

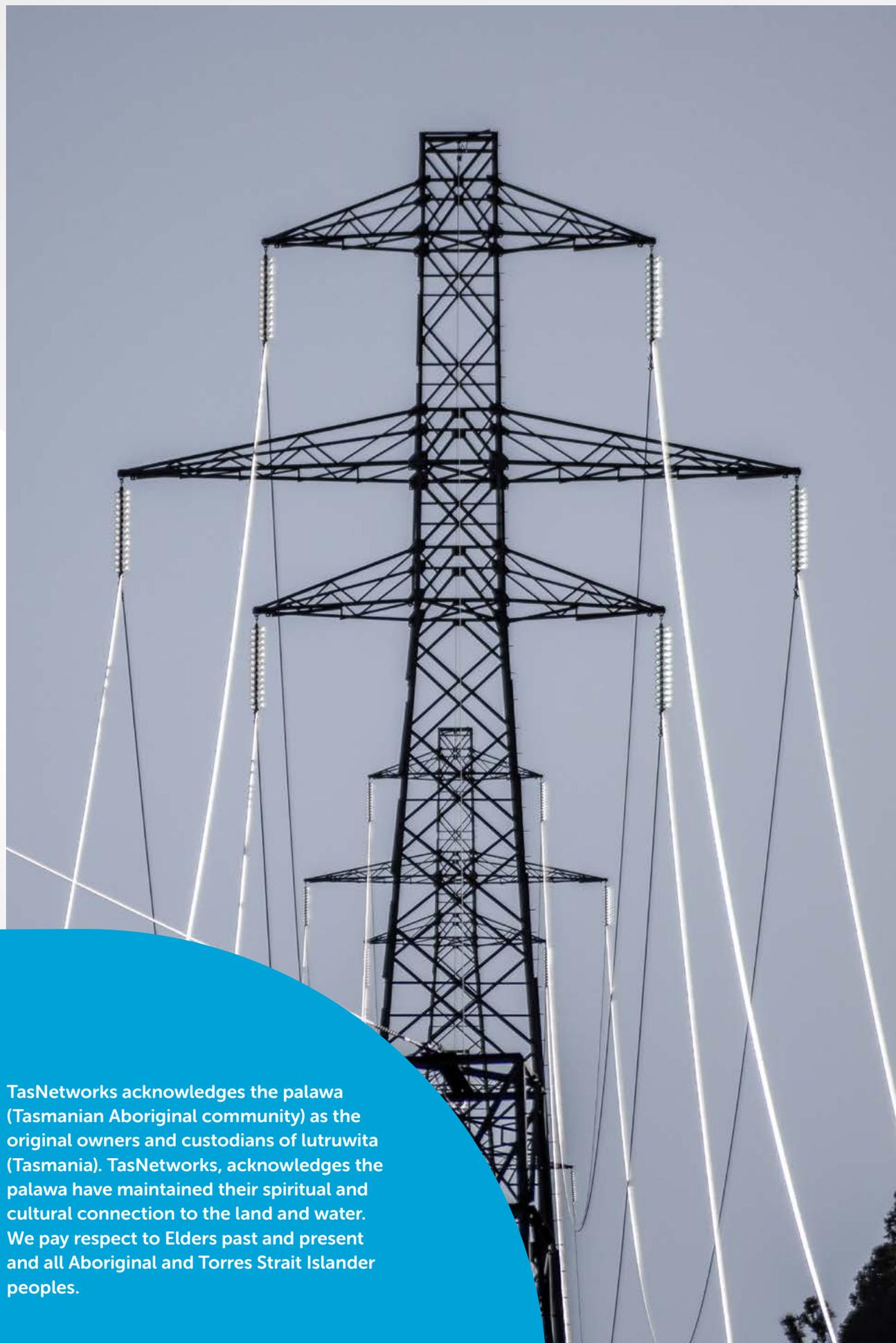
Annual Planning Report

2022



TasNetworks

Powering a
Bright Future



TasNetworks acknowledges the palawa (Tasmanian Aboriginal community) as the original owners and custodians of lutruwita (Tasmania). TasNetworks, acknowledges the palawa have maintained their spiritual and cultural connection to the land and water. We pay respect to Elders past and present and all Aboriginal and Torres Strait Islander peoples.

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Executive Summary

As the Tasmanian Transmission and Distribution Network Service Provider, TasNetworks is well positioned to develop and optimise network development plans with a focus on short, medium and longer term strategic outcomes. We produce a combined transmission and distribution planning report, prepared in accordance with the National Electricity Rules (The Rules) and jurisdictional requirements.

Tasmania continues to be 100% self-sufficient in renewable generation, with sufficient energy production to meet the state's annual electricity consumption. Tasmania's challenge under the legislated Tasmanian Renewable Energy Target (**TRET**) is to deliver 200 per cent of the 2020 baseline generation (10,500 GWh) per year by 2040 through renewable sources, while continuing to be a major contributor of firming services to the National Electricity Market (**NEM**).

As highlighted previously in our 2021 Annual Planning Report (**APR**), these objectives will mean that up to 2,500 – 3,000 MW of new wind farms will be developed in Tasmania over the next 18 years. This may be accompanied by 1,000 MW of hydrogen production capacity as this emerging industry begins to expand. Coupled with Marinus Link, a proposed 1,500 MW interconnector to Victoria, the required energy transfer across the network will double, and maximum demand is forecast to increase 2.5 times. As such, over the next two decades, TasNetworks will be managing a significant step change in the generation and transmission of electricity through the Tasmanian network.

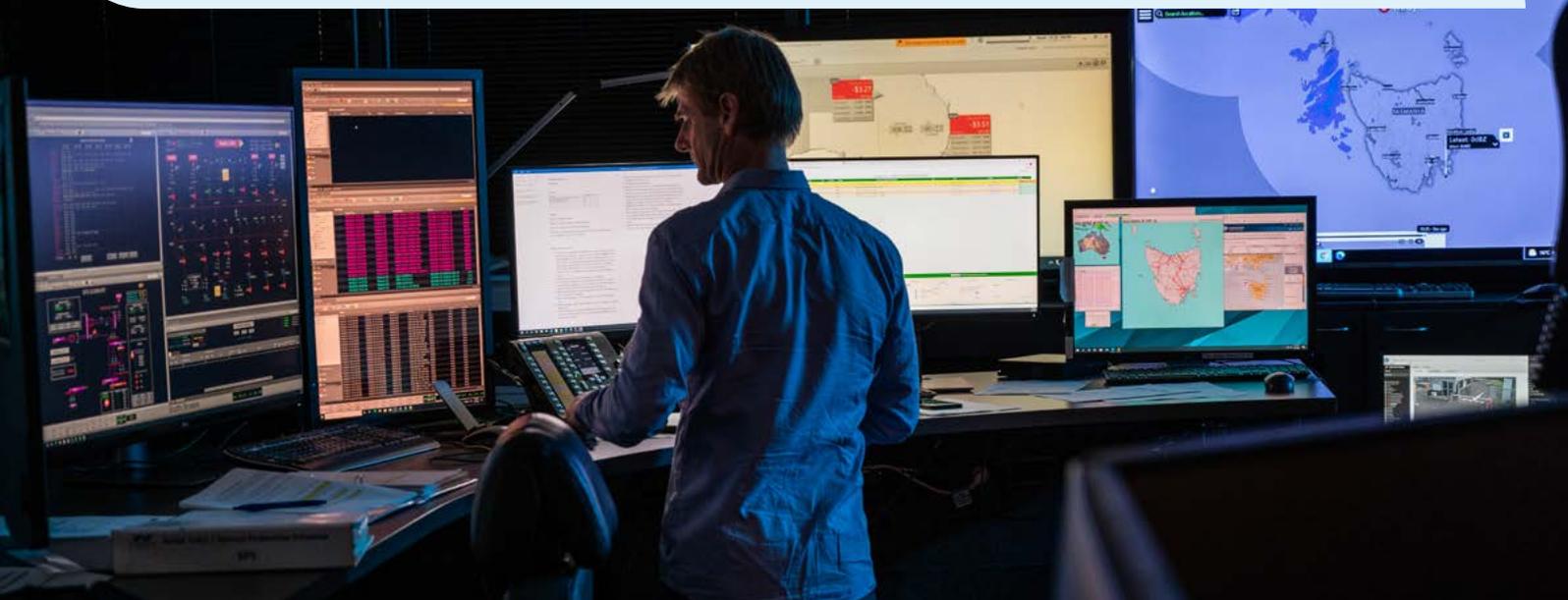
Under its Tasmanian Renewable Energy Action Plan, the Tasmanian Government established Renewables, Climate and Future Industries Tasmania (**ReCFIT**) and finalised its Renewable Energy Coordination Framework (**RECF**). In July 2022, TasNetworks was appointed as the Tasmanian Renewable Energy Zone (**REZ**) Planner, and in this role we are supporting ReCFIT as it works toward identifying Tasmania's priority locations for

the development of the new generation capacity to ensure the maximum utilisation of existing transmission network capability. This work will also result in the determination of the ongoing role TasNetworks will fulfil as the process moves beyond the REZ prioritisation stage.

The existing transmission network across the Central Highlands provides the largest initial potential, with some capability (in selected areas) in the north-west and north-east of Tasmania. Following the planned North West Transmission Developments (**NWTD**), significant potential in north-west Tasmania becomes accessible. With some transmission corridor augmentation, there are opportunities to support further large-scale energy developments in the Central Highlands.

Marinus Link Pty Ltd (**MLPL**) was operationalised as a wholly owned subsidiary of TasNetworks with the responsibility of progressing a second interconnector to Victoria. However; TasNetworks continues to be responsible for the delivery of the proposed NWTD. Marinus Link has been reclassified in the Australian Energy Market Operator's (**AEMO**) 2022 Integrated System Plan (**ISP**) as a single actionable ISP project without decision rules¹. MLPL is proposing to register with AEMO as an Intending Participant, looking to become a Transmission Network Service Provider in anticipation of Marinus Link being classified as a prescribed transmission service.

¹ ISP decision rules were requirements that needed to be satisfied to allow a project to proceed.



These objectives are guiding our planning for the Tasmanian electricity network, and we present the plans as part of this APR.

The key observations within the 2022 APR are:

- The optimal transmission development pathway for north-west Tasmania and Marinus Link is a new 220 kV transmission 'rectangle' incorporating the existing substations at Sheffield and Burnie, as well as the planned High Voltage Direct Current (HVDC) converter stations to be located at a new site at Heybridge;
- Palmerston–Sheffield 220 kV transmission corridor augmentation, is required to support the vast majority of future scenarios including TRET, hydrogen developments and Marinus Link;
- System strength and inertia requirements provided by sources outside of the energy market will continue to increase as inverter-based resources (e.g., wind farms, solar farms and HVDC) continue to displace the dispatch of existing synchronous generators.

Our Future Distribution System Vision and Roadmap establishes a foundational plan for Tasmania's distribution network with a major focus on facilitating customer adoption of Distributed Energy Resources (DER) including rooftop solar photovoltaics (PV), battery storage, and electric vehicles. Our vision is to bring agility to our distribution system for the advantage of all our customers. The roadmap leads Tasmania's electrical distribution system development. We have commenced stakeholder consultation and are looking forward to refining and co-designing each component.

Careful management of power system security continues to be a high priority for TasNetworks given the increasing possibility that all Tasmanian load demand could be supplied from inverter based resources in the near future, without any need for local synchronous generation support.

As the Tasmanian Transmission Network Service Provider, we are the *Inertia Service Provider* and *System Strength Service Provider* and are responsible for providing sufficient quantities of both services to allow AEMO to securely operate the Tasmanian power system. AEMO, in its 2022 ISP, has forecast ongoing shortfalls for both system strength and inertia network services in Tasmania. We are working towards addressing future shortfalls by evaluating submitted Expressions of Interest from potential providers. New Rules for the real time management of system strength commence in December 2025. The new framework will require a number of new approaches for the procurement and dispatch of system strength, including the allocation of costs to generators and loads who rely on grid-following inverters to interface with the network.

Whilst transmission system performance for 2021 was above target across all metrics, the distribution system encountered challenging operating conditions due to severe weather events during the first half of 2022. These events had wide-spread impacts and resulted in significant supply interruptions to customers. Consequentially, the distribution system did not meet the majority of Tasmanian Electricity Code (**the Code**) and incentive scheme targets. We always aim to meet reliability performance requirements, and continue to undertake reliability improvement projects to address issues experienced by specific communities, where performance is consistently below target.

TasNetworks welcomes feedback and enquiries on our APR, particularly from anyone interested in discussing opportunities for alternate network solutions to those identified. 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 register² on our website at: www.tasnetworks.com.au/forms/Industry-Engagement-register

² A recent rule broadened the scope of the "Demand Side Engagement Register" so that it is now known as the Industry Engagement Register.



01 Tasmania's renewable energy transformation

- The Renewable Energy Coordination Framework has been finalised to support the Tasmanian Renewable Energy Action Plan.
- The Tasmanian Government is building international connections to realise Tasmania's green hydrogen export goals.
- We continue with our 'Towards 2030' strategy to ensure ongoing success as the energy transition continues across the National Electricity Market.
- Our Future Distribution System Vision and Roadmap project is establishing a foundational plan for Tasmania's distribution network.
- Marinus Link and North West Transmission Developments (**NWTD**) are identified as urgent in the 2022 ISP based on current forecasts of generation retirements and renewable developments.
- We have made material progress towards the Marinus Link Tender Readiness decision gate and NWTD procurement strategy.

02 Tasmanian power system

- Tasmania has continued to maintain its energy independence, with on island generation supplying 100% of the State's annual energy requirements.
- Our transmission connected customers, dominated by four major industrial energy users were responsible for contributing 31 per cent to the total network maximum demand and consuming 50 per cent of the total energy delivered through the transmission network in 2021.

- The energy consumption and maximum demand of the existing customer base is forecast to increase materially over the forecast period, with increases from residential demand and electric vehicle (**EV**) uptake.
- The development of Marinus Link and large-scale hydrogen will more than double the energy transmitted through the network, with network maximum demand forecast to increase 2.5 times over the next 20 years.

03 Transmission network developments

- Tasmanian transmission planning activities continue to focus on the optimum development path for the network to accommodate future large scale renewable energy sources, new interconnection with Victoria, upgrading of existing power stations, export scale hydrogen production and integration of energy "firming" facilities such as battery energy storage systems (**BESS**) and pumped hydro.
- We have developed transmission augmentation options that support a range of market scenarios as the Australian electricity system transitions to renewable energy sources, informed by AEMO's identification of REZs in the ISP.
- We confirmed that augmentation of the Palmerston–Sheffield 220 kV transmission corridor is required under the majority of future scenarios.
- We held an extensive program of community engagement events at locations near the proposed NWTD.
- We assembled a regional Youth Panel to put young people at the front and centre of framework design process.



04 Area planning constraints and developments

- We consider five geographic planning areas in Tasmania: North West, West Coast, Northern, Central, and South.
- We have transmission and sub-transmission load connection points with capacity to connect new load, requiring minimal or no augmentation at the connection point substation.
- We continue with targeted reliability improvement projects for specific communities.
- We retain exemptions from jurisdictional planning requirements for three parts of the transmission network in the North West and West Coast planning areas.
- We welcome feedback on prospective alternative solutions to our augmentation and asset retirement and replacement plans.

05 Network security performance

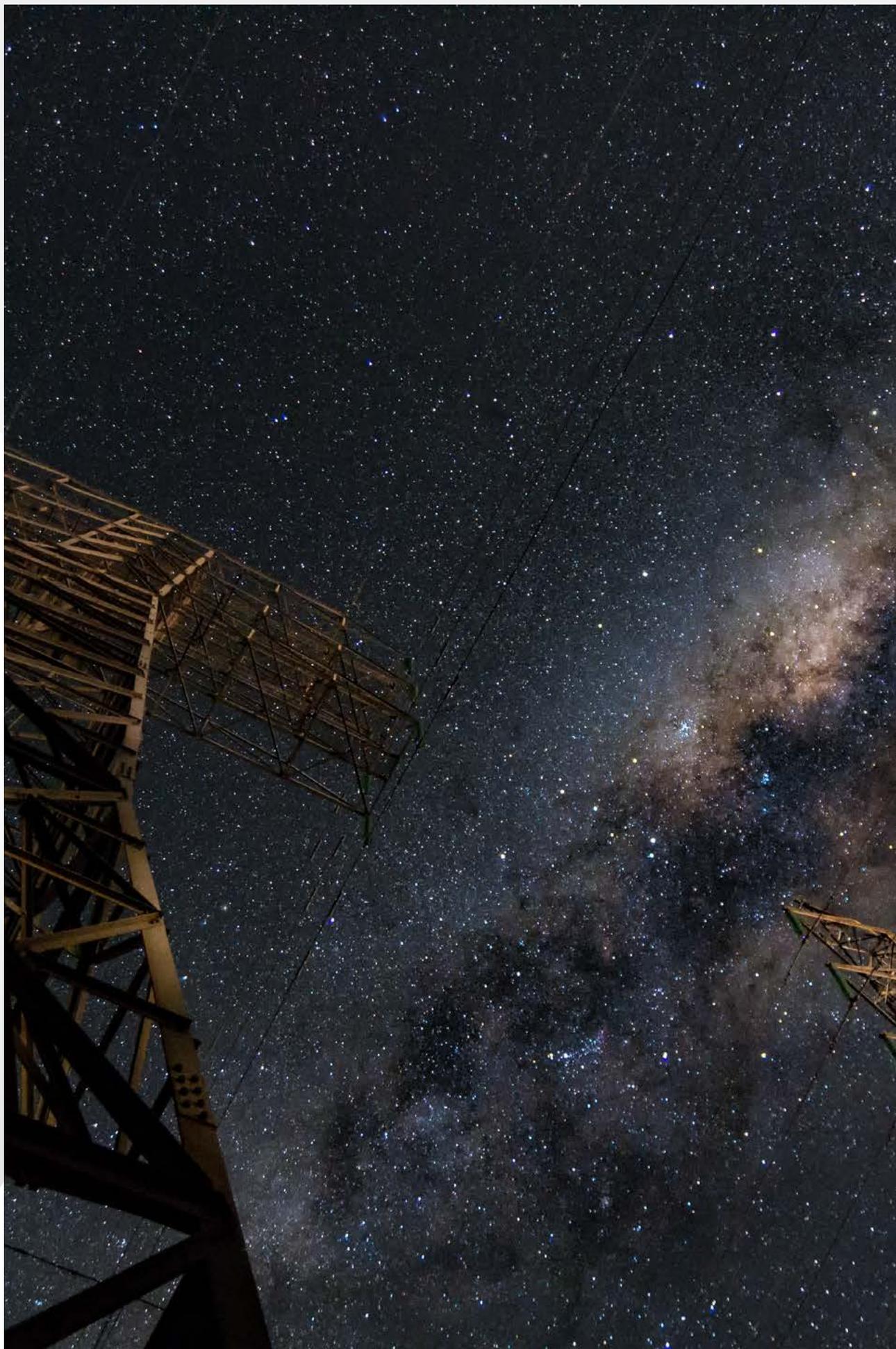
- Due to limited load growth over the last 12 months, Tasmania continues to be in a situation where it is theoretically possible to supply all Tasmanian demand from inverter-based resources, i.e., wind farms and Basslink import.
- Modelling associated with AEMO's 2022 ISP has forecast ongoing shortfalls for both system strength and inertia network services in the Tasmanian region.
- We are working towards addressing future shortfalls by evaluating Expressions of Interest submitted from potential service providers who are capable of

providing Inertia and System Strength Services from April 2024 onward.

- New Rules for the management of system strength commence in December 2025. The new framework will require novel approaches for the procurement and dispatch of system strength, including the allocation of costs to generators and loads who rely on grid-following inverters to interface with the network.

06 Service delivery performance

- Transmission network performance for 2021 was within service target performance incentive scheme targets across all parameters.
- Distribution network performance did not meet our Code reliability standards or service target performance incentive scheme targets over the past year.
- In the aftermath of a severe storm event, we collaborated with key stakeholders; in particular, farmers to ensure priority was given to animal welfare.
- There is a downward trend in distribution customer feedback received for under and over voltage issues.
- There are over 45,000 rooftop PV installations in Tasmania, with an installed capacity is 226 MW. This represents a 22 per cent increase during 2021.



01 Tasmanian renewable energy transformation

- The Renewable Energy Coordination Framework has been finalised to support the Tasmanian Renewable Energy Action Plan.
- The Tasmanian Government is building international connections to realise Tasmania's green hydrogen export goals.
- We continue with our Towards 2030 strategy to ensure success as the national renewable energy transition continues.
- Our Future Distribution System Vision and Roadmap is establishing a foundational plan for Tasmania's distribution network.
- Marinus Link and North West Transmission Developments (NWTD) are identified as urgent in the Australian Energy Market Operators' (AEMO)'s 2022 Integrated System Plan (ISP) based on current forecasts of generation retirements and renewable developments.
- We have progressed towards the Marinus Link Tender Readiness decision gate and the NWTD procurement strategy.

Tasmanian renewable energy transformation

1.1. Introduction

As the Tasmanian jurisdictional Transmission and Distribution Network Service Provider, we present the Tasmanian Networks Pty Ltd (**TasNetworks**) Annual Planning Report (**APR**). We have prepared the APR in accordance with the National Electricity Rules (**the Rules**) and jurisdictional requirements.

Tasmania continues to be 100% energy self-sufficient using renewable energy sources. Tasmania's challenge under the legislated Tasmanian Renewable Energy Target (**TRET**)³ is to deliver by 2040, 200 per cent of our 2020 baseline of 10,500 GWh of renewable generation per year, with an interim target of 15,750 GWh by 31 December 2030.

Under its Tasmanian Renewable Energy Action Plan (**TREAP**)⁴, the Tasmanian Government established Renewables, Climate and Future Industries Tasmania (**ReCFIT**)⁵ and finalised its Renewable Energy Coordination Framework⁶.

Although our large industrial and business customers operate in a challenging environment, Tasmania's economic recovery efforts and diversification (such as establishing a green hydrogen economy) paint a positive picture driving increasing demand for a range of services. Demand for connections to our distribution network is strong, with new dwelling starts currently more than 23.5 per cent above the decade average.

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

4 https://recfit.tas.gov.au/___data/assets/pdf_file/0012/313041/Tasmanian_Renewable_Energy_Action_Plan_December_2020.pdf

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

6 https://recfit.tas.gov.au/___data/assets/pdf_file/0007/343618/Renewable_Energy_Coordination_Framework_May_2022_web.pdf



We continue to progress the North West Transmission Developments through the Design and Approvals phase as part of preparations to connect Marinus Link and assess the implications of development options for Tasmania's Renewable Energy Zones (REZs). Our plans are informed by the TREAP, development of new variable renewable energy (VRE) generation, and the Battery of the Nation (BOTN) hydro system expansion.

This chapter outlines Tasmania's role as a participant in the National Electricity Market (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 2021 APR.

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.

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

Tasmania is part of the 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', which also includes rooftop photovoltaics (PVs). The components of the Tasmanian power system are presented in Figure 1-1. The role of TasNetworks is shown in blue.

As a transporter of electricity, we charge for our services through a component of prices paid by electricity end-users who either purchase 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 the electricity to smaller industrial and commercial users, as well as irrigation and residential customers.

Our responsibilities include:

- keeping our people, customers and the community safe and protecting the environment;
- undertaking the role of Tasmanian jurisdictional planner 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;
- maintaining a public lighting system;
- recording and providing regulated meter data to retailers; and
- providing telecommunications to participants in the Tasmanian electricity supply industry.

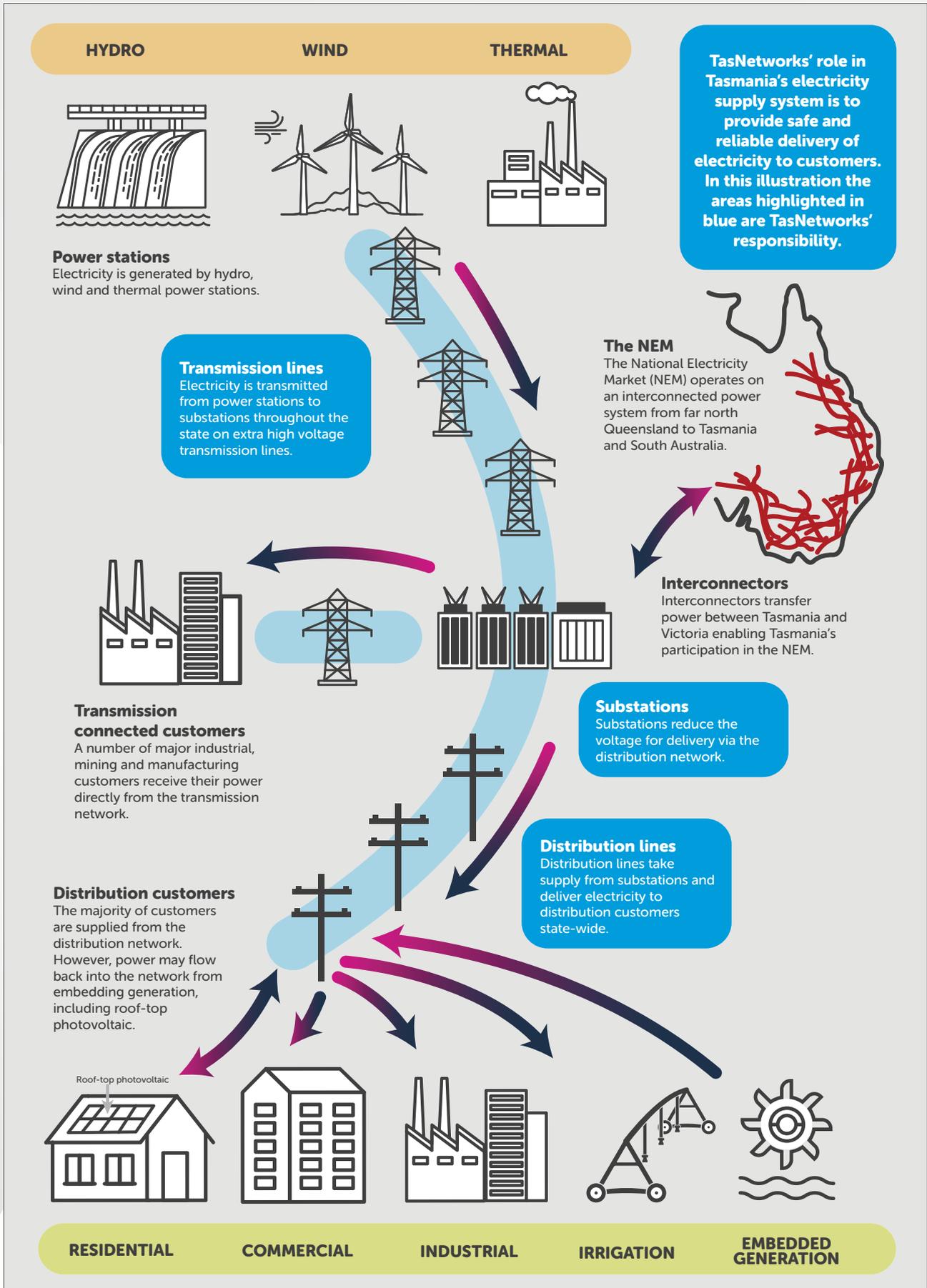


Figure 1-1: Tasmania's power system

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 Section 4.10.2.

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.

Our subsidiary 42-24 also 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 network both 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 is published by 31 October in accordance with clauses 5.12.2 and 5.13.2 of the Rules for transmission and distribution APRs on an annual basis.

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

- opportunities to address 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 to 2032. Some aspects are based on shorter planning periods. In particular, our distribution line loads are based on a 2- year planning horizon.

1.4. Strategic planning environment

Our planning activities are undertaken within the Rules framework and informed by the Tasmanian

Government's TREAP and the ISP⁷.

The TREAP continues the strategy of utilising renewable energy as a key economic driver that benefits all Tasmanians through job creation, investment, and economic development.

As articulated in the TREAP, it:

"details the Government's vision for our renewable energy future. It sets clear targets and actions designed to build on Tasmania's natural competitive advantages and attract large scale investment to significantly grow and expand Tasmania's renewable energy sector into the future."

Under its TREAP, the Tasmanian Government established ReCFIT and finalised its Renewable Energy Coordination Framework. Additional to its statutory obligations and responsibilities as Director of Energy Planning under the *Energy Co-ordination and Planning Act 1995* and the Jurisdictional System Security Coordinator, ReCFIT advises the Government on the State's strategic direction on climate change, renewable energy growth and emissions reduction.

The following key objectives 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 Tasmania Renewable Hydrogen Action Plan⁸;
- supporting AEMO's 2022 ISP;
- supporting BOTN initiatives; and
- advancing Marinus Link, which includes delivering the North West Transmission Developments.

In our appointed role as Tasmanian REZ Planner, we are supporting ReCFIT as it works to identify Tasmania's preferred REZ for initial development. In particular, we are 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.

The ability of each REZ to accommodate new renewable generation will evolve as the development of Marinus Link and transmission infrastructure developments proceed.

⁷ <https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp>

⁸ [Tasmanian_Renewable_Hydrogen_Action_Plan_web_27_March_2020.pdf](https://www.recf.it.tas.gov.au/Tasmanian_Renewable_Hydrogen_Action_Plan_web_27_March_2020.pdf) (recfit.tas.gov.au)

1.4.1. Network transformation forecast expenditure profile

While Tasmania will continue to play a prominent role in supporting transformation of the NEM, TasNetworks remains committed to a conscientious and prudent approach in our appraisal of all investments to our network.

In doing so, we recognise that significant investment will be required in the future in order to upgrade the network to meet the future needs. Figure 1-2 provides an indication of the expected scale of regulated investment associated with future augmentation developments, should they eventuate.

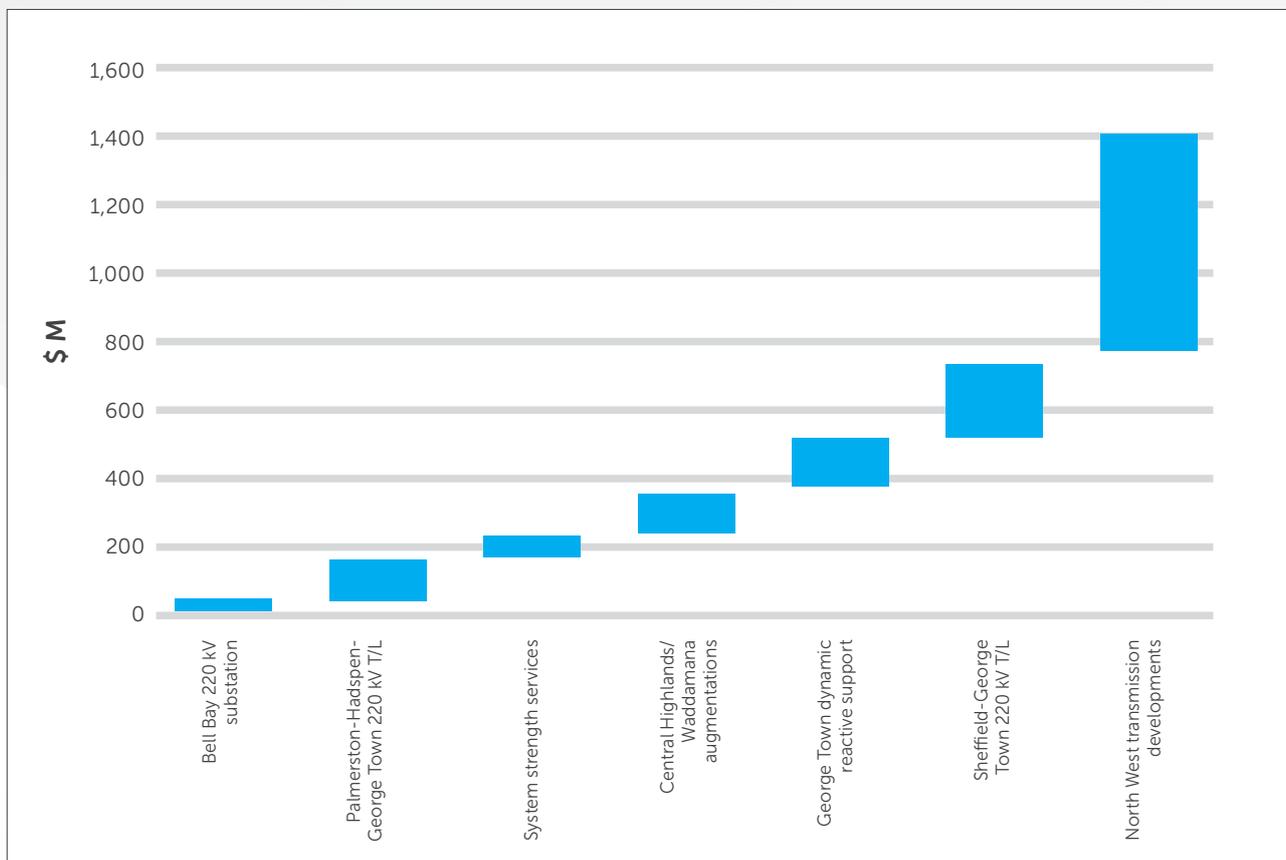


Figure 1-2: Forecast expenditure Profile: Regulated works

1.4.2. Tasmanian Renewable Energy Target

The Tasmanian Renewable Energy Coordination Framework (**RECF**) focuses on how to deliver orderly, sustainable, and integrated large-scale renewable energy projects needed to unlock generation capacity to achieve the TRET. The Framework details four pillars to guide energy growth:

Integrated Infrastructure – to deliver the least cost and optimally located generation and transmission to meet load where it is needed.

Environment – to protect and enhance our State’s environmental values – biodiversity, cultural and aboriginal heritage.

Economic – to stimulate job creation and business growth through renewable energy investment to build a skilled workforce for generations.

Community – to engage communities to ensure benefits are tangible and valued and make positive contributions to shaping their future.

Tasmania has the key advantage of significant renewable hydropower capacity for firming intermittent renewable energy sources. The TRET is a legislated target to increase Tasmania’s renewable energy generation to a total of 21,000 GWh per year by 2040. To achieve this target using Tasmania’s world leading wind resources, will require 2,500 – 3,000 MW of new installed wind capacity, depending on assumed capacity factor. This wind requirement would change if other renewable energy sources (solar, ocean, biomass, geothermal) are developed.

The integration of such large quantities of variable renewable generation into the Tasmanian electricity system will involve significant additional transmission infrastructure requiring careful planning to meet the above four pillars.

Also relevant to the TRET, is to reduce Tasmania’s transport emissions and costs, and improve the State’s energy security by supporting the uptake of electric vehicles (**EVs**) powered by locally-produced renewable energy.

1.4.3. Renewable Hydrogen and large scale load connections

As outlined in its TREP, the Tasmanian Government has a vision to produce large-scale green hydrogen for domestic use and export. The Tasmanian Renewable Hydrogen Action Plan identifies that Tasmania has a number of industrial precincts with available land and access to high quality infrastructure, including access to electricity transmission, roads, rail, and ports.

We continue to see strong interest from green hydrogen proponents, both in production and consumption, with proposals ranging from large scale consumers and small domestic use end cases, to export scale developments. Small scale proposals are being received for connection within the distribution network, while export scale developments are centred around Tasmania's proposed hydrogen hub within the Bell Bay Advanced Manufacturing Zone (**BBAMZ**), and the future north-west network.

The BBAMZ is an ideal site for large-scale export renewable hydrogen production and for domestic applications. Proposals of up to 1,500 MW of hydrogen production facilities may be developed in the BBAMZ in the medium to longer term. Tasmania's north-west coastal region is also well suited to large-scale renewable hydrogen production. Both these regions have access to the existing transmission network and abundant renewable energy resources (particularly wind and hydropower), notwithstanding that network augmentations will be necessary to support significant hydrogen developments going forward.

A critical part of realising Tasmania's green hydrogen export goals is to build international connections which create export market links but also allow Tasmanian businesses and government agencies to learn and collaborate on joint projects. Progressing this, the Tasmanian Government has signed Memorandum of Understanding (**MOU**) with both the Port of Rotterdam and the region of Flanders in Northern Belgium. The partnerships will support the development of a hydrogen industry in Tasmania. The aim is to facilitate project cooperation across the hydrogen value chain and support the development of hydrogen pilot projects and demonstrations.

The Tasmanian Government has concluded the first round of the Tasmanian Renewable Hydrogen Industry Development Funding Program⁹. That round supported three project feasibility studies, with two projects located in the BBAMZ and one at Port Latta:

- estimated load exceeding 500 MW producing annually 420,000 tonnes of ammonia;
- nominal 100 MW load to produce hydrogen and methanol; and
- 90 – 100 MW load producing hydrogen.

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

We have also seen proponent interest seeking to establish carbon neutral fuel production, which represents potential future growth within both the domestic hydrogen market and for energy consumption within Tasmania.

There has been continued interest from data centre proponents, looking to establish new connections at various locations across the state. In the past 24 months, potential interest has totalled more than 300 MW, with the size of connections ranging between 5 MW to greater than 100 MW.

1.4.4. Integrated System Plan

The ISP published on 30 June 2022 by AEMO is a whole-of-system plan that provides a roadmap over the next 20 years. Its primary objective is to:

"maximise value to end consumers by designing the lowest cost, secure and reliable energy system capable of meeting any emissions trajectory determined by policy makers at an acceptable level of risk."

The ISP identifies REZs and Offshore Wind Zones (**OWZ**) across the NEM, three REZs and one OWZ being in Tasmania. It forecasts changes in the current generation mix and then develops a strategic plan to support development of the energy system to deliver electricity from the forecast future mix of generation. Consumer behaviour is forecast to change seeing consumption patterns evolve over time.

With Marinus Link built, the ISP forecasts 2.5 GW of new wind in Tasmania over next decade. Of that, approximately 1.5 GW is projected to be installed in the Central Highlands REZ, and 1 GW in the North West Tasmania REZ. No further VRE capacity is forecast and currently there is no offshore wind projected in any scenario.

As the penetration of utility-scale wind and solar and Distributed Energy Resources (**DER**) increases, so does the complexity of managing the operation of the grid and the need for complementary dispatchable resources. The ISP highlights that with greater sharing of resources across the NEM via transmission, it may be possible to avoid Unserved Energy (**USE**) when there is minimal or no sunshine and wind for extended periods – the so called "*Dunkelflaute events*¹⁰".

Substantially expanded community engagement programs are needed to explore the social licence for both generation and transmission investments. AEMO proposes preparatory activities that can be triggered for future ISP projects covering:

- Preliminary engineering design;
- Desktop easement assessment;
- Cost estimates based on preliminary engineering design and route selection;

10 "*Dunkelflaute*" is a term used in the renewable energy sector to describe a period of time in which little to no energy can be generated from wind or solar generating systems.

- Preliminary assessment of environmental and planning approvals; and
- Appropriate stakeholder engagement.

REZ Design Reports are required as part of a new framework that go beyond the scope of preparatory activities exploring the technical, economic, and social barriers to unlocking REZs. This requires a significant undertaking for TasNetworks, involving:

- Engineering designs, cost estimates and easement investigations that considers developer and community interest;
- Augmentation plans that can be delivered to meet capacity targets in the ISP;
- Identification of barriers to community acceptance and estimates of costs associated with overcoming them; and
- A draft report and a six-week consultation.

1.4.5. Marinus Link

Under the Bilateral Energy and Emissions Reduction Agreement with the Australian Government, Marinus Link Pty Ltd (**MLPL**), on behalf of the State of Tasmania and the Australian Government, continues to progress investigation into Marinus Link, a new interconnector between Victoria and Tasmania. MLPL is a subsidiary of TasNetworks and is responsible for progressing Marinus Link.

Marinus Link is proposed to consist of two 750 MW staged electricity interconnections that will increase transmission capacity between Tasmania and the mainland. Marinus Link involves approximately 255 kilometres of undersea HVDC cable, approximately 90 kilometres of underground HVDC cable and converter stations in Tasmania and Victoria.

The ISP re-confirmed that Marinus Link is a critical part of Australia's clean energy future and needs to progress as urgently as possible. The ISP outlines the optimal development path of essential transmission investments in Australia, forecast to deliver \$28 billion in net market benefits and efficiently enable low-cost, firmed renewable energy to replace retiring coal generation. For Marinus Link, the ISP highlights Tasmania's opportunity to develop its clean energy resources for the benefit of all Australians, playing a critical role in supporting the transition to cleaner energy at lowest cost.

According to AEMO, Marinus Link and the North West Transmission Developments are a single actionable ISP project without decision rules and is expected to deliver positive net market benefits of \$4.5 billion to the NEM under the most likely 'Step Change' scenario. Marinus Link will enable improved access to Tasmania's dispatchable capacity and high-quality wind resources, reducing the need for less efficient investments on mainland Australia. Without Marinus Link, more mainland capacity would be required for the equivalent

volume of energy that Tasmania can provide. The sooner Marinus Link is delivered, the greater the value to the NEM; therefore, AEMO finds that Marinus Link is required urgently.

In June 2022, MLPL completed the pre-qualification of suppliers for the HVDC cables and converters and announced the selection of seven reputable and proven international HVDC businesses to tender for the manufacture, construction and commissioning of Marinus Link; more information is available on the Marinus Link website¹¹.

The 220 kV transmission network that carries electricity from hydro and wind projects in the north-west of Tasmania requires a significant increase in capacity to support new developments and to accommodate increased power flows to and from Marinus Link. TasNetworks continues to be responsible for the delivery of the proposed North West Transmission Developments, which aim to provide this increased capacity.

We present more information on the progress of Marinus Link and NWTD in Section 1.9.2 and Section 3.3 and on our website¹².

1.5. Our customers

Our customers place varying demands on the network. A summary of these and our services to customers includes:

- more than half of the energy delivered in the State is to a small number of large industrial and commercial customers which are connected directly to our transmission network;
- the balance of consumers in the State are connected via 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; and
- we provide network access to hydro, wind and solar energy generation sources, a large capacity natural gas fired power station and to the Basslink interconnector.

Our customers are sensitive to increases in electricity prices. Accordingly, along with our customer strategic vision that '*we care for our customers and make their experience easier*', we aim to improve safety, price, and service outcomes while maintaining reliability levels. We are exploring new ways through our Policy and

11 <https://www.marinuslink.com.au/2022/06/marinus-link-project-update/>

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

Regulatory Working Group¹³ to involve our customers in pricing considerations, and in our move towards more cost-reflective pricing.

We are improving our systems to increase customers' ease of doing business with us and optimise value and service for all our customers. We constantly look for ways to improve the way customers can engage with us, the ways in which we communicate with customers and improve the customer experience through more effective processes, access to data, and other tools.

1.5.1. Industry Engagement Strategy and Industry Engagement Register

Assets on our network are subject to constraints and limitations due to a range of factors, including asset condition and peak demand. Network solutions, like augmentation, are traditionally considered to mitigate these issues. However, we also pursue alternatives to address asset management and peak demand issues, such as demand management and Stand Alone Power Systems (SAPS).

When the capacity of our network approaches its limit due to high electricity use, TasNetworks can either increase network capacity or take steps to reduce present and forecast peak demand. Reducing peak demand is called demand management. Typically, this can be achieved by:

- shifting some of the peak appliances or loads from peak time to an off-peak time;
- shedding non-critical loads;
- changing loads from electricity to another fuel source (like gas);
- reducing the electricity used by appliances for short periods (such as hot water load control);
- operating generators within a customer's electrical installation; and
- installing battery storage and using some of the battery capacity to address peak demand issues (like customer-owned batteries).

1.5.1.1. Stand Alone Power Systems

Our network serves a broad range of customers over a diverse geographic region. In order to serve some remote customers, long lines traversing difficult terrain may be required, and must be maintained to the same standard as all other lines in our network. In some cases the ongoing cost required to keep these lines operational may be higher than the cost involved in constructing an off-grid system. In such circumstances, off-grid systems may be considered.

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 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.

1.6. TasNetworks Towards 2030

By 2030, Australia's renewable energy transition will be in full swing. Some of the large coal-fired electricity generation plants such as Liddell (New South Wales), Eraring (New South Wales) and Yallourn (Victoria) are projected to close and others may retire ahead of their presently forecast closure dates. Households and businesses will continue to invest in PVs and batteries as these devices become increasingly attractive and affordable to generate and store electricity.

We are already preparing for these changes and are engaged in a number of innovative projects of State and national significance, including the progress of Marinus Link to a final investment decision. The Battery of the Nation, Marinus Link and North West Transmission Developments will support Australia's transition to a low emissions future by delivering the low cost, reliable and clean energy that our customers expect.

The regulatory environment is very dynamic. Climate change risks, including bushfires and floods, and changes in the economic and political environment all affect us. We have carefully considered the changes in our operating environment and have identified five key longer-term trends – which are clean energy, technology, industry, society, and demographics – that will change the way we operate our business over the next decade.

Our ten year strategy Towards 2030, articulates the Focus Areas, that will help us achieve our vision to be *"trusted by our customers to deliver today and create a better tomorrow"*.

¹³ <https://tasnetworks.com.au/poles-and-wires/pricing/modernising-pricing>

Success in 2030 looks like:

- **Sustainable prices** for our customers
- **Renowned** for delivering solutions of value
- **Reliably integrated** wind farms, pumped hydro, solar PV and batteries
- **Marinus Link** benefiting Australians
- **Enabling** Tasmanians and Tasmanian business to use our network to their advantage

To ensure success, **we will focus on:**



Figure 1-3: 2030 focus areas

We remain focused on improving our core regulated services as we explore potential and grow new services. While the complexity of our system grows, we will continue to harness our expertise in connecting, transferring and balancing energy so customers can trust us to keep the system safe, stable and affordable. By doing these things, we will make sure we can continue to deliver energy – whether customers are using it or selling it.

In line with shifting social attitudes, we continue to place societal responsibility at the forefront of our planning and strategy - that includes planning for climate change and mitigation plans that ensure our assets remain resilient to changes in the climate. We will continue to listen to and be influenced by our customers, ensuring lowest sustainable prices and maximising the capability of the network to host new generation resources.

1.7. Future Distribution System Vision and Roadmap

Our Future Distribution System Vision and Roadmap establishes a foundational plan for Tasmania's distribution network in response to the evolving needs of our customers, emerging community expectations and efficiencies from accelerating technological advances. A major focus is facilitating customer adoption of DER, which include rooftop solar PV, battery storage and EVs. We have commenced stakeholder consultation and look forward to refining and co-designing each component.

As a central feature in the roadmap, we intend to establish a new business role to provide novel ways for customer DER to participate within the distribution network. Developing Distribution System Operator (**DSO**) capabilities will allow us to maximise the utility customer DER can provide to TasNetworks and our customers. Key capabilities highlighted in the Future Distribution System Roadmap are listed below, with a full list provided in Appendix A:

- strong pipeline of tests and pilots by 2024;
- proven DER approaches that promote DER uptake and satisfaction by 2025; and
- trusted provider of appropriate DER network products and services by 2027

Our vision for the distribution system is to bring agility to our distribution system for the advantage of all our customers. The roadmap plans to lead Tasmania's electrical distribution system journey as a trusted expert brand offering timely well-designed new network services that enable customers on their terms. Our principles are to share DER value equitably, use DER to improve electricity affordability, optimise access for DER connections and support DER's contribution to the TRET. The following roadmap milestones are split across four pillars of:

Customers

The grid is becoming more visible and interactive for our customers. We must prioritise creating customer centric solutions that are responsive to market shifts,

customer feedback and observed behaviours based on quality data and analysis. Closer relationships with large distribution customers are important, as is further engagement with other customer groups. Working with external providers will help us identify and develop the new markets that benefit our customers.

People

The energy transition requires all staff to fully understand the choices they make within their role. This means insight, broader skills, teamwork and collaboration so effort can be diverted into tasks that deliver the most long-term value. The entire new energy spectrum is able to be understood by combining and building the deep domain knowledge of our teams. Much of this will be done through coordinated tests and pilots of all scales that are designed to grow valuable knowledge, skills and business cases for further work.

Business

Growing utilisation and importance of the distribution system requires complex interrelated systems that ingest a new scale of data to automatically optimise work and manage the grid in real time. This is a worldwide trend that we have to implement, not solve. Interoperability is a key purpose, allowing new digital capabilities to be layered where and when it makes most sense.

Tasmanian community

The evolution of the distribution system and DER is part of wider transitions that have potential to create massive change. We will champion prudent investment that prepares for future needs, equitable customer participation, resilience and regulatory obligations. This must be designed to fit the wider context, shaped through healthy stakeholder discussion and taking the lead in areas of comparative expertise. EVs may change the distribution system, for example, but also the mobility of our society and the success of many large industries. This discussion requires clear communication through multiple channels. The proposed roadmap is outlined in Appendix A.8

1.7.1. Intelligent asset management

Intelligent asset management is a suite of initiatives and projects that provide the capability for data-driven decision in our organisation. This consists of two key initiatives:

Asset management improvement program

We are constantly refining and improving our data-driven decision process for managing network assets to appropriately consider risk and deliver value to TasNetworks and the Tasmanian community.

Data and analytics

Utilising existing data connections, and new data connections such as advanced meter data and smart sensors (Internet of Things), we continue to optimise network performance and move from reactive to proactive asset management.

1.7.2. Advanced distribution management system

An advanced distribution management system (**ADMS**) will enhance our capability to operate, control and monitor the distribution network. We have implemented automated fault restoration schemes at selected locations to return supply to our customers rapidly following a high voltage fault. The automated fault restoration function will in near-real-time locate a fault, display it to the network controller and then, where appropriate, automatically switch the network to isolate the faulty section and restore customer supply. The ADMS will be the engine room of our smart grid, becoming the central hub for real-time automated decision making.

1.7.3. Derwent Bridge microgrid

Our distribution network is rapidly evolving, and this is providing new opportunities for utilities like TasNetworks to investigate the feasibility of microgrid solutions that benefit local customers, lower network costs and prove concepts for the wider grid.

The Derwent Bridge Microgrid Feasibility Project is being run by TasNetworks in conjunction with the University of Technology Sydney, Redback Technologies and the Australian Power Institute, and is being funded by a \$1.6 million dollar grant from the Australian Government. The project aims to develop an innovative microgrid design solution that will improve the reliability of the power supply for residents in Derwent Bridge and can be transferred to other rural and remote communities across Australia that have a similar climate.

The project is currently helping us to better understand:

- microgrid design, especially in areas with severe weather and limited solar resources;
- the key customer needs and how best to engage with stakeholders; and
- new and upcoming DER technologies.

With several key findings have been gathered through customer engagement activities and a microgrid literature review. Customers have asked for increased reliability at no extra cost. The literature has highlighted uncertainties in key microgrid design areas such as regulation, technology and commercial agreements that will be addressed in the study. Over the coming months the project team will be continuing to engage with key stakeholders to further understand their needs, and build upon literature to ensure robust design and techno-economic analysis.

1.7.4. Electric vehicles

Australia is increasing its uptake of EVs as part of a broader move towards decarbonisation and electrification. Roughly a quarter of light vehicles globally by 2030 will be EVs, with significant implications for electrical utilities such as TasNetworks.

Our EV Strategy will play a critical role in this transition by preparing our energy networks for changing behaviours in the community. We are working towards better understanding our customers' expectations and evolving needs to determine the best way to integrate EVs and other emerging technologies into our network. This includes hydrogen vehicle possibilities in line with the Tasmanian Government's hydrogen ambitions. Our vision is to be an enabler of EV uptake with a whole of system approach. We want our customers to easily connect to our network, and at an affordable price. Some of the areas we are taking action to deliver this are:

- increasing the availability and accuracy of our EV data to inform our near-future forecasting, monitoring and planning efforts;
- actively informing investment and industry policy based on the needs of our customers; and
- maximising the efficiency of our existing infrastructure by investigating the use of smart solutions.

We are currently running an EV Grid trial, in line with our EV Strategy to help further our EV knowledge. The Australian Renewable Energy Agency (**ARENA**) partly funded the EV Grid trial project in collaboration with four other Distribution Network Service Providers (**DNSPs**) from Victoria and the Australian Capital Territory. The trial recruited 176 residential customers nationally to demonstrate the capability of smart charging technology. Using real-time network capacity information, we can better prepare to manage the potential impacts of high EV uptake on our network. The EV Grid trial is helping us to understand:

- technology and customer behaviour in managing EV charging of residential customers in real-time;
- available spare capacity in the low voltage network; and
- how to appropriately integrate EVs without excessive network augmentation.

The trial started recruiting participants in the first half of 2021 followed by the installation of hardware and development of software platforms which were the first two phases on the project. Currently, the trial is progressing well and is in phase three where the project team is running demand response and 'solar soak' events to understand consumer behaviour and gain insights. The final phase of the project, phase four, will include the analysis and reporting of the data gathered through this trial which will be shared with the industry. The trial will end in February 2023.

More information on our EV Grid trial is available on the ARENA website: <https://arena.gov.au/projects/jemena-dynamic-electric-vehicle-charging-trial/>

1.7.5. Embedded generation

There has been a continued increase in the number of generators connecting to the distribution network, including dedicated generators, as well as customers generating electricity on their own premises. These forms of DER are called embedded generation. Larger embedded generators tend to use rotating machines, whereas low power generators are dominated by inverter connected rooftop solar PV and, over time, other inverter connected energy sources like batteries and 'vehicle-to-grid' EVs. These quickly growing levels of embedded generation mean that the traditional passive approach to low voltage (**LV**) management will soon cease being fit for purpose.

The widespread connection of small-scale generation and storage means that understanding and managing the technical aspects of the network (such as power flows and voltage regulation) becomes more challenging. We are conducting LV hosting capacity analysis to determine the maximum headroom available on the electricity network, and options to accommodate the connection of forecast DER. This includes obtaining accurate network information and developing assessment approaches. We will continue to work with all industry stakeholders to maximise embedded generation uptake and improve the overall connection process while continuing to ensure system security is maintained.

1.8. Project consultations

We undertake regulatory investment tests (**RIT**) for both transmission (**RIT-T**) and distribution (**RIT-D**) network investments that exceed the cost threshold of \$7 million and \$6 million respectively. Projects required to address an urgent and unforeseen network issue and would otherwise be subject to a RIT-T 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 provisions of the Rules. We welcome feedback and enquiries on this APR including any listed project, not only those projects subject to a RIT.

We did not complete any RITs in the past year and we are not currently initiating any RITs for projects presented in this APR.

1.9. What has changed since 2021

1.9.1. Integrated System Plan

Substantially expanded community engagement programs are needed to explore the social licence for both proposed generation and transmission investments. AEMO proposes the need for Preparatory Activities and REZ Design Reports as part of the new framework.

The ISP highlights that with greater sharing of resources across the NEM via increased transmission access it may be possible to avoid USE when there is minimal or no sunshine and wind for extended periods.

1.9.2. Marinus Link

This year, MLPL was established as a fully operational subsidiary of TasNetworks and is the responsible entity for progressing the Marinus Link HVDC interconnector and connecting converter stations.

The Marinus Link project continues to progress through the Design and Approvals phase under MLPL, working towards a Final Investment Decision (**FID**), targeted for 2024. As outlined in section 1.4.5, the 2022 ISP classified Marinus Link as an actionable ISP project without decision rules. The Commonwealth-Tasmania Bilateral agreement on Energy and Emissions Reduction also provided funding to progress the project to a FID.

As part of the Marinus Link development program, TasNetworks continues to progress the North West Transmission Developments through landowner, community and other stakeholder consultation activities as well as field surveys to support the planning, heritage and environmental approvals processes and final technical design¹⁴.

1.9.3. Renewable Energy Zones

Since its formation, TasNetworks has continued to work closely with ReCFIT to provide support and guidance towards future transformation of the network which supports significant renewable energy developments.

The Tasmanian Government, through ReCFIT, is soon to announce Tasmania's first priority REZ. The announcement is currently expected to be made by December 2022. Announcing Tasmania's first priority REZ is an action under the Renewable Energy Coordination Framework (**RECF**)¹⁵, to support a coordinated approach to the development of new VRE in Tasmania to meet the TRET.

¹⁴ <https://talkwith.tasnetworks.com.au/north-west-transmission-developments-2>

¹⁵ https://recfit.tas.gov.au/renewables/tasmanian_renewable_energy_action_plan

1.9.4. Load forecasts

TasNetworks uses AEMO's State regional forecasts as the basis for developing our load forecasts. The 2022 forecast for the State (existing customer base) scenario shows moderate increases in both energy consumption and maximum demand over the planning period, particularly for distribution customers. This growth is driven by increases in residential consumption and EV uptake. Further, some connection points show growth—driven by new point load connections.

This APR includes scenarios for forecast use of the network to also support future interconnector flows (through Basslink and Marinus Link) and to supply large-scale renewable hydrogen. These developments will transform network demand and power system operation. With Marinus Link and large-scale hydrogen developed, the required energy transfers across the network will double over the next 20 years, with network maximum demand forecast to increase by more than double its existing size.

TasNetworks takes into consideration the AEMO state level forecast when producing its connection point and feeder level forecasts. As AEMO no longer publish connection point forecasts for Tasmania, TasNetworks has made changes to the demand forecast production cycle. As a consequence, the demand forecast impacts seen at a state level will be considered and analysed at a local level throughout the upcoming planning cycle.

1.9.5. System strength and inertia

In May 2021, AEMO declared an inertia and system strength shortfall in Tasmania. We adequately addressed this shortfall notice by using non-network solutions, more specifically, establishing a services agreement with a registered generator to provide sufficient synchronous machine capabilities that enable AEMO to manage power system security on an ongoing basis.

As noted in the most recent AEMO System Security Report¹⁶, the current agreement is due to expire in April 2024 which will result in shortfalls re-emerging. TasNetworks is already proactively working toward addressing this foreseeable gap. While AEMO has not yet published any additional requirements, TasNetworks believes it prudent to begin planning for increased shortfalls based on forecast wind generation developments modelled in the ISP.

1.9.6. Planned investments and forecast limitations

Material differences in planned investments and forecast limitations from those reported in our 2021 APR are summarised in Table 1-1. The table also provides reference to the relevant sections of this APR where we present the actual investment or forecast limitation.

¹⁶ AEMO; "2021 System Security Reports – System strength, inertia and NSCAS reports for the National Electricity Market", Version 1.0, 17 December 2021.

Table 1-1: Differences in planned investments and forecast limitations reported in 2021 APR

Location	Summary of change	APR Reference
Now completed		
Port Latta Substation	Supply reconfiguration from loop-in-and-out to double tee and weather stations for dynamic line rating.	Table 4-4
Rosebery Substation	Supply transformer (T5) replacement.	Table 4-15
Richmond Rural Zone Substation	Supply transformers including HV regulator and switchgear replacement.	Table 4-15
North Hobart Substation	11 kV switchgear including transformer and feeder protection schemes and Supervisory Control and Data Acquisition (SCADA) replacement.	Table 4-16
Palmerston Substation	220 kV switchgear replacement.	Table 4-16
Sheffield – Burnie 220 kV transmission line	Transmission line protection replacement.	Table 4-17
Lindisfarne Substation	Busbar protection replacement.	Table 4-17
Chapel Street Substation	Busbar protection replacement.	Table 4-17
Sheffield Substation	SCADA replacement.	Table 4-17
Now committed		
Emu Bay Substation	Installation of 22 kV/11 kV auto transformers for connection of 11 kV feeders to 22 kV switchboard.	Table 4-4
Port Latta Substation	North West Dynamic Reactive Support - installation of ± 8 MVar STATCOM.	Table 4-4
Zeehan reliability community	44 kV sub-transmission line switching augmentation and additional generational support to improve reliability.	Table 4-4
George Town Substation	Replace 220 kV bus coupler.	Table 4-9
Port Latta Substation	Replace supply transformers.	Table 4-15
Kermandie Substation	Replace supply transformers.	Table 4-15
Emu Bay Substation	11 kV switchgear replacement.	Table 4-16
Farrell Substation	220 kV switchgear replacement.	Table 4-16
Gordon Substation	220 kV switchgear replacement.	Table 4-16
Lindisfarne Substation	110 kV switchgear replacement.	Table 4-16
Ulverstone Substation	22 kV switchgear replacement.	Table 4-16
Hadspen Substation	220 kV and 110 kV busbar protection replacement.	Table 4-17
Hadspen Substation	T60 transformer relay replacements replacement.	Table 4-17
New development / limitation		
Farrell-Que-Savage River-Hampshire transmission line reliability	The combined loading on the 110 kV transmission line supplying customers at Que, Savage River, at times exceeds network planning requirements (25 MW, and 300 MWh of unserved energy following a single element outage).	Section 4.5.3.1
New asset replacement or retirement		
Claremont Zone Substation	33 kV sub-transmission cable replacement.	Table 4-14
New Town Zone Substation	33 kV sub-transmission cable replacement.	Table 4-14
Sandy Bay Zone Substation	33 kV sub-transmission cable replacement.	Table 4-14
Programme	Protection spares replenishments.	Table 4-17
Programme	SCADA replacements.	Table 4-17
Now deferred or averted		
St Marys Substation	As the substation continues to meet reliability planning criteria, and with limited load growth, we propose to continue the post-contingency load-shedding scheme.	Table 4-10

02 Tasmanian power system

- Tasmania has continued its trend of energy neutrality in 2021, with on island generation supplying 100% of the State's annual energy requirements.
- Our transmission –connected customers, dominated by four major industrial customers were responsible for contributing 31 per cent towards the total network maximum demand and consuming 50 per cent of the total energy delivered through the transmission network in 2021.
- The energy consumption and maximum demand of the existing customer base is forecast to materially increase over the forecast period, with increases coming from residential demand and Electric Vehicle (EV) uptake.
- The development of Marinus Link and large-scale hydrogen will more than double the energy transmitted through the network, with network maximum demand forecast to increase 2.5 times over the next 20 years.

Tasmanian power system

2.1. Load and generation characteristics

2.1.1. Load characteristics

Our transmission network supplies 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. The median demand during 2021 was approximately 1,198 MW, and for 50% of the time was between 1,100 and 1,300 MW.

The maximum demand on the transmission network during 2021 to supply only Tasmanian customers was 1,744 MW. The total network maximum demand of 2,199 MW included power transfers across Basslink. Peak demand in Tasmania occurs during winter, driven primarily by increased heating load. Figure 2-1 presents the transmission network demand duration curves for supply to both Tasmanian customers (only) and total network demand inclusive of Basslink exports.



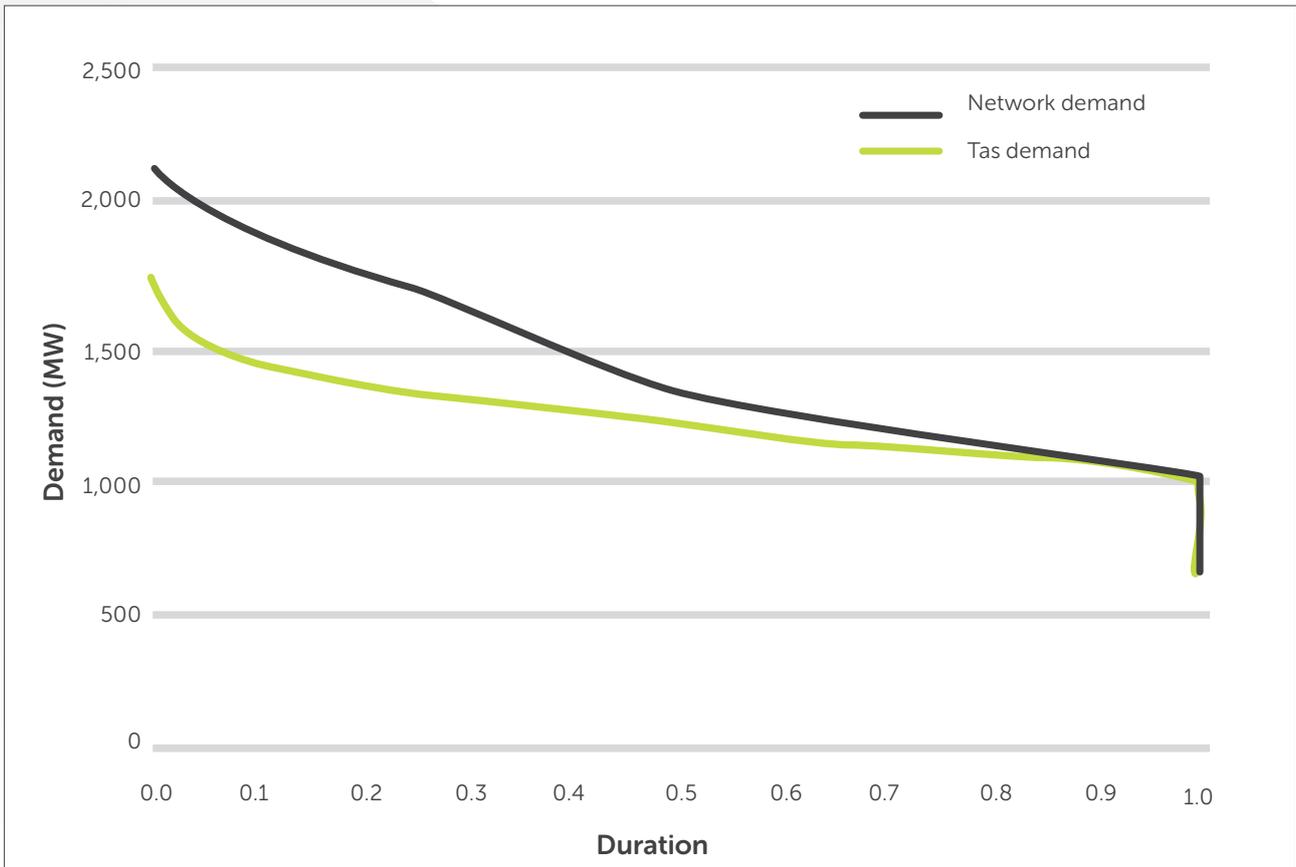


Figure 2-1: Transmission network demand duration curves 2021

A relatively high proportion of the energy flow through the Tasmanian network is used to supply 10 large customers directly connected to our transmission network. Collectively, transmission-connected customers—dominated by four major industrial energy users—used 50 per cent of the total energy flow delivered through the transmission network and contributed to 31 per cent of the total network maximum demand in 2021. This is 57 per cent and 40 per cent of the Tasmanian-customer energy and demand, respectively. The relative energy use in 2021 supplied from our transmission network is presented in Figure 2-2.

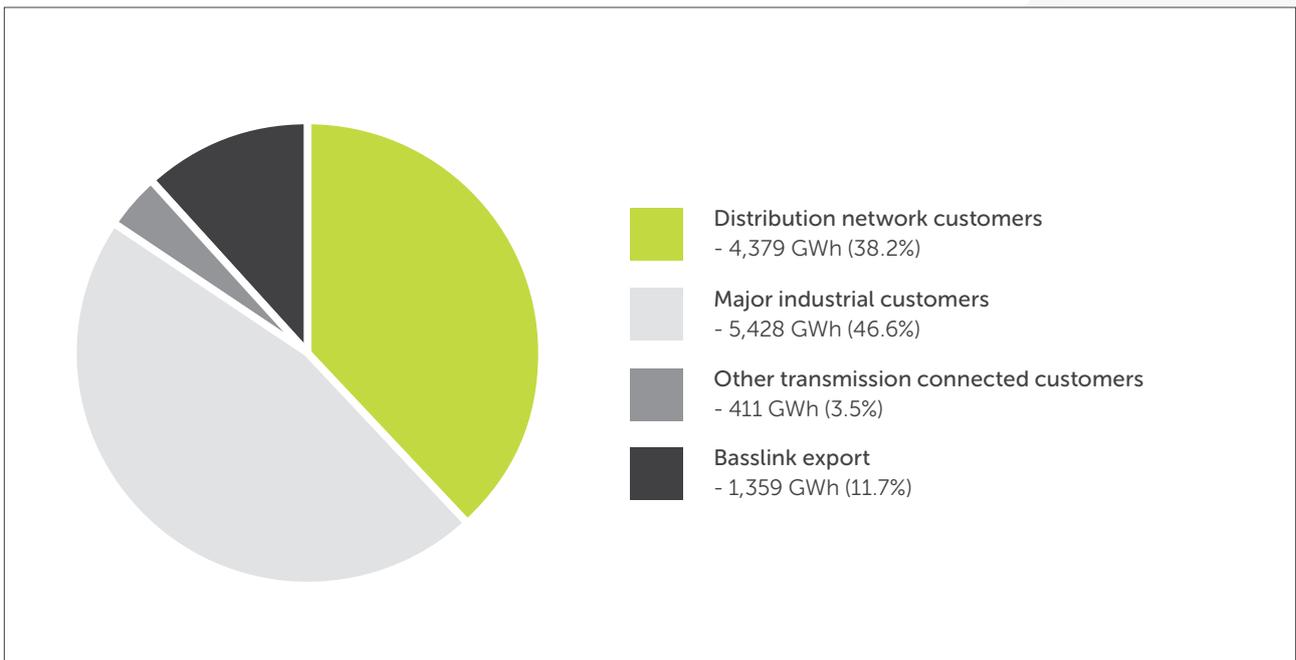


Figure 2-2: Relative transmission network use in 2021

2.1.2. Energy and maximum demand forecasts

2.1.2.1. Introduction

This section presents the Tasmanian energy and maximum demand forecast attributable to the existing customer base and scenarios under the Tasmanian Renewable Energy Action Plan for Marinus Link and large-scale renewable hydrogen. Forecasts present the demand on the transmission and distribution networks, as measured at the network entry points. For the transmission network that is generation connection points and Basslink imports. For the distribution network, it is the interface points 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 developments.

At a state level, we align with energy and maximum demand forecasts published by the Australian Energy Market Operator (**AEMO**) for the existing customer base, extrapolating the forecast out past 2030. Transmission-connected customers (excluding Basslink) account for a large portion of the demand within Tasmania, currently over 50 per cent of on-island energy consumption

within Tasmania (refer Section 2.1.1). Within the distribution network, maximum demand is temperature sensitive with increased heating load at times of lower ambient temperatures driving the distribution network and overall Tasmanian maximum demand. We plan our network for 50 per cent probability of exceedance (**POE**) maximum demand forecast. The temperature sensitivity is not as acute as seen in other NEM states which experience their maximum demand during times of extreme summer temperatures.

Substations, zone substations, feeder maximum demand forecasts and substations load profiles are available as downloadable appendices to this Annual Planning Report (**APR**) on our website:

www.tasnetworks.com.au/apr

2.1.2.2. Forecast scenarios

Annually, we develop Tasmanian transmission and distribution network energy consumption and maximum demand forecasts for each year of the planning period. To inform the likely impacts of new interconnection with Victoria, Renewable Energy Zone (**REZ**) build-outs and industrial scale hydrogen developments on the demand forecast of transmission network, a number of scenarios were developed. Table 2-1 presents an overview of the forecast scenarios.

Table 2-1: Forecast scenarios

Scenario	Forecast	Description
State (existing customer base) Distribution network	Central scenario (extrapolated past 2030) in AEMO's updated 2022 Electricity Statement Of Opportunities ¹⁷ .	Forecast demand on the transmission and distribution networks to supply the existing customer base within Tasmania, represented at a total state level.
State and interconnectors	Marinus Link Stage 1 in 2029–30, Stage 2 in 2031–32.	Forecast demand on the transmission network to supply existing customer base within Tasmania, and facilitate interconnector flow across Basslink and Marinus Link. Derived from the 2022 Integrated System Plan (ISP) Step change scenario.
State, interconnectors, and large-scale hydrogen	Marinus Link Stage 1 in 2029–30, Stage 2 in 2031–32. Hydrogen 300 MW by 2026–27, 1000 MW by 2030–31, and more than 2,000 MW in 2040–41.	Forecast demand on the transmission network to supply all of existing customer base within Tasmania, facilitate interconnector export, and supply large-scale hydrogen facility within Tasmania. Derived from the 2022 ISP Step change scenario with hydrogen developments based on Tasmanian State Government objectives.

The State scenarios present the forecast use of the transmission network to supply the existing customer base. No new large scale customer developments are included. The State and interconnector flow scenario presents the forecast use of the transmission network to supply the existing Tasmanian customer base and support interconnector flow across Basslink and Marinus Link. In this scenario, Marinus Link is developed in two 750 MW stages in 2029–30 and 2030–31.

¹⁷ https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2022/update-to-2021-electricity-statement-of-opportunities.pdf?la=en

The State, interconnector, and large-scale hydrogen scenario includes the requirements to support both Marinus Link and large-scale renewable hydrogen in Tasmania. Marinus Link is developed on the same timeline as the previous scenario, with hydrogen developed as 300 MW by 2026–27, 1000 MW by 2030–31, and more than 2,000 MW by 2040–41¹⁸.

The State scenario considers maintaining the “status quo” for supply to existing transmission-connected customers, with negligible increases from existing loading levels.

The distribution network forecast considers committed spot loads and transfers within the distribution network. Material forecast demand increases are expected across Tasmania from increased residential consumption and continued EV uptake. Further, we forecast growth at some individual connection points due to new local connections over time.

2.1.2.3. Annual energy forecast

Figure 2-3 presents the actual to date and forecast Tasmanian energy requirements that will be imposed on the transmission network over the next 20 years to 2042. Forecasts are presented for the distribution network, and under the three planning scenarios for the transmission network. The Central State scenario transmission forecast from our 2021 APR is included for comparison.

18 Note that interconnector flows differ between scenarios with and without large-scale hydrogen development.

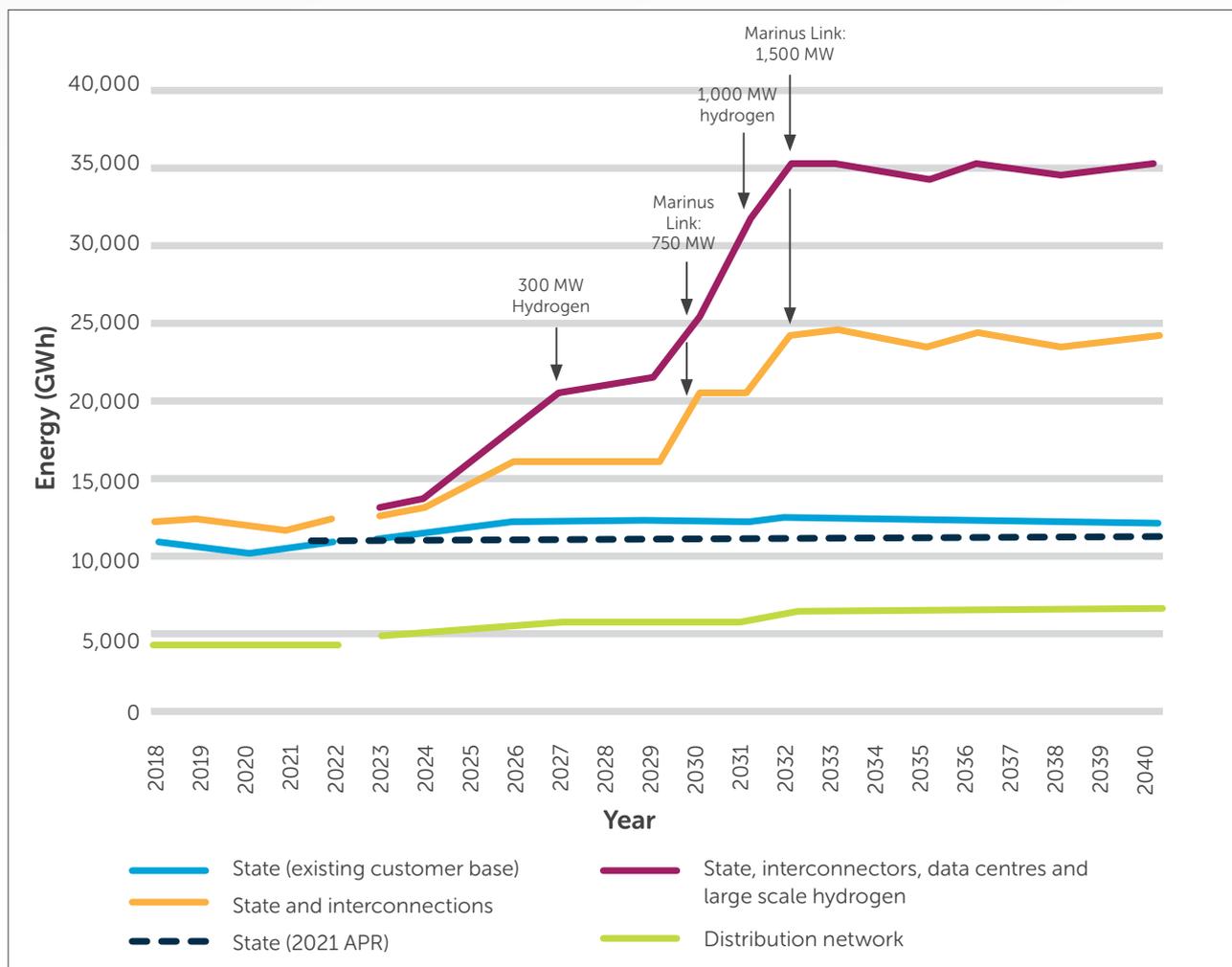


Figure 2-3: Annual energy forecast

In 2021, the total annual energy consumption in Tasmania increased slightly from the previous year. Energy consumption increased for transmission-connected customers (including major industrial loads) and distribution customers.

The State region energy consumption (existing customer base) scenario indicates material demand growth for distribution connected customers, with an average rate of growth of 2.96%.

The development of Marinus Link and large-scale hydrogen in Tasmania will significantly increase the energy transfer requirements across the transmission network. Energy transfer is forecast to near-double or more over the forecast

period, from approximately 10,500 GWh today, to support these developments.

In the State region, interconnectors, and large-scale hydrogen scenario, the requirement is forecast to exceed 20,000 GWh by 2029 and exceed 30,000 GWh by 2031.

Changes in timing or scale of hydrogen developments, or Marinus Link, will change the forecast transmission network energy transfer requirements.

2.1.2.4. Maximum demand forecast

Similar to the annual energy forecasts, the development of Marinus Link and large-scale hydrogen in Tasmania will see a significant increase in the transmission network maximum demand. Figure 2-4 presents the maximum demand forecast for Tasmania and the broader transmission network out to 2042.

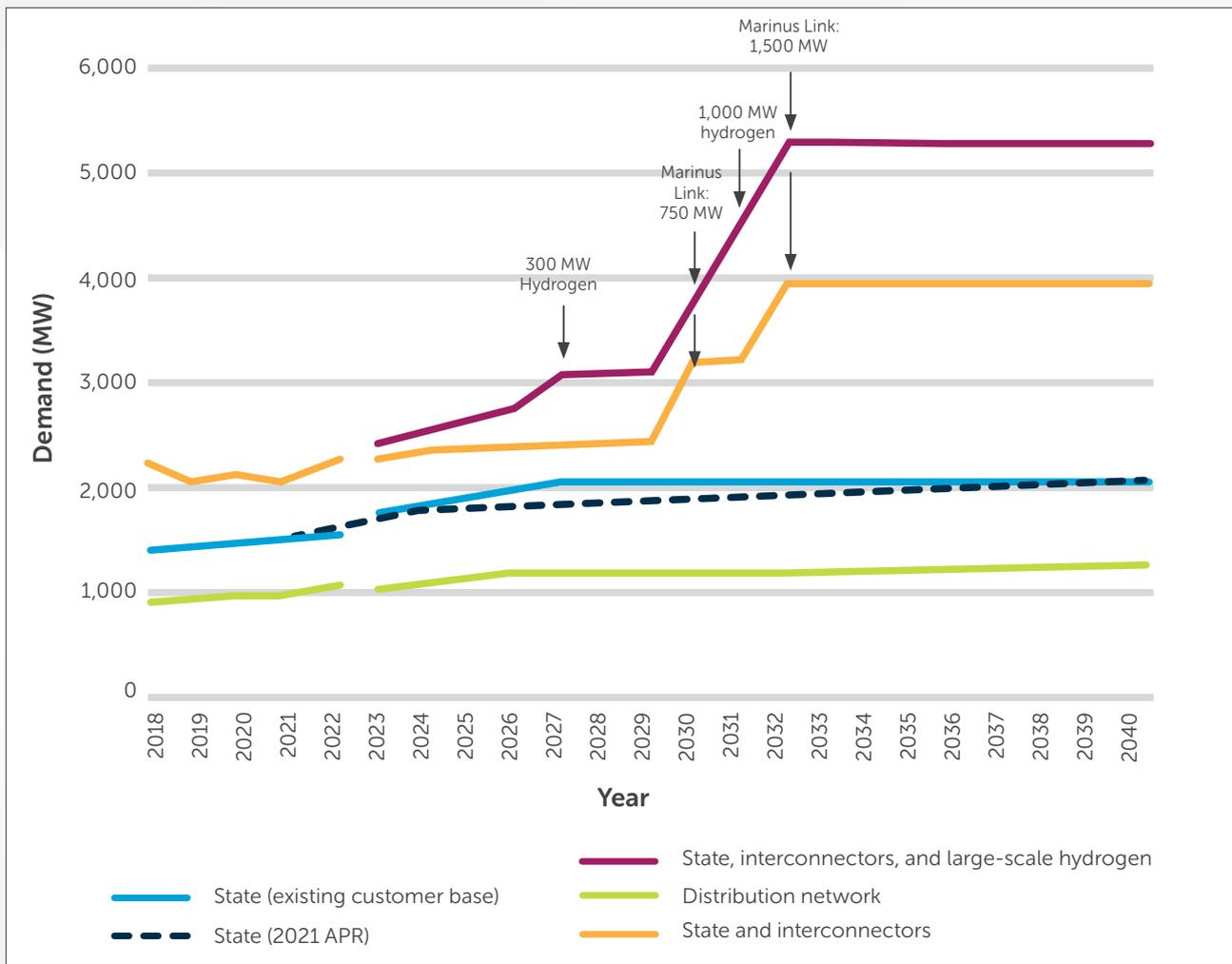


Figure 2-4: Maximum demand forecast

In the State and interconnectors scenario, the maximum demand on the transmission network is forecast to double over the next decade. By 2032, maximum demand is forecast to exceed 5,000 MW in the State, interconnectors, and large-scale hydrogen scenario—more than 2 times that of the existing network.

In 2021, and over the previous five years, the maximum demand on the transmission network to simultaneously support the State demand and interconnector (Basslink) requirements varied depending on the coincidence of high interconnector export and high Tasmanian demand. In the State (existing customer base) scenario, maximum demand is forecast to increase by approximately 0.9 per cent annually, due to projected residential consumption and EV uptake. The State maximum demand is forecast to exceed 2,000 MW by 2027. TasNetworks takes into consideration the AEMO state level forecast when producing its connection point and feeder level forecasts. As AEMO no longer publish connection point forecasts for Tasmania, TasNetworks has made changes to the demand forecast production cycle. As a consequence, the demand forecast impacts seen at a state level will be considered and analysed at a local level throughout the upcoming planning cycle.

In Tasmania, rooftop photovoltaic (PV) contributions do not materially reduce the maximum electricity demand, due to the maximum demand occurring either early morning or late afternoon-early evening in winter when PV output is minimal.

Forecast Limitations

Demand and energy forecast projects intend to present, at a high level, the degree of change imposed on the existing network. The forecasts do not consider factors such as:

- the necessity for Tasmania to maintain energy self sufficiency;
- the technical capability of the future transmission to support loads of this magnitude; and
- the capability of generation resources within the state to support the necessary energy.

2.2. Generation characteristics

Table 2-2 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. The details of individual transmission-connected and embedded generation sites are listed in Table 2-2.

Table 2-2: Existing generation capacity

Generation type	Number of sites	Total name-plate rating (MW)	Proportion of in-stalled capacity (%)	Contribution to Tasmanian network flows (%)
Hydro	25	2,463	63	74.9
Wind	5	564	15	14.6
Gas	1	386	10	<0.1
Basslink import	1	478	12	10.4
Total	32	3,891	100	100

The Tamar Valley Power Station combined cycle gas turbine (CCGT) is listed by AEMO as an announced withdrawal in 2015, though available for short-term recall (less than three months lead-time)¹⁹. We consider the CCGT as part of the existing generation capacity and consider its use in planning studies where it has a material impact.

In 2021, Tasmania has continued to operate as energy self-sufficient, with increased contributions from wind and hydro. The generation mix in the State during the 2019-2021 period is presented in Figure 2-5. This includes generation within Tasmania and net Basslink flows.

¹⁹ NEM generation information publications, July 2022 <http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information>

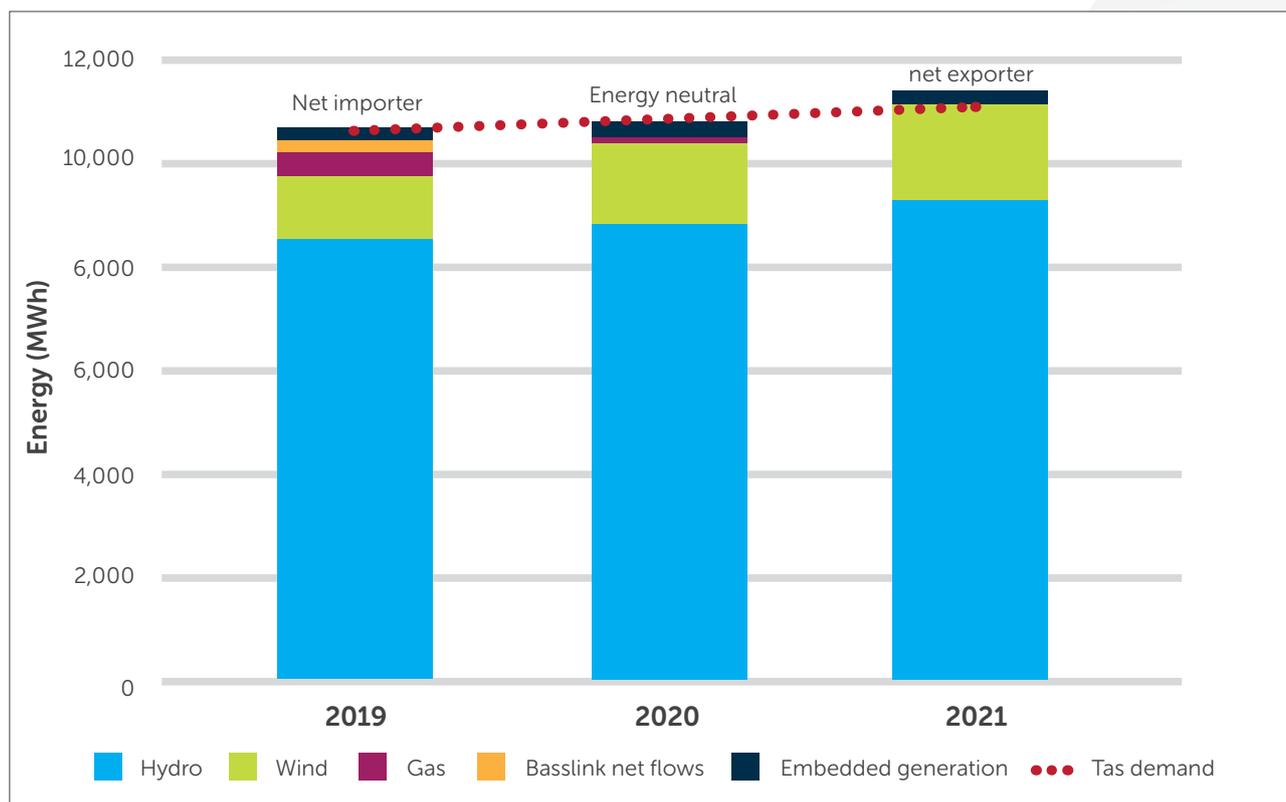


Figure 2-5: Supply contribution by type: 2019 to 2021

In 2019, Basslink import was required to supplement the existing on island generation in order to meet the Tasmanian annual energy demand. Progressive growth of new renewable energy in Tasmania has seen the state achieve “energy neutrality”, whereby in 2020 the on-island generation effectively matched the energy demands requirements. In 2021, Tasmania produced, on average, a surplus of energy, with the excess exported to the mainland.

2.3. Transmission network

The transmission network in Tasmania 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 loads are concentrated in the north and south-east of the state. Bulk 220 kV supply points are located at Burnie and Sheffield (supplying the north-west), George Town and Hadspen (supplying Launceston and the north-east), and Chapel Street and Lindisfarne (supplying Hobart and the south-east) substations. Smaller load centres are supplied via the 110 kV fringe transmission network.

Our transmission network map is presented in Figure 2-6, and a summary of the transmission network infrastructure is in Table 2-3.

Table 2-3: Transmission infrastructure

Asset	Quantity
Substations	49
Switching stations	8
Circuit kilometres of transmission lines	3,326
Route kilometres of transmission lines	2,316
Circuit kilometres of transmission cable	24
Transmission line support structures (towers and poles)	7,700
Easement area (Hectares)	11,176

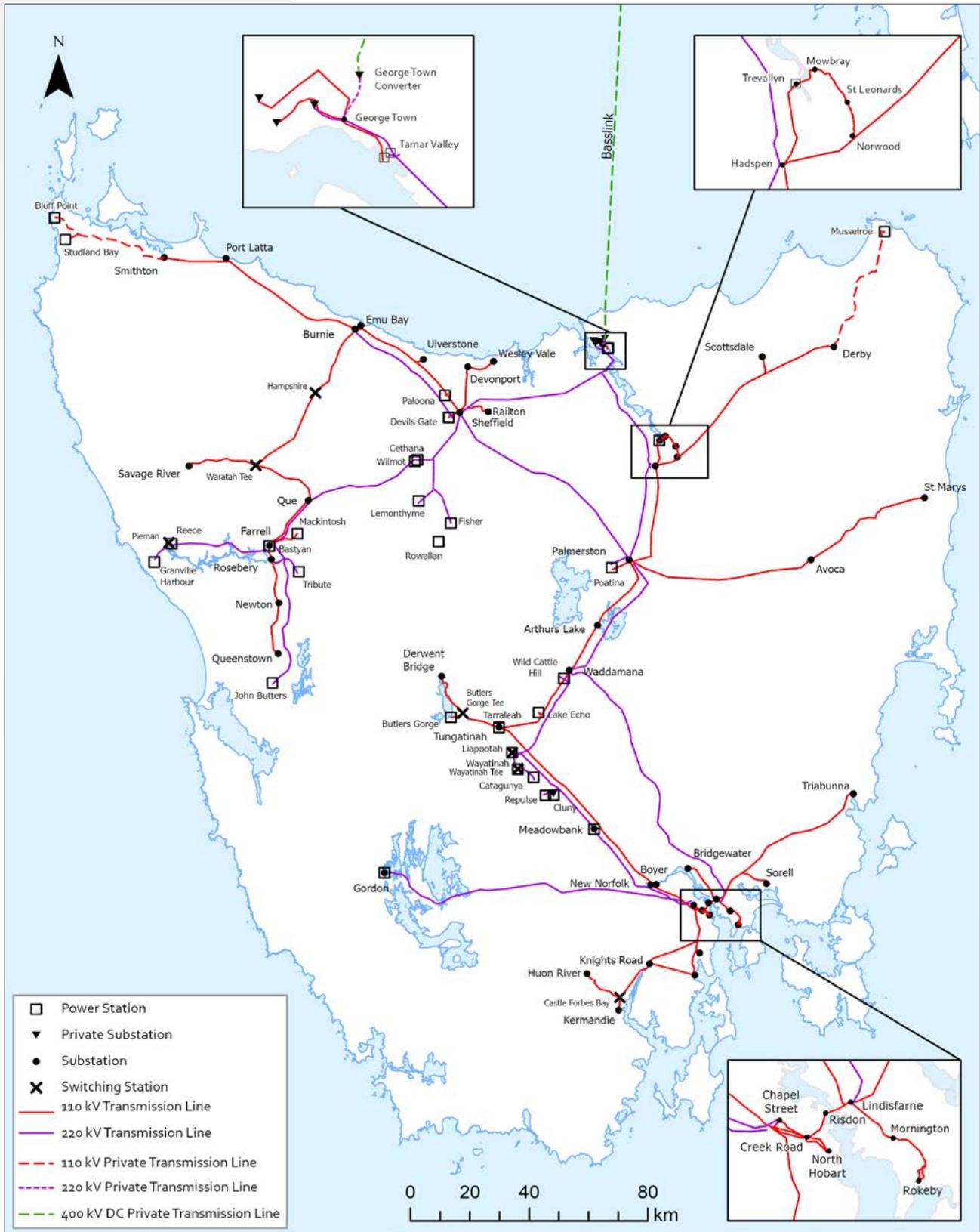


Figure 2-6: Tasmania's electricity transmission network

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 customers and comprises:

- 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 most customers in Tasmania.

Figure 2-7 presents our distribution network map by voltage.

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

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

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 distribution and more interconnections with other urban lines. Restoration following interruptions to supply is usually quicker than in rural areas.



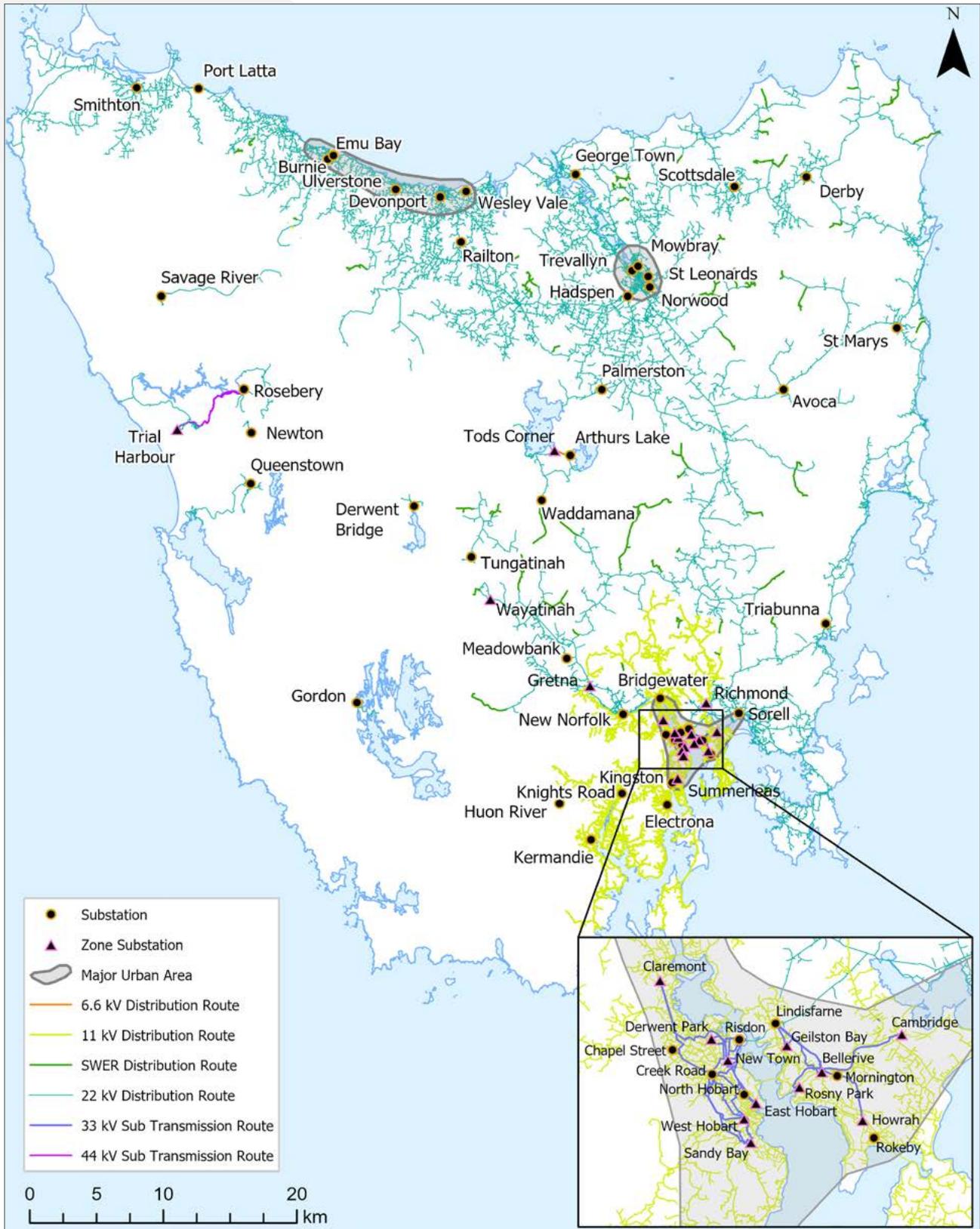


Figure 2-7: Tasmanian distribution voltage areas

A summary of our distribution network infrastructure is presented Table 2-4.

Table 2-4: 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 ²⁰	22 and 11	6
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	131
Minor zone substations	22 and 11	3
Minor zone distribution lines	22 and 11	8
Distribution substations		
Overhead		29,896
Ground mounted		2078
Route data		
High voltage overhead (km)	6.6 to 44	15,415
High voltage underground (km)		1,114
Low voltage overhead (km) ²¹	0.4	4,562
Low voltage underground (km) ⁵	0.4	1,326
Poles	All voltages	231,643

20 Includes minor zone alternate-supply lines.

21 Excludes customer service lines.

03 Transmission network developments

- Tasmanian transmission planning activities continue to focus on the optimum development path for the network to accommodate future large scale renewable energy sources, new interconnection with Victoria, upgrading of existing power stations, export scale hydrogen and integration of energy “firming” facilities such as battery energy storage systems (BESS) and pumped hydro stations.
- We have developed transmission augmentation options that support a range of market scenarios as the Australian electricity system transitions to renewable energy sources, informed by the Tasmanian Renewable Energy Target (TRET) inclusive of plans to develop a renewable energy hydrogen industry, and identification by the Australian Energy Market Operator (AEMO) of Renewable Energy Zones (REZs) and transmission augmentation.
- We confirmed that augmentation of the Palmerston–Sheffield 220 kV transmission corridor is likely to be required under the majority of future scenarios—irrespective of which scenario(s) develop or in what order
- We held an extensive program of community engagement events at locations near the proposed North West Transmission Developments (NWTD).
- We assembled a regional Youth Panel to put young people at the front and centre of framework design process.

Transmission network developments

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 new renewable energy generation to support the TRET in the three Tasmanian REZs in the north-west, the north-east and central highlands regions.

The Tasmanian Renewable Hydrogen Action Plan, previously identified potential locations for large-scale renewable hydrogen production and export in Tasmania. Since then, TasNetworks has progressed planning strategies specifically for hydrogen integration at the Bell Bay Advanced Manufacturing Zone (**BBAMZ**).

In March 2022, TasNetworks published its Transmission Network Strategy²², which provides our customers and stakeholder an overview of the Tasmanian power system, the outlook for electricity generation and consumption over the longer term and TasNetworks' plans for developing the State's transmission network at the lowest sustainable cost. Transmission development plans to address local supply area issues are discussed in Chapter 4 under individual planning area plans.

²² <https://www.tasnetworks.com.au/transmission>

3.2. The backbone transmission network

The backbone Tasmanian transmission network comprises a 220 kV network and some parallel 110 kV networks. Its role is the intra-regional transfer of electricity from generation to load centres, and inter-regional to mainland Australia via interconnection with Victoria. The main considerations in planning the backbone transmission network are the technical requirements of the National Electricity Rules (**the Rules**) and opportunities for developments that provide a market benefit to customers. The Rules set how we define the technical envelope in which we must operate the power system, and market benefit developments may either release lower-cost generation or reduce the risk of unserved energy to customers. Our jurisdictional network planning requirements also apply to the backbone transmission network for certain credible and non-credible contingencies, with further details available in Appendix A.3.3.

3.3. Marinus Link

Marinus Link Pty Ltd (**MLPL**) is a wholly owned subsidiary of TasNetworks which has responsibility for progressing Marinus Link. The new interconnector will be comprised of two 750 MW High Voltage Direct Current (**HVDC**) monopoles based on voltage source converter (**VSC**) technology, creating a 1,500 MW transmission pathway which will increase energy transfer capabilities between Tasmania and the rest of the National Electricity Market (**NEM**).

MLPL is now registered with AEMO as an Intending Participant in the transmission network service provider category, in anticipation of Marinus Link being classified as a prescribed transmission service. 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 Tasmania REZ. This network augmentation work is being progressed by the NWTDT.

MLPL and TasNetworks continue to undertake joint planning activities for the integration of Marinus Link, with our core focus centred on the strategic requirements for the Tasmanian transmission network.

The total combined current cost of Marinus Link and the NWTDT, as identified in the 2022 Integrated System Plan (ISP) is estimated at \$3.8 billion (\$2021). The proposed transmission network topology that will need to be developed to accommodate the 1,500 MW link and associated renewable energy developments in the North West region is outlined in Section 3.5.1.

3.4. Renewable energy development

3.4.1. 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, or a combination of these factors. They are best suited to renewable energy production to support the NEM as it transitions away from fossil fuel-fired generation. The 2022 Integrated System Plan (ISP) identifies 47 potential REZs across the NEM, with 41 REZs based onshore and six Offshore Wind Zones (OWZs). Tasmania has three onshore REZs and one OWZ, with wind resource quality of the Tasmanian REZs being amongst the highest across the NEM²³. The location of these REZs is presented in Figure 3-1.

²³ 2022 Inputs and assumptions workbook, Capacity Factors tab, 10 December 2021, <https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios>

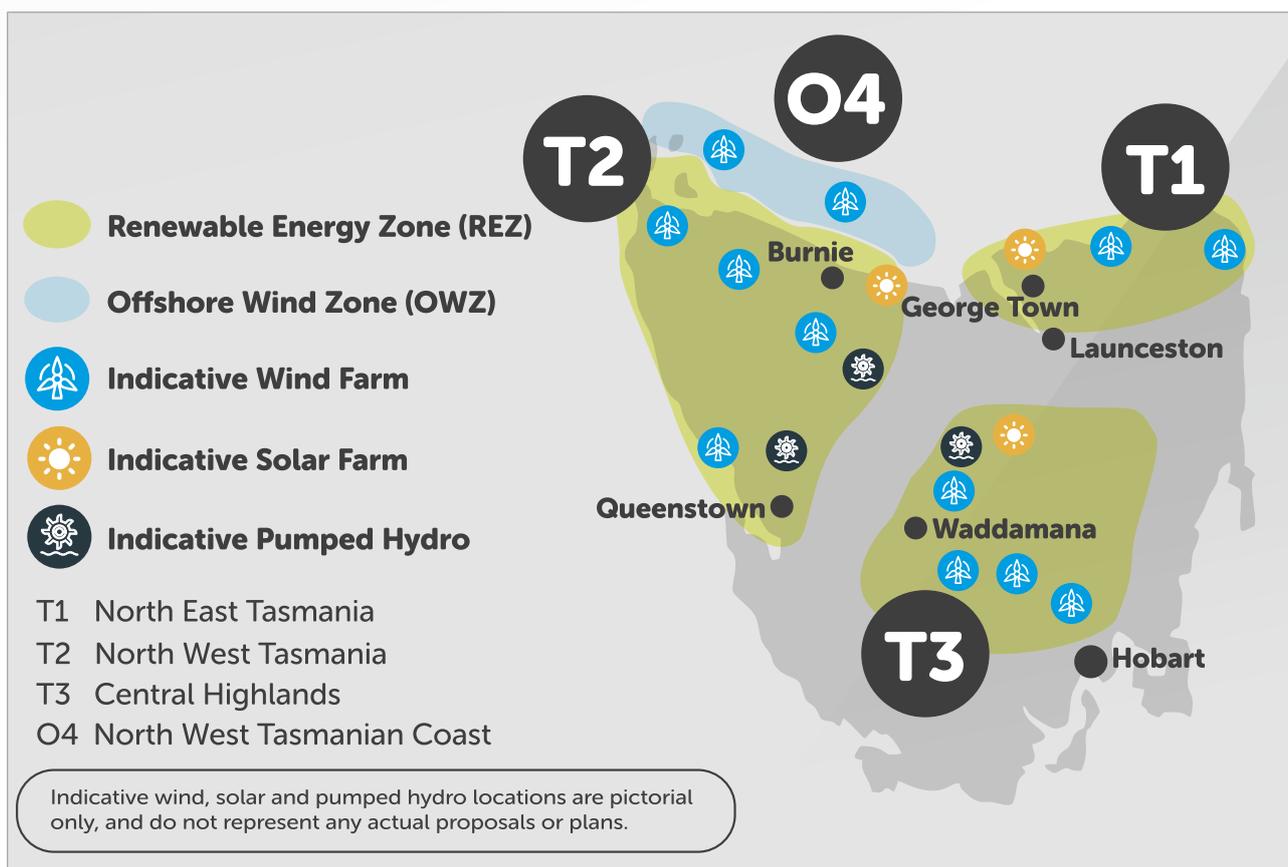


Figure 3-1: Tasmanian REZs

Although AEMO only identified an OWZ in north-west Tasmania, we foresee the broader Bass Strait area as having potential for offshore wind development. We have already been approached by a number of proponents. It is important to note that the concept of REZs does not preclude any new generation from being developed outside these nominated areas.

New variable renewable energy (VRE) may come from both wind and solar, however in Tasmania wind is expected to be the dominant resource developed. In addition, repurposing and expansion of the hydropower system in Tasmania—including pumped hydro energy storage—will support REZ development.

Significant development of new VRE in Tasmania is expected over the next 20 years to meet the objectives of the Tasmanian Renewable Action Plan (TREAP):

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

The TREAP is presented in detail in Section 1.4 of this Annual Planning Report (APR). In addition to the TREAP, the potential large-scale development of data centres in Tasmania will also contribute to an increased need for new VRE to maintain an energy balance in the Tasmanian region, consistent with government objectives.

REZ developments in Tasmania will be informed by the impending announcement by Renewables, Climate & Future Industries Tasmania (ReCFIT) of the first REZ for targeted development. Ultimately, we expect new VRE to be developed across all Tasmanian REZs to meet the TREAP renewable energy objectives.

3.4.2. Tasmanian Renewable Energy Target

The Tasmanian Government has legislated TRET, setting targets for renewable electricity generation by 2030 and 2040. To meet these targets, new generation is required within Tasmania, the majority of which is expected to be new wind farms. To meet the targets purely through the installation of new wind generation, the required installed capacity will need to reach:

- 1,250 – 1,500 MW by 2030 to meet the interim target of 5,250 GWh additional energy generation; and
- 2,500 – 3,000 MW by 2040 to meet the full target of 10,500 GWh additional energy generation.

The ultimate installed capacity of new wind to meet the TRET will depend on the assumed capacity factor. The requirements would change if other renewable energy sources (e.g. solar) are developed, or a different capacity factor is realised in practice.

While the TRET sets a target for new VRE, it may not be sufficient to meet all the renewable energy requirements of the TREAP. As presented in the energy

and demand forecasts in Section 2.1.2, the energy requirement to support Marinus Link, supply large-scale hydrogen and data centre load, while maintaining Tasmania's energy balance may require more than 10,500 GWh of new energy production. Figure 2-3 forecasts an additional 19,000 GWh energy demand by 2040 to meet all renewable energy requirements, far exceeding the TRET and requiring up to 5,300 MW of new wind to be installed.

3.4.2.1. Establishing Tasmania's first REZ

The Tasmanian Government, through ReCFIT, is soon to announce Tasmania's first priority REZ. The announcement is expected to be made by December 2022. Announcing Tasmania's first priority REZ is an action under the Renewable Energy Coordination Framework, to support a coordinated approach to the development of new VRE in Tasmania to meet the TRET.

We expect any new VRE proposals coming out of Tasmania's priority REZ announcement to be established alongside currently progressing VRE developments. There are a number of well-progressed projects in Tasmania which we expect will continue to progress. There is already sufficient known interest in the Tasmanian region to meet or exceed the TRET targets.

3.4.3. Battery of the Nation

Hydro Tasmania is progressing with its clean energy initiative, Battery of the Nation (BOTN)²⁴. This initiative includes a number of different proposals which look to repurpose existing hydropower assets and establish pumped hydro energy storage (PHES). The Battery of the Nation, with increased interconnection provided by Marinus Link, will enable Tasmania to provide firming services—both dispatchable capacity and storage—to the mainland NEM as it transitions to a future dominated by VRE generation.

The proposals under the BOTN initiative will increase the capacity of renewable energy in Tasmania, but do not provide significant levels of additional energy storage compared to existing capabilities. That is, more dispatchable capacity is available, but it will generate less often and when required to meet energy deficits in the mainland NEM. BOTN proposals include:

- repurposing the Tarraleah hydropower scheme, including replacing the existing Tarraleah Power Station (capacity increase from 90 MW to 220 MW);
- opportunistic upgrades as part of mid-life refurbishments of power stations located on the West Coast of Tasmania (100 MW capacity increase); and
- establishing a PHES system at Lake Cethana (750 MW capacity).

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

Tarraleah repurposing and West Coast upgrades are expected to be developed with the first stage of Marinus Link, with Cethana PHES developed with the second 750 MW stage. There are other elements of Battery of the Nation, however these are associated with optimising the existing hydropower system and do not provide any significant capacity increases.

3.4.4. 2022 Integrated System Plan

The 2022 ISP²⁵ produces a least-cost build out of new VRE and storage across the NEM to replace existing thermal generation sources (coal and gas) as it retires over coming years. The ISP looks out to 2050, and across a number of scenarios. It identifies the step change scenario as the most probable to occur, with this scenario having thermal generation retire earlier than previously announced and the subsequent rapid build out of new VRE and storage to replace it.

The ISP includes the TRET as a basis for its modelling across scenarios, ensuring sufficient VRE is built in Tasmania to meet the legislated interim and full targets. It also assumes that the BOTN activities providing a capacity increase are developed.

The ISP only 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 may be developed, nor does it consider other aspects such as government, community and stakeholder support, i.e. locational specific social licence issues. The ISP also does not consider large-scale hydrogen development across scenarios, except for the Hydrogen Superpower scenario which involves very large hydrogen (and subsequent VRE) developments across the NEM. It does not consider any of the currently-proposed VRE developments in Tasmania are sufficiently progressed to include as 'anticipated' or 'committed' projects in its analysis, meaning these specific projects are not modelled in the ISP analysis.

The ISP includes Marinus Link (including the NWTD) as an actionable project, being part of the Optimal Development Path for the NEM. It also forecasts 2,500 MW of new VRE generation—all wind—is built in Tasmania by 2040 to meet the TRET.

Table 3-1 presents the ISP outlook for new VRE (all wind) under the Step Change and Progressive Change scenarios by REZ over the next 10 and 20 years (to 2031–32 and 2041–42 respectively). It also presents the current publicly-announced VRE proposals which we are aware, the majority of which have commenced initial connection processes with us, however none of which are yet considered as committed.

Table 3-1: VRE publicly-announced proposals and 2022 ISP outlook (MW)

REZ	Publicly-announced proposals	Step change scenario		Progressive scenario	
		2031–32	2041–42	2031–32	2041–42
North East Tasmania (T1)	2,540	100	100	100	100
North West Tasmania (T2)	1,977	1,300	1,300	540	1,300
Central Highlands (T3)	470	1,100	1,100	1,100	1,150
North West Tasmanian Coast (O4)	0	0	0	0	0
Total	4,987	2,500	2,500	1,740	2,550

Under the Step Change scenario, all new VRE (i.e. achieving TRET) is built by 2031–32 to meet the rapid retirement of thermal generation across the NEM. The VRE build out in the Progressive Change scenario is more closely aligned to the specific TRET targets. No new VRE is built once the TRET has been met, under either scenario. This includes any new VRE required to support renewable (green) hydrogen and data centre development in Tasmania in addition to Marinus Link, as these load developments were not considered in the ISP analysis.

The ISP outlook includes strong VRE build initially in the Central Highlands REZ, to take advantage of the premium wind resource in close proximity to the existing transmission network which offers a reasonable hosting capacity. This is followed by strong VRE build in the North West REZ once Marinus Link is established (along with the North West Transmission Developments which significantly increases the hosting capacity of this zone). The ISP outlook is for limited VRE build in the North East REZ due to limited resource within close proximity to the existing transmission network, and no development of any offshore wind.

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



3.5. Renewable Energy Zone development

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

It should be noted that the network capabilities as presented are based on likely thermal limitations and have not considered more detailed dynamic analysis and power system security assessments.

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 ISP outlook for VRE in Tasmania, with consideration for publicly-announced proposals, are 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 the regulatory investment test for transmission (**RIT-T**).

As presented in Table 3-1, the current publicly-announced VRE proposals exceed the ISP outlook for Tasmania and the TRET. While not all proposals may develop, or to their full potential, it presents that there is sufficient wind resource already identified to meet these targets. The individual proposals are shown in Figure 3-2.

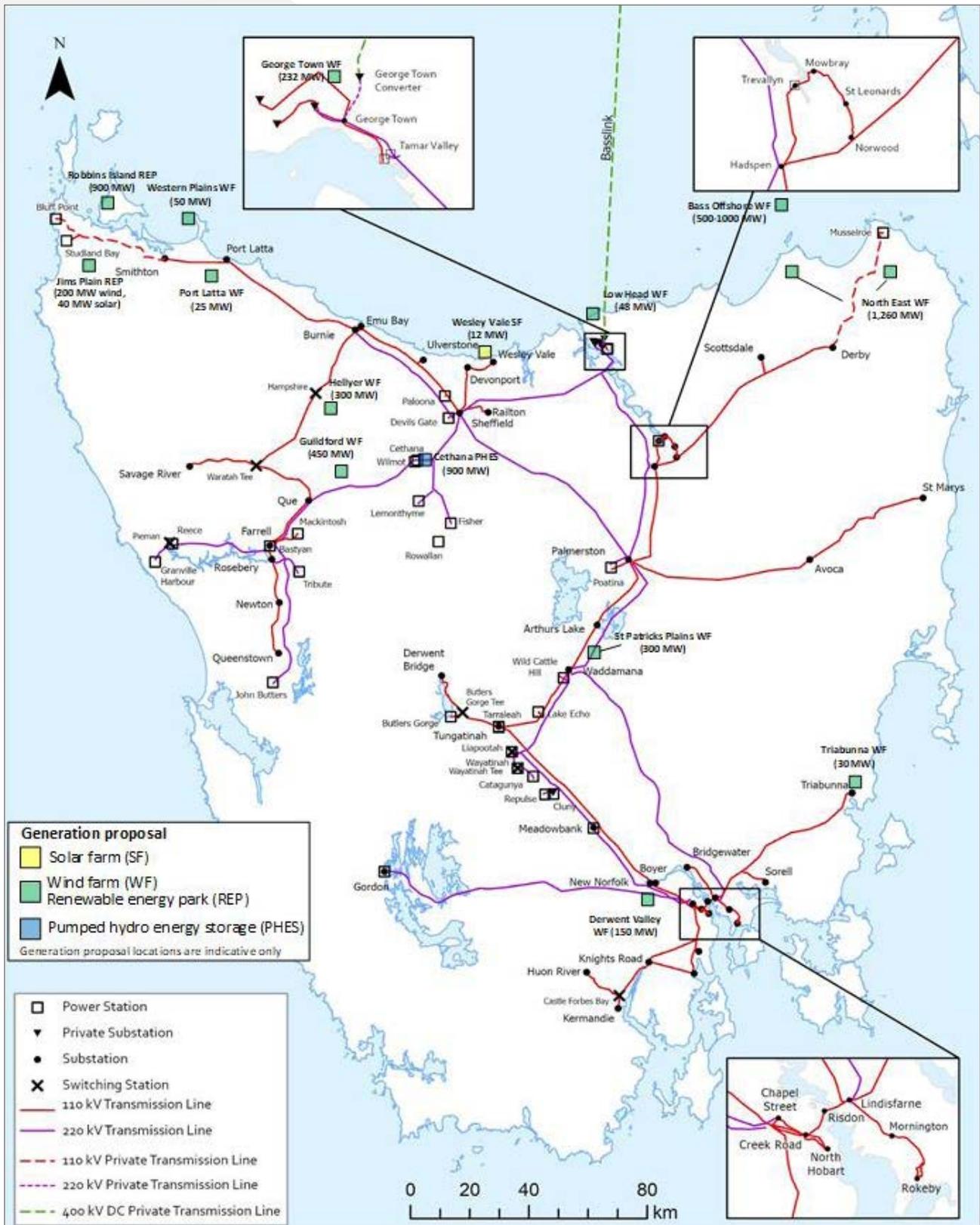


Figure 3-2: Publicly-announced generation proposals

3.5.1. North West Tasmania REZ

Given their close proximity and shared transmission network, the North West REZ and North West Coast OWZ are presented together in this section as the North West REZ.

The North West REZ has strong potential for new wind generation. The proposed connection location for Marinus Link is within this REZ at Heybridge (near Burnie). There is significant interest in locating new generators 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 to final feasibility²⁶.

Figure 3-3 presents the North West Tasmania REZ transmission network, including North West Transmission Developments, and the network capability to accommodate new wind generation.

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

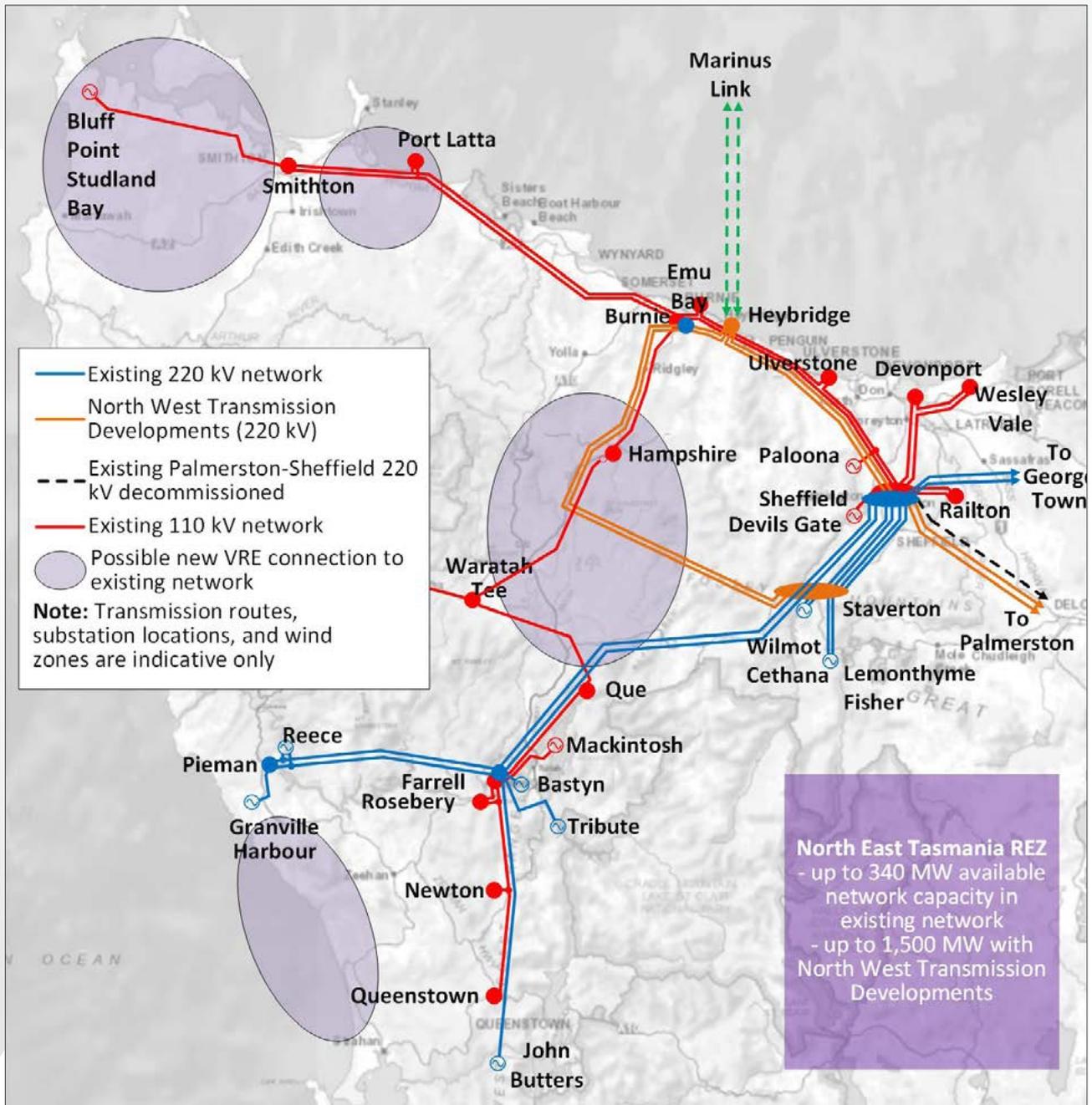


Figure 3-3: North West Tasmania REZ transmission network and hosting capability

Table 3-2 presents the publicly-announced VRE proposals in the North West Tasmania REZ.

Table 3-2: North West Tasmania REZ publicly-announced VRE proposals

Name	Proponent	Type	Capacity (MW)
Guildford Wind Farm	Epuron	Wind	450
Hellyer Wind Farm	Epuron	Wind	300
Jim's Plain Renewable Energy Park	ACEN Australia	Wind	200
		Solar	40
Port Latta Wind Farm	Aquila Capital	Wind	25
Robbins Island Renewable Energy Park	ACEN Australia	Wind	900
Wesley Vale Solar Farm	Epuron	Solar	12
Western Plains Wind Farm	Epuron	Wind	50
Total			1,977

There is capability in the existing North West Tasmania REZ transmission network to accommodate approximately 340 MW of new VRE subject to a number of already identified limitations being adequately addressed including provision of adequate system strength.

3.5.1.1. North West Transmission Developments

In order to enable the 1,500 MW transfer capability of Marinus Link, the construction of two new double circuit 220 kV transmission lines from Sheffield Substation to Marinus Link converter station will be required, together with the augmentation of the 220 kV transmission line from Sheffield substation to Palmerston substation. Providing separate corridors for the two transmission lines between Sheffield and Heybridge substations allows for route diversity and for the efficient connection of new generation in the North West Tasmania REZ.

The optimal transmission development for the North West REZ and Marinus Link is a new 220 kV transmission 'rectangle' in North West Tasmania, plus increased transmission capacity between Sheffield and Palmerston substations, specifically:

- **new 220 kV switching stations:** at Staverton 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 combined cost of the North West Transmission Developments is approximately \$680 million.

The North West Transmission Developments project has achieved a number of significant milestones in the reporting period (2021-22 financial year):

- **July 2021:** Refurbishment of existing TasNetworks Deloraine Depot, provides office and meeting space to support project work in the region.
- **October 2021:** Stakeholder Liaison Group established. Independently chaired, the group meets six times per year and includes representation across key industry groups, peak bodies, education, skills and training sectors and state government organisations.
- **December 2021:** Revised Staverton to Hampshire Hills Preferred Route announced to avoid areas with sensitive ecology and geology.
- **November 2021 and March 2022:** Economic Development workshops with key stakeholders to inform the Economic Development Strategy.
- **March 2022:** Youth Panel formed to help co-design the North West Transmission Developments community benefits sharing program framework.
- **March 2022:** Environment Protection and Biodiversity Conservation (EPBC) referrals were lodged with the Department of Agriculture, Water and the Environment.
- **April 2022:** Funding for the remainder of the Design and Approvals phase secured as part of the Marinus Link, Bilateral Energy and Emissions Reduction Agreement with the Australian Government announcement.
- North West Transmission Developments Procurement Strategy developed (supported by market consultation). Tender process to engage Head Contractor commenced in July 2022.

3.5.1.2. North West Community Engagement

An extensive program of community engagement events have been held at locations near the proposed North West Transmission Developments in north-west Tasmania. These include regular drop-in and pop-up information sessions at community halls, events and outside shopping centres, online webinars and forums, online and telephone surveys, and at the Future Energy Hub in Burnie.

We also took a unique approach to commencing development of a community benefit sharing program framework. This occurred through the assembly of a regional Youth Panel, to put young people at the front and centre of the framework design process. Engaging with youth as the first step in the design process recognised that young people are not often included in decisions affecting their communities, and that for the North West Transmission Developments, they are the community members who will live alongside the infrastructure for the longest time period.

The process was designed to ensure participants gained as much as possible from the experience, with information shared through presentations, guest speakers and a tour of some of the proposed sites to help panel members visualise the likely impacts of the developments.

The next step is to seek feedback on the Youth Panel's community benefits sharing program framework recommendations from the broader community, as well as work with community stakeholders to identify a suitable community governance model. Engagement with communities has focussed on awareness raising and information. Community engagement events are gearing up ahead of the Environmental Impact Assessment process which will commence towards the end of 2022 with public release of the Environmental Impact Statement for public consultation ahead of lodgement for relevant cultural heritage, planning and environmental approvals.

For more information on community engagement and to register for e-news or find out about upcoming events visit TasNetworks' dedicated engagement website www.talkwith.tasnetworks.com.au

3.5.1.3. North West Landowner engagement

Working with directly affected landowners is critical to the success of any major infrastructure project. Across the North West Transmission Developments there are a diverse set of more than 400 landowners. Some landowners own more than one property that is affected. TasNetworks is meeting with individual landowners on their land to assess impacts and where possible we are taking land use into account as we finalise the technical design – this includes tower placements and access tracks. Impacts to land use is a particular concern of farmers who have pivot irrigators. Landowner engagement is progressing well with the majority of landowners, about 75% providing access

for field assessments. This represents 90% of all land parcels for the North West Transmission Developments. TasNetworks is in regular contact with directly affected landowners through a dedicated team of Landowner Relationship Advisors.

3.5.1.4. North West Surveys and technical reports

Field surveys and technical reports to inform the final technical design and approvals process including the Environmental Impact Statement are progressing including geotechnical, ecological, cultural heritage and social impact assessments. Results of some areas of interest for surveys undertaken on the Staverton to Hampshire Hills route will be shared with community members ahead of the Environmental Impact Assessment, to help inform interested community members.

3.5.1.5. North West Tasmania REZ development plan

Once Marinus Link and the North West Transmission Developments are commissioned, there will be sufficient network capacity to facilitate the 2030 new wind generation forecast in the North West Tasmania REZ under both the ISP Progressive Change and Step Change scenarios (presented in Table 3-1).

If new VRE is established in the North West Tasmania REZ prior to Marinus Link, some elements of the Marinus Link supporting North West Transmission Developments may need to be progressed early. These are augmentations to the Palmerston–Sheffield and Sheffield–Burnie 220 kV transmission corridors.

Palmerston–Sheffield 220 kV transmission augmentation

The existing Palmerston–Sheffield 220 kV transmission line would become more congested if new large generation connects to the west of Sheffield Substation, prior to Marinus Link being developed. A new double-circuit 220 kV transmission line will alleviate these constraints. Prior to Marinus Link, construction of this line can be triggered by 230 MW of new generation in the North West Tasmania REZ – when the benefits of relieving the congestion exceeds project costs²⁷. This has been included as a contingent project in our current 2019–24 regulatory period.

Sheffield–Burnie 220 kV transmission augmentation

The existing Sheffield–Burnie 220 kV transmission line would become congested if new large generation connects at, or near, Burnie Substation, prior to Marinus Link being developed. A new double-circuit 220 kV transmission line in this corridor would remove these constraints. Prior to Marinus Link, it can be triggered by 277 MW of new generation connected at Burnie

²⁷ The trigger was identified as 342 MW in our revenue submission for the 2019–24 regulatory period. Granville Harbour Wind Farm (112 MW) has since connected to the network, meaning the 'remaining' trigger is 230 MW of new generation.

Substation 220 kV or west of Burnie Substation – when the benefits of relieving the congestion exceed project costs. This has been included as a contingent project in our current 2019–24 regulatory period.

3.5.2. 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. We are aware of one publicly-announced VRE proposal within in the Central Highlands REZ (St Patricks Plains Wind Farm), with two others within the southern transmission network, presented in Table 3-3. While not directly in the REZ, the location of the other two projects must be considered when analysing the capability and augmentation options within it.

Table 3-3: Central Highlands REZ publicly-announced VRE proposals

Name	Proponent	Type	Capacity (MW)
Derwent Valley Wind Farm	West Coast Renewables	Wind	150
St Patricks Plains Wind Farm	Epuron	Wind	290
Triabunna Wind Farm	Fera Australia	Wind	30
Total			470

The transmission network within the REZ is strong, however, the transmission network from the Central Highlands REZ to the rest of the network limits capacity for new VRE to 480 MW. If Marinus Link is established, the Palmerston–Sheffield 220 kV transmission line augmentation as part of the North West Transmission Developments is established, an additional 450 MW of new VRE could be accommodated (930 MW total), appropriately partitioned between the Waddamana area (and further south) and Palmerston Substation.

The capability of the Waddamana–Palmerston transmission corridor limits the amount of new VRE that could be established in the Waddamana area and further south. The wind resource is relatively weaker in the area around Palmerston Substation compared to Waddamana Substation. This means it is unlikely that new wind will directly connect near Palmerston Substation, and therefore the limit for new wind into the existing network in Central Highlands REZ will likely occur before 930 MW is reached.

Figure 3-4 presents the Central Highlands REZ transmission network, including the new Palmerston–Sheffield 220 kV transmission line as part of North West Transmission Developments (with the existing single-circuit line decommissioned). The figure also shows possible connection locations to utilise the existing available network capacity.

The VRE outlook from the ISP for the Central Highlands REZ, presented in Table 3-1, exceeds the existing transmission network capability by 2031–32 under both the Step Change and Progressive Change scenarios. Therefore it is likely that transmission augmentation—especially in the Waddamana–Palmerston corridor—will be required to support this amount of new VRE. Any network augmentations will only be developed as the actual investment need arises, including as new generation develops, and will be subject to the RIT-T.

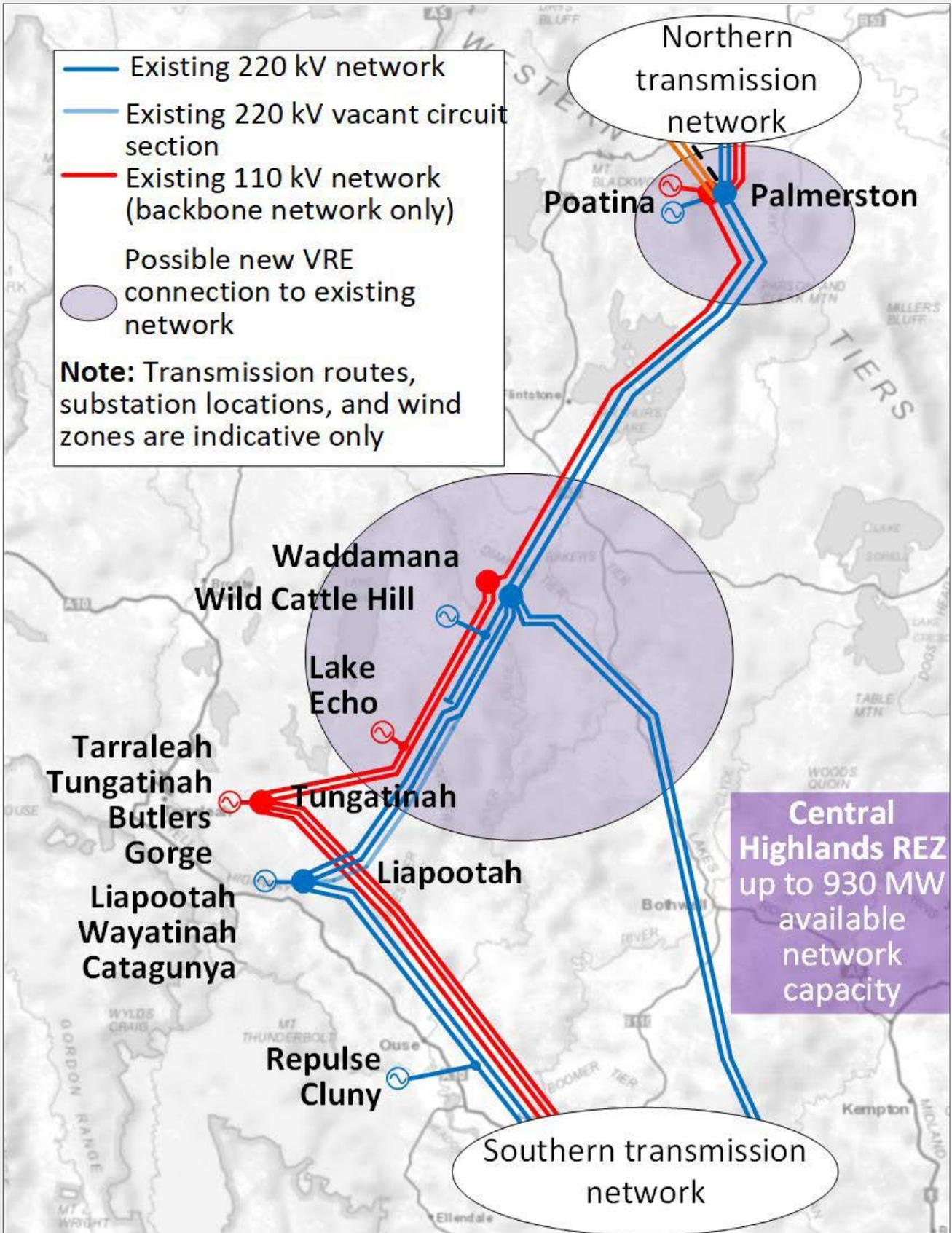


Figure 3-4: Central Highlands REZ transmission network and hosting capability

3.5.2.1. Waddamana–Palmerston transmission corridor augmentations

The proposed construction of the new Palmerston–Sheffield 220 kV transmission line as part of the North West Transmission Developments, detailed in Section 3.5.1 will provide transmission capacity for 930 MW new VRE in the Central Highlands REZ. There are a number of additional projects required to support this capacity increase.

Waddamana–Palmerston 220 kV terminal equipment capacity upgrade

The capacity of the Waddamana–Palmerston 220 kV transmission line is constrained by terminal equipment limitations at Palmerston Substation. Both circuits are constrained, to different levels. We propose to augment the terminal equipment at Palmerston Substation to remove the circuit constraints. This project is estimated to cost \$2.2 million.

Waddamana Substation ‘fit out’

Currently the Liapootah–Waddamana and Waddamana–Palmerston 220 kV transmission circuits do not terminate into Waddamana Substation. They operate as a ‘tee’ arrangement, with Liapootah–Waddamana–Palmerston transmission circuits. A ‘fit out’ of Waddamana Substation will allow these circuits to terminate at the substation. This will reduce the impact to the power system of transmission line contingencies, allowing additional power transfers through this corridor. The estimated cost for this project is \$7.5 million. It is likely that this project will be undertaken as part of other augmentation projects affecting Waddamana Substation.

Waddamana–Palmerston 110 kV transmission line conversion to 220 kV operation

The single-circuit Waddamana–Palmerston 110 kV transmission line previously operated at 220 kV. It can be reverted back to 220 kV operation with minor augmentation. This augmentation would support increases to power system security by providing three 220 kV circuits in the corridor, and provide approximately 100 MW capacity increase. This project is estimated to cost \$20 million.

New Waddamana–Palmerston 220 kV transmission line

A new transmission line is required to provide significant increase in transfer capability in the Waddamana–Palmerston transmission corridor. It is likely that this will be required to support the VRE outlook provided in the ISP by 2030, from both a transmission capacity and power system security perspective. The new Waddamana–Palmerston 220 kV transmission line would operate in parallel to the existing line. This may happen following, or instead of, reverting the 110 kV transmission line to 220 kV operation, depending on the actual development of new generation in the REZ. The estimated cost of the new transmission line is up to \$113 million.

3.5.2.2. Liapootah–Waddamana transmission corridor augmentation

The Liapootah–Waddamana transmission corridor contains two transmission lines, a lower capacity single-circuit line (1957 built) and a higher capacity double-circuit line (1999 built). The double-circuit transmission line is strung one-side only for most of its route, with the mismatched circuit capacities limiting the transfer capability of the corridor. With significant new VRE forecast in Central Highlands REZ, it is credible a large amount could be established in the Liapootah–Waddamana transmission corridor. To increase the transfer capability of this corridor, we propose to string the vacant side of the higher capacity double-circuit transmission line. This project is estimated to cost \$5.2 million.

3.5.3. North East Tasmania REZ

As with other Tasmanian REZs, the North East Tasmania REZ also has excellent wind resources. The existing transmission network from George Town Substation to the rest of the network has strong thermal capability, with four 220 kV transmission circuits, Basslink and George Town itself being a large load centre with two large major industrial loads. Table 3-4 presents the publicly-announced VRE proposals in the North East Tasmania REZ. The proposed offshore wind farm in North East Tasmania is included in this REZ.

Table 3-4: North East Tasmania REZ publicly-announced VRE proposals

Name	Proponent	Type	Capacity (MW)
Bass Offshore Wind Energy	Nexsphere	Wind (offshore)	1,000
George Town Solar Farm	Sun Spot 9	Solar	358
George Town Wind Farm	West Coast Renewables	Wind	232
Low Head Wind Farm	Equis	Wind	48
North East Wind	ACEN Australia	Wind	1,260
Total			2989

There is significant capability in the existing North East Tasmania REZ transmission network at George Town to accommodate new VRE, however the majority will require long connection asset to the network. We expect there is a local VRE resource of approximately 400 MW close to George Town Substation which could be directly connected to the existing network.

The VRE resources in Far North East and North East offshore would require a substantial new transmission line or cable to connect to the George Town area—though there remains no requirement to augment the existing shared transmission network. The actual integration of this amount of new VRE would be subject to power system security requirements.

Figure 3-5 presents the North East Tasmania REZ transmission network and the possible new VRE resource locations which could be connected to the existing transmission network. New VRE from Far North East Tasmania and North East offshore area must connect to the 220 kV network, as the 110 kV network does not have sufficient capability to support these resources.

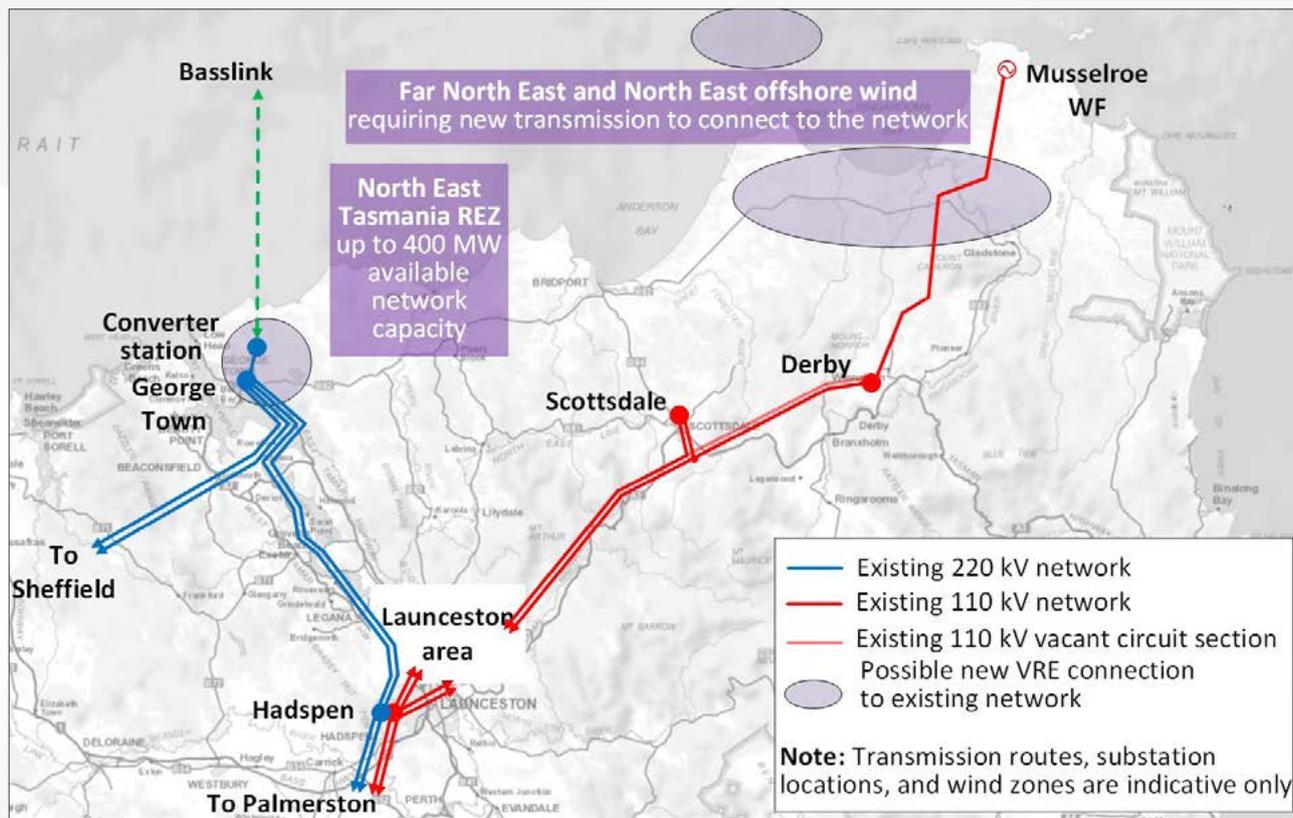


Figure 3-5: North East Tasmania REZ transmission network and hosting capacity

3.5.3.1. Scottsdale–Derby corridor capacity

At various times, Musselroe Wind Farm can be constrained by the limited thermal capacity within this corridor. Thermal constraints bound for more than 500 dispatch intervals in 2021, as outlined in Table 5-5 in chapter 5.

Installation of a weather station near Derby would enable this corridor to be operated using dynamic line ratings which would provide access to additional capacity under many practical scenarios to help mitigate existing generation constraints. The project is estimated at \$0.3 million and is planned to be delivered in 2025.

3.6. Hydrogen development

The Tasmanian Government is highly supportive of a green hydrogen industry in Tasmania. Section 1.4.3 provides an overview of the Tasmanian Renewable Hydrogen Action Plan. The plan identifies two locations for large-scale renewable hydrogen production and potential export facilities; the BBAMZ, and industrial precincts in north-west Tasmania (such as Port Latta or Burnie).

The upper-end of potential hydrogen load is significant in comparison to the size of the existing Tasmanian power system. As presented in Section 2.1.1, the median demand in Tasmania is approximately 1,198 MW. Many hydrogen proposals are in the hundreds of megawatts, with the Tasmanian Renewable Hydrogen Action Plan presenting a potential 1,000 MW total installed capacity. As such, the integration requirements of large-scale hydrogen production into the Tasmanian network are being carefully considered. The network requirements to facilitate hydrogen development will be dependent on the size, location, and technology of the loads.

It is assumed the connection of Hydrogen projects is likely to occur broadly in four tranches:

- Tranche 1, up to 300 MW;
- Tranche 2, an additional 200 to 400 MW (up to approximately 700 MW);
- Tranche 3, a further 300 MW (up to 1,000 MW); and
- Tranche 4, beyond 1,000 MW

The connection of loads of the magnitudes currently being contemplated, will need to be considered from four separate but highly interrelated perspectives:

- Network capacity;
- The overall energy balance that can be achieved in Tasmania;
- Access to sufficient levels of firming capacity; and
- Power system security and resilience outcomes.

3.6.1. Bell Bay Developments

The BBAMZ has been identified as the site for one of two potential hydrogen hubs in Tasmania, due to its access to:

- certifiable renewable energy;
- high-quality fresh water;
- deep-water port facilities; and
- significant vacant industrial land in close proximity to the port.

The George Town area is supplied via two double circuit 220 kV transmission lines and the Basslink HVDC interconnector. There is also currently 386 MW of gas fuelled generation within the George Town area. The overview of the Northern network, with indicative future augmentations supporting the proposed tranches of hydrogen and future renewable energy developments is shown in Figure 3-6.

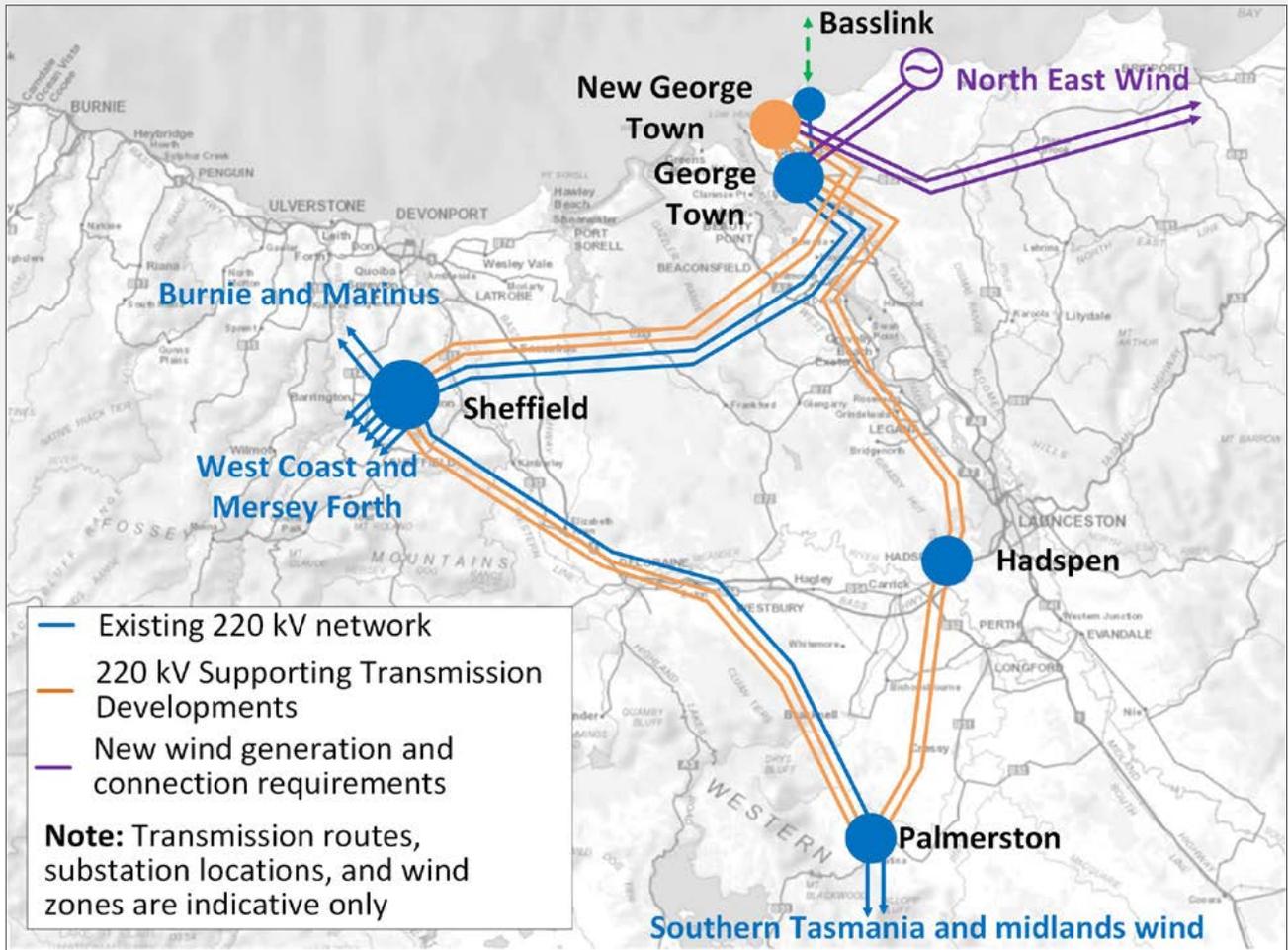


Figure 3-6: Northern transmission indicative network developments supporting hydrogen load connections

The various tranches of new load are being differentiated by the level of augmentation required to increase the supportable load within the George Town area while also taking account of the new generation that will be developed in parallel.

Table 3-5: Future hydrogen driven network augmentations: Bell Bay region

Sequence	Development considerations
<p>Tranche 1: up to 300 MW</p>	<p>Up to 300 MW of new load could be supplied within the BBAMZ from the existing transmission network, with appropriate reactive support and participation of the new load(s) in the Tasmanian Integrated System Protection Scheme (TISPS).</p> <p>It is assumed that Tasmania will aim to keep its energy independence in the longer term and that the 300 MW of new load will be developed in parallel with 600 – 750 MW of new wind generation.</p> <p>One of the material considerations is where and when the new Tasmanian generation is developed. While it is possible to supply the load (when considered in isolation) without material network augmentation, in order to maintain the on island energy independence, it is likely to require the augmentation of the Palmerston to Sheffield 220 kV transmission line. Power system security requirements are also likely to dictate this augmentation once the additional load is connected at George Town.</p> <p>This quantum of new load (300 MW) would still permit up to 500 MW of Basslink export when generation from the west and south can be relatively balanced to prevent overloading of the Hadspen – George Town corridor.</p> <p>New switchyards in the George Town area are also being proposed to assist with managing a number of challenges and system risks associated with connecting significant new loads into the existing George Town substation. The location of the new switchyards is currently being determined and will be dimensioned to accommodate all reasonably anticipated developments including both load and generation.</p>
<p>Tranche 2: An additional 200 to 400 MW (up to approximately 700 MW)</p>	<p>Once the new load supplied from George Town exceeds 300 MW, in the absence of network augmentation, Basslink exports will become increasingly constrained over longer periods of time.</p> <p>Additional reactive support and participation of the new load(s) in the required TISPS will also be required, including duplication of the Sheffield-George Town 220 kV corridor.</p>
<p>Tranche 3: A further 300 MW (up to 1,000 MW);</p>	<p>In order to either connect additional load or reinstate /maintain Basslink export capability, the next network augmentation that will be required to facilitate the next tranche of load is the augmentation of the Palmerston to Sheffield 220 kV transmission line, if it has not already been augmented due to generation requirements. At the upper end of the loading scale, the Palmerston-Hadspen-George Town 220 kV corridor will need to be augmented to increase its capacity.</p>

Tranche 4:**Beyond 1,000 MW**

Once the total area load starts to exceed 1,000 MW, the network augmentations required to transfer the energy to the new load becomes increasingly dependent on where the energy is coming from.

Coordinating the placement of the new renewable generation to maximise the utilisation of existing transmission capacity will materially reduce the amount of required network investment.

The ability of the network to support of hydrogen related load in the Bell Bay area would depend on:

- the required load factor;
- the expected flow path(s) for the required energy (North East REZ, North West REZ, Central Highlands REZ, or Basslink);
- what other new loads are being connected in the George Town supply corridors;
- additional system strength requirements;
- the reactive power requirements of the load; and
- participation by the producers of hydrogen in relevant System Protection Schemes.

Detailed technical analysis is currently being undertaken to determine the maximum supportable load in the George Town area once a new high capacity 220 kV double circuit transmission is commissioned and the appropriate level of additional reactive support is provided.

3.6.2. North West hydrogen developments

The north-west area is supplied via a combination of old 110 kV and 220 kV transmission lines. In support of a wind proposal located in the far north-west, TasNetworks and the wind farm proponent are progressing planning approvals for a transmission line from the wind farm site, via Hampshire Hills, to Staverton and Sheffield. The indicative future North West network, supporting interconnectors, renewable energy and potential load connections is outlined in Section 3.5.1.

Should the wind development in the far north-west not proceed and the establishment of a north-west hydrogen hub precede the establishment of Marinus Link, then it would be necessary to bring forward the upgrade to the existing Sheffield–Burnie 220 kV line ahead of the Marinus Link requirement.

Table 3-6: Future hydrogen driven network augmentations: North West region

Sequence	Development considerations
Tranche 1: up to 300 MW	<p>Should the first 750 MW stage of Marinus Link proceed and 300 MW of load associated with the production of hydrogen emerge in the Burnie area, the maximum demand in the north-west would exceed 1,100 MW.</p> <p>North-west transmission upgrades concurrent with the first stage of Marinus Link will be sufficient to also support the development of up to a 300 MW hydrogen hub in the Burnie area.</p>
Tranche 2: An additional 200 to 400 MW (up to approximately 700 MW)	<p>If a hydrogen hub develops in the north-west involving loads of up to 700 MW, including the load associated with stage 1 of Marinus Link, maximum demand in the north-west would possibly exceed 1,550 MW.</p> <p>This load could be supported by the north-west transmission upgrades concurrent with Marinus Link.</p> <p>If stage 2 of Marinus Link progresses, with 700 MW hydrogen related load in the north-west, the maximum demand in the north-west could potentially exceed 2,300 MW. The north-west transmission developments concurrent with Marinus Link would still be sufficient to meet this higher load, but only if significant wind generation is developed within the North East Tasmanian REZ. This is considered a likely outcome given the amount of load in the north-west area associated with both Marinus Link and hydrogen production.</p> <p>If sufficient wind generation does not emerge in the North West Tasmanian REZ and is, instead, developed in the North East Tasmanian REZ and Central Highlands REZ, then the transmission capacity from those REZs to the north-west would be required, in addition to the proposed north-west transmission developments concurrent with Marinus Link.</p>
Tranche 3: A further 300 MW (up to 1,000 MW);	<p>Were up to 1,000 MW of hydrogen related load to be added in the north-west, the possible maximum demand in the area would exceed 1,850 MW for Marinus Link stage 1 and 2,600 MW for stage 2.</p> <p>The development of the transmission network to support this level of load is again dependent on the extent to which new wind generation is developed in the North West Tasmanian REZ.</p> <p>If sufficient wind generation is developed in the north-west Tasmanian REZ, then the transmission network developments in north-west Tasmania concurrent with Marinus Link would be sufficient to cater for this level of load.</p> <p>If sufficient wind generation does not emerge in the North West Tasmanian REZ and is, instead, developed in the North East Tasmanian REZ and Central Highlands REZ, then transmission capacity from those REZs to the Burnie area would be required, in addition to the proposed north-west transmission developments concurrent with Marinus Link.</p>
Tranche 4: Beyond 1,000 MW	<p>Coordinating the placement of the new renewable generation to maximise the utilisation of existing transmission capacity will materially reduce the amount of required network investment.</p>

Our website provides a Renewable Hydrogen Connections document for those seeking more information on opportunities, network pricing guidelines and attributes of the Tasmanian power system: www.tasnetworks.com.au/Connections/Connections-content/Renewable-Hydrogen

3.7. Palmerston–Sheffield 220 kV transmission corridor

The Palmerston–Sheffield 220 kV transmission line is a critical part of the existing transmission network. It forms part of the Palmerston–Sheffield–George Town triangle, which:

- connects the north-west and West Coast, George Town, and southern area networks;
- supplies the major industrial customers in George Town;
- enables Basslink export and import from George Town Substation; and
- transmits generation from the north-west and West Coast to Hobart and southern Tasmania.

The Palmerston–Sheffield 220 kV transmission line is single-circuit only and has a lower thermal capacity than the other circuits in the triangle. It also plays a major role in transient stability constraints given that loss of this circuit dramatically increases the transmission distance between Sheffield and Palmerston. It will become a constraining element in a future network state when increased power flows are needed across the network. Figure 3-7 presents the Palmerston–Sheffield 220 kV transmission line and Palmerston–Sheffield–George Town triangle.

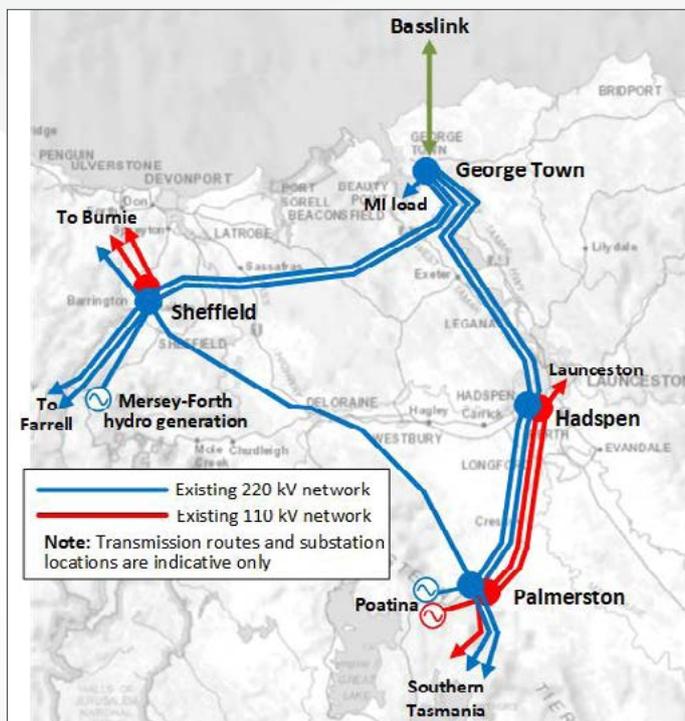


Figure 3-7: Palmerston–Sheffield 220 kV transmission line and the Palmerston–Sheffield–George Town triangle

As described in this chapter, there is a number of future power system scenarios where augmentation of the Palmerston–Sheffield 220 kV transmission corridor is required:

• Marinus Link

The existing transmission network in north-west Tasmania will require augmentation to support the increased power flows to and from Marinus Link. This includes augmentation of the Palmerston – Sheffield 220 kV corridor. Refer Section 3.3 for more information.

• North West Tasmania REZ

If new large VRE develops in the North West Tasmania REZ, the Palmerston–Sheffield 220 kV transmission line will become more congested. Augmentation of the Palmerston–Sheffield 220 kV transmission corridor can be triggered by 230 MW of new generation in the North West Tasmania REZ, prior to Marinus Link. Refer Section 3.5.1.5 for more information.

• Hydrogen development

The existing transmission network can accommodate up to 300 MW load in the BBAMZ, with the existing Palmerston–Sheffield 220 kV transmission line being a limiting factor. Augmentation of the Palmerston–Sheffield 220 kV transmission corridor will enable higher amounts of hydrogen load to be supported at George Town. Refer Section 3.6 for more information on hydrogen development.

Given the criticality of the Palmerston–Sheffield 220 kV transmission corridor for almost all future scenarios, we are exploring strategies to complete an augmentation ahead of the Marinus Link requirements, if required. This includes addressing critical-path items which may impact our ability to deliver any augmentation to meet external triggers.

We engaged with AEMO so that the importance of the Palmerston–Sheffield 220 kV transmission corridor to all future scenarios is appropriately highlighted in the 2022 ISP.

3.8. Upper Derwent 110 kV transmission network

The Upper Derwent 110 kV transmission network comprises the transmission lines and substations from Tungatinah Substation to Waddamana Substation (northwards) and New Norfolk Substation in the southern transmission network (southwards). This network is some of the oldest in Tasmania, with sections originating from the 1930s constructed to support the Tarraleah hydropower scheme.

The 110 kV network operates independently from the 220 kV network in this area, with the interconnection to the 220 kV network only occurring at Palmerston Substation in the north and in Hobart area in the southern transmission network. Figure 3-8 presents the Upper Derwent 110 kV transmission network and surrounds. 3.8.1. Reducing losses in Upper Derwent 110 kV transmission network

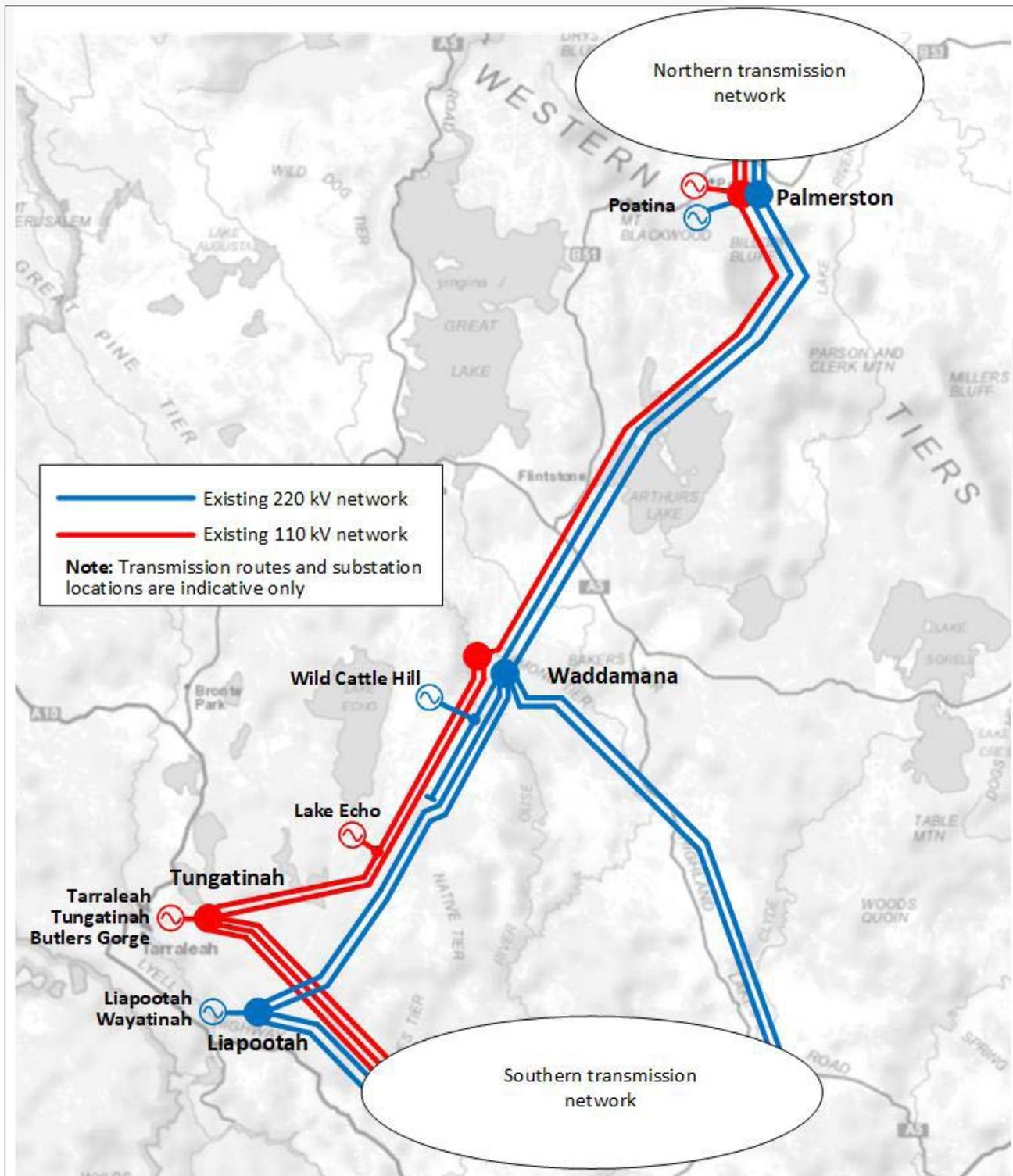


Figure 3-8: Upper Derwent area transmission network

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 from power stations connected to Tungatinah Substation, which is transmitted via the 110 kV network to Palmerston Substation and the southern transmission network. Providing a local interconnection between the 110 kV and 220 kV will allow for more efficient transfer of the power through the 220 kV network, reducing network losses.

We have assessed two options to provide access for Upper Derwent 110 kV generation to the 220 kV network, as presented in Figure 3-9.

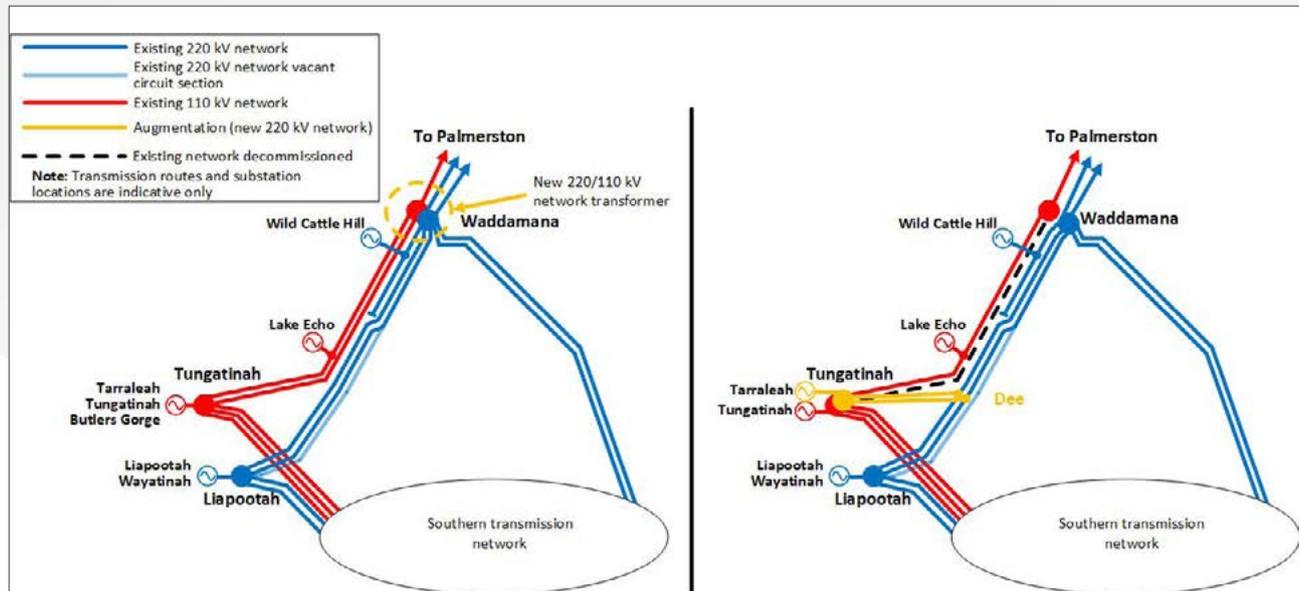


Figure 3-9: Options to reduce losses in Upper Derwent 110 kV transmission network

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. This is the option, presented on left in Figure 3-9, retains the 110 kV network and allows power to flow to the 220 kV network at Waddamana Substation. It is a relatively low complexity solution, and is economically justified immediately with the savings in reduced network losses being greater than the cost of installing the transformer. This option is estimated to cost \$9.6 million.

3.8.2. Repurposing the Tarraleah hydropower scheme

As part of its BOTN initiative, under the *Hydropower system improvement* study area, Hydro Tasmania is assessing the repurposing of Tarraleah hydropower scheme²⁸. The scheme currently has 90 MW of installed capacity, with no effective short-term flexibility to vary generation output. It is also one of Tasmania's oldest hydropower schemes, and requires significant investment to ensure its operation into the future. Repurposing the scheme will allow Tarraleah to meet the needs of the future power system by increasing the installed generation capacity and changing its dispatch flexibility from a base-load power station to being fully flexible.

Hydro Tasmania is continuing to assess its preferred option for repurposing the Tarraleah hydropower scheme, including maintaining the existing station (though this option appears less likely). However the installed capacity may be up to 220 MW, with a 220 kV network connection. The project timing is proposed to align with the first 750 MW stage of Marinus Link in 2029.

We continue to engage with Hydro Tasmania in determining its preferred option to repurpose the Tarraleah hydropower scheme, and the transmission network connection and augmentation requirements to facilitate it.

3.9. 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 5.2.2 of this APR.

In 2021, TasNetworks progressed a project to install new dynamic reactive support in the north-west in order to address the previously identified system strength limitations at Burnie 110 kV substation. The provision of fast acting dynamic support will allow the network to successfully operate at a lower minimum pre-contingent fault level of 750 MVA (down from the 850 MVA currently required). A ± 8 MVar STATCOM will be installed at Port Latta Substation to deliver these benefits, at an estimated cost of \$3.0 million. It will be implemented by Q1 2023.

²⁸ <https://www.hydro.com.au/clean-energy/battery-of-the-nation/hydro-system-improvement/hydro-system-faqs>

3.10. Data centre load developments and battery energy storage systems connections

There has been continued interest from data centre proponents, looking to establish new connections at various locations across the state. In the past 24 months, potential interest has totalled more than 700 MW, with the size of connections ranging between 5 MW to greater than 100 MW.

The larger of these connections presents a significant increase in local demand, in some cases equivalent to more than double the full loading capacity of many existing substations in the network.

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 loads and their potential impact on frequency management).

TasNetworks continues to work with existing and prospective data centre proponents for new and modified connections to understand the impacts on transmission system capability and operation, as well as review of the relevant performance specifications.

TasNetworks has also received a notable level of interest from battery proponents, who can offer potential network services including power balancing across the broader network, system strength and inertia support, voltage and frequency control capabilities and power quality support. We continue to consult with prospective battery proponents to identify the optimal solutions for connection and integration to our network.



04 Area planning constraints and developments

- We consider a number of geographic planning areas in Tasmania: North West and West Coast, Northern, Central, and South.
- We are continuing with targeted reliability improvement projects for specific reliability communities.
- We retain exemptions from jurisdictional planning requirements for three locations in the transmission network in the North West and West Coast planning area.
- We welcome feedback on prospective alternative solutions to our augmentation and asset retirement and replacement plans.

Area planning constraints and developments

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 Appendices A.2 and A.3, which 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 transmission and distribution networks for each planning area:

- 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 telecommunications network.

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 in Tasmania and Table 4-1 provides brief descriptions.





Figure 4-1: Geographical planning areas

Table 4-1: Network planning areas

Planning area	Description
North west and West Coast	North west 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. The West Coast of Tasmania, covering the area supplied from Farrell Substation.
Northern	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 Coles Bay. This area is supplied from the 220 kV backbone network at Hadspen, George Town and Palmerston (near Poatina) substations.
Central	The Central Highlands and Derwent Valley areas of Tasmania. This area also includes the supply at Strathgordon. The area is generally supplied from the 110 kV network between New Norfolk, Tungatinah (near Tarraleah) and Waddamana substations.
Southern	Southern planning area covered by the Greater Hobart and other areas of southern Tasmania. Localities outside of Greater 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 broadly is supplied through three 220 kV connections from Gordon, Liapootah and Waddamana between Chapel Street (in Glenorchy), Creek Road, Risdon, and Lindsfarne substations. Areas to the north and east of Greater Hobart are supplied via the peripheral 110 kV network from Lindsfarne Substation. Areas to the south of Greater Hobart are supplied from the 110 kV network from Chapel Street Substation.

4.3. Notes for all geographic planning areas

4.3.1. Planning area diagrams

The diagrams in each planning area show the transmission and sub-transmission networks, and the distribution supply area of each connection point substation.

4.3.2. Availability to connect to the network

We have connection points at both the transmission and sub-transmission levels across our network with capability to connect load and generation. Hosting capacity is dependent on factors which include ratings of connection points and upstream network, network stability, security and reliability considerations.

These sections present the available firm headroom at the time of substation maximum demand for each connection point substation. 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.

New loads above the available headroom presented may be connected without capacity augmentation, however would require operational solutions. Examples of these include load management (where load is reduced at times of high demand to maintain the substation within firm ratings) or post-contingent load reduction schemes (potentially utilising substation short-term ratings).

Detailed information on substation capabilities and substation load profiles are provided as supplementary information to this APR, and are available as downloadable appendices ‘Maximum demand and energy forecasts’ and ‘Substation load profiles’ on our website: www.tasnetworks.com.au/apr

4.3.3. Network limitations and developments

The network limitations and development sections provide details on our proposed augmentation projects over the next ten years that address forecast network limitations. We identify points on the network that are inadequate to meet forecast generation or demand due to limited thermal capacity, a jurisdictional network planning requirement or other technical limit. Section 4.4 presents technical factors affecting the network in Tasmania. Reliability planning criteria is presented in Appendix A.3.3 (transmission) and A.3.4 (distribution).

We include information on the type of limitation and our preferred network solution, with estimated timing and cost, and other potential solutions. We identify the opportunity for demand management solutions where a 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.

4.3.4. Additional information on limitations

We provide more information on all limitations as supplementary information to this Annual Planning Report (APR) '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. These are provided to enable consistency of information for readers when comparing between APRs of transmission and distribution network service providers across the National Electricity Market (NEM).

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

4.3.5. Future connection points

This section presents 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 cost.

4.3.6. Targeted reliability corrective action

This section presents any targeted reliability corrective action projects in each planning area. Distribution reliability community performance is presented in Section 6.4.1, with our reliability compliance and corrective action programs presented in Section 6.4.4. In this chapter, we present the larger targeted reliability improvement projects.

4.3.7. Committed and completed developments

This section for each planning area presents the material network projects that are committed or that have been completed since our 2021 APR. Our definition of committed projects is as used in the Regulatory Investment Test (RIT). We will report on the progress of our committed projects in future APRs.

4.4. Other factors affecting the network

4.4.1. Fault levels

Network fault level is defined in terms of apparent power (mega-volt ampere (MVA)) or 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 to this APR 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.

4.4.1.1. 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, as in Table 4-2. These sites are managed through appropriate operational strategies which we review as network changes occur.

Fault level constraints exist at three additional connection points due to limitations within the distribution network. In the Scottsdale area, some fuse assemblies have a low fault rating and at Smithton Substation, a distribution earthing issue has required the fault level to be reduced until corrective action can be implemented. There are also fault level limitations at Port Latta Substation to comply with a customer connection agreement. We are currently undertaking

action to remove the limitation at Scottsdale Substation, and assessing options to address the limitations at Port Latta and Smithton substations. Table 4-2 presents the operational procedures in place to manage the fault level issues at these connection points in the meantime.

Table 4-2: 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)		
Smithton (22)	Distribution earthing issue	Ongoing investigations to assess and address earthing issues at Smithton substation.
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)		
Electrona (11)	Fault level exceeds 13 kA	High voltage bus coupler operated normally-open.
Port Latta (22)	Customer connection agreement	
Scottsdale (22)	Low fault rating of distribution fuses	Fuse assemblies being replaced in the Scottsdale area to address issue, with options for Port Latta Substation being assessed.

4.4.1.2. Fault levels and 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 switchings 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.

High Voltage Direct Current (HVDC), wind and solar farms also 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. This means that future wind or solar farms which may seek connection in weaker parts of the network may be required to install system strength remediation schemes. The Australian Energy Market Commission (AEMC) finalised a rule change in October 2021 which introduces significant reforms addressing who is responsible for provision of system strength, when services must be available and how the services are paid for. Details of this rule change are outlined in Section 5.2.2.5.

4.4.2. Voltage management

Maintaining voltages within target ranges ensures the safety of our people and equipment, and also 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 Section 5.3.

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 photovoltaic (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 by National Electricity Rules (**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 on the TasNetworks website.

4.4.3. 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 with planned investments to address asset management requirements identified in Section 4.9.

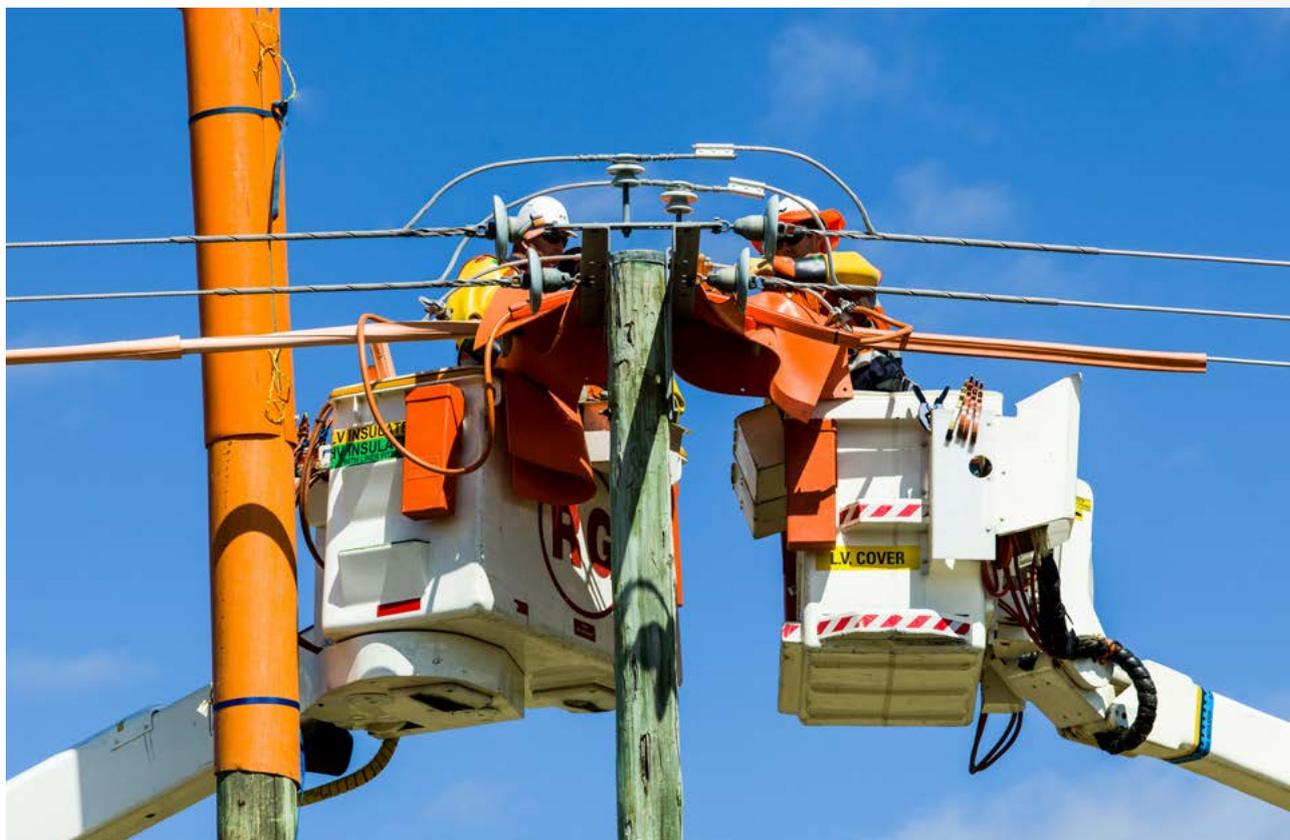
4.5. North West and West Coast planning area

The North West and West Coast planning area covers two separate areas 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 area comprises residential, commercial, and small to medium scale industries. There are two customers connected directly to the transmission network. Emu Bay Substation, which was established to supply a now-closed paper manufacturing plant, supplies part of the Burnie central business district and is the only 11 kV network in the area.

The West Coast area is characterised by mining loads, supplied from both the transmission and distribution networks, and tourism and aquaculture centres. 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 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 West Coast (Granville Harbour Wind Farm) of Tasmania.



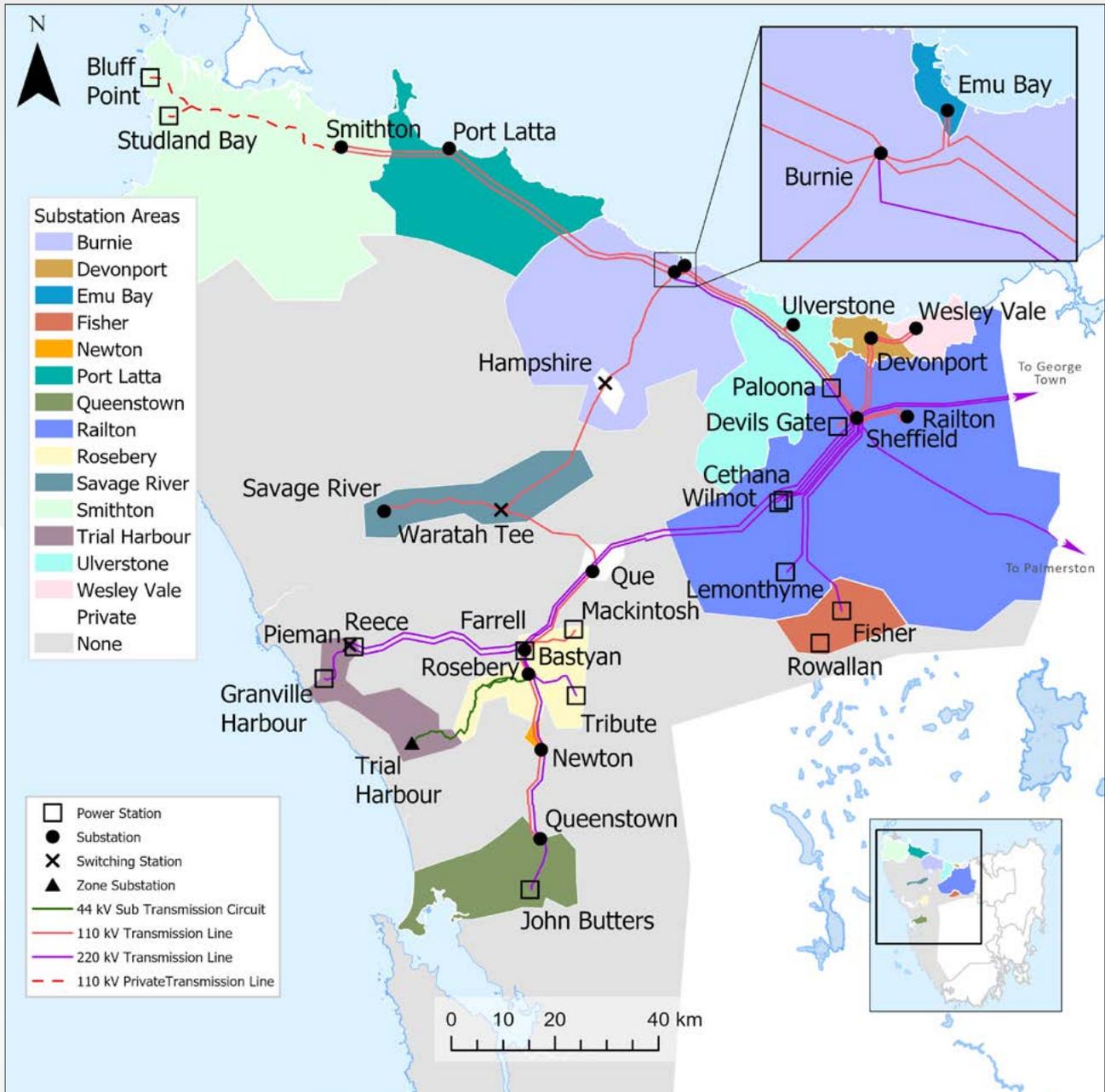


Figure 4-2: North West and West Coast planning area network

4.5.1. Availability to connect to network

Table 4-3 provides the available headroom for new load at each connection point substation in the North West and West Coast planning area. The table also provides the installed total and firm capacity of each substation. For single-transformer substations and substations where existing demand exceeds the substation firm capacity, the available headroom is zero.

Table 4-3: North West and West Coast planning area substation available headroom

Substation	Installed capacity (MVA)		Available headroom (MVA)
	Total	Firm	Firm
Rosebery (44 kV)	102	66	19
Emu Bay	76	38	28
Queenstown (22 kV)	50	25	19*
Trial Harbour Zone	40	20	0*
Ulverstone	90	45	13
Smithton	70	35	12
Wesley Vale	50	25	13
Rosebery (22 kV)	19	9	7
Devonport	110	60	5
Port Latta	45	22.5	0
Burnie	120	60	0
Railton	100	50	2
Savage River	45	22.5	0*
Sheffield	25	0	0
Newton	22.5	0	0*
Que	50	0	0*

* Non-firm transmission or sub-transmission network connection

4.5.2. Network limitations and developments

The following tables present our completed and committed projects, future connection points, and targeted reliability corrective action in the North West and West Coast planning area over the next 10 years. There are no forecast network limitations or proposed developments.

4.5.2.1. Farrell-Que-Savage River-Hampshire transmission line reliability

The combined loading on the 110 kV transmission line supplying customers at Que and Savage River, at times exceeds network planning requirements²⁹ (25 MW of lost load, and 300 MWh of unserved energy following a single element outage). TasNetworks is progressing investigations to assess this issue which may trigger network augmentation or a supply exemption.

Table 4-4: North West and West Coast planning area completed and committed projects

Project and description
Completed
Port Latta Substation supply reconfiguration from loop-in-and-out to double tee.
Committed
Emu Bay Substation:
Replacement of the existing aged and deteriorating Merlin Gerin 11 kV switchgear with new 22 kV rated switchgear.
Installation of 22 kV/11 kV auto transformers for connection of 11 kV feeders to 22 kV switchboard.
North West Dynamic Reactive Support- installation of ± 8 MVar STATCOM at Port Latta Substation.
Zeehan reliability improvement (44 kV sub-transmission line switching augmentation and additional generation support).

²⁷ 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

Table 4-5: North West and West Coast planning area future connection points

Project description	Initial loading level	Timing	Cost (\$m)
<p>Emu Bay Substation 22 kV conversion</p> <p>The existing 11 kV switchboards are in declining condition and do not have arc fault containment which is a safety concern and does not align with TasNetworks' strategy.</p> <p>Emu Bay Substation supplies an isolated 11 kV network within a greater 22 kV distribution network in north-west Tasmania; a major consequence of this network arrangement is that the load supplied by Emu Bay Substation has no alternative supply points and cannot provide network support to the surrounding substations.</p> <p>The objective of this project is to utilise the ability to reconfigure the secondary winding of the supply transformers at Emu Bay Substation, introducing a new 22 kV supply point within the Burnie area. Emu Bay Substation will in future be able to supplement the 22 kV network and potentially de-load/transfer load away from the Burnie Substation 22 kV supply point.</p> <p>The project consists of discrete stages, the first of which involves the replacement of the existing 11 kV switchgear; installation of new 22/11 kV transformers to maintain supply to existing 11 kV feeders, both committed and in progress.</p>	10 MW	2025	2.3

Table 4-6: North West and West Coast planning area 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 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. Refer Figure 4-3.</p> <p>We have already undertaken two projects, and are currently undertaking another, to improve reliability the Zeehan community (refer Table 4-4). We will monitor the reliability improvement from these projects, and propose one further project—to provide a second injection point into the Zeehan community.</p> <p>We propose to introduce a new 22 kV connection point at Pieman Switching Station to provide an alternative supply to Zeehan via feeder 99981 under contingency scenarios.</p> <p>This project is estimated to cost \$6 million with completion anticipated by 2026. A regulatory investment test for distribution (RIT-D) will be required for this project.</p>

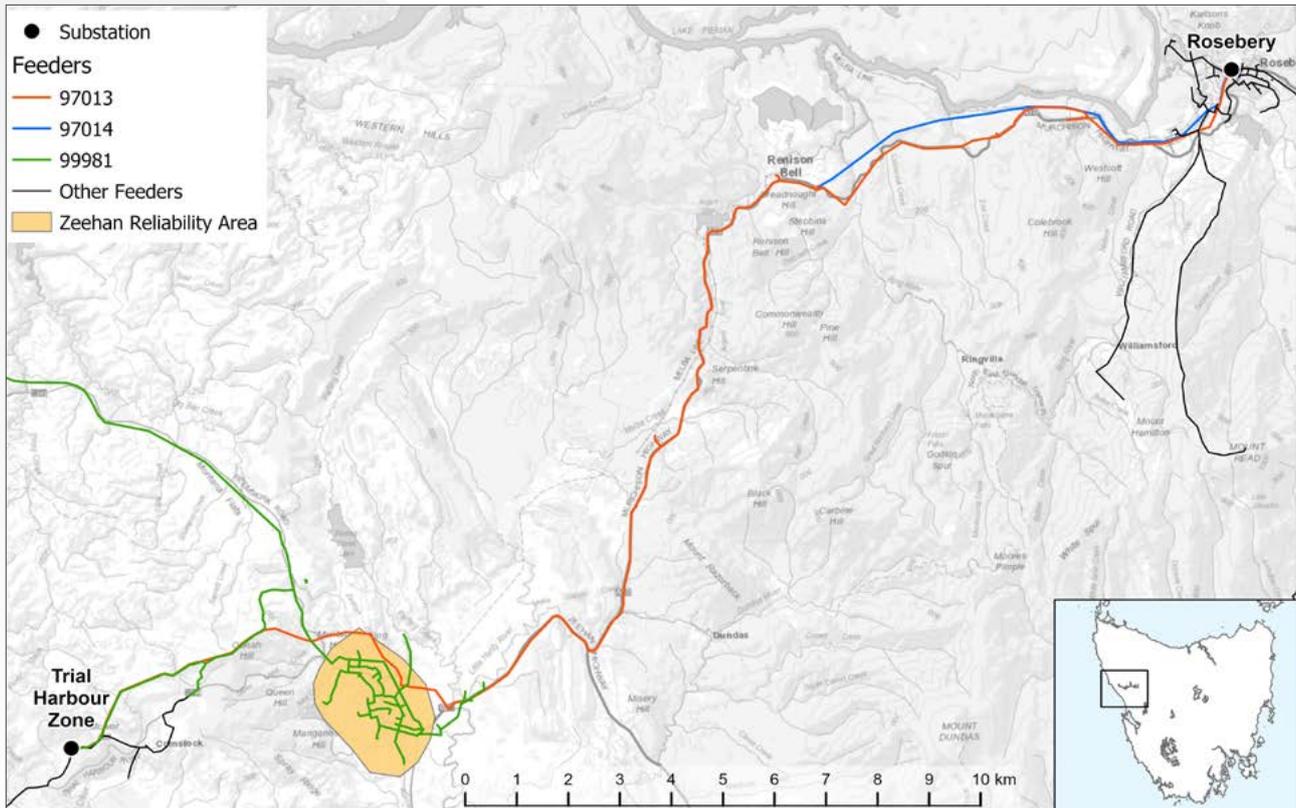


Figure 4-3: Zeehan reliability community

4.5.3. Deferred or averted limitations

4.5.3.1. Exemptions under jurisdictional network planning requirements

We have exemption agreements with affected customers under the jurisdictional planning requirements for three parts of the transmission network in the North West and West Coast planning area. 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

Asset	Location of affected customers	Performance requirement	Exemption ceases
Farrell–Rosebery–Newton–Queenstown 110 kV transmission circuit	Newton and Queenstown substations	Loss of circuit may exceed 300 MWh of unserved energy.	2025
Newton Substation supply transformer	Newton Substation	Loss of supply transformer may exceed 300 MWh of unserved energy	2025
Waratah–Savage River 110 kV transmission circuit section	Savage River Substation	Loss of circuit section may exceed 300 MWh of unserved energy	2023

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. We do not consider circumstances to have materially changed since the exemption period commenced and will consult the relevant customers at the time the current agreement ends.

4.6. Northern planning area

The Northern planning area is diverse with the urban and commercial area in 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 and the north-east and east coast of Tasmania. Figure 4-4 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 load 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.

4.6.1. Availability to connect to the network

Table 4-8 provides the available headroom for new load at each connection point substation in the Northern planning area. The table also provides the installed total and firm capacity of each substation. For single-transformer substations and substations where existing demand exceeds the substation firm capacity, the available headroom is zero.

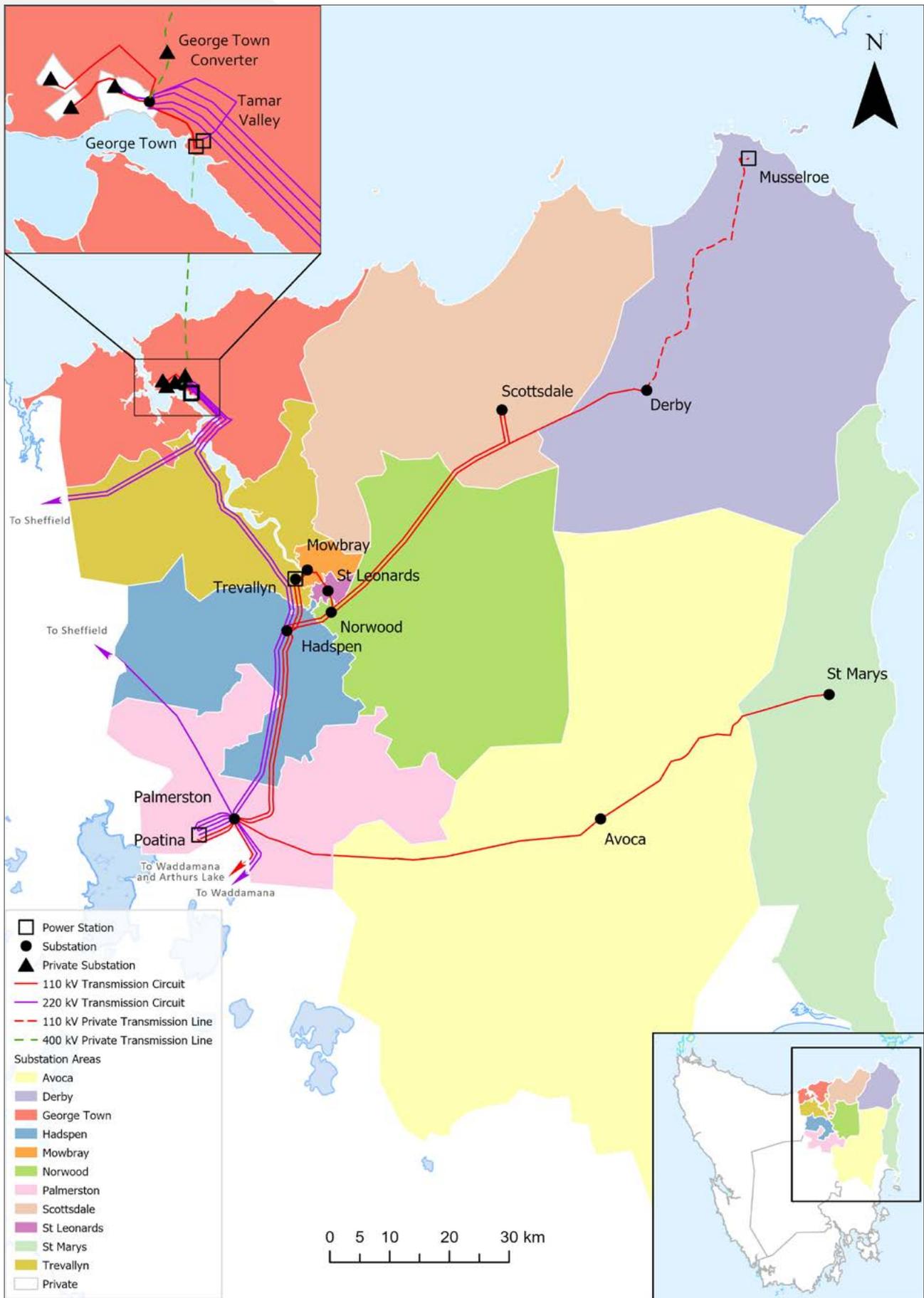


Figure 4-4: Northern planning area network

Table 4-8: Northern planning area substation available headroom

Substation	Installed capacity (MVA)		Available headroom (MVA)
	Total	Firm	Firm
Trevallyn	150	100	33
St Leonards	120	60	10
George Town	96	48	26
Norwood	100	50	21
Scottsdale	63	31.5	19
Palmerston	50	25	12
Mowbray	100	50	12
Hadspen	100	50	0
St Marys	20	10	0*
Avoca	17	0	0*
Derby	25	0	0*

* Non-firm transmission or sub-transmission network connection

4.6.2. Network limitations and developments

The following tables present our completed and committed projects and forecast network limitations and the proposed solutions in the Northern planning area over the next 10 years. There are no proposed future connection points, or targeted reliability corrective action.

4.6.2.1. George Town 220 kV bus coupler replacement

The existing 220 kV bus coupler was identified as having insufficient protection functionality. A replacement circuit breaker assembly to restore full bus section protection is planned to be installed in Q1 2023.

Table 4-9: Northern planning area completed and committed projects

Project and description
Completed
Nil
Committed
George Town Substation 220 kV bus coupler replacement.

Table 4-10: Northern planning area network limitations and proposed solutions

Limitation	Proposed solution	Timing	Cost (\$m)
St Marys Substation Currently, supply transformers operate non-firm. However, continue to meet reliability planning criteria	As the substation continues to meet reliability planning criteria, and with limited load growth, we propose to continue the post-contingency load-shedding scheme Other augmentation solutions include permanent load transfer, and supply transformer replacement.	N/A	N/A

4.6.3. Deferred or averted limitations

4.6.3.1. St Marys Substation

As the substation continues to meet reliability planning criteria, and with limited load growth, we propose to continue the post-contingency load-shedding scheme.

Other augmentation solutions include permanent load transfer, and supply transformer replacement.

4.7. 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. There is one major industrial customer supplied directly from the transmission network. Figure 4-5 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. Power stations in the Derwent hydropower scheme have a capacity of more than 500 MW and connect into both the 110 kV and 220 kV networks. Gordon Power Station has a capacity of 432 MW. Wild Cattle Hill Wind Farm (144 MW) connects to Waddamana Substation.

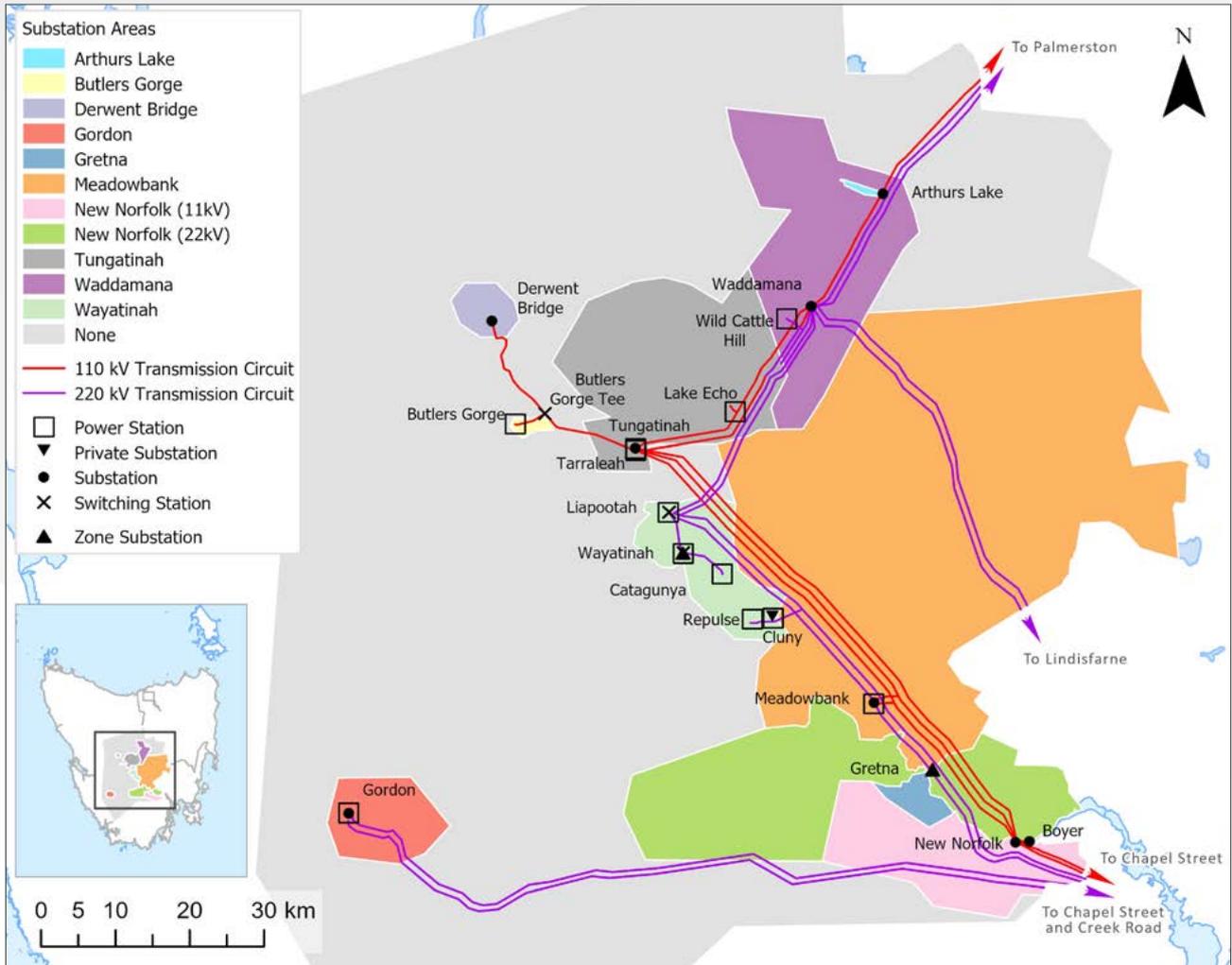


Figure 4-5: Central planning area network

4.7.1. Availability to connect to the network

Table 4-11 presents the available headroom for new load at each connection point substation in the Central planning area. The table also provides the installed total and firm capacity of each substation. For single-transformer substations and substations where existing demand exceeds the substation firm capacity, the available headroom is zero.

Table 4-11: Central planning area substation capacity availability

Substation	Installed capacity (MVA)		Available headroom (MVA)
	Non-Firm	Firm	Firm
New Norfolk	60	30	11
Arthurs Lake	25	0	0*
Derwent Bridge	6	0	0*
Meadowbank	10	0	0*
Tungatinah	13	0	0*
Waddamana	4	0	0*

* Non-firm transmission or sub-transmission network connection

4.7.2. Network limitations and developments

There are no forecast limitations, proposed network developments, targeted reliability corrective action, or future connection points in the Central planning area over the next 10 years.

4.8. Southern planning area

The Southern planning area covers the Greater Hobart region and the southern part of Tasmania. The Greater Hobart area is mostly urban, with rural supplies towards the north. Load in the Greater Hobart area is a mixture of commercial, industrial and urban residential loads, however the area north to Kempton and the South Arm peninsula, supplied from Rokeby Substation, is predominately rural load.

The Greater Hobart area is in most part supplied from the backbone transmission network 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. The distribution network is also supplied directly from transmission substations, as it is in the majority of the network. 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. There is one major energy user directly connected to the transmission network.

The southern part of Tasmania also 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 4-6 presents a diagram of the Southern planning area with substation supply areas.

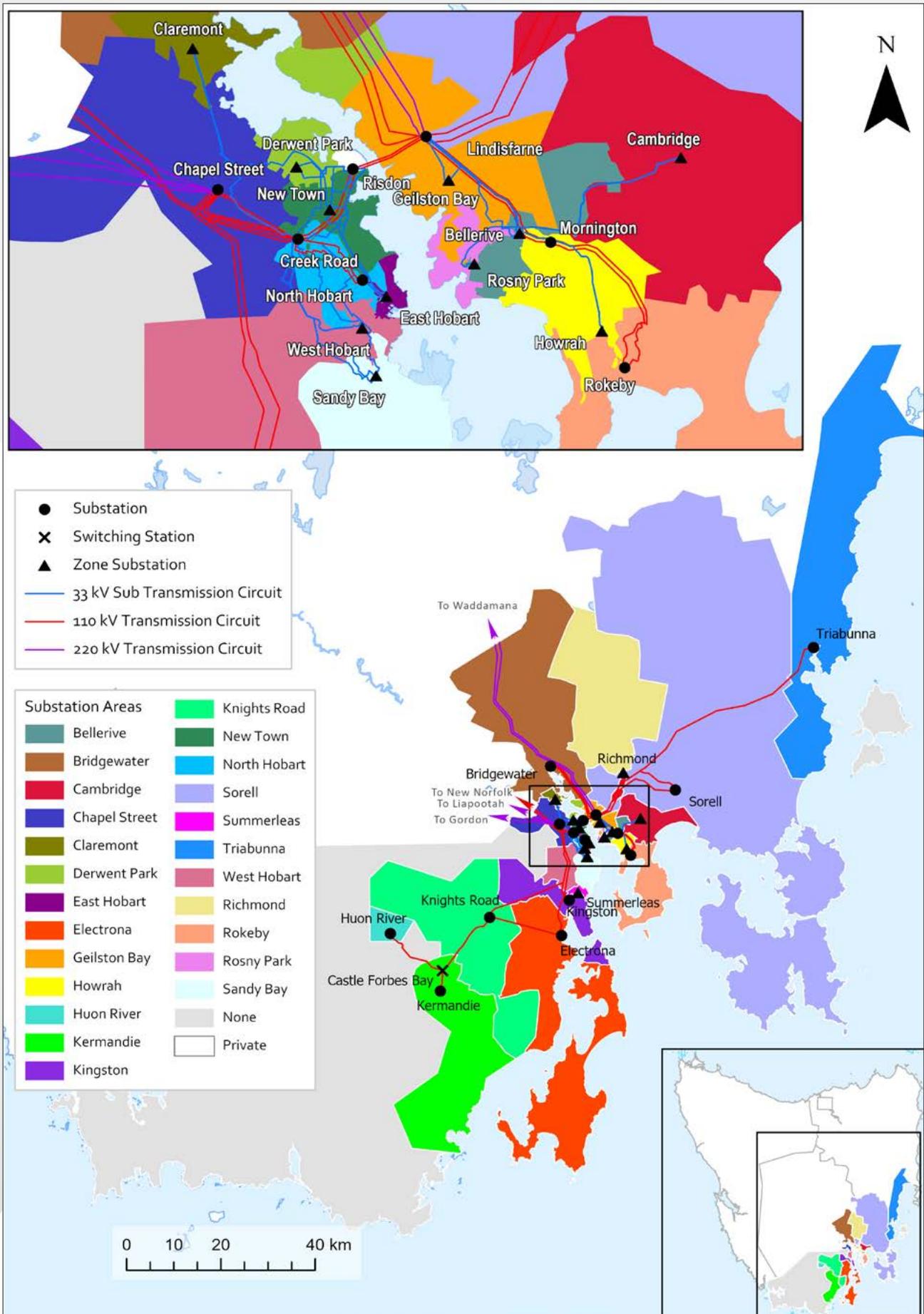


Figure 4-6: Southern planning area network

4.8.1. Availability to connect to the network

Table 4-12 provides the available headroom for new load at each connection point substation in the Southern planning area. The table also provides the installed total and firm capacity of each substation. For single-transformer substations and substations where existing demand exceeds the substation firm capacity, the available headroom is zero.

Table 4-12: Southern planning area substation available headroom

Substation	Installed capacity (MVA)		Available headroom (MVA)		Substation	Installed capacity (MVA)		Available headroom (MVA)
	Non-Firm	Firm	Firm	Firm		Non-Firm	Firm	Firm
Kingston (33 kV)	120	60	49		Kingston (11 kV)	70	35	10
West Hobart Zone	90	60	27		Electrona	50	25	9
Sandy Bay Zone	90	60	27		Howrah Zone	50	25	7
Creek Road	180	120	28		Geilston Bay Zone	45	22.5	6
Sorell	120	60	28		Cambridge Zone	40	20	6
Risdon	150	100	27		Claremont Zone	50	25	4
East Hobart Zone	90	60	25		Knights Road	40	20	1
Lindisfarne	120	60	24		Bridgewater	70	35	0
Mornington	120	60	22		Derwent Park Zone	45	22.5	1
Chapel Street	120	60	21		Kerlandie	20	10	1*
Rokeyby	70	35	14		New Town Zone	45	22.5	0
Triabunna	50	25	19*		Rosny Park Zone	25	0	0*
North Hobart	90	45	11		Huon River	25	0	0*
Bellerive Zone	45	22.5	10		Summerleas Zone	25	0	0*

* Non-firm transmission or sub-transmission network connection

4.8.2. Network limitations and proposed developments

The following tables present our network limitations and proposed network developments in the Southern planning area over the next 10 years. There are no targeted reliability corrective action or proposed connection points. There were no projects committed or completed over the past year.

Table 4-13: Southern planning area network limitations and proposed solutions

Limitation	Deferral requirement (MVA)		Proposed solution	Timing	Cost (\$m)
	1 year	5 years			
33 kV sub-transmission lines:					
- Risdon–New Town	1.2	1.7	Replace over-head conductors and re-rate underground cables to increase capacity of non-firm Risdon to Derwent Park, East Hobart, and New Town sub-transmission corridors. No credible alternatives were identified.	2029	2.8
- Risdon–Derwent Park	2.4	3.0			
- Risdon–East Hobart	1.7	2.4			
Currently, these sub-transmission corridors operate non-firm.					
Knights Road to Huonville (North)-Ranelagh-Judbury-Lonnavele 22 kV distribution line	0.3	0.4	Establish a new distribution line from Knights Road Substation to relieve loading on the existing Knights Road to Huonville (North)-Judbury-Lonnavele 22 kV distribution line. An alternate solution is to establish a new distribution feeder from Huon River Substation.	2024	0.9
In summer, this distribution line is overloaded.					

4.9. Network asset retirements and replacements

This section presents our forecast network asset retirements over the next 10 years. Almost all our 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, and 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 4-14: Network asset retirements and replacements – overhead lines and cables

Completed		
Nil		
Committed		
Bruny Island 11 kV supply cable replacement		
Proposed	Timing	Cost (\$m)
George Town–Temco 110 kV transmission line	2027	3.6
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 4-15: Network asset retirements and replacements – power transformers

Completed		
Richmond Rural Zone Substation supply transformers (including HV regulator and switchgear)		
Rosebery Substation supply transformer (T5)		
Committed		
Port Latta Substation supply transformers		
Kermandie Substation supply transformers		
Proposed	Timing	Cost (\$m)
Transmission substations		
Boyer Substation		
Supply transformers (T13 and T14)	2029	5.4
Supply transformer (T2)	2029	1.7
Burnie Substation supply transformers	2032	4.9
Sheffield Substation network transformers (RIT-T Required)	2028	7.8
St Marys Substation supply transformers	2027	4.8
Rosebery Substation supply transformers (RIT-T Required)	2028	8.8
Savage River Substation supply transformers	2026	5.0
Waddamana Substation supply transformer	2027	2.8
Knights Road Substation supply transformers 11 kV switchgear	2030	1.8
Zone substations		
Gretna Rural Zone Substation supply transformers (including HV regulator)	2025	1.1
Derwent Park Zone Substation supply transformers	2026	2.9
Tods Corner Rural Zone Substation supply transformers	2025	0.8
Geilston Bay Zone Substation supply transformers	2027	2.6
Bellerive Zone Substation supply transformers	2028	3.0

Table 4-16: Network asset retirements and replacements – switchgear and instrument transformers

Completed		
North Hobart Substation 11 kV switchgear (including transformer and feeder protection schemes, and Supervisory Control and Data Acquisition (SCADA))		
Palmerston Substation 220 kV switchgear		
Committed		
Emu Bay Substation 11 kV switchgear		
Farrell Substation 220 kV switchgear		
George Town Substation 220 kV bus coupler replacement (refer section 4.6.2.1)		
Gordon Substation 220 kV switchgear		
Lindisfarne Substation 110 kV switchgear		
Ulverstone Substation 22 kV switchgear		
Proposed	Timing	Cost (\$m)
Boyer Substation 6.6 kV switchgear	2029	4.0
Chapel Street Substation 11 kV switchgear	2029	3.7
Railton Substation 22 kV switchgear	2029	1.9
Rosebery Substation 44 kV switchgear (including gantries and busbar)	2025	2.8
Sheffield Substation 220 kV switchgear	2028	3.0
Sorell Substation 22 kV switchgear	2029	1.9

Table 4-17: Network asset retirements and replacements – protection and SCADA

Completed		
Sheffield–Burnie 220 kV transmission line protection		
Lindisfarne busbar protection replacement		
Chapel Street busbar protection replacement		
Sheffield Substation SCADA		
Committed		
Hadspen Substation network transformer protection		
Hadspen Substation 220 kV and 110 kV busbar protection		
Hadspen T60 transformer relay replacements		
Palmerston Substation SCADA		
Proposed	Timing	Cost (\$m)
Protection spares replenishments	2025-2029	6.1
SCADA replacements	2025- 2029	15.7

Table 4-18 presents our investments in state-wide asset programs classified by network and asset class over the planning period to 2031. 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 4-18: State-wide asset investment programs

Network, asset class and description	Cost (\$m)									
	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32
Distribution network										
<i>Distribution overhead</i>										
Asset replacement and refurbishment	20.0	20.0	28.5	29.5	30.6	30.5	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	0.8	0.1	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
<i>High voltage regulators</i>										
Asset replacement and refurbishment	0.1	0.3	0.4	0.7	0.4	0.7	0.4	0.7	0.4	0.7
Safety and environmental programs	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
<i>High voltage and low voltage cables</i>										
Asset replacement	1.0	1.0	1.3	1.5	1.5	1.3	1.3	1.3	1.3	1.3
<i>Ground substations</i>										
Asset replacement and refurbishment	7.3	7.3	5.24	5.24	5.24	5.24	5.24	5.24	5.24	5.24
Safety and environmental programs	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
<i>Low voltage services</i>										
New and replacement of assets to customer installations	2.75	2.75	2.75	2.75	2.75	2.75	2.75	2.75	2.75	2.75
New and replacement of public lighting assets	2.0	2.0	3.5	3.5	3.9	3.9	1.6	1.6	1.6	1.6
Meter panel replacement	1.0	1.0	0.6	0.5	0.4	0	0	0	0	0
Transmission network										
<i>Transmission lines</i>										
Asset replacement and refurbishment	7.9	5.2	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3
Substandard clearance rectification	0.6	0.6	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
<i>Transmission substations</i>										
Asset replacement and refurbishment	10.6	12.9	5.5	12.4	12.1	10.1	2.4	13.4	13.4	13.4
Protection and control (distribution and transmission)										
Asset replacement	0.4	0.5	4.0	4.0	4.2	4.4	4.5	4.3	4.4	4.4
Network control systems (distribution and transmission)										
Asset replacement	0.4	0	0.4	0.4	0	0.4	0.4	0	0.4	0.4

4.10. Investments in operational support systems and telecommunication systems

4.10.1. Operational support systems programs

Operational support systems programs are critical in enabling us to improve our performance, efficiencies and effectiveness in asset management and network operation. Operational support systems comprise of network operational control systems (**NOCS**) and asset management systems (**AMS**). Elements of focus for successful information systems 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 also building a network digital twin service, which will 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 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 the Australian Energy Market Operator (**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 systems programs in the transmission and distribution networks.

4.10.1.1. Investment in the past year

Our regulated investments in operational support systems programs in 2021–22 are summarised in Table 4-19.

Table 4-19: Regulated investment in operational support systems in the past year

Project	Description	Investment (\$m)
Enterprise geographical information system (GIS) 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.	2.3
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.	1.7
Phasor Measurement Units Analytics	Upgrade of existing Phasor Measurement data visualisation product to maintain vendor support.	0.2

4.10.1.2. Investment in forward planning period

Our planned investments in operational support systems programs in the forward planning period to 2031–32 are summarised in Table 4-20.

Table 4-20: Operational support systems expected investment forward planning period

Project	Description	Investment (\$m)
Enterprise geographical information system (GIS) strategy implementation	Consolidation and modernisation of the geographical information system and capability.	6.0
Advanced Distribution Management System (ADMS)	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.	9.1
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.	4.7

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.

4.10.2.1. Investment in the past year

Our regulated investments in telecommunications systems programs in 2021–22 are summarised in Table 4-21.

Table 4-21: Regulated investment in telecommunications systems in the past year

Project	Description	Investment (\$m)
Infrastructure	Telecommunication sites	0.3
Bearer and management systems	Backbone bearers and Network Management Systems (NMS)	0.3
Multiplexer systems	Multiplexer systems in the networks	0.6
Ethernet systems	Ethernet systems within the network	0.5

4.10.2.2. Investment in forward planning period

Our planned regulated investments in telecommunications systems programs in the forward planning period to 2031–32 is summarised in Table 4-22. The majority of these are ongoing programs, with the investment our commitment over the duration of the program.

Table 4-22: Regulated investment in telecommunications systems in the forward planning period

Project	Description	Investment (\$m)
Infrastructure	Telecommunication sites	4.4
Bearer and management systems	Backbone bearers and Network Management System	8.0
Multiplexer systems	Multiplexer systems in the networks	2.3
Ethernet systems	Ethernet systems within the network	2.3

05 Network security performance

- Due to limited load growth over the last 12 months, Tasmania continues to be in a situation where it is theoretically possible to supply all Tasmanian demand from inverter-based resources, i.e. wind farms and Basslink import. Given that it is possible at times to operate the network without any need for local synchronous generation, careful management of power system security continues to be a high priority.
- Modelling associated with the Australian Energy Market Operator's (AEMO) 2022 Integrated System Plan (ISP) has forecast 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 April 2024.
- We are working towards addressing future shortfalls by evaluating Expressions of Interest submitted from potential service providers who believe they are capable of providing Inertia and System Strength Services from April 2024 to December 2025.
- New additions to the National Electricity Rules (**the Rules**) for the management of system strength commence in December 2025. The new framework will require a number of new approaches for the procurement and dispatch of system strength, including the allocation of costs to generators and loads who rely on grid-following inverters to interface with the network.

Network security performance

5.1. Network security introduction

This chapter outlines how the performance of the transmission network impacts on the operation of the wholesale electricity market and the level of services provided to our customers.

Managing power system security is extremely challenging under operating conditions when theoretically all Tasmanian demand can be met without the need for any synchronous generators to provide energy. Given the ongoing situation in Tasmania, AEMO has declared two inertia and system strength shortfalls, the first in November 2019, with an updated shortfall assessment published in May 2021. In accordance with the National Electricity Market Rules (**the Rules**), we identified the least-cost solution to address the declared shortfalls which was to enter into a commercial agreement with a suitably capable service provider. The existing contract will continue until 2024, subject to further regulatory changes or changes in solutions as a result of network developments.

5.2. Power system security

Power system security is the safe scheduling, operation and control of the power system on a continuous basis in accordance with the principles set out in Chapter 4 of the Rules. A key issue that is increasingly impacting on power system security is the growing penetration of inverter based resources (**IBR**) associated with wind and solar PV generation, as well as power exchanges across High Voltage Direct Current (**HVDC**) interconnectors. The decreasing reliance on synchronous generation is at times resulting in very low levels of inertia and system strength across increasingly larger areas of the National Electricity Market (**NEM**).



5.2.1. Frequency operating standards

As Tasmania operates as a synchronous island and has particular frequency control characteristics, it has region-specific frequency standards irrespective of interconnection with mainland Australia³⁰.

The largest generation event in the Tasmanian region is limited to 144 MW. Generation events greater than 144 MW are required to be mitigated by automatic load tripping schemes. The definition of a generation event includes the disconnection of generation as a result of a 'credible contingency' which impacts a dedicated connection asset providing connection to one or more generating systems from the shared transmission network. This includes transmission lines and transformers which TasNetworks may own and operate. TasNetworks is currently interacting with the Reliability Panel of the Australian Energy Market Commission (AEMC) as part of its 2022 review of the frequency operating standards.

5.2.2. System strength and inertia

In a power system, inertia and frequency control are interrelated issues. Following a system disturbance that causes an imbalance between generation and demand, high inertia power systems can resist rapid changes in frequency. On the other hand, lower levels of inertia mean that the power system is susceptible to rapid changes in frequency following a disturbance, potentially giving rise to cascading adverse impacts if not adequately controlled.

System strength encapsulates a number of individual issues that link back to two key concerns, being adequate control of the voltage waveform (at each point in the network) and the provision of sufficient short circuit current during network faults. Low system strength conditions give rise to more volatile network voltages and may also lead to unstable behaviour of power electronic based equipment. Maintaining minimum acceptable levels of fault current is important to ensure that protection systems operate as expected, especially in the distribution network which is more heavily reliant on basic over-current protection devices like fuses.

The Rules impose requirements on AEMO and transmission network service providers (TNSPs) to maintain minimum levels of system strength and inertia. As the Tasmanian TNSP, we are both the *Inertia Service Provider* and *System Strength Service Provider* for the Tasmanian region. As a result, we are responsible for providing sufficient capabilities to AEMO to enable the operational limits listed in Table 5-1 and Table 5-2 to be met.

Table 5-1: System strength requirements (intact network)

Defined fault level node	Minimum three phase fault level (MVA)
George Town 220 kV	1,450
Waddamana 220 kV	1,400
Burnie 110 kV	850
Risdon 110 kV	1,330

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

5.2.2.1. Changing generation mix

Inertia and system strength are inherently supplied by synchronous generators when they are connected to the power system. In contrast, grid following IBR do not provide inertia³¹ and are limited in their ability to provide short circuit current.

As the penetration of wind and solar generation continues to expand and imports via HVDC interconnectors increase, the number of synchronous generators required to be online at certain times is correspondingly reduced. The challenge for an increasing number of power systems around the world is defining how many synchronous generators are required to be maintained online to adequately manage power system security requirements including inertia and system strength.

³⁰ <https://www.aemc.gov.au/markets-reviews-advice/review-of-the-frequency-operating-standard>

³¹ Noting that grid forming inverters are being trialled as part of several projects on the mainland, mainly associated with battery energy storage systems (BESS). The provision of inertia from certain categories of IBR may become more common in the future.

5.2.2.2. Shortfall declarations

To date, AEMO has declared two shortfalls within the Tasmanian region associated with both system inertia and system strength. The first notice of shortfall was published on 13 November 2019, with a subsequent increase in shortfalls declared on 7 May 2021 as listed in Table 5-3.

Table 5-3 Declared shortfalls for the Tasmanian region in May 2021

Inertia level	Inertia shortfall (MW.s)
To achieve Secure Operating Level of Inertia	2,620
Fault level node	Fault level shortfall (MVA)
George Town 220 kV	770
Waddamana 220 kV	620
Burnie 110 kV	200
Risdon 110 kV	580

We adequately addressed both shortfall notices using non-network solutions, more specifically, establishing a services agreement with a registered Generator to provide sufficient synchronous machine capabilities as described below in Section 5.2.2.4.

As noted in the most recent AEMO System Security Report³², the current agreement is due to expire in April 2024. While AEMO has not yet published any additional shortfall notices, TasNetworks believes it prudent to begin planning for increasing shortfalls based on ISP modelling results published in the 2021 System Security Report, listed in Table 5-4.

Table 5-4 Forecast shortfalls based on latest AEMO ISP modelling.

Year	2022-23	2023-24	2024-25	2025-26
Inertia shortfall	MW.s	MW.s	MW.s	MW.s
To achieve Secure Operating Level of Inertia	2,163	2,163	2,473	2,620
System strength shortfall	MVA	MVA	MVA	MVA
George Town 220 kV	544	633	750	829
Waddamana 220 kV	304	354	519	633
Burnie 110 kV	294	322	386	423
Risdon 110 kV	310	342	505	623

As a result, on 13 May 2022 we requested Expressions of Interest from any potential service providers who believe they are capable of:

1. helping address the forecast shortfalls for the period 15 April 2024 to 1 December 2025, and
2. offering services prior to 15 April 2024 for potential use in conjunction with existing contracted capabilities.

Potential providers had until the 17 June 2022 to submit an Expression of Interest.

Due to a change in the regulatory framework associated with system strength that takes full effect from 2 December 2025³³, a future Expression of Interest process will be necessary as discussed in Section 5.2.2.5.

5.2.2.3. Identification of services to address the shortfalls

Rules' Clauses 5.20B.4 and 5.20C.3 require that *Inertia* and *System Strength Service Providers* must prepare and publish information to enable potential providers of relevant services to develop *non-network options* for consideration in parallel with network investment solutions. *Inertia* and *System Strength Service Providers* must ultimately make available to AEMO the least cost option, or combination of options, which addresses any identified shortfall within the required time period.

³² AEMO; "2021 System Security Reports – System strength, inertia and NSCAS reports for the National Electricity Market", Version 1.0, 17 December 2021.

³³ Efficient management of system strength on the power system ERC0300 | AEMC Australian Energy Market Commission Rule Determination 21 October 2021

In that context, TasNetworks published the request for Expressions of Interest in accordance with Rules' Clauses 5.20B.4(g) and 5.20C.3(e) to ascertain the type, location, capacity and potential cost of various forecast services.

The scope of the request for Expressions of Interest was limited to the provision of the following:

- *Inertia network services,*
- *Inertia support activities, and*
- *System strength services.*

Inertia network services are utilised to supplement the *inertia* coming from synchronous generators dispatched through the spot markets to deliver energy and frequency control ancillary services (**FCAS**). Insufficient inertia can lead to unacceptably high rates of change of frequency (**ROCOF**) following credible and non-credible contingency events. This can lead to excessive FCAS requirements and/or unintended disconnection of power system equipment (with risk of widespread supply disruptions).

Inertia support activities reduce the *inertia* that is required to be online within a *region*. This is generally achieved by injecting or absorbing active power in a controlled manner with a speed of response that can influence ROCOF across the critical time periods (which are likely to be specific to a particular *sub-inertia network*).

System strength services are utilised to supplement the contributions to *three phase fault level* coming from synchronous generators dispatched through the spot markets to deliver energy and FCAS. Low system strength conditions give rise to more volatile network voltages and may also lead to unstable behaviour of power electronic based equipment including HVDC interconnectors, wind farms and solar farms. Unstable behaviour can include sympathetic tripping of equipment during network faults, leading to much larger contingency events than initially anticipated.

TasNetworks has previously identified the following *non-network options* which will or are likely to meet the minimum technical performance requirements and that can be deliverable within the necessary time frames:

1. Synchronous condenser units;
2. Synchronous generating units operated at minimum MW loading; and
3. Battery energy storage systems (**BESS**).

It can also be noted that future network augmentations will assist with the transfer of system strength, reducing the reliance on localised sources of support in certain areas of the network. As an example, it is expected that the challenges associated with supporting the Burnie system strength node will decrease in future years as 220 kV network developments occur in the area.

We are currently working towards addressing the shortfalls by evaluating submitted Expressions of

Interest from potential service providers who believe they are capable of providing Inertia and System Strength Services.

5.2.2.4. Contracted services

To address the first shortfall declaration in November 2019, TasNetworks entered into formal contract negotiations with Hydro Tasmania starting in December 2019. The negotiations covered the provision of inertia network services and system strength services in sufficient quantity to meet the then declared shortfall volumes. The negotiation process was supported throughout by both AEMO and the Australian Energy Regulator (**AER**).

The original services were formally made available to AEMO on the 15 April 2020.

5.2.2.5. Rule change: efficient management of system strength on the power system

The AEMC has now finalised the rule change titled "Efficient Management of System Strength on the Power System." The change reformed the responsibilities for provision, consumption and payment of costs associated with managing system strength in a transitioning power system. The Rule change provides for the following three part approach to providing efficient levels of system strength:

1. **Supply side:** a new obligation on *system strength service providers (SSSP)*³⁴ to provide sufficient system strength in a planning timeframe to support the connection of IBRs as forecast by AEMO.
2. **Demand side:** new access standards for those parties that 'demand' system strength including large controllable loads like hydrogen electrolysers and batteries, as well as utility-scale generators including solar and wind farms - to make sure they use system strength efficiently, reducing demand for it and minimising costs associated with supply.
3. **Coordination of supply and demand sides:** new way of charging for system strength, giving generators and certain large loads a choice to pay to use system strength services offered by SSSPs or to provide their own system strength.
4. Additionally, there are new Annual Planning Report (**APR**) requirements associated with system strength activities, including the publication of locational factors. These requirements commence for our 2023 Transmission APR and 2023 Distribution APR.

³⁴ Noting that the SSSP in each NEM region will be the TNSP that is also the nominated Jurisdictional Planner.

5.3. Transmission network constraints

A network constraint is when the power flow through part of the transmission network must be restricted in order to avoid exceeding a known technical limit and to maintain the power system in a secure operating state. AEMO develops constraint equations which define how the dispatch of generation, as well as Basslink, should be scheduled to avoid exceeding these technical limits. The equations are based on limit advice which we provide for our transmission network.

While not strictly transmission network constraints, there are also certain power system operating restrictions that are required to maintain broader aspects of power system security. This includes system frequency control requirements, inertia and system strength, as well as various limits associated with the status of system protection schemes which are used to extend the permissible operating boundary of the network. Constraints are invoked and withdrawn depending on the status of the network at any given time.

We undertake periodic reviews of all binding and violating constraints and provide AEMO with revised limit advice to modify, remove or add new constraints (as required). This is to ensure power system security is maintained and the available transmission capacity is maximised. The market impact component (**MIC**) of the AER's service target performance incentive scheme creates a financial incentive for us to minimise the impact of transmission constraints.

Figure 5-1 illustrates binding and violated constraints due to thermal and stability issues during 2021. Binding constraints impact generation output and/or Basslink power transfer limits through re-dispatch, while violated constraints are where a technical limit was exceeded. It shows the number of five-minute NEM dispatch intervals in which constraints occurred in various parts of the network. "Thermal limit – no outage" indicates the constraint bound or violated without any outage. "Thermal limit – with outage" means the constraint was caused by one or more transmission elements being out of service.

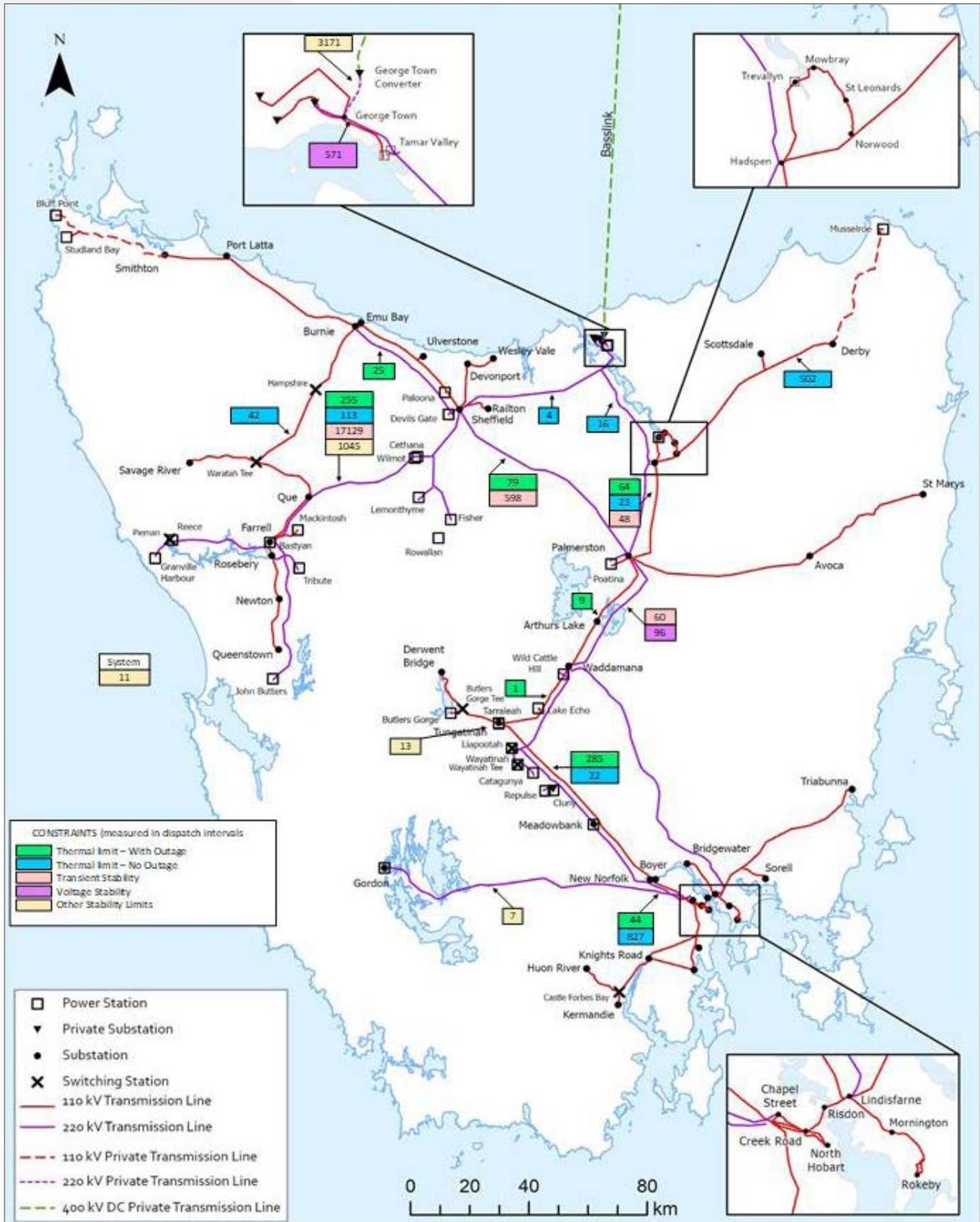


Figure 5-1: Transmission constraints during 2021

Table 5-5 presents the number of dispatch intervals for binding and violated constraints on major transmission network elements for 2020 and 2021 calendar years, categorised by whether the constraint increased or decreased from the previous year. It shows constraints where the total bound or violated periods exceed 150 dispatch intervals, or 12.5 hours. It includes network constraints and those specifically related to Basslink.

Table 5-5: Major binding constraints and significant changes in 2021

Constraint	Period constraint bound or violated			
	2020		2021	
	Dispatch intervals	Time (hours)	Dispatch intervals	Time (hours)
Constraints with increased binding in 2021				
Farrell–Sheffield 220 kV transient stability	3,809	317	17,129	1,427
New Norfolk to Chapel St thermal limit with no outage	40	3	827	69
Loss of double circuit declared credible on West Coast	482	40	684	57
Palmerston–Sheffield 220 kV transient stability	299	25	598	50
Basslink rate-of-change limit	302	25	527	44
Derby to Scottsdale Tee 110 kV thermal limit with no outage	391	33	502	42
Discretionary limit on West Coast generation	91	8	354	30
Farrell–Sheffield 220 kV thermal limit with outage	0	0	248	21
Tungatinah to New Norfolk 110 kV thermal limit with outage	0	0	226	19
Basslink Energy and FCAS related constraint (i.e. Basslink no go zone)	199	17	226	19
Constraints with decreased binding in 2021				
George Town 220 kV bus voltage stability limit	835	70	571	48
Basslink import limited due to load unavailability for Frequency Control System Protection Scheme operation	4,146	346	2,857	238

The following sections present more information on our top three constraints from 2020 to 2021. It presents the reason for the constraint, and potential actions to reduce periods of binding (if apparent). We continually monitor the impact of constraints, and will undertake corrective action (e.g. network augmentation) where it is cost-effective to do so.

Farrell–Sheffield 220 kV transient stability

The most limiting constraint in 2021 was the ‘Farrell–Sheffield 220 kV transient stability’ constraint. This constraint limits the amount of West Coast generation that can be transmitted to Sheffield. This was also the constraint with the largest increase in binding in 2021, as there was higher generation output from the West Coast area, including from Hydro power generation and Granville Harbour Wind Farm as more wind turbines were commissioned. 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, or encouraging new load into the West Coast area.

New Norfolk–Chapel St 110 kV thermal limit with no outage

The ‘New Norfolk–Chapel St 110 kV thermal limit with no outage’ was another constraint that bound significantly more than the previous year. This is a result of there being more dispatches intervals when the Derwent 110 kV generation was at high output while the New Norfolk area demand was low.

Hydro Tasmania is currently investigating options to redevelop the Tarraleah power station, this includes moving a relatively large amount of generation from the 110 kV network to the 220 kV network. The outcome of this investigation is critical for TasNetworks planning the configuration of the Derwent area and releasing this constraint.

Basslink import limited due to load unavailability for FCSPS operation

The second most limiting constraint in 2021 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.

This was also the constraint with the largest decrease in binding in 2021, as Basslink was on import from Victoria less. One contributing factor to this was that the new wind farms at Granville Harbour and Cattle Hill being commissioned towards the end of 2020, which resulted in higher energy production for 2021.

Scottsdale - Derby corridor capacity

Currently, connected wind farm generation is constrained by the corridor thermal capacity in some dispatch intervals. We are progressing the installation of a weather station near Derby to allow the corridor to utilize dynamic line ratings, thereby alleviating the corridor constraints. This project is outlined in Section 3.5.3.1.

5.4. System stability and emergency controls

Power system stability must be maintained to avoid consequences that lead to severe disruption. This is required under both normal operation and following contingency events, including protected events³⁵. This is achieved through a combination of network constraints and protection and control systems installed on generation plant and transmission infrastructure, as well as through the implementation of emergency control schemes. The latter occurs in consultation with AEMO.

We have had in place for some time emergency frequency control (**EFC**) schemes which are designed to help mitigate the impacts of non-credible contingency events. The schemes are designed on a 'best endeavours' basis noting that it is not practical to implement schemes that are capable of managing every conceivable combination of network event, for example, disconnection of all generating units.

The two EFC schemes which exist in the Tasmanian region are the:

- Under Frequency Load Shedding (**UFLS**) scheme; and
- Over Frequency Generator Shedding (**OFGS**) scheme.

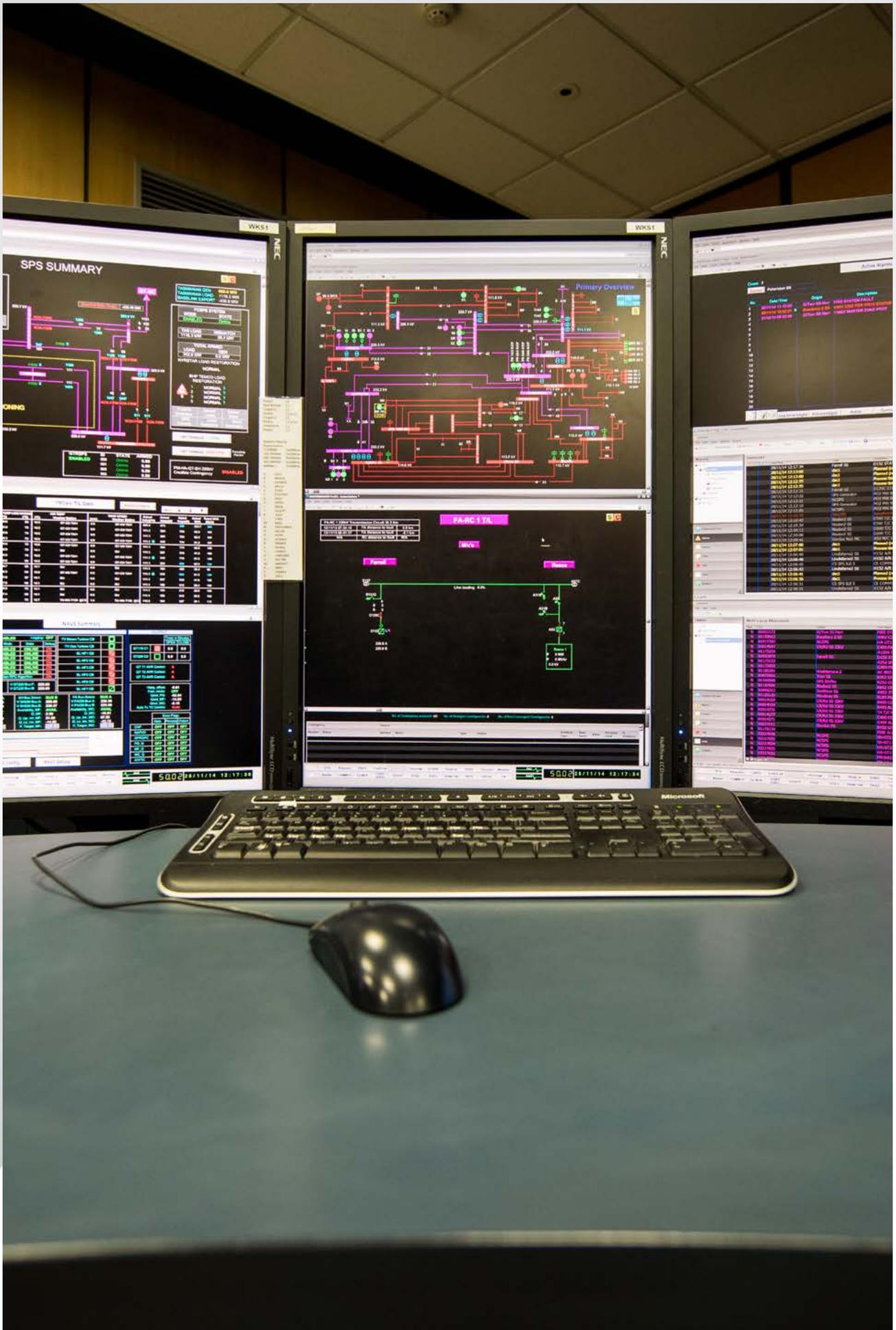
We also operate and maintain a number of other schemes which are designed to mitigate specific contingency events. The most notable of these schemes are the:

- **FCSPS** associated with the Basslink HVDC interconnector;

- Network Control System Protection Scheme (**NCSPS**) that enables the use of the non-firm thermal capability of the transmission network during Basslink export conditions;
- Tamar Valley Generator Contingency Scheme (**TVGCS**) which reduces the effective size of the generator contingency associated with the combined cycle gas turbine to no more than 144 MW (in accordance with the Frequency Operating Standards); and
- Musselroe Wind Farm Generator Contingency Scheme (**MRWFGCS**) which reduces the effective size of the generator contingency associated with the loss of the wind farm to no more than 144 MW (in accordance with the Frequency Operating Standards).

We also continue to work with customers to explore the availability and application of new technologies to help address stability limitations, in particular the provision of frequency control capabilities that operate in parallel to, or directly participate in, the **FCAS** markets managed by AEMO.

³⁵ **protected event** means a non-credible contingency event that the Reliability Panel has declared to be a protected event



06 Service delivery performance

- Transmission network performance for 2021 was within service target performance incentive scheme targets across all metrics.
- Distribution network performance did not meet the Tasmanian Electricity Code reliability standards and service target performance incentive scheme targets in the past year.
- During recovery in the aftermath of a severe storm event we collaborated with key stakeholders, in particular farmers to ensure priority was given to animal welfare.
- There is a downward trend in distribution customer feedback received for under and over voltage issues.
- There are over 45,000 rooftop photovoltaic (PV) installations in Tasmania with an installed capacity is 226 MW, a 22 per cent increase over the course of 2021.

Service delivery performance

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 the requirements of our customers, our community and regulatory obligations.

Our objectives in relation to service performance are:

- safety is our top priority and we will ensure our safety performance continues to improve;
- 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 will be improved through prioritisation and efficiency improvements that enable 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 capability will be continually improved to support our cost and service performance, 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 communities with service levels below target levels are discussed along with our strategy to undertake corrective actions.

Following an extended wet period, high winds during a severe weather event resulted in significant tree fall particularly across parts of north and north-west Tasmania impacting on distribution assets and



interrupting supply to customers. Parts of southern Tasmania were also impacted, although the winds were generally lighter. The transmission system generally held up well throughout the storm, with the only localised issue reported on the Palmerston – Avoca 110 kV transmission line.

During restoration efforts we collaborated with key stakeholder and sector agencies to understand their requirements. In particular, Dairy Tas and the Tasmanian Farmers and Graziers Association, to triage restoration efforts accordingly wherever possible. This coordination prioritised supply restoration to timeframes that allowed farmers to maintain appropriate animal welfare.

6.2. Tasmanian network and supply reliability

Reliability is measured in two ways; (1) reliability of network elements, and (2) 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 loss of supply (**LOS**) events and average circuit outage rate for our transmission network, and a system average interruption frequency index (**SAIFI**) for our distribution network.

Outage duration reflects our effectiveness in responding to unplanned or forced outages. It is measured using rate of unplanned circuit outages and average of LOS durations for our transmission network, and a system average customer supply interruption duration index (**SAIDI**) for our distribution network.

We have a requirement to monitor and report supply reliability (among other measures) to the Australian Energy Regulator (**AER**) and Office of the Tasmanian Economic Regulator (**OTTER**). Relevant supply reliability performance metrics are used by the AER in each of our distribution and transmission service target performance incentive schemes (**STPIS**). Additionally, we have an obligation under the Tasmanian Electricity Code (**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, the AER sets service targets in terms of the number of LOS events that occurred during the year, circuit outage rate, and the average LOS event duration, based on historical performance.

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 demand³⁶. 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 years³⁷. Performance measures are as defined by the AER in the service target performance incentive scheme³⁸. Red values indicate where we did not meet our standard.

³⁶ In Tasmania, an event of one system minute equates to about 31.2 MWh of unserved energy

³⁷ Performance reporting to the AER under STPIS can be viewed at <https://www.aer.gov.au/networks-pipelines/compliance-reporting>

³⁸ <https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/service-target-performance-incentive-scheme-version-5-september-2015-amendment>

Table 6-1: Transmission network performance

Performance measure	Regulatory period 2014-19				Regulatory period 2019-2024		
	Target	2017	2018	2019	Target	2020	2021
Transmission network reliability performance							
Number of LOS events >0.1 system minute	0	4	2	2	3	8	2
Number of LOS events >1.0 system minute	3	1	0	1	1	0	0
Transmission circuit outage rate							
Transformer circuit fault outage rate (%)	11.60	8.26	10.00	8.26	8.40	5.51	4.55
Transmission circuit fault outage rate (%)	31.17	9.37	15.89	21.70	16.90	13.21	13.08
Capacitor circuit fault outage rate (%)	3.33	33.30	23.08	0	17.90	23.08	7.69
Transmission average circuit outage duration							
Average of LOS duration (minutes)	112	410	46	273	149	105	19

The performance of the transmission system for 2021 was better than targeted across all metrics. There were two LOS events greater than 0.1 system minutes during 2021 impacting Kingborough, Savage River and Que customers. Across the network, the majority of fault outages were triggered by environmental causes such as lightning and adverse weather. The remaining fault outages were mainly caused by equipment issues.

A significant amount of LOS events have occurred between January and June 2022. Six LOS events greater than 0.1 system minutes have occurred in the first six months of 2022, three of them being greater than 1.0 system minutes. These have been attributed to factors such as adverse weather events, mal-operation events, and animal interactions within the network.

6.4. Distribution network reliability

We report distribution network reliability to the OTTER and the AER on a geographic segmentation basis. Tasmania is divided into 101 reliability areas and then to one of five reliability categories. The reliability category determination is based on energy use per unit area with boundaries defined by natural features (like roads, rivers and land) and municipal boundaries.

The five reliability categories are:

- critical infrastructure (1 area);
- high-density commercial (8 areas);
- urban and regional centres (32 areas);
- high-density rural (33 areas); and
- low-density rural (27 areas).

The Code specifies performance standards for each:

- category, which represents the average level of service expected by areas of that category; and
- area, which represents 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 excluding outages caused by third-party faults, customer plant and the transmission network. The Code standards and performance during 2021–22 are presented in Table 6-2 at category level. Historic performance against the Code standards is in Appendix D. 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 supply reliability category 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	0.5	30	82
High-density commercial	1	1.1	60	105
Urban and regional centres	2	1.3	120	150
High-density rural	4	2.6	480	361
Low-density rural	6	4.0	600	643

Our performance in SAIFI (the frequency of outages measure), did not meet our standard in the Critical infrastructure category. For SAIDI (the duration of outages measure), we did not meet our standard in the Critical infrastructure, High-density commercial, Urban and regional centres, High and Low-density rural categories. Communities in these categories were primarily impacted by planned work, with vegetation, equipment condition and unknown cause also contributing to the totals.

Table 6 3 presents the Code standard for our 101 reliability areas, and the number of communities that did not meet these in 2021-22. Thirty six did not meet their SAIDI standards, with eight of these also not meeting their SAIFI standards.

Table 6-3: Code supply reliability area standards and performance

Supply reliability category (number of communities)	Annual number of supply interruptions (on average) (SAIFI)		Annual duration of supply interruptions (on average) (SAIDI)	
	Standard	No. of communities below standard	Standard	No. of communities below standard
Critical infrastructure (1)	0.2	1	30	1
High-density commercial (8)	2	0	120	2
Urban and regional centres (32)	4	2	240	11
High-density rural (33)	6	3	600	10
Low-density rural (27)	8	0	720	12
Total (101)		6		36

6.4.2. Distribution STPIS reliability targets and performance

The AER sets service component parameters of the STPIS as part of our regulatory determination. They are based on historic performance and exclude planned outages, major event days³⁹, transmission network outages, customer installation faults, and 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 D, with details available in the regulatory information notices (RIN) on the AER website⁴⁰.

We did not meet the reliability targets in 2021–22 for High-density commercial and Low-density rural for SAIFI and High-density commercial, Urban and regional centres, High-density rural and Low-density rural for SAIDI measures. Similarly to our reasons for not meeting the Code standard (refer Section 6.4.1), these categories were heavily impacted by equipment condition, unknown and vegetation causes. Our reliability compliance and corrective action programs are presented in Section 6.4.4.

6.4.2.1. Forecast distribution reliability performance

Table 6-4 and Table 6-5 also show our forecast reliability performance to the end of our current regulatory period, 2023–24. We forecast our reliability performance in alignment with the AER's methodology, from a five-year historical average. This presents as the forecast reliability performance will not meet the current target for High-density commercial (SAIDI) and Urban and regional centres (SAIFI and SAIDI) due to past poor performance in these categories. Red values indicate either where we did not meet or are not forecast to 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	2021–22 performance	Forecast to 2023–24
Critical infrastructure	0.251	0.051	0.078
High-density commercial	0.260	0.655	0.366
Urban and regional centres	1.081	1.019	1.114
High-density rural	2.466	2.278	2.222
Low-density rural	3.219	3.452	2.900

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

Supply reliability category	Annual duration of supply interruptions (on average) (SAIDI)		
	Target	2021–22 performance	Forecast to 2023–24
Critical infrastructure	32.984	3.418	6.26
High-density commercial	20.074	56.993	35.4
Urban and regional centres	89.657	96.858	96.72
High-density rural	250.959	279.612	239.99
Low-density rural	400.401	468.122	373.62

³⁹ 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

⁴⁰ TasNetworks (distribution) 2019–20 – Annual Reporting RIN – non-financial templates, <https://www.aer.gov.au/networks-pipelines/network-performance/tasnetworks-aurora-energy-distribution-network-information-rin-responses>

6.4.3. Distribution AER STPIS reporting

As part of our RIN submissions, we submit data used for our STPIS compliance requirements to the AER. Under the STPIS the AER can apply three reliability parameters to each customer category⁴¹:

- SAIDI;
- SAIFI; and
- Momentary system average interruption frequency index (**MAIFI**).

The AER has not applied the MAIFI parameter to our STPIS, however we do include it in our performance reporting. We expect to be subject to MAIFI from 1 July 2024⁴².

In addition to these reliability parameters, the AER has also applied a customer service performance parameter for call centre phone answering.

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

A summary of our reported 2021-22 performance is presented in Table 6-6 and Table 6-7. Both 'total' and 'removing exclusions' measures are reported, where exclusions are defined excluded events and major event days. In addition to the annual performance, daily performance for each supply reliability category is available on the AER website⁴³.

Reliability

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	87.468	113.522	184.086	553.717	1263.604	343.921
	Removing exclusions	3.418	56.993	96.858	279.612	468.122	181.319
SAIFI	Total	0.495	1.096	1.480	3.174	4.860	2.015
	Removing exclusions	0.051	0.655	1.019	2.278	3.452	1.579
MAIFI	Total	0.034	0.675	1.882	5.733	8.261	3.435
	Removing exclusions	0.034	0.675	1.792	4.857	7.155	3.068
Average customer numbers and planned basis of future reporting ('000s)		1.84	1.84	4.57	199.35	46.65	45.84

Phone answering

The phone answering parameter is defined as the number of calls answered in 30 seconds, divided by the total number of calls received (after removing exclusions).

Table 6-7: Customer Service performance

Phone answering	Total	Removing Exclusions
Number of calls	35,999	32,582
Number of calls answered in 30 seconds	25,804	25,804
Percentage of calls answered within 30 seconds	71.6	79.1
STPIS Target (%)		76.30

41 <https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/service-target-performance-incentive-scheme-november-2009-amendment>

42 <https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/service-target-performance-incentive-scheme-2018-amendment>

43 TasNetworks (distribution) 2019-20 – Annual Reporting RIN – non-financial templates, <http://www.aer.gov.au/networks-pipelines/network-performance/tasnetworks-aurora-energy-distribution-network-information-rin-responses>

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 communities, network reinforcement and ongoing asset management activities.

Reliability corrective action is targeted, with action coming from a variety of programs as presented in Table 6-8 (with their relative benefits). We also undertake targeted reliability improvement projects which are larger projects that may require significant investment. These larger reliability improvement projects are presented by planning area in Chapter 4.

Table 6-8: 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 6-9 presents the number of applications received in recent years, which are made up almost exclusively of rooftop PV applications. The average time between the submission of an application to approval for energisation is 63 days.

Table 6-9: Embedded generation connection applications

Year	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22
Number of applications	2,293	2,651	2,538	2,708	2,945	3,533	4,215	4,760

Small generators – less than 5 MW – are automatically exempt from full compliance with Chapter 5 of the National Electricity Rules (**The Rules**)⁴⁴. 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.

In the last year there have been two large scale embedded generators commissioned, a 1,067 kVA landfill gas generator in Copping and a 785 kVA mini hydro in Scottsdale.

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 45,000 systems with an installed capacity of 226 MW in June 2022. Figure 6.1 presents the

⁴⁴ <https://www.aemo.com.au/energy-systems/electricity/nationalelectricity-market-nem/participate-in-the-market/networkconnections>

growth in installed capacity and number of installations of rooftop PV since 2016. Residential battery storage has also experienced growth, with a steep increase from 2016, as shown in Figure 6.2⁴⁵.

45 This includes PV systems registered under the Small-scale Renewable Energy Scheme and batteries installed alongside solar PV systems. Figures excludes 2022 data. www.cleanenergyregulator.gov.au/RET/Forms-and-resources/Postcode-data-for-small-scale-installations

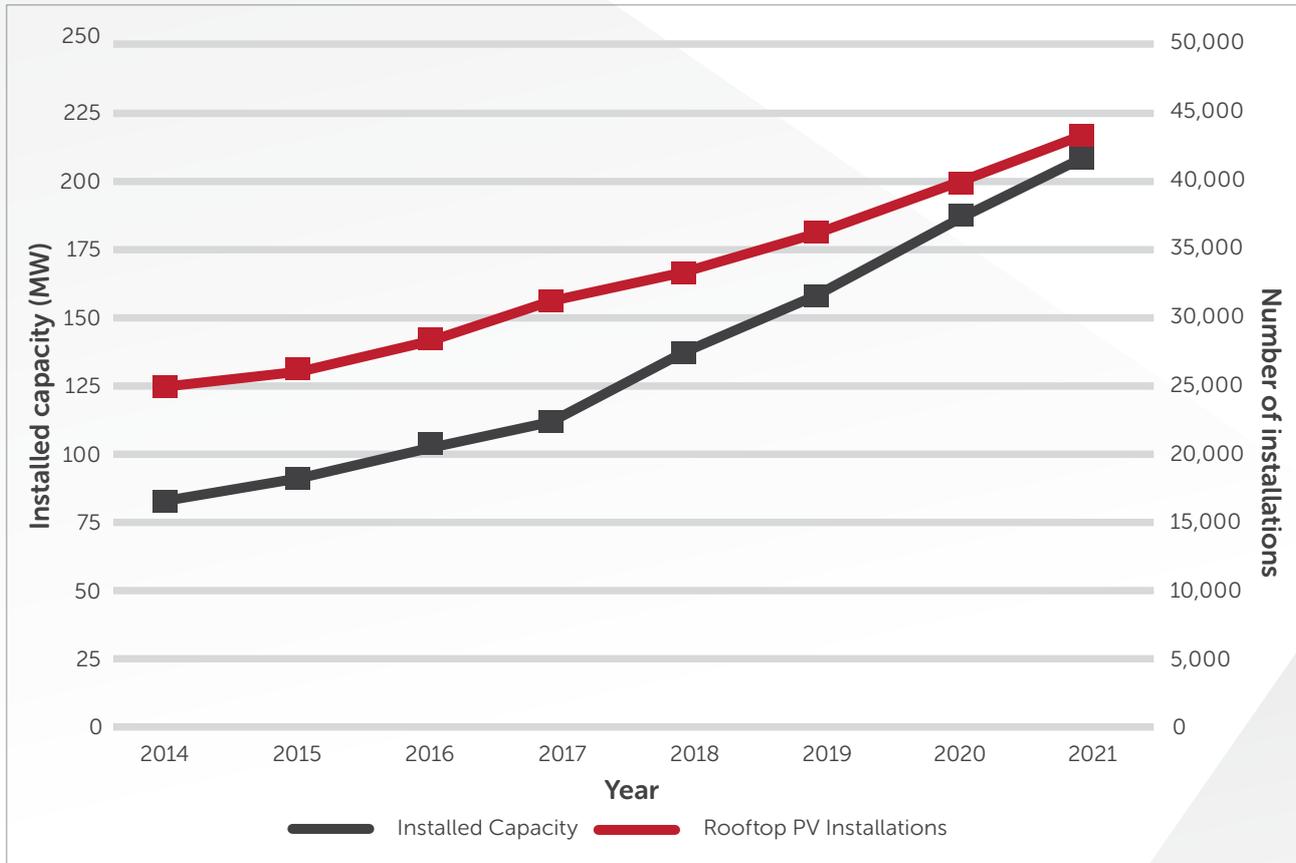


Figure 6-1: Solar PV penetration

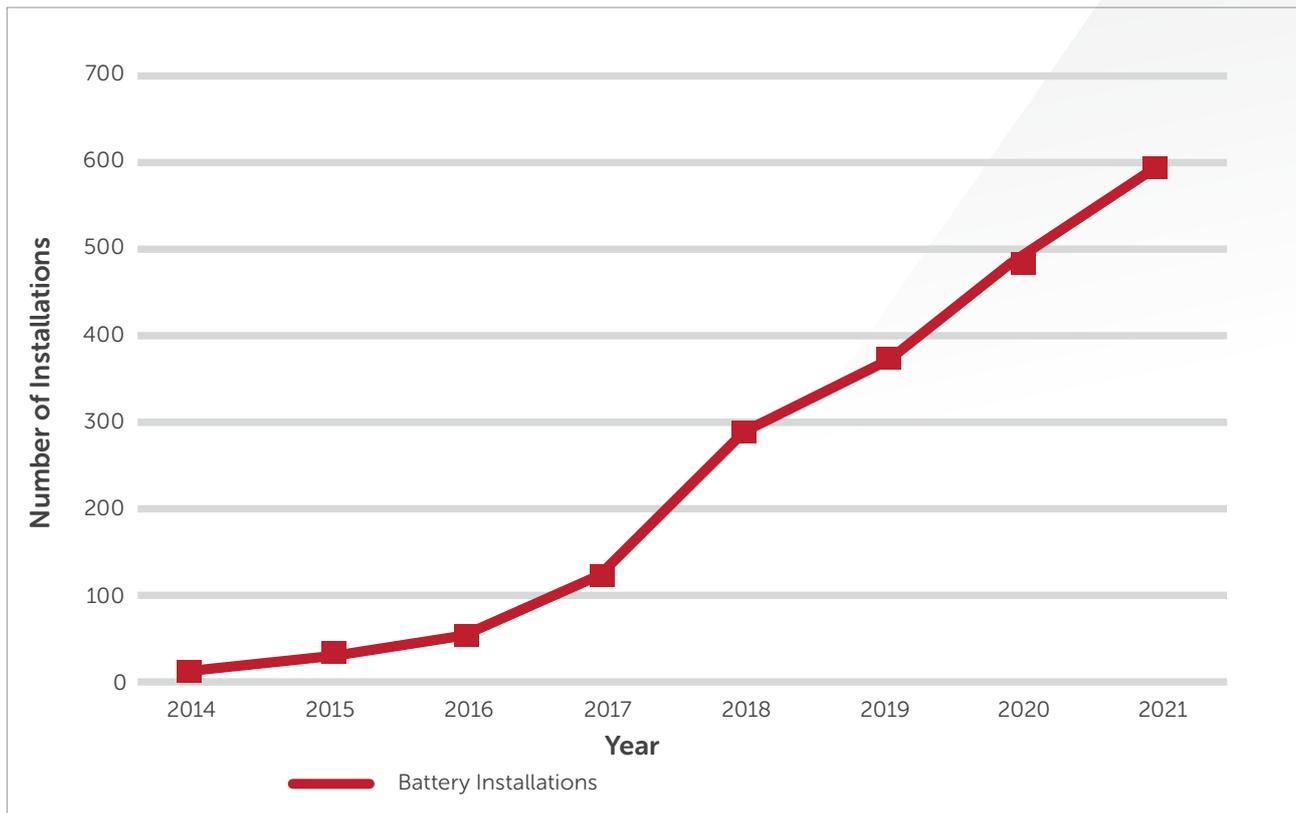


Figure 6-2: Residential battery penetration

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 6-10. Where identified, we study these limitations and apply corrective action (if appropriate).

Table 6-10: Customer feedback on over and under voltages

Category	2016–17	2017–18	2018–19	2019–20	2020–21	2021–2022
Over voltage	70	86	31	32	31	18
Under voltage	24	24	42	18	8	6
Total	94	110	73	51	39	24

TasNetworks regularly undertakes proactive investigations of advanced meter data and applies proactive actions. The performance results of the most recent investigation using advanced meter data are shown below in Table 6-11. A reduction in over voltages and an increase in under voltages for the most recent investigation were observed, which is likely attributed to winter bias in the data provided to TasNetworks by the metering providers.

Table 6-11: Advanced meter survey results

Study date range	Meters sampled	Under voltage	Over voltage	Under and over voltage
Jul 19 – Feb 20	8,181	0.6%	1.3%	< 0.1%
Dec 19 – Jun 20	17,336	0.2%	1.6%	< 0.1%
Mar 21 – Sep 21	8,009	1.9%	0.5%	0.3%

We continue to share the advanced meter data with the University of Wollongong for its Long Term Power Quality Survey. The most recent results from University of Wollongong considered data from 2019–20 and noted that our sites were ranked second out of the ten participating Australian distribution network service providers for voltage compliance.

07 Appendices and reference material

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 Annual Planning Report (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
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
APR	Annual Planning Report
ARENA	Australian Renewable Energy Agency
AS	Australian Standards
CCGT	Combined Cycle Gas Turbine
CESS	Capital Expenditure Sharing Scheme
CSIS	Customer Service Incentive Scheme
DER	Distributed Energy Resources
DMIAM	Demand Management Innovation Allowance Mechanism
DMIS	Demand Management Incentive Scheme
DNSP	Distribution Network Service Provider
EBSS	Efficiency Benefit Sharing Scheme
ESB	Energy Security Board
EV	Electric Vehicle
FCAS	Frequency Control Ancillary Services
FCSPS	Frequency Control System Protection Scheme
GSL	Guaranteed Service Level
GWh	Gigawatt-hour
HV	High Voltage
HVDC	High Voltage Direct Current
Hz	Hertz
IBR	Inverter Based Resources
ISP	Integrated System Plan
kA	Kiloamps
kV	Kilovolts
LOS	Loss of Supply
MAIFI	Momentary System Average Interruption Frequency Index
MIC	Market Impact Component
MVA	Megavolt-amperes

MVar	Megavolt-amperes reactive
MW	Megawatts
MWh	Megawatt-hour
NCSPS	Network Control System Protection Scheme
NEM	National Electricity Market
OTTER	Office of the Tasmanian Economic Regulator
OWZ	Offshore Wind Zone
OFGS	Over Frequency Generation Shedding
PACR	Project Assessment Conclusions Report
PADR	Project Assessment Draft Report
PHES	Pumped Hydro Energy Storage
POE	Probability of Exceedance (chance that the value is exceeded)
PV	Photovoltaic [solar generation system]
REZ	Renewable Energy Zone
RIN	Regulatory Information Notice
RIT-T/D	Regulatory investment test for transmission (or) distribution
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAPS	Stand Alone Power Systems
SCADA	Supervisory Control and Data Acquisition
SCR	Short Circuit Ratio
STATCOM	Static Synchronous Compensator
TRET	Tasmanian Renewable Energy Target
STPIS	Service Target Performance Incentive Scheme
TNSP	Transmission Network Service Provider
UFLS	Under Frequency Load Shedding
VRE	Variable Renewable Energy

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. System strength issues need to be addressed while ensuring electricity is affordable for consumers. The transition of the NEM will continue to pose challenges for all NEM connected customers, 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 assist customers in identifying cost-effective demand management solutions and connecting embedded generation. Outlined is our demand management assessment process and common issues faced by the connection of embedded generation.

A.1. Regulatory framework

We operate under both state and national regulatory regimes. As a registered participant in the NEM, we are required to develop, operate and maintain the electricity supply system in accordance with 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, which are issued by the Office of the Tasmanian Economic Regulator (**OTTER**) under the *Electricity Supply Industry Act 1995*. We are also subject to a number of other Acts and industry-specific regulations in planning our network. 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.

Our revenue for prescribed transmission and distribution network services in Tasmania is regulated and determined by the Australian Energy Regulator (**AER**).

A.1.1. Tasmanian Electricity Code

The Code is published and maintained by OTTER⁴⁶. It contains arrangements for the regulation of Tasmania's electricity supply industry additional to those in the Rules. The Code largely relates to the operation of our distribution network. It contains the 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 we earn from our customers is determined by the AER. In setting our revenue allowances, the AER expects us to improve our efficiency by reducing the costs of the services we provide while maintaining or improving the quality and reliability of our services.

This regulation exists primarily to protect electricity customers by ensuring specific performance standards are met and capping revenue based on efficient costs - which are forecast, benchmarked and scrutinised by the AER before each regulatory period (usually five years). TasNetworks' regulated revenue is primarily determined by an official rate of return, which is set by the AER and applied to the value of TasNetworks' distribution and transmission networks. The rate of return provides network businesses, like TasNetworks, with the revenue they need to service the interest on the borrowings they use to finance network assets, as well as a fair return on equity for the investors in those businesses.

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

The most recent determination was made by the AER in April 2019⁴⁷. This applies for the 2019–24 regulatory period and was TasNetworks' first combined transmission and distribution determination. This revenue determination, together with the efficiencies achieved by TasNetworks, has helped keep downward pressure on the delivered cost of electricity in Tasmania, while ensuring we maintain a safe and reliable network. The capital expenditure program for network services in our revenue determination included many of the proposed investments identified in this APR.

A.2. Integrated planning

We are responsible for planning the future transmission and distribution electricity network in Tasmania. This includes ensuring the network remains safe and reliable, complies with relevant laws, National Electricity Rules (**the Rules**), and good electricity industry practice, and other standards, and that it remains adequate to accommodate changes to the generation and load. We also identify augmentations, and non-network alternatives, that will provide a net economic benefit to all customers in the National Electricity Market (**NEM**). We achieve this through our network planning process to ensure solutions pursued balance both the economic and technical requirements of customers and the network.

To support this, integrated into our planning processes are our:

- Transformation Roadmap 2025 and strategy to 2030 ensures that we are adapting to the changing operating environment and continue to provide the most cost-effective services to our customers. An overview of our 2025 roadmap and 2030 strategy is presented in Section 1.6;
- network reliability strategy – at least maintaining current overall network reliability while reducing the total outage costs;
- asset management strategy – replacement of transmission and distribution assets is considered based on asset condition and risk, rather than age; and
- future networks strategy – maximise benefits of the existing networks to our customers through technology and non-network solutions.

⁴⁷ <https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/tasnetworks-determination-2019-24>

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 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 Annual Planning Report (**APR**) is a view at a particular point in time, the planning environment is dynamic and plans can and do adjust with changing circumstances.

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

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

A.2.2. Annual planning review

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

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

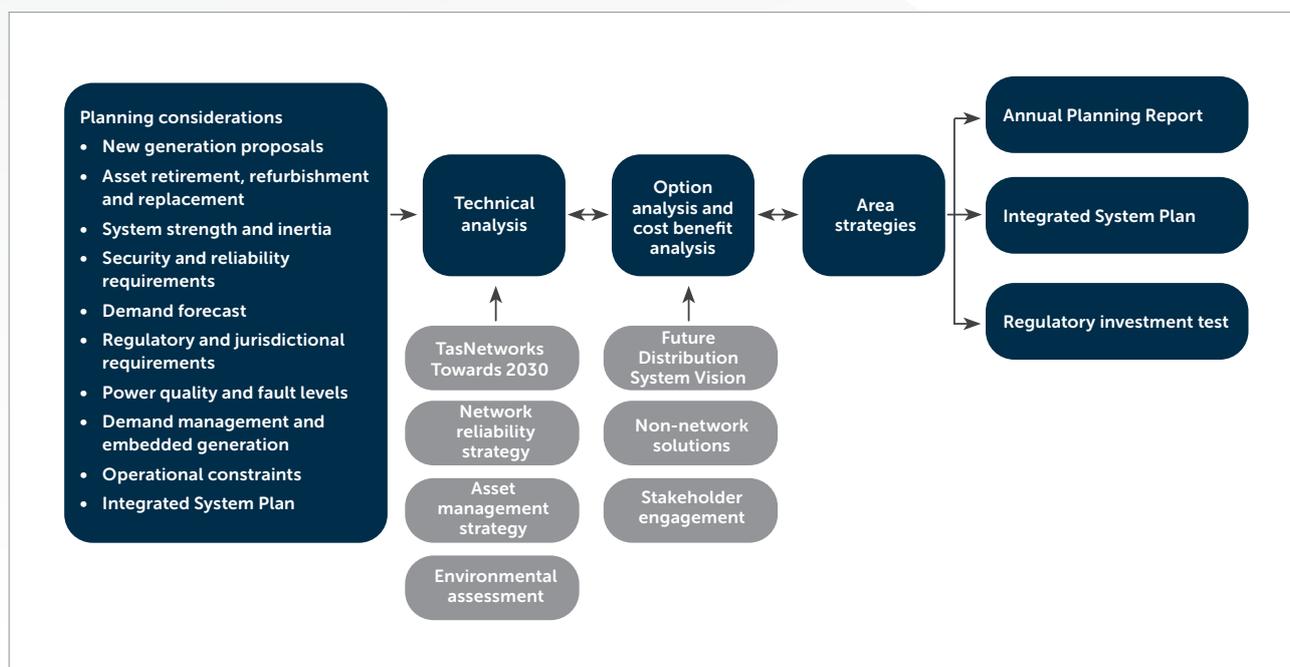


Figure A-1: The network planning process

A.3. Planning considerations and technical analysis

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

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

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 control⁴⁸. 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 per cent 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.

We use the AEMO Tasmanian regional forecast, with the April 2021 forecast the basis for the annual planning review presented in this APR⁴⁹. We engage with AEMO during the development of the forecast to ensure local conditions are accounted for, including the inclusion of committed loads.

We directly adopt AEMO's connection point forecast as our transmission-distribution connection point forecast. We then use it to develop area and locality forecasts for transmission planning, and for sub-transmission, zone substation and distribution feeder forecasts for distribution planning. AEMO publishes its connection point forecasting methodology on its website⁵⁰.

We use the connection point forecast to produce maximum demand forecasts for zone substations and distribution lines. These forecasts are developed for the central economic scenario only. 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.

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

49 <http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Transmission-Connection-Point-Forecasting/Tasmania>

50 <http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Transmission-Connection-Point-Forecasting/Tasmania>

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 network⁵¹. 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).

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

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

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 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 and monitoring equipment and control equipment.

The following provides a perspective on these Planning Requirements by relating them to the into perspective

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 3000 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 – 3000 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 OTTER⁵² 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.

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

A.4. Asset management strategy

Managing our existing assets and the planning for future network requirements are processes that must be coordinated to deliver the required service levels in the most cost-efficient manner. The asset management strategy focuses on ensuring the replacement of assets is determined objectively by asset 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
- understanding how we manage our assets with the changing use of our network from initiatives such as Marinus Link, the Integrated System Plan (ISP) and Battery of the Nation.

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.

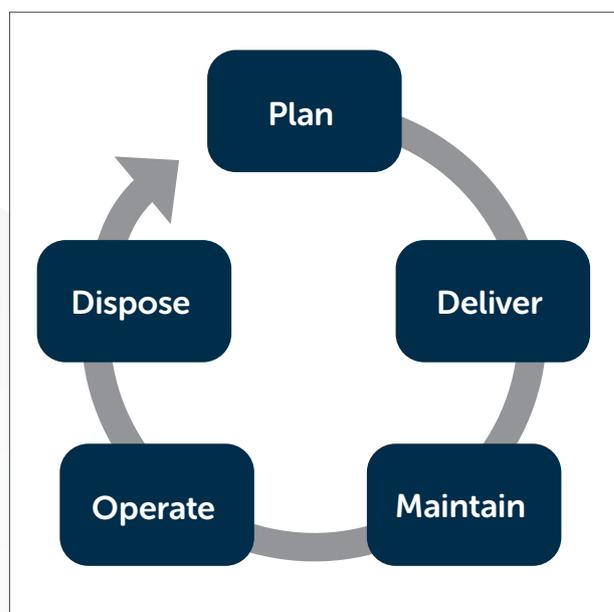


Figure A-2: Asset life cycle management

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:

- condition-based risk management;
- reliability-centred maintenance;
- time-based asset condition assessment; and
- run to failure.

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 which are materially affected, 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 meet the RIT 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 associated with a distribution system 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)⁵³ 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 NEM⁵⁴.

⁵³ <https://www.tasnetworks.com.au/Poles-and-wires/Planning-and-developments/Planning-our-network>

⁵⁴ <http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Loss-factor-and-regional-boundaries>

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 regulatory investment test 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 non-network and Stand Alone Power Systems (SAPS) opportunities during the planning cycle when investigating solutions to network limitations, with particular focus on the distribution network. To that end, we have developed an Industry Engagement Strategy 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.

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 regulatory investment test, 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.

A.7. Connecting embedded generation

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 devices⁵⁵. In addition to local anti-islanding protection devices, a telecommunications based anti-islanding inter-trip⁵⁶ 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.

⁵⁵ 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

⁵⁶ 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.

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 significantly 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.

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. Future Distribution System Vision and Roadmap

Our Future Distribution System Vision and Roadmap establishes a foundational plan for Tasmania's distribution network in response to the evolving needs of our customers, emerging community expectations and efficiencies from accelerating technological advances. A major focus is facilitating customer adoption of Distributed Energy Resources (**DER**), which include rooftop PVs, battery storage and electric vehicles (**EVs**). We have commenced stakeholder consultation and look forward to refining and co-designing each component. The proposed roadmap is outlined below:

A.9. Incentive schemes

As part of the regulatory framework, both the AER and Office of the Tasmanian Economic Regulator (**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 maximum allowable revenue. This is passed through to customers as an increase or decrease to network prices annually, or as part of our revenue setting process (depending on the incentive scheme).

A.10. Service target performance incentive schemes

The Service target performance incentive schemes (**STPIS**) for transmission and distribution provide financial rewards to network businesses for improvements in performance, which is largely measured in terms of the frequency and duration of supply interruptions, and penalties for reductions in performance.

The STPIS for transmission comprises three components: a service component, a market impact component and a network capability component. The STPIS for distribution has two components: reliability of supply and customer service, with customer service being assessed in terms of TasNetworks' performance in answering calls to its electrical emergency and outages call centre.

A.11. Guaranteed Service Level Scheme

TasNetworks' is subject to a guaranteed service level (**GSL**) scheme administered by OTTER. The STPIS for distribution networks also includes a GSL scheme but if there is already a jurisdictional scheme in place, the jurisdictional scheme applies.

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 101 geographical communities, with each community assigned to one of five reliability categories and different reliability standards applying to each category.

Milestones for the Future Distribution System

	FY2022	FY2023	FY2024	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030	FY2031	FY2032	FY2033	FY2034
EV strategy													
Customer digital comms.													
Workforce strategy													
Digital tech. strategy													
AMI Market Systems BW & analytics													
GIS strat. NOCS strategy/AFR/OMS													
Digital tech. strategy EAM Roadmap													
TREA TRET													
Stake holder engagement strategy													
Customers													
People													
Business													
Owners													
Lead 01: Customer enablement	Clear customer support of our role in the technology landscape.	Expertly accelerated early EV connections.	Proven DER approaches promote DER satisfaction in all customer classes.	Normalised customer centric engagement for DER solutions.	Significant customer experience uplift and substantial DER participants.	Operating envelopes available with limitations. Customer led innovation a key network evolution.	Dynamically helping all customers on their terms.	Operating envelopes established and supported. Cost reflective tariffs widely deployed and supported.					
Lead 02: Distribution system brand and communication channels	Centralised relationship management across all customer classes and stakeholders.	Optimised communication across all customer classes and stakeholders.	Trusted provider of appropriate DER products and services.	Extensive real-world testing integral to regulatory and engineering processes.	Minimum viable products for all promising new revenue sources.	Tests and pilots embraced as a primary skills pathway.	Established training of new skills and discipline cross-overs.	All promising new technologies have tested standard designs.	Highly accurate LV and MV network models. Smart meters replaced Cable-PI.	Automated predictions and outage notification.	Substantial access to our data and models.	Established customer third-party services.	Mature operating distribution system product.
Lead 03: Distribution system tests and pilots	Dedicated end-to-end work that assesses designs and tests metrics for BAU owners.	Strong pipeline of valuable tests and pilots.	All staff knowledgeable in value of DER to customers.	DMS functionality with other utilities. Dependency, Data set importance and access procedures clearly established.	Strong pipeline of new opportunities enabled by system improvements.	Dependency: Single source-of-truth interfaces automated between core systems.	Ready to deploy commercial aggregator services at scale.	Comprehensive data collection for network operations.	New energy services providers have equitable access to our assets.	Expert in macro network trends and DER trends.	Detailed business strategies endorsed and well actioned.	High degree of trust in our distribution expertise.	Active leader in DER conversations in Tasmania.
Lead 04: Currency of skills	Customer facing staff knowledgeable in DER.	DMS functionality with other utilities. Dependency, Data set importance and access procedures clearly established.	Strong pipeline of new opportunities enabled by system improvements.	Ready to deploy commercial aggregator services at scale.	Comprehensive data collection for network operations.	New energy services providers have equitable access to our assets.	Expert in macro network trends and DER trends.	Detailed business strategies endorsed and well actioned.	High degree of trust in our distribution expertise.	Active leader in DER conversations in Tasmania.			
Lead 05: Design of flexible systems	DMS functionality with other utilities. Dependency, Data set importance and access procedures clearly established.	Strong pipeline of new opportunities enabled by system improvements.	Ready to deploy commercial aggregator services at scale.	Comprehensive data collection for network operations.	New energy services providers have equitable access to our assets.	Expert in macro network trends and DER trends.	Detailed business strategies endorsed and well actioned.	High degree of trust in our distribution expertise.	Active leader in DER conversations in Tasmania.				
Lead 06: Data stewardship and system integration	Completed strategic uplift of distribution asset data.	Deploy foundational monitoring and aggregation system.	Detailed asset management strategy endorsed and well actioned.	High degree of trust in our distribution expertise.	Active leader in DER conversations in Tasmania.								
Lead 07: New distribution management system (DMS) performance	Completed strategic uplift of distribution asset data.	Deploy foundational monitoring and aggregation system.	Detailed asset management strategy endorsed and well actioned.	High degree of trust in our distribution expertise.	Active leader in DER conversations in Tasmania.								
Lead 08: Distribution system operation partnerships	Completed strategic uplift of distribution asset data.	Deploy foundational monitoring and aggregation system.	Detailed asset management strategy endorsed and well actioned.	High degree of trust in our distribution expertise.	Active leader in DER conversations in Tasmania.								
Lead 09: Future distribution system strategy	Completed strategic uplift of distribution asset data.	Deploy foundational monitoring and aggregation system.	Detailed asset management strategy endorsed and well actioned.	High degree of trust in our distribution expertise.	Active leader in DER conversations in Tasmania.								
Lead 10: Future distribution system advocacy	Completed strategic uplift of distribution asset data.	Deploy foundational monitoring and aggregation system.	Detailed asset management strategy endorsed and well actioned.	High degree of trust in our distribution expertise.	Active leader in DER conversations in Tasmania.								

A.12. Customer Service Incentive Scheme

The AER has the power to develop incentives for network businesses to provide services in a manner that contributes to the achievement of the National Electricity Objective (NEO). Since the AER's last determination for TasNetworks in 2019, the AER has introduced a Customer Service Incentive Scheme (CSIS) to encourage distribution businesses to improve the aspects of their service delivery that their customers want improved. Since then, TasNetworks has been consulting with customers to determine the parameters that best reflect their expectations and is working with the AER to implement a CSIS in the next regulatory period, which starts in July 2024. There is no proposal from the AER to introduce a similar scheme for transmission businesses at present.

A.13. Efficiency Benefit Sharing Scheme

The efficiency benefit sharing scheme (EBSS) provides financial rewards to network businesses that underspend on regulated services operational expenditure (OPEX) and sustain the savings over time. The EBSS also penalises network businesses that overspend against their opex allowance and/or do not sustain savings over time. 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.14. 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 overspending. 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.15. Incentives for Demand Management – Distribution

There are two demand management schemes for distribution businesses overseen by the AER. They are:

- 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. We have formerly utilised DMIAM to fund the development of customer-owned storage as a peak demand management tool and for investigating the impact of demand-based tariffs on reducing peak demand.

A.16. Demand Management Incentive Allowance – Transmission

For transmission business there is only one demand management related incentive scheme, the DMIAM for transmission. The criteria for funding is as for distribution with the addition that demand management projects that also improve wholesale market outcomes should be considered, and prior public commitment is made to share the results, learnings and insights of the project. The DMIAM for transmission will not apply in Tasmania until the next regulatory control period for TasNetworks, which commences in July 2024.

Appendix B

Generator information

Table B-1 lists the Tasmanian generators connected to the transmission network⁵⁷. 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 ⁵⁸	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	Sheffield
Devils Gate	63	West Coast	
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	144	Central	Waddamana
Musselroe	168	Northern	Derby
Bluff Point	65	North West and	Smithton
Studland Bay	75	West Coast	
Granville Harbour	112		Farrell

57 Capacity information sourced from:

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

58 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.

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	North West and West Coast	Mowbray 62006
Tunbridge	Hydro	5.0	4.9		Avoca 56004
Little Fisher	Hydro	0.8	0.8		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
Quioba	Solar	0.51	0.51		Devonport 80003
Ulverstone	Natural gas	7.9	2.0	Ulverstone 82006	
Woolnorth	Wind	0.6	0.55	Southern	Smithton 93005
Wynyard	Natural gas	2.0	0.0		Burnie 91004
Glenorchy	Biomass	1.7	1.5		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 Section 6.4. 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 Tasmanian Electricity Code (**the Code**). The performance presented here is what we provide to Office of the Tasmanian Economic Regulator (**OTTER**) as part of our normal reporting process. From 2017–18 we report performance based on customer rather than kVA. In this below table, prior to 2017–18 is now calculated using customer. The standards exclude outages caused by third-party outages transmission network and fire.

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

Supply reliability category	Standard (interruptions)	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22
Critical infrastructure	0.2	0.42	0.15	0.14	0.25	0.15	0.3
High density commercial	1	0.14	0.38	0.41	0.33	0.46	0.7
Urban and regional centres	2	1.25	1.48	1.25	1.28	1.42	1.2
High density rural	4	3.29	3.18	2.39	2.55	2.30	2.8
Low density rural	6	3.86	3.72	3.37	3.26	3.23	4.2

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

Supply reliability category	Standard (minutes)	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22
Critical infrastructure	30	25.77	29.61	40.90	26.62	15.10	69.76
High density commercial	60	18.49	70.16	49.66	55.62	62.04	86.31
Urban and regional centres	120	168.30	227.31	138.38	148.50	182.89	161.10
High density rural	480	600.87	543.70	291.35	321.20	309.57	503.94
Low density rural	600	737.58	700.48	527.03	544.40	549.10	1130.70

C.1.2. Supply reliability communities

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 communities within the categories.

Table C-3 and Table C-4 present our performance for the 101 supply reliability communities against the SAIFI and SAIDI standards, respectively. The table presents the standards specified in the Code for each community across the five categories, and the number of communities in each category that is not meeting the standard.

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

Supply reliability category (number of communities)	Standard (interruptions)	2016–17	2017–18	2018–19	2019–20	2020-21	2021-22
Critical infrastructure (1)	0.2	1	0	0	1	0	1
High density commercial (8)	2	0	0	1	1	0	0
Urban and regional centres (32)	4	4	2	1	2	2	2
High density rural (33)	6	4	2	3	1	1	3
Low density rural (27)	8	1	0	1	1	0	2
Total (101)		10	4	6	6	3	8

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

Supply reliability category (number of communities)	Standard (minutes)	2016–17	2017–18	2018–19	2019–20	2020-21	2021-22
Critical infrastructure (1)	30	1	0	1	1	0	1
High density commercial (8)	120	0	1	1	2	2	2
Urban and regional centres (32)	240	8	13	6	11	10	11
High density rural (33)	600	9	9	5	4	3	10
Low density rural (27)	720	11	12	6	8	6	12
Total (101)		29	35	19	26	21	36

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 STPIS and are calculated on our actual performance for the preceding five years. The targets set by the AER exclude planned outages, major event days, total fire ban day related outages, transmission network outages, fire 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.

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

Regulatory period	2012–17		2017–19			2019–24			
	Target	2016–17	Target	2017–18	2018–19	Target	2019–20	2020-21	2021-22
Supply reliability category									
Critical infrastructure	0.22	0.39	0.28	0.06	0.01	0.251	0.168	0.104	0.051
High density commercial	0.49	0.10	0.30	0.27	0.31	0.260	0.274	0.349	0.655
Urban and regional centres	1.04	0.91	1.03	1.26	1.11	1.081	1.074	1.186	1.019
High density rural	2.79	2.53	2.41	2.46	2.15	2.466	2.358	2.056	2.278
Low density rural	3.20	3.10	3.22	2.79	2.86	3.219	2.892	2.773	3.452

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

Regulatory period	2012–17		2017–19			2017–19			
	Target	2016–17	Target	2017–18	2018–19	Target	2019–20	2020–21	2021–22
Critical infrastructure	20.79	72.69	27.83	3.58	5.88	32.984	11.160	7.310	3.418
High density commercial	38.34	4.86	25.32	21.89	27.18	20.074	43.704	28.895	56.993
Urban and regional centres	82.75	71.48	81.31	104.72	93.89	89.657	90.638	107.493	96.858
High density rural	259.48	241.22	235.29	242.58	227.59	250.959	250.665	215.617	279.612
Low density rural	333.16	349.88	416.13	320.45	366.43	400.401	390.294	360.762	468.122

C.2.2. Customer service

As part of the AER's distribution service target performance scheme (STPIS) and OTTER regulatory reporting requirements, we report on customer service performance in terms of a telephone answering parameter, Table C-7. This parameter is defined as the number of calls answered in 30 seconds, divided by the total number of calls received (after removing exclusions).

Table C-7: Customer service performance

Telephone answering	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22
Number of Calls	40,944	42,634	37,433	31,402	21,943	32,582
Number of calls answered in 30 seconds	33,504	34,315	31,236	27,537	17,027	25,804
Percentage of calls answered within 30 seconds	81.83	80.49	83.45	87.69	77.60	79.1
Performance target (%)	73.3	74.78	76.30	76.30	76.30	76.30



[TasNetworks.com.au](https://www.tasnetworks.com.au)