

TasNetworks Annual Planning Report 2025



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Executive summary

Tasmanian Networks Pty Ltd (TasNetworks) presents its 2025 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. In accordance with the Rules, as the sole Tasmanian Transmission Network Service Provider (TNSP), we are also the System Strength Service Provider (SSSP) and Inertia Service Provider.

This combined transmission and distribution APR provides an overview of our existing networks and considers several key developments and activities that will shape them over the next 10 years; chiefly:

- variable renewable energy generation growth;
- progression of development of a renewable hydrogen industry;
- increased interconnection capacity with the mainland; and
- adaptation of the network with regards to the procurement and management of system strength.

These developments contribute to, and are influenced by national objectives, such as the Australian Energy Market Operator's (AEMO) Integrated System Plan (ISP).

In May 2025 TasNetworks and Marinus Link Pty Ltd (MLPL) boards recommended that shareholders make positive Final Investment Decisions (FID) to proceed with Stage 1 of Project Marinus (the combination of Marinus Link interconnector and North West Transmission Developments (NWTD)), a project of national significance with benefits across the NEM and in particular Tasmania and Victoria. Subsequently, a positive confirmation was made to proceed with Project Marinus Stage 1.

This project has by far the biggest impact on proposed development of TasNetworks' transmission and distribution networks through enabling large investments in renewable energy to meet the legislated Tasmanian Renewable Energy Target (TRET), establishing new industry, securing Tasmania's energy needs, and contributing to the national transition to variable renewable energy.

Renewable energy development

The Tasmanian electricity supply industry makes progress towards contributing to meeting the TRET that, by the end of 2040, aims to deliver 200% of Tasmania's 2020 baseline of 10,500 GWh of renewable generation per year. In this regard there are a number of prospective projects currently at various stages of development across Tasmania, comprising nearly 5,000 MW of wind farms, 1,000 MW of large-scale solar-photovoltaics (PVs), 750 MW of pumped hydro energy storage (PHES), and 800 MW of battery energy storage systems (BESS).

In aggregate, these developments represent an increase of more than double the existing total generation capacity of 3,400 MW of on-island generation covering hydro, gas, wind, and large-scale PVs in Tasmania.

The Tasmanian Government's Renewables, Climate and Future Industries Tasmania (ReCFIT) progressed the Tasmanian Renewable Energy Action Plan (TREAP) aimed at leveraging investment opportunities and growing Tasmania's economy through the energy transition. Under the Renewable Energy Coordination Framework (RECF), ReCFIT completed the Renewable Energy Assessment Process Review resulting in a Renewable Energy Approval Pathway (REAP) being a suite of actions that will support projects, such as wind farms and transmission lines, entering the Major Projects assessment process under the Land Use Planning and Approvals Act 1993 (LUPAA).



Renewable energy zones

Four candidate Tasmanian Renewable Energy Zones (**REZ**) have been identified; 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 have continued to refine our strategies for the future development of these REZs in response to new and currently progressing energy projects across Tasmania.

After announcing the north-west of Tasmania to be the first region to be explored for the development of a REZ, ReCFIT, as the REZ Coordinator, concluded consultation on the candidate REZ in north-west Tasmania to inform any REZ declaration. Draft amending legislation to support REZ objectives will allow the government to declare a REZ along with a set of rules to coordinate how projects are progressed and how associated infrastructure, such as transmission lines, should be developed.

The existing transmission network within the Central Highlands REZ has the capability to host approximately 530 MW of new generation, limited by both the Waddamana–Palmerston transmission corridor capability and the transmission network to the rest of the network. There are proposals for approximately 1,300 MW of new wind generation expected to occur in the Waddamana area and surrounds, including to the south along both the Waddamana–Liapootah and Waddamana–Lindisfarne transmission corridors. Additionally, upgrades to the Tarraleah hydropower scheme progressed including replacement of Tarraleah Power Station with a capacity increase from 90 MW to approximately 210 MW.

There is capability in the existing North West REZ transmission network to accommodate approximately 277 MW of new variable renewable energy. The NWTN supporting the establishment of Marinus Link will increase the future hosting capacity of this REZ. Interest to develop new generation in the area has a combined capacity of approximately 1,900 MW. Additionally, Hydro Tasmania has announced Lake Cethana as its preferred pumped hydro energy storage with a capacity of 750 MW.

The existing transmission network from George Town Substation to the rest of the network comprises four high capacity 220 kV transmission circuits, with the Basslink high voltage direct current (**HVDC**) interconnector terminating at this location. New variable renewable energy from the North East REZ, as well as the north-east offshore area, must connect to the 220 kV network as the 110 kV network does not have sufficient capability to support new connections at any significant scale.

Prospective variable renewable energy developments including wind, PV, and BESS in the North East REZ have a combined capacity approaching 2,000 MW. Hosting capacity is currently limited to approximately 400 MW. Variable renewable energy resources in the far north-east and north-east offshore area would require substantial new transmission assets to connect to the George Town area.

New industry

In 2025, development continued towards the establishment of green hydrogen production in Tasmania, with Bell Bay Powerfuels announced as the provisional proponent for the Tasmanian Green Hydrogen Hub. The Bell Bay Powerfuels Project with scheduled commercial operation in 2029 consists of a 300 MW electrolyser, capable of producing approximately 360,000 tons of methanol per year. Additionally, HIF Tasmania plans to develop Australia's first commercial-scale e-fuels facility near Burnie. The facility will use renewable energy to power 255 MW electrolysers and residue biomass to produce an anticipated 200,000 tons of e-methanol per year.

The development of the State's first green Hydrogen Production & Research Facility at BOC Australia's Lutana site will support research and training development for blue economy industries whilst providing commercial-scale hydrogen.

Our 2024-2029 revenue determination included several contingent projects to support successive tranches of hydrogen developments in Tasmania. Since then, we have progressed a Regulatory Investment Test for Transmission (**RIT-T**) project for the initial tranche of new load connection at George Town.

Integrated System Plan

AEMO is currently developing the 2026 ISP that is 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 identifies the 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 current (2024) version of the ISP modelling indicates:

- Over 600 MW of new wind generation is projected for the Central Highlands REZ 2026-27, with around 1,300 MW projected by 2029-30 to utilise the full capacity of Project Marinus Stage 1. This REZ now has the highest variable renewable energy projection in the Tasmanian region, with nearly 2,300 MW forecast by 2046-47.
- The North West REZ sees a gradual increase of 380 MW of new wind generation by 2034-35, reaching a maximum of 500 MW by 2046-47.
- There is 400 MW of new wind projected for the North East REZ by 2031-32.
- There is no major change in forecast utility-scale variable renewable energy capacity beyond 2042-43.
- There is no utility scale PV or offshore wind development projected in the Step Change scenario for Tasmania. Small scale distributed PV will continue to grow in capacity.

The 2024 ISP optimal development path (**ODP**) further identifies the following transmission augmentations in Tasmania:

- Project Marinus is classified as a single actionable project, with full capacity timing of 2030 and 2032 assumed based on timing advised by the proponent;
- Waddamana- Palmerston upgrade as an actionable project, with earliest feasible timing being July 2029; and
- North West REZ Expansion and Central Highlands REZ Extension network upgrades as future ISP projects.

In addition, AEMO published its second Enhanced Locational Information Report (**ELIR**) providing:

“a collection of metrics and indicators that represent important locational characteristics of the power system, and which may be relevant to inform better regulatory, generator investment, or transmission augmentation decisions.”¹

Whilst the ELIR provides high level locational signals and preliminary guidance it is only a precursor to commencing the connection enquiry and application processes with a network service provider.

Interconnection with the Mainland

Marinus Link is 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.

Following MLPL board’s recommendation to proceed with Stage 1 of Marinus Link, MLPL’s three-part equity owners, the Australian Government (49%), the Victorian Government (33.3%), and the Tasmanian Government (17.7%), undertook detailed analysis, due diligence, and risk assessments and issued a formal FID to proceed with construction commencing in 2026.

In April 2023, MLPL lodged with the Australian Energy Regulator (**AER**) an application for a revenue determination for Marinus Link. The AER’s Commencement and Process Paper sets out a staged approach comprising:

- Stage 1, Part A (early works): a revenue determination for pre-construction activities;
- Stage 1, Part B (construction costs): a construction cost determination; and
- Stage 2: a full revenue determination.

The AER made its determination for Stage 1, Part A, accepting MLPL’s proposed \$196.5 million (\$2022/23) in forecast capital expenditure for early works.

The AER made its initial draft decision² to accept MLPL’s forecast capital expenditure of \$1,632.2 million (\$2023) for the market tested programs. A final decision on Stage 1, Part B (Construction cost) is expected in December 2025.

In 2025, the Project Marinus RIT-T was progressed through its feedback loop process with AEMO in order to confirm that Project Marinus remains on the optimal development path in the ISP.

On 15 August 2025, AEMO published a notice confirming that:

- Project Marinus addresses the relevant identified need specified, and aligns with the ODP referred to, in the 2024 ISP; and
- the total cost of the project, including Stage 1 and Stage 2, does not change the status of the actionable ISP project as part of the ODP specified in the 2024 ISP.

On 26 June 2025, the AER made its final decision to approve APA Group’s application to convert the Basslink interconnector from a market network service to a prescribed transmission service from 1 July 2026. When Basslink becomes regulated, TasNetworks will likely be appointed the Coordinating Networks Service Provider for Tasmania and be required to recover the proportion of Basslink’s allowed revenue allocated to Tasmanian customers.

1 <https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/enhanced-locational-information>

2 AER Initial Draft Decision - Marinus Link Stage 1, Part B (Construction costs) Transmission Determination 2025-30 | Australian Energy Regulator (AER)

North West Transmission Developments

The sequence of the NWTD has been developed to ensure that the minimum network requirements for Marinus Link Stage 1 and allows for the network to be further expanded to deliver that necessary to support Marinus Link Stage 2.

The revised scope for the first stage of the NWTD comprises a new double circuit transmission corridor between Palmerston, Sheffield, and Burnie, with an interim tee connection to Heybridge to connect the first 750 MW stage of Marinus Link.

The AER made its determination to approve \$151.9 million (\$2023/24) in forecast NWTD Stage 1 early works capital expenditure. We intend to submit a contingent project application for Stage 1 construction and delivery costs in late 2025.

Waddamana to Palmerston transfer capability upgrade

The ISP designates the Waddamana–Palmerston transfer capability upgrade as an actionable ISP project. TasNetworks is currently progressing the associated RIT-T to assess the relative cost and benefits of each credible option, being either a new transmission line or an upgrade to the existing transmission line. The AER agreed to extend the Project Assessment Draft Report (**PADR**) publishing date to 28 February 2026.

North West Tasmania REZ Expansion

The ISP designates the North West Tasmania REZ Expansion as a future ISP project. Consequently, we also considered development scenarios where components of the remaining NWTD strategy that include connections to Burnie and Sheffield are brought forward ahead of Marinus Link Stage 2. Either may be progressed through various mechanisms, including:

- a contingent project with regulated funding;
- an actionable project identified in AEMO's ISP;
- Dedicated Network Asset (**DNA**) funded by the Dedicated Network Asset beneficiary; or
- REZ infrastructure utilising a REZ framework developed by the Tasmanian Government.

Central Highlands REZ Extension

The ISP identifies subsequent increases to network capacity, established through the initial Waddamana to Palmerston upgrades. The Central Highlands REZ extension consists of constructing a second Palmerston to Sheffield transmission line, increasing the power transfer from the Central Highlands REZ to the north of the Tasmanian network and the broader NEM. This project is envisioned to be developed over the longer planning timeframe in 2042-43.

It is credible to expect that up to 700 MW of new generation can be developed with connection to Liapootah Switching Station therefore increasing the flow northward towards Waddamana. TasNetworks proposed an augmentation to the Liapootah-Waddamana 220 kV transmission line has been progressed and accepted under the Network Capability Incentive Parameter Action Plan (**NCIPAP**) framework, to be delivered in the 2024-2029 regulatory period.

Community Batteries

Community batteries are emerging as an innovative solution to enhance energy resilience and sustainability. TasNetworks successfully acquired funding for two community batteries through the Australian Government's Community Batteries for Household Solar program. The batteries have been installed in Shorewell Park, in the north of the State, and Glebe Hill, in the south. Each is rated at 120 kW with 258 kWh energy storage capacity. In addition, TasNetworks received funding from the Australian Renewable Energy Agency (**ARENA**) to develop six additional community batteries, with a delivery planned for 2026.

System strength and inertia

Careful management of power system security continues to be a high priority to enable connection of forecast levels of inverter-based resources. Key elements are system strength and inertia network services with TasNetworks being the System Strength Service Provider and Inertia Service Provider for Tasmania.

AEMO's 2024 Network Support and Control Ancillary Services (**NSCAS**) report published on 2 December 2024 notes that there are no system strength and inertia shortfalls in Tasmania for the period up to 1 December 2025 on account of an existing contract with Hydro Tasmania. However; for the period beyond December 2025, AEMO projects shortfalls in inertia and system strength attributed to the expiry of this contract.

To meet our obligations to procure the required services, TasNetworks completed a RIT-T, including the publication of the:

- Project Specification Consultation Report (**PSCR**) and a Request for Expression of Interest (**REOI**) in August 2023;
- Project Assessment Draft Report (**PADR**) in November 2024 setting out assessment of options to meet the system strength requirement and identified a preferred solution; and
- Project Assessment Conclusions Report (**PACR**) in June 2025.

The PACR confirmed the preferred option to meet TasNetworks' obligations is to contract with existing owners of synchronous condensers and generation assets as it met system strength requirements efficiently and cost-effectively.

We welcome feedback

TasNetworks welcomes feedback and enquiries on our APR, particularly from anyone interested in discussing opportunities for alternate 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 renewable energy transformation

- The overarching direction of our company strategy is to deliver safe, reliable, and affordable electricity services to Tasmania.
- The Tasmanian Government, through Renewables, Climate and Future Industries Tasmania (**ReCFIT**), as the Renewable Energy Zone Coordinator, concluded public consultation on the candidate Renewable Energy Zone (**REZ**) in north-west Tasmania.
- Draft amending legislation prepared to support REZ objectives will allow the government to declare a REZ.
- Government prepared the Renewable Energy Approval Pathway (REAP) being a suite of actions that will support projects entering the Major Projects assessment process under the Land Use Planning and Approvals Act 1993 (**LUPAA**)
- Bell Bay Powerfuels was announced as the provisional proponent for the Tasmanian Green Hydrogen Hub.
- Government support continues for the development of Marinus Link, the North West Transmission Developments (**NWTD**), Hydro Tasmania's Cethana pumped hydro energy storage (**PHES**) and Tarraleah power station redevelopment.
- Marinus Link Pty Ltd (**MLPL**) board recommended that its shareholders make a Final Investment Decision (**FID**) to proceed with Stage 1 of Marinus Link.
- TasNetworks' board made the decision to progress NWTD to financial close and recommended that the Tasmanian Government make a FID to proceed with NWTD.
- On 1st of August 2025, MLPL shareholders and the Tasmanian Government made a positive FID to proceed with Project Marinus Stage 1.
- The Australian Energy Regulator (**AER**) made its initial draft decision to accept MLPL's forecast capital expenditure for the market tested components and continues to consider the application for a revenue determination for the period 2025 to 2030.
- The AER made its final decision to approve APA Group's application to convert the Basslink interconnector from a market network service to a prescribed transmission service from 1 July 2026.
- The Australian Energy Market Operator (**AEMO**) commenced preparation of the 2026 Integrated System Plan (**ISP**).
- Community batteries were installed in Shorewell Park, in the north of the State, and Glebe Hill, in the south each rated at 120 kW with 258 kWh energy storage capacity. We also received funding from the Australian Renewable Energy Agency (**ARENA**) to develop six additional community batteries.

Chapter 2

Tasmanian power system

- During 2024, Tasmanian generation (hydro, wind, gas, and embedded generation) provided 85% of the State total energy requirements, with 15% (or approximately 1,640 GWh) of electrical energy imported into Tasmania over Basslink.
- Our transmission-connected customers, dominated by four major industrial sites, were responsible for 35% of the network's maximum demand and consuming 49% of the total energy delivered through the transmission network in 2024.
- Under the 2024 ISP step change scenario, an increase in consumption was forecast for the second half of the decade, largely due to the anticipated emergence of a new hydrogen industry. AEMO have significantly revised down their hydrogen projections in the 2025 Electricity Statement of Opportunities (ESOO), published in August 2025.
- Noting this change to the energy consumption forecast, TasNetworks recognises the continued interest for local hydrogen industry at different locations in Tasmania.

Chapter 3

Transmission Network Developments

- Tasmanian transmission network planning activities continue to focus on identifying the optimum development path to accommodate future large-scale renewable energy resources, a new interconnection with Victoria, upgrading of existing power stations, connection of export-scale hydrogen, and integration of energy “firming” facilities such as battery energy storage systems (**BESS**) and pumped hydro energy storage (**PHES**).
- We have developed transmission augmentation options that support a range of market scenarios as the Australian electricity system transitions towards more renewable energy sources, informed by the Tasmanian Renewable Energy Target (**TRET**), plans to develop a renewables-based hydrogen industry, and identification by the Australian Energy Market Operator (**AEMO**) of Renewable Energy Zones (**REZs**) and associated transmission augmentations.
- The North West Transmission Developments (**NWTD**) project comprises upgrades to the network in Tasmania supporting the establishment of Marinus Link interconnector stages 1 and 2. The first stage of the project, comprising a new 750 MW interconnector with connection to the North West Tasmanian network via a coastal route, is planned to be delivered in 2030/31. The second stage timing of Marinus Link and NWTD is yet to be determined.
- To support a delivery mechanism for new renewable energy connections to the network, following the commissioning of Marinus Link Stage 1, TasNetworks is pursuing a pathway to develop a Designated Network Asset (**DNA**) in the north-west comprising a new 220 kV double circuit transmission line between Burnie to a new switching station at Hampshire Hills. This augmentation is a portion of works that would be brought forward ahead of Marinus Link Stage 2 and NWTD.
- We have initiated a Regulatory Investment Test for Transmission (**RIT-T**) for augmentations at George Town triggered by an initial tranche of new load, such as hydrogen.
- We have initiated a new Network Investment Capability Parameter Action Plan (**NICIPAP**) 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

- The Australian Energy Market Commission's (**AEMC**) Reliability Panel previously revised the Frequency Operating Standard (**FOS**). A new rate of change of frequency (**ROCOF**) limit has been introduced, with a different limit defined for Tasmania compared to the mainland given the characteristics of our system.
- 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, careful management of power system security continues to be a high priority.
- Modelling associated with AEMO's 2024 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 1 December 2025.
- The National Electricity Rules (**the Rules**) framework for managing system strength introduced significant new obligations for System Strength Service Providers (**SSSP**) which commence on 2 December 2025. TasNetworks is the SSSP for the Tasmanian region of the National Electricity Market (**NEM**). The new framework introduces 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**) addressing 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.

Chapter 6

- In 2024, transmission system performance remained within targets for transmission line and transformer circuit fault outage rate metrics but was outside the target for capacitor circuit fault outage rate. Transmission Loss of Supply (**LOS**) event counts over 0.1 and 1.0 system minutes were on target, and the average outage duration of all LOS events was within the nominated target.
- Distribution system performance for 2024-25 was outside the Tasmanian Electricity Code (**the Code**) System Average Interruption Frequency Index (**SAIFI**) standards for Critical Infrastructure category and outside the System Average Interruption Duration Index (**SAIDI**) standards for Critical Infrastructure, Urban and Regional Centres, and Lower Density Rural categories.
- Distribution system performance for 2024-25 was outside the Australian Energy Regulator (AER) Service Target Performance Incentive Scheme (**STPIS**) SAIFI standards for Critical Infrastructure, High Density Commercial and High Density Rural categories and outside the SAIDI standards across all categories.
- Our network now hosts over 60,000 Distributed Energy Resource (**DER**) systems with an installed capacity of 380 MW, a 15% increase over the course of 2024-25 financial year.

Chapter 1

Tasmanian renewable energy transformation

- The overarching direction of our company strategy is to deliver safe, reliable, and affordable electricity services to Tasmania.
- The Tasmanian Government, through Renewables, Climate and Future Industries Tasmania (ReCFIT), as the Renewable Energy Zone Coordinator, concluded public consultation on the candidate Renewable Energy Zone (REZ) in north-west Tasmania.
- Draft amending legislation prepared to support REZ objectives will allow the government to declare a REZ.
- Government prepared the Renewable Energy Approval Pathway (REAP) being a suite of actions that will support projects entering the Major Projects assessment process under the Land Use Planning and Approvals Act 1993 (LUPAA).
- Bell Bay Powerfuels was announced as the provisional proponent for the Tasmanian Green Hydrogen Hub.
- Government support continues for the development of Marinus Link, the North West Transmission Developments (NWTd), and Hydro Tasmania's Cethana Pumped Hydro Energy Storage (PHES) and Tarraleah power station redevelopment.
- Marinus Link Pty Ltd (MLPL) board recommended that its shareholders make a Final Investment Decision (FID) to proceed with Stage 1 of Marinus Link.
- TasNetworks' board has made the decision to progress NWTd to financial close and recommended that the Tasmanian Government make a FID to proceed with NWTd.
- On 1st of August 2025, MLPL shareholders and the Tasmanian Government made a positive FID to proceed with Project Marinus Stage 1.
- The Australian Energy Regulator (AER) made its initial draft decision to accept MLPL's forecast capital expenditure for the market tested components and continues to consider the application for a revenue determination for the period 2025 to 2030.
- The AER made its final decision to approve APA Group's application to convert the Basslink interconnector from a market network service to a prescribed transmission service from 1 July 2026.
- The Australian Energy Market Operator (AEMO) commenced preparation of the 2026 Integrated System Plan (ISP).
- Community batteries were installed in Shorewell Park, in the north of the State, and Glebe Hill, in the south each rated at 120 kW with 258 kWh energy storage capacity. We also received funding from the Australian Renewable Energy Agency (ARENA) to develop six additional community batteries.

1. Introduction

Tasmanian Networks Pty Ltd (**TasNetworks**) presents its 2025 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, and the only Tasmanian Transmission Network Service Provider, we are also the System Strength Service Provider and Inertia Service Provider.

This Chapter outlines:

- Tasmania's role as a participant in the NEM;
- the preparedness of the Tasmanian network for the energy market transition;
- externalities that guide our planning;
- TasNetworks' customers and our interactions with them;
- the purpose of the report and our current consultations on major projects; and
- concludes with a description of significant changes and developments since our 2024 APR.

The Tasmanian electricity supply industry makes progress towards contributing to meeting the legislated Tasmanian Renewable Energy Target (**TRET**)³ that, by the end of 2040, aims to deliver 200% of Tasmania's 2020 baseline of 10,500 GWh of renewable generation per year. In this regard, on-island projects currently at various stages of development total nearly 7,000 MW of wind farms, 800 MW of large scale solar-photovoltaics (**PVs**), 750 MW of PHES, and 700 MW of battery energy storage systems (**BESS**). In perspective, there is currently near 3,400 MW of on-island generation covering hydro, gas, wind, and large-scale PVs.

The Tasmanian Government established ReCFIT⁴ to progress the Tasmanian Renewable Energy Action Plan (**TREAP**)⁵ aimed at aligning a rapidly transitioning energy sector, with the opportunities of a changing climate and to help shape a sustainable energy system for Tasmania.⁶

Tasmania is well placed to contribute to the emerging clean fuels economy. The State is in a strong position to produce clean fuels like renewable hydrogen, green methanol, and advanced biofuels, to serve both domestic and export markets.⁷ This Strategy builds on the Tasmanian Renewable Hydrogen Action Plan (**TRHAP**)⁸ and incorporates the insights and progress made over the past four years.

Commitment to upgrade the approval pathway for major renewable energy projects was an outcome of ReCFIT's Renewable Energy Assessment Process Review completed under the Renewable Energy Coordination Framework (**RECF**)⁹. The resultant REAP¹⁰ is a suite of actions that will support projects, such as wind farms and transmission lines, entering the Major Projects assessment process under the Land Use Planning and Approvals Act 1993 (**LUPAA**).

After announcing the north-west of Tasmania to be the first region to be explored for the development of a REZ,¹¹ ReCFIT, as the REZ Coordinator, concluded consultation on the candidate REZ in north-west Tasmania to inform any REZ declaration.¹² Draft amending legislation to support REZ objectives will allow the government to declare a REZ along with a set of rules to coordinate how projects are progressed and how associated infrastructure, such as transmission lines, should be developed.

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

4 <https://recfit.tas.gov.au/home>

5 https://recfit.tas.gov.au/policies_strategies_plans/renewable-energy/renewable_energy_action_plan

6 https://recfit.tas.gov.au/what_is_recfit

7 https://recfit.tas.gov.au/what_is_recfit/future_industries/draft-future-clean-fuels-strategy

8 https://recfit.tas.gov.au/what_is_recfit/energy_vision/green_hydrogen_hub_vision

9 https://recfit.tas.gov.au/___data/assets/pdf_file/0009/489690/Renewable_Energy_Coordination_Framework_May_2022.pdf

10 https://recfit.tas.gov.au/what_is_recfit/energy_vision/renewable_energy_approval_pathway

11 https://recfit.tas.gov.au/what_is_recfit/energy_vision/renewable_zones

12 <https://www.renewableenergyzones.tas.gov.au/consultation-hub/proposed-rez>

Government support continues for the development of Marinus Link, the NWT D, and Hydro Tasmania's Cethana PHES¹³ and Tarraleah power station redevelopment.¹⁴ The Department of Treasury and Finance finalised the Project Marinus Whole-of-State Business Case providing a comprehensive assessment of the opportunities and challenges of the projects. The MLPL Board recommended that its shareholders make a FID to proceed with Stage 1 of Marinus Link. Similarly, TasNetworks' board made the decision to progress NWT D to financial close and recommended that the Tasmanian Government make a FID to proceed with NWT D.

Accordingly, MLPL shareholders and the Tasmanian Government decided to proceed with Project Marinus.

1.2 What we do

TasNetworks owns, operates, and maintains the electricity transmission and distribution networks in Tasmania and a supporting telecommunications network. TasNetworks is a state-owned company operating as a commercial business with assets of over \$3.5 billion.

1.2.1 Transmission and distribution networks

We deliver monopoly and competitive electricity supply services to more than 295,000 residential, commercial, and industrial customers. We undertake our monopoly service obligations in accordance with the Rules as outlined in Appendix A.

Our responsibilities include:

- keeping our people, customers, and the community safe and protecting the environment;
- undertaking the role of Tasmanian jurisdictional planning body in the NEM;
- maintaining and replacing network infrastructure to ensure reliable services 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 fault restoration activities;
- maintaining a public lighting system;
- recording and providing regulated meter data to retailers; and
- providing telecommunications to participants in the Tasmanian electricity supply industry.

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.

We facilitate the transfer of electricity between Victoria and Tasmania via Basslink, a privately-owned, sub-sea high voltage direct current (HVDC) electricity interconnector. Our subsidiary businesses provide telecommunications, technology services, and connections support.

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 PVs. The components of the Tasmanian power system are presented in Figure 1-1. The role of TasNetworks is highlighted in blue.

¹³ <https://www.hydro.com.au/clean-energy/our-major-projects/pumped-hydro>

¹⁴ <https://hydro.com.au/clean-energy/our-major-projects/hydro-system-improvement>

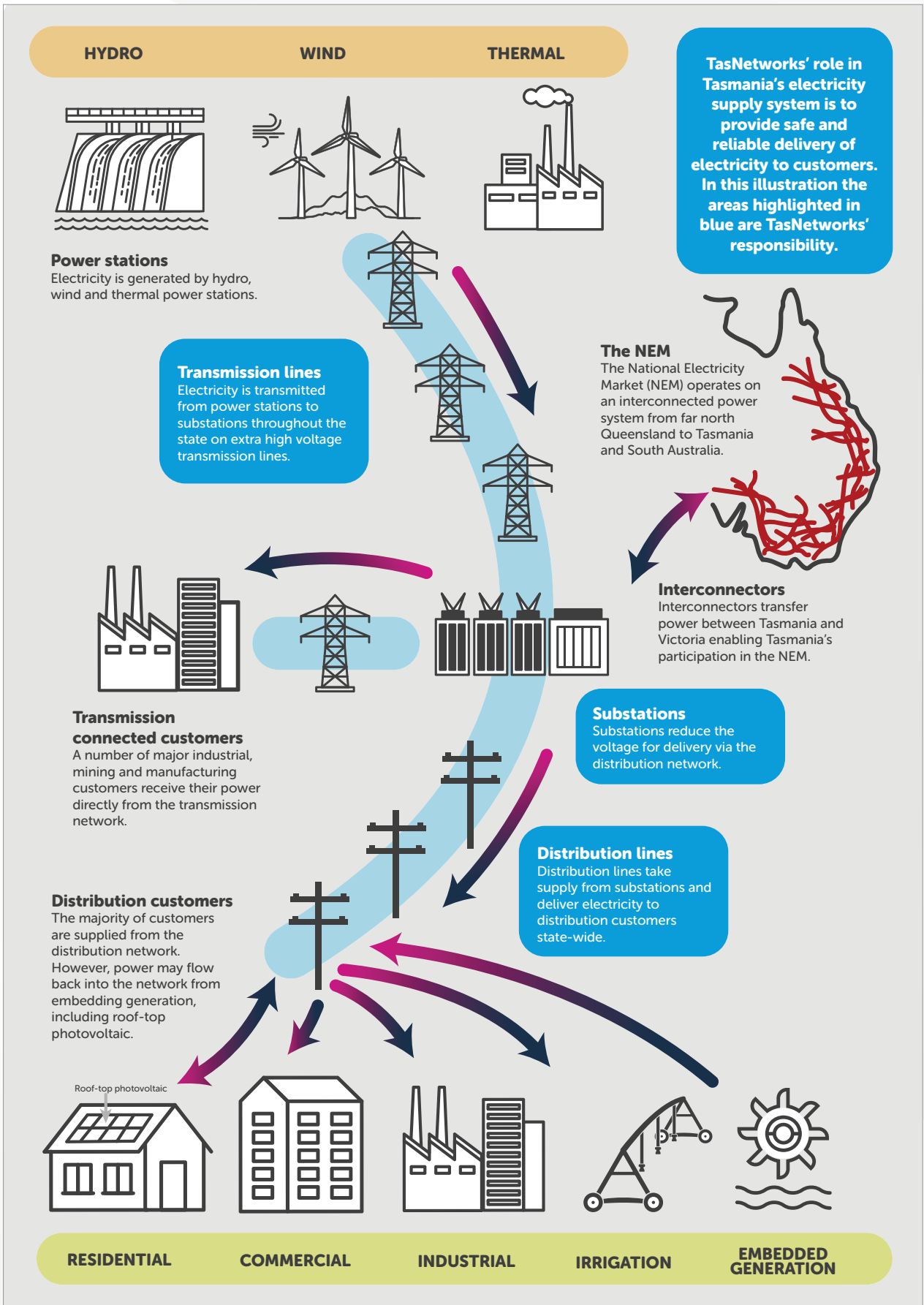


Figure 1-1: Tasmania's power system

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. Further details are provided in Chapter 4.

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

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.

1.3 Purpose of this Annual Planning Report

As a key business activity, TasNetworks continuously reviews 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 2035. Some aspects are based on shorter planning time frames. In particular, our distribution line loads are based on a 2-year planning horizon.

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's TREAP 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:

- enabling Tasmania to deliver the legislated TRET;
- progressing development of a renewable hydrogen industry as outlined in the TRHAP;
- supporting the ISP;¹⁵
- supporting generation and PHES initiatives;
- advancing Marinus Link; and
- delivering the NWTD.

1.4.1 Tasmanian Renewable Energy Target

Tasmania has the key advantage of significant renewable hydropower capacity for firming variable renewable energy sources. To achieve the TRET of 21,000 GWh by 2040 using Tasmania's world leading wind resources, will require up to 3,000 MW of new installed wind capacity. This requirement will change if other renewable energy sources (PV, ocean, biomass, geothermal) are also developed.

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

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. To support such major projects entering the Major Projects assessment process under the LUPAA the Tasmanian Government is developing the REAP to:

- establish a Major Renewable Energy Project case management¹⁶ function and coordinated end-to-end assessment process;
- provide for the development of sector specific renewable energy information requirement guidelines for the Major Projects process;
- provide more resourcing for regulatory agencies including the Tasmanian Planning Commission, Environment Protection Agency, and Aboriginal Heritage Tasmania; and
- establish a coordinated pre-assessment process, including consideration of the Reserve Activity Assessment and related assessment processes, in parallel with the Major Projects process.

Other committed options that will complement and support the establishment and ongoing operation of the REAP include:

- progress bilateral assessment agreements with the Australian Government for the Major Projects assessment pathway;
- explore improvement of other protocols between the Governments to address current delays and inconsistent advice (underway);
- establish a guideline on community benefit schemes specific to Tasmania and identify a benefit funding model that provides greater certainty to regional communities and earlier realisation of benefits (completed); and
- respond to recommendations from the Future of Local Government Review.

The REAP initiatives will provide certainty and clarity for proponents, Government agencies, and the community in submitting, processing, and reviewing renewable energy project applications. Implementation of the REAP will require amendments to LUPAA, to enable the use of this process for major renewable energy projects. The Government has identified the Bell Bay Wind Farm located near George Town and Cellars Hill Wind Farm located in the Central Highlands as the first two projects to be piloted under the new approach.

1.4.2 Renewable hydrogen and large-scale load connections

Over the past 12 months, continued progress has been made towards the establishment of industrial scale green hydrogen production in Tasmania with Bell Bay Powerfuels announced as the provisional proponent for the Tasmanian Green Hydrogen Hub.¹⁷

The Bell Bay Powerfuels Project currently under development involves a green hydrogen and green methanol production facility with commercial operation scheduled to commence in 2029.

The project is expected to give rise to the development of new power generation assets providing sufficient renewable power for the proposed 300 MW electrolyser unit.

Additionally, 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 and residue biomass to produce an anticipated 200,000 tons of e-methanol per year, helping to underpin the further growth of renewable energy in Tasmania.¹⁸

The development of the State's first green Hydrogen Production & Research Facility at BOC Australia's Lutana site will support research and training development for blue economy industries whilst providing commercial-scale hydrogen.¹⁹

The facility features a 700 kW electrolyser attached to a sophisticated microgrid system that can recreate the inputs from renewable energy such as wind, PV or ocean energy, and mirror loads from industry to simulate real-life applications.

16 https://recfit.tas.gov.au/grants_programs/energy/reap_case_management_service

17 https://recfit.tas.gov.au/what_is_recfit/energy_vision/green_hydrogen_hub_vision

18 <https://hifglobal.com/locations/tasmania>

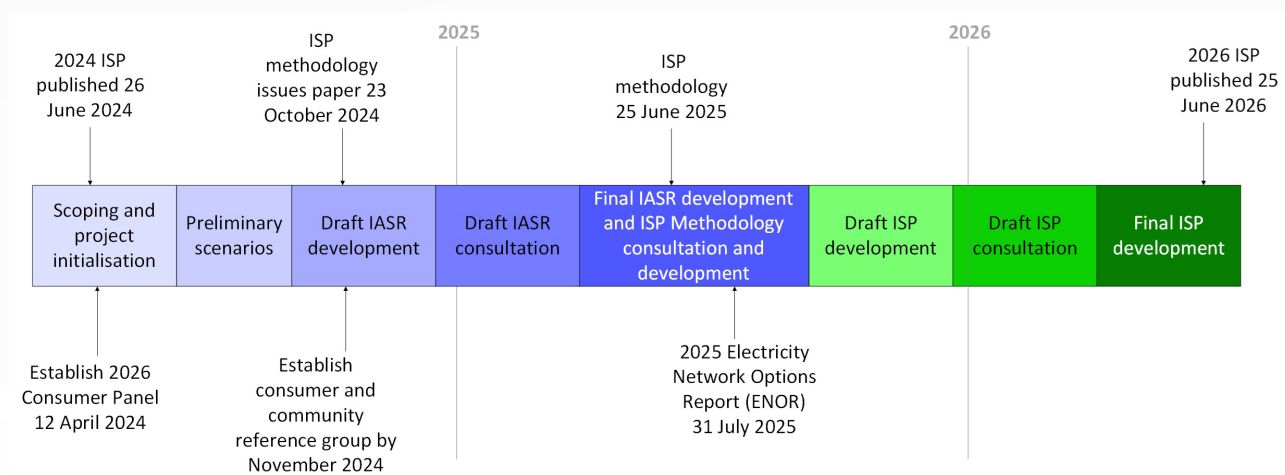
19 <https://blueeconomycrc.com.au/hydrogen-facility>

In response to the State Government’s medium and long term initiatives and progress of active proposals, we have initiated a Regulatory Investment Test for Transmission (**RIT-T**) to augment George Town Substation. This investment was included in our 2024-2029 revenue determination as a contingent project, triggered by the first tranche of approximately 200 MW of additional load.

We present more information on hydrogen developments in Chapter 3.

1.4.3 Integrated System Plan

AEMO is currently developing the 2026 ISP based on the below timetable.²⁰ The ISP to be published in June 2026 is 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.



AEMO has progressed three documents that play a key role in the development of the ISP.

The Inputs, Assumptions, and Scenarios Report (**IASR**)²¹, finalised in July 2025, includes a wealth of inputs and assumptions that apply to planning and are used across the industry for other planning purposes, including for use in a RIT-T.

The ISP Methodology,²² finalised in June 2025, describes the integrated approach to energy market modelling, combined with relevant power system analysis. The objective of the suite of models and analysis is to determine an optimal development path aimed at maximising benefits to consumers and meets government energy and emissions targets between now and 2050.

The Electricity Network Options Report²³ identifies potential augmentation options in electricity networks that are an important input to the development of the ISP. The report includes both transmission and distribution opportunities, including proposed distribution network opportunities for investment to facilitate the operation of forecast uptake of consumer energy resources and other distributed resources, and further consideration of social licence for transmission.

We present more information on the ISP in Chapter 3.

20 <https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp>

21 <https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp/2025-26-inputs-assumptions-and-scenarios>

22 <https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp/isp-methodology>

23 <https://aemo.com.au/consultations/current-and-closed-consultations/2025-electricity-network-options-report-consultation>

1.4.4 Marinus Link

The MLPL board recommended that its shareholders make a FID to proceed with Stage 1 of Marinus Link, 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.

The recommendation advises that there is a sound financial and economic investment case for proceeding with the construction phase of Marinus Link Stage 1, based on an assessment of forecast costs, revenue, associated benefits, and risks.

On 1st of August 2025, MLPL shareholders and the Tasmanian Government made a positive FID to proceed with Project Marinus Stage 1.

In April 2023, MLPL lodged with the Australian Energy Regulator (**AER**) an application for a revenue determination for Marinus Link.²⁴ The AER's Commencement and Process Paper²⁵ sets out a staged approach comprising:

- Stage 1, Part A (Early works): a revenue determination for pre-construction activities;
- Stage 1, Part B (Construction costs): a construction cost determination; and
- Stage 2: a full revenue determination.

At the time of writing, the AER has made a determination on Stage 1, Part A costs²⁶ and an initial draft decision on certain Stage 1 Part B costs.²⁷

The AER made its determination for Stage 1, Part A, accepting MLPL's proposed \$196.5 million (\$2022/23) in forecast capital expenditure for early works.

The AER made its initial draft decision²⁸ to accept MLPL's forecast capital expenditure of \$1,632.2 million (\$2023) for the market tested:

- converter station design and equipment supply of \$737.2 million (\$2023) and
- the high voltage direct current cable system of \$895.0 million (\$2023).

These programs account for 46% of the total proposed capital expenditure for the construction of the first Marinus Link cable. The initial draft decision also includes positions on the application for the capital expenditure sharing scheme, cost pass throughs, and the contingent project for the second 750 MW stage.

Following updated costings on the remaining costs for the balance of works, support activities, and risk allowance, a final decision on Stage 1, Part B (Construction cost) is expected in December 2025.

The Project Marinus RIT-T was progressed through its feedback loop process with AEMO in order to confirm that Project Marinus remains on the optimal development path in the ISP.

On 15 August 2025, AEMO published a notice confirming that:

- Project Marinus addresses the relevant identified need specified, and aligns with the ODP referred to, in the 2024 ISP, and
- the total cost of the project, including Stage 1 and Stage 2, does not change the status of the actionable ISP project as part of the ODP specified in the 2024 ISP.

We present more information on the progress of Marinus Link and NWTD in Chapter 3 of the APR, as well as on our website.²⁹

24 <https://www.aer.gov.au/all-aer-projects/marinus-link-intending-transmission-network-application>

25 <https://www.aer.gov.au/documents/aer-marinus-link-updated-commencement-and-process-paper-march-2024>

26 <https://www.aer.gov.au/industry/registers/determinations/marinus-link-determination-2025-28-stage-1-part-early-works/final-decision>

27 <https://www.aer.gov.au/industry/registers/determinations/marinus-link-intending-transmission-network-application/draft-decision>

28 <https://www.aer.gov.au/documents/aer-initial-draft-decision-marinus-link-stage-1-part-b-construction-coststransmission-determination-2025-30>

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

1.4.5 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 which carry high bandwidth services.

On 26 June 2025, the AER made its final decision to approve APA Group's application to convert the Basslink interconnector from a market network service to a prescribed transmission service from 1 July 2026.³⁰ The AER also released a Consultation Paper amending the Commencement and Process Paper setting out the timetable and process for Basslink's revenue determination.³¹

When Basslink becomes regulated, TasNetworks will likely be appointed the Coordinating Network Service Provider for Tasmania. This means we will be required to recover Basslink's 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.

TasNetworks will also be responsible for applying any positive inter-regional settlement residues allocated to us by AEMO to offset transmission charges or, in the case of negative inter-regional settlement residues recovering these from customers.

1.5 Our customers

To help us better understand the varied needs of our customers, we have developed two customer segmentation models that group customers into categories based on similarities and characteristics. Our research included analysis of usage and billing data, behaviours, and attitudes from a cross section of Tasmania's residential and business communities.

The segmentation models enable us to shift to a more customer-centric culture by improving our engagement through targeted activities that are meaningful to each customer segment. We continue to explore ways to improve our customers' experience when they engage with us through continuous process and data improvements and tailored solutions.

Key insights across our customer base include:

- More than half of the energy delivered in Tasmania is to a small number of large industrial and commercial customers that are connected directly to our transmission network.
- The balance of Tasmania's energy consumers are connected to our distribution network and include residential, commercial, small-scale industrial, and irrigation customers, as well as embedded generators.
- While directly connected transmission customers use more energy, our distribution customers contribute more to Tasmanian peak demand.
- Customers have different levels of engagement appetite with their energy consumption behaviours, which is often based on their lifestyle choices, application, and/or financial position.
- We also provide network access to hydro, wind, and grid-connected PV generation sources, a large capacity natural gas fired power station, and to the Basslink interconnector.

Rising cost of living pressures are elevating our customers' sensitivity to increasing utility prices. We are focused on keeping prices affordable for our customers and have also introduced programs like the Energy Support Program (in partnership with Uniting Tasmania) to help our customers better understand, manage, and reduce their household energy use.

³⁰ Final decision: Basslink conversion | Australian Energy Regulator (AER)

³¹ Consultation Paper: Amendments to Commencement and Process Paper | Australian Energy Regulator (AER) <https://www.aer.gov.au/system/files/2023-09/Basslink%20-%20Conversion%20and%20transmission%20determination%202025-30%20-%2015%20September%202023.pdf>

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 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 battery storage 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.

At TasNetworks we are currently investigating the development of a framework to support our analysis of non-network solutions. Our objective is to work with our customers to identify cost-effective non-network and SAPS solutions which allow us to defer or avoid the need for network investment and reduce the long-term costs of our network. We offer financial incentives to those who can provide solutions. 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 have developed an 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 at an affordable price. We observe that uptake of EVs and demand for additional charging options have been relatively slow compared to other states due to uncertainties in charger ownership models.

We have been engaging with external stakeholders including councils and EV charging networks, to better understand their needs and what new capabilities they could expect from us. One key area of development has been around sharing the location and capacity of low voltage assets so developers and councils can better target sites for EV charger rollout. We used smart meter data to calculate transformer loads and capacity and developed a pilot network capacity map, which is being shared with selected councils prior to a public release.

1.5.3 Community batteries

Community batteries are emerging as an innovative solution to enhance energy resilience and sustainability. 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.

TasNetworks successfully acquired funding for two community batteries through the Australian Government's Community Batteries for Household Solar program.³² The batteries have been installed in Shorewell Park, in the north of the State, and Glebe Hill, in the south. Each is rated at 120 kW with 258 kWh energy storage capacity. In addition, TasNetworks received funding from ARENA to develop six additional community batteries, with a delivery planned for 2026. One of these will be trialled for reliability benefits by feeding a local community centre during power outages.

1.6 TasNetworks' strategy

Our strategy is focused on delivering safe, reliable, and affordable electricity services to Tasmania, and making sure we are ready to meet the changing needs and expectations of our customers and stakeholders.

It considers external market trends that influence our business and clearly identifies what we need to do to deliver meaningful and sustainable change. It also provides the framework to help us organise our priorities and plan how we will deliver them.

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 can deliver the services they value. Our priorities aim to deepen our relationships with our customers and be better positioned to tailor our services and build their trust in us.

Deliver operational excellence

We maintain our continued commitment to keep our people, the community, and the environment safe, deliver reliable and affordable electricity services, and manage our operations efficiently to keep our costs as low as possible.

Innovate in a targeted way

We adapt to changing customer needs through innovation. We are targeting areas of our network and ways of working to improve our performance and keep prices affordable for customers.

Our strategy drives the delivery of the key business objectives we have defined to track our progress and measure our success. These key business objectives are centred on our core – the delivery of safe, reliable, and affordable electricity services to Tasmania – and put our customers at the centre of our decision making. They also recognise the wider role that TasNetworks plays in the Tasmanian community.

³² <https://www.dcceew.gov.au/energy/renewable/community-batteries>

Our key business objectives are:

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 performance metrics are focused on the physical, psychological, and environmental wellbeing of these stakeholders.

Deliver value for our customers

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

Supply reliable essential services

We understand our services are critical and need to be reliable, and we recognise our role to serve and create value for Tasmania. We have an opportunity to proactively drive reliability and sustainability for the Tasmanian community.

Provide a sustainable financial return

We seek to balance affordable prices for customers and provide sustainable profits to our owner, the State of Tasmania. We are focused on the efficiency of our operations, so our profits can be reinvested to benefit the Tasmanian community.

1.7 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. During 2024, we completed the following RIT-Ts:

Table 1-1: Summary of Completed RIT-T and RIT-D investments

| RIT-T Investment | Identified Need |
|--|---|
| Managing safe and reliable operation of Chapel St substation | Address escalating risk costs associated with aging switchgear at Chapel St substation. |
| Managing risk on the George Town – TEMCO transmission line | Address escalating risk costs associated with the aging George Town-TEMCO transmission line. |
| Managing safe and reliable operation of St Marys substation | Address escalating risk costs associated with aging transformers at St Marys substation. |
| Meeting the System Strength Standard in Tasmania from December 2025 onward | From 2 December 2025, provide sufficient system strength to satisfy minimum fault level requirements and facilitate forecast developments of IBR in Tasmania. |
| NWTD Stage 1 | Contingent Project construction and delivery costs |

Five further RIT-Ts are identified for our forthcoming 2024–29 revenue period as presented in Table 1-2, three of which have been initiated. We do not plan to initiate any RIT-Ds.

Table 1-2: Summary of proposed and current RIT-T and RIT-D investments

| 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. | 2024-2026 |
| Improving transfer capacity between Waddamana and Palmerston | Address constraints in the Waddamana to Palmerston corridor following connection of new renewable generation in the Central Highlands REZ. | 2025-2026 |
| Reducing line losses in the Upper Derwent | Reduce power system losses in the Upper Derwent transmission network. | 2025-2026 |
| Managing safe and reliable operation of Sheffield Substation | Address escalating risk costs associated with aging transformers at Sheffield Substation. | 2025-2026 |
| Managing safe and reliable operation of Rosebery Substation | Address escalating risk costs associated with aging transformers at Rosebery Substation. | 2025-2026 |

1.8 What has changed since 2024

1.8.1 North West Transmission Developments

The first stage of the NWTDD comprises a new double circuit transmission corridor between Palmerston, Sheffield and Burnie and Heybridge to connect the first 750 MW stage of Marinus Link.

In March 2025, the AER made a decision to approve \$151.9 million (\$2023/24) in forecast NWTDD Stage 1 early works capital expenditure proposed by TasNetworks in a contingent project application submitted in October 2024.³³ TasNetworks intends to submit a contingent project application for NWTDD Stage 1 construction and delivery costs in late 2025.

On 15 August 2025, the Project Marinus RIT-T was updated by MLPL and AEMO confirming that Project Marinus remains on the optimal development path in the ISP.

More information on this project is provided in Chapter 3.

1.8.2 Waddamana to Palmerston transfer capability upgrade

TasNetworks is currently progressing the RIT-T for the Waddamana-Palmerston corridor capacity upgrade to determine the preferred option. The RIT-T will assess the relative cost and benefits of each credible option, comprising either a new transmission line or an upgrade to the existing transmission line. The AER has agreed to extend the date by which TasNetworks must publish the Project Assessment Draft Report (**PADR**) for the Waddamana to Palmerston Transfer Capability Upgrade project, to 28 February 2026. The additional time will allow TasNetworks to further explore the costs and benefits of credible options.

³³ <https://www.aer.gov.au/industry/networks/contingent-projects/tasnetworks-north-west-transmission-developments-stage-1-early-works-contingent-project/final-decision>

1.8.3 Renewable Energy Zones

TasNetworks supports ReCFIT in its investigations of REZs by providing wide-ranging advice that will inform scenario planning to identify:

- the hosting capability of the existing network for new renewable energy projects in each REZ;
- the network augmentations required once this existing capability is exhausted;
- the type and form of possible REZ transmission assets; and
- the possible delivery mechanisms for these works, including social licence, financing, regulatory and legislative opportunities, and limitations.

TasNetworks continues to work closely with ReCFIT to provide support and guidance towards future transformation of the network to support significant renewable energy developments.

Draft amending legislation to support REZ objectives will allow the government to declare a REZ along with a set of rules applies to coordinate how projects are progressed and how associated infrastructure, such as transmission lines, should be developed including:

- Long-term planning identifying the optimal pathway for REZ development will ensure the State achieves its renewable energy goals while minimising new transmission;
- The REZ Coordinator having a key role in REZ strategic planning;
- Declaration of a REZ, the Minister can declare an area of Tasmania to be a REZ by making a declaration order;
- The REZ Coordinator providing advice to the Minister on the need for, and potential location of, REZs;
- Application of an Access Scheme, a physical cap on connections, introduced to help provide revenue certainty for generation and storage projects and to ensure network infrastructure is efficiently utilised;
- Cost Recovery framework provides flexibility in how costs are recovered;
- Community Benefit Sharing as a key element of the REZ model to ensure that communities hosting renewable energy developments directly benefit;
- Proponent Commitment to a competitive expression of interest process which will be run for projects seeking to connect to the REZ;
- REZ Regulation framework included in the draft Bill which will protect REZ participants from the potential power imbalance that comes with a monopoly service provider; and
- REZ Roles and Functions required for planning, delivery, maintenance, and operation of a REZ model being set out in the legislation.

The Tasmanian Government, through ReCFIT as the REZ Coordinator, concluded consultation on the candidate REZ in north-west to inform any REZ declaration and new legislation needed to support REZ objectives.

1.8.4 Load forecasts

For the 2025 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 consists of a top-down approach, utilising AEMO's state-level forecasting as a basis for developing individual connection point forecasts.

The AEMO state-level forecast serves as the foundation for TasNetworks connection point demand 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 components.

The key scenarios used by AEMO for forecasting in the 2024 ESOO are the Progressive, Central (Step Change), and Green Energy Exports. For each of these scenarios, 10%, 50% and 90% probability of exceedance (**POE**) forecasts are utilised. In the 2025 ESOO the scenarios are renamed to Progressive Change, Central (Step Change), and Accelerated Transition.

Whilst using AEMO's 2024 Step Change and Progressive Change scenarios we reviewed AEMO's 2025 ESOO scenarios that significantly revised down hydrogen projections. In doing so, TasNetworks considered the impacts of new, large scale customer developments on future energy consumption; in particular, the development of new large-scale hydrogen production facilities in Tasmania that will significantly increase the energy transfer requirements across the transmission network.

Tasmania's state-level forecast prepared previously for the 2024 APR is included for comparison.

1.8.5 Distribution resilience in the NER

The Australian Energy Market Commission (AEMC) released a Final Rule³⁴ to establish a formal framework for distribution network resilience in the Rules. This includes new resilience expenditure factors for TasNetworks and the AER to consider in regulatory determination, AER guidelines and requirements for consideration in TasNetworks' APR.

TasNetworks 2028 APR will feature new information on severe weather events and the performance of the network during such events and descriptions of the resilience related expenditure projects that TasNetworks has undertaken, amongst other requirements.

The AER also introduced a value of network resilience methodology to be used in cost-benefit analysis for proposed network investments that will have an impact on network resilience.³⁵

1.8.6 NEM Access Standards

The AEMC progressed two Rule changes to improve the technical requirements for connection to the NEM. Package 1 of the rule change³⁶ has been finalised 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, which will help to reduce costs and time for connecting parties, TasNetworks, and AEMO in negotiations undertaken when connecting plant.

Package 2 of the rule change³⁷ is still being consulted on by stakeholders but focuses on the access standards for large, inverter-based loads, such as data centres, and hydrogen electrolysers. The rule change request proposes amendments to facilitate the planning and design of large loads in a way that supports future power system security.

1.8.7 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 are currently in place until 1 December 2025. TasNetworks has published the Project Assessment Conclusions Report confirming that the preferred option is to contract with existing owners of synchronous condensers and generation assets to meet the system strength standard in Tasmania from December 2025 to June 2029 under the new framework for managing system strength that commences 2 December 2025.

1.8.8 Planned investments and forecast limitations

Material differences between planned investments and forecast limitations from those reported in our 2024 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.

34 Including distribution network resilience in the National Electricity Rules | AEMC

35 Value of Network Resilience 2024 | Australian Energy Regulator (AER)

36 Improving the NEM access standards – Package 1 | AEMC

37 Improving the NEM access standards – Package 2 | AEMC

Table 1-4: Differences in planned investments and forecast limitations reported in 2024 APR

| Location | Summary of change | APR Reference |
|----------------------|--|----------------------|
| Now completed | | |
| Statewide | T60 transformer relays | Table 4-12 |
| Gordon | Gordon Substation 220 kV switchgear | Table 4-11 |
| Norwood | Norwood Substation 110 kV switchgear | Table 4-11 |
| Farrell | Farrell Substation 220 kV switchgear | Table 4-11 |
| Chapel Street | Chapel Street Substation 110 kV disconnectors | Table 4-11 |
| Port Latta | Dynamic Reactive Support (STATCOMs) | Chapter 3 |
| Now committed | | |
| George Town | George Town Substation 220 kV disconnectors | Table 4-11 |
| Wesley Vale | Wesley Vale Substation 110 kV disconnectors | Table 4-11 |
| Sorell | Sorell Substation 22 kV switchgear | Table 4-11 |
| Savage River | Savage River Substation 110 kV disconnectors and gantry | Table 4-11 |
| Sheffield | Sheffield Substation 220 kV disconnectors and current transformers | Table 4-11 |
| Sheffield | Sheffield Substation 110 kV disconnectors | Table 4-11 |
| St Mary's | St Mary's Substation transformers | Table 4-10 |
| Chapel St | Chapel St Substation 11 kV switchgear | Table 4-11 |
| Bridgewater | Bridgewater Substation 110 kV circuit breakers | Table 4-11 |
| Statewide | Statewide protection relays | Table 4-12 |
| Statewide | Statewide SCADA scheme (part replacements Gateway RTU only) | Table 4-12 |

Chapter 2

Tasmanian power system

- During 2024, Tasmanian generation (hydro, wind, gas, and embedded generation) provided 85% of the State total energy requirements, with 15% (or approximately 1,640 GWh) of electrical energy imported into Tasmania over Basslink.
- Our transmission-connected customers, dominated by four major industrial sites, were responsible for 35% of the network's maximum demand and consuming 49% of the total energy delivered through the transmission network in 2024.
- Under the Step Change scenario, an increase in consumption was forecast for the second half of the decade, largely due to the anticipated emergence of a new hydrogen industry. The Australian Energy Market Operator (AEMO) has significantly revised down their hydrogen projections in the 2025 Electricity Statement of Opportunities (ESOO), published in August 2025. Noting this change to the energy consumption forecast, TasNetworks recognises the continued interest for local hydrogen industry at different locations in Tasmania.

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 547 – 1,812 MW in 2024. The load duration characteristic for Tasmanian customers and total network (including Basslink export) during 2024 is presented in Table 2-1.

Table 2-1: Tasmanian load duration characteristic for 2024

| Duration / operating point | Tasmanian customers (MW) | Total native demand ³⁸ (MW) (including Basslink export) (MW) |
|----------------------------|--------------------------|--|
| Maximum | 1,812 | 2,216 |
| 25th percentile | 1,298 | 1,411 |
| 50th percentile | 1,185 | 1,217 |
| 75th percentile | 1,095 | 1,105 |
| Minimum | 547 | 547 ³⁹ |

The maximum demand on the transmission network during 2024 to supply Tasmanian customers was 1,812 MW, with the total network maximum demand of 2,216 MW including power transfers across Basslink. 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.

³⁸ Native demand is inclusive of connected loads and network losses

³⁹ Derived with the assumption of 0 MW through Basslink

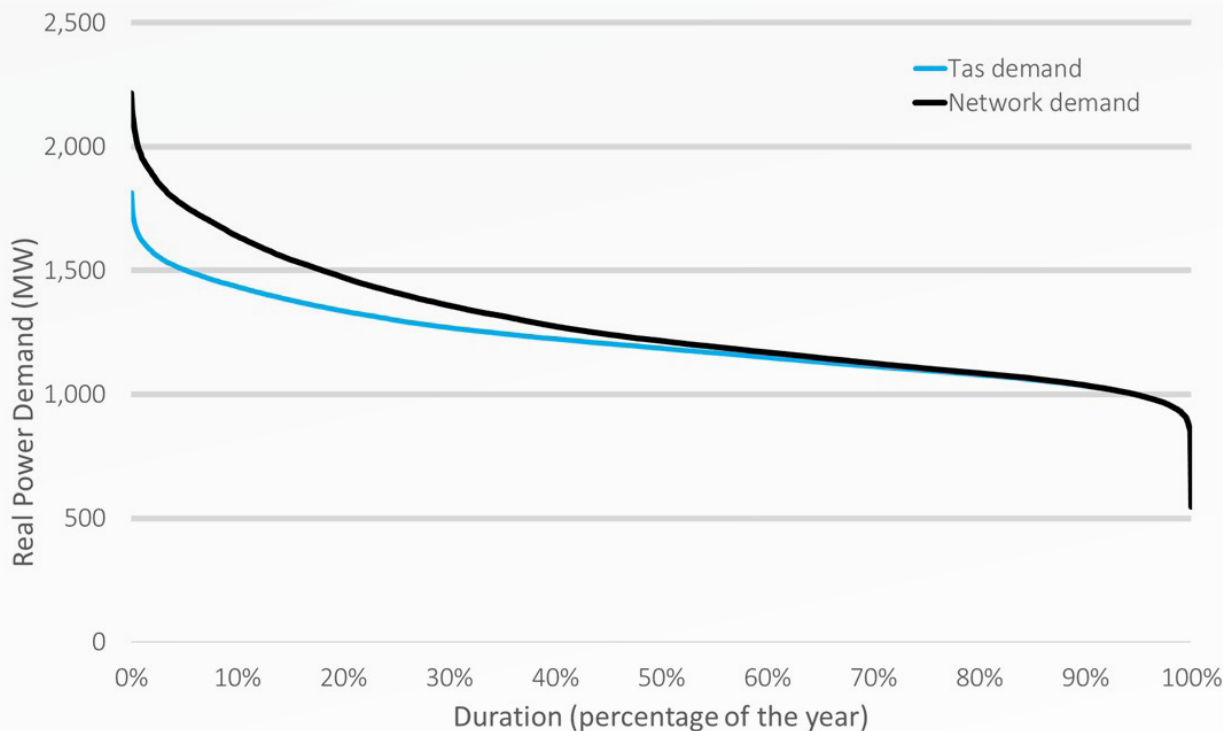


Figure 2-1: Transmission network demand duration curves 2024

In 2024, 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 demand duration characteristic, inclusive of customer and broader transmission network needs is presented in Figure 2-2.

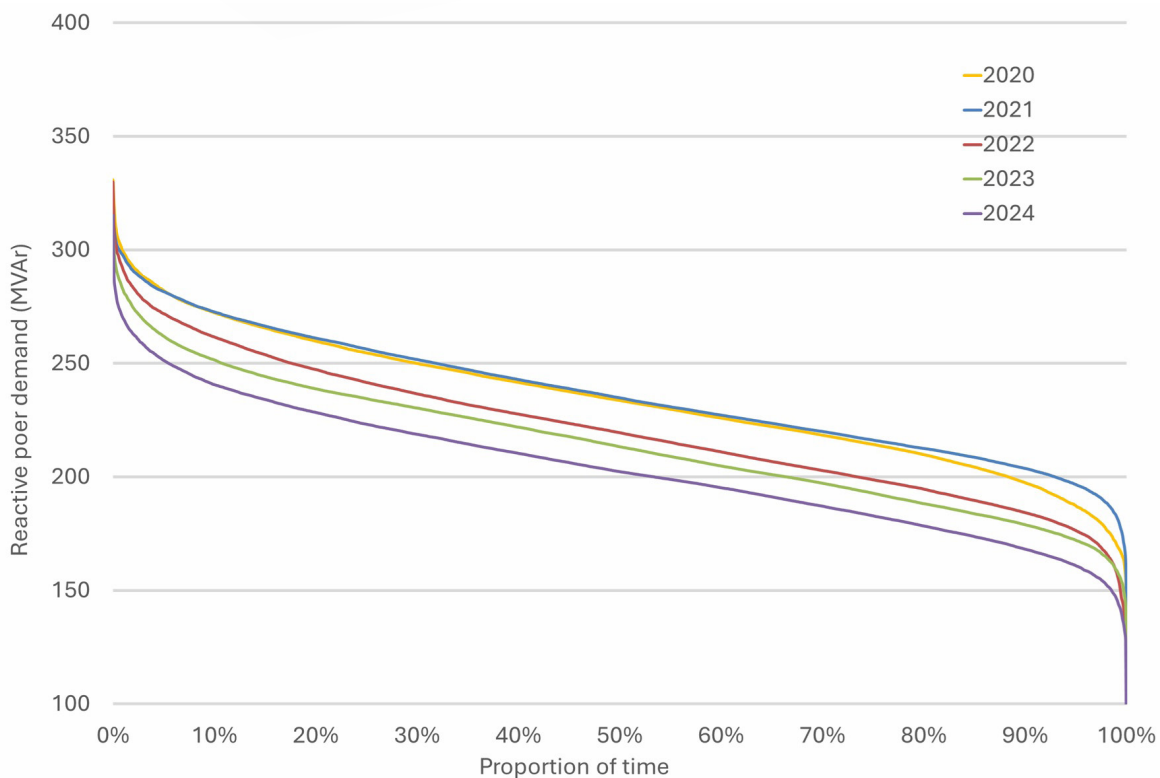


Figure 2-2: Total network reactive demand duration curves 2020-2024

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 four major industrial customers, with a small remaining portion attributed to remaining transmission customers. Distribution consumption is comparably divided between commercial and residential customers. The 2024 energy consumption profile for Tasmania is presented in Figure 2-3.

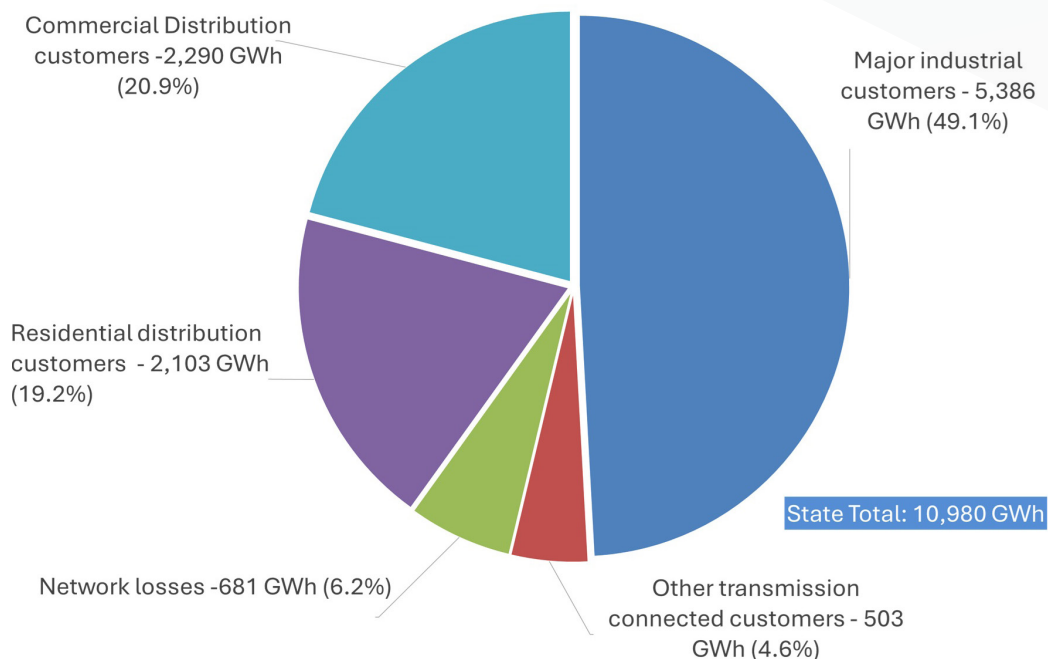


Figure 2-3: Annual Tasmanian energy consumption in 2024

In 2024, the four major industrial customers consumed 5,386 GWh or 49.1% of the state total, with the remaining transmission customers consuming 503 GWh (4.6%). Residential distribution customers accounted for 2,103 GWh (19.1%) and commercial customers accounted for 2,290 GWh (20.9%).

Network losses accounted for approximately 681 GWh, or 6.2% of the state total per annum.

2.1.3 Generation characteristics

Table 2-3 presents the total existing and committed 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 in 2024 (%) |
|---|-----------------|-----------------------------|--------------------------------------|---|
| Hydro | 25 | 2,267 | 55.5 | 61.1 |
| Wind | 5 | 568 | 13.9 | 16.8 |
| Gas | 1 | 386 | 9.5 | 3.9 |
| Embedded generation ⁴⁰ | 63,104 | 382 | 9.4 | 3.3 |
| Interconnector net energy flow (import) | 1 | 479 | 11.7 | 14.9 |

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.

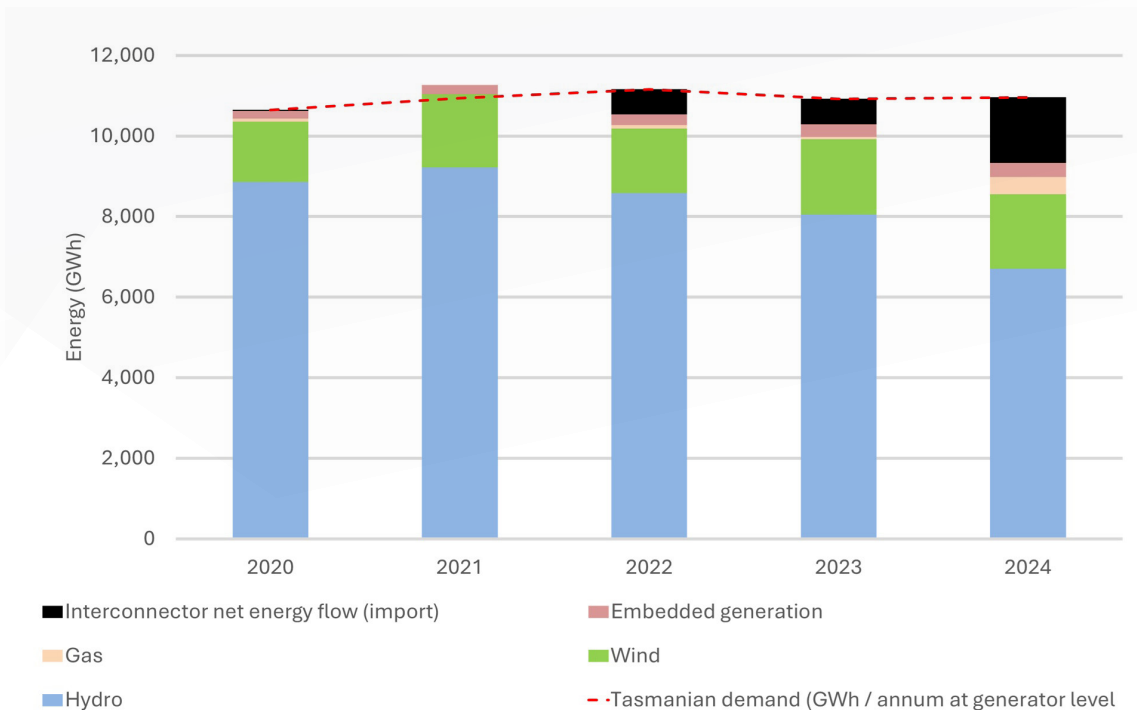


Figure 2-4: Supply contribution by type: 2020 to 2024

In 2024, overall energy demand in Tasmania was approximately 10,980 GWh, very similar in magnitude to the previous year. Wind energy and embedded generation contributions were largely consistent with the previous year at approximately 1,850 GWh and 350 GWh respectively.

The energy supply contributions from hydro generation in Tasmania was approximately 6,700 GWh, a 16% reduction from 2023. As a result, additional contributions from gas generation (426 GWh) and Basslink imports was used to meet the State’s annual energy demand.

⁴⁰ Generation capacity is predominantly Solar PV installations.. Number of installations refers to the total population at time of publication, annual energy contribution of embedded generation calculated over the previous year.

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 2025 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 a large proportion of the demand, currently sitting at over 50% of on-island energy consumption (refer Section 2.1.1). 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 for other NEM states which experience their maximum demand 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

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

AEMO's state-level forecast serves as the foundation for TasNetworks' connection point demand forecasts. AEMO, through its annual ESOO,⁴¹ provides maximum demand forecasts for all regions in the NEM. The state-level forecast referred to as native demand forecast constitutes distribution total demand, major industrial transmission customer demand, and transmission losses. Three key scenarios used by AEMO and adopted by TasNetworks for forecasting are the Progressive, Central (Step Change), and Green Energy Exports. Table 2-2 presents an overview of forecast scenarios.

41 AEMO Electricity Statement of Opportunities 2024, Appendix A4: Tasmania Outlook

Table 2-2: Forecast scenarios – 2024 ESOO & ISP

| Scenario | Description |
|----------------------|---|
| Progressive Change | The Progressive Change scenario meets Australia’s current Paris Agreement commitment of 43% emissions reduction by 2030 and net zero emissions by 2050. This scenario has more challenging economic conditions, higher technology costs and more supply chain challenges relative to other scenarios. |
| Step Change | <p>The Step Change scenario achieves a scale of energy transformation that supports Australia’s contribution to limiting global temperature rise to below 2°C compared to pre-industrial levels. The NEM electricity sector plays a significant role in decarbonisation and the scenario assumes the broader economy takes advantage of this, aligning broader decarbonisation outcomes in other sectors to a pace aligned with beating the 2°C abatement target of the Paris Agreement.</p> <p>Consumers provide a strong foundation for the transformation, with rapid and significant continued investments in Consumer Energy Resources (CERs), including electrification of the transportation sector.</p> |
| Green Energy Exports | The Green Energy Exports scenario reflects very strong decarbonisation activities domestically and globally aimed at limiting temperature increase to 1.5°C, resulting in rapid transformation of Australia’s energy sectors, including a strong use of electrification, green hydrogen, and biomethane. The electricity sector plays a very significant role in decarbonisation. |

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 connection point demand projections.

Due to the timeframes surrounding the annual planning review process, TasNetworks uses the 2024 ESOO energy and demand forecasts as its basis for the 2025 APR. The 2024 APR used energy and demand forecast data used for the 2024 ISP.

TasNetworks notes the recent publication of AEMO’s 2025 ESOO, which presents updates to energy and demand forecasts, as well as the latest supporting assumptions for each forecasting scenario.

For comparison, we report on the 2025 ESOO Step Change energy forecast because AEMO significantly reduced their hydrogen consumption outlook for Tasmania and the broader NEM.

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 2045. Forecasts are presented for the distribution network and whole of State. Forecasts from our 2024 APR are included for comparison.

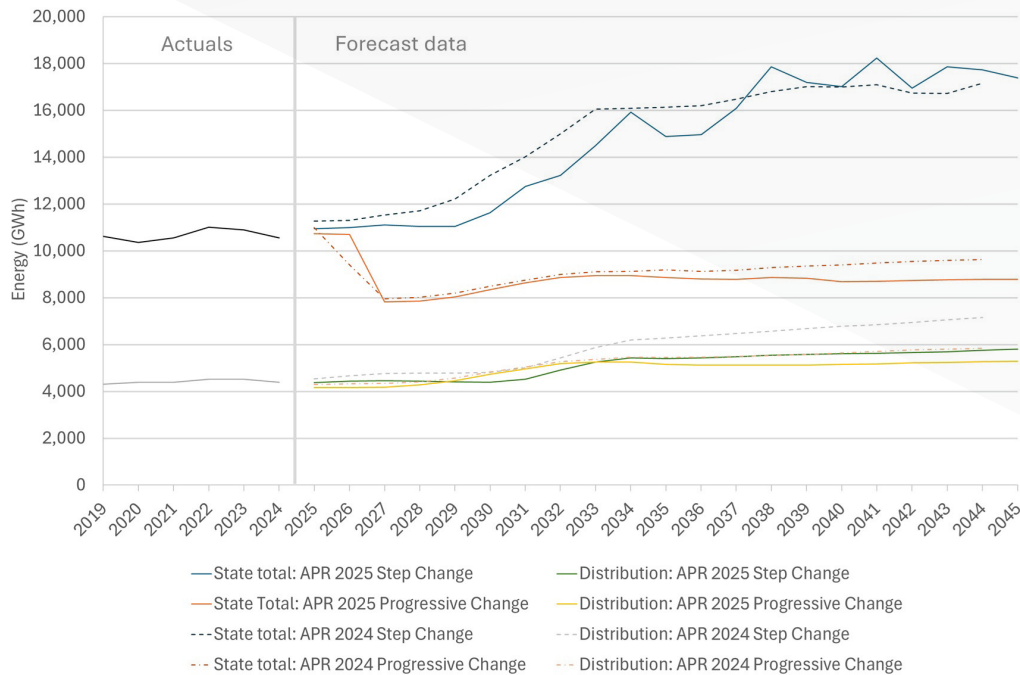


Figure 2-5: Annual energy forecast

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

| Timeframe | Description |
|-------------|--|
| 1-10 Years | <p>In Step Change scenario, the energy consumption outlook is relatively flat in the first four years until it starts to rise considerably, driven by the renewable hydrogen production. An increase in electrification (mostly in business) at later years with a slower pace also contributes to this energy consumption rise.</p> <p>In Progressive Change scenario, potential MI closure risk continues to be explored, which brings state total energy consumption down by about 41% in 2027. This is offset by a slightly lower amount of electrification uptake, compared to Step Change scenario.</p> <p>Although overtaken by Step Change scenario by 2035, distribution energy consumption under Progressive Change scenario is forecast to be higher between 2029 and 2033, largely due to an earlier uptake of business electrification.</p> |
| 11-20 Years | <p>In Step Change scenario, state total energy consumption experiences fluctuations over this decade due to the continued driving of hydrogen development. Meanwhile, electrification is forecast to stabilize with very slow growth, mostly in the agricultural sector. Forecast for EVs uptake shows a progressive increase but at a slower pace than APR 2024.</p> <p>Progressive Change scenario witnesses a lower uptake of the decarbonization drivers such as hydrogen, EVs, and electrification.</p> <p>Distribution energy consumption is lower than APR 2024 forecast, especially in Step Change scenario. It remains fairly flat under both scenarios with a compound annual growth rate of 0.7% under Step Change scenario and 0.26% under Progressive Change scenario.</p> |

Figure 2-6 provides a breakdown of each energy consumption category over the forecast planning period under the Step Change scenario.

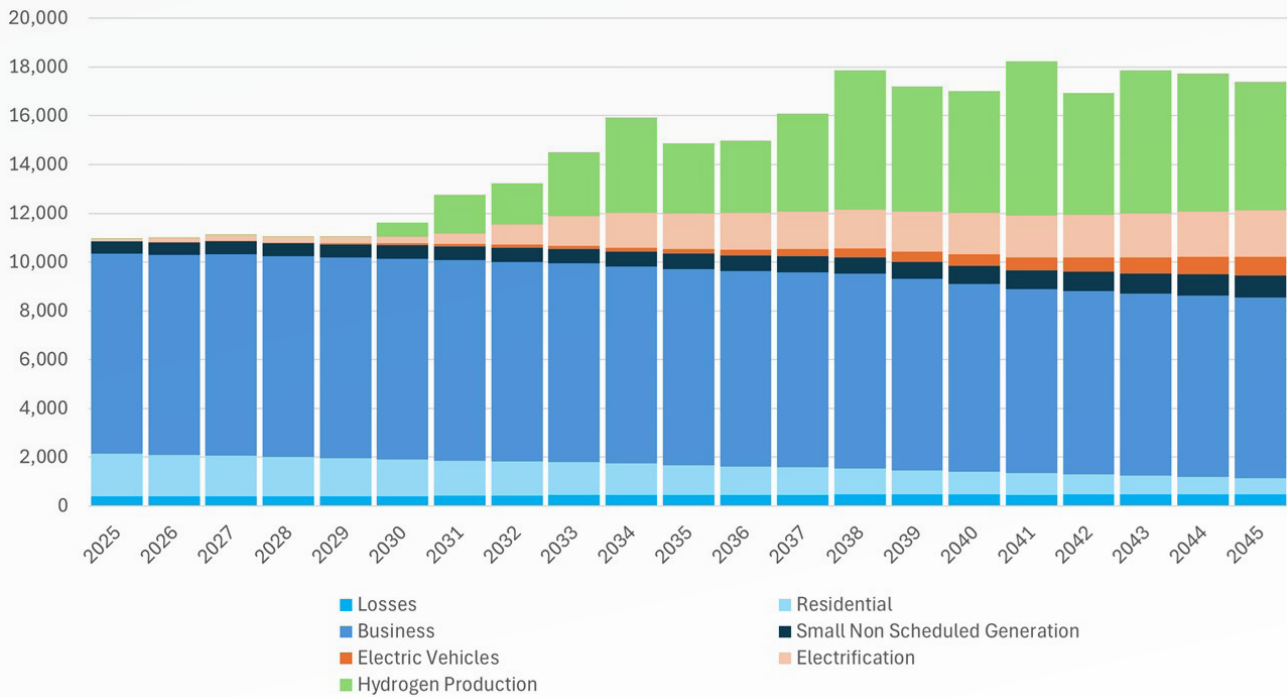


Figure 2-6: Tasmanian annual energy forecast-consumption by category-Step Change scenario

For the 2024 ESOO Step Change scenario, hydrogen production accounts for the largest increase in future energy consumption in Tasmania, accounting for up to 30% of total energy consumed in each year by the end of the forecast period. The hydrogen development trajectory commences in 2030, with nearly 4,000 GWh of annual consumption by 2034.

In the 2025 ESOO, published in August 2025, AEMO revised down these figures to a fraction of this value, with hydrogen production accounting for less than 850 GWh at the same point in time.

On a local level, we note the continued interest from hydrogen proponents to progress new production facilities, with an aggregate energy consumption of approximately 3,800 GWh across multiple locations over the coming decade.

In recognition of this continued activity, we continue to progress the Regulatory Investment Test (RIT) Project for network augmentations at George Town Substation.

Excluding hydrogen, overall energy consumption is moderated by reductions through energy efficiency and increases through the progression of business electrification and electric vehicle uptake.

The pace of development for new load and generation will impact the overall energy supply and demand balance for Tasmania. Figure 2-7 presents a projection of the State’s forecast consumption, under the Step Change scenario, for the 2024 ESOO and recent 2025 ESOO compared against the total projected Tasmanian energy production capability under the 2024 ISP Step Change scenario.

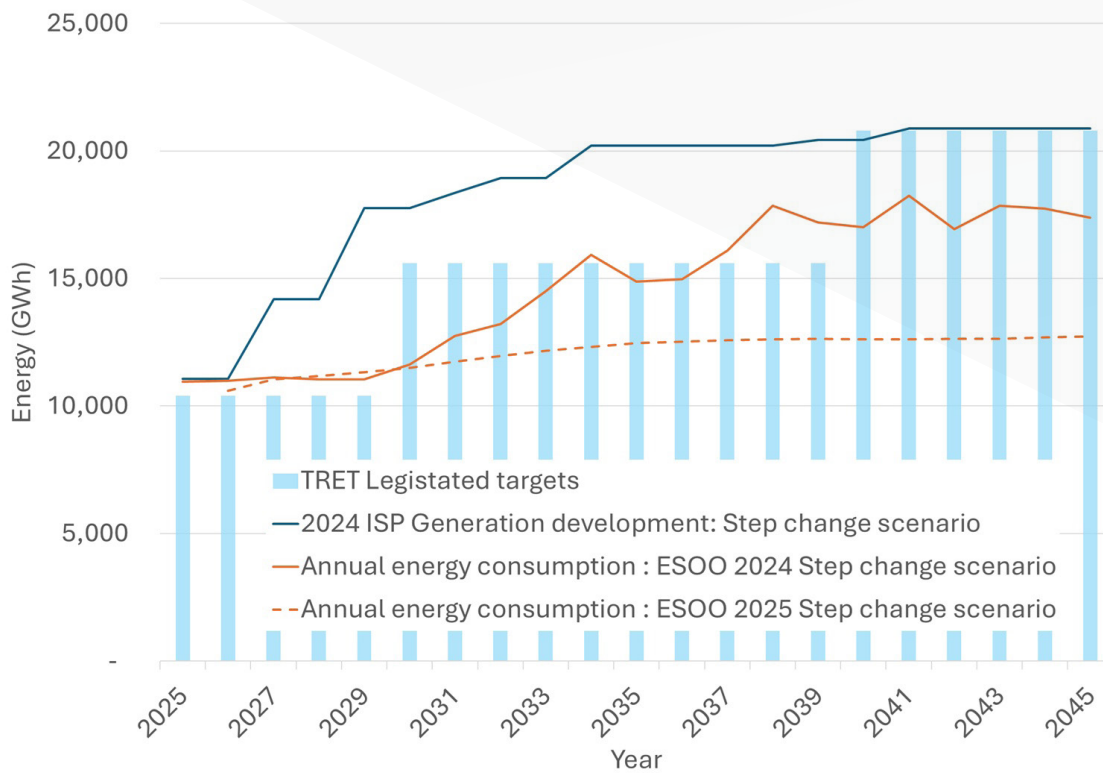


Figure 2-7: Annual energy forecast – supply and demand in Tasmania

The Tasmanian Renewable Energy Target (**TRET**) sets energy production targets as follows:

- an interim target of achieving 150% of Tasmania’s existing renewable generation by 2030; and
- a 2040 target of achieving 200% of Tasmania’s current energy needs, equating to a renewable generation capability of 21,000 GWh per annum.

When compared against the State energy demand forecast under the Step Change scenario, the TRET mandated renewable energy zone (**REZ**) build across Tasmania progresses at a pace that meets or exceeds the future consumption requirements over the next 20 years.

2.2.4 Annual maximum demand forecast

Figure 2-8 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 2045. As with the energy forecasts, the previous year’s state level demand forecast is included for comparison.

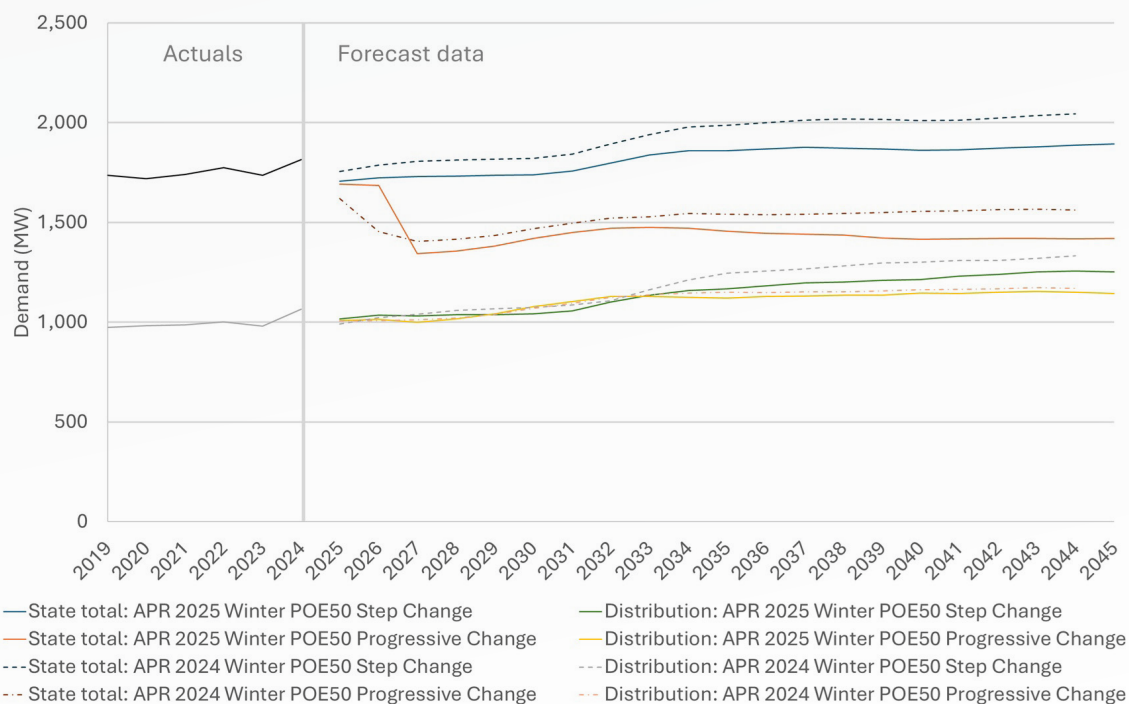


Figure 2-8: Maximum Demand forecast

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 Progressive Change scenarios are as follows:

| Timeframe | Description |
|-------------|---|
| 1-10 Years | <p>Maximum native demand forecast (50% POE) is expected to be lower than the 2023 outlook in both Step Change and Progressive Change scenario. This results from a lower growth of electric vehicle (EV) uptake and small to medium business loads, complemented by reductions in the pace of electrification investment.</p> <p>In Step Change scenario, the maximum demand remains relatively flat due to slow growth in underlying demand and minimal change in large industrial loads. From 2031, electrification uptake is forecast to increase, uplifting the maximum demand of the state total as well as the distribution component.</p> <p>In Progressive Change scenario, a large industrial load closure risk is considered, dropping the maximum demand of the state by approximately 26% in 2027. State total maximum demand is then forecast to slightly recover due to increased electrification uptake.</p> |
| 11-20 Years | <p>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.</p> <p>The average growth rate of the state total maximum demand forecast over this forecast horizon is 0.18% in Step Change scenario and -0.24% in Progressive Change scenario. In Step Change scenario, increasing demand for business mass market, electrification and EVs continues to drive to the distribution and state total maximum demand forecast. Meanwhile, the low forecast for these drivers, together with the gradual fall in large industrial loads, corresponds to the decreasing trend in maximum demand forecast under Progressive Change scenario.</p> |

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 Hadsden (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 2-9, 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 | 3,312 |
| Route kilometres of transmission lines | 2,361 |
| Circuit kilometres of transmission cable | 25.2 |
| Transmission line support structures (towers and poles) | 7,700 |
| Easement area (Hectares) | 11,176 |

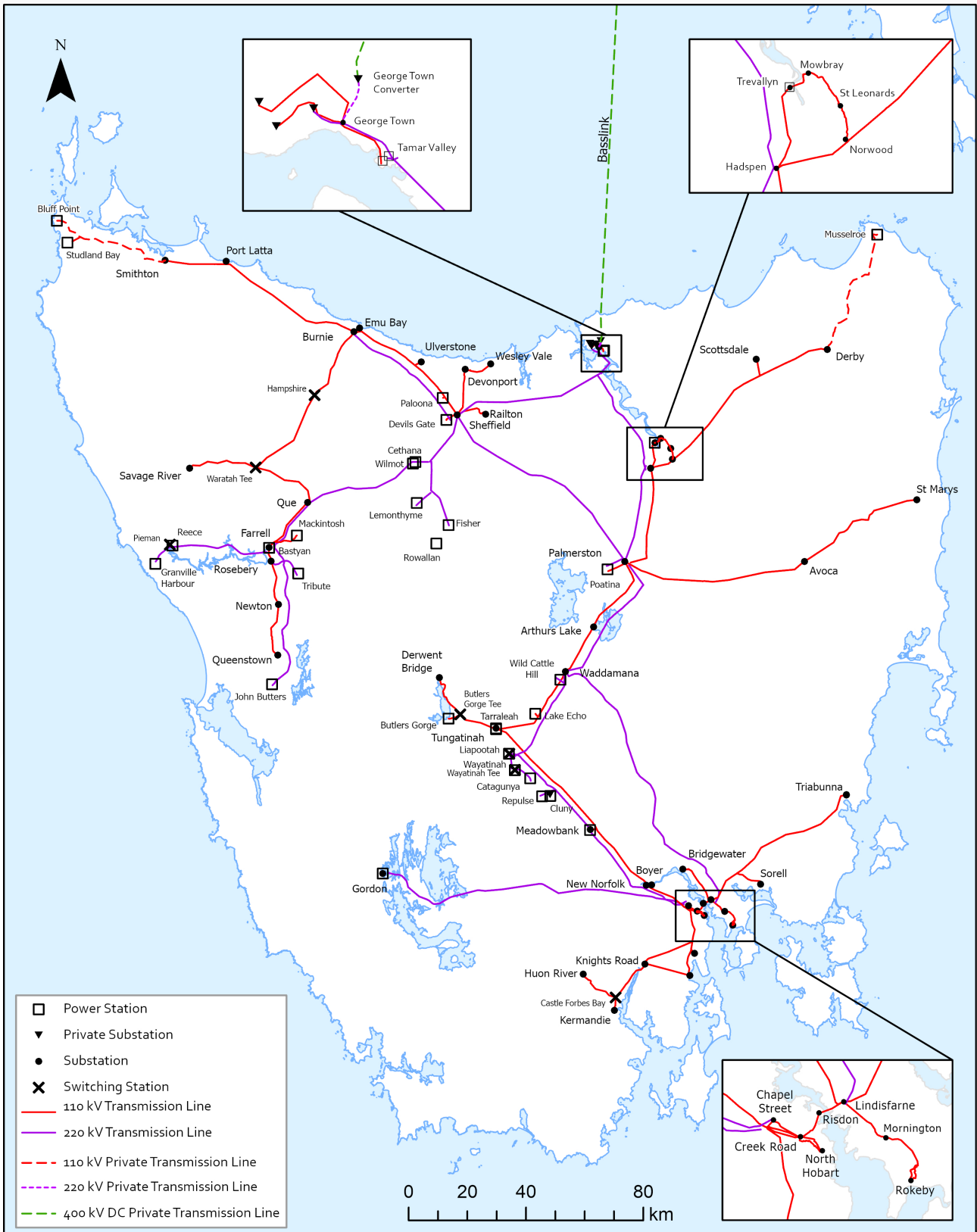


Figure 2-9: Tasmania's electricity transmission network

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 2-10 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 alternate 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.

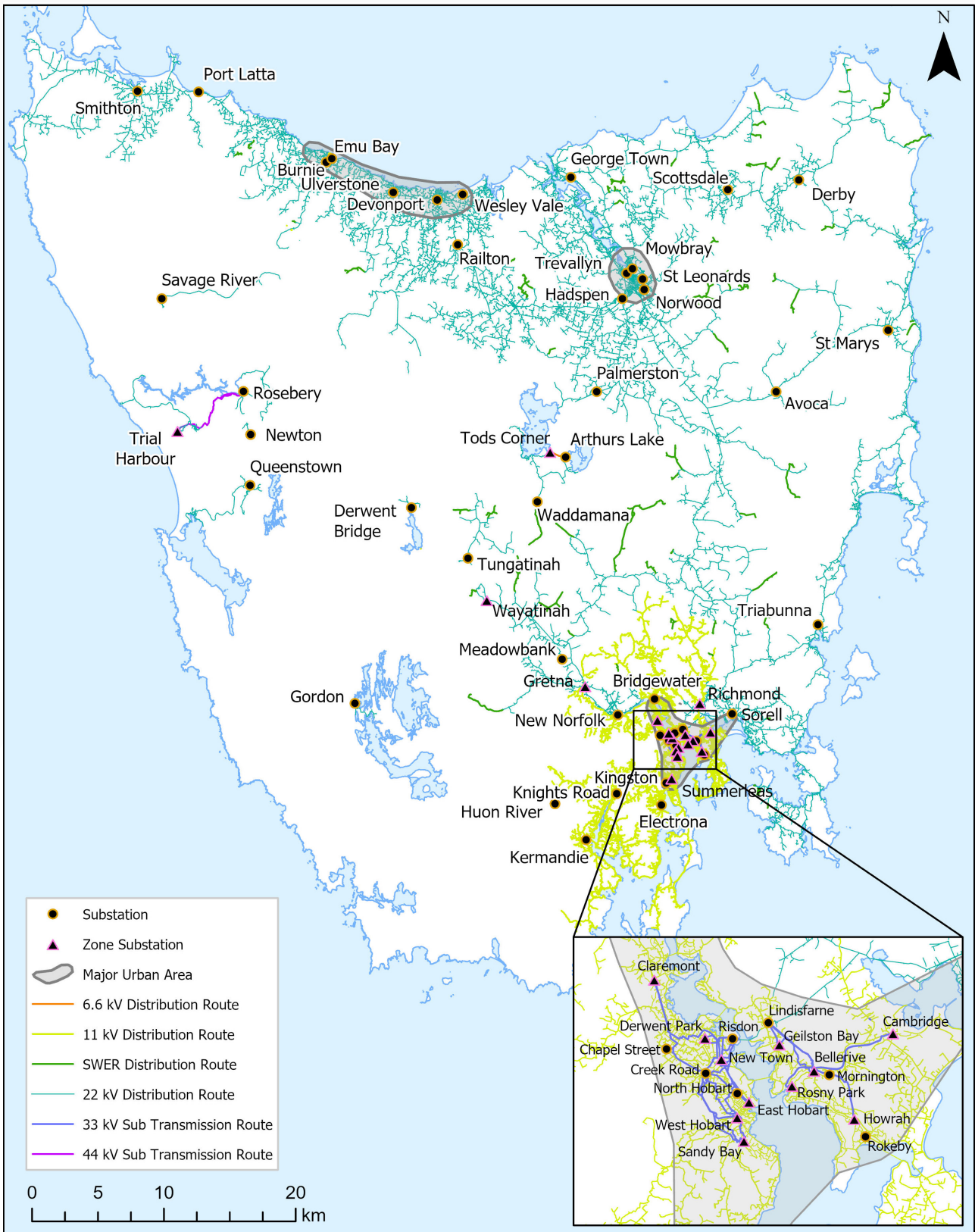


Figure 2-10: Tasmanian distribution voltage areas

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 ⁴² | 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 | | 2,138 |
| Route data | | |
| High-voltage overhead (km) | 6.6 to 44 | 15,415 |
| High-voltage underground (km) | | 1,317 |
| Low-voltage overhead (km) ⁴³ | 0.4 | 4,562 |
| Low-voltage underground (km) | | 1,480 |
| Poles | All voltages | 231,643 |

⁴² Includes minor zone alternate-supply lines

⁴³ Excludes customer service lines

Chapter 3

Transmission network development

- Tasmanian transmission network planning activities continue to focus on identifying the optimum development path to accommodate future large-scale renewable energy resources, a new interconnection with Victoria, upgrading of existing power stations, connection of export-scale hydrogen, and integration of energy “firming” facilities such as battery energy storage systems (**BESS**) and pumped hydro energy storage (**PHES**).
- We have developed transmission augmentation options that support a range of market scenarios as the Australian electricity system transitions towards more renewable energy sources, informed by the Tasmanian Renewable Energy Target (**TRET**), plans to develop a renewables based hydrogen industry, and identification by the Australian Energy Market Operator (**AEMO**) of Renewable Energy Zones (**REZs**) and associated transmission augmentations.
- The North West Transmission Developments (**NWTD**) project comprises upgrades to the network in Tasmania supporting the establishment of Marinus Link interconnector stages 1 and 2. The first stage of the project, comprising a new 750 MW interconnector with connection to the North West Tasmanian network via a coastal route, is planned to be delivered in 2030/31. The second stage timing of Marinus Link and NWTD is yet to be determined.
- We have initiated a Regulatory Investment Test for Transmission (**RIT-T**) for augmentations at George Town triggered by an initial tranche of new load, such as hydrogen.
- We have initiated a new Network Investment Capability Parameter Action Plan (**NICIPAP**) 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 backbone transmission network in accordance with regulatory requirements as outlined in Appendix A. It presents our plans to support the development of Marinus Link and new renewable energy generation in the North West, the North East and Central Highlands REZs required to achieve the TRET.

The Tasmanian Renewable Hydrogen Action Plan (**TRHAP**)⁴⁴ previously identified potential locations for large-scale renewable hydrogen production and export. Since then, TasNetworks has progressed planning strategies prioritised for hydrogen integration within the Bell Bay Advanced Manufacturing Zone (**BBAMZ**). At the end of 2024, TasNetworks initiated a RIT-T for augmentation works at George Town Substation, supporting the first tranche of new load connection, expected within the 2024-2029 period. TasNetworks published the Project Specification Consultation Report (**PSCR**)⁴⁵ for upgrade works and additional reactive support at George Town Substation, triggered by 210 MW or more of new load.

3.2 The backbone transmission network

The backbone of the Tasmanian transmission system 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 Basslink, the interconnection with Victoria. The main considerations when planning the backbone transmission network are the technical requirements of the National Electricity Rules (**the Rules**) 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 also need to be considered, with further details available in Appendix A.3.3.

3.3 Committed and Completed Projects

3.3.1 System strength remediation at Burnie 110 kV fault level node

AEMO determines system strength requirements, including fault level nodes and minimum three-phase fault levels, which must be maintained to manage power system security. The details of our system strength obligations are presented in Section 5.4 of this Annual Planning Report (**APR**).

In 2021, TasNetworks installed new dynamic reactive support in the north-west to address previously identified system strength limitations at Burnie 110 kV substation. The provision of fast acting dynamic support allows the network to operate at a lower minimum pre-contingent fault level of 750 MVA (down from the 850 MVA currently required). Two 6 MVar static synchronous compensators (**STATCOM**) were installed at Port Latta Substation to deliver these benefits, at a cost of approximately \$7.0 million. The project was completed in Q4 2024.

44 Tasmanian Renewable Hydrogen Action Plan | ReCFIT

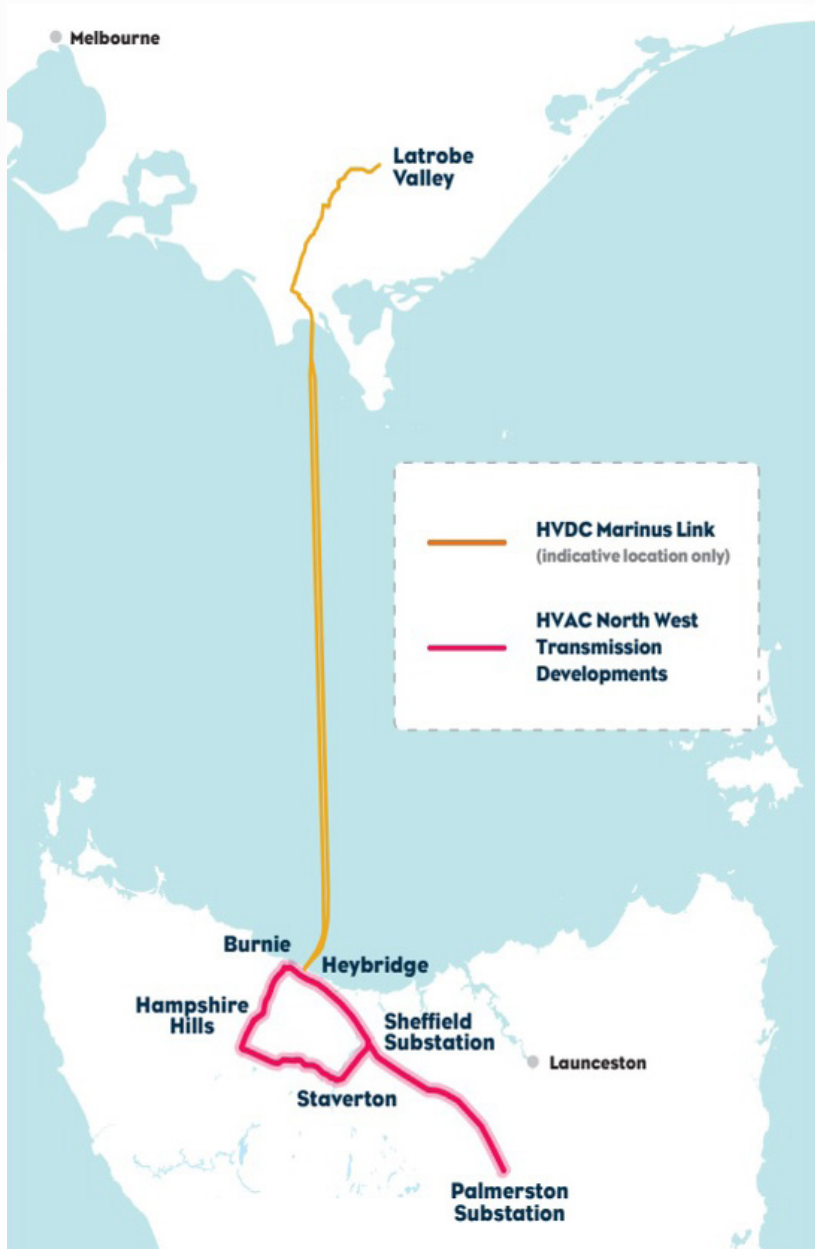
45 <https://www.tasnetworks.com.au/planning-and-projects/regulatory-investment-test-projects>

3.4 Marinus Link

Marinus Link Pty Ltd (**MLPL**) is a three-part equity ownership between the Australian Government (49%), the Victorian Government (33.3%) and the Tasmanian Government (17.7%). MLPL has responsibility for progressing Marinus Link, a new subsea interconnection to Victoria comprising two 750 MW High Voltage Direct Current (**HVDC**) transmission systems using voltage source converter (**VSC**) technology. When completed, Marinus Link will create a 1,500 MW transmission pathway, significantly increasing energy transfer capabilities between Tasmania and the rest of the National Electricity Market (**NEM**).

In anticipation of Marinus Link being classified as a prescribed transmission service, MLPL registered with AEMO as an Intending Participant in the Transmission Network Service Provider (**TNSP**) category. In addition, MLPL has an Electricity Supply Industry Transmission Licence issued by the Tasmanian Economic Regulator. Further information about Marinus Link is available from the Marinus Link website.

The existing 220 kV transmission network in north-west Tasmania will require augmentation to support the increased power flows to and from Marinus Link and a pipeline of renewable generation and storage projects proposed for the North West and Central Highlands REZs.



MLPL and TasNetworks continue to undertake joint planning activities for the integration of Marinus Link, with our core focus centred on the strategic developments required across the Tasmanian transmission network. In July 2025, MLPL published a RIT-T update for the project, in advance of the revised Revenue Proposal.⁴⁶ The purpose of the RIT-T update was to ascertain whether the proposed transmission investment for Marinus Link and supporting NWTG continued to be the optimal solution, where circumstances have changed materially since the original RIT-T assessment. The assessment utilised a modelling approach consistent with the Project Assessment Conclusions Report (**PACR**) and subsequent RIT-T updates, with updated AEMO inputs and assumptions.

A least-cost generation dispatch and capacity development plan for the NEM was computed for two scenarios in AEMO Draft 2025 Input, Assumptions, and Scenarios Report (**IASR**), being the Step Change and Progressive Change scenarios.

The modelling for each of these scenarios used the following updated input assumptions:

- the Draft 2025 IASR assumptions relating to policies, costs, and generator technical parameters;
- AEMO's August 2024 Electricity Statement of Opportunities demand projections, excluding hydrogen demand; and
- the Draft 2025 IASR hydrogen demand projections.

The assumed timing for major transmission upgrades was based on AEMO's outcomes from their 2024 Integrated System Plan (**ISP**) or the proponent's earliest in-service date where these dates were later.

The outcome from the updated modelling was that the preferred option, which is to proceed with the first cable as soon as practicable and to keep the timing of the second cable under review, remains unchanged from the PACR in June 2021 and the RIT-T update in April 2024.

The proposed transmission network topology to accommodate both stages of Marinus Link, as well as associated renewable energy developments across the three Tasmania REZs, is outlined in Section 3.6.

3.5 Renewable energy developments

3.5.1 Renewable energy zones

REZs are "high renewable resource areas" identified by AEMO due to their weather patterns, 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 ISP identifies 43 potential REZ across the NEM, of which 41 are located onshore, with a further six being Offshore Wind Zones (**OWZs**). Tasmania has three onshore REZ and one OWZ, with the wind resource quality of the Tasmanian sites being amongst the highest across the NEM.⁴⁷ The locations of the four Tasmanian REZs are presented in Figure 3-1.

⁴⁶ Summary-RIT-T-update-report-July-2025-1.pdf

⁴⁷ 2024 ISP, Appendix A3: <https://aemo.com.au/-/media/files/major-publications/isp/2024/appendices/a3-renewable-energy-zones.pdf?la=en>



Figure 3-1: Tasmanian REZs

We take the view that the REZ concept does not restrict the development and connection of any new generation outside of these nominated areas.

New variable renewable energy (VRE) generation may utilise a variety of natural resources, however in Tasmania, the ISP forecasts that wind will be the dominant energy source that is developed. In addition, repurposing and expansion of the existing hydropower system in Tasmania, including future PHES, will support REZ development.

We continue to review and refine our network planning strategy to support each REZ, as well as the core grid, to meet the objectives of the Tasmanian Renewable Energy Action Plan (**TREAP**) which includes the following elements:

- the TRET;
- Marinus Link; and
- establishment of a renewable (green) export hydrogen industry in Tasmania.

The TREAP is presented in detail in Section 1.4 of this APR.

3.5.2 Tasmanian Renewable Energy Target

Tasmania has the potential to play a significant role in decarbonisation of the NEM, directly through the installation of significant renewable energy resources, and indirectly by providing access to flexible firming capacity and deep storage via existing (and new) hydro generation assets. Additional transmission interconnector capacity in the form of Marinus Link will enable Tasmania to contribute more significantly to the future needs of the NEM, as well as encourage local generation and customer developments.

The Tasmanian Government has legislated the TRET, setting targets for renewable electricity generation by 2030 and 2040, which was captured as a key input to the 2022 and 2024 ISP documents. To meet these targets, significant new generation sources are required within the Tasmanian region, with the majority expected to be wind farm developments. To meet the TRET, the required new wind capacity needing to be installed is approximately:

- 1,500 MW by 2030 to meet the interim target of an additional 5,250 GWh (more than twice the existing annual wind energy production in Tasmania); and
- 3,000 MW by 2040 to meet the full target of an additional 10,500 GWh (twice the total existing Tasmanian annual energy consumption in 2020).

The estimated installed capacity of new wind to meet the TRET is dependent on the assumed capacity factor, with 40% being a typical 'annual' value used for network planning purposes in Tasmania. The required installed capacity would change if other renewable energy sources (e.g. solar-photovoltaic (**PV**)) are also developed.

As presented in the 'energy and demand forecasts' described in Section 2.2, under the Step Change scenario, the projected energy generation capacity is sufficient to supply the state's future energy consumption requirements, which includes an initial tranche of large-scale hydrogen developments.

3.5.3 Establishing Tasmania's first REZ

In December 2022, The Tasmanian Government announced that the north-west of Tasmania would be explored for its potential to host the state's first REZ. Renewables, Climate and Future Industries Tasmania (**ReCFIT**) is progressing the evaluation through community engagement, a detailed examination of how any future REZ might overlap with existing land uses and values, the ability of the electricity network to host more renewables, and market interest in new generation. ReCFIT, with the support of TasNetworks, has now initiated targeted activities such as hosting capacity assessments. ReCFIT consulted on draft REZ legislation in 2024 which will allow the government to declare REZs in suitable areas of Tasmania.⁴⁸ The proposed REZ area of consultation is outlined in Figure 3-2.

⁴⁸ <https://www.renewableenergyzones.tas.gov.au/>

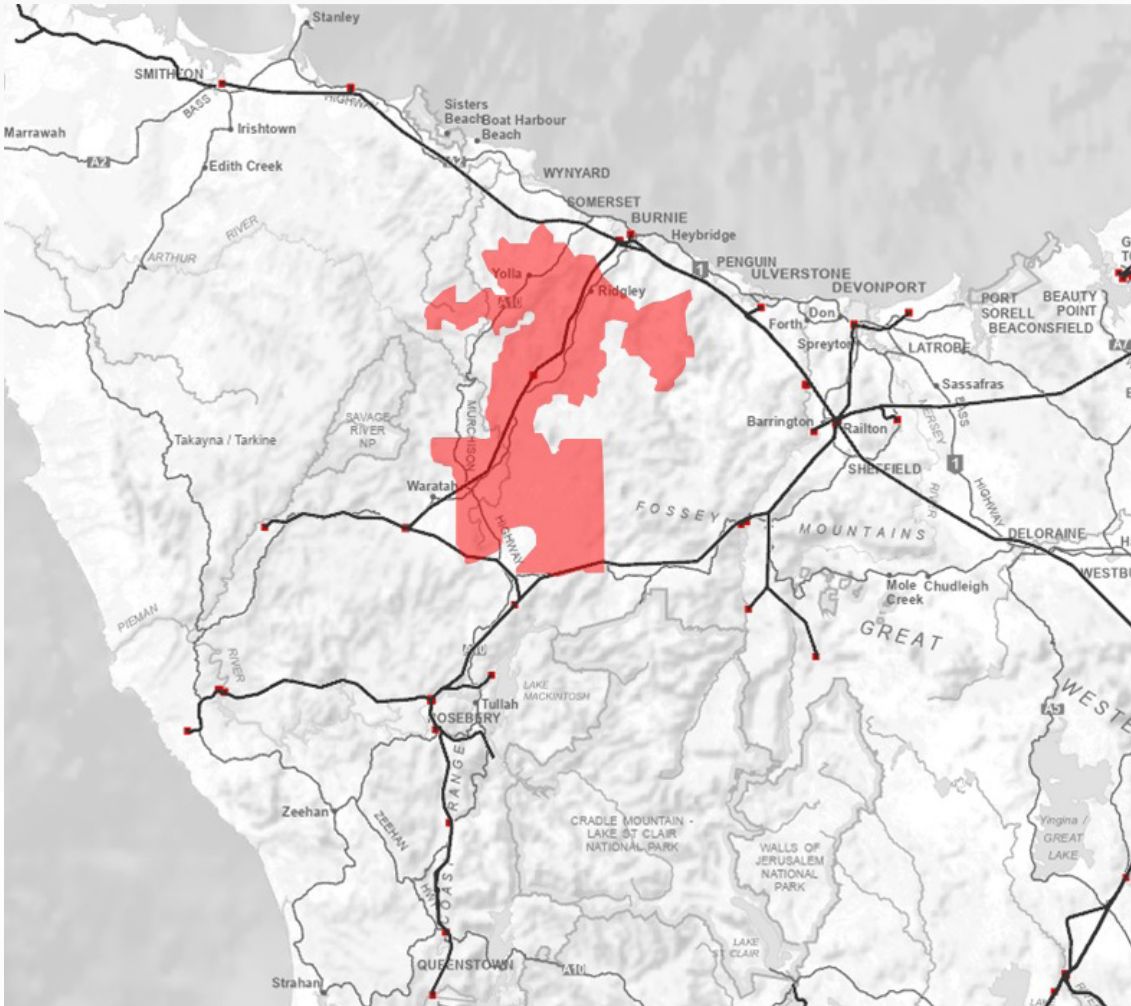


Figure 3-2: North West REZ Proposed area of consultation

Ultimately, new VRE is expected to be developed across all identified Tasmanian REZs to meet the TREAP objectives. The strategic plan for the future North West REZ, with its anticipated generation, load, and interconnector developments is outlined in Section 3.6.1.

3.5.4 Hydro Generation Developments

Hydro Tasmania is progressing its future energy vision, which includes a series of proposals to repurpose existing hydropower assets and establish PHES. These proposals, along with increased interconnection provided by Marinus Link, will enable Tasmania to provide firming services—both dispatchable capacity and deep storage—to the mainland NEM as it transitions to a future dominated by VRE generation.

The current proposals being actively progressed aim to increase the dispatchable capacity of renewable energy resources in Tasmania to meet short-term energy deficits on the mainland. These include:

- repurposing the Tarraleah hydropower scheme,⁴⁹ including replacement of the existing Tarraleah Power Station (capacity increase from 90 MW to approximately 210 MW); and
- establishing a PHES system at Lake Cethana⁵⁰ (750 MW capacity)

TasNetworks takes into consideration various scenarios for the introduction of new hydro generation and storage capacity to the network, particularly regarding the progression of Marinus Link and supporting upgrades to the transmission network.

These generation projects will influence the future network strategy in the following ways:

- Should Cethana PHES be developed before Marinus Link stage 2, this drives the need to advance some elements of NWTG for Marinus Stage 2.
- In addition to impacting the Upper Derwent transmission network, the Tarraleah upgrade contributes towards the aggregate generation development that drives the need to upgrade the capacity of the Central Highlands network.

3.5.5 Summary of ISP forecasts

The ISP is published every 2 years, with the most recent version published in June 2024.⁵¹ The 2024 ISP is the current version considered throughout this APR.

The ISP outlines an optimal development path for new generation (predominantly VRE), transmission, and storage across the NEM to replace existing thermal generation sources (coal and gas) as it retires over coming years. The ISP projects out to 2050, and across three scenarios, as described in section 2.2.2. The Step Change scenario, adopted by TasNetworks for energy and demand forecasts, assumes thermal generation retirements earlier than previously announced, and the subsequent rapid development of new VRE, transmission, and energy storage to replace it.

The ISP includes the TRET as a basis for its modelling across all scenarios, ensuring sufficient VRE is built in Tasmania to meet the legislated interim and final targets.

The ISP considers VRE resource quality across each REZ, along with existing transmission capability and augmentation requirements. It does not consider the specific locations within the REZ where VRE might be developed. The ISP Step Change scenario considers some hydrogen developments, with the most pronounced changes seen in the Green Energy Exports scenario which involves very large hydrogen (and subsequent VRE) developments across the NEM.

In Tasmania, approximately 1,500 MW of new utility-scale wind generation is projected by 2030-31, utilising transmission capacity released by the development of Project Marinus Stage 1.

The 2024 ISP modelling indicates:

- Over 600 MW of new wind generation is projected for the Central Highlands REZ by 2026-27, with around 1,300 MW projected by 2029-30 to utilise the full capacity of Project Marinus Stage 1. This REZ now has the highest VRE projection in the Tasmanian region, with nearly 2,300 MW forecast by 2046-47.
- The North West REZ sees a gradual increase of 380 MW of new wind generation by 2034-35, reaching a maximum of 500 MW by 2046-47.
- There is 400 MW of new wind projected for the North East REZ by 2031-32.
- There is no major change in forecast utility-scale VRE capacity beyond 2042-43.
- There is no utility scale PV or offshore wind development projected in the Step Change scenario for Tasmania. Small scale distributed PV will continue to grow in capacity.

⁴⁹ Reimagining Tarraleah | Connect Hydro

⁵⁰ <https://connect.hydro.com.au/cethana-pumpedhydro>

⁵¹ <https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp>

Table 3-1 presents the 2024 ISP outlook for new large scale VRE under the Step Change and Progressive Change scenarios by REZ for 2029–30 and 2039–40.

Table 3-1: 2024 ISP VRE projections (MW)

| REZ | Step Change scenario | | Progressive Change scenario | |
|----------------------------|----------------------|--------------|-----------------------------|--------------|
| | 2029–30 | 2039–40 | 2029–30 | 2039–40 |
| North East Tasmania (T1) | 250 | 400 | 250 | 350 |
| North West Tasmania (T2) | 0 | 400 | 0 | 0 |
| Central Highlands (T3) | 1,300 | 1,400 | 700 | 1,550 |
| North Tasmanian Coast (T4) | 0 | 0 | 0 | 0 |
| Total | 1,550 | 2,200 | 950 | 1,900 |

The 2024 ISP optimal development path further identifies the following transmission augmentations in Tasmania:

- Marinus Link Stages 1 and 2 (including NWTG) are classified as a single actionable project, commencing in 2030 based on timing advised by the proponent;
- Waddamana- Palmerston upgrade is now an actionable project, with earliest feasible timing being July 2029; and
- North West REZ expansion and Central Highlands REZ extension network upgrades as future ISP projects.

The ISP does not consider any of the currently proposed VRE developments in Tasmania to be sufficiently progressed to be included as ‘anticipated’ or ‘committed’ projects in its analysis, meaning that specific projects are not modelled in the ISP.

AEMO is currently developing the 2026 ISP.⁵² The Draft 2026 ISP is scheduled to be published 11 December 2025, and the 2026 ISP published 25 June 2026. In the 2026 ISP, AEMO is increasing opportunities for development in the distribution network (Consumer Energy Resources (CER) and other distributed resources) to support the transition to net zero. Engagement through the 2026 ISP process is available through AEMO.

3.6 Tasmanian REZ and associated network developments

This section describes each Tasmanian REZ, the capability of each REZ to host new VRE with existing network assets, and potential augmentations required to support further VRE development.

The ISP outlook for VRE in Tasmania, with consideration also given to publicly announced proposals, is used as the basis for our REZ development plans presented in this section. Network augmentations will only be developed as the actual investment need arises, including as new generation develops, and each will be subject to a RIT-T.

For each REZ, TasNetworks also maintains a register of proposed generation developments which is used to help inform the potential utilisation of the existing network and determine future network augmentation requirements. The aggregate generation profiles comprise proposals in various stages of development, including active connection enquiries and applications. 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. This represents an ongoing work stream for TasNetworks. Detailed investigations will occur as the sequence of development across each REZ becomes clearer, along with the timing of individual projects. The difference between the total generation being forecast and the existing hosting capacity signals the extent of new investment that is needed in the network if operational constraints are to be minimised (noting that it may not be economical to eliminate all future constraints).

As part of the analysis presented, we have included the current 2024 ISP Step Change and Progressive Change scenario projections for comparison for each REZ.

⁵² <https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp>

3.6.1 North West REZ

The North West REZ has significant potential for new wind generation developments. The connection location for Marinus Link is within this REZ at Heybridge (near Burnie). There is significant interest to develop new generation in the area, as well as the first tranche of PHES. Hydro Tasmania has announced Lake Cethana as its preferred PHES site and is progressing it to final feasibility.⁵³

Figure 3-3 presents the North West REZ transmission network, including NWTD.



Figure 3-3: North West Tasmania REZ transmission network with NWTD

Figure 3-4 summarises the existing hosting capacity of the North West REZ transmission network, including publicly announced generation developments. Included for comparison is the generation forecast under the 2024 ISP Step Change and Progressive Change scenarios.

⁵³ <https://www.hydro.com.au/clean-energy/battery-of-the-nation/pumped-hydro>

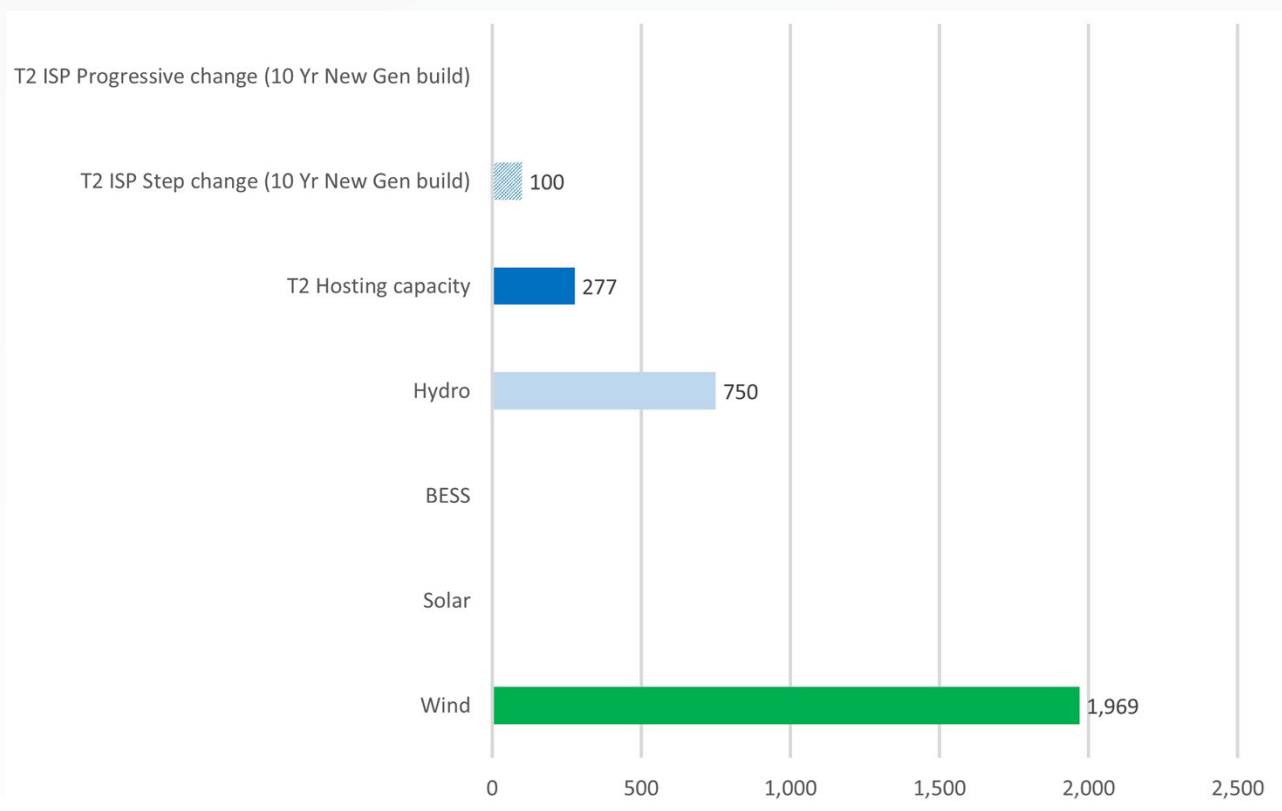


Figure 3-4: North West Tasmania REZ forecast generation and hosting capacity

There is capability in the existing North West REZ transmission network to accommodate approximately 277 MW of new VRE subject to a number of already identified limitations being adequately addressed including provision of adequate system strength.

There is a combined interest of approximately 1,600 MW of new generation in this REZ, the vast majority being wind generation.

The Step Change scenario of the ISP forecasts a slower uptake of new generation in this area compared with the other land based REZs, with only 100 MW of new generation predicted in the next 10 years. The Progressive Change scenario forecasts no new generation over the same period.

3.6.1.1 North West Transmission Developments

The NWTD will enable 1,500 MW export and import capability of Marinus Link. The NWTD comprises a new, high capacity 220 kV double circuit transmission network in the north-west and reinforcement of the Sheffield-Palmerston transmission corridor.

The optimal transmission development for the north west is a new 220 kV transmission 'rectangle', plus increased transmission capacity between Sheffield and Palmerston substations, specifically:

- **New 220 kV switching stations:** at Staverton, Hampshire Hills and Heybridge;
- **New 220 kV double-circuit transmission ring:** Sheffield–Heybridge–Burnie–(via Hampshire)–Staverton;
- **New 220 kV double-circuit transmission line:** Palmerston–Sheffield; and
- **Decommission:** existing single-circuit Palmerston–Sheffield and Sheffield–Burnie 220 kV transmission lines.

The north-west transmission ring will traverse separate coastal and inland routes, allowing for route diversity and for the efficient connection of new generation in the North West REZ.

More information on the NWTD, as well as progress on the design and approvals phase, is available from the TasNetworks website at:

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

The build sequence of the NWTD has been developed to ensure that the minimum network requirements for Marinus Link Stage 1 can be met at the least cost for our customers. The sequencing also allows for the network to be further expanded to deliver that necessary to support Marinus Link Stage 2 which will see the interconnector reach its full 1,500 MW transfer capacity.

The 'coastal' route of the NWTD, shown in Figure 3-5, comprises a new double circuit 220 kV transmission corridor between Palmerston, Sheffield and Burnie, with an interim tee arrangement to allow connection of Heybridge Switching Station and the first 750 MW Marinus Link interconnector.

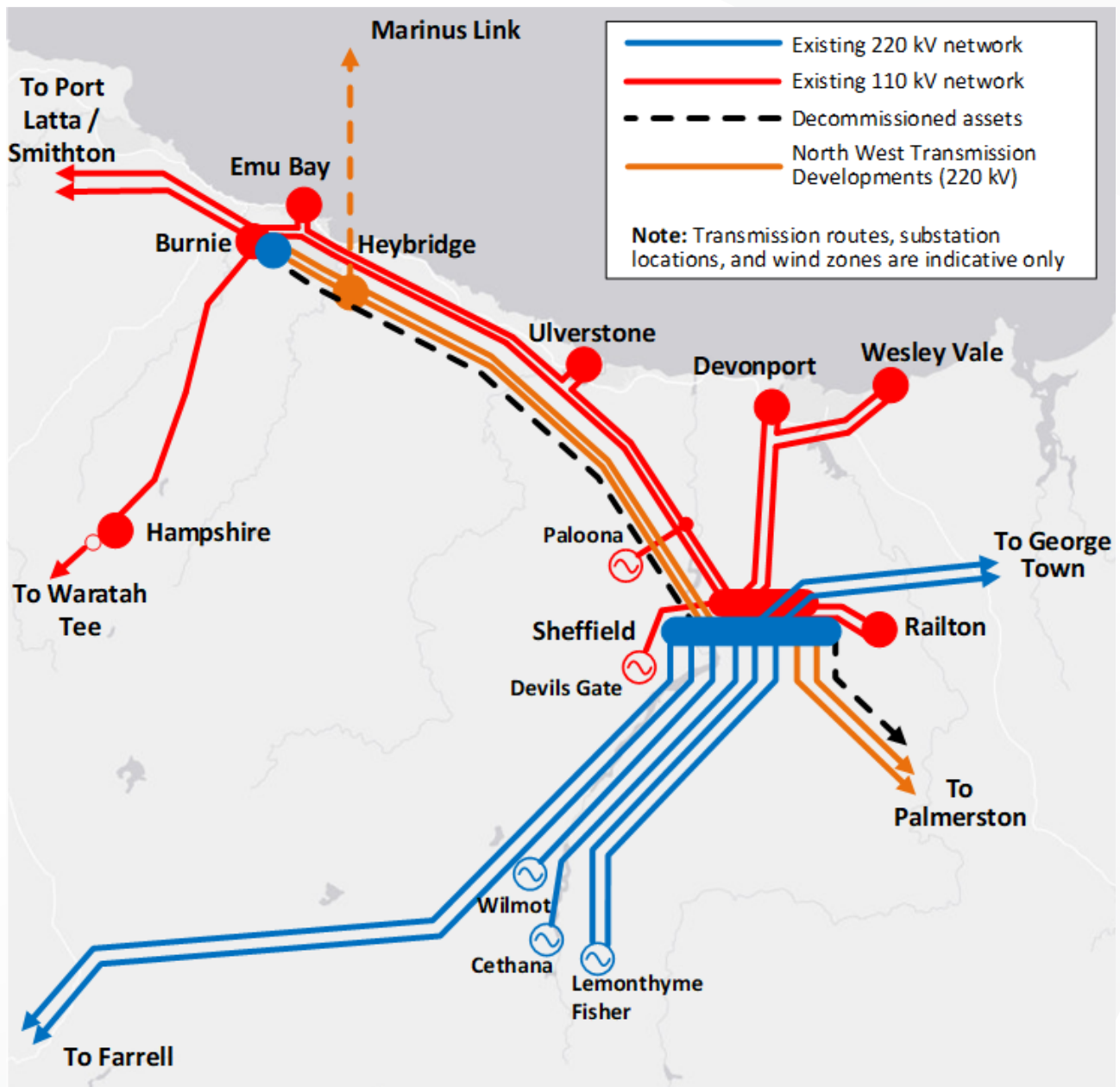


Figure 3-5: Marinus NWTD Stage 1 Coastal route

Stage 1 of the NWTD comprises the following assets:

- **One new 220 kV switching station** at Heybridge;
- **One new 220 kV double-circuit transmission line** between Sheffield, Heybridge, and Burnie;
- **One new 220 kV double-circuit transmission line** between Palmerston and Sheffield; and
- **Decommissioning** of the existing Palmerston-Sheffield and Sheffield-Burnie 220 kV single-circuit transmission lines.

The augmentation works will increase the hosting capacity of the north west REZ to more than 800 MW. The estimated cost of this first stage of works is \$1,144 million.

The key assumptions which underpin the NWT Stage 1 developments include:

- Construction of the new transmission lines will be undertaken in a manner that minimises the operational risk to customers and generators connected in the north west.
- Development of a double circuit 220 kV connection for Marinus link Stage 1 is to ensure that the interconnector is not significantly impeded by transmission network capacity limitations.

We have also considered REZ development scenarios after NWT Stage 1 where components of the remaining NWT strategy are brought forward ahead of Marinus Link Stage 2, shown in Figure 3-6, including:

- (1) **Burnie approach:** Developing the Burnie-Hampshire Hills 220 kV transmission line; or
- (2) **Sheffield approach:** Developing the Hampshire Hills-Staverton 220 kV line, along with Staverton Switching Station.

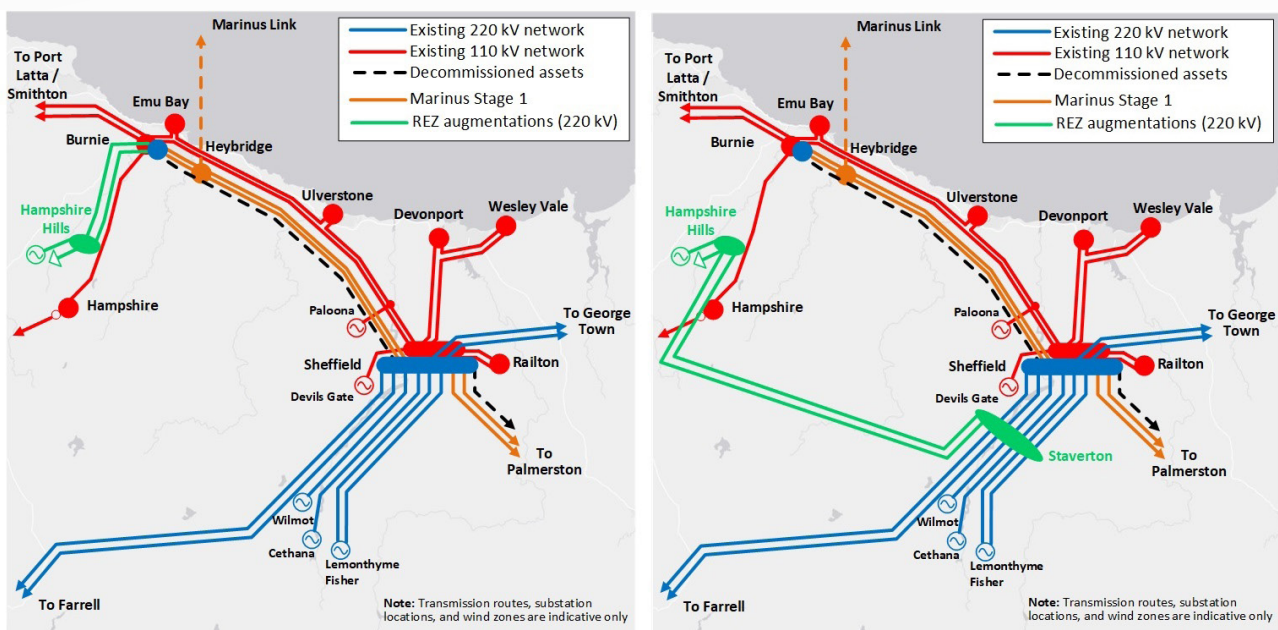


Figure 3-6: Potential investments driven by North West REZ

Either option may be progressed through various mechanisms, including:

- a contingent project with regulated funding, triggered by the commitment of new generation or load, and justified through a RIT-T;
- an actionable project identified in the ISP, whereby a RIT-T is undertaken by TasNetworks and if successful, the preferred option is progressed as a regulated asset;
- a DNA, whereby the augmentation is funded by the DNA owner; or
- REZ infrastructure utilising a REZ framework developed by the Tasmanian Government.

3.6.2 Central Highlands REZ

The ISP identifies the capacity factor for new wind generation in the Central Highlands REZ as the highest in the NEM. Coupled with the existing transmission network capacity, there is significant opportunity for new wind generation to be developed within the REZ immediately.

Figure 3-7 presents the Central Highlands REZ transmission network, including the new Palmerston–Sheffield 220 kV transmission line as part of NWT. The figure also shows possible connection locations that could utilise existing network capacity. We anticipate that new wind generation will be developed in the Waddamana area and surrounds, while new PV would more likely develop on flatter terrain around Palmerston at the base of the Western Tiers.

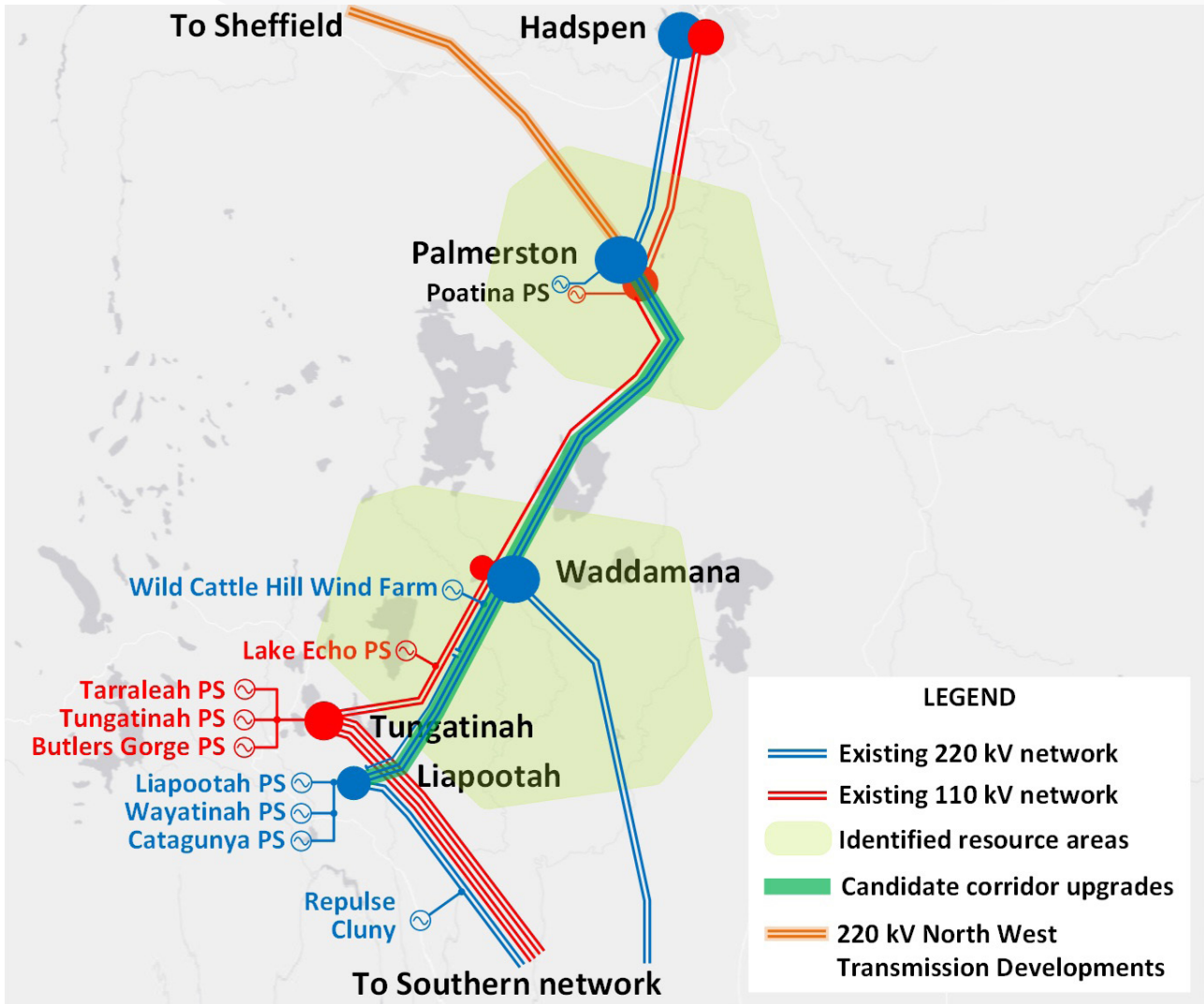


Figure 3-7: Central Highlands REZ transmission network

Figure 3-8 presents the existing hosting capacity of the Central Highlands REZ transmission network, including publicly announced generation developments. Included for comparison is the generation forecast under the 2024 ISP Step Change and Progressive Change scenarios. The 2024 ISP only forecasts the development of wind generation in this REZ, without any PV.

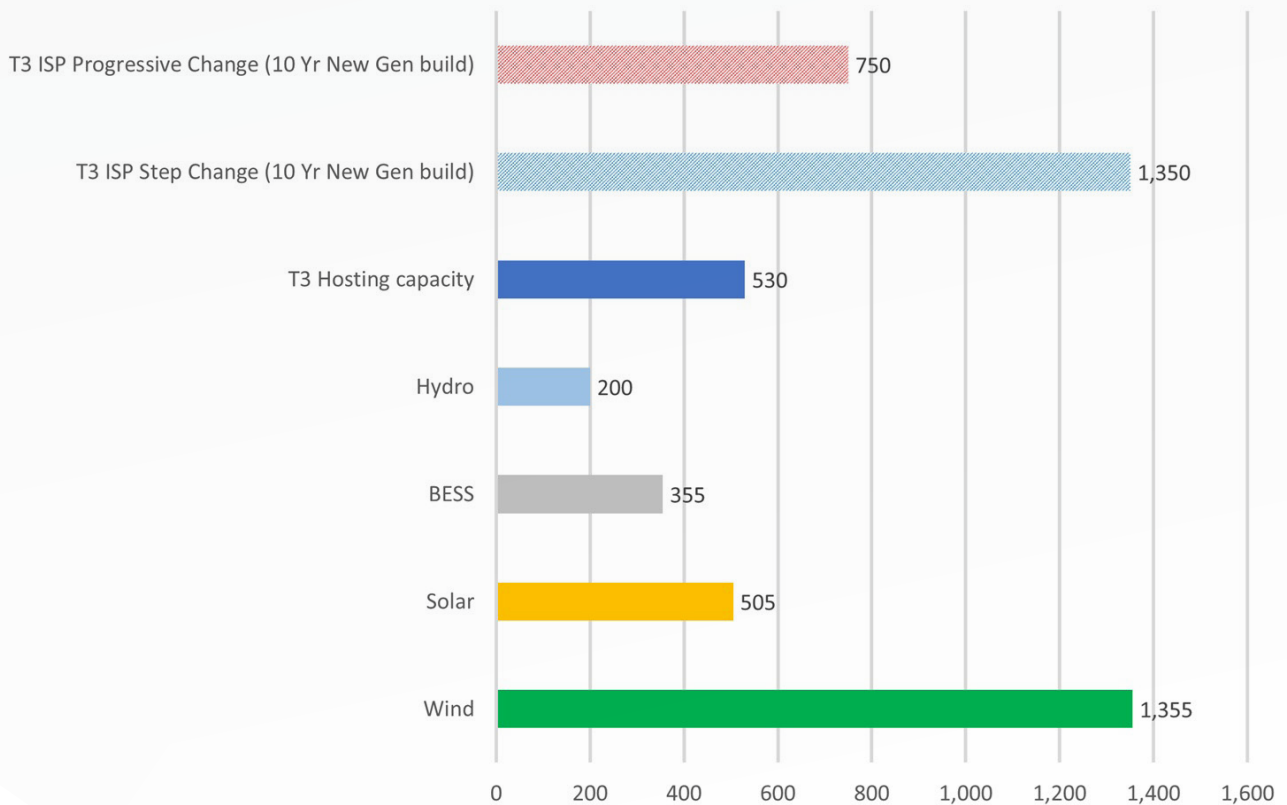


Figure 3-8: Central Highlands REZ forecast generation and hosting capacity

The existing transmission network within the REZ has the capability to host approximately 530 MW of new generation, limited by both the Waddamana–Palmerston transmission corridor capability and the transmission network from the Central Highlands REZ to the rest of the network.

3.6.2.1 Waddamana to Palmerston transfer capability upgrade

There is significant new wind generation proposed in the Central Highlands REZ over coming years. This is expected to occur in the Waddamana area and surrounds, including to the south along both the Waddamana–Liapootah and Waddamana–Lindisfarne transmission corridors (refer Figure 3-9). There are proposals for 1,544 MW of new wind generation in this area across several projects, as well as the Tarraleah Power Station replacement (refer Section 3.5.4).

The 2024 ISP has also identified significant wind developments in coming years, with Waddamana to Palmerston transfer capability upgrade now an actionable project for all scenarios, required by the early 2030s.⁵⁴ This is necessary to increase transfer capacity between the north and south of the state. With a Waddamana to Palmerston transfer capability upgrade, the outlook for wind generation in the Central Highlands REZ under the Step Change scenario is 1,350 MW by 2029–30 and 1,400 MW by 2039–40. For the Progressive Change scenario, the figures are slightly more modest with 750 MW by 2029–30 and 1,550 MW by 2039–40. Two options are being assessed to provide a Waddamana–Palmerston transfer capability upgrade, with high-level scope of:

Option 1: new transmission line build

- Construct a new (second) Waddamana–Palmerston 220 kV transmission line, on a diverse route from the existing transmission line; and
- Augment Palmerston and Waddamana substations to accommodate the new transmission line.

Option 2: upgrade existing transmission line

- Upgrade the Waddamana–Palmerston 110 kV transmission line to 220 kV operation (line did previously operate at 220 kV), including select structure replacement;
- Reconductor transmission line with high temperature-low sag conductor providing increased transfer capability;

⁵⁴ <https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp>

- Install 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
- Augment Palmerston and Waddamana substations to accommodate the upgraded transmission line and new network transformer.

Both options contain low-cost operational upgrades of the existing Waddamana–Palmerston and Palmerston–Hadspen 220 kV transmission lines to maximise existing network capability.

AEMO and TasNetworks have separately undertaken calls for non-network options. No credible non-network options were identified. TasNetworks is currently progressing the RIT-T to determine the preferred option. 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 is due to be published in February 2026.

More information on the Waddamana to Palmerston transfer capability upgrade is available at: <https://www.tasnetworks.com.au/Planning-and-projects/Major-Projects/Waddamana-to-Palmerston>

A new (second) Waddamana–Palmerston 220 kV transmission line was accepted by the Australian Energy Regulator (**AER**) as a contingent project in our 2024–29 regulatory determination. TasNetworks will not progress the contingent project application through the regulatory determination while we progress the proposed development as an actionable ISP project.

3.6.2.2 Liapootah to Waddamana capacity upgrade

The projected new generation build in the central highlands also provides an opportunity for potential low-cost capacity upgrades in the network to accommodate the significant new wind development forecast in the Central Highlands REZ.

With the combined new generation enquiries within the central highlands exceeding 1,500 MW, it is credible to expect that up to 700 MW can be developed by 2030 in the Ouse and Dee area, with connection to Liapootah Switching Station and therefore increasing the flow northward towards Waddamana, posing a risk of constraining circuits in this corridor.

TasNetworks has proposed an augmentation that involves stringing the vacant side of the Liapootah-Waddamana 220 kV transmission line TL527. Enabling the operation of the upgraded corridor with non-firm winter thermal rating with 95% margin will increase the thermal capacity by 237 MVA (from 715 MVA to 952 MVA).

This project has a capital cost of approximately \$6.8M and has been progressed and accepted under the NCIPAP framework, to be delivered in the 2024-2029 regulatory period.

3.7 Upper Derwent 110 kV transmission network

The Upper Derwent 110 kV transmission network comprises the transmission lines and substations from Tungatinah to Waddamana Substations (northwards), as well as New Norfolk Substation in the south. The 110 kV network operates in parallel with the 220 kV network in this area, with interconnection occurring at Palmerston Substation in the north and at Chapel Street and Lindsfarne substations in the south.

3.7.1 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.

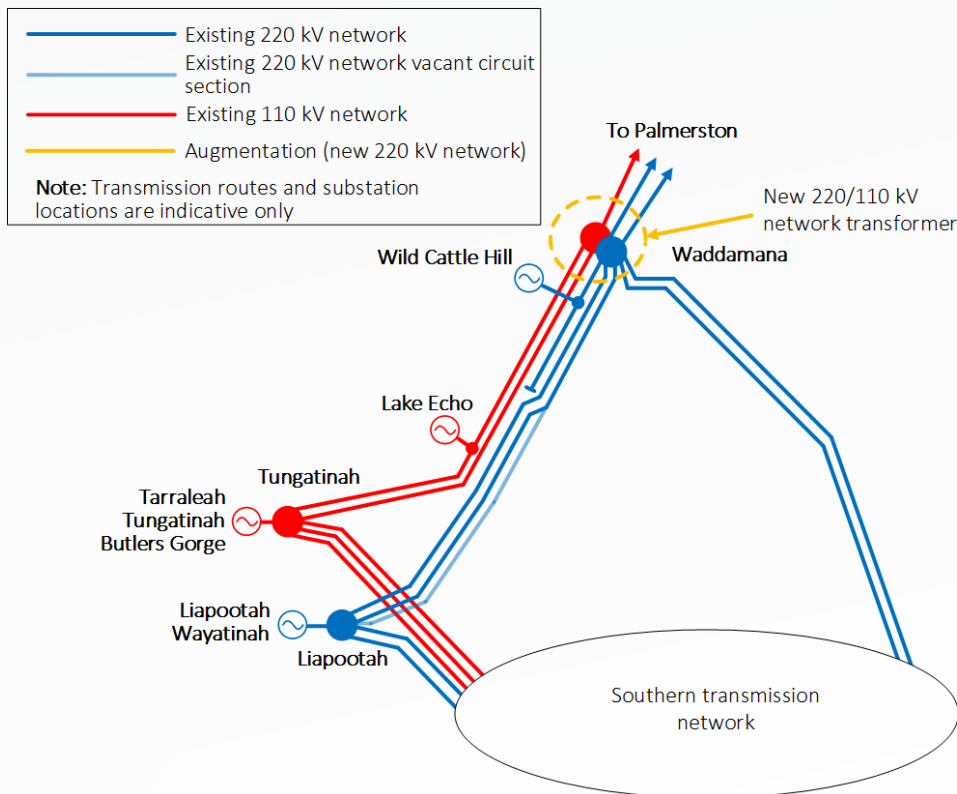


Figure 3-9: Options to reduce losses in Upper Derwent 110 kV transmission network

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 3-9. 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.

The option is estimated to cost \$10.9 million and is scheduled to be completed by 2029. The project has been accepted as part of our most recent regulatory proposal.

3.8 North East REZ

The existing transmission network from George Town Substation to the rest of the network has strong thermal capability, with four 220 kV transmission circuits and the Basslink HVDC interconnector terminating at this location. George Town is a large load centre supporting two large major industrial customers.

Figure 3-10 presents the North East REZ and the existing transmission network. Also highlighted are possible new VRE resource locations that may seek connection to the network over time. New VRE from the far north-east, as well as the north-east offshore area, must connect to the 220 kV network. The existing 110 kV network does not have sufficient capability to support new connections at any significant scale.

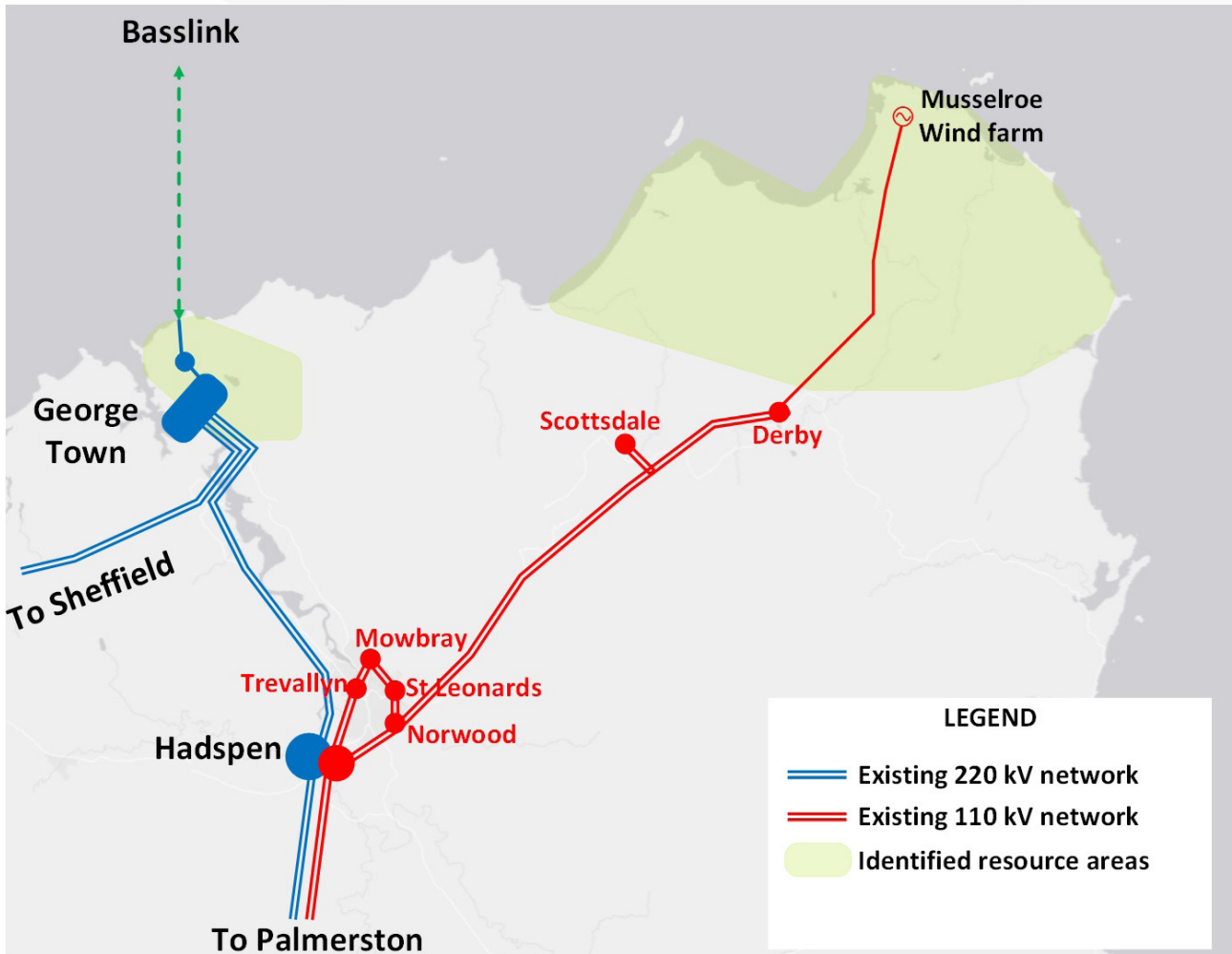


Figure 3-10: North East Tasmania REZ transmission network

Figure 3-11 presents the existing hosting capacity of the North East transmission network from George Town, including publicly announced generation developments. Included for comparison is the generation forecast under the 2024 ISP Step Change and Progressive Change scenarios.

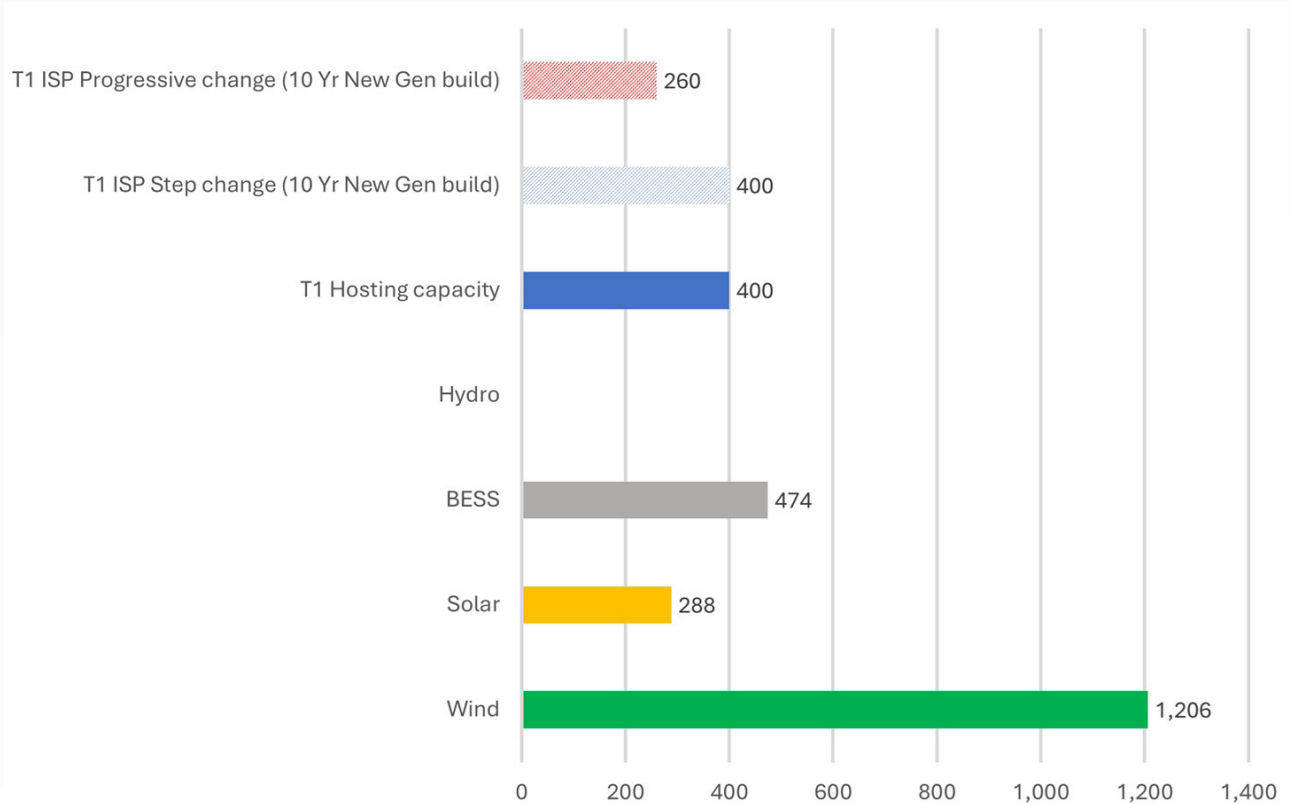


Figure 3-11: North East Tasmania REZ forecast generation and hosting capacity

Prospective VRE developments in the north-east and far north-east region of Tasmania have a combined capacity approaching 2,000 MW. Hosting capacity of the overall REZ is currently 400 MW. VRE resources in the far north-east and north-east offshore area would require substantial new transmission assets to connect to the George Town area. This is a limiting factor for the projected generation build in the ISP.

3.9 Hydrogen development

The state government is actively pursuing the development of a green hydrogen industry in Tasmania through its Tasmanian Renewable Hydrogen Action Plan (TRHAP).⁵⁵ The plan identifies two locations for large-scale renewable hydrogen production and potential export facilities, being the BBAMZ, and industrial precincts in north-west Tasmania (such as Port Latta or Burnie). The network requirements to facilitate hydrogen development will depend on the size, location, and technology being deployed.

George Town Substation is supplied via two double-circuit 220 kV transmission lines and the Basslink interconnector. It is the load connection point for two major industrial customers at 220 kV and 110 kV that in aggregate represent approximately 35-40% of the state's instantaneous load demand. It provides the interface to the Basslink interconnector and 386 MW of gas fuelled generation. An overview of the network at George Town and Bell Bay is shown in Figure 3-12.

⁵⁵ https://recfit.tas.gov.au/_data/assets/pdf_file/0013/313042/Tasmanian_Renewable_Hydrogen_Action_Plan_web_27_March_2020.pdf

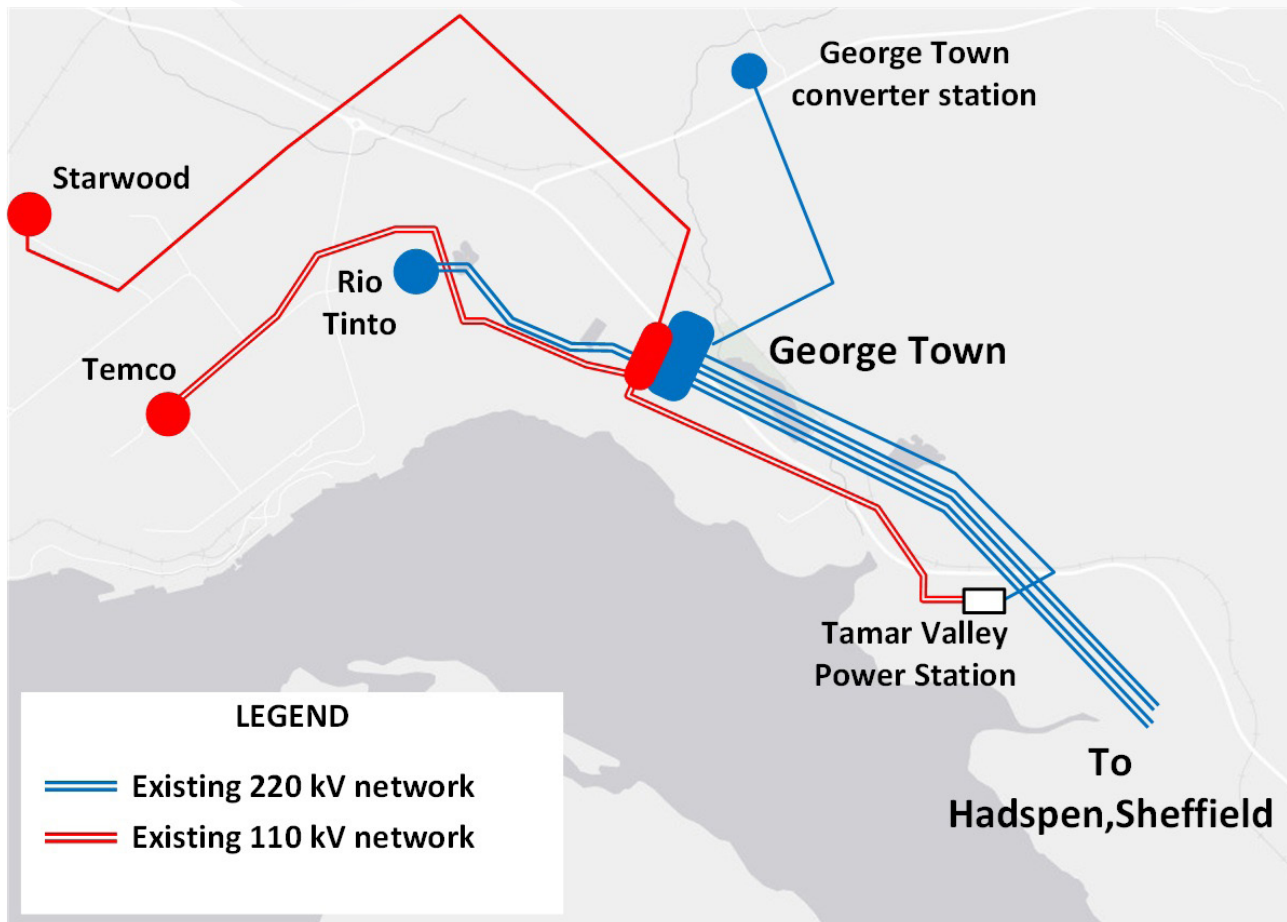


Figure 3-12: George Town and Bell Bay region

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.

Bell Bay has been identified as one of the candidate sites for the establishment of a hydrogen hub in Tasmania due to access to certifiable renewable energy, high-quality fresh water, a deep-water port facilities and significant vacant industrial land in close proximity to the port.

3.9.1 Meeting network planning requirements at George Town

TasNetworks has initiated a RIT-T for network augmentations at George Town Substation that support the establishment of industrial scale hydrogen production in Tasmania. Two main issues arise in the network following new load connection at George Town. Both issues are related to the minimum network performance requirements in the Network Planning Requirements (NPR)⁵⁶ and the Rules.

Specifically, as the NPR are deterministic reliability requirements, any new load exceeding 210 MW connecting to George Town Substation will require a reliability corrective action to meet the NPR, in preventing the occurrence of a system black event.

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

Compliance with NPR: Single contingency size

George Town is dominated by major industrial loads with a largely flat consumption profile throughout the year. The proportion of this load to total state demand, varies between 40-57% seasonally. The addition of 210 MW or more of new load at George Town will at times equal or exceed 60% of the total state load.

The NPR compliance breach is due to 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 required to allow new loads to connect to maintain compliance with this NPR requirement.

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 oscillation 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 to the 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.

To address the identified need, TasNetworks proposed the following solution:

| Description | Estimated cost | Proposed commissioning date |
|--|--|-----------------------------|
| <ul style="list-style-type: none">Reconfigure the existing George Town 220 kV substation and construct a new substation. | <ul style="list-style-type: none">\$83 million for substation works | 2028 - 2032 |
| <ul style="list-style-type: none">Install 550 MVar of reactive power compensation (combination of STATCOMs and capacitors) | <ul style="list-style-type: none">\$80⁵⁷ million for reactive support | |

We have commenced a RIT-T for this augmentation and further information can be found on our website:

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

⁵⁷ Based on technical studies undertaken during 2024, TasNetworks has identified greater reactive compensation requirements at George Town in response to new load than previously considered by TasNetworks as part of the Revenue Reset process. Costs are indicative based on the AEMO cost database v2.0 and are subject to changes based on final design specification

3.10 Battery energy storage systems connections

TasNetworks has received a notable level of interest from BESS proponents, who can offer potential network services including congestion management, system strength and inertia support, voltage and frequency control capabilities, and power quality support.

Some identified challenges to be managed include:

- impact on network thermal capability;
- steady state voltage control and reactive power requirements;
- power quality (including harmonics and dynamic voltage management); and
- transient and dynamic stability of the network (in particular, the fault ride through performance of such devices and their potential impact on frequency management).

We continue to consult with prospective BESS proponents to identify the optimal solutions for connection and integration into our network.

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 constraints

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;
- committed and completed projects;
- limitations and developments;
- 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.

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 Table 4-1 provides a brief description of each.

Table 4-1: Network planning areas

| Planning area | Description |
|----------------------------------|---|
| North West and West Coast | <p>The north-west of Tasmania 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.</p> <p>The West Coast covers the network area supplied from Farrell Substation.</p> |
| Northern | <p>The greater Launceston area, George Town and north-east Tasmania. It includes the West Tamar, Hadspen, Northern Midlands, and Break O’Day Local Government Areas and as far south as Coles Bay on the east coast. This area is supplied from the 220 kV backbone network at Hadspen, George Town, and Palmerston substations.</p> |
| Central | <p>The Central Highlands and Derwent Valley areas of Tasmania. This area also includes the supply point at Strathgordon. The area is generally supplied from the 110 kV network between New Norfolk, Tungatinah (near Tarraleah), and Waddamana substations.</p> |
| Southern | <p>The area covering Greater Hobart and the smaller communities of southern Tasmania. Localities outside Hobart include Southern Midlands, Glamorgan-Spring Bay, Sorell, and Tasman Local Government Areas to the north and east and Kingborough and Huon Valley Local Government Areas to the south. The Southern 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.</p> <p>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.</p> |

4.3 Notes for all geographic planning areas

The Annual Planning Report (APR) contains information on each planning area of the network, as summarised in the following table:

Table 4-2: General Notes for all Planning Areas

| Component | Description |
|---|--|
| Committed and completed developments | This section presents the material network projects that are committed or that have been completed since our 2024 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. |
| Planning area diagrams | The diagrams for each planning area show the transmission and sub-transmission networks and the distribution supply area of each connection point substation. |
| Availability to connect to the network | <p>We provide the capability to connect load and generation at connection points at both the transmission and sub-transmission levels across our network. Hosting capacity is dependent on factors that include the rating of equipment at each connection point and upstream network, network stability, security, and reliability considerations.</p> <p>These sections present the available firm headroom at the time of substation maximum demand for each connection point substation, based on the load forecast for APR publication. It also provides the total and firm capacity of each substation. Capacity and headroom are based on substation continuous ratings. For single-transformer substations, the firm rating is inherently zero.</p> |
| Network limitations and developments | <p>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. For each planning area, Section 4.4 describes the characteristics of the area network, customers, and generation. Reliability planning criteria are presented in Appendices A.3.3 (transmission) and A.3.4 (distribution).</p> <p>We include 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.</p> <p>Substation capacity headroom is assumed to be based on the 2025 forecast year for network demand with applicable asset ratings applied.</p> |
| Additional information on limitations | <p>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).</p> <p>The reports are available as a downloadable appendix from our website: www.tasnetworks.com.au/apr</p> |
| Future connection points | We present our forecast of future transmission-distribution connection points over the planning period for each planning area. Where applicable, we include the location and description of the future connection points, along with future loading levels and estimated timing and costs. |
| Targeted reliability corrective action | In this Chapter, we present individual targeted reliability improvement projects. Distribution reliability community performance, compliance, and corrective action programs are presented in Chapter 6. |

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.

4.4 Overview of Planning Areas

4.4.1 North West and West Coast planning area

The North West and West Coast planning area covers two separate geographic locations with different network characteristics. The area is connected to the rest of the network through Sheffield Substation, with other 220 kV injection points at Burnie and Farrell substations. Figure 4-2 presents a diagram of the North West and West Coast planning area and substation supply areas.

The North West planning area comprises 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 alternate 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.

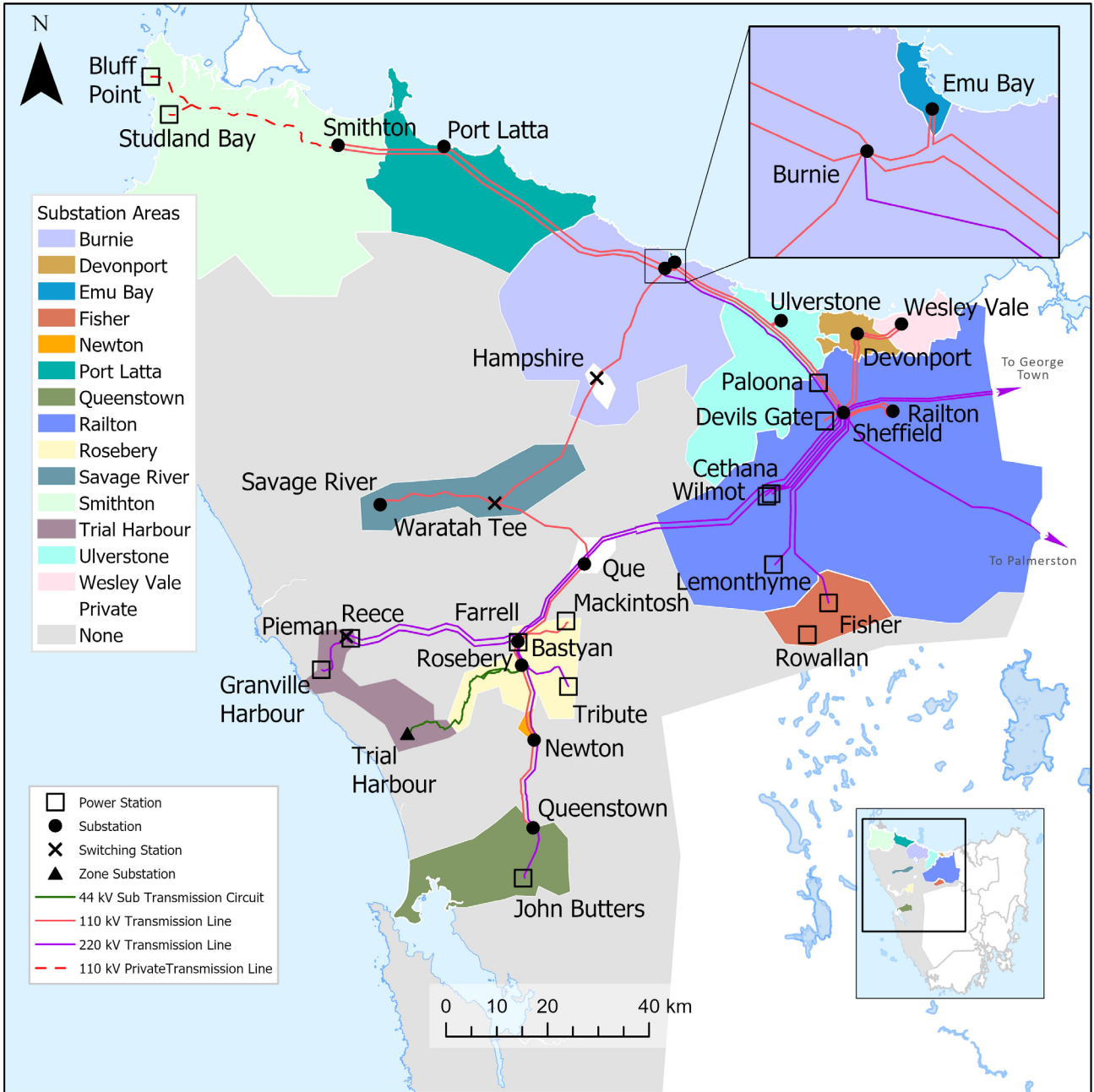


Figure 4-2: North West and West Coast planning area network

4.4.2 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. Figure 4-3 presents a diagram of the Northern area with substation supply areas.

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. There are two major energy users and one other transmission connected customer, all supplied from George Town Substation.

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.

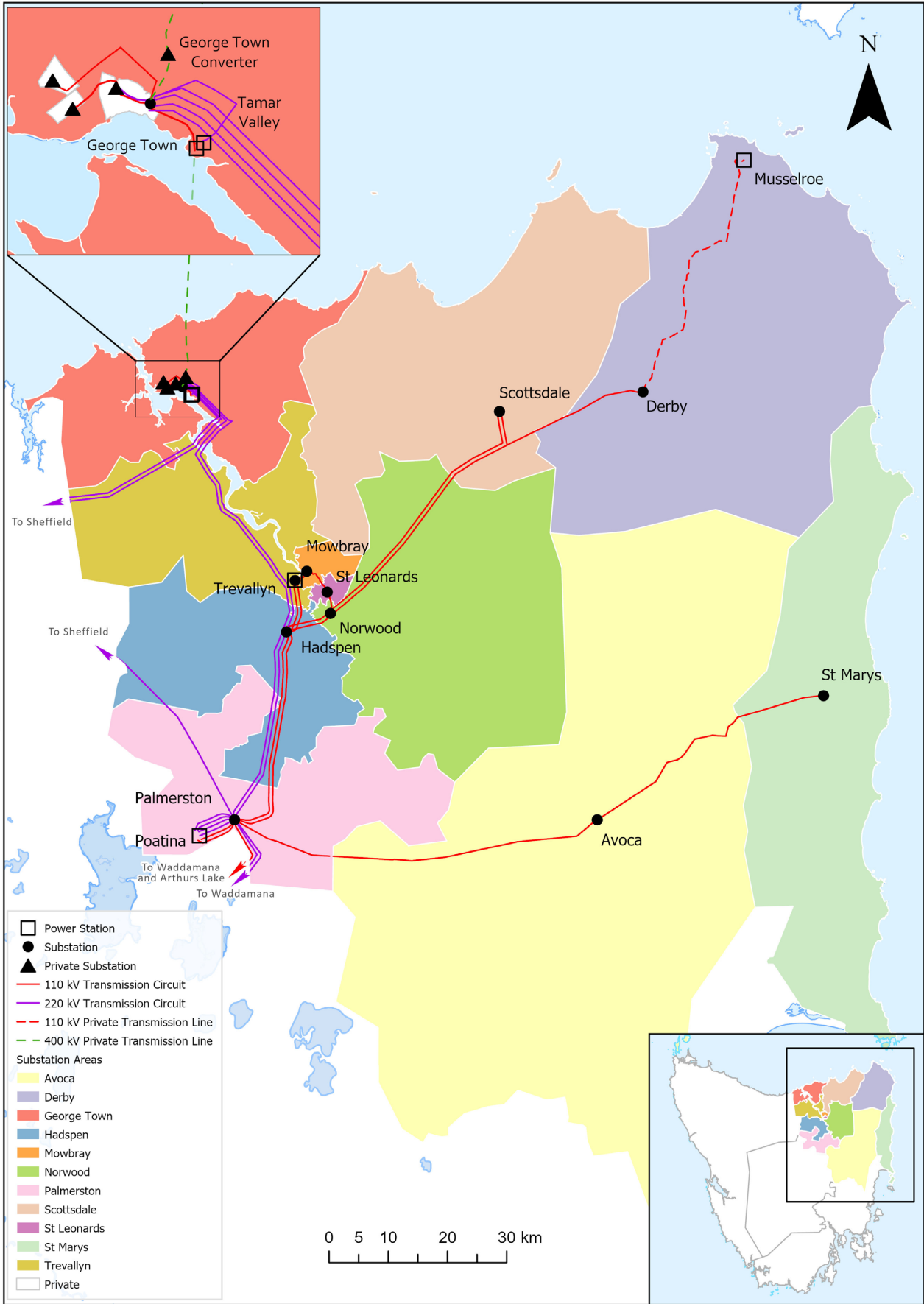


Figure 4-3: Northern planning area network

4.4.3 Central planning area

The Central planning area supplies 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. There is one major industrial customer supplied directly from the transmission network. Figure 4-4 presents a diagram of the Central planning area with substation supply areas.

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.

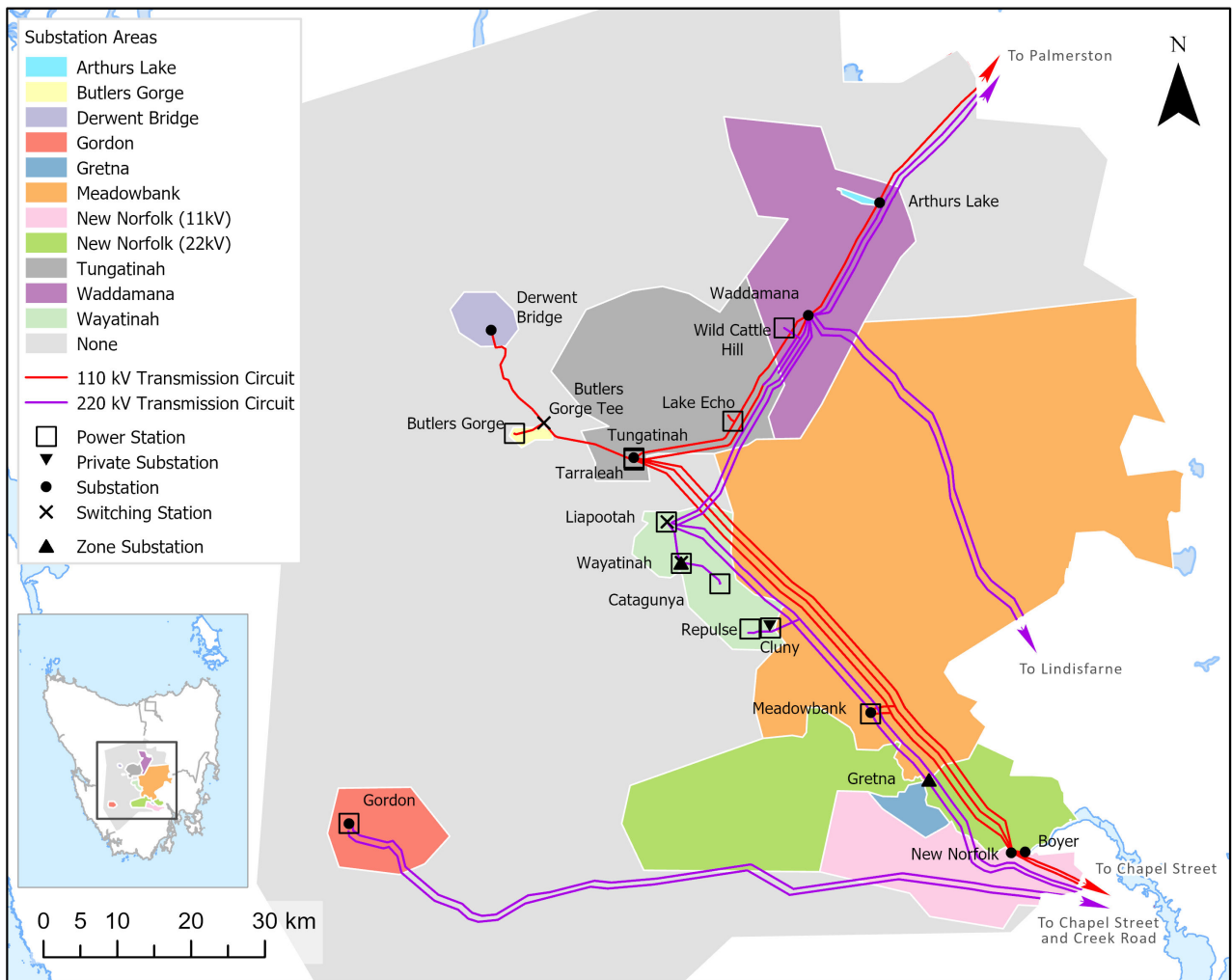


Figure 4-4: Central planning area network

4.4.4 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 Greater Hobart area is in most part supplied from the backbone transmission network terminating at Chapel Street and Lindisfarne substations. 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. There is one major energy user directly connected to the transmission network.

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. Figure 4-5 presents a diagram of the Southern planning area with substation supply areas.

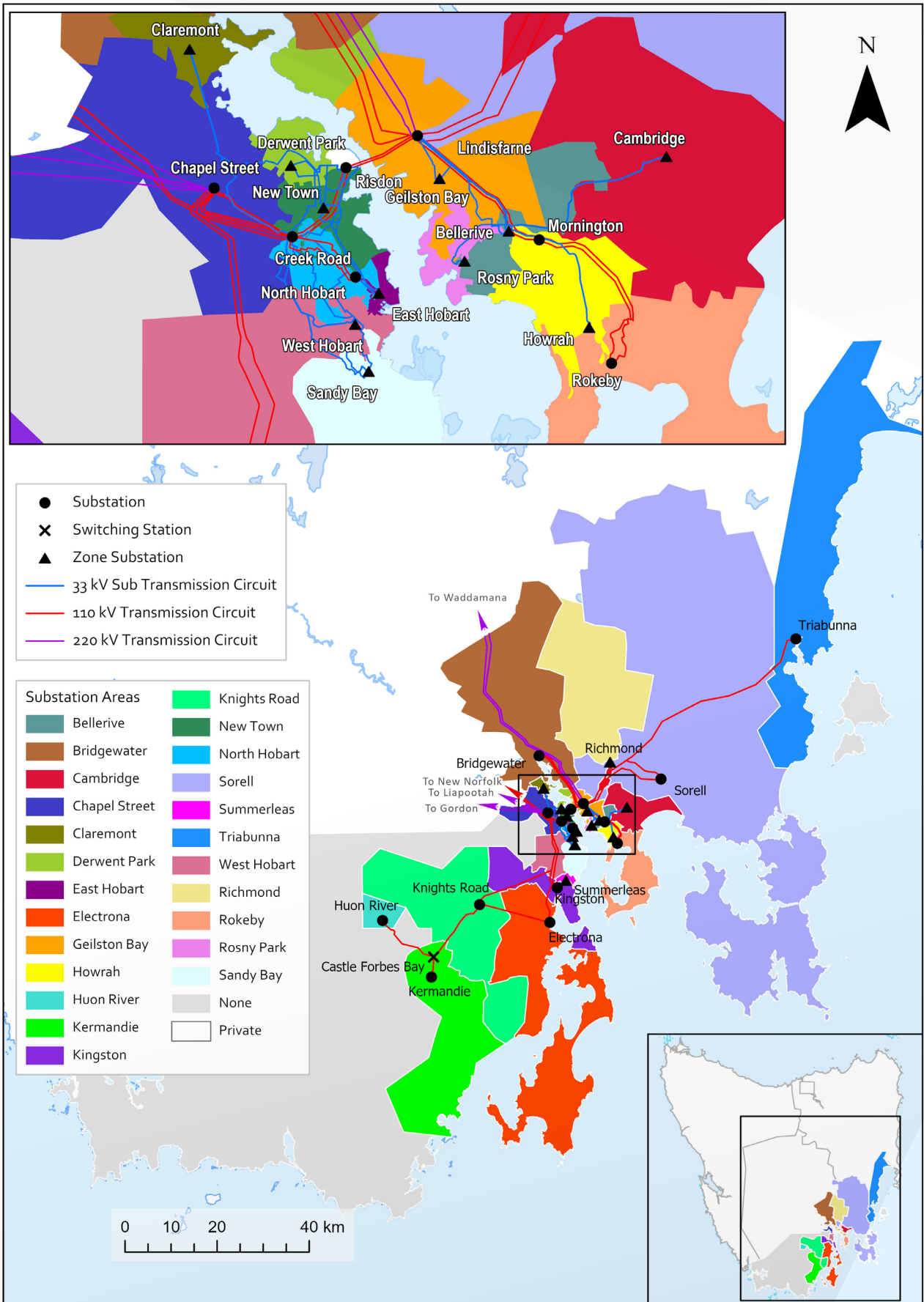


Figure 4-5: Southern planning area network

4.5 Availability to connect to network

Table 4-3 provides the available headroom to accommodate new load at each connection point substation in each planning area. The table 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 4-3: Substation available headroom by planning area.

| Planning Area | Substation Name | Voltage (kV) | Installed capacity (MVA) | | 2026 Maximum demand (MVA) | Available headroom (MVA) |
|---------------------------|--------------------|--------------|--------------------------|------|---------------------------|--------------------------|
| | | | Total | Firm | | Firm |
| North West and West Coast | Emu Bay | 110/22 | 76 | 30 | 9.1 | 20.1* |
| | Queenstown (22 kV) | 110/22 | 50 | 25 | 5.7 | 19* |
| | Queenstown (11kV) | 110/11 | 50 | 25 | 3.8 | 21* |
| | Trial Harbour Zone | 44/22 | 40 | 20 | 8.8 | 9.2* |
| | Rosebery (44 kV) | 110/44 | 102 | 66 | 24.4 | 41.6 |
| | Rosebery (22 kV) | 44/22 | 16 | 6 | 2.7 | 3.3 |
| | Ulverstone | 110/22 | 90 | 45 | 27.8 | 17.2 |
| | Wesley Vale | 110/22 | 50 | 25 | 18.1 | 6.9 |
| | Smithton | 110/22 | 70 | 35 | 23.4 | 11.6 |
| | Devonport | 110/22 | 110 | 60 | 52.9 | 7.1 |
| | Port Latta | 110/22 | 50 | 25 | 23.8 | 1.2 |
| | Railton | 110/22 | 100 | 50 | 47.9 | 2.1 |
| | Burnie | 110/22 | 120 | 60 | 23.0 | 0* |
| | Savage River | 110/22 | 45 | 22.5 | 4.5 | 2.1 |
| | Sheffield | 110/22 | 25 | 0 | 3.8 | 0* |
| | Newton | 110/22 | 22.5 | 0 | 5.6 | 0* |
| | Que | 110/22 | 50 | 0 | 5.7 | 0* |
| Northern | George Town | 110/22 | 96 | 48 | 22.1 | 25.9 |
| | Trevallyn | 110/22 | 150 | 100 | 69.3 | 30.7 |
| | Norwood | 110/22 | 100 | 50 | 29.1 | 20.9 |
| | Scottsdale | 110/22 | 63 | 31.5 | 12.9 | 18.6 |
| | Mowbray | 110/22 | 100 | 50 | 38.4 | 11.6 |
| | Palmerston | 110/22 | 50 | 25 | 16.4 | 8.6 |
| | St Leonards | 110/22 | 120 | 60 | 51.3 | 8.7 |
| | Hadspen | 110/22 | 100 | 50 | 57.5 | 0.0 |
| | St Marys | 110/22 | 20 | 10 | 14.6 | 0* |
| | Avoca | 110/22 | 17 | 0 | 8.5 | 0* |
| | Derby | 110/22 | 25 | 0 | 7.1 | 0* |
| Central | New Norfolk | 110/22 | 60 | 30 | 16.9 | 13.1 |
| | Arthurs Lake | 110/6.6 | 25 | 0 | 6.9 | 0* |
| | Derwent Bridge | 110/22 | 6 | 0 | 0.3 | 0* |
| | Meadowbank | 110/22 | 25 | 0 | 8.5 | 0* |
| | Tungatinah | 110/22 | 13 | 0 | 1.0 | 0* |
| | Waddamana | 110/22 | 4 | 0 | 0.7 | 0* |

| Planning Area | Substation Name | Voltage (kV) | Installed capacity (MVA) | | 2026 Maximum demand (MVA) | Available headroom (MVA) |
|-----------------|--------------------|--------------|-----------------------------|------|------------------------------|--------------------------------|
| | | | Total | Firm | | Firm |
| Southern | Kingston (33 kV) | 110/33 | 120 | 60 | 10.5 | 49.5 |
| | Creek Road | 110/33 | 180 | 120 | 87.2 | 32.8 |
| | Risdon | 110/33 | 150 | 100 | 67.1 | 32.9 |
| | Lindisfarne | 110/33 | 120 | 60 | 37.5 | 22.5 |
| | Sorell | 110/22 | 120 | 60 | 33.5 | 26.5 |
| | Mornington | 110/33 | 120 | 60 | 43.3 | 16.7 |
| | Chapel Street | 110/11 | 120 | 60 | 37.5 | 22.5 |
| | Kermandie | 110/11 | 50 | 25 | 8.5 | 16* |
| | Triabunna | 110/22 | 50 | 25 | 6.9 | 18.1 |
| | Rokeyby | 110/11 | 70 | 35 | 26.5 | 8.5 |
| | East Hobart Zone | 33/11 | 90 | 60 | 27.5 | 15** |
| | Sandy Bay Zone | 33/11 | 90 | 60 | 33.8 | 14** |
| | Bellerive Zone | 33/11 | 45 | 22.5 | 9.6 | 9** |
| | North Hobart | 110/11 | 90 | 45 | 34.1 | 10.9 |
| | Electrona | 110/11 | 50 | 25 | 17.0 | 8.0 |
| | Kingston (11 kV) | 110/11 | 70 | 35 | 26.5 | 8.5 |
| | West Hobart Zone | 33/11 | 90 | 60 | 37.8 | 13** |
| | Howrah Zone | 33/11 | 50 | 25 | 17.8 | 7.2 |
| | Geilston Bay Zone | 33/11 | 45 | 22.5 | 17.9 | 3** |
| | Cambridge Zone | 33/11 | 40 | 20 | 16.7 | 2** |
| | Claremont Zone | 33/11 | 50 | 25 | 21.5 | 0** |
| | Knights Road | 110/11 | 40 | 20 | 19.8 | 0.2 |
| | Bridgewater | 110/11 | 70 | 35 | 34.8 | 0.2 |
| | Derwent Park Zone | 33/11 | 45 | 22.5 | 18.2 | 1** |
| | New Town Zone | 33/11 | 45 | 22.5 | 20.9 | 0** |
| | Rosny Park Zone | 33/11 | 25 | 0 | 14.7 | 0* |
| | Huon River | 110/11 | 25 | 0 | 1.1 | 0* |
| Summerleas Zone | 33/11 | 25 | 0 | 10.4 | 0* | |

* Non-firm transmission or sub-transmission network connection

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

4.6 Network limitations and developments

The following tables present our completed and committed projects, future connection points, network limitations and proposed solutions, and targeted reliability corrective actions for all planning areas over the next 10 years.

Table 4-4: Completed and committed projects

| Planning Area | Project and description |
|---------------------------|---|
| Completed | |
| North West and West Coast | Emu Bay Substation conversion from 11 kV to 22 kV. |
| | Zeehan reliability improvement (additional generation support). |
| | North West Dynamic Reactive Support- Installation of 2 x ± 6 MVar STATCOM at Port Latta Substation. |
| Northern | Palmerston Feeder 4 Stage 2 (22 kV link) |
| Southern | Risdon–East Hobart 33 kV sub-transmission line capacity increase. |
| Committed | |
| North West and West Coast | Zeehan reliability improvement (44 kV sub-transmission line switching augmentation). |
| | New 22 kV feeders from Emu Bay Substation. |
| Northern | Palmerston new 22 kV feeder. |
| Southern | Knights Road to Huonville (North)-Ranelagh-Judbury-Lonnavale 22 kV distribution line |

Table 4-5: Network limitations and proposed solutions

| Planning Area | Limitation | Deferral requirement (MVA) | | Proposed solution | Timing | Cost (\$m) |
|---------------|--|----------------------------|---------|---|--------|------------|
| | | 1 year | 5 years | | | |
| Northern | <p>Palmerston–Avoca 110 kV transmission line</p> <p>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.</p> | 1.4 | 3.6 | <p>Options being considered are:</p> <ul style="list-style-type: none"> • Distribution solutions to unload St Marys Substation and reduce the load at risk. • Non-network solutions to reduce load interruption following contingency events. | 2031 | TBA |
| Southern | <p>Chapel Street–Kingston 110 kV transmission line</p> <p>From 2031, loss of the double-circuit Chapel Street–Kingston 110 kV transmission line may result in 3,000 MWh of unserved energy in Kingborough and Huon Valley areas. This will not meet the jurisdictional network planning requirements.</p> | 4 | 13 | <p>Extend the 33 kV sub-transmission network out of Sandy Bay to provide load transfer away from Kingston Substation and reduce unserved energy below 3,000 MWh.</p> <p>An alternate solution is to provide a third 110 kV circuit to the Kingston area.</p> | 2031 | TBA |
| | <p>Southern area voltage stability</p> <p>Voltage stability cannot be maintained for southern area load above 800 MW, forecast for 2032.</p> | 38 | 77 | <p>Install 2 x 40 MVar capacitor banks in southern area.</p> | 2032 | 10 |

Table 4-6: Targeted reliability corrective action

| Reliability community | Description |
|-----------------------|--|
| Zeehan | <p>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. Alternate supply is only available on the sub-transmission line for the first 10 km up to Renison Bell.</p> <p>Supply to the Zeehan reliability community does not meet the reliability standard. We are undertaking a program of works to improve supply reliability to meet the standard. As presented in Table 4-4 , we completed the installation of additional mobile generation support and are currently installing additional switching capability between the 44 kV sub-transmission lines. We propose one further initiative to improve supply reliability.</p> <p>The proposed initiative is to install 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.</p> |

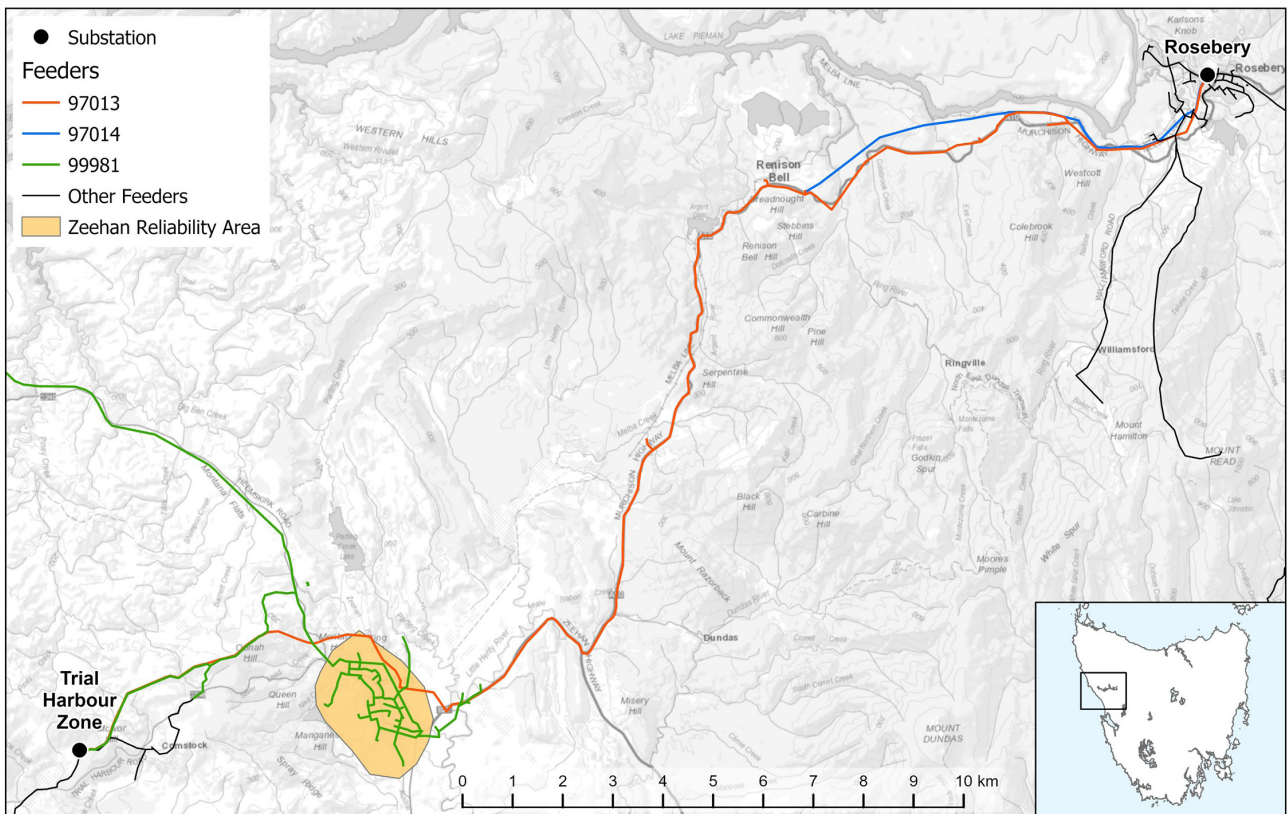


Figure 4-6: Zeehan reliability community

4.7 Deferred or averted limitations

4.7.1 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. Table 4-7 presents the assets for which we have agreed exemptions.

Table 4-7: 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. | 2030 |
| | Newton Substation supply transformer | Newton Substation | Loss of supply transformer may exceed 300 MWh of unserved energy | 2030 |
| | Waratah–Savage River 110 kV transmission circuit section | Savage River Substation | Loss of circuit section may exceed 300 MWh of unserved energy | 2029 |
| | Farrell–Rosebery 110 kV dual transmission line (TL451) | Rosebery, Newton, and Queenstown substations | Loss of dual circuit section may exceed 3000 MWh of unserved energy | 2030 |

Our agreements exist on the basis that 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 4-7, or when an affected customer considers remedial action has sufficient benefit, or circumstances have materially changed.

4.7.2 Farrell-Rosebery-Queenstown transmission line limitation

Recently proposed load increases at Rosebery Substation will contribute to the combined loading on the 110 kV transmission line supplying customers at Rosebery, Newton, and Queenstown substations exceeding the network planning performance requirements⁵⁸ (3000 MWh of unserved energy following an outage of the double circuit Farrell-Rosebery transmission line (TL451). TasNetworks will write to impacted transmission customers seeking a new exemption for this transmission line, to be valid for 5 years.

⁵⁸ Our jurisdictional network planning requirements are in place to ensure that the network is planned to withstand credible and certain non-credible contingencies. Details are available in Appendix A.3.3

4.8 Other factors affecting the network

4.8.1 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.

4.8.1.1 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 4-8 presents the operational procedures in place to manage the fault level issues at these connection points.

Table 4-8: 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. |

4.8.1.2 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**), the Australian Energy Market Operator (**AEMO**) now publish 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.

4.8.2 Voltage management

Maintaining voltages within target ranges ensures the safety of our people and equipment, contributes to the efficient and secure operation of 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>

4.8.3 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.

4.9 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. Where 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 4-9: Network asset retirements and replacements – overhead lines and cables

| Committed | | |
|--|---------------|-------------------|
| George Town–Temco 110 kV transmission line | | |
| Proposed | Timing | Cost (\$m) |
| East Hobart 33 kV sub-transmission cable | 2027 | 3.0 |
| Claremont 33 kV sub-transmission cable | 2030 | 3.1 |
| New Town 33 kV sub-transmission cable | 2031 | 2.2 |
| Sandy Bay 33 kV sub-transmission cable | 2032 | 1.7 |
| Lindisfarne–Bellerive 33 kV sub-transmission cable | 2032 | 2.7 |

Table 4-10: Network asset retirements and replacements – power transformers

| Committed | | |
|--|---------------|-------------------|
| St Marys Substation supply transformers | | |
| Proposed | Timing | Cost (\$m) |
| Transmission substations | | |
| Sheffield Substation network transformer T1 | 2027 | 10.7 |
| Waddamana Substation supply transformer | 2030 | 3.5 |
| 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 |

Table 4-11: Network asset retirements and replacements – switchgear and instrument transformers

| Completed | | | |
|--|--|---------------|-------------------|
| Gordon Substation 220 kV switchgear | | | |
| Norwood Substation 110 kV switchgear | | | |
| Railton Substation 22 kV switchgear | | | |
| Farrell Substation 220 kV switchgear | | | |
| Farrell and Ulverstone Substations 110 kV switchgear | | | |
| Chapel Street Substation 110 kV disconnectors | | | |
| Committed | | | |
| George Town Substation 220 kV disconnectors | | | |
| Wesley Vale Substation 110 kV disconnectors | | | |
| Sorell Substation 22 kV switchgear | | | |
| Savage River Substation 110 kV disconnectors and gantry | | | |
| Sheffield Substation 220 kV disconnectors and current transformers | | | |
| Sheffield Substation 110 kV disconnectors | | | |
| Bridgewater Substation 110 kV circuit breakers | | | |
| Chapel Street Substation 11 kV switchgear | | | |
| 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 4-12: 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 4-13 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.

Table 4-13: State-wide asset investment programs

| 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 |

| 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 |
|--|---------|---------|---------|---------|---------|---------|---------|---------|---------|---------|
| 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 |

4.10 Investments in operational support systems and telecommunication systems

4.10.1 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 2024–25 are summarised in the following table:

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

| Completed Projects | Description | Investment (\$m) |
|---|--|------------------|
| Distribution Management System extension | Extension of the Distribution Management System with improved capability to display fault locations in real time, improve the ability to switch more devices on the electricity distribution network and improve the functionality to visualise complex information in real time to improve real time decision making. | 0.04 |
| Phasor measurement unit analytics | Upgrade of existing phasor measurement data visualisation product to maintain vendor support. | 0.03 |
| Enterprise geographical information system strategy implementation | Consolidation and modernisation of the geographical information system and capability. | 1.6 |
| 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. | 2.1 |
| 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. | 0.23 |

Our planned investments in operational support system programs in the forward planning period to 2034–35 are summarised in the following table:

Table 4-15: 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. | 7.0 |
| 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. | 6.3 |
| 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. | 25 |

4.10.2 Telecommunications systems

The telecommunications network supports operation of the 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. 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, and some power line carrier equipment.

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

Our regulated investments in telecommunications systems programs in 2024–25 are summarised in Table 4-16.

Table 4-16: 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 | 0.2 |
| Multiplexer systems | Multiplexer systems in the networks | 0.9 |
| Ethernet systems | Ethernet systems within the network | 0.3 |

Our planned regulated investments in telecommunications systems programs in the forward planning period to 2034–35 is summarised in Table 4-17. The majority of these are ongoing programs, with the investment commitment over the duration of the program.

Table 4-17: 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 | 14.6 |
| Multiplexer systems | Multiplexer systems in the networks | 0.3 |
| Ethernet systems | Ethernet systems within the network | 4.1 |

Chapter 5

Network security performance

- The Australian Energy Market Commission's (AEMC) Reliability Panel revised the Frequency Operating Standard (FOS) to adapt to changes occurring in the power system. A new rate of change of frequency (ROCOF) limit has been introduced, with a different limit defined for Tasmania compared to the mainland given the characteristics of our system.
- 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, careful management of power system security continues to be a high priority.
- Modelling associated with AEMO's 2024 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 1 December 2025.
- The National Electricity Rules (the Rules) framework for managing system strength introduced significant new obligations for System Strength Service Providers (SSSP) which commence on 2 December 2025. TasNetworks is the SSSP for the Tasmanian region of the National Electricity Market (NEM). The new framework introduces 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 addressing 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.

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 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,⁵⁹ 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 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.

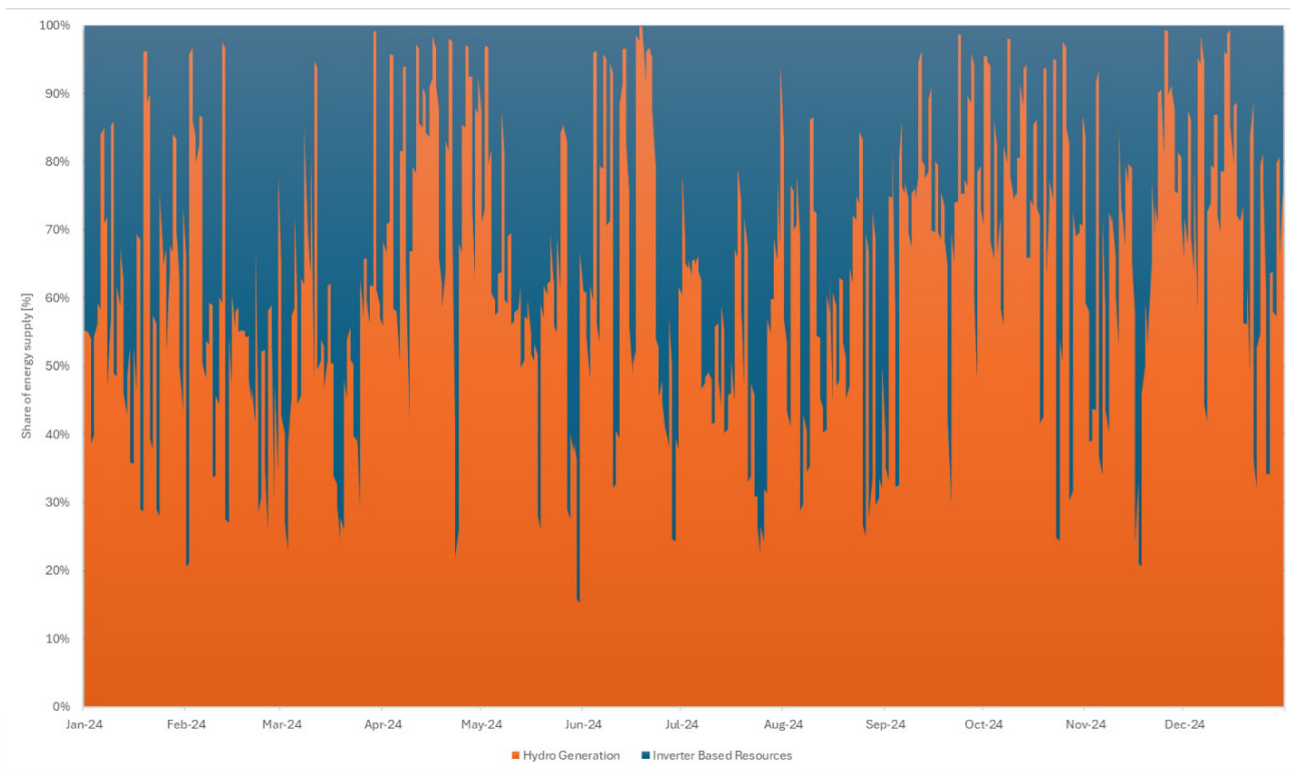


Figure 5-1 Tasmanian Electricity supply mix for the year 2024

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.

⁵⁹ 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 | 2022-23 | 2023-24 | 2023-24 |
|--------------------|---------|---------|---------|
| Peak SNSP recorded | 90.8% | 88.7% | 93.70% |
| 99th Percentile | 76.5% | 80.9% | 80.9% |
| 95th Percentile | 66.5% | 73.4% | 73.4% |
| 50th Percentile | 31.0% | 40.2% | 44.6% |

Over the past year, we repeatedly encountered situations where more than 90% of Tasmania's electricity supply was derived from energy sources other than synchronous generating units. High SNSP conditions often occur overnight, when operational demand is lower, and from early to mid-afternoon. This pattern is now observable throughout the entire year. In Tasmania, these conditions typically arise when high PV output on the mainland leads to lower market prices, frequently resulting in increased Basslink imports. When this aligns with high generation output from local wind farms, high SNSP conditions occur.

As additional wind and PV are integrated into Tasmania's energy mix, 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 AEMO Engineering Roadmap to 100% Renewables

Since 2021, TasNetworks has been actively involved in the NEM Engineering Framework Review.⁶⁰ 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, the Australian Energy Market Operator (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 – FY2025 Priority Actions,”*⁶¹ outlines the activities AEMO plans to undertake in the 2024–25 financial year (FY2025) 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.”*⁶² 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 the 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 ROCOF poses difficulties, 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.

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 majority of the TRET will be fulfilled by new wind generation, understanding the engineering required to achieve these practical outcomes is essential.

5.3 Important changes to power system security management

5.3.1 Frequency operating standards

Since Tasmania and the mainland power systems are not synchronously connected, and Tasmania has its own unique frequency control characteristics, separate frequency standards have been in place since the Basslink interconnector was commissioned in 2006. The AEMC’s Reliability Panel concluded its latest review of the FOS on 6 April 2023,⁶³ which led to a new standard effective as of 9 October 2023. This update introduced several significant changes to accommodate the evolving nature of the power system. The changes to the FOS require TasNetworks to formally address technical issues when designing and establishing network operational limits.

The main aspects of the revised FOS relevant to Tasmania include:

- After a *credible contingency event*, the ROCOF must not exceed ± 3 Hz/s when measured over any 250 ms period, aligning with our previous general design approach based on engineering judgment.
- Following a *non-credible contingency event*, or multiple contingency events that are not protected, AEMO should make reasonable efforts to maintain ROCOF within ± 3 Hz/s over any 300 ms period.
- The existing 144 MW limit for generation events, originally introduced in December 2008, has been expanded to include load and network events. This limit applies to the design and operation of the intact network, with provisions to assist in managing planned and forced outages of short duration.
- The minimum threshold for a generation event has been lowered from 50 MW to 20 MW, aligning it with the current threshold for a load event.
- The operational frequency tolerance band during system restoration has been tightened from 48 Hz – 52 Hz to a more restricted range of 49 Hz – 51 Hz, to better align with Schedule 5.2 of the Rules, which specify generator connection requirements.
- The time error standard has been removed from the FOS.

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

61 <https://aemo.com.au/-/media/files/initiatives/engineering-framework/2024/nem-engineering-roadmap-fy2025-priority-actions.pdf?la=en&hash=E934DFFF6D4544B9F117BAF6A6E4088D>

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

63 Further details can be found at : <https://www.aemc.gov.au/markets-reviews-advice/review-of-the-frequency-operating-standard>

There were no additional changes to various frequency control bands that govern system performance during normal operations and after contingency events. The normal operating frequency band remains at 49.85 Hz – 50.15 Hz, which is the range frequency should remain within for most network operating conditions.

5.3.2 Rules framework for managing system strength

On 21 October 2021, the AEMC finalised a Rule change determination for the “Efficient Management of System Strength on the Power System.”⁶⁴ 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.

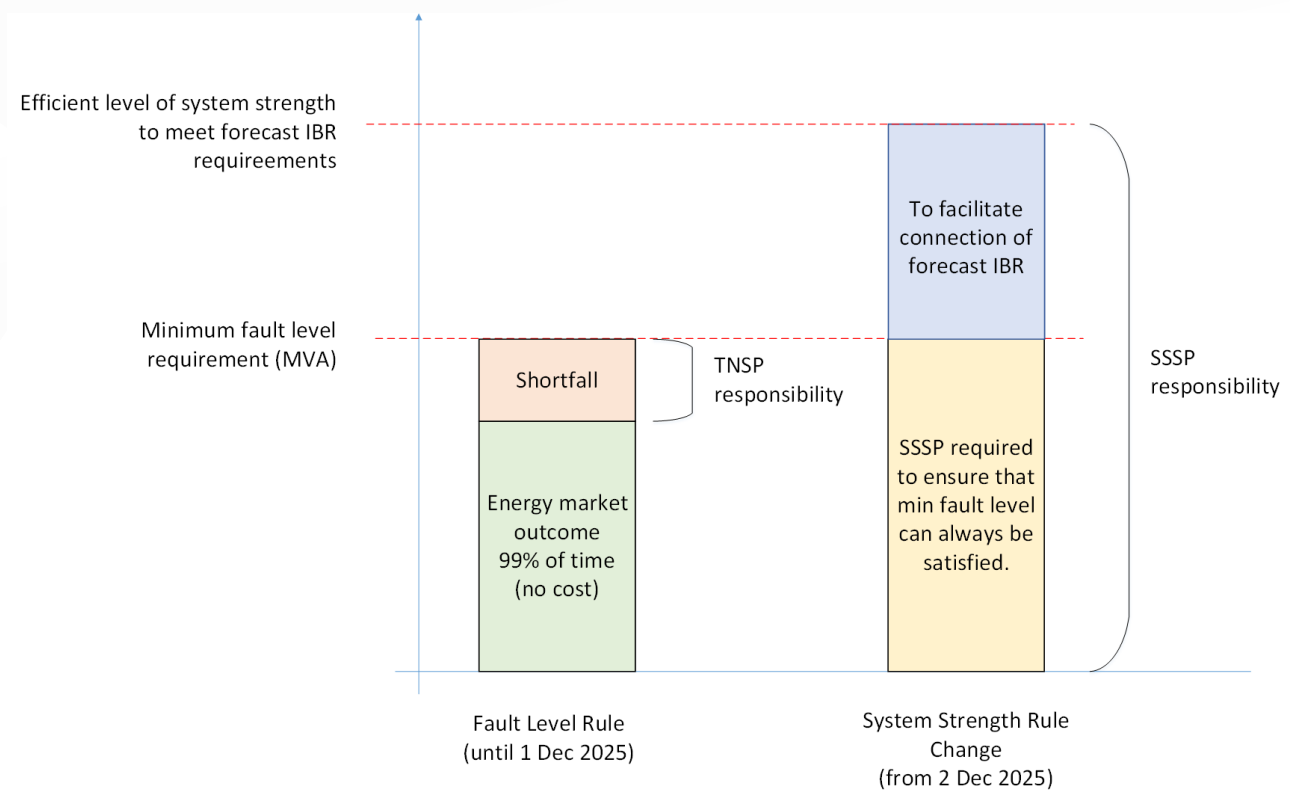


Figure 5-2: Comparison of system strength Rule frameworks

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 5.3.3

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

5.3.3 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 (TNSP) 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.

5.3.4 Transition plan for System Security

AEMO published its first annual Transition Plan for System Security⁶⁵ 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, System Security reports, and the Engineering Roadmap program.⁶⁶ 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.

5.4 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

⁶⁵ <https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/transition-planning>

⁶⁶ <https://aemo.com.au/initiatives/major-programs/engineering-roadmap>

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 IBR 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 for 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 the Transmission Network Service Provider 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 ⁶⁷ |
| Risdon 110 kV | 1,330 |

The 2024 NSCAS report published on 2 December 2024 notes that there are no system strength and inertia shortfalls in Tasmania for the period up to 1 December 2025 on account of an existing contract with Hydro Tasmania for the provision of these services. However, for the period beyond December 2025, AEMO projects shortfalls in inertia and system strength as presented in Table 5-4 and Table 5-5 below.

The forecast shortfall is attributed to the expiry of the current contract with Hydro Tasmania for the provision of these services. TasNetworks completed the Regulatory Investment Test for Transmission (**RIT-T**) process for the procurement of system strength services, approval of which will allow TasNetworks to meet its system strength and potentially inertia obligations out to June 2029, refer Section 5.4.3.6.

Table 5-4: Forecast system strength shortfalls

| System Strength Node | Identified shortfall (MVA) | | | |
|----------------------|----------------------------|-----------|-----------|-----------|
| | 2024 -2025 | 2025-2026 | 2026-2027 | 2027-2028 |
| George Town 220kV | 0 | 687 | 892 | 866 |
| Waddamana 220kV | 0 | 382 | 695 | 657 |
| Burnie 110kV | 0 | 262 | 354 | 341 |
| Risdon 110kV | 0 | 366 | 630 | 589 |

⁶⁷ Minimum pre-contingent three phase fault level requirement reduced from 850MVA to 750MA on account of commissioning of 2 STATCOMs at Port Latta addressing wind farm Fault Ride Through (FRT) issues

Table 5-5 : Forecast inertia shortfall

| | 2024-2025 | 2025-2026 | 2026-2027 | 2027-2028 |
|---|-----------|-----------|-----------|-----------|
| Secure level of inertia (MWs) | 3,800 | 3,800 | 3,800 | 3,800 |
| Available inertia 99.87% of the time (MW.seconds) | 3,800 | 1,616 | 1,090 | 1,193 |
| NSCAS gap (MWs) | 0 | 2,184 | 2,710 | 2,610 |

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

From 2 December 2025, locations previously referred to as *fault level nodes* for the purposes of managing fault level shortfalls, will transition 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 |

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

Beginning 2 December 2025, TasNetworks is 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 IBR forecast for Tasmania, as detailed in the 2024 System Strength Report⁶⁸ published by AEMO, is presented in Table 5-7. For clarity, this forecast includes only anticipated future developments of wind, with PV, and BESS developments forecast as zero in the current IBR forecast. It is important to note that there is a significant reduction in IBR forecast for the Burnie SSN for the period 2029 to 2034, a portion of which TasNetworks had proactively allocated to the forthcoming Hampshire Hills SSN (from Burnie 110 kV) in the last APR. Consistent with AEMO’s approach of not allocating IBR forecast to SSNs that are not yet formally declared, we are not allocating any IBR to the Hampshire Hills 220 kV node in this APR. The main reason for this is the reduction in IBR projections in the Burnie area. Changes in the IBR forecast for all other SSNs 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 | 2035 | 2035 |
|------------------------|----------|------------|------------|------------|--------------|--------------|--------------|--------------|--------------|--------------|
| Burnie 110 kV | 0 | 6 | 6 | 15 | 15 | 15 | 134 | 142 | 142 | 387 |
| George Town 220 kV | 0 | 112 | 112 | 242 | 242 | 242 | 400 | 400 | 400 | 400 |
| Waddamana 220 kV | 0 | 599 | 599 | 641 | 1,304 | 1,304 | 1,383 | 1,392 | 1,392 | 1,392 |
| Risdon 110 kV | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Hampshire Hills 220 kV | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Aggregate (MW) | 0 | 717 | 717 | 898 | 1,561 | 1,561 | 1,917 | 1,934 | 1,934 | 2,179 |

Table 5-8: Change in IBR forecast with reference to 2023 System Strength Report

The minimum new renewable generation required in Tasmania to meet the TRET⁶⁹ is currently considered to be approximately 2,500 MW by 2040, based on an assumed capacity factor for large-scale wind farms. The 2024 ISP does not forecast any additional utility-scale wind or PV developments in Tasmania beyond 2032, with ongoing generation growth limited to distributed PVs.

In line with the new Rule requirements, TasNetworks has translated the forecast 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.⁷⁰ Additionally, where future changes in network topology are known and have been communicated to AEMO and the wider industry,⁷¹ 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 2035. The results of this analysis are illustrated in Figure 5-3. The analysis assumes 100% IBR-based grid-following (rather than grid-forming) 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.

68 2024-system-strength-report-final.pdf

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

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

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

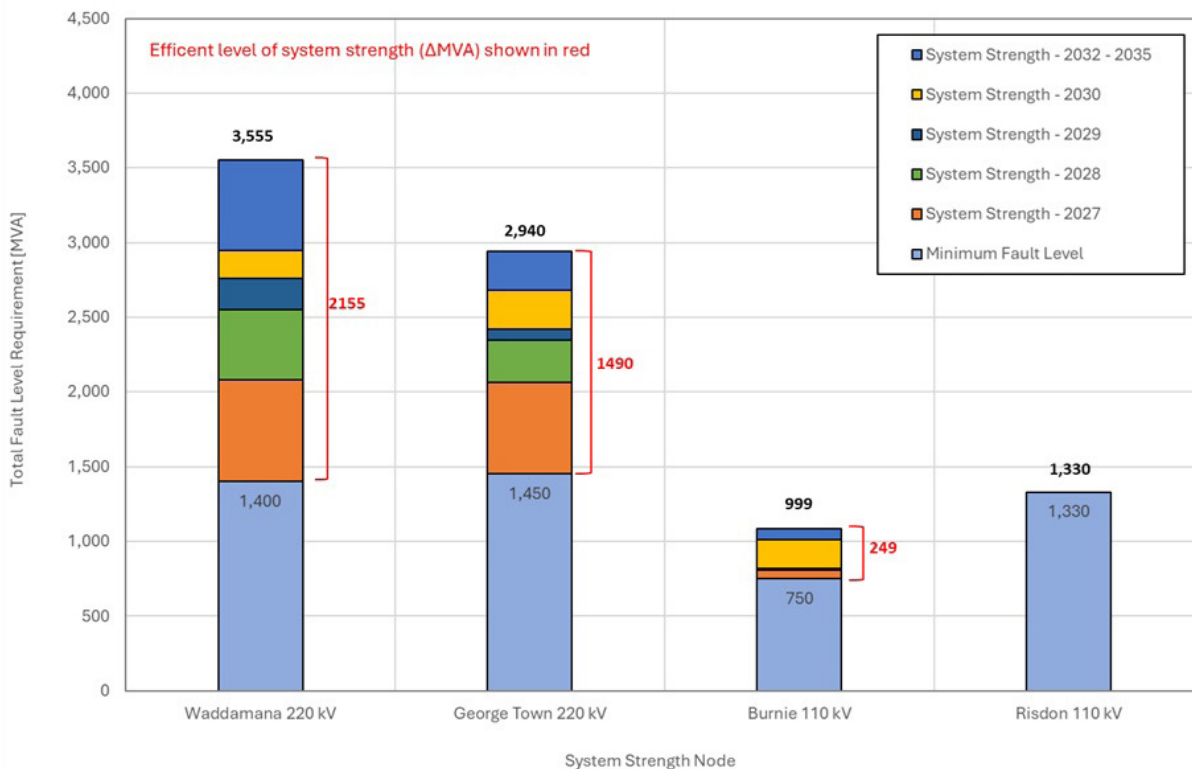


Figure 5-3: Estimated efficient level of system strength at each SSN, 2026-2035

The forecasts indicate an increase in system strength requirements between 2027 and 2030 corresponding to approximately 1,150 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, the requirements increase again to support an additional 1,178 MW of new wind generation, the majority of which is forecast to be developed in the Central Highlands REZ, with Waddamana SSN as the reference location.

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

A requirement of the Rules clause 5.20C.3(f)(3) requires the SSSP to provide a forecast of the AFL at each SSN over the period for which AEMO has determined system strength requirements, which is currently until 2035.

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 5-3 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),⁷² 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 alternate mechanisms will be required to maintain power system security. This is represented by an increasing duration below the minimum fault level requirement.

⁷² Generation closure year details are included in : https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/generation_information/2024/generating-unit-expected-closure-year.xlsx

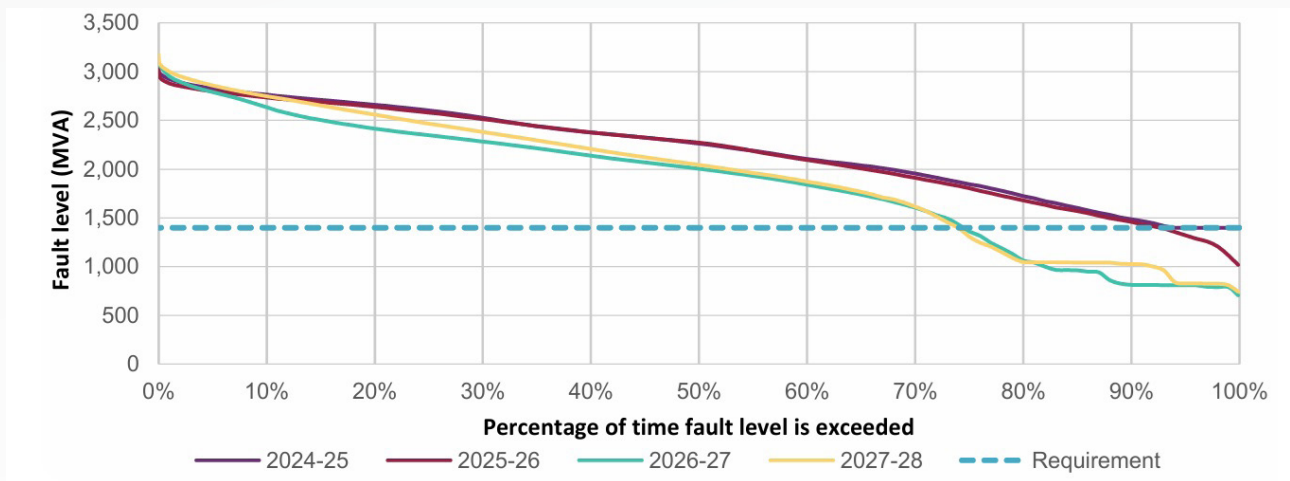


Figure 5-4: Forecast fault level at the Waddamana 220 kV SSN⁷³

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 5-2.

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.⁷⁴
- Synchronous condensers currently contracted to TasNetworks will remain available to support the network.⁷⁵ 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 forecast by TasNetworks,⁷⁶ 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.

⁷³ Extracted from AEMO 2024 System Strength Report

⁷⁴ As described in Section 5.2.2

⁷⁵ Please note that this assumption has been used for study purposes, noting the current RIT-T for System Strength and Inertia procurement is currently underway and may result in a different outcome post 2 December 2025

⁷⁶ TasNetworks IBR forecast is informed by connection applications and inquiries. At aggregate level, TasNetworks forecast closely aligns with AEMO forecast

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 REZ. 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 2027. Such measures are also expected to positively affect other parts of the network.

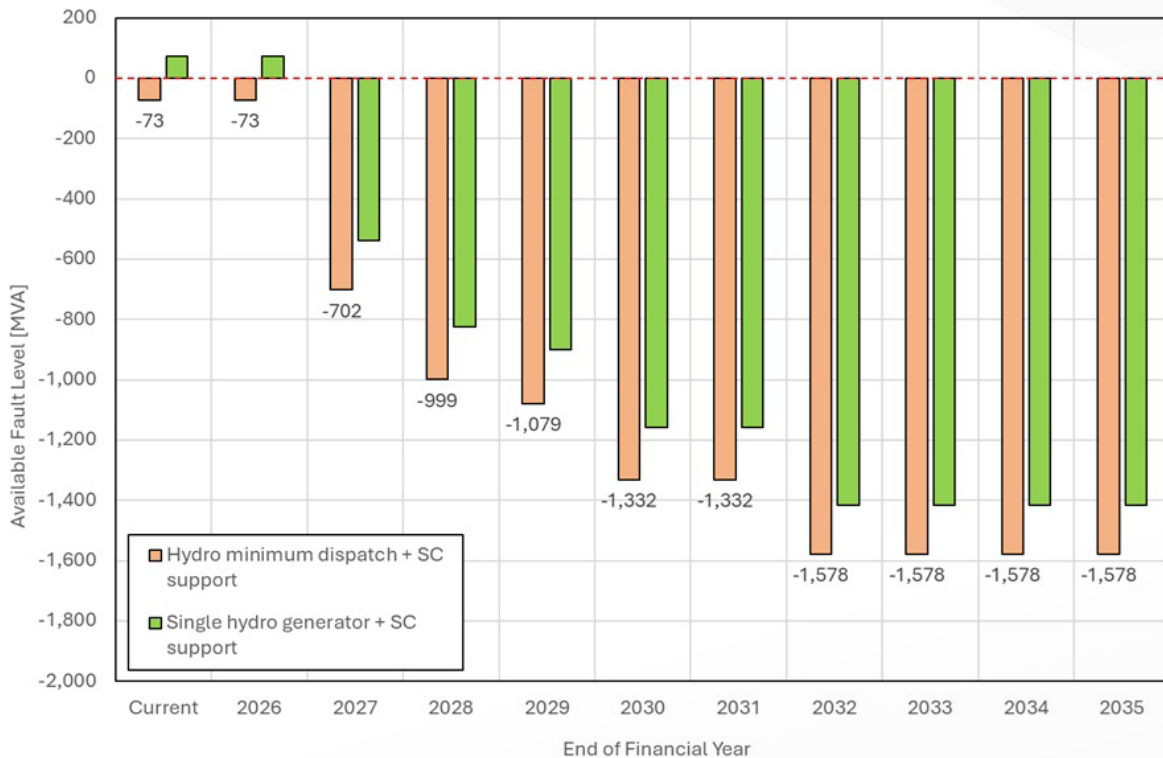


Figure 5-5: Forecast AFL at George Town 220 kV SSN

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 700 MW, anticipated for 2028, is constructed near the Waddamana switching station as part of the Central Highlands REZ.

In 2032, there is a significant increase in the AFL deficit, aligning with further planned IBR developments in the order of 430 MW. Additional system strength support beyond the current operational arrangements will likely become necessary post commissioning of Marinus Stage 1 and transmission augmentation works under NWTB, but this will depend on the precise scale and timing of IBR developments in the Central Highlands REZ.

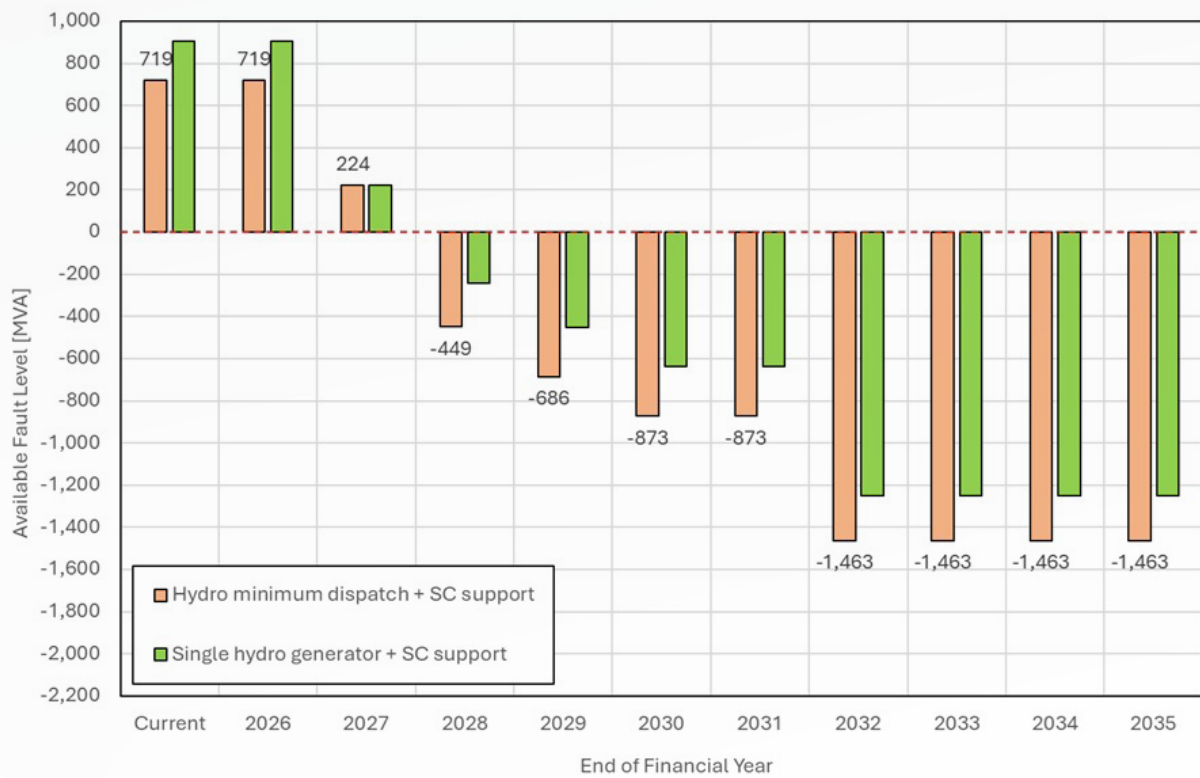


Figure 5-6: Forecast AFL at Waddamana 220 kV SSN

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 2035, even with over 450 MW of IBR connected in the North West Tasmania REZ (T2) 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.

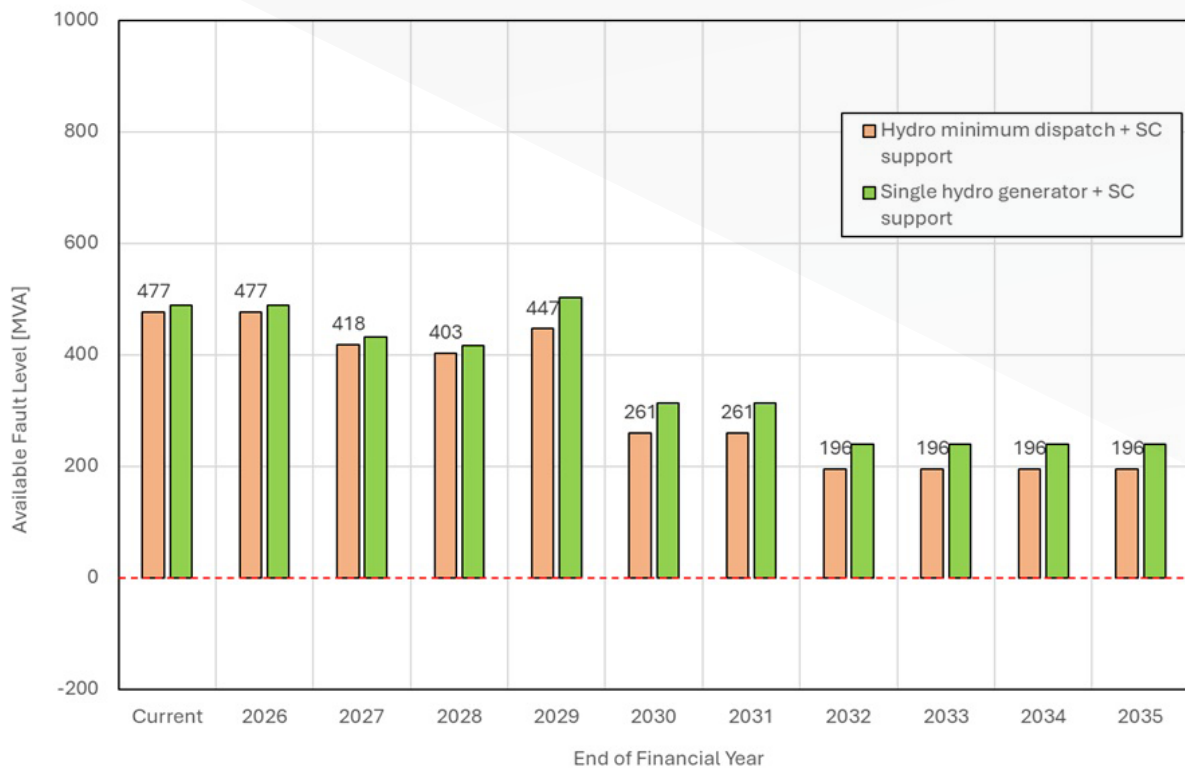


Figure 5-7: Forecast AFL at Burnie 110 kV SSN

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.

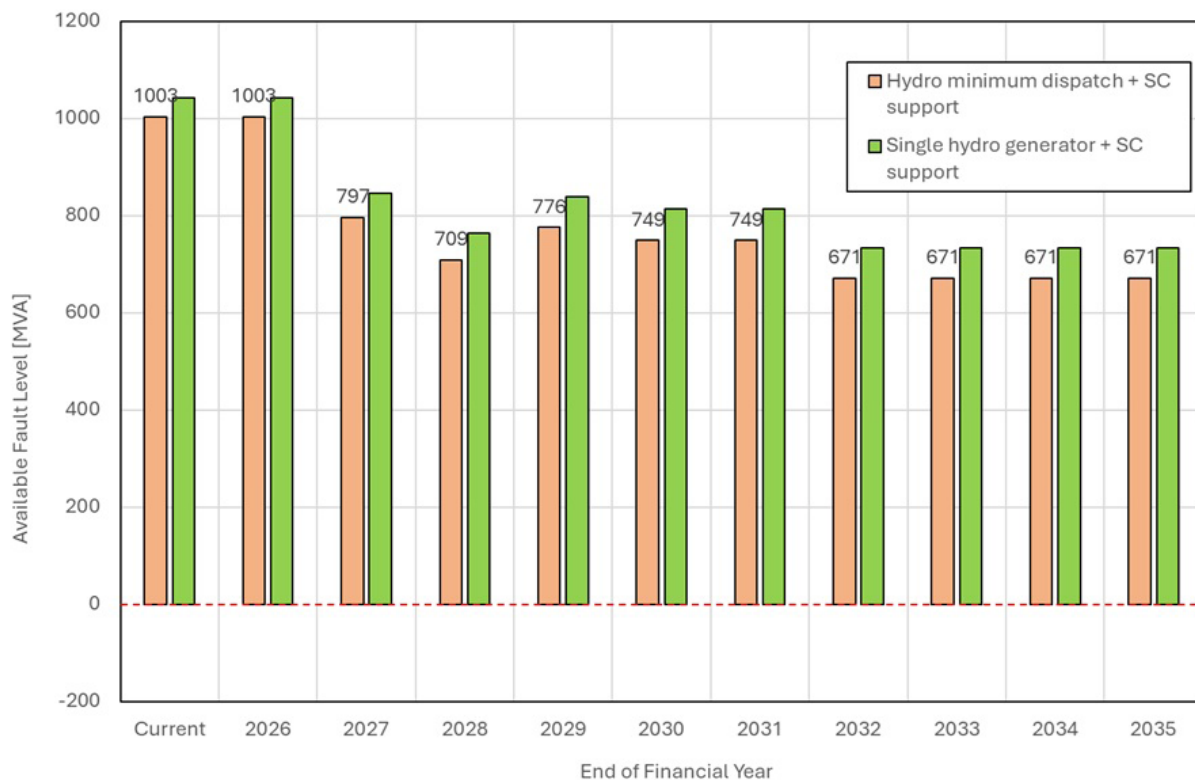


Figure 5-8: Forecast AFL at Risdon 110 kV SSN

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 5-2 and the SSN specific AFL results discussed earlier; specifically, indications that the *efficient levels of system strength* exceed what is necessary, with Burnie 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 Commencement of a RIT-T for the provision of future system strength requirements

To comply with the new system strength Rule requirements, TasNetworks initiated a RIT-T with the publication of a Project Specification Consultation Report (**PSCR**) and a Request for Expression of Interest (**EOI**) in early August 2023.⁷⁷ 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 2029 and identified a preferred solution.

We published the Project Assessment Conclusions Report (**PACR**) confirming that the preferred option is to contract with existing owners of synchronous condensers and generation assets. Publication of this PACR represents the final step in the RIT-T process.

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 2024 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 – no outage’ signifies that the constraint was binding or violated without any corresponding outage event in the network, whereas ‘Thermal limit – with outage’ indicates that the constraint was affected by one or more transmission elements being out of service.

⁷⁷ Further information can be obtained on the System Strength RIT-T progress is available at <https://www.tasnetworks.com.au/Poles-and-wires/Planning-and-developments/Our-current-projects/Meeting-System-Strength-Requirements>

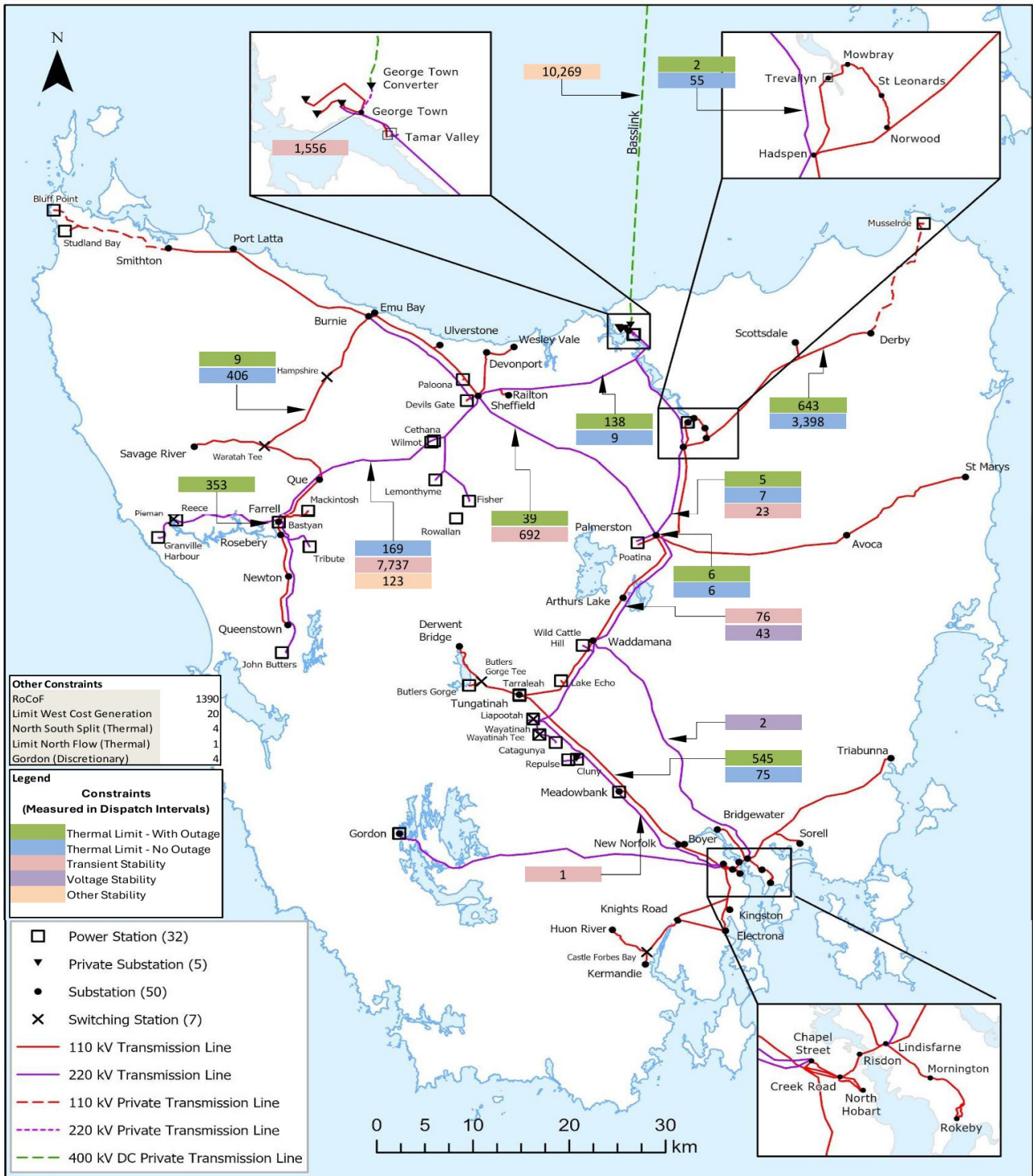


Figure 5-9: Transmission constraints during 2024 calendar year

Table 5-9 lists the number of trading intervals during which binding or violated constraints took place on major transmission corridors during the 2023 and 2024 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 2024

| Constraint | Period constraint bound or violated | | | |
|--|-------------------------------------|--------------|-------------------|--------------|
| | 2023 | | 2024 | |
| | Trading intervals | Time (hours) | Trading intervals | Time (hours) |
| Constraints with increased prevalence in 2024 | | | | |
| Basslink Energy and FCAS related constraint (i.e. Basslink no go zone) | 295 | 25 | 305 | 25 |
| Basslink import limited due to load unavailability for FCSPS operation | 4,936 | 411 | 9,442 | 787 |
| Basslink rate-of-change limit | 680 | 57 | 897 | 75 |
| Derby to Scottsdale Tee 110 kV thermal limit with no outage | 420 | 35 | 3,395 | 283 |
| George Town 220 kV bus voltage stability limit | 394 | 33 | 1,556 | 130 |
| Limit TAS non-synchronous generation and Basslink | 726 | 61 | 1,226 | 102 |
| Rate of Change of TAS Frequency | 9 | 1 | 164 | 14 |
| Scottsdale Tee to Norwood 110 kV thermal limit with outage | 60 | 5 | 643 | 54 |
| Farrell 220/110 kV transformer thermal limit | - | - | 353 | 29 |
| Hampshire-Que-Waratah Tee 110 kV thermal limit | - | - | 397 | 33 |
| Constraints with decreased prevalence in 2024 | | | | |
| Farrell-Sheffield 220 kV thermal limit with no outage | 719 | 60 | 169 | 14 |
| Farrell-Sheffield 220 kV transient stability | 19,880 | 1,657 | 7,737 | 645 |
| Palmerston-Sheffield 220 kV transient stability | 1,367 | 114 | 692 | 58 |

The following sections present more information on our top three constraints from 2023 to 2024.

Summary

The 2024 calendar year statistics were heavily impacted by Basslink which accounted for 38% of the total number of constrained trading intervals. Overall, the total number of trading intervals experiencing binding constraints (both major and minor) decreased by approximately 8% from 30,807 in 2023 to 28,395 in 2024.

Basslink import limited due to load unavailability for FCSPS operation

The most frequently limiting constraint in 2024 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 load blocks for the FCSPS to balance frequency for the loss of Basslink. TasNetworks has no control over this constraint as the FCSPS loads are contracted by third parties.

Farrell-Sheffield 220 kV transient stability

Despite a significant reduction in constrained trading intervals, the 'Farrell-Sheffield transient stability' constraint was the second most limiting constraint in 2024. This constraint is primarily driven by generation output from the King and Pieman hydro schemes, as well as Granville Harbour Wind Farm. Supervisory Control & Data Acquisition (SCADA) data shows a 25% reduction in West coast generation in 2024. This reduction reduced the number of constrained trading intervals. TasNetworks will investigate if there are any economical options to reduce this constraint in the future, including revisiting the limit advice with updated generator models.

Derby to Scottsdale Tee 110 kV thermal limit with no outage

The third most limiting constraint in 2024 was the 'Derby to Scottsdale Tee 110 kV thermal limit with no outage' constraint. This constraint limits generation at Musselroe Wind farm to prevent overload of the Derby – Scottsdale Tee 110kV line.

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."* 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.

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 non-regulated 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.

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.



Ateco

| | |
|----------------|-------|
| RATED CAPACITY | 272kg |
| No. PERSONS | 2 |
| EQUIPMENT | 80kg |
| LINER WEIGHT | 32kg |

FLAME
RETARDANT

1300 1ALTEC

Chapter 6

Service delivery performance

- In 2024, transmission system performance remained within targets for transmission line and transformer circuit fault outage rate metrics but was outside the target for capacitor circuit fault outage rate. While transmission Loss of Supply (LOS) event counts over 0.1 and 1.0 system minutes were on target, the average outage duration of all LOS events was within the target.
- Distribution system performance for 2024-25 was outside the Tasmanian Electricity Code (the Code) System Average Interruption Frequency Index (SAIFI) standards for Critical Infrastructure category and outside the System Average Interruption Duration Index (SAIDI) standards for Critical Infrastructure, Urban and Regional Centres, and Lower Density Rural category.
- Distribution system performance for 2024-25 was outside the Australian Energy Regulator (AER) Service Target Performance Incentive Scheme (STPIS) SAIFI standards for Critical Infrastructure, High Density Commercial, and High Density Rural categories and outside the SAIDI standards across all categories.
- Our network now hosts over 60,000 Distributed Energy Resource (DER) systems with an installed capacity of 380 MW, a 15% increase over the course of 2024-25 financial year.

6.1 Service 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 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 August and September of 2024, severe storms caused significant damage to Tasmania's transmission and distribution network, resulting in widespread power outages and extended restoration times due to safety concerns and access limitations. The storms, described as the worst in decades, impacted over 47,000 customers.

During 2024-25, the distribution service experienced eleven major event days, primarily due to inclement weather and a vehicle-related incident. On 12 August 2024, a vehicle caused damage to assets, resulting in a prolonged supply disruption. From 26 August to 4 September 2024 (excluding 29 August), strong winds and rain affected the state, leading to vegetation-related incidents that disrupted distribution supply and impacted customers. In response, we activated our Incident Contingency System, enabling Regional Team Leaders to prioritise actions and deploy work crews efficiently to support timely and targeted supply restoration efforts. On 23 September 2024, severe weather impacted the north-west region of the state and on 12 March 2025, lightning mostly in the north-west, affected the network, causing further supply interruptions.

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 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 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 targets.

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.⁷⁸ LOS events are split into two categories:

- major events (exceeding 1.0 system minute); and
- all events exceeding 0.1 system minute, 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 Service Target Performance Incentive Scheme (STPIS)⁷⁹. Red values indicate where we did not meet our standard.

Table 6-1: Transmission network performance

| Performance measure | Regulatory period 2019–24 | | | | | |
|---|------------------------------|-------|-------|-------|-------|-------|
| | Target 2019-24 | 2020 | 2021 | 2022 | 2023 | 2024 |
| Transmission network reliability performance | | | | | | |
| Number of LOS events >0.1 system minute | ≤3 | 8 | 2 | 7 | 3 | 3 |
| Number of LOS events >1.0 system minute | ≤1 | 0 | 0 | 3 | 1 | 1 |
| Transmission circuit outage rate | | | | | | |
| Transformer circuit fault outage rate (%) | ≤8.40 | 5.51 | 4.55 | 2.70 | 4.50 | 6.31 |
| Transmission line circuit fault outage rate (%) | ≤16.90 | 13.21 | 13.08 | 15.89 | 12.15 | 16.82 |
| Capacitor circuit fault outage rate (%) | ≤17.90 | 23.08 | 7.69 | 15.38 | 7.69 | 23.08 |
| Transmission average circuit outage duration | | | | | | |
| Average of LOS duration (minutes) | ≤149 | 105 | 19 | 204.6 | 394.5 | 59.33 |

In 2024, the transmission system fault outage rates were within target for transmission line and transformer circuit and outside for capacitor circuit. The LOS event counts were on target and average duration of LOS events was within the target.

The majority of outages contributing to these metrics were caused by equipment and environmental causes.

⁷⁸ In Tasmania, an event of one system minute equates to about 31.2 MWh of unserved energy

⁷⁹ Service Target Performance Incentive Scheme version 5

6.4 Distribution network reliability

We report distribution network reliability to OTTER and the AER on a geographic segmentation basis. For 2024–25, 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 days,⁸⁰ transmission network outages, environmental-fire, total fire ban day-related outages, and certain third-party outages. The Code standards and performance during 2024–25 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 our 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

| Supply reliability category | Annual frequency of supply interruptions (on average) (SAIFI) | | Annual duration of supply interruptions (on average) (SAIDI) | |
|-----------------------------|---|-------------|--|-------------|
| | Standard | Performance | Standard | Performance |
| Critical Infrastructure | 0.2 | 0.23 | 30 | 66.98 |
| High Density Commercial | 1 | 0.41 | 60 | 46.41 |
| Urban and Regional Centres | 2 | 1.18 | 120 | 140.97 |
| High Density Rural | 4 | 2.73 | 480 | 359.64 |
| Lower Density Rural | 6 | 3.44 | 600 | 603.37 |

Our performance in SAIFI (the frequency of outages measure), is within our standard in all categories except Critical Infrastructure, which was impacted by planned work.

For SAIDI (the duration of outages measure), we did not meet our standard in Critical Infrastructure, Urban and Regional Centres, and Lower Density Rural categories. Areas in these categories were impacted by planned work, equipment, vegetation, 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 2024-25. Twenty-seven areas did not meet their SAIDI standards and eleven did not meet their SAIFI standards.

⁸⁰ 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 | 1 | 30 | 1 |
| High Density Commercial (8) | 2 | 0 | 120 | 1 |
| Urban and Regional Centres (44) | 4 | 6 | 240 | 12 |
| High Density Rural (41) | 6 | 3 | 600 | 5 |
| Lower Density Rural (27) | 8 | 1 | 720 | 8 |
| Total (121) | | 11 | | 27 |

6.4.2 Distribution STPIS reliability targets and performance

The AER sets service component 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 2024–25, we did not meet the SAIFI standards in the Critical Infrastructure, High Density Commercial, and High Density Rural categories and SAIDI standards in all categories. These categories were heavily impacted by equipment, vegetation, 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, 2024–25. We report our reliability performance in with the AER's methodology. Red values indicate where we did not meet our standard.

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 | 2024–25 performance |
| Critical Infrastructure | 0.070 | 0.087 |
| High Density Commercial | 0.377 | 0.415 |
| Urban and Regional Centres | 1.015 | 0.958 |
| High Density Rural | 2.171 | 2.397 |
| Lower Density Rural | 2.948 | 2.945 |

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 | 2024–25 performance |
| Critical Infrastructure | 5.948 | 23.044 |
| High Density Commercial | 38.012 | 39.218 |
| Urban and Regional Centres | 92.118 | 92.945 |
| High Density Rural | 244.061 | 260.839 |
| Lower Density Rural | 398.899 | 465.402 |

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 2024-25 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 | High-density rural | Low-density rural | Whole network |
|--|---------------------|-------------------------|-------------------------|---------|--------------------|-------------------|---------------|
| SAIDI | Total | 64.358 | 60.229 | 364.151 | 1343.006 | 2707.954 | 867.684 |
| | Removing exclusions | 23.044 | 39.218 | 92.945 | 260.839 | 465.402 | 174.679 |
| SAIFI | Total | 0.249 | 0.698 | 1.729 | 4.406 | 5.343 | 2.674 |
| | Removing exclusions | 0.087 | 0.415 | 0.958 | 2.397 | 2.945 | 1.473 |
| Average customer numbers ('000s) ⁸¹ | | 2.00 | 4.53 | 205.38 | 48.27 | 46.59 | 306.77 |

⁸¹ For AER purposes classification customer numbers are assigned based on pre-2024 community boundary definitions to align with AER STPIS performance targets

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.

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 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 | 2020-21 | 2021-22 | 2022-23 | 2023-24 | 2024-2025 |
|------------------------|---------|---------|---------|---------|-----------|
| Number of applications | 4,320 | 4,436 | 5,244 | 6,403 | 5,835 |

Small generators – less than 5 MW – are automatically exempt from full compliance with Chapter 5 of the National Electricity Rules (**the Rules**).⁸² 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 solar PV makes up the vast majority of all embedded generation and has seen steady growth in recent years, reaching a total of over 70,000 systems with an installed capacity of approximately 380 MW by the end of June 2025. Figure 6-1 presents the growth in installed capacity and number of installations of rooftop PV since FY 2014/15.

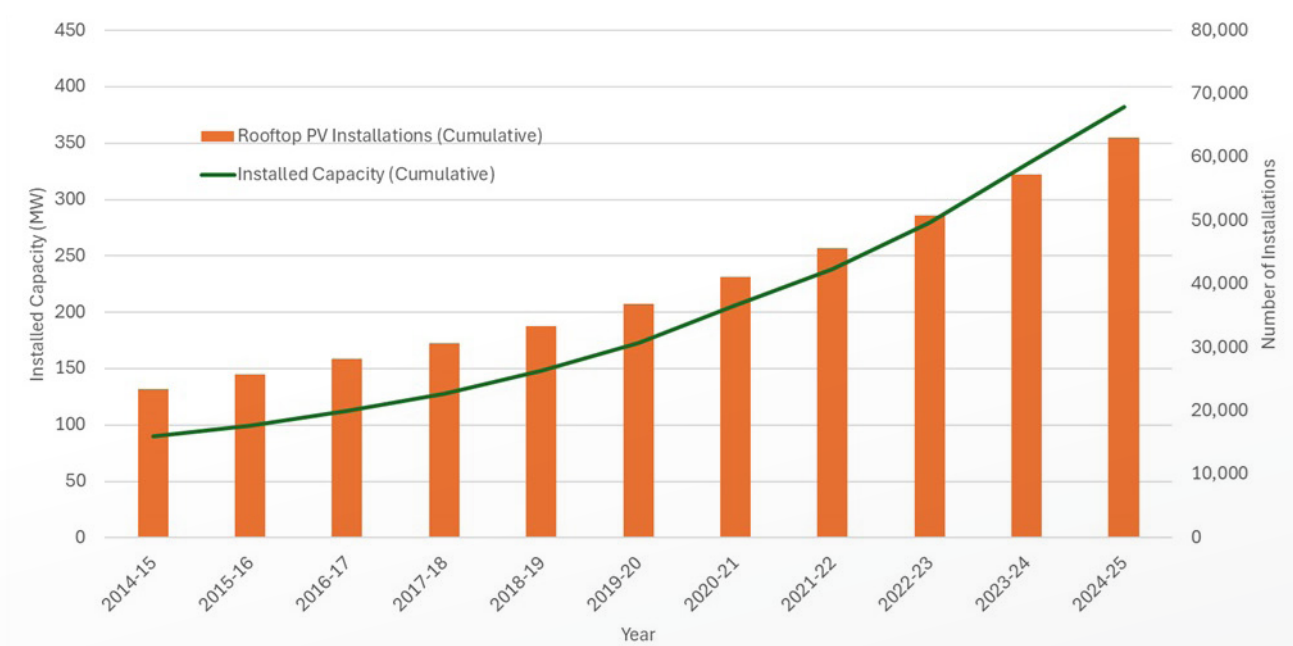


Figure 6-1: Solar PV penetration

The average size of new solar PV systems has also steadily grown, from under 4 kW in 2014-15 to over 9 kW in 2024-25, as shown in Figure 6.2.

⁸² <https://www.aemo.com.au/energy-systems/electricity/nationalelectricity-market-nem/participate-in-the-market/networkconnections>

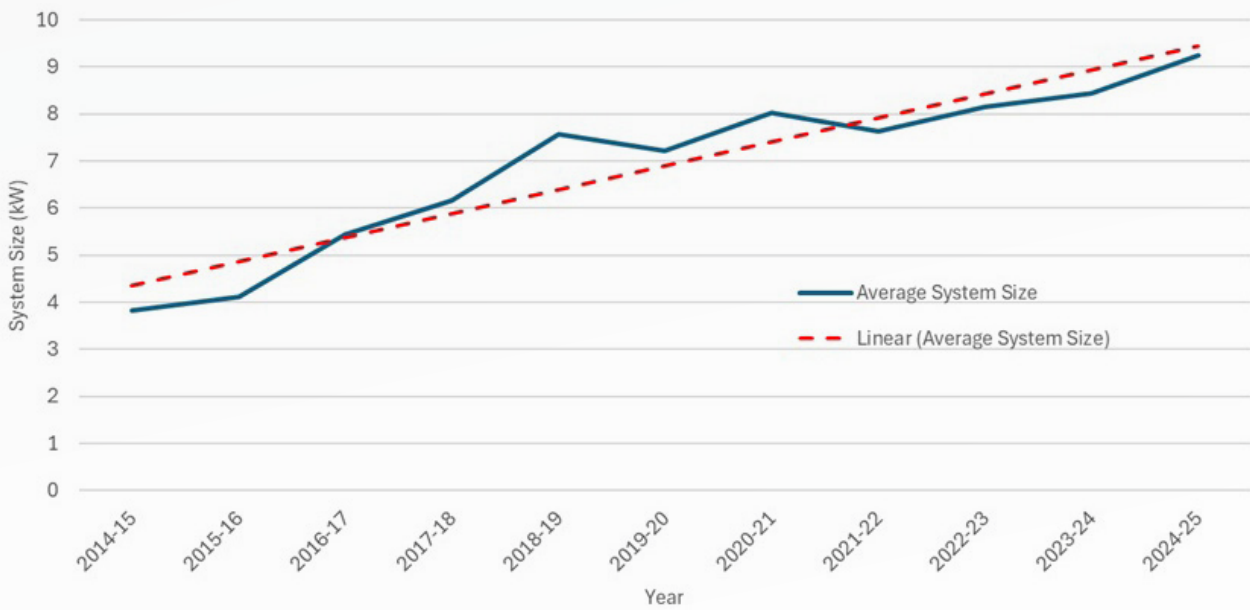


Figure 6-2: Average Solar PV system size

Residential battery storage has increased substantially over the past 3 years, with new installations totalling more than 2,500 across the state, as shown in Figure 6.3

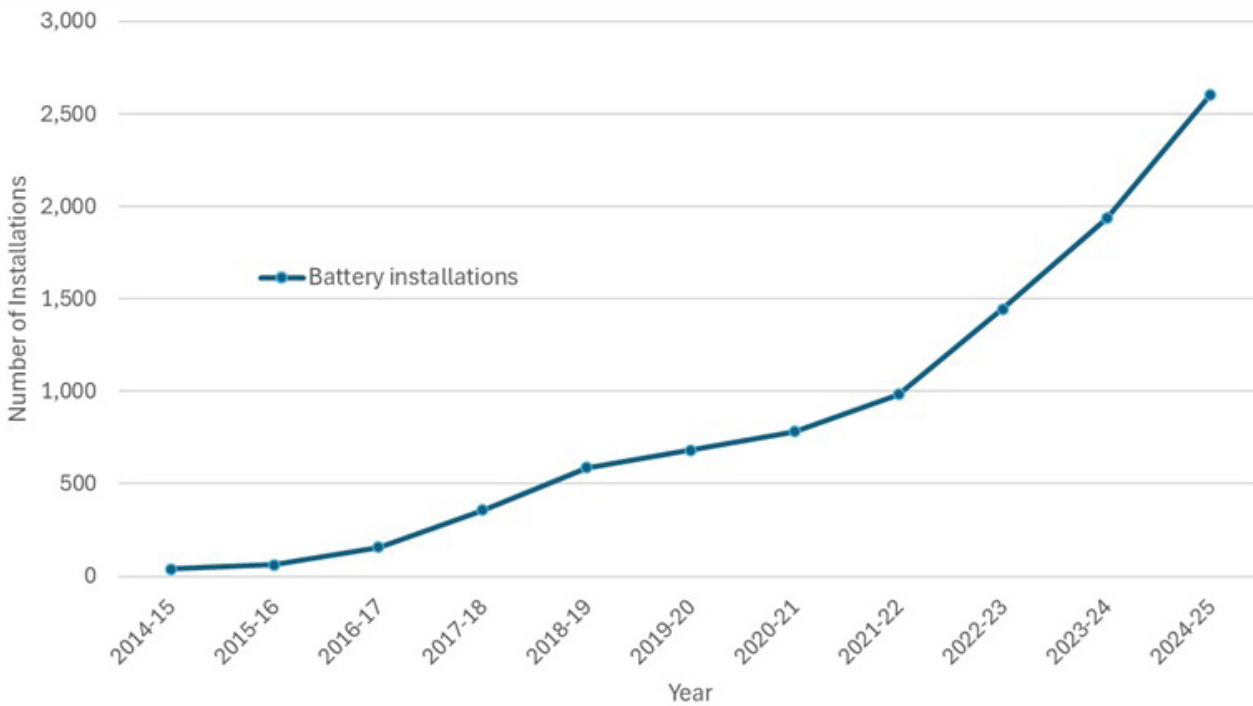


Figure 6-3: Residential battery penetration

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 |

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 <i>Electricity Supply Industry (Network Planning Requirements) Regulations 2018</i> , 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] |

Abbreviations

| | | | |
|--------------|---|----------------|---|
| AC | Alternating Current | MIC | Market Impact Component |
| AEMC | Australian Energy Market Commission | Mva | Megavolt-amperes |
| AEMO | Australian Energy Market Operator | Mvar | Megavolt-amperes reactive |
| AER | Australian Energy Regulator | MW | Megawatts |
| APR | Annual Planning Report | MWh | Megawatt-hour |
| ARENA | Australian Renewable Energy Agency | NCSPS | Network Control System Protection Scheme |
| AS | Australian Standards | NEM | National Electricity Market |
| CCGT | Combined Cycle Gas Turbine | OTTER | Office of the Tasmanian Economic Regulator |
| CESS | Capital Expenditure Sharing Scheme | OWZ | Offshore Wind Zone |
| CSIS | Customer Service Incentive Scheme | OFGS | Over Frequency Generation Shedding |
| DER | Distributed Energy Resources | PACR | Project Assessment Conclusions Report |
| DMIAM | Demand Management Innovation Allowance Mechanism | PADR | Project Assessment Draft Report |
| DMIS | Demand Management Incentive Scheme | PHES | Pumped Hydro Energy Storage |
| DNSP | Distribution Network Service Provider | POE | Probability of Exceedance (chance that the value is exceeded) |
| EBSS | Efficiency Benefit Sharing Scheme | PV | Photovoltaic [solar generation system] |
| ESB | Energy Security Board | REZ | Renewable Energy Zone |
| EV | Electric Vehicle | RIN | Regulatory Information Notice |
| FCAS | Frequency Control Ancillary Services | RIT-T/D | Regulatory investment test for transmission (or) distribution |
| FCSPS | Frequency Control System Protection Scheme | SAIDI | System Average Interruption Duration Index |
| GSL | Guaranteed Service Level | SAIFI | System Average Interruption Frequency Index |
| GWh | Gigawatt-hour | SAPS | Stand Alone Power Systems |
| HV | High Voltage | SCADA | Supervisory Control and Data Acquisition |
| HVDC | High Voltage Direct Current | SCR | Short Circuit Ratio |
| Hz | Hertz | STATCOM | Static Synchronous Compensator |
| IBR | Inverter Based Resources | TRET | Tasmanian Renewable Energy Target |
| ISP | Integrated System Plan | STPIS | Service Target Performance Incentive Scheme |
| kA | Kiloamps | TNSP | Transmission Network Service Provider |
| kV | Kilovolts | UFLS | Under Frequency Load Shedding |
| LOS | Loss of Supply | VRE | Variable Renewable Energy |
| MAIFI | Momentary System Average Interruption Frequency Index | | |

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.⁸³ 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 before each regulatory period (usually five years).

The most recent determinations for TasNetworks were made by the AER in April 2024⁸⁴ for the 2024–2029 regulatory period. This revenue determination, together with the efficiencies achieved by TasNetworks since it took over running Tasmania's transmission and distribution networks in 2014, will 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.

⁸³ <https://www.economicregulator.tas.gov.au/electricity/regulatory-framework/codes/tasmanian-electricity-code-background>

⁸⁴ TasNetworks - Determination 2024–29 | Australian Energy Regulator (AER)

The capital expenditure program for network services in our revenue determination included many of the proposed investments identified in this APR.

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 data centre, 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 Annual Planning Report (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.

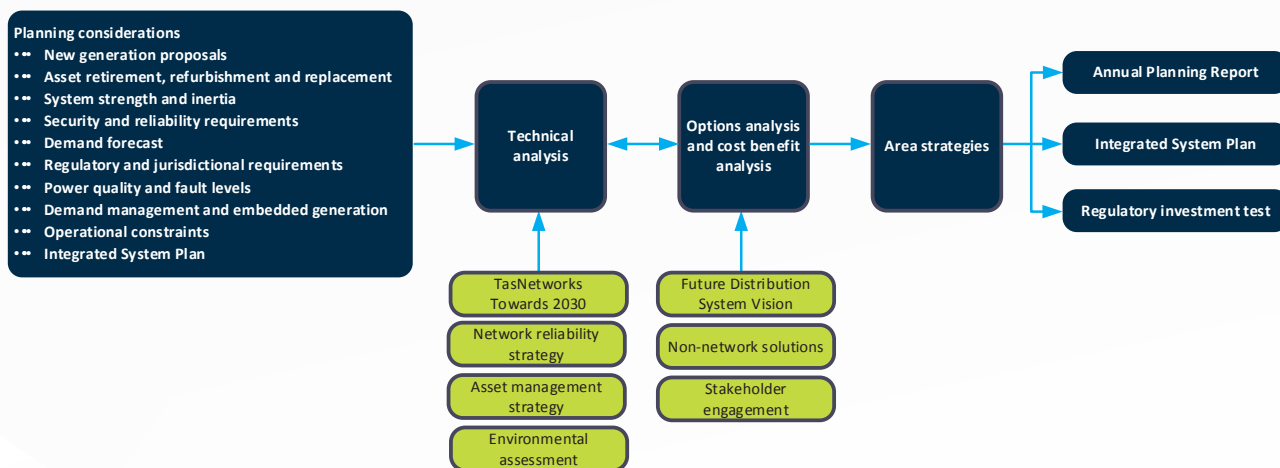


Figure A-1: The network planning process

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.

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.⁸⁵ 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.⁸⁶ 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).

⁸⁵ <https://www.aemc.gov.au/regulation/energy-rules/national-electricity-rules/current>

⁸⁶ <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**) targets 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 OTTER⁸⁷ 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.

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 asset criticality, condition, and risk, rather than simply age. 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:

- managing our assets to ensure safety and the environment are not compromised;
- maintaining the reliability of the network;
- where we can safely do so, running our network harder rather than building more;
- responding to the changing nature of customer behaviours and requirements by participating in trials;
- taking a whole of life (life cycle) approach to optimise cost and service outcomes for our customers;
- working hard to ensure we deliver the lowest sustainable prices; and

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

- understanding how we manage our assets with the changing use of our network from 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.

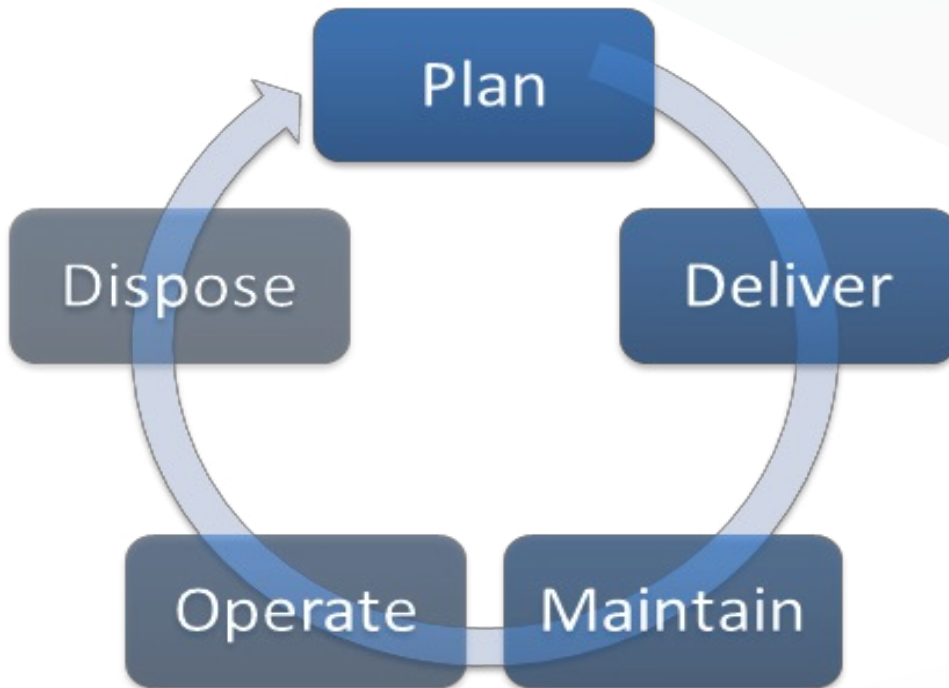


Figure A-2: Asset life cycle management

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);
- optimisation of investment value (value Based); and
- run to failure.

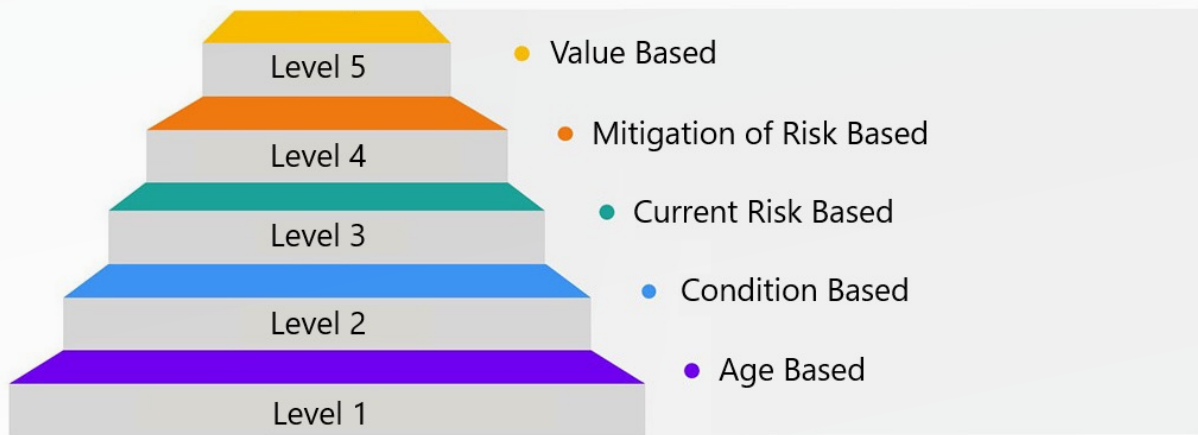


Figure A-3: Asset management decision making hierarchy

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**)⁸⁸ 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.⁸⁹

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.

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 Strategy⁹⁰ 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.⁹¹

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.

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

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

90 <https://www.tasnetworks.com.au/Forms/Industry-Engagement-Register/Industry-Engagement>

91 <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 process⁹² 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^{93,94}. '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.⁹⁵ In addition to local anti-islanding protection devices, a telecommunications based anti-islanding inter-trip⁹⁶ 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.

92 <https://www.tasnetworks.com.au/embedded-generation>

93 <https://aemo.com.au/energy-systems/electricity/der-register>

94 <https://www.tasnetworks.com.au/connections/distributed-energy-resource-register>

95 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

96 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 three components: a service component, a Market Impact Component (**MIC**) 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 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.8.3 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.8.4 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.8.5 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.8.6 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.8.7 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. The DMIAM for transmission was published in May 2021, mid-way through TasNetworks’ 2019 – 2024 regulatory control period, and so applies in Tasmania for the first time in the 2024-2029 regulatory control period.

Appendix B Generator information

Table B-1 lists the Tasmanian generators connected to the transmission network.⁹⁷ 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 ⁹⁸ | 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 | 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 |

⁹⁷ Capacity information sourced from:

- <https://www.hydro.com.au/clean-energy/our-power-stations>
- <http://www.cattlehillwindfarm.com/>
- <https://granvilleharbourwindfarm.com.au/>

⁹⁸ 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 | | Farrell |
| Granville Harbour | 112 | | |

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 | solar | 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 | Solar | 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 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 our standard.

Table C-1: SAIFI supply reliability category performance (the Code)

| Supply reliability category | Standard (interruptions) | 2020-21 | 2021-22 | 2022-23 | 2023-24 | 2024-25 |
|-----------------------------|--------------------------|---------|---------|---------|---------|---------|
| Critical Infrastructure | 0.2 | 0.15 | 0.27 | 0.12 | 0.20 | 0.23 |
| High Density Commercial | 1 | 0.46 | 0.74 | 0.34 | 0.74 | 0.41 |
| Urban and Regional Centres | 2 | 1.42 | 1.19 | 1.14 | 1.30 | 1.18 |
| High Density Rural | 4 | 2.30 | 2.80 | 2.84 | 2.87 | 2.73 |
| Lower Density Rural | 6 | 3.23 | 4.21 | 3.79 | 3.94 | 3.44 |

Table C-2: SAIDI supply reliability category performance (the Code)

| Supply reliability category | Standard (minutes) | 2020-21 | 2021-22 | 2022-23 | 2023-24 | 2024-25 |
|-----------------------------|--------------------|---------|---------|---------|---------|---------|
| Critical Infrastructure | 30 | 15.10 | 69.76 | 27.84 | 50.04 | 66.98 |
| High Density Commercial | 60 | 62.04 | 86.31 | 42.87 | 72.42 | 46.41 |
| Urban and Regional Centres | 120 | 182.89 | 161.10 | 125.64 | 148.16 | 140.97 |
| High Density Rural | 480 | 309.57 | 503.94 | 342.49 | 366.91 | 359.64 |
| Lower Density Rural | 600 | 549.10 | 1130.70 | 535.78 | 611.23 | 603.37 |

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 is not meeting the standard.

Table C-3: Number of poor performing areas (SAIFI)

| Supply reliability category (number of areas) | | Standard (interruptions) | 2020-21 | 2021-22 | 2022-23 | 2023-24 | 2024-25 |
|--|-----|-----------------------------|---------|---------|---------|---------|---------|
| Critical Infrastructure (1) | 0.2 | 0 | 1 | 0 | 0 | 1 | |
| High Density Commercial (8) | 2 | 0 | 0 | 0 | 0 | 0 | |
| Urban and Regional Centres (44) | 4 | 2 | 2 | 3 | 2 | 6 | |
| High Density Rural (41) | 6 | 1 | 3 | 5 | 0 | 3 | |
| Lower Density Rural (27) | 8 | 0 | 2 | 0 | 1 | 1 | |
| Total (121) | | | 3 | 8 | 8 | 3 | 11 |

Table C-4: Number of poor performing areas (SAIDI)

| Supply reliability category (number of areas) | Standard (minutes) | 2020-21 | 2021-22 | 2022-23 | 2023-24 | 2024-25 |
|--|-----------------------|---------|---------|---------|---------|---------|
| Critical Infrastructure (1) | 30 | 0 | 1 | 0 | 1 | 1 |
| High Density Commercial (8) | 120 | 2 | 2 | 1 | 1 | 1 |
| Urban and Regional Centres (44) | 240 | 10 | 11 | 7 | 9 | 12 |
| High Density Rural (41) | 600 | 3 | 10 | 6 | 9 | 5 |
| Lower Density Rural (27) | 720 | 6 | 12 | 6 | 8 | 8 |
| Total (121) | | 21 | 36 | 20 | 28 | 27 |

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 our standard.

Table C-5: SAIFI supply reliability category performance (AER)

| Regulatory period | 2020–24 | | | | | 2024–25 | |
|-----------------------------|----------------|---------|---------|---------|---------|----------------|---------|
| Supply reliability category | Target 2019-24 | 2020-21 | 2021-22 | 2022-23 | 2023-24 | Target 2024-29 | 2024-25 |
| Critical Infrastructure | 0.251 | 0.104 | 0.051 | 0.015 | 0.019 | 0.070 | 0.087 |
| High Density Commercial | 0.260 | 0.349 | 0.655 | 0.297 | 0.649 | 0.377 | 0.415 |
| Urban and Regional Centres | 1.081 | 1.186 | 1.019 | 0.948 | 1.114 | 1.015 | 0.958 |
| High Density Rural | 2.466 | 2.056 | 2.278 | 2.510 | 2.560 | 2.171 | 2.397 |
| Lower Density Rural | 3.219 | 2.773 | 3.452 | 3.438 | 3.479 | 2.948 | 2.945 |

Table C-6: SAIDI supply reliability category performance (AER)

| Regulatory period | 2020–24 | | | | | 2024–25 | |
|-----------------------------|----------------|---------|---------|---------|---------|----------------|---------|
| Supply reliability category | Target 2019-24 | 2020–21 | 2021-22 | 2022-23 | 2023-24 | Target 2024-29 | 2024-25 |
| Critical Infrastructure | 32.984 | 7.31 | 3.418 | 2.018 | 4.713 | 5.948 | 23.044 |
| High Density Commercial | 20.074 | 28.895 | 56.993 | 27.971 | 57.787 | 38.012 | 39.218 |
| Urban and Regional Centres | 89.657 | 107.493 | 96.858 | 75.236 | 98.106 | 92.118 | 92.945 |
| High Density Rural | 250.959 | 215.617 | 279.612 | 256.752 | 271.564 | 244.061 | 260.839 |
| Lower Density Rural | 400.401 | 360.762 | 468.122 | 436.126 | 475.141 | 398.899 | 465.402 |

