-9%	-9%
Risdon 110 kV	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Aggregate (MW)	0%	-100%	-12%	35%	32%	32%	23%	22%	22%	9%

57 AEMO 2025 Transition Plan for System Security

The minimum new renewable generation required in Tasmania to meet the TRET[58] is currently considered to be approximately 2,500 MW by 2040, based on an assumed capacity factor for large-scale wind farms. AEMO's 2026 ISP forecasts an additional 271 MW of wind in the Burnie region, a 338 MW BESS at George Town, and an additional 160 MW of wind in the Waddamana region scheduled to be commissioned before 2042.

In line with the new Rule requirements, TasNetworks has translated the forecasted IBR developments into an equivalent *three-phase fault level* to represent the required *efficient level of system strength* at each SSN. Due to the absence of detailed design information for future IBR connection points, we have estimated the necessary system strength levels for the coming years using the *Available Fault Level* (**AFL**) methodology, as outlined in Section 3.4.3 of the AEMO System Strength Impact Assessment Guidelines.[59] Additionally, where future changes in network topology are known and have been communicated to AEMO and the wider industry60, these developments have been included in our modelling activities for the year we reasonably expect them to become operational.

TasNetworks acknowledges the limitations of the AFL methodology but considers it valuable for indicating the potential volume of services needed relative to the current proven network operating limits. We have compared the results from our current detailed preliminary system strength studies to the computed AFL values, and they are comparable. The AFL method is also helpful for understanding the relationships between IBR connection points across the network, giving insights into which areas might face challenges as more IBRs connect. This provides locational signals for future network planning activities.

By using the IBR forecast published by AEMO together with the AFL methodology, we have estimated the three-phase fault level requirements at each SSN for future years, extending out to 2036. The results of this analysis are illustrated in Figure 5-3. The analysis assumes 100% IBR-based grid following generation technology (worst case) in the Tasmanian region, with no fault level contributions from synchronous sources, making it a conservative estimate of the network's future needs. It is anticipated that the actual requirements at each SSN will be lower than those depicted in Figure 5-3.

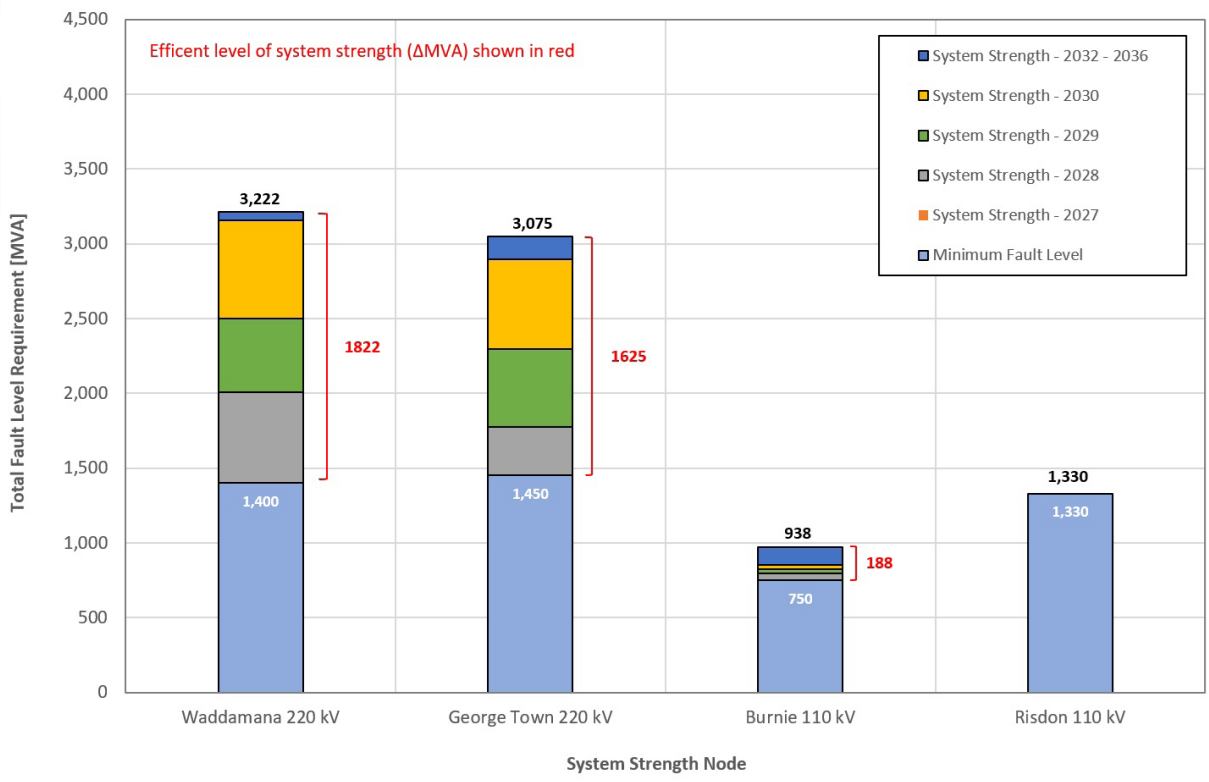


Figure 5-3: Estimated efficient level of system strength at each SSN, 2026-2036

58 TRET sets out renewable energy production capability of approximately 16,000 GWh / annum by 2030 and approximately 21,000 GWh / annum by 2040

59 Available at : www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/participate-in-the-market/network-connections/system-strength-impact-assessment-guidelines

60 Refer to chapter 3 for details on expected additional transmission network developments

The forecasts indicate an increase in system strength requirements between 2028 and 2030 corresponding to approximately 2,065 MW of new IBR connections across the North East, North West, and Central Highlands Renewable Energy Zones (**REZ**). The George Town and Waddamana 220 kV SSNs experience the greatest relative increases during this period. Post 2030, following the expected commissioning of Marinus Link Stage 1, the requirements for George Town and Burnie SSNs increase again to support an additional 300 MW of IBR forecast to connect in these regions.

While the AFL methodology cannot predict the exact requirements, it is clear that additional system strength support will be required over and above that currently provided as the minimum three-phase fault level. Except for Risdon 110kV, all other SSNs will be materially impacted, with George Town and Waddamana exhibiting the most significant increases above the existing baseline requirements.

5.4.3.4 Forecast of available fault level at system strength nodes

The Rules clause 5.20C.3(f)(3) requires that SSSP provide a forecast of the AFL at each SSN over the period for which AEMO has determined system strength requirements, which is currently until 2036.

AFL is largely determined by the dispatch of synchronous generation at any point in time and is therefore not a fixed quantity. As an example, consider Figure 5-4 which presents a series of duration curves for the forecast three-phase fault level at the Waddamana 220 kV SSN. Because Tasmania will not experience a permanent withdrawal of synchronous generation as is progressively occurring on the mainland (due to coal fired power stations being decommissioned as per the timeframes published by AEMO[61]), access to system strength support will continue to be available. However; as more IBR is connected, there will be increasing periods of time when that capability is not naturally dispatched in the energy market and alternative mechanisms will be required to maintain power system security. This is represented by an increasing duration below the minimum fault level requirement.

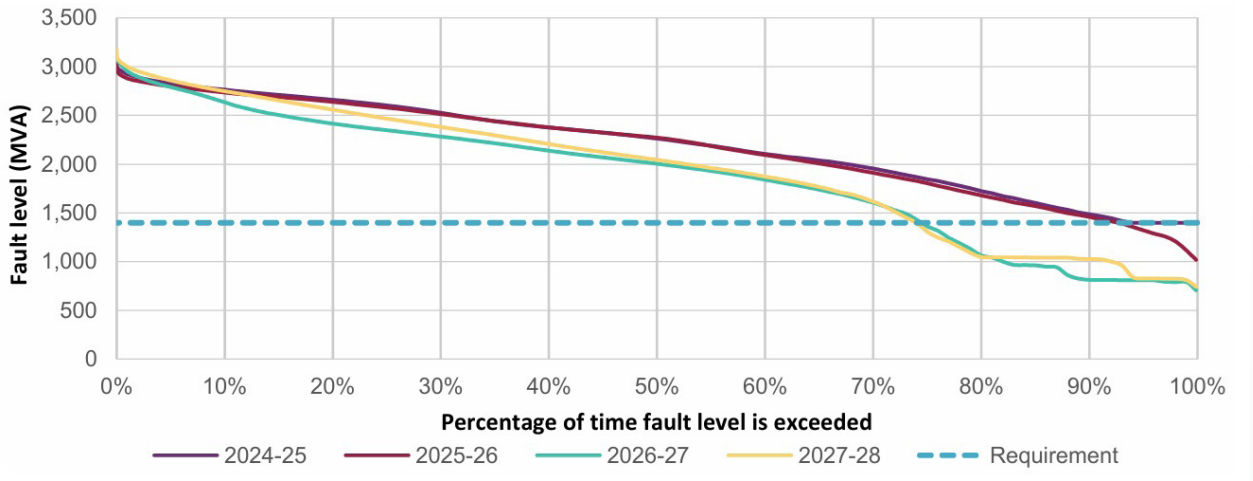


Figure 5-4: Forecast fault level at the Waddamana 220 kV SSN[62]

At present, during such operating periods, contracted system strength services are dispatched to raise the three-phase fault level to meet at least the minimum requirement. Moving ahead, it will be important to sustain not only the minimum fault level but also the efficient level of system strength, as illustrated in Figure 5-3.

In TasNetworks' view, the purpose of Rules clause 5.20C.3(f)(3) is to inform developers about which areas of the network are currently better suited to accommodate new IBR connections. Conversely, some parts of the network may already be nearing established performance limits and might pose a greater challenge when integrating new IBR.

The following AFL estimates for each SSN have been prepared based on these assumptions:

- Two minimum hydro generator dispatch scenarios have been explored as part of a sensitivity analysis. Both scenarios are more onerous than current operating practices but align with future planning scenarios currently under review.[63]

61 Generation closure year details are included in : https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/generation_information/2026/generating-unit-expected-closure-year---jan-2026.xlsx

62 Extracted from AEMO 2025 TPSS

63 Further details in Section 5.2.2

- Synchronous condensers currently contracted to TasNetworks will remain available to support the network. For each generation scenario, a minimum number of synchronous condensers have been dispatched to meet the minimum three-phase fault level at each SSN. The results are based on one particular configuration of synchronous condensers in operation, although multiple credible variations are possible.
- The generation and synchronous condenser dispatch combinations have been developed for the network as of 2025 and remain constant in all future years. Anticipated future changes in network topology have been included as appropriate for each year. The impacts of increasing levels of IBR, as forecasted by TasNetworks,[64] are thus compared with the 2025 base case.

For clarity, the forecast AFL for each SSN should be interpreted as follows:

- A large positive AFL indicates that adverse system impacts are unlikely (though not impossible), suggesting that the SSN is likely capable of supporting the proposed level of IBR under consideration.
- An AFL close to zero indicates a rising risk of adverse system impacts, necessitating detailed analysis to understand how IBR would perform under such operating conditions.
- An increasingly negative AFL indicates a high risk of adverse system impacts, with a growing likelihood that additional system strength support will be needed to maintain power system security.

The AFL methodology is not designed to provide a precise pass or fail outcome but rather to indicate risk. This information can be integrated into network planning activities, highlighting areas for more detailed analysis techniques that require additional time, personnel, and costs.

George Town 220 kV

The forecast AFL for the George Town 220 kV SSN is depicted in Figure 5-5. As anticipated, the analysis shows that the available operating margin is already quite low due to the impact of in-service IBR, especially the Basslink HVDC interconnector. As projected IBR developments are gradually introduced in the following years, the AFL deteriorates significantly, primarily from IBR growth within the Central Highlands and North East REZs. Since George Town is situated near the electrical centre of the Tasmanian power system, almost all future IBR connections negatively affect the AFL; this is because the electrical distance from George Town to many proposed development sites is not substantial, increasing the risk of adverse interactions. Current analysis suggests that the George Town 220 kV SSN is a vulnerable location and will likely need additional system strength services beyond the current operational arrangements, preferably before 2029. Such measures are also expected to positively affect other parts of the network.

64 TasNetworks IBR forecast is informed by connection applications and inquiries. At aggregate level, TasNetworks forecast closely aligns with AEMO forecast

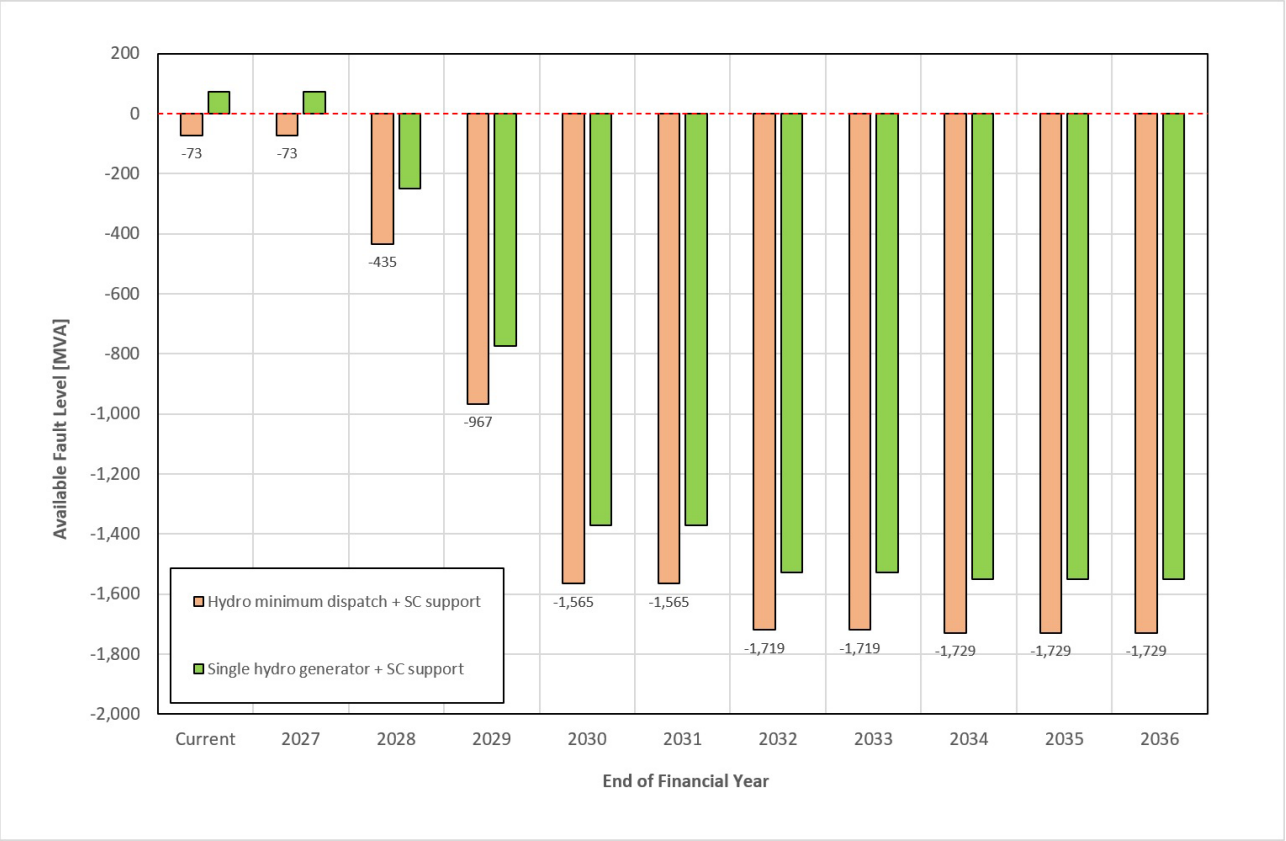


Figure 5-5: Forecast AFL at George Town 220 kV SSN

Waddamana 220 kV

The forecast AFL for the Waddamana 220 kV SSN is illustrated in Figure 5-6. Considering the system strength services already required to effectively manage areas like George Town, and the fact that only one wind farm is currently operating in the vicinity, Waddamana presently has sufficient margins. The AFL remains positive until the expected substantial IBR growth of approximately 901 MW, anticipated between 2028-2029, is constructed near the Waddamana switching station as part of the Central Highlands REZ.

In 2030, there is a further increase in the AFL deficit, aligning with planned IBR developments in the order of 368 MW scheduled to connect in this region. Additional system strength support beyond the current operational arrangements will likely become necessary post commissioning of Marinus Stage 1 and transmission augmentation works under NWTD, but this will depend on the precise scale and timing of IBR developments in the Central Highlands REZ.

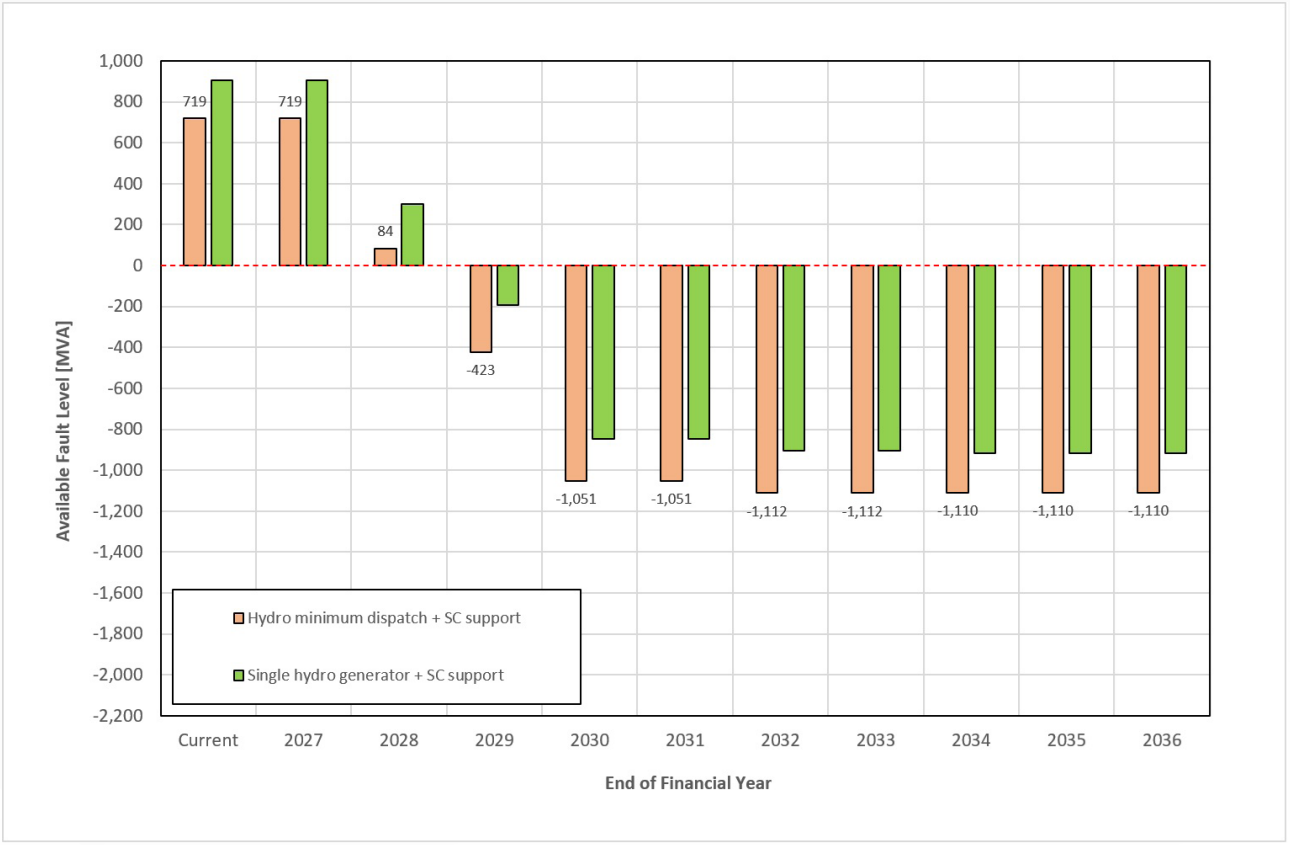


Figure 5-6: Forecast AFL at Waddamana 220 kV SSN

Burnie 110 kV

The forecast AFL for the Burnie 110 kV SSN is shown in Figure 5-7. The results suggest a positive AFL through to 2036 even with the estimated 471 MW of IBR to connect in the North West Tasmania REZ during this period.

It is worth noting for Burnie that AEMO has reduced the minimum fault level requirement at Burnie from 850 MVA to 750 MVA following the commissioning of two STATCOMs at Port Latta in 2024. The STATCOMs have been installed to provide dynamic voltage support to existing nearby wind farms, supporting voltage ride through and stability performance.

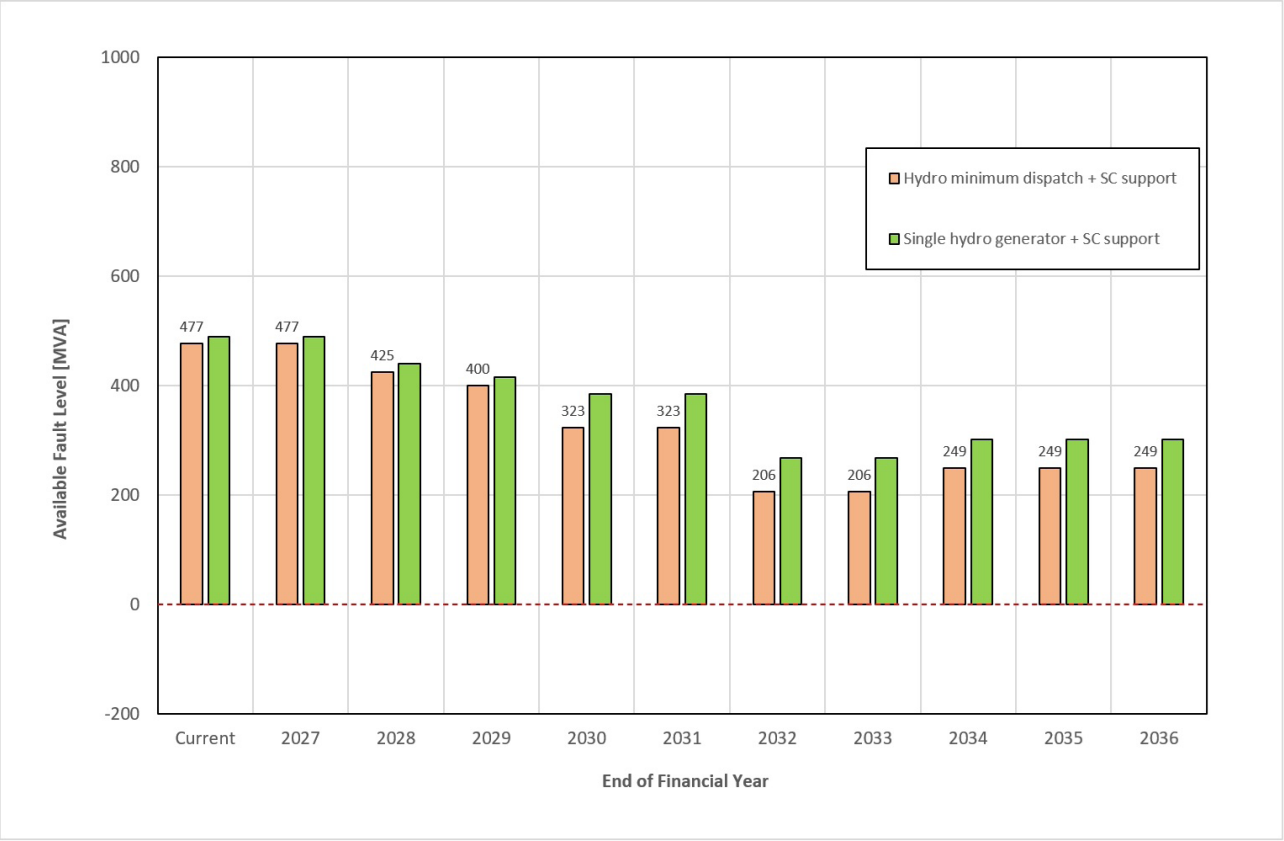


Figure 5-7: Forecast AFL at Burnie 110 kV SSN

Risdon 110 kV

The forecast AFL for the Risdon 110 kV SSN is illustrated in Figure 5-8. Since Risdon Substation is situated in the southern part of Tasmania and is electrically isolated from most anticipated IBR developments, the AFL remains relatively high throughout the forward planning period.

However; a challenge already identified at Risdon is the ability to maintain the minimum fault level requirement of 1,330 MVA in future years, particularly if the hydro generation patterns in the south change significantly with the proposed re-development of Tarraleah Power Station. This new station is designed to facilitate flexible operations, enabling it to be shut down based on market conditions. In contrast, the existing station lacks flexibility due to limitations in the water conveyancing system, leading to a relatively constant base load operation providing various benefits to the network. TasNetworks is aware of this potential future change and is exploring various options to ensure power system security in southern Tasmania during periods of low or no hydro generation.

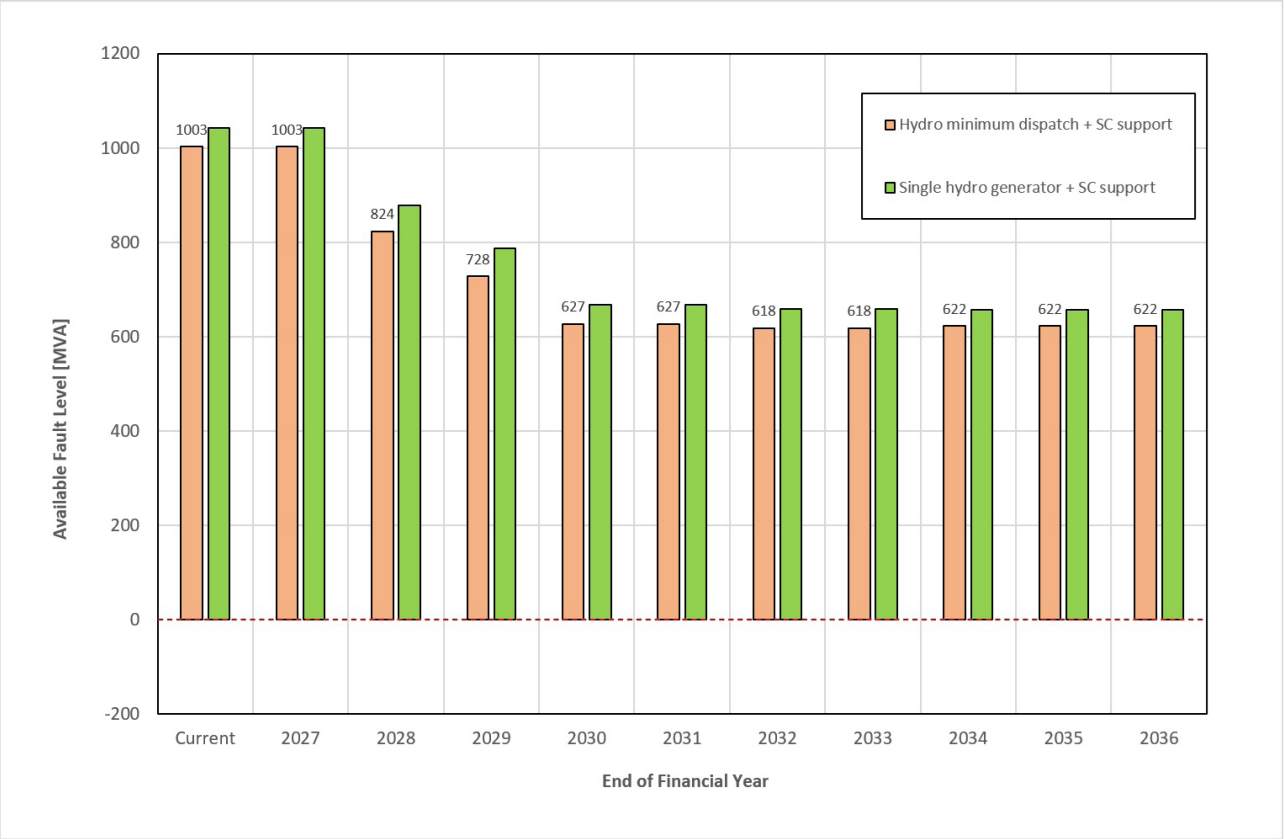


Figure 5-8: Forecast AFL at Risdon 110 kV SSN

Hampshire Hills 220 kV

As the Hampshire Hills 220 kV Substation is not yet formally designated as an SSN, an AFL analysis has not been performed. TasNetworks will incorporate this site in future Transmission Annual Planning Reports as necessary to comply with the Rules.

5.4.3.5 Alignment with efficient levels of system strength

It is important to highlight an apparent discrepancy between the *efficient levels of system strength* presented in Figure 5-3 and the SSN specific AFL results discussed earlier; specifically, indications that the *efficient levels of system strength* exceed what is necessary, with Waddamana serving as a notable example.

This discrepancy arises from the limitations of a calculation methodology that uses fault level as a proxy for managing system strength. The fault level determined at any given point in the network depends on the number and location of all fault current sources. Additionally, there are interdependencies, meaning the contribution from one source is influenced by the contributions of other sources nearby. This calculation is often characterised as 'non-linear'.

To estimate the *efficient level of system strength*, TasNetworks assumed that no additional synchronous generation is connected to the network. This approach should yield a conservative estimate of the future requirements of the network, establishing an upper limit on expectations.

The AFL calculations presented were based on onerous yet credible dispatch scenarios for hydro generation and supporting synchronous condensers. As a result, the AFL outcomes serve as a 'snapshot' from a broad spectrum of potential results that vary according to the case assumptions.

Overall, both sets of results clearly demonstrate that locations expected to accommodate significant IBR developments in the future will almost certainly need additional system strength support beyond current operational practices. George Town and Waddamana are particularly affected by the anticipated IBR connections, while ongoing management of the existing minimum fault levels at Burnie and Risdon 110 kV remains a priority at these sites.

5.4.3.6 Conclusion of the RIT-T for the provision of future system strength requirements

To comply with the new system strength Rule requirements, TasNetworks initiated a RIT-T, which included the publication of a Project Specification Consultation Report (**PSCR**) and a Request for Expression of Interest (**EOI**) in early August 2023. Then, in November 2024, TasNetworks published a Project Assessment Draft Report (**PADR**) which set out assessment of options to meet the system strength requirement in Tasmania from 2 December 2025 to June 2029 and identified a preferred solution.

In June 2025, the RIT-T process concluded with the PACR[65], that evaluated each option considered to meet the future system strength requirements. The preferred option, "*to contract with existing owners of synchronous condensers and generation assets — considered credible as it met system strength requirements efficiently and cost-effectively*" was nominated based on commercial and technical feasibility, whilst being able be implemented in time to meet the identified need. Contracting system strength services will therefore meet the system strength requirements until June 2029, upon which a new RIT-T will be formalised to assess the options for meeting the future system strength requirements.

5.4.3.7 Commencement of very fast FCAS market and implications for inertia requirements

Following the completion of the *"Fast Frequency Response Market Ancillary Service"* Rule Change in July 2021, AEMO has made progress towards introducing two new market ancillary services into the NEM. These new services are the very fast raise (R1) and very fast lower (L1) Frequency Control Ancillary Services (**FCAS**) markets, both of which are defined with a 1-second delivery timeframe. The new markets commenced operation as of 9 October 2023.

TasNetworks has been collaborating with AEMO on various aspects of this implementation, including investigating potential sources of very fast FCAS and engaging in the Market Ancillary Service Specification (**MASS**) consultation. In the current market, we will continue to assess how these new services may affect the existing minimum inertia requirements defined for Tasmania. While fast frequency response capability is not a direct substitute for inertia due to the typical measurement time delays involved, there may be opportunities to optimise Tasmanian inertia requirements further.

5.5 Transmission network constraints

A constraint occurs when the power flow through a section of the transmission network needs to be curtailed to prevent exceeding a known technical limit, which could jeopardise power system security. AEMO formulates constraint equations for use in its market systems that define how generation dispatch and Basslink must be coordinated to avoid breaching these technical limits. The equations are based on limit advice provided by us for our transmission network. Such advice is typically developed using power system simulation software that allows for the examination of a wide range of network operating conditions to identify acceptable scenarios and those that must be avoided.

Operating restrictions are often influenced by the status of critical network components and the control and protection schemes designed to extend the permissible operating boundaries of the network. For example, the Network Control System Protection Scheme (**NCSPS**) in the Tasmanian network enables various parts of the transmission system to operate in a 'non-firm' capacity. Additionally, TasNetworks utilises dynamic ratings for transmission lines, which depend on real-time measurements of ambient temperature and wind speed to determine the maximum allowable power flow through a specific circuit based on its design parameters. Depending on the status of these schemes and supporting infrastructure, different constraints are enabled to ensure the network maintains a secure operating state.

We conduct periodic reviews of all binding and violating constraints and provide AEMO with updated limit advice to modify, remove, or establish new constraints as network conditions change. This ensures that power system security is upheld while maximising available transmission capacity. The market impact component (**MIC**) of the Australian Energy Regulator's (**AER**) Service Target Performance Incentive Scheme (**STPIS**) creates a financial incentive for us to minimise the impact of transmission constraints.

Figure 5-9 illustrates constraints that were binding or violated due to thermal or stability issues during the 2025 calendar year. Binding constraints affect generation output and/or Basslink power transfer through market re-dispatch, while violated constraints indicate instances where a technical limit was exceeded. The figure details the number of five-minute NEM trading intervals during which constraints occurred across different parts of the network. 'Thermal limit – with outage' indicates that the constraint was affected by one or more transmission elements being out of service, whereas 'Thermal Limit – No Outage', 'Transient Stability', 'Voltage Stability' and 'Other Stability' signifies that the constraint was binding or violated without any corresponding outage event in the network.

65 TasNetworks-System-Strength-RIT-T-PACR-June-2025

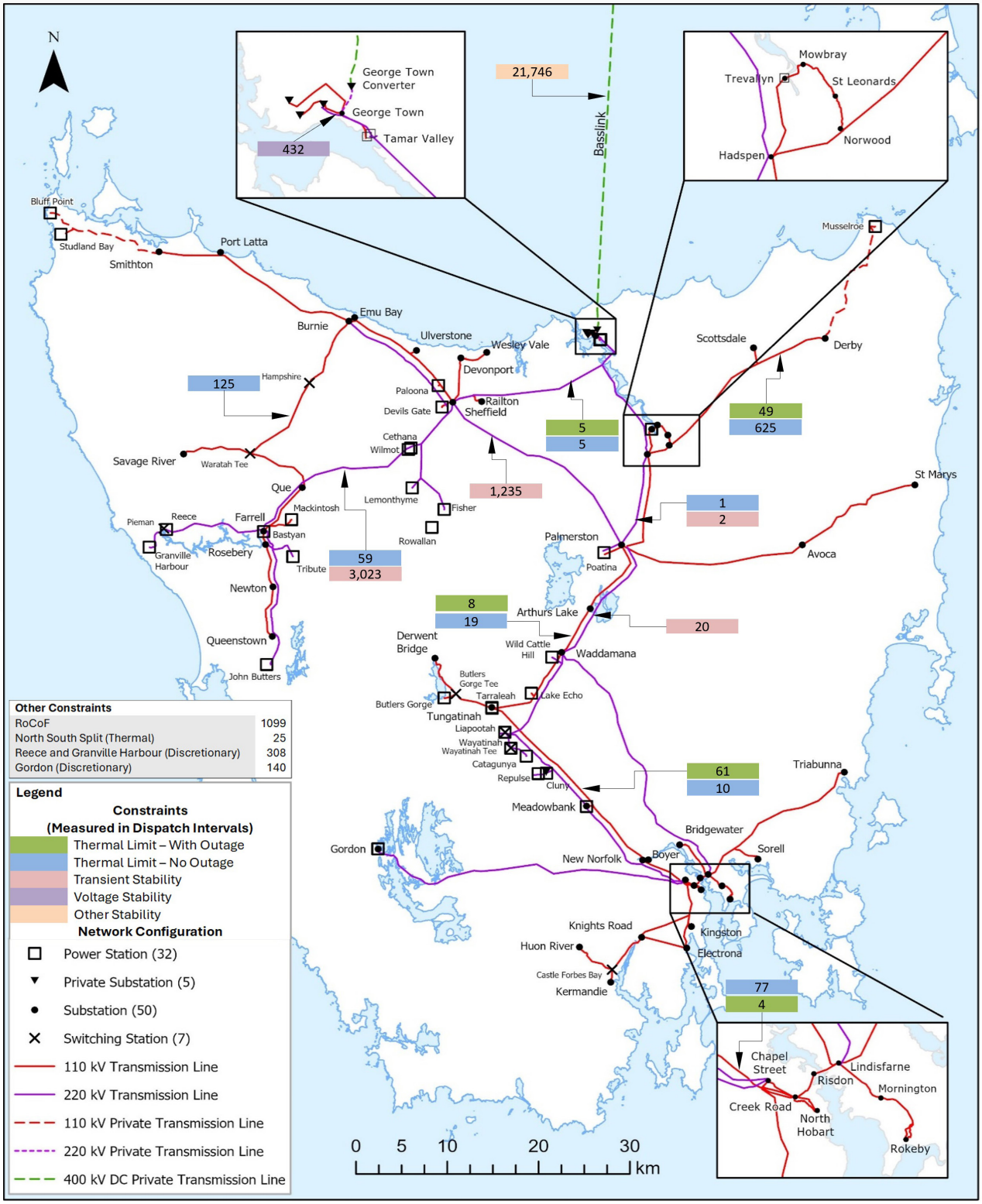


Figure 5-9: Transmission constraints during 2025 calendar year

Table 5-9 lists the number of trading intervals during which binding or violated constraints took place on major transmission corridors during the 2024 and 2025 calendar years, classified by whether the number of constraints increased or decreased compared to the previous year. It includes only those constraints where the total number of bound or violated periods surpassed 150 trading intervals, equivalent to 12.5 hours. The table encompasses both network constraints and those specifically associated with Basslink.

Table 5-9: Major binding constraints and significant changes in 2025

	Period constraint bound or violated			
	2024		2025	
Constraint	Trading intervals	Time (hours)	Trading intervals	Time (hours)
Constraints with increased prevalence in 2025				
Basslink inverter commutation instability limit	71	6	178	15
Basslink import limited due to load unavailability for FCSPS operation	9,442	787	21,067	1756
Discretionary limit on west coast generation	98	8	324	27
Limit Reece and Granville Harbour WF generation	-	-	308	26
Palmerston-Sheffield 220 kV transient stability	692	58	1,235	103
Rate of Change of TAS Frequency	164	14	1,099	92
Constraints with decreased prevalence in 2025				
Basslink Energy and FCAS related constraint (i.e. Basslink no go zone)	305	25	285	24
Basslink rate-of-change limit	897	75	567	47
Derby to Scottsdale Tee 110 kV thermal limit with no outage	3,395	283	625	52
George Town 220 kV bus voltage stability limit	1,556	130	432	36
Hampshire-Que-Waratah Tee 110kV thermal limit	397	33	125	10
Scottsdale Tee to Norwood 110 kV thermal limit with outage	643	54	49	4
Farrell–Sheffield 220 kV thermal limit with no outage	169	14	59	5
Farrell–Sheffield 220 kV transient stability	7,737	645	2,989	249

The following sections present more information on our top three constraints during the 2025 calendar year.

Summary

The 2025 calendar year statistics were dominated by Basslink, which accounted for 76% of the number of constrained trading intervals. Overall, the total number of trading intervals experiencing binding constraints (both major and minor) increased by approximately 2% from 28,395 in 2024 to 28,993 in 2025. Excluding the contributions of Basslink, the total number of binding constraints decreased by approximately 57% from 17,698 in 2024 to 7,668 in 2025.

Basslink import limited due to load unavailability for FCSPS operation

The most limiting constraint in 2025 was the 'Basslink import limited due to load unavailability for frequency control system protection scheme (FCSPS) operation' constraint. This constraint limits the import from Victoria to Tasmania due to the unavailability of FCSPS load blocks to balance frequency for the loss of Basslink. In May 2025, one of the major load contributors for the FCSPS scheme, Liberty Bell Bay, was placed into voluntary administration. This directly impacts the level at which Basslink can import, and therefore raised the number of intervals in which Basslink was constrained. TasNetworks currently has no control over this constraint as Liberty Bell Ball and the remainder of the FCSPS loads are contracted by third parties; however, the impacts of this load change are to be addressed with the redesign of the FCSPS scheme for the introduction of Marinus Link.

Farrell–Sheffield 220 kV transient stability

The second most limiting constraint for the 2025 calendar year was the 'Farrell-Sheffield transient stability' constraint. This constraint is primarily driven by generation output from the King and Pieman hydro schemes, as well as Granville Harbour Wind Farm. Despite the 4% increase in west coast generation over the 2025 calendar year, the prevalence of this constraint reduced by approximately 61% when compared to the 2024 calendar year. The changes to Basslink operation during the 2025-2026 financial year are the main contribution to the reduction of this constraint.

Palmerston-Sheffield 220 kV transient stability

The third most limiting constraint in 2025 was the 'Palmerston-Sheffield 220 kV transient stability' constraint. This constraint is influenced by Basslink flows, whereby a higher export reduces the likelihood of this constraint in a dispatch interval. During the 2024-2025 financial year, Basslink was exporting approximately 78% of the time, whereas in the 2025-2026 financial year, this decreased to approximately 49% of the time, leading to the increase of this constraint.

5.6. System stability and emergency controls

Instabilities in the power system can manifest in various forms and have the potential to cause significant disruptions to the network. Stability phenomena are generally classified into two broad categories: large signal and small signal. Large signal instabilities are typically linked to network contingency events, such as electrical faults, whereas small signal instabilities can arise at any time without any significant initiating disturbance.

The Rules require AEMO and TNSPs to operate the power system in a manner that maintains stability during both normal operations and following credible contingency events, including protected events. This is usually accomplished through the application of network constraints as well as the installation and maintenance of various network control and protection systems. Control systems are used to actively mitigate certain instability mechanisms and extend the network's capabilities, while protection systems detect unstable events (including electrical faults) and swiftly remove network elements from service to restore acceptable operation.

Furthermore, TNSPs are obligated to install, maintain, and upgrade emergency controls within their networks where the consequences of non-credible contingency events could lead to severe supply disruptions. The purpose of these emergency controls is *"to minimise disruption to any transmission or distribution network and to significantly reduce the likelihood of cascading failure."*[66] The design and implementation of such schemes are carried out in consultation with AEMO.

TasNetworks has long had Emergency Frequency Control (**EFC**) schemes in place, designed to mitigate the impacts of non-credible contingency events that could severely disrupt the supply-demand balance. These schemes have been developed on a 'best endeavours' basis, recognising that it is impractical to manage every potential combination of non-credible network events, such as the near-simultaneous disconnection of all generating units.

The two EFC schemes operating in the Tasmanian region are:

- Under Frequency Load Shedding (**UFLS**) Scheme: This scheme utilises the provisions of the Rules clause 4.3.5(a) to trip at least 60% of each market customer's load demand to manage severe under-frequency events.
- Over Frequency Generator Shedding (**OFGS**) Scheme: This scheme coordinates the disconnection of certain units based on the technical limitations of specific plants to provide a coordinated response to control severe over-frequency conditions.

66 As stated from the Rules clause S5.1.8

The UFLS and OFGS schemes serve as the 'last line of defence' in many scenarios that could otherwise lead to the cascading failure of the entire Tasmanian power system.

Additionally, we operate and maintain several protection schemes on behalf of specific network users under commercial agreements. These schemes are designed to mitigate specific credible contingency events and are generally required for network users to comply with the FOS, particularly the 144 MW contingency size limit. The most notable of these schemes include:

- **FCSPS**: Exclusively associated with the Basslink HVDC interconnector, this scheme addresses the instantaneous loss of Basslink, which is always considered a credible contingency event. The FCSPS allows power transfers significantly over 144 MW (both import and export) by promptly tripping loads or generation if Basslink power transfer is disrupted, thereby helping to maintain the supply-demand balance in Tasmania and preventing excessive frequency fluctuations.
- Tamar Valley Generator Contingency Scheme (**TVGCS**): To meet the FOS requirements, the effective size of the generator contingency event associated with the combined cycle gas turbine (CCGT) at Tamar Valley Power Station is limited to no more than 144 MW. With a rated capacity of 208 MW, the unit requires contracted load tripping services to support high generation output.
- Musselroe Wind Farm Generator Contingency Scheme (**MRWF GCS**): Similar to the situation at Tamar Valley, Musselroe Wind Farm faces the same issue. As the wind farm is rated at 168 MW and can export more than 144 MW through its registered connection point, it also requires contracted load tripping services to facilitate operation up to its installed capacity.

Network Control Special Priotection Scheme (**NCSPS**): This scheme allows for above firm power flows through nominated transmission circuits and which provides the means for Basslink export and nominated generation to be tripped in a co-ordinated fashion, following a credible contingency to prevent thermal overload.

We continue to collaborate with network users to explore the availability and application of new technologies that can help address stability limitations, particularly focusing on the provision of frequency control capabilities that work in parallel with, or directly participate in, the FCAS markets operated by AEMO.

Chapter 6

Service delivery performance

- In 2025, transmission system performance remained within target for transformer and capacitor circuit fault outage rate metrics but was outside target for the transmission line fault outage rate.
- Transmission Loss of Supply (**LOS**) event count was outside target for events greater than 0.1 system minutes and on target for events greater than 1.0 system minute. The average outage duration of all LOS events remained within target.
- Distribution system performance for 2025-26 was outside the Tasmanian Electricity Code (the Code) System Average Interruption Duration Index (**SAIDI**) standards for Urban and Regional Centres category.
- Distribution system performance for 2025-26 was outside the Australian Energy Regulator's (**AER**) Service Target Performance Incentive Scheme (**STPIS**), System Average Interruption Frequency Index (SAIFI) standards for Critical Infrastructure, High Density Commercial, High Density Rural and Lower Density Rural categories and outside the SAIDI standards for Critical Infrastructure, High Density Rural and Lower Density Rural categories.
- Distributed Energy Resource (**DER**) systems reached over 60,000 with a total installed capacity of 415 MW, a 15% increase over the course of 2025-26.

6.1 delivery introduction

We manage our network by balancing cost, risk, and performance to deliver affordable levels of supply reliability and quality to our customers. Network service performance is a critical aspect of our customer service and must meet customer expectations and regulatory obligations.

Our objectives in relation to service performance are:

- safety is our top priority, and we will endeavour to continue improving our safety performance;
- service performance will be maintained at current overall network service levels, while service to poor-performing reliability areas will be improved for enhanced customer experience and to meet regulatory requirements;
- cost performance improved through prioritisation and efficiency gains enabling us to provide predictable and lowest sustainable pricing to our customers;
- customer engagement will be improved to ensure our decision-making will maximise value to our customers and customer views are taken into account;
- our program of work will be developed and delivered on time and within budget; and
- our asset management improved to support our cost and service objectives and deliver efficiency improvements.

Reports are also provided on transmission asset outage occurrences and the reliability and quality of supply provided to our distribution customers. Issues associated with customer areas with service levels outside target levels are discussed along with our strategy to undertake corrective actions.

In 2025-26, significant weather and bushfire events impacted Tasmania's electricity network, damaging assets and interrupting electricity supply to customers.

- In October 2025, destructive winds and severe weather caused widespread outages across Tasmania. Regional Fault Management (**RFM**), previously known as the Incident Control System (**ICS**) was established to manage the operational response.
- In December 2025, bushfires occurred on the east coast and in the State's south.

6.2 Tasmanian network and supply reliability

Reliability is measured in two ways:

- reliability of network elements; and
- impact of supply interruptions to customers.

Reliability considers both the frequency and duration of outages.

Outage frequency reflects the effectiveness of our asset management strategies in the prevention of outages. It is measured using the number of LOS events and average circuit outage rate for our transmission network, and a SAIFI for our distribution network.

Outage duration reflects our effectiveness in responding to unplanned outages. It is measured using the average outage duration of LOS events for our transmission network, and a SAIDI for our distribution network.

We have a requirement to monitor and report supply reliability (among other measures) to the AER and the Office of the Tasmanian Economic Regulator (**OTTER**). Relevant supply reliability performance metrics are used by the AER in the STPIS scheme for each of our distribution and transmission networks. Additionally, we have an obligation under the Code to use reasonable endeavours to meet jurisdictional reliability standards.

The following sections provide information on network reliability targets and current performance.

6.3 Transmission network reliability

Transmission network reliability is monitored and reported to the AER and OTTER. Under the STPIS and based on historical performance, the AER sets service targets in terms of the number of LOS events that occurred during the year, average circuit outage rate, and the average LOS event duration.

LOS is measured in system minutes and is calculated by dividing the total energy (MWh) not supplied to customers during an event by the energy supplied during one minute at the time of historical Tasmanian maximum demand.[67]

LOS events are split into two categories:

- major events (exceeding 1.0 system minute); and
- all events exceeding 0.1 system minutes, including major events.

Table 6-1 lists the performance of our transmission network over the past five years. Performance measures are as defined by the AER in the STPIS. Red values indicate where we did not meet the target.

Table 6-1: Transmission network performance

Regulatory period	2021-24					2025	
Performance measure	Target 2019-24	2021	2022	2023	2024	Target 2024-29	2025
Transmission network reliability performance							
Number of LOS events >0.1 system minutes	≤3	2	7	3	3	≤4	5
Number of LOS events >1.0 system minutes	≤1	0	3	1	1	≤1	1
Transmission circuit outage rate							
Transmission line circuit fault outage rate (%)	≤16.90	13.08	15.89	12.15	16.82	≤15.95	16.82
Transformer circuit fault outage rate (%)	≤8.40	4.55	2.70	4.50	6.31	≤6.20	4.50
Capacitor circuit fault outage rate (%)	≤17.90	7.69	15.38	7.69	23.08	≤13.85	0.00
Transmission average circuit outage duration							
Average of LOS duration (minutes)	≤149	19	204.6	394.5	59.33	≤129.50	75.88

In 2025, the transmission system fault outage rates were within target for transformer and capacitor circuit and outside for transmission line circuit. The LOS event counts were on target for >1.0 system minutes and outside target for >0.1 system minutes and average duration of LOS events was within the target.

The majority of outages contributing to these metrics were caused by vegetation (outside clearance and windborne), environmental (lightning), and equipment causes.

67 In Tasmania, an event of one system minute equates to about 31.2 MWh of unserved energy

6.4 Distribution network reliability

We report distribution network reliability to OTTER and the AER on a geographic segmentation basis. For 2025-26, Tasmania was divided into 121 reliability areas – each one allocated to one of five reliability categories. The reliability category determination is based on energy use per unit area with boundaries defined by considering average transformer capacity and land parcel sizes.

The five reliability categories are:

- Critical Infrastructure (1 area);
- High Density Commercial (8 areas);
- Urban and Regional Centres (44 areas);
- High Density Rural (41 areas); and
- Lower Density Rural (27 areas).

The Code specifies performance standards for each:

- category, representing the average level of service expected by areas of that category; and
- area, representing the minimum level of service expected by the areas in each category.

We report SAIFI and SAIDI at the reliability category level to the AER each financial year. The AER sets targets for reliability categories in each regulatory period as a part of our distribution STPIS. These targets are calculated from our average performance in the preceding five years.

6.4.1 Tasmanian Electricity Code standards and performance

Distribution performance against the Code standards is measured by excluding outages on major event days68, transmission network outages, environmental-fire, total fire ban day-related outages, and certain third-party outages. The Code standards and performance during 2025-26 are presented in Table 6-2 at category level. Historic performance against the Code standards is in Appendix C.
Red values indicate where we did not meet the standard. Our reliability compliance and corrective action programs are presented in Section 6.4.4.

Table 6-2: Code – all supply reliability areas SAIFI and SAIDI standards and performance

	Annual frequency of supply interruptions (on average) (SAIFI)		Annual duration of supply interruptions (on average) (SAIDI)	
Supply reliability category	**Standard**	**Performance**	**Standard**	**Performance**
Critical Infrastructure	0.2	0.12	30	24.21
High Density Commercial	1	0.49	60	56.19
Urban and Regional Centres	2	1.38	120	210.43
High Density Rural	4	3.25	480	416.72
Lower Density Rural	6	4.08	600	598.76

Our performance in SAIFI (the frequency of outages measure) is within the standard in all categories.

For SAIDI (the duration of outages measure), we did not meet the standard in Urban and Regional Centres category. Areas in these categories were impacted by planned work, equipment, vegetation, vehicle and unknown cause events.

Table 6-3 presents the Code standard for our 121 reliability areas, and the number of areas that did not meet these in 2025-26. Thirty-eight areas did not meet their SAIDI standards and twelve did not meet their SAIFI standards.

68 A major event day is a day when the number of system minutes caused by outages exceeds an annually calculated threshold. These are predominately a result of large storms across wide areas of the state

Table 6-3: Code – each supply reliability area SAIFI and SAIDI standards and performance

Supply reliability category (number of areas)	Annual number of supply interruptions (on average) (SAIFI)		Annual duration of supply interruptions (on average) (SAIDI)	
	Standard	Number of areas below standard	Standard	Number of areas below standard
Critical Infrastructure (1)	0.2	0	30	0
High Density Commercial (8)	2	0	120	1
Urban and Regional Centres (44)	4	7	240	21
High Density Rural (41)	6	4	600	8
Lower Density Rural (27)	8	1	720	8
Total (121)		**12**		**38**

6.4.2 Distribution STPIS reliability targets and performance

The AER sets reliability of supply parameters of STPIS as part of our regulatory determination. They are based on historic performance and excludes planned outages, major event days, transmission network outages, environmental-fire, total fire ban day-related outages, and certain third-party outages. The STPIS targets and our performance levels are provided in Table 6-4 and Table 6-5. A summary of historical performance against AER targets are provided in Appendix C, with details available in the Regulatory Information Orders (**RIO**) on the AER's website.

In 2025-26, we did not meet the SAIFI targets in the Critical Infrastructure, High Density Commercial, High Density Rural and Lower Density Rural categories and SAIDI standards in Critical Infrastructure, High Density Rural and Lower Density Rural categories. These categories were heavily impacted by equipment, vegetation, environmental, vehicle and unknown cause events. Our reliability compliance and corrective action programs are presented in Section 6.4.4.

6.4.2.1 Distribution reliability performance

Table 6-4 and Table 6-5 show our reliability performance for regulatory period, 2025-26. We report our reliability performance in with the AER's methodology. Red values indicate where we did not meet the target.

Table 6-4: STPIS supply reliability category SAIFI targets and performance

Supply reliability category	Annual number of supply interruptions (on average) (SAIFI)	
	Target 2024-29	2025-26 performance
Critical Infrastructure	0.070	0.079
High Density Commercial	0.377	0.461
Urban and Regional Centres	1.015	0.928
High Density Rural	2.171	2.621
Lower Density Rural	2.948	3.478

Table 6-5: STPIS supply reliability category SAIDI targets and performance

Supply reliability category	Annual duration of supply interruptions (on average) (SAIDI)	
	Target 2024-29	2025-26 performance
Critical Infrastructure	5.948	16.597
High Density Commercial	38.012	33.686
Urban and Regional Centres	92.118	88.556
High Density Rural	244.061	259.243
Lower Density Rural	398.899	444.153

6.4.3 Distribution AER STPIS reporting

As part of our RIO submissions, we submit to the AER data for STPIS compliance requirements. Under the STPIS the AER may apply three reliability parameters to each customer category:

- System Average Interruption Duration Index (SAIDI);
- System Average Interruption Frequency Index (SAIFI); and
- Momentary Average Interruption Frequency Index (MAIFI).

For the current regulatory period, the AER has applied the SAIDI and SAIFI parameter to our STPIS.

The AER does not apply the guaranteed service level (**GSL**) component of the STPIS to TasNetworks because we are already subject to a jurisdictional GSL through OTTER as part of the Code.

A summary of our reported 2025-26 performance is presented in Table 6-6. Both the 'total' and 'removing exclusions' measures are reported.

Table 6-6: STPIS reliability parameter

Reliability measure	Measure	Critical Infrastructure	High Density Commercial	Urban and Regional Centres	High Density Rural	Lower Density Rural	Whole Network
SAIDI	Total	25.154	61.345	221.125	431.336	795.350	337.810
	Removing exclusions	16.597	33.686	88.556	259.243	444.153	168.185
SAIFI	Total	0.124	0.547	1.403	3.180	4.353	2.110
	Removing exclusions	0.079	0.461	0.928	2.621	3.478	1.570
Average customer numbers ('000s)[69]		1.96	4.58	206.71	48.83	46.84	308.92

6.4.4 Network and supply reliability compliance

Our reliability strategy seeks to:

- maintain current overall network reliability performance;
- comply with regulation, codes, and legislation;
- manage our risk profile to maintain a safe and reliable network; and
- reduce total outage costs for our network.

We undertake corrective action to improve and maintain the reliability of our distribution network under three streams:

- targeted investigations into our top 10 poorest performing reliability areas and feeders;
- network reinforcement; and
- ongoing asset management activities.

Reliability corrective action is targeted, with action coming from a variety of programs as presented in Table 6-7 (with their relative benefits). We also undertake larger targeted reliability improvement projects that may require significant investment. These larger reliability improvement projects are presented in Chapter 4.

69 For AER purposes classification customer numbers are assigned based on pre-2024 community boundary definitions to align with AER STPIS performance targets

Table 6-7: Reliability corrective action programs

Program	Benefit
Line trunk reliability improvement (protection reviews, targeted vegetation management, and asset renewal/relocation)	Reducing the probability of an unplanned outage occurring.
Remote switching reinforcement (automatic restoration schemes and multiple switches)	Reducing supply restoration time following an unplanned outage.
Distribution line interconnections (including new lines)	Reducing customer exposure to unplanned outages.
Standby generation	Reducing supply restoration time following an unplanned outage.

We also have a number of ongoing asset management activities that drive reliability outcomes:

- vegetation management;
- prioritised defect rectification;
- review of protection settings;
- targeted and specialised inspection programs; and
- utilisation of new technologies that minimise the duration of supply interruptions.

6.5 Embedded generation connections

Applications to connect embedded generation to the network are continuing to grow. Table 6-8 presents the number of applications received in recent years, which are made up almost exclusively of rooftop solar-photovoltaic (**PV**) applications. The average time between the submission of an application to approval for energisation is 63 days.

Table 6-8: Embedded generation connection applications

Financial Year	2022-23	2023-24	2024-25	2025-26
Number of applications	4,708	5,605	5,051	4783

Small generators – less than 5 MW – are automatically exempt from full compliance with Chapter 5 of the National Electricity Rules (**the Rules**).[70] While this removes many administrative barriers, small systems still interact with the broader power system. This means that small systems are still required to obtain a connection agreement with us and must meet our connection guidelines. Some of the network factors that we consider when connecting embedded generation are outlined in Appendix A.7.

More information on connecting embedded generation is available on our website: www.tasnetworks.com.au/embedded-generation

There were no large-scale embedded generation installations in the last year.

Rooftop PV makes up the vast majority of all embedded generation and has seen steady growth in recent years, reaching a total of over 60,000 systems with a total installed capacity of 415 MW by the end of June 2026. Figure 6-1 presents the growth in installed capacity and number of installations of rooftop PV since 2015-16.

70 https://www.aemo.com.au/energy-systems/electricity/nationalelectricity-market-nem/participate-in-the-market/networkconnections

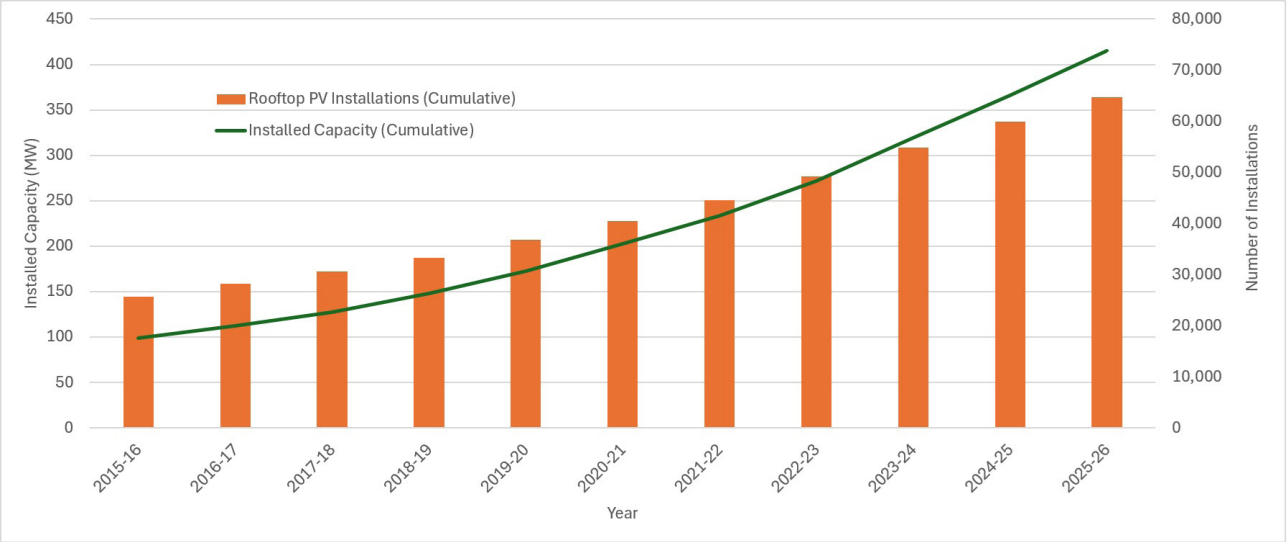


Figure 6-1: PV penetration

The average size of new PV systems has also steadily grown, from under 4 kW in 2016 to over 10 kW in 2026, as shown in Figure 6-2.

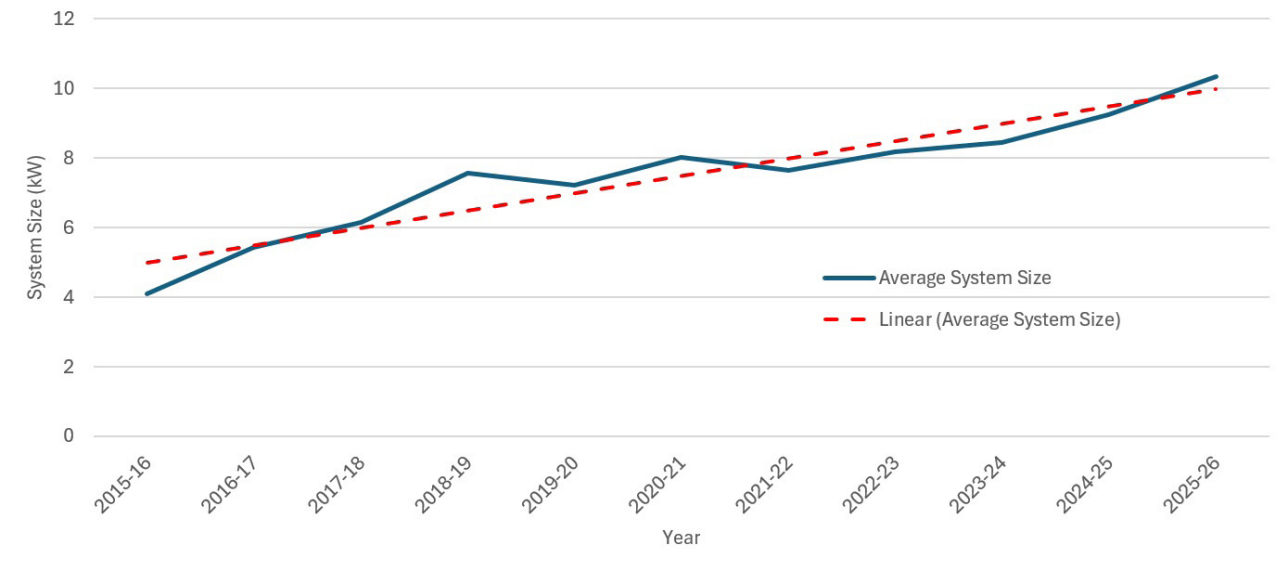


Figure 6-2: Average PV system size

Residential battery storage has continued to increase steadily across the State. Recent updates to recording and reporting data indicates that total installations now exceeds 6,000 across the State, as shown in Figure 6.3.

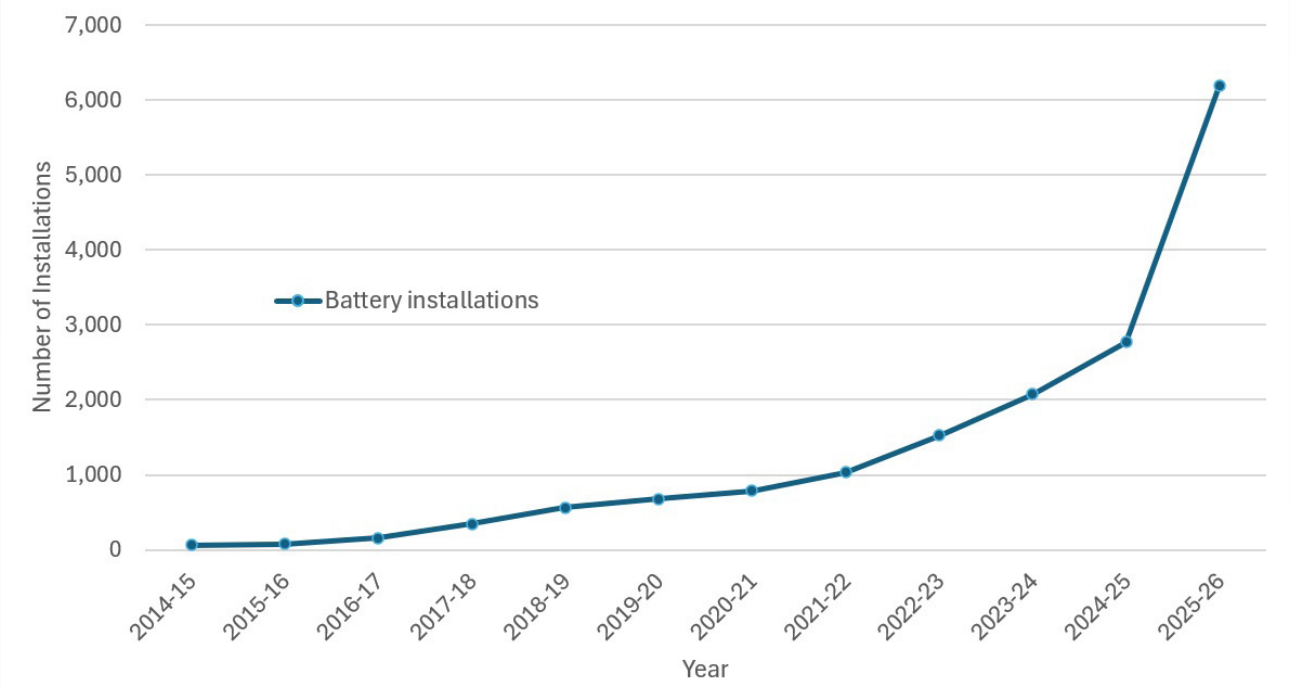


Figure 6-3. Residential battery penetration

6.6 Distribution quality of supply performance

Issues with distribution quality of supply are generally identified by:

- customer feedback that largely relates to voltage magnitude issues;
- proactive investigation of advanced meter data;
- operational limitations; and
- load or voltage studies arising from new connections or limitations.

Issues that are identified by customer feedback are resolved as a first priority. The issues that are identified through the analysis of advanced meter data are proactively addressed through our program of works. Supply impact studies and performance standards applied to customer installations are key preventative measures to maintain quality of supply across all of its dimensions.

The trend in customer feedback received in relation to over and under voltages is presented in Table 6-9. Where identified, we study these limitations and apply corrective action (if appropriate).

Table 6-9: Customer feedback on over and under voltages

Category	2019–20	2020–21	2021–22	2022-23	2023-24	2024-2025
Over voltage	32	31	18	7	9	6
Under voltage	18	8	6	9	9	8
Total	51	39	24	16	18	14


CREST

Appendices

Glossary

The definitions provided here are common electricity industry definitions, provided to assist readers who may be unfamiliar with particular industry terminology.

Terms marked [R] are also formally defined in Chapter 10 of the National Electricity Rules (**the Rules**). The definitions given below may be different from the Rules definitions. For the purposes of interpreting the requirements of the Rules, the formally defined terms within the Rules should be used.

asynchronous generator	asynchronous generators include Basslink, wind farms, solar PV, and some mini-hydro or micro-hydro generators. See also: synchronous generator.
Basslink	a privately owned undersea cable connecting the Tasmanian electricity network to that of mainland Australia.
circuit kilometre	the physical length of a transmission circuit that transports power between two points on the transmission system. A transmission line containing two circuits will traverse two circuit kilometres for every one route kilometre. See also: route kilometre.
Code	refers to the Tasmanian Electricity Code. The Code addresses Tasmanian jurisdictional interests which are not dealt with by the Rules.
committed load	the electrical power that has been agreed under an executed connection agreement to be delivered at a connection point to a person or to another network.
committed project	a project which has received board commitment, funding approval, has satisfied the regulatory investment test (where relevant) and a firm date has been set for commencement, or is currently underway.
constraint	a technical limitation in a part of the power system which makes it necessary to restrict the power flowing through that part of the system. [R]
constraint equation	a mathematical representation of a constraint, which is then programmed into AEMO's generation dispatch system. The use of constraint equations allows generators' outputs to be automatically adjusted so that constraints are not exceeded.
contingency event	an unplanned fault or other event affecting the power system. Typical contingency events include: lightning strikes, a generator or load or transmission circuit tripping, objects (such as bark, fallen trees, or possums) coming into contact with conductors, bushfire smoke causing a short circuit. [R]
dispatch interval	a five minute period during which the process of generator scheduling is undertaken. [R]
embedded generator	a generating unit that is directly connected to the distribution network as opposed to the transmission network. [R]
energy generated	the total amount of electrical energy injected into the transmission network to meet the Tasmanian energy sales. It comprises the energy sent out from Tasmania's power stations, plus the energy imported via Basslink, minus energy exported to Basslink. It includes network losses but excludes power station auxiliary loads.
fault level	the amount of current that would flow if a short circuit occurred at a specified location of the network. From a power system planning and operation perspective, fault level is also an indicator of the resilience of the network: a portion of the network with high fault levels is less likely to be affected by faults elsewhere in the network.
firm	indicates that the network, or a portion of the network, has the capacity to maintain supply to customers following a contingent event. See also: non-firm.
frequency	for alternating current electricity, the number of cycles occurring in each second. The term Hertz (Hz) corresponds to cycles per second [R]
guaranteed service level scheme	a payment scheme where our distribution customers are compensated for prolonged and excessive interruptions to their supply.
high voltage (HV)	voltage greater than 1 kV [R]

inertia	the rotating mass inside a generator. The more inertia a power system contains, the more slowly its frequency will deviate from 50 Hertz following a contingency event. Only generators that are running (and therefore spinning) contribute inertia to a power system.
island	a part of the network, which has become disconnected from the remainder of the network, and contains at least one generator. An island can potentially remain live and stable provided the generation and load within the island are nearly equal.
Jurisdictional network planning requirements	reference to the *Electricity Supply Industry (Network Planning Requirements) Regulations 2018*, described in Section A.3.3.
kilo-Volt	one kilo-Volt equals 1,000 Volts. See also: voltage.
low voltage (LV)	nominal voltage of 400 Volts or 230 Volts
limitation	network constraint or inability to meet a network planning requirement. See also: constraint.
network	the apparatus, equipment, plant and buildings used to convey, and control the conveyance of, electricity to customers. See also: distribution network; transmission network. [R]
non-firm	indicates that a contingent event on the network, or portion of the network, may result in the loss of supply to customers. See also: firm.
non-network solution	a solution to a network limitation that does not require the construction of a network augmentation. Examples include electronic control schemes and demand side management.
power factor	the ratio of real power to the apparent power at a metering point. [R]
probability of exceedance (POE)	probability of dropping the temperature below the reference temperature used in estimating/forecasting the relevant demand. As temperature is inversely proportionate to demand in Tasmania, the probability is implied as probability to exceed the estimated/forecasted demand with respect to changes in temperatures.
protection	equipment which rapidly detects electrical faults in the network, and then disconnects that part of the network in order to prevent damage.
route kilometre	the physical length of transmission infrastructure required to transport power between two points on the transmission system. See also: circuit kilometre
substation	an installation of electrical infrastructure at a strategic location on the network to provide the functions of voltage transformation, switching and voltage conversion. [R]
switching station	an installation of electrical infrastructure at a strategic location on the network to provide the function switching at a single voltage level.
synchronous generator	for the purposes of this APR, synchronous generators refer to generators driven by hydro, gas, or steam (i.e. coal-fired) turbines. NB: There are no coal-fired power stations in Tasmania. See also: asynchronous generator. [R]
the Rules	the National Electricity Rules
transmission network	the suite of electrical infrastructure required to transmit power from the generating stations to the distribution network and directly connected industrial consumers. In Tasmania, the transmission network comprises the network elements that operate at voltages of either 220 kV or 110 kV, plus the equipment required to control or support those elements. [R]
trip	the sudden disconnection of a generator, load or transmission or distribution circuit from the remainder of the network.
voltage	the force which causes electrical current to flow. [R]

Appendix A Regulatory framework and planning process

This appendix outlines the National and jurisdictional frameworks under which TasNetworks plans the Tasmanian transmission and distribution systems. These frameworks include the integrated planning process, our asset management strategy, planning considerations, and technical analysis – including demand forecasting.

The transition of the National Energy Market (**NEM**) to a lower emission generation mix is complex and multifaceted. Renewable generation needs to connect to the electricity network in a way that is coordinated and minimises costly augmentation of the transmission network. The transition of the NEM will continue to pose challenges and TasNetworks will continue to advocate for regulatory outcomes that will benefit all Tasmanians.

Sections A.6 and A.7 show how TasNetworks is using the regulatory environment to help customers identify cost-effective demand management solutions and connect embedded generation. Outlined is our demand management assessment process and common issues faced by the connection of embedded generation.

A.1 Regulatory framework

TasNetworks operates under both State and national regulatory regimes. As a registered participant in the NEM, TasNetworks is required to develop, operate, and maintain the electricity supply system in accordance with the National Electricity Rules (**the Rules**), including the technical requirements of Schedule 5.1 System Standards. In addition, there are local requirements we must comply with under the terms of our licences, that are issued by the Office of the Tasmanian Economic Regulator (**OTTER**) under the *Electricity Supply Industry Act 1995*. TasNetworks is also subject to a number of other Acts and industry-specific regulations in planning our networks. These include:

- the *Electricity Supply Industry (Network Planning Requirements) Regulations 2018*;
- the Tasmanian Electricity Code (**the Code**); and
- a number of environmental, cultural, land use planning and other acts.

The revenue TasNetworks can recover from customers for the provision of prescribed transmission services and distribution network services in Tasmania is regulated by the Australian Energy Regulator (**AER**).

A. 1.1 Tasmanian Electricity Code

The Code is published and maintained by OTTER.[71] It contains arrangements for the regulation of Tasmania's electricity supply industry in addition to those in the Rules. The Code largely relates to the operation of the distribution network. It contains technical standards for power quality, standards of service for embedded generators and distribution network reliability standards.

A.1.2 Revenue determination

As a monopoly provider of transmission and distribution network services, the revenue TasNetworks earns from its customers is determined by the AER. In setting TasNetworks' revenue allowances, the AER expects TasNetworks to improve its efficiency by reducing the costs of the services we provide, while maintaining or improving the quality and reliability of its services.

This regulation exists primarily to protect electricity customers by ensuring specific performance standards are met and capping revenues based on efficient costs – which are forecast, benchmarked and scrutinised by the AER prior to the commencement of each 5-year regulatory control period.

The most recent determinations for TasNetworks were made by the AER in April 2024[72] for the 2024–2029 regulatory control period. This revenue determination, together with ongoing efficiencies achieved by TasNetworks, help keep downward pressure on the delivered cost of electricity in Tasmania, while ensuring we have the resources needed to maintain a safe and reliable network. The capital expenditure program for network services in our revenue determination included many of the proposed investments identified in this Annual Planning Report (**APR**).

71 https://www.economicregulator.tas.gov.au/electricity/regulatory-framework/codes/tasmanian-electricity-code-background

72 TasNetworks - Determination 2024–29 | Australian Energy Regulator (AER)

A.2 Integrated planning

TasNetworks is responsible for planning the future of the electricity transmission and distribution networks in Tasmania. This includes ensuring the networks remain safe and reliable, comply with relevant laws, the Rules, good electricity industry practice, and other standards, and that they remain adequate to accommodate changes in both generation and load. We also identify network augmentations, and non-network alternatives, that will provide net economic benefit to all customers in the NEM. This is achieved through our network planning process, which ensures the solutions implemented by TasNetworks balance both the economic and technical requirements of customers and the network.

TasNetworks' annual planning process is informed by a number of strategies, including:

- TasNetworks' Transformation Roadmap 2025 and strategy to 2030, which ensure that we adapt to the changing operating environment and continue to provide cost-effective services to our customers. (An overview of TasNetworks' 2025 roadmap and 2030 strategy is presented in Section 1.6);
- TasNetworks' network reliability strategy, which aims to at least maintain current overall network reliability while reducing total outage costs;
- TasNetworks' asset management strategy, under which the replacement of transmission and distribution assets is based on asset condition and risk, rather than age; and
- TasNetworks' embedded generation connection and non-network and stand-alone power systems assessments that look to maximise benefits for our customers through the use of new technology.

A.2.1 The network planning process

We consider transmission and distribution planning as an integrated function, planning for one electricity network. Our network planning process aims to identify what changes to the electricity network will be required in future years in response to a number of factors:

- new generation, including embedded generators, may be constructed, or old ones removed from service. These changes influence where electricity flows in a network;
- as network equipment ages and its condition deteriorates, it becomes more likely to fail. We investigate whether it is best to continue maintenance, replace, or if it may be possible to decommission and use alternative parts of the network, or implement non-network solutions;
- electricity demand can change. For example, the existing network may not have sufficient capacity to supply additional electricity to a rapidly expanding suburban area. Or there may be a general overall increase – or decrease – in the amount of electricity used per household. A new large load, such as a AI factories, or closure of large load, such as a mine, will also cause changes in electricity demand; and
- technological changes impact the network. Historically, residential customers only used electricity. Now with solar-photovoltaic (**PV**) and battery storage technology, our customers are producing and storing electricity – and supplying into the network. This affects the way we plan and operate the network.

As part of our planning process, we consider the transmission and distribution network requirements with our customer and stakeholder requirements. The network planning process is ongoing and while the APR is a view at a particular point in time, the planning environment is dynamic and plans can and do adjust with changing circumstances.

From this, we create 15-year network strategies that inform the network limitations and developments included in our APR for a 10-year timeframe. As our annual planning review is for 15 years, we can revise our plans if forecast generation and load changes, or other factors change or do not eventuate.

We also identify the changes in the network that may be required in the long term (beyond 15 years), from different generation and load scenarios. From this, we ensure our development plans can accommodate a range of possible futures for the network and customers.

A.2.2 Annual planning review

We perform an annual planning review to identify and report on existing and future limitations in our network. A summary of the outcomes from our annual planning review forms the basis of our APR. Our APR presents the foreseeable network needs, the potential options to resolve them, and–where a particular option looks favourable–the likely cost and timing of that option. It is a summary of how things appear now. Because network planning is a recurring process, we may find the expected needs change from one year to the next–some proposed network changes may not be required, others may be required sooner.

The network planning process followed by the annual review is presented in Figure A-1 and outlined in the following sections.

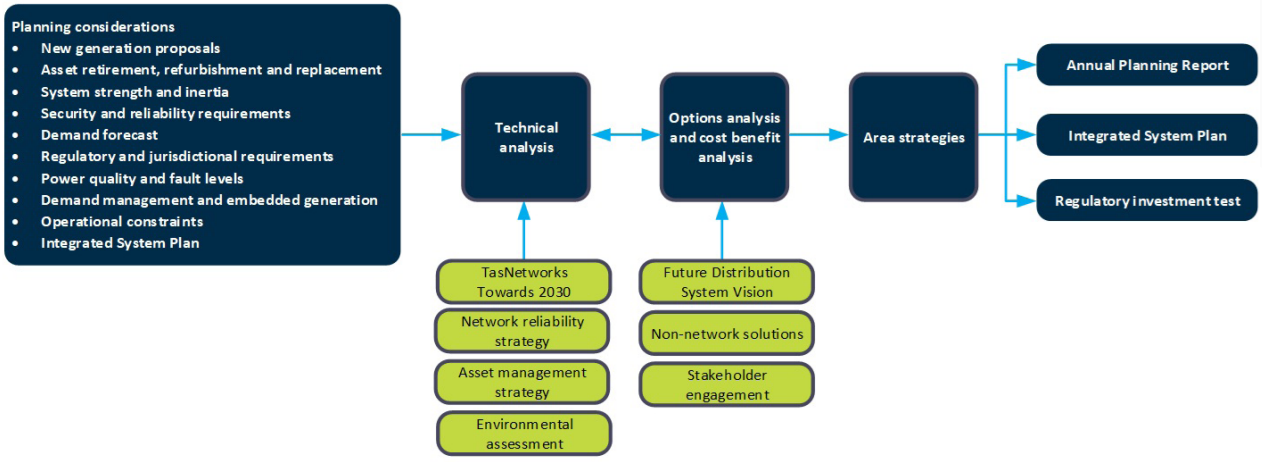


Figure A-1: The network planning process

A.3 Planning considerations and technical analysis

There are a number of planning considerations incorporated into our annual planning review. These include forecast factors that can change from year to year such as generation and demand changes and asset condition assessments, and planning and operation requirements that tend to remain constant against which we assess generation and load changes.

We become aware of new or changed generation developments through our connection process, and publicly announced information. We develop our demand forecasts for planning areas, zone substations, and sub-transmission and distribution feeders of the network from the Australian Energy Market Operator's (**AEMO**) Tasmanian regional forecast and our own insights.

The power system is modelled to identify where the network will no longer be adequate with the planning considerations assessed. This includes where assets are planned to be retired due to condition and other issues. Limitations relate not only to the design capacity of equipment, but also to other regulations that dictate how the network must perform in the event of a fault.

Sensitivity analysis is conducted where a future network limitation is identified and where a change in the input assumptions may have a material impact on the timing or severity of the limitation occurring. We consult with our customers in accordance with our customer engagement policies, and including this APR, on the risk (probability and impact) associated with the limitation. The sensitivity analysis and consultation are key inputs into our decision of what solution, if any, is required and the optimal timing to implement it.

A.3.1 National Electricity Rules Schedule 5.1

Schedule 5.1 of the Rules describes the planning, design and operating criteria that must be applied by network service providers to the networks which they own, operate or control.[73] These criteria are quantitative and relate to electrical characteristics such as: voltage limits, voltage unbalance, short-term voltage fluctuations, harmonic voltage limits, protection operation times, and power system stability.

A.3.2 Demand forecasts

The demand forecast is a key component of our network area planning process. We use the demand forecast to identify the timing of capacity and other technical limitations in the network. We plan our network to 50% probability of exceedance (**POE**) forecasts, for both winter and summer maximum demands. We conduct sensitivity analysis to determine the impact a change in the demand forecast may have on the timing of a limitation, its severity, or the preferred solution for addressing it.

Moderate forecast demand increases are expected across Tasmania over the medium to long term from increased residential consumption and continued electric vehicle (**EV**) uptake. The demand forecast also captures the effects of international geopolitics, and global economic conditions on the Australian economy. We then develop area and locality forecasts for transmission planning, and for sub-transmission, zone substation, and distribution feeder forecasts for distribution planning.

We also consider the AEMO State level forecast, that is produced as part of the annual electricity statement of opportunities (**ESOO**). The ESOO forecasts are limited to State level, and therefore cannot be used for connection point forecasting; however, they provide some insight into Tasmania's projected demand in the broader context of the NEM.

We use the connection point forecast to produce maximum demand forecasts for zone substations and distribution lines. The forecasts are determined by multiplying the historic demand by the ratio of the forecast maximum demand and the historic maximum demand of the associated transmission-distribution connection point. Post model adjustments are made to these zone substation and distribution line maximum demands to reflect known changes in point loads.

Substations, zone substations and feeder maximum demand forecasts, and substations load profiles are available as downloadable appendices to this APR on our website: **www.tasnetworks.com.au/apr**

A.3.3 Transmission system planning requirements

In planning our transmission network at a planning area level, our main considerations are our jurisdictional network planning requirements and opportunities for developments that provide a market benefit. The jurisdictional network planning requirements are to ensure that the network is planned to withstand credible and certain non-credible contingencies. Market benefit developments may either release lower cost generation or reduce the risk of unserved energy.

In planning the transmission network, we utilise the short-term rating (generally four-hour) for supply and network transformers where appropriate. These ratings depend on cyclic loads, so cannot be used for energy-intensive and continuous loads. We rate our transmission circuits to their seasonal static rating, with our first check for any limitation being how the limit is impacted when applying our dynamic ratings which are used in normal operation of the network.

The *Electricity Supply Industry (Network Planning Requirements) Regulations 2018* specify the reliability standards we must use when planning the transmission network.[74] The regulations define the maximum extent of power interruptions following contingency events. They only apply to our transmission network, not our distribution network. They are referred to as "applicable regulatory instruments" under the Rules, being our jurisdictional network planning requirements (and are referred to that in this APR for the transmission network).

73 https://www.aemc.gov.au/regulation/energy-rules/national-electricity-rules/current

74 https://www.legislation.tas.gov.au/view/html/inforce/current/sr-2018-002

Minimum transmission network performance requirements

(1) Power system planning in respect of a relevant transmission system must be such that the system is likely to meet the following network performance requirements:

(a) in respect of an **intact transmission system** –

(i) no more than 25 MW of load is to be capable of being interrupted by a **credible contingency event**; and

(ii) no more than 850 MW of load is to be capable of being interrupted by a **single asset failure**; and

(iii) load that is interrupted by a **single asset failure** is not to be capable of resulting in a black system; and

(iv) the unserved energy to load that is interrupted consequent on damage to a **network element** resulting from a credible contingency event is not to be capable of exceeding 300 MWh at any time; and

(v) the unserved energy to load that is interrupted by a **single asset failure** is not to be capable of exceeding 3 000 MWh at any time;

(b) in respect of a transmission system that is **not an intact transmission system**, the active energy exposed to interruption by a **credible contingency event** is not to be capable of exceeding 18,000 MWh at any time.

(2) The network performance requirements under subregulation (1) constitute the service standards that a Provider must take into account, for the purposes of the Regulatory Investment Test for Transmission (**RIT-T**) in carrying out power system planning in respect of a relevant transmission system.

(3) For the purpose of meeting the requirements under subregulation (1), a Provider may use load shedding –

(a) to control network load after a **non-credible contingency event**; or

(b) as specified in a contract, agreement or arrangement entered into by the Provider and a **Transmission Customer**.

(4) For the purpose of calculating unserved energy under subregulation (1) , any replacements or repairs undertaken must be taken to not exceed –

(a) 48 hours to repair a transmission line; or

(b) 8 days to replace a transformer; or

(c) 18 days to replace an autotransformer

A **credible contingency** event

Means a contingency event the occurrence of which AEMO considers to be reasonably possible in the surrounding circumstances including the technical envelope.

network element

A single identifiable major component of a transmission system or distribution system involving:

(a) an individual transmission or distribution circuit or a phase of that circuit; or

(b) a major item of apparatus or equipment associated with the function or operation of a transmission line, distribution line or an associated substation or switchyard which may include transformers, circuit breakers, synchronous condensers, reactive plant, monitoring equipment, and control equipment.

transmission line

A power line that is part of a transmission network.

single asset

(a) one double transmission line circuit that contains 2 three-phase circuits; or

(b) one circuit breaker as defined in Australian Standard AS 1852-441 entitled "International Electrotechnical Vocabulary, Chapter 441 – switchgear, control gear, and fuses" published by Standards Australia on 7 June 1985, as amended or substituted from time to time; or

(c) one substation busbar

Single asset failure

means one single incident (**other than a credible contingency event**) that results in the failure of one **single asset** to perform its intended function.

The following provides a perspective on the implications of the transmission network planning requirements as they relate to quantities of load demand.

Damage to a network element resulting from a credible contingency event is not to be capable of exceeding 300 MWh

Transmission Line – 300 MWh over 48 hours equates to an average demand of 6.25 MW

Transformer – 300 MWh over 8 days equates to an average demand of 1.56 MW

Single asset failure is not to be capable of exceeding 3,000 MWh

Transmission Line – 3,000 MWh over 48 hours equates to an average demand of 62.5 MW

Circuit Breaker or Busbar – Period of time for calculation is not stipulated; however, circuit breaker and busbar replacements can take extended periods of time – 3 000 MWh over 8 days equates to an average demand of 15.6 MW

These regulations allow for exemptions from the performance requirements, based on consultation with our customers. If all transmission customers – whose supply reliability would be affected by a proposed network augmentation – consider it would not be beneficial, then we must report this in our APR. We are then exempt for five years from undertaking that augmentation and from meeting that network planning requirement. The exemption may end early if the circumstances surrounding the exemption change or if one of the affected transmission customers no longer wishes the exemption to remain.

A.3.4 Distribution System planning requirements

In our sub-transmission and distribution network, our reliability planning requirements are our System Average Interruption Frequency Index **(SAIFI)** and System Average Interruption Duration Index (**SAIDI**) standards under the Code. As part of our strategy to minimise outage impact on reliability, we plan our sub-transmission network and zone substations to firm (N-1) reliability. Switched firm – transferring interrupted load to an alternative supply in a short time – is generally acceptable.

In capacity planning of our distribution lines, we determine their capacity via simulation. We determine the capacity by identifying at what loading any element of the line trunk is at its limit for either thermal capacity or voltage compliance with the Code requirements.

Distribution system planning criteria are associated with augmentation of terminal and zone substations and sub-transmission assets aimed at meeting regional adequacy and security requirements.

Adequacy criteria relate to the capability to meet the demand within network element capacities (ratings), quality of supply limits, fault level, and accessibility expectations.

Security criteria relate to the ability of the power system to cope with incidents without the uncontrolled loss of load.

Security criteria are associated with supply survivability, being the ability to cope with incidents without the uncontrolled loss of load. Survivability comprises three elements:

- susceptibility – ability to avoid incidents (*prevent*),
- vulnerability – ability to withstand incidents; that is to maintain supply, (*minimise*) and
- recoverability – ability to restore functionality; that is to restore supply (*respond*).

Network planning criteria only cover vulnerability and recoverability. Susceptibility is the subject of detailed network element design.

Security network planning criteria are referenced by deterministic N, N-1, N-2 measures and the variants. Security planning philosophy is a conjunction of the deterministic standard as well as a group firm philosophy. The application of this approach allows deferment of major capital investment whilst understanding the level of risk that may result.

Three N-1 standards are applied representing the mechanism by which continuity of supply is maintained:

N-1 (A). Full N-1: Duplicate (parallel) supply at substation busbar (this level of security implies the parallel operation of critical elements under normal circumstances; a momentary outage of duration <60 seconds while automatic switching takes place may be necessary in specific circumstances).

N-1 (B). Remote Switch N-1: Short outage (restoration target ≤30 minutes) may occur while load transfers are undertaken via remote control.

N-1 (C). Manual Switch N-1: Medium outage (restoration target ≤3 hours) may occur while field switching is undertaken to effect load transfers.

N security restoration requires repair or reinstatement. Restoration targets are:

For loss of a substation ≤12 hours

For loss of a sub-transmission line ≤6 hours (loads greater than 5 MVA)

For loss of a sub-transmission line <12 hours (loads less than 5 MVA)

Terminal and zone substation and sub-transmission reliability normally have second order impacts on the overall service reliability. As a consequence, correlation between outcome reliability performance and planning criteria is second order. Thus the planning criteria concern the requirement for:

- transmission terminal substations,
- sub-transmission,
- zone substations, and
- numbers of feeders.

An underlying tenet of the required level of network service is that, with the network in its normal topological state, the network will have sufficient *adequacy* to meet all network loading demand; that is, no involuntary supply interruptions.

Distribution substation, feeder, and reticulation augmentations are largely required to meet situation-specific drivers with design criteria aimed at meeting quality of supply requirements. The outcome reliability is largely determined by distribution substation, feeder, and reticulation performance which, in turn, is largely determined by operation, maintenance, and fault response practices.

The service levels are those associated with Clause 8.6.11 of the Code, Interruptions to Supply. In addition to the Code requirements, we are subject to Guaranteed Service Level scheme agreed with OTTER[75] and in combination with other performance measures forms the Service Target Performance Incentive Scheme under the Rules.

Technical performance as required by the Rules and Code are mandated requirements and are not discussed specifically as application of the input reliability planning criteria largely delivers the required quality.

75 Guideline Guaranteed Service Level Scheme July 2012 https://www.economicregulator.tas.gov.au/electricity/regulatory-framework/guidelines

A.4 Asset management strategy

Managing our existing assets and the planning for future network requirements are processes that must be coordinated to deliver the required service levels in the most cost-efficient manner. The asset management strategy focuses on ensuring the repair and replacement of assets are determined objectively by overall risk (taking account of asset criticality and condition). Our Strategic Asset Management Plan outlines the systems and strategies developed to effectively and efficiently manage the delivery of electricity and telecommunication network services to our customers and to provide information to our stakeholders regarding the environment in which we operate.

Key themes supporting our asset management approach and associated levels of investment are:

- addressing safety and/or environmental impacts;
- maintaining the reliability of the network;
- maximising asset life and utilisation in preference to asset replacement;
- considering future network and customer needs in decision making;
- conduct a rigorous asset selection process, including trials, to deliver customer outcomes;
- taking a whole of life (life cycle) approach to optimise cost and service outcomes for our customers;
- balancing investment expenditure with customer price impacts; and
- aligning our ongoing asset management activities with industry initiatives such as Marinus Link, AEMO's Integrated System Plan (**ISP**), Hydro Tasmania's Cethana pumped hydro energy storage, and Tarraleah power station redevelopment.

Our approach centres on asset life cycle management extending over five phases, as presented in Figure A-2.

Each phase of the life cycle has a corresponding life cycle strategy detailing our objectives and approach to the particular activities in that phase to ensure performance to required levels. Each phase is monitored and managed to close the feedback loop back into asset investment planning.

Figure A-2: Asset life cycle management

Most of our asset management activities are managed at an asset category level. The strategies for each asset category are contained in Asset Management Plans. These plans identify the performance and risks presented by each asset type within the category and define actions that must be undertaken to sustain asset and system performance. These actions can take the form of particular asset-based decision methods and include:

- age-based risk management;
- condition-based risk management;
- criticality- based risk management (current risk);
- mitigated risk-based management (reliability); and
- optimisation of investment value (value Based).

Our Strategic Asset Management Plan and Asset Management Policy are available on request.

A.5 Options and cost-benefit analysis

When we find network changes are required, we identify the possible options to address the need. Options could include expansion of the network, working with customers to reduce their energy or demand to defer the need, or other options. Only options that are economic and will meet the current and future needs of the network and customers are considered. We determine the advantages and disadvantages of each option and investigate each one in detail to confirm its feasibility. For feasible options, we estimate the cost and the potential economic benefits (for example, there may be an economic benefit in averting or reducing the loss of supply to a particular area) to identify the preferred solution.

Upon identification of a preferred solution, we consult with affected customers to confirm if there is sufficient benefit in proceeding.

A.5.1 Regulatory investment test

The Regulatory Investment Test (**RIT**) defines the economic analysis and public consultation process a network service provider must undertake in selecting an option to address a need in the power system.

The RIT and application guidelines are published by the AER under clause 5.16 (transmission) and clause 5.17 (distribution) of the Rules. As a transmission and distribution network service provider, we are required to apply the test for all transmission (RIT-T) and distribution (RIT-D) projects that exceed the RIT expenditure thresholds. Some projects are exempt from the RIT, for example those that are in response to a customer's connection application.

A.5.2. Accounting for network losses

Network losses are electrical energy (active energy) losses incurred in transporting electricity over transmission and distribution networks. Electrical energy losses can be classified as:

- technical losses comprising:
  - series losses associated with the flow of electricity and the resistance of the electricity circuits; and
  - shunt losses which is "leakage" of electrical energy associated with "charging up" or "excitation" of the network and occur regardless of the amount of electrical power flowing through the network.
- non-technical losses due to metering data errors, un-metered supplies, unbilled customers, information system deficiencies, modelling assumptions and theft.

Each financial year we calculate distribution loss factors (**DLFs**)[76] that describe the average electrical energy lost in transporting electricity from a transmission network connection point (or virtual transmission node) to a distribution customer connection. These loss factors account for both technical and non-technical losses. AEMO uses these DLFs in market settlements to calculate the electrical energy attributed to each retailer at each transmission network connection point.

Similarly, AEMO calculates forward-looking transmission loss factors to facilitate efficient scheduling and settlement processes in the NEM.[77]

As losses impact the price of electricity, they are an important consideration when developing and implementing asset management and investment strategies. Loss management is an optimisation between cost of infrastructure and loss reduction and the management of quality of supply and electricity flows across the network. Losses are a consideration in the RIT in calculating the costs and benefits associated the economic justification of projects at both transmission and distribution levels.

76 https://www.tasnetworks.com.au/Poles-and-wires/Planning-and-developments/Planning-our-network

77 http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Loss-factor-and-regional-boundaries

A.6 Non-network and Stand Alone Power Systems assessments

We consider Stand Alone Power Systems (**SAPS**) and other non-network opportunities during the planning cycle when investigating solutions to network limitations, with particular focus on the distribution network. To that end, we have developed an Industry Engagement Strategy[78] that explains how we will engage and consult with our customers and suppliers to deliver solutions for our distribution network. We encourage non-network and SAPS resource providers to register with us on our website.[79]

An early analysis of possible solutions is completed at a high level and includes desktop studies, site visits and discussions with our customers and providers. The assessment of solutions comprises four stages and involves analysis of the costs, benefits, and risks of each option.

Stage 1: Investigation

We investigate the network issue and assess network, non-network, and SAPS options to solve it. If either a non-network or SAPS option is credible, we determine the economic benefit provided by deferring or avoiding any network solution.

Stage 2: Development

We then compare the non-network or SAPS options against network options and evaluate for cost, risk, and potential benefits. During this stage, if a non-network or SAPS project is subject to the RIT, we publish an options screening report (for distribution projects) or project specification consultation report (for transmission projects). The information enables proponents to assess their options.

Stage 3: Assessment

We ask for proposals from our customers and demand management providers to address an issue. These are evaluated against conventional project implementation criteria and costs and benefits.

Stage 4: Reporting

All enquiries and proposals receive a written response and interested parties are advised of the status of their assessment at regular intervals. We publish the initial results in a draft project assessment report and allow our customers and providers to provide feedback. We consider feedback and then publish a final report for the preferred solution and the reason for its selection.

78 https://www.tasnetworks.com.au/Forms/Industry-Engagement-Register/Industry-Engagement

79 https://www.tasnetworks.com.au/Forms/Demand-Management-Industry-Engagement-Register

A.7 Connecting embedded generation

Connecting generation can be a complex process with electricians or retailers able to provide assistance with the process and determining the appropriate connection type. As part of the embedded generation connection process[80] TasNetworks is required to provide information on every Distributed Energy Resource (**DER**) connected to the distribution network to AEMO to feed into their DER Register.[81,82] 'As-built' information is a mandatory step in the application process prior to TasNetworks completing a connection.

A.7.1 Synchronous generators

Synchronous generators (rotating machines) can pose risks to other network users (and the synchronous generator) during islanding-type faults. An "island" is a situation where part of our network, which contains a generator, becomes disconnected from the remainder of our network. Should that generator continue to operate, the islanded part of our network will still be live, with possibly minimal control over the voltage and frequency unless operating as a dedicated microgrid. This would pose a danger to our people, customers, and electrical equipment. It is therefore necessary to ensure embedded generators are equipped with anti-islanding protection devices.[83] In addition to local anti-islanding protection devices, a telecommunications based anti-islanding inter-trip[84] may be required to ensure any generation is disconnected upon detection of an island.

We must approve the anti-islanding protection of the synchronous generator before network connection. Similarly, the nature of synchronous generation is that they cannot be re-connected to the network without firstly ensuring that conditions are suitable for them to do so. It is customary to have automatic reclose schemes on distribution feeders that can quickly restore supply. Before these schemes can restore supply, all sources of generation must be disconnected from the network. Sudden disconnection of distribution connected synchronous generation can lead to unacceptable reductions in local network voltage. In such circumstances, appropriate voltage control schemes approved by us will be required.

A.7.2 Asynchronous generators

Asynchronous generators connecting to our network are mainly inverter based systems, which use power electronics to convert electrical power from either direct current, or a variable frequency alternating current (**AC**) waveform, to a 50 Hz AC supply which allows connection to the main network.

There are both network-wide and local issues associated with PV installations. From a network-wide perspective, and for maintenance of power system security, it is important PV installations remain connected following frequency disturbances. This is a major issue because:

- being a relatively small power system, frequency disturbances are relatively common; and
- our operational frequency bands are wider than mainland Australia.

Disconnection of a high proportion of PV installations during a low-frequency disturbance would magnify the frequency excursion, which could lead to unanticipated load tripping. In the worst case, this could occur in response to even a single contingency event, which would be unacceptable for our customers and contravene the Rules.

High penetration of PV along with other asynchronous generation can result in reduction in system strength required to maintain a stable power system. As outlined in Section 5.2.2, a power system fault level framework sets out clear allocation of roles and responsibilities for AEMO and Network Service Providers in the management of system strength. It requires Transmission Network Service Providers (**TNSPs**) to procure system strength services needed to provide the levels determined by AEMO.

80 https://www.tasnetworks.com.au/embedded-generation

81 https://aemo.com.au/energy-systems/electricity/der-register

82 https://www.tasnetworks.com.au/connections/distributed-energy-resource-register

83 An anti-islanding protection device will cause the generator to shut down should its part of the network become disconnected from the rest of the network. All compliant grid-connected PV inverters are designed with anti-islanding protection

84 Local anti-islanding protection devices may not always detect an island situation. A telecommunications based inter-trip will ensure that generation will be disconnected by monitoring the status of the connecting distribution equipment

Local issues mainly relate to voltage regulation in our distribution network. Unlike mainland jurisdictions, in Tasmania PV contributes very little to reducing the maximum demand on the network. Maximum PV output usually occurs in the middle of the day in summer when solar radiation is highest. Maximum demand in Tasmania occurs during early mornings or evenings in winter, when there is virtually zero contribution from PV. Essentially, PV penetration further depresses the summer minimum load and a number of low-voltage circuits are becoming net generators with the result that voltages can rise to unacceptable levels.

A.8 Incentive schemes

As part of the regulatory framework, both the AER and OTTER apply a number of incentive schemes to encourage network service providers to make efficient spending decisions in the long-term interests of customers. Balanced incentives are designed to encourage businesses to continually improve spending efficiency without compromising network service and performance.

Most incentives are recovered through adjustments to our revenue allowances determined by the AER. Depending on the incentive scheme, these adjustments to TasNetworks' revenue are passed through to customers via annual increases or decreases in network charges, or as part of the AER's revenue setting process.

A.8.1 Service Target Performance Incentive Schemes

The Service Target Performance Incentive Schemes (**STPIS**) for transmission and distribution networks provide financial rewards to network businesses for improvements in performance, which are largely measured in terms of the frequency and duration of supply interruptions. Financial penalties are applied for reductions in performance.

The STPIS for transmission comprises two components: a service component, and a network capability component.

The STPIS for distribution has one component – reliability of supply. This evaluates TasNetworks performance in outage duration and frequency against pre-determined targets.

A.8.2 Changes to Transmission STPIS

In May 2026, the AEMC made a rule to disapply the market impact component (**MIC**) of STPIS. The MIC intends to incentive TNSPs to schedule planned outages at times which minimise the impact on spot market outcomes. However, in a review by the AER, it was determined that due to changes in the energy generation mix caused by the transition to more distributed energy resources, the MIC was no longer working as intended.

A.8.3 Guaranteed Service Level Scheme

TasNetworks' is subject to a guaranteed service level (**GSL**) scheme administered by OTTER. The purpose of the scheme is to ensure customers throughout Tasmania receive at least a minimum level of network reliability. Where the number of outages or the cumulative duration of outages experienced by a customer over a rolling 12month period exceeds the maximum number or duration of outages set under the Code, affected customers are entitled to a payment from TasNetworks. Under the Code, the State is divided into 121 geographical communities, with each community assigned to one of five reliability categories and different reliability standards applying to each category.

A.8.4 Customer Service Incentive Scheme

The AER has introduced the CSIS to encourage distribution businesses to improve the aspects of their service delivery that their customers want improved. TasNetworks has consulted with customers to determine the service parameters that best reflect their expectations and the AER has approved a CSIS for the 2024-2029 regulatory period which is based on measurements of:

- customers' satisfaction with TasNetworks' handling of complaints;
- customer satisfaction with TasNetworks' management of outages (both planned and unplanned);and
- customers' satisfaction with TasNetworks' provision of new connections.

A.8.5 Efficiency Benefit Sharing Scheme

The efficiency benefit sharing scheme (**EBSS**) provides financial rewards to network businesses that are able to reduce their operational expenditure (**OPEX**) on regulated services and sustain those savings over time. The EBSS also penalises network businesses that overspend against their OPEX allowance and/or do not sustain previously realised savings. There are separate schemes for transmission and distribution networks which, nonetheless, are based on very similar principles.

The EBSS works on the principle that OPEX in a year "resets" the efficient level of OPEX under the EBSS. Performance is measured against this new EBSS target and the operating allowance that is set as part of a regulatory determination cycle. A network may retain any annual efficiency gain for a period of five years or be penalised for any inefficiency for five years.

A.8.6 Capital Expenditure Sharing Scheme

The capital expenditure sharing scheme (**CESS**) creates an incentive for network businesses to undertake efficient capital expenditure (**CAPEX**) during each regulatory control period. Businesses are rewarded for spending less than their regulatory allowance or penalised for spending over the allowance.

The AER conducts reviews of networks' CAPEX in setting their CAPEX allowances as part of the regulatory determination process, and again at the end of each regulatory control period, to ensure customers do not bear the costs of inefficient spending. CESS bonuses or penalties are taken into account by the AER when calculating the allowed revenue for each network service provider in the next regulatory control period.

A.8.7 Incentives for Demand Management – Distribution

There are two demand management schemes for distribution businesses overseen by the AER. They are the:

- Demand Management Incentive Scheme (**DMIS**); and
- Demand Management Innovation Allowance Mechanism (**DMIAM**).

The DMIS provides distribution businesses with an incentive to undertake efficient expenditure on relevant non-network options relating to demand management.

The DMIAM provides funding (through an ex-ante allowance) for research and development in demand management projects that have the potential to reduce long term network costs. TasNetworks has previously utilised the DMIAM to fund the development of customer-owned storage as a peak demand management tool and to investigate the potential for demand-based tariffs to be used to reduce peak demand.

A.8.8 Demand Management Innovation Allowance Mechanism – Transmission

For electricity transmission network service providers there is only one demand management related incentive scheme, the DMIAM. The criteria for DMIAM funding is as for the Demand Management Innovation Allowance Mechanism for distribution network service providers, with the addition that demand management projects that also improve wholesale market outcomes should be considered. Transmission network businesses are also required, where requested, to share the results, learnings, and insights gained from implementing any projects or programmes that receive funding under the DMIAM.

Appendix B Generator information

Table B-1 lists the Tasmanian generators connected to the transmission network.[85] It includes committed generation developments.

Table B-1: Transmission-connected generation

Generator	Capacity (MW)	TasNetworks planning area	Connection to shared network
Gas			
Tamar Valley	386	Northern	George Town
Hydro			
Butlers Gorge and Nieterana[86]	14.9	Central	Butlers Gorge Tee
Catagunya	50		Liapootah
Cluny	19.7		Liapootah–Chapel Street 220 kV
Gordon	450		Gordon
Lake Echo	33.5		Tungatinah–Waddamana 110 kV
Liapootah	87.3		Liapootah
Meadowbank	43.8		Meadowbank
Repulse	29.1		Liapootah–Chapel Street 220 kV
Tarraleah	93.6		Tungatinah
Tungatinah (unavailable)	142.2		Tungatinah
Wayatinah	45		Liapootah
Poatina	363	Northern	Palmerston
Trevallyn	102.8		Trevallyn
Cethana	100	North West and West Coast	Sheffield
Devils Gate	63		
Fisher	46		
Lemonthyme	54		
Rowallan	11		
Wilmot	32		
Paloona	31.5		Sheffield–Ulverstone 110 kV
Bastyan	81		Farrell
John Butters	145		
Mackintosh	89		
Reece	244		
Tribute	92		
Wind			
Wild Cattle Hill	148	Central	Waddamana
Musselroe	168	Northern	Derby

85 Capacity information sourced from:
https://www.hydro.com.au/clean-energy/our-power-stations
http://www.cattlehillwindfarm.com/
https://granvilleharbourwindfarm.com.au/

86 Nieterana is a mini-hydro power station, which is connected to Butlers Gorge Power Station. The total power generated by Butlers Gorge (capacity 12.7 MW) and Nieterana (2.2 MW) flows through this connection point to the network

Generator	Capacity (MW)	TasNetworks planning area	Connection to shared network
Bluff Point	65	North West and West Coast	Smithton
Studland Bay	75		
Granville Harbour	112		Farrell

Table B-2 lists the embedded generation sites within the distribution network. Hydro Tasmania also operates two power stations, Upper Lake Margaret Power Station (8.3 MW) and Lower Lake Margaret mini-hydro (3.2 MW) that are connected to the switchboard at Mt Lyell copper mine. These are not classified as embedded generation as they are not connected within the distribution network, however may export to the transmission network.

Table B-2: Embedded generation over 0.5 MW

Location	Source	Capacity (MW)	Export (MW)	TasNetworks planning area	Connecting distribution line
Maydena	Hydro	0.56	0.56	Central	New Norfolk 39571
Tods Corner	Hydro	1.7	1.7		Arthurs Lake 49101
Ouse	Hydro	1.0	1.0		Wayatinah 49412
Derby	Hydro	1.12	1.12	Northern	Derby 55001
Herrick	Hydro	0.9	0.9		Derby 55002
Launceston	Natural gas	2.0	2.0		Trevallyn 61026
Mowbray	Biomass	2.2	1.1		Mowbray 62006
Tunbridge	Hydro	5.0	4.9		Avoca 56004
George Town	PV	4.95	4.95		George Town 53003
Little Fisher	Hydro	0.8	0.8	North West and West Coast	Railton 85001
Meander	Hydro	1.9	1.9		Railton 85006
Nietta	Hydro	0.9	0.9		Ulverstone 82004
Parangana Lake	Hydro	0.78	0.78		Railton 85001
Quoiba	PV	0.51	0.51		Devonport 80011
Ulverstone	Natural gas	7.9	2.0		Ulverstone 82006
Woolnorth	Wind	0.6	0.55		Smithton 93005
Wynyard	Natural gas	2.0	0.0		Burnie 91004
Glenorchy	Biomass	1.7	1.5	Southern	Chapel Street 20551
South Hobart	Biomass	1.1	1.1		West Hobart 13045
Copping	Biomass	1.1	1.1		Sorell 41515

Appendix C Distribution network reliability performance measures and results

Historical distribution reliability performance is presented in this section. This is supporting information for the discussion in Sections – 6.4.1 and 6.4.2. The information presented here is our performance against the standards set out in the Tasmanian Electricity Code (**the Code**) and targets by the Australian Energy Regulator (**AER**) over the last five years.

C.1 Performance against the Code standards

C.1.1 Supply reliability categories

Table C-1 and Table C-2 present our performance for reliability categories for System Average Interruption Frequency Index (**SAIFI**) and System Average Interruption Duration Index (**SAIDI**), respectively, against the standards specified in the Code. The performance presented here is what we provide to the Office of the Tasmanian Economic Regulator (**OTTER**) as part of our normal reporting process. The reliability category performance excludes outages on major event days, transmission network outages, environmental-fire, total fire ban day-related outages and certain third-party outages. Red values indicate where we did not meet the standard.

Table C-1: SAIFI supply reliability category performance (the Code)

Supply reliability category	Standard (interruptions)	2021-22	2022-23	2023-24	2024-25	2025-26
Critical Infrastructure	0.2	0.27	0.12	0.20	0.23	0.12
High Density Commercial	1	0.74	0.34	0.74	0.41	0.49
Urban and Regional Centres	2	1.19	1.14	1.30	1.18	1.38
High Density Rural	4	2.80	2.84	2.87	2.73	3.25
Lower Density Rural	6	4.21	3.79	3.94	3.44	4.08

Table C-2: SAIDI supply reliability category performance (the Code)

Supply reliability category	Standard (minutes)	2021-22	2022-23	2023-24	2024-25	2025-26
Critical Infrastructure	30	69.76	27.84	50.04	66.98	24.21
High Density Commercial	60	86.31	42.87	72.42	46.41	56.19
Urban and Regional Centres	120	161.10	125.64	148.16	140.97	210.43
High Density Rural	480	503.94	342.49	366.91	359.64	416.72
Lower Density Rural	600	1130.70	535.78	611.23	603.37	598.76

C.1.2 Supply reliability areas

In addition to performance requirements for supply reliability categories presented in Section C.1.1, the Code also sets performance standards for the supply reliability areas within the categories.

Table C-3 and Table C-4 present our performance for the 121 supply reliability areas against the SAIFI and SAIDI standards, respectively. The tables present the standards specified in the Code for each community across the five categories, and the number of areas in each category that are not meeting the standard.

Table C-3: Number of poor performing areas (SAIFI)

Supply reliability category (number of areas)		Standard (interruptions)	2021-22	2022-23	2023-24	2024-25	2025-26
Critical Infrastructure (1)	0.2	1	0	0	1	0	
High Density Commercial (8)	2	0	0	0	0	0	
Urban and Regional Centres (44)	4	2	3	2	6	7	
High Density Rural (41)	6	3	5	0	3	4	
Lower Density Rural (27)	8	2	0	1	1	1	
Total (121)			**8**	**8**	**3**	**11**	**12**

Table C-4: Number of poor performing areas (SAIDI)

Supply reliability category (number of areas)	Standard (minutes)	2021-22	2022-23	2023-24	2024-25	2025-26
Critical Infrastructure (1)	30	1	0	1	1	0
High Density Commercial (8)	120	2	1	1	1	1
Urban and Regional Centres (44)	240	11	7	9	12	21
High Density Rural (41)	600	10	6	9	5	8
Lower Density Rural (27)	720	12	6	8	8	8
Total (121)		**36**	**20**	**28**	**27**	**38**

C.2 Performance against AER targets

C.2.1 Reliability of supply

At the commencement of each distribution regulatory period, the AER, as part of our revenue determination, sets standards for distribution network reliability. These standards form part of our Service Target Performance Incentive Scheme (**STPIS**) and are calculated on our actual performance for the preceding five years. The targets set by the AER excludes planned outages, major event days, transmission network outages, environmental-fire, total fire ban day-related outages and certain third-party outages.

Table C-5 and Table C-6 present our performance for reliability categories for SAIFI and SAIDI, respectively, against the standards specified by the AER. Red values indicate where we did not meet the standard.

Table C-5: SAIFI supply reliability category performance (AER)

Regulatory period	2021-24				2024-26		
Supply reliability category	**Target 2019-24**	**2021-22**	**2022-23**	**2023-24**	**Target 2024-29**	**2024-25**	**2025-26**
Critical Infrastructure	0.251	0.051	0.015	0.019	0.070	0.087	0.079
High Density Commercial	0.260	0.655	0.297	0.649	0.377	0.415	0.461
Urban and Regional Centres	1.081	1.019	0.948	1.114	1.015	0.958	0.928
High Density Rural	2.466	2.278	2.510	2.560	2.171	2.397	2.621
Lower Density Rural	3.219	3.452	3.438	3.479	2.948	2.945	3.478

Table C-6: SAIDI supply reliability category performance (AER)

Regulatory period	2021-24				2024-26		
Supply reliability category	**Target 2019-24**	**2021-22**	**2022-23**	**2023-24**	**Target 2024-29**	**2024-25**	**2025-26**
Critical Infrastructure	32.984	3.418	2.018	4.713	5.948	23.044	16.597
High Density Commercial	20.074	56.993	27.971	57.787	38.012	39.218	33.686
Urban and Regional Centres	89.657	96.858	75.236	98.106	92.118	92.922	88.556
High Density Rural	250.959	279.612	256.752	271.564	244.061	260.839	259.243
Lower Density Rural	400.401	468.122	436.126	475.141	398.899	465.402	444.153


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