Annual Planning Report
2015

TasNetworks
Delivering your power

Contents

Executive summary

TasNetworks

TasNetworks is Tasmania's electricity network service provider. We commenced operations on 1 July 2014, with the merger of Aurora Energy's distribution network (the poles and wires) and Transend Networks' transmission network (the big towers and lines). We supply the power from generation sources to homes and business in Tasmania through a network of transmission towers, substations and power lines.

The TasNetworks vision is to be "Trusted by our customers to deliver today and create a better tomorrow".

The purpose of our business is "We deliver electricity and telecommunications network services, creating value for our customers, our owners and our community".

Part of our function is to plan for the future requirements of the electricity network in Tasmania. This Annual Planning Report presents the outcomes of the planning undertaken in the past year. It meets our requirements in publishing transmission and distribution Annual Planning Reports.

Maintaining reliability

Our plans in this report align with our strategies of maintaining overall network service performance, while ensuring lowest sustainable prices for our customers. The outcomes of this report flow through to our revenue submissions to the Australian Energy Regulator, which saw a large reduction in proposed capital expenditure for our 2014–19 transmission revenue proposal and we are working towards further reductions as part of our distribution revenue proposal for the period commencing in 2017.

Planning outcomes

Electricity consumption and the maximum demand on the network in Tasmania have been falling since 2008, however the rate of decline has settled in the last three years. Our forecast indicates demand growth in the medium to long term, although the forecast rate of increase is subdued and has softened. Our forecast growth rate of 1.1 per cent per annum means we do not expect overall demand to again reach 2008 levels before 2025.

As a result of the softening demand forecast, the majority of our forecast issues and proposals have been deferred – a number to outside our 10-year planning horizon.

Customer engagement

In line with our company vision, a key focus of our business is customer engagement. As part this we will consult with affected customers and stakeholders on our project proposals, in addition to what is presented in this report. We welcome feedback on the issues and proposals included in this report at any time, as well as submissions on any alternate options to address network issues. For further information, please contact:

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Chapter 1

Overview

TasNetworks publishes an Annual Planning Report to provide information about the Tasmanian power system, any current or emerging network issues and proposed solutions, and opportunities for new load or generation customers to connect to the network. Chapter 1 explains the background to the Annual Planning Report. It also provides a summary of the major changes that have occurred since 2014.

1 Introduction

1.1 About TasNetworks

Tasmanian Networks Pty Ltd (TasNetworks) delivers electricity and telecommunication network services, creating value for our customers, our owners and the community. We commenced operations on 1 July 2014. We were formed from the merger of Transend Networks Pty Ltd, previously owner and operator of the electricity transmission network, and the distribution business of Aurora Energy Pty Ltd[1], owner, operator and maintainer of the electricity distribution network. TasNetworks is owned by the Tasmanian Government.

TasNetworks is the sole licensee for regulated transmission and distribution network services on mainland Tasmania. We are registered with the Australian Energy Market Operator (AEMO) as both a Transmission and Distribution Network Service Provider and operate in the National Electricity Market (NEM). TasNetworks is unique in the NEM in that it is the only combined Transmission and Distribution Network Service Provider providing services to all customers in its jurisdiction.

As a monopoly provider of transmission and distribution network services, our revenue for these services is regulated. We prepare submissions to the Australian Energy Regulator (AER) which determine our revenue and the maximum amount we can recover from customers, generally for periods of five years.

1.2 What we do

TasNetworks owns, operates and maintains the transmission and distribution electricity networks on mainland Tasmania and Bruny Island.[2] We deliver electricity generated from our generation customers at hydro, wind and gas-fired power stations to approximately 280,000 demand customers throughout the state. Our demand customers range from domestic and commercial customers to major energy users connected directly to the transmission network. Our network also allows electricity generated from private generating units to be transported to other customers. The widespread adoption of rooftop photovoltaic (PV) systems has dramatically increased the use of the network for this purpose in recent years.

1 *Aurora Energy still exists as an electricity and gas retailer in Tasmania.*

2 *Hydro Tasmania is responsible for the electricity networks on King and Flinders Islands.*

We also facilitate the transfer of electricity to and from mainland Australia. The Basslink Interconnector is a privately-owned under-sea cable between George Town in Tasmania and Loy Yang in Victoria. Basslink can transfer electricity in either direction.

TasNetworks also owns and operates a high-reliability telecommunications network. This network supports the operation of the electricity network, and also provides communications services to other customers.

1.3 Purpose of this document

We produce the Annual Planning Report (APR) to provide information on the planning activities we have undertaken in the past year. We conduct an annual planning cycle to analyse the existing network and consider its future requirements to accommodate changes to load and generation, and whether there are any problems in meeting the required performance standards. We then look for opportunities for innovative solutions to address any emerging issues. We do this in consultation with our customers and in accordance with our relevant legal obligations.

This APR presents the outcomes of these planning studies, in accordance with our obligations under clause 5.12.2 and 5.13.2 of the National Electricity Rules (the Rules) for the publication of Transmission and Distribution Annual Planning Reports. The APR also includes the requirements of the Tasmanian Annual Planning Statement, in accordance with clause 15 of our transmission license issued under the *Electricity Supply Industry Act 1995* and as set by the Office of the Tasmanian Energy Regulator (OTTER). We are required to publish the APR by 30 June each year, in accordance with clause 5.12.2(a) and 5.13.2(a)(1) of the Rules and in conjunction with clause 8.3.2 of the Tasmanian Electricity Code (the Code).

In addition to these requirements, we present further information to better inform our audience about the issues and opportunities in our network. We provide this information so that our audience is aware of:

- the capability of our network to transfer electrical energy;
- how the network may affect their operations;
- the locations that would benefit from supply capability improvements or network support initiatives; and
- locations where new loads or generation could be readily connected.

We actively investigate alternate options to traditional network augmentation or straight like-for-like equipment replacements to address issues. Our intent is that this APR provides existing and potential new customers and non-network solution providers with preliminary information to prompt discussion on opportunities for solutions to address issues.

1.4 Audience

This APR is primarily written for people with an interest in the Tasmanian electricity industry. It specifically provides information which will be useful to existing transmission-connected customers and larger customers connected to the distribution network; potential new generation and load customers; non-network solution providers; AEMO; the AER and other interested parties. While this is the case, our intent is also that those without a direct interest in the electricity industry can gain an appreciation of the operation of the electricity network, network planning and the drivers for network investment.

1.5 Planning horizon

This APR covers a 10-year planning period from 1 July 2015 to 30 June 2025. However, some aspects are planned based on shorter planning periods. Distribution line overloads are planned to a 2-year planning horizon, as loading in the distribution network is dynamic and loads are often easily transferable between circuits.

1.6 Strategic context of the APR

This APR supports our capital works program over our current and forthcoming regulatory periods and beyond. However, the purpose of the APR means it does not include all capital investments included in the program. The APR focuses on augmentation and reliability projects in the transmission and sub-transmission networks, with only overloads within the next two years of distribution lines. Proposed asset replacement projects over $5 million in the transmission network and over $2 million or projects considered significant in the distribution network are included, however programs and smaller replacement projects are not.

Our transmission revenue proposal included significant reductions in operating expenditure, capital expenditure, and the rate of return, compared to the previous regulatory period. This is in part due to prudent network investment in previous years. It also reflects the state-wide demand outlook, where very little augmentation or connection expenditure is required in the transmission network. Our transmission forecasts also reflect the drive for further efficiency across our operations.

We are adopting a similar sustained cost minimisation focus in preparing for our next distribution determination. However, our distribution network faces different challenges to our transmission network. Looking forward, there are some areas of Tasmania where irrigation load and other load growth are driving targeted distribution reinforcement and augmentation investment. We also forecast a continuing program of customer-initiated work, some of which is directly funded by those customers through capital contributions.

Our forward distribution capital expenditure is also focussed on replacing, refurbishing and maintaining assets to maintain the reliability and quality of customer supply. A number of our distribution assets are approaching the end of their useful life, presenting challenges in maintaining supply reliability. We continue to refine our asset management strategies, to prioritise our expenditure to address these challenges.

1.7 What has changed since 2014

This is the first APR published by TasNetworks, and the first Tasmanian APR covering both the transmission and distribution networks. Therefore the structure of this report is significantly different from that presented in the 2014 APRs published by Aurora Energy and Transend Networks. The key differences in network needs and proposed solutions from 2014 APRs is summarised in Table 1-1.

Table 1-1: Differences in network needs and proposed solutions since 2014

Area	Location	Summary of change	Reference
State-wide and inter-area	Waddamana–Bridgewater	Timing of supply configuration change to Bridgewater Substation to allow decommissioning of poor condition transmission line has been deferred from 2017 to 2019.	6.9.2.4
	Waddamana–Palmerston	Due to reduction in load forecast, there is insufficient benefit to convert this transmission line from 110 kV to 220 kV. The project has been deferred past 2025.	6.9.3.1
	Hobart and surrounding areas	Due to reduction in load forecast, the requirement for voltage support in this area has been deferred past 2025.	6.9.3.2
	All substation supply points	The proposal to purchase a transportable substation for emergency and short-term deployment has been deferred from 2015 to 2019.	6.9.2.6
	State-wide	We are not currently developing our residential demand management initiative further due the limited benefit in the program and softening load forecast.	6.9.4.6
West Coast	Rosebery	The loading issue on the transformers is being addressed through the installation of forced cooling and dynamic rating. The preferred option presented in 2014 was to replace the transformers with larger units.	6.2.2.1
	Queenstown and Newton	Due to reduction in customer load, a single asset failure will now not result in more than 300 MWh of unserved energy. The previous proposal to alleviate this issue is now deferred indefinitely.	6.2.4.1
		The issue of condition of Queenstown–Newton 110 kV transmission circuit remains.	6.2.3.5
	Farrell	Due to reduction in area load, the economic benefit from mitigating a single asset failure is not sufficient. The previous proposal is now deferred indefinitely.	6.2.4.2
	Newton	Due to the public announcement that the major customer supplied from the substation will close, we have ceased investigations into the existing transformer security at the substation.	6.2.4.3
North West	Wesley Vale	The proposal to change the distribution voltage from 11 kV to 22 kV is currently being reviewed.	6.3.4.1
	Burnie and Emu Bay	Due to reduction in load forecast, the requirement to de-load Burnie Substation has been deferred past 2025.	6.3.4.2
Northern	Palmerston	New issue for 2015 APR is the poor condition of the disconnectors, earth switches and some protection and control equipment. Replacement and refurbishment of assets proposed.	6.4.3.6
	George Town	The voltage control issues at George Town Substation are now being managed by constraint equations. However, we are investigating options to relieve these constraints.	4.1.3 6.4.4.1
	Derby	Due to a reduction in load forecast, the requirement for increased security to Derby Substation has been deferred past 2025.	6.4.4.2
Central	Butlers Gorge–Derwent Bridge	Timing of transmission line replacement with distribution line to address asset condition issues has been deferred from 2016 to 2017.	6.5.3.7
Greater Hobart	Creek Road	We will re-assess the maximum allowable fault levels at connection points and review previous proposals to install fault current limiters.	6.6.4.2
	North Hobart	Timing of switchboard replacement at North Hobart Substation has been deferred from 2017 to 2018.	6.6.3.11
	Bridgewater	Due to a reduction in load forecast, the requirement for a new zone substation at Austins Ferry or Brighton to manage loading issues at Bridgewater Substation has been deferred past 2025.	6.6.4.1
	Geilston Bay and Bellerive	The loading issues at Geilston Bay Zone Substation and on Bellerive Zone Substation sub-transmission feeders have been addressed by the establishment of a new zone substation at Rosny Park.	6.6.2.1
Eastern	Avoca and St Marys	The requirement for a smart-grid controller to manage load restoration in the Avoca and St Marys area has been assessed as not providing an overall benefit in its establishment.	6.7.4.1
	St Marys	Due to a reduction in load forecast, the risk of substation capacity being insufficient has been deferred past 2025.	6.7.4.2
Kingston-South	Bruny Island submarine cable	We are managing the overload risks on one of the cables supplying Bruny Island by utilising peak-shaving generation.	6.8.4.1
	Electrona	Due to a reduction in load forecast, particularly at Electrona Substation, the requirement for a new zone substation at Margate has been deferred past 2025.	6.8.4.2

1.8 Overview of this document

Chapter 1:	introduces TasNetworks, and the purpose of the Annual Planning Report.
Chapter 2:	provides information on the environment TasNetworks operates in and considerations in planning the electricity network.
Chapter 3:	introduces the Tasmanian electricity network, the transmission and distribution networks, and where TasNetworks fits in the Tasmanian electricity supply industry.
Chapter 4:	details the performance of the electricity network. It details our performance against transmission and distribution reliability targets, transmission network constraints, and factors that materially affect network performance.
Chapter 5:	describes the forecast electricity demand over the next ten years, the factors that influence that demand, and provides an assessment of whether the generation supply is sufficient to meet the forecast demand.
Chapter 6:	details the parts of the Tasmanian electricity network, by planning area, forecast to require enhancement into the future, and describes the options available to achieve this. It also summarises how our proposals align with national transmission planning performed by AEMO, and those subject to the regulatory investment test.
Chapter 7	provides a summary of information which would be useful for owners of generators or large loads that are connected, or are considering connecting to, the transmission network.
Appendices:	provide additional and supporting data, notably a glossary of technical terms in Appendix A. Bulk data is available as downloadable supplementary information, and is not included in this report.

1.9 Feedback and enquiries

We welcome feedback on our 2015 Annual Planning Report. We are particularly interested in discussing opportunities for interested parties to participate in demand-side management or other innovative solutions to manage network issues.

We also welcome feedback on the content of this report, to allow us to improve it in future years.

Please address enquiries to:

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Chapter 2

Overview

Chapter 2 discusses relevant aspects of the legal framework which governs network planning and expansion activities in Tasmania, and informs key aspects of network planning and asset management strategy. This chapter also discusses our stakeholder engagement plans and how customers and other stakeholders can be engaged in the planning process.

2 Planning considerations

2.1 The regulatory framework

TasNetworks operates under both jurisdictional and national regulatory regimes. As a participant in the NEM, we are required to develop, operate and maintain the electricity supply system in accordance with the Rules. In addition, there are local requirements that we must comply with under the terms of our licences issued by the Tasmanian Economic Regulator under the *Tasmanian Electricity Supply Industry Act 1995*. We are also subject to a number of industry-specific Tasmanian Acts and Regulations.

The regulations which are relevant to power system planning are:

- the technical requirements of Schedule 5.1 of the National Electricity Rules;
- the *Electricity Supply Industry (Network Planning Requirements) Regulations 2007*;
- the Tasmanian Electricity Code; and
- the regulatory investment test.

2.1.1 National Electricity Rules Schedule 5.1

Schedule 5.1 of the Rules describes the planning, design and operating criteria that must be applied by Network Service Providers to the networks which they own, operate or control. 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.

2.1.2 Electricity Supply Industry (Network Planning Requirements) Regulations 2007

The *Electricity Supply Industry (Network Planning Requirements) Regulations 2007* (referred to as "ESI Regulations" in the remainder of this document) are Tasmanian regulations which specify reliability standards that we must aim to meet when planning the transmission network. The ESI Regulations define the maximum extent of power interruptions following contingency events. The ESI Regulations apply to the transmission network only, not the distribution network.

The ESI 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 upgrade, consider that the upgrade would not be sufficiently beneficial, then we must report this in our Annual Planning Report. We are exempt from undertaking that upgrade for five years, and we are also exempt, for five years, from meeting the performance standard in the ESI Regulations which was the basis for the proposed upgrade. The exemption may cease early if the circumstances surrounding the exemption change, or if one of the affected transmission customers no longer wishes the exemption to remain.

2.1.3 Tasmanian Electricity Code

The Tasmanian Electricity Code (the Code) is published and maintained by the Tasmanian Economic Regulator. It contains arrangements for the regulation of the Tasmanian electricity supply industry additional to those in the Rules. The Code largely relates to operation of the distribution network. The Code contains the technical standards for power quality, standards of service for embedded generators, and reliability of supply standards for the distribution network.

2.1.4 The regulatory investment test

The regulatory investment test (for transmission and distribution) is a procedure published by the AER under clause 5.16 and clause 5.17 of the Rules. As a transmission and distribution network service provider, we are required to apply the regulatory investment test for transmission and distribution projects over $5 million.

The regulatory investment test defines the economic analysis and public consultation process that a network service provider must undertake when proposing to address a need in the power system. The objective of the regulatory investment test is to ensure the option which the network service provider selects, in order to fulfil the need, has the greatest long term economic benefit for electricity consumers and producers.

The regulatory investment test allows for external parties, who may be able to provide a solution, to discuss the solution and submit proposals to the network service provider. The network service provider is obliged to consider any credible proposals objectively.

There are some cases in which a network service provider is not obliged to undertake a regulatory investment test. These are described in clause 5.16.3(a) and clause 5.17.3(a) of the Rules and include proposals in response to a connection application or where the most costly option does not exceed $5 million.

2.2 Revenue determination

The revenue we earn from providing monopoly transmission and distribution services is set by the AER. This is currently done separately for transmission and distribution services. We effectively prepare two proposals for the AER, outlining our expenditure plans to efficiently provide network services for a five-year period.

The AER released its final decision on 30 April for our transmission revenue proposal for the 2014–2019 regulatory period, in which it accepted our proposal. The current Distribution Determination cycle commenced on 1 July 2012 for the 2012–2017 regulatory period. TasNetworks is continually seeking ways to provide services to its customers as efficiently as possible.

From 2019, we will align our transmission and distribution reset processes. To achieve this, we are currently preparing a two year distribution reset for a 2017–2019 regulatory period. The intended outcomes of merging the determination processes are to reduce costs through combined planning, contribute to our strategic objective of 'one business' and allow us to engage meaningfully with our customers on the full service suite offered.

2.2.1 Service target performance incentive scheme

Included in the revenue determination is a set of regulatory incentive schemes. Incentive schemes are used by the AER to provide incentives for network businesses to sustainably reduce costs whilst also maintaining or improving service levels. The service target performance incentive scheme (STPIS) is one such incentive scheme that we use to measure our performance. The STPIS is based on a number of parameters and sub-parameters. The intent of the scheme is to reward network businesses for improvements in performance, and penalise them where performance has decreased.

The STPIS for transmission consists of three components; the service component, the market impact component, and the network capability component. The STPIS for distribution is intended to focus a distribution networks' attention on the service that it provides to its customers. It has two components; reliability of supply and customer service. This also includes a guaranteed service level scheme (GSL scheme) whereby our customers are compensated for prolonged and excessive interruptions to their supply.

2.3 TasNetworks integrated planning

As the only transmission and distribution network service provider in Tasmania, we have a responsibility to ensure that the infrastructure to supply Tasmanians with electricity evolves to meet customer and network requirements, in an economically optimal way. To this end, we have integrated the following business strategies into our planning.

- Network reliability strategy – at least maintaining current overall network reliability whilst reducing the total outage costs;
- Network development strategy – transmission and distribution issues are studied as one integrated function taking account of the forecast changes in both networks; and
- Asset management strategy – replacement of transmission and distribution assets is considered based on asset condition and risk, rather than age.

2.3.1 Network reliability strategy

Transmission network reliability is measured in terms of the number of loss of supply (LOS) events that occur during a calendar year. We have an obligation to monitor and report against service measures and objectives to national (AER) and state (OTTER) regulatory bodies, and to customers such as Hydro Tasmania and major industrials.

In meeting these requirements we actively undertake:

- performance monitoring;
- performance benchmarking;
- incident investigations; and
- implementation of service improvement initiatives.

Distribution network reliability is a measure of performance with regard to frequency (number of events) and duration of unplanned interruptions to our customers. We have an obligation under the Code to manage the reliability performance of our network, and to mitigate any reliability impacts on our customers and the broader Tasmanian community.

Our reliability management strategy seeks to:

- at least maintain current overall network reliability performance in accordance with the principles of the economic incentive scheme whilst providing lowest sustainable prices and maximising value to our customers;
- ensure compliance with regulation, codes and legislative requirements;
- manage our risk profile to maintain a safe and reliable network, now and into the future with respect to cost effectiveness and reliability; and
- reduce total outage costs for the network.

The strategy does not preclude enhancing network reliability where community, feeder or circuit performance is inadequate or where asset risk is unacceptably high. It is proposed that all reliability activities will be managed within the cost allowance approved for reliability maintenance or improvement in the 2012–17 distribution regulatory period.

Section 4.2 presents how we manage our distribution supply reliability for both the supply reliability communities and the categories.

2.3.2 Network development strategy

2.3.2.1 Network planning

Network planning is the process of identifying what changes to the electricity network will be needed in future years. The need for network changes can arise from a number of factors:

- 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 consumed per household. A new specific large load, such as a new shopping centre, or closure of large load, such as a mine, will also cause changes in electricity demand that need to be considered.
- As network equipment ages, it becomes more likely to fail. We investigate whether it is best to continue maintenance of the existing equipment, replace the equipment entirely, or whether it may be possible to decommission equipment and use alternative parts of the network, or non-network solutions, to supply electricity.
- New power stations may be constructed, or old ones removed from service. These changes influence where electricity flows in a network.
- Technological changes impact on the network. Historically end-use customers only consumed electricity. Now with PV and battery storage technology, customers are producing electricity. These technological developments affect the way we plan our network.

We consider transmission and distribution planning as one integrated function, planning it as one electricity network. Our plans take account of transmission and distribution network requirements as required by our regulatory obligations and in consultation with our customers and other stakeholders.

2.3.2.2 Planning timeframes

We perform an annual planning cycle to identify and report on existing and future issues in the electricity network. From these detailed studies on the Tasmanian power system, we create 15-year area strategies. These strategies consider the elements outlined in Section 2.3.2.1 and result in the network needs identified in this Annual Planning Report, for a 10-year timeframe. Because the detailed annual planning looks ahead 15 years, we can revise our plans if forecast load or generation changes do not eventuate.

Going forward, we will be further developing a longer term vision for the electricity network in Tasmania. This will identify the changes in the network that may be required in the long term, depending on what load and generation changes take place. From this, we will be better placed to ensure that our future development plans can accommodate a range of possible futures for the network and consumers in Tasmania.

2.3.2.3 Overview of the network planning process

The network planning process comprises a number of steps, shown in Figure 2-1.

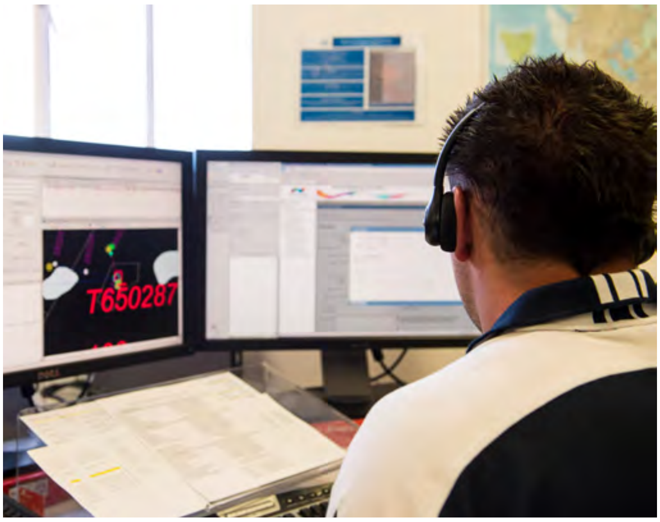
A key input to the planning process is the electricity demand forecast. We have developed an overall energy and demand forecast from forecasts provided by:

- National Institute of Economic and Industrial Research (NIEIR). NIEIR provides an overall forecast based on current economic trends;
- directly connected transmission customers – who forecast their demand based on their business outlook; and
- our forecast of demand at our distribution connection points based on the NIEIR retail forecast.

After finalising our demand forecast, we undertake computer simulations of the power system to determine whether the network is capable of meeting the forecast demand without exceeding technical limits. These limits 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.

Where a future network constraint or issue is identified, we conduct a sensitivity analysis on it. This is to determine the impact of a change in the demand forecast or other assumptions may have on the timing of the issue occurring, or its severity. We consult with customers and other stakeholders on the risk (probability and impact) associated with the issue occurring. 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.

When we find that network changes are likely to be needed, we identify the possible options that would solve the problem. Options could include expansion of the network, or working with customers to reduce their energy or demand to eliminate the problem, or some other alternative. We determine the advantages and disadvantages of each option, and investigate each one in detail to confirm its feasibility. For those options that are feasible, we estimate the cost of each option and the potential economic benefits it would bring (for example, averting or reducing the loss of supply to an area has an economic benefit).



We use probabilistic planning techniques when conducting our economic analysis. This means, when assessing the economic benefits of a proposal which may, for example, serve to increase the reliability of supply to a remote area, we include the probability of the area losing its supply as part of the analysis. It may eventuate that the probability of the area losing supply is so low, or the cost to improve reliability is so high, that it is not economically beneficial to undertake works to improve the supply reliability. Upon identification of a preferred solution, we consult with affected customers and stakeholders to confirm if there is sufficient benefit in proceeding with the proposal.

The Annual Planning Report is a summary of the outcomes of our annual planning process. It 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, in 2015. Because network planning is a cyclic process, we may find the expected needs change from one year to the next. If demand changes at a different rate than is currently forecast, some proposed network changes may not be required. Others may be required sooner.

When it becomes clear that significant remedial work will definitely be needed and the cost of the potential credible option to address the identified need is greater than $5 million, we undertake a regulatory investment test. This is the final – and public – options selection and consultation process. Once the final option has been selected via this process, we can then commence the implementation of that option.

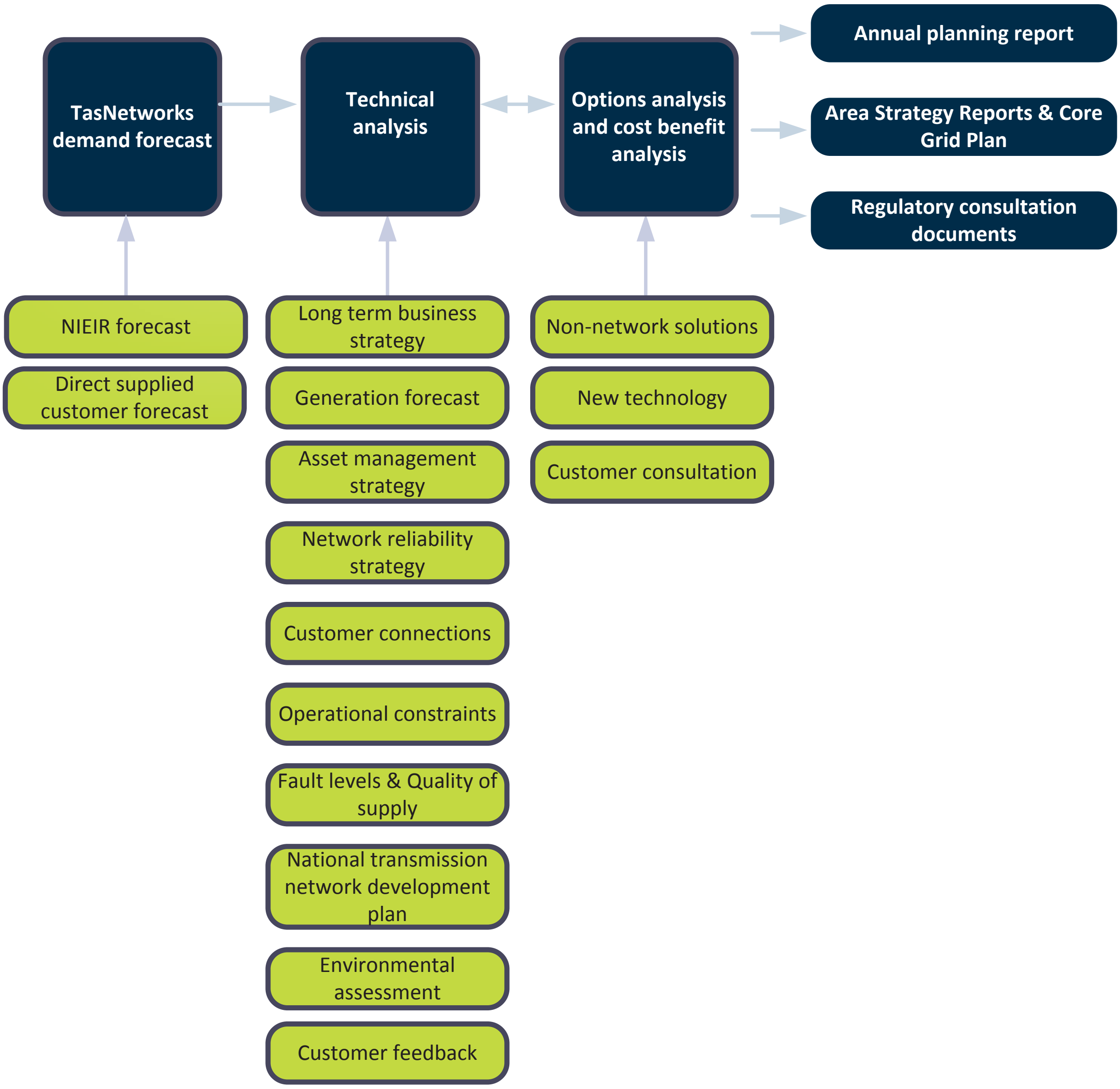


Figure 2-1: Overview of the network planning process

2.3.3 Asset management strategy

We have developed an integrated asset management framework, together with supporting processes and systems, to ensure that performance objectives are consistently achieved. The framework ensures that the approach to asset management delivers prudent and efficient outcomes that optimise the performance of the transmission and distribution networks. The goal of infrastructure asset management is to meet the required level of service in the most cost-effective manner, through the prudent and efficient management of assets for present and future network users. Figure 2-2 presents our asset management documentation framework that supports the asset management process.

As presented in Figure 2-2 and discussed in Section 2.3.2.1 ageing and potentially unreliable assets are managed as part of our overall asset management strategy. The focus of this strategy is to ensure that replacement of assets is determined on asset condition and risk rather than age. In developing strategies in relation to potentially unreliable assets; we take a holistic approach to asset renewals, augmentations and decommissioning, across both transmission and distribution networks. We ensure that our asset management plans align with our development plans to drive the most efficient outcome.

Our Asset Management Plans can be obtained from our website[3] or by request.

3 *https://www.tasnetworks.com.au/Our-network/Network-revenue-pricing/Transmission-Revenue-Proposal-Documentation/Asset-Management-Plans*

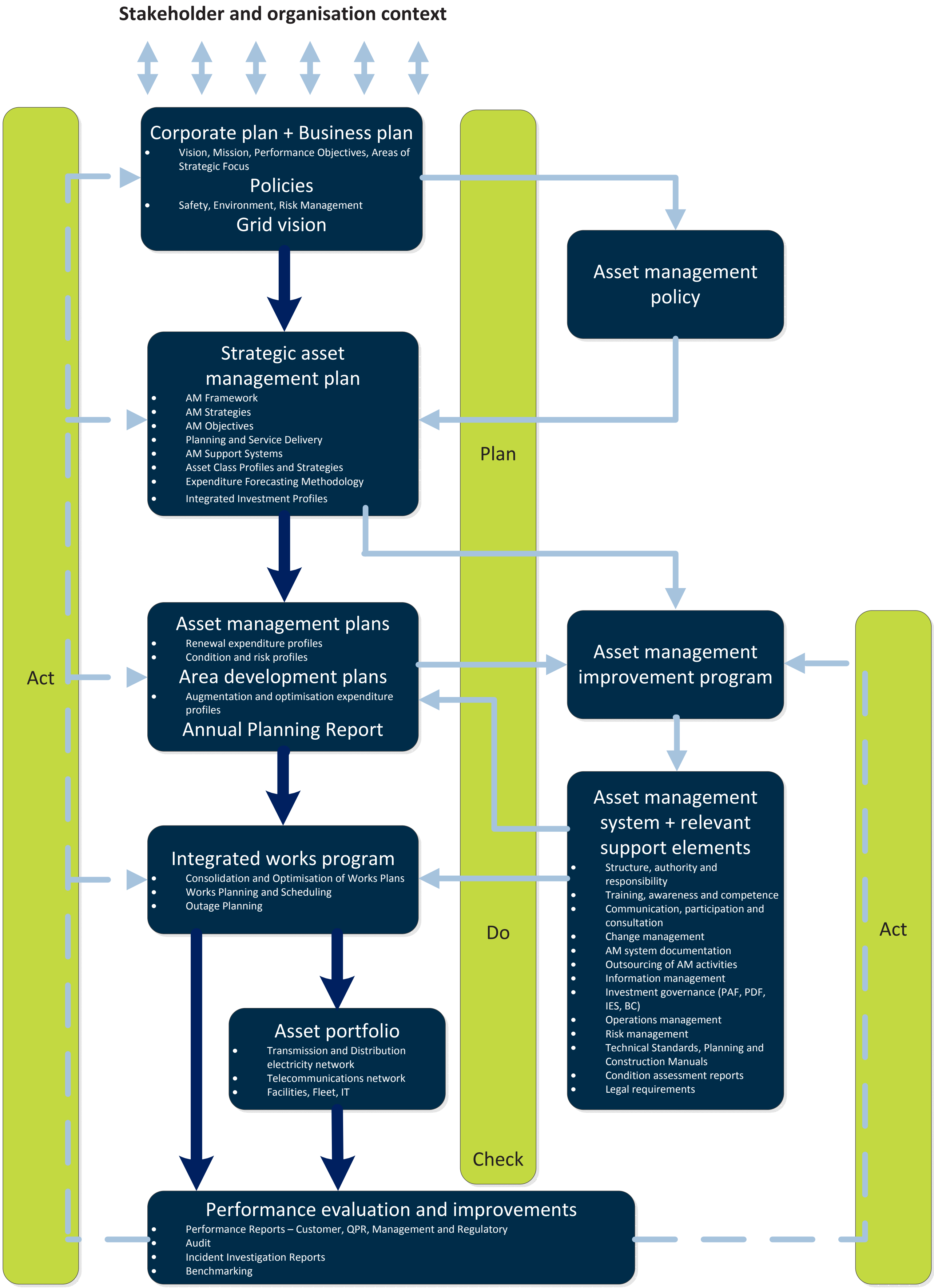


Figure 2-2: Asset management documentation framework

2.3.3.1 Network losses

Schedule 5.8(k)(1A) of the Rules requires us to explain how we take account of the cost of distribution losses when developing and implementing asset management and investment strategies. We are not funded under the current regulatory framework to manage losses at distribution level. However, where material we calculate and include the benefits of reduction in losses in the economic justification of projects to address network constraints.

2.3.4 Innovations

In recent years we have seen significant changes in the electricity network. Not only is the technology that we use to solve network issues changing, but use of the network itself is changing. External influences, such as embedded generation and the 'internet of things' has accelerated this change. Innovative solutions and trial projects we either currently have underway or are recently completed are described in Section 6.9.4.

Innovation is thought of in three streams of work:

2.3.4.1 New solutions to existing problems

Is there a better way to solve the problem, for example finding alternatives to network expansions? The backup generator at Strahan is an example of this. The poor reliability could have been rectified by duplicating the existing 22 kV feeder at a cost of around $6 million. A backup generator site was constructed instead at a cost of $700,000. This solution is soon to be extended by automating the operation of these generators.

Our standard network planning considers these options, but it is possible that alternative solutions to known issues exist that we are unaware of. This report provides an opportunity for interested parties to put forward these options.

2.3.4.2 New solutions to new problems

We may be able to use new technologies to address constraints that had in the past been normal, or 'business as usual', issues.

This may for instance include increasing efficiency of fault response, or new technologies that remove the need to respond entirely. In essence it is the answer to the question *'Is there a better way?'*

An example of this was the trial of FuseSavers. These devices prevent fuses blowing for intermittent faults such as wind borne debris striking lines. This saves both the nuisance interruption to customers and removes the need for us to dispatch fault crews to replace the fuses.

2.3.4.3 Response to new situations

New situations often involve new thinking. The third consideration is especially relevant because of the recent introduction of large amounts of solar generation in the distribution network. Grid storage and electric vehicles will exacerbate this change. It is expected that the network, instead of being a path from generators to loads as it has been in the past, will become transactional. Energy will flow in all directions and the network will become a conduit between customers. We must be flexible to these changes while ensuring that customers pay a fair rate for the level of network service they are receiving.

Forecasting the impact of electric vehicles on the electricity network is part of this third stream of work being undertaken by TasNetworks. The introduction of electric vehicles to Tasmania would bring many broader benefits to the Tasmanian community. It also provides the opportunity for greater utilisation of our assets. Initial results of our study show that there is available capacity within the network to support residential recharging with the forecast uptake of electric vehicles in the next 10 years. The results so far also indicate that the impact on the network can be reduced significantly if charging can be encouraged to occur during off-peak times, particularly as uptake of the technology increases past the 10 year study period. This type of study allows us to evaluate the use of tariff incentives to encourage and enable the uptake of this technology, as well as to put in place measures to minimise adverse impacts.

A large part of innovation comes from our customer consultations. Increasingly customers form part of the solution to network issues through network support or simply telling us whether they want increased reliability. We continue to work with our customers, and welcome input from them or third-party providers of innovative solutions to network issues.

2.3.5 Joint planning

In the past, Aurora Energy and Transend Networks met regularly to ensure network plans were in alignment and optimal solutions were pursued for identified network needs. In TasNetworks, the transmission and distribution planning functions are integrated into one business function. The Network Planning team is responsible for the following transmission and distribution planning activities:

- forecast of electricity consumption for terminal substations, zone substations and feeders;
- analysing the performance of the existing transmission and distribution network;
- identifying current and emerging transmission and distribution issues;
- integrating asset management strategies into the planning process;
- management of ongoing and new customer connection enquiries;
- preparation of the future supply-demand outlook of our customers;
- consultation with our customers on network planning strategies;
- preparation of the Annual Planning Report; and
- establishment of long-term network strategies.

The result of the integrated planning process is area strategies, which are fundamental to the planning process in ensuring prudent investment decisions are made. Each strategy is developed in consultation with customers and other stakeholders, giving them opportunity to provide feedback and discuss alternative solutions to addressing network needs. Projects that are justified through an economic analysis and are greater than $5 million are subject to a formal consultation process under the regulatory investment test, giving interested parties further opportunity for input.

2.4 Customer connections

Customers can connect to our network as a load customer, generation customer, or a combination of both. Most load connections and small generating systems are at low voltage, and are connected to the distribution network. Larger load customers can be connected directly to the transmission network. Whether a particular customer can be cost-effectively connected depends on the size of the load or generator and the technical limitations of the local network.

When undertaking network planning studies, we include the impacts of a new connection in our detailed technical and economic analyses only once the connection reaches a committed stage. We consider proposed and advanced projects in our network planning on a case by case basis.

2.5 Stakeholder engagement

TasNetworks works with our stakeholders to:

- understand the issues we collectively face;
- help to identify options to address these issues;
- influence what changes we make to the network;
- help to clarify the decisions we must make; and
- gain support for the decisions that we make.

We have a broad group of stakeholders who have many different contact points across the business. As a newly merged business we are working to develop a consistent approach to engaging with our stakeholders, as well as driving our commitment and approach to building strong relationships.

We are improving our engagement with our stakeholders and are supporting this with a formal, business-wide stakeholder engagement strategy. The strategy is currently in development with the key objectives being to:

- build a consistent approach to stakeholder engagement across the business;
- ensure stakeholders have two-way communication mechanisms so their issues and feedback can be heard and considered;
- proactively engage with all stakeholders to build two-way understanding in developing TasNetworks' strategic direction;
- support our people with their stakeholder interactions; and
- ensure we meet our regulatory requirements to consult and engage with our customers.

Chapter 3

Overview

Chapter 3 provides an overview of a number of aspects of the Tasmanian electricity supply system. It discusses the entities in the supply chain and their responsibilities. It points out those aspects of the Tasmanian electricity system that are distinctly different from the mainland Australian states. It also discusses the main components of the Tasmanian electricity network and details the geographical planning areas.

3 The Tasmanian network

3.1 Overview of the Tasmanian power system

The key stakeholders in the Tasmanian electricity supply chain comprise:

- power stations and wind farms that generate large-scale electricity;
- an extra-high voltage transmission network that transmits electricity from generators to the distribution network and large industrial and mining customers, and facilitates electricity exchange with mainland Australia through Basslink;
- a distribution network that supplies industrial, commercial, irrigation and residential electricity customers;
- embedded generation, which is small-scale generation connected within the distribution network;
- retailers that provide energy services to customers; and
- end use consumers of electricity. In recent times, many consumers have also become producers of electricity via their own small embedded generating units (predominantly roof-top photovoltaic).

We own and are responsible for the transmission and distribution networks on mainland Tasmania. The Tasmanian power system is shown pictorially in Figure 3-1.

The Tasmanian power system forms a part of the eastern Australian power system, which extends from north Queensland to South Australia. Tasmania is connected to the mainland network via Basslink, a privately owned undersea cable. Basslink has the capability to transfer electricity in either direction.

There are currently five generating companies which have power stations connected to the Tasmanian transmission network:

- Hydro Electric Corporation Pty Ltd (Hydro Tasmania);
- Aurora Energy (Tamar Valley) Pty Ltd (AETV)[4];
- Musselroe Wind Farm Pty Ltd;
- Woolnorth Bluff Point Wind Farm Pty Ltd; and
- Woolnorth Studland Bay Wind Farm Pty Ltd.

Mainland generators also supply energy to the Tasmanian transmission network via Basslink. A number of other small generators that are connected within the distribution network, termed embedded generation, are also licensed to operate in Tasmania. Very small embedded generation, such as roof-top photovoltaic systems, do not require a generating licence but must still have a connection agreement with TasNetworks.

All large generators sell electricity to a central market, the NEM. AEMO coordinates the dispatch of generators so that the power supplied into the network, at any instant, matches the total being consumed. The interconnected nature of the NEM allows electricity to flow across state borders, which means electricity can be sourced from whichever generators can supply it at the lowest cost.

TasNetworks is responsible for the transmission and distribution networks in the Tasmanian power system. The transmission network provides bulk power transfer from generators, often in remote areas, to substations near load centres throughout Tasmania, and to large customers directly connected to the transmission network. The distribution network distributes the electricity from substations to smaller industrial and commercial, irrigation and residential customers.

Electricity is sold to end-use consumers, including those directly connected to the transmission network, by retailers, who purchase electricity in bulk quantities from the NEM and sell it to the businesses and residences that use it. The price of electricity includes a component for the use of the transmission and distribution networks in delivery.

3.1.1 Unique features of the Tasmanian electricity system

The Tasmanian electricity system has a number of features which make it unique in the NEM.

3.1.1.1 Small load

Tasmania's median load during 2014 was approximately 1140 MW. The largest generating system in Tasmania which connects via a single transmission line is rated at 168 MW, and there are five more generating units which are effectively rated at 144 MW each.[5] These generators each have the capacity to supply a much larger portion of the state's load compared with the largest generating units in other NEM states. This gives rise to larger frequency deviations in Tasmania than occur in mainland NEM regions. Consequently, Tasmania's Frequency Operating Standards differ from those of the mainland. The technical implications of this are discussed further in Section 7.2.

3.1.1.2 Customer load base

The majority of the electrical energy consumed in Tasmania is from the large customers directly connected to the transmission network. We have 11 load customers who are directly connected to the transmission network. Collectively they consumed approximately 58 per cent of the electrical energy in Tasmania and contributed to approximately 44 per cent of the state-wide peak demand in 2014. Of these 11, four are major industrial customers which themselves consumed 54 per cent of the energy. Figure 3-2 presents the relative energy consumption in 2014 supplied from the transmission network.

4 *AETV was acquired by Hydro Tasmania in 2013.*

5 *Appendix F shows there is one generating system rated 205 MW. A high speed tripping scheme will disconnect some customer load if this generator disconnects suddenly, which effectively limits the amount of generation lost to no more than 144 MW.*

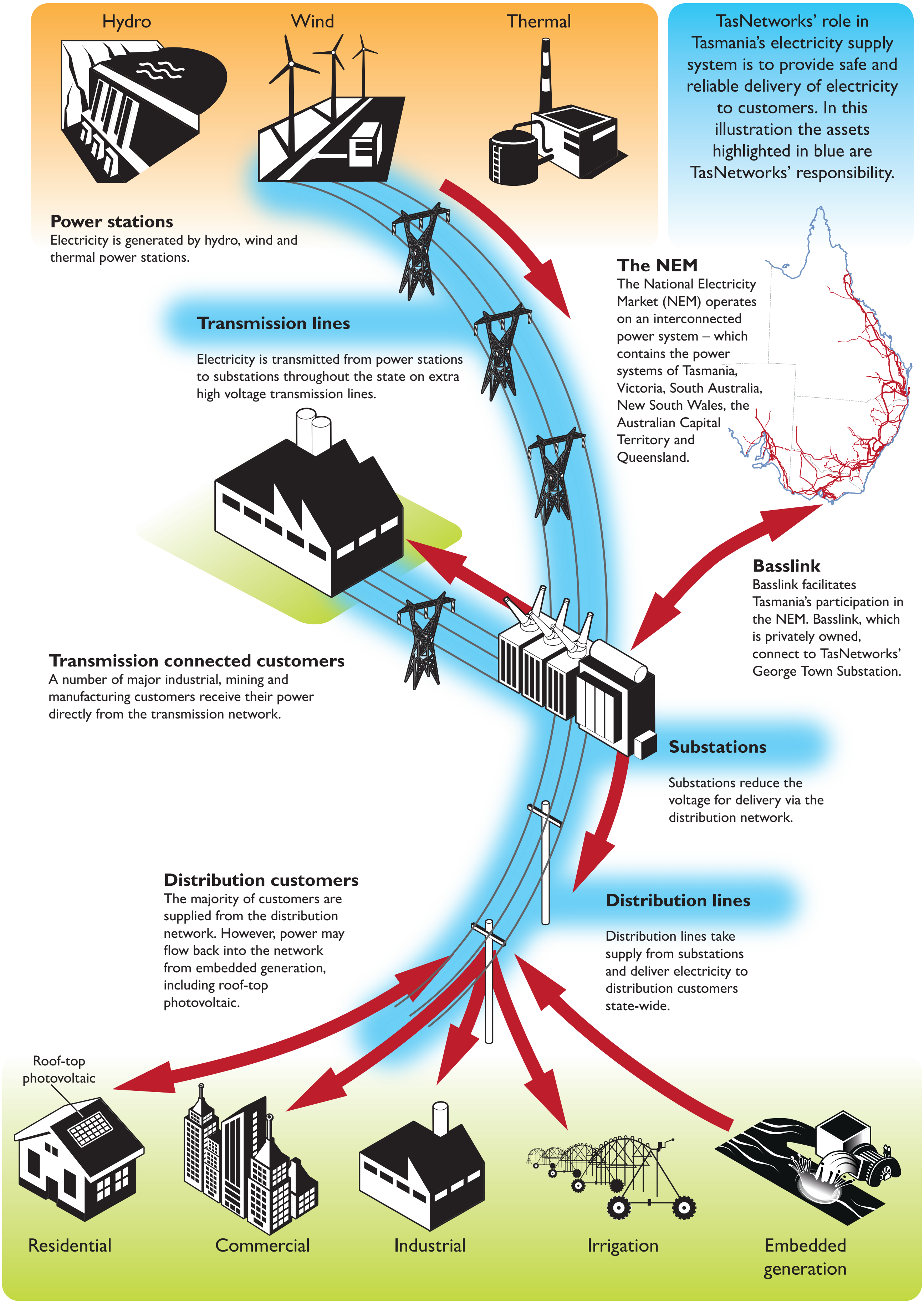


Figure 3-1: Tasmania's electricity supply industry

As major industrial and other transmission connected customers consume a significant portion of electric energy transferred through the transmission network, their operation can have a significant impact upon the power system. Changes to the transmission-connected customer base, such as a permanent reduction in load, would alter the normal operation of the power system and impact on such things as power flow and utilisation of the transmission network. We continue to engage with our customers and be cognisant of their operations in our planning activities.

3.1.1.3 Hydro generation dominated

Figure 3-3 shows the relative composition of the generators located in Tasmania. Power generation is dominated by hydro generating units, which are dispersed throughout Tasmania. The dominance and geographic diversity of hydro generation has the following impacts:

- hydro generating units are much slower to respond to frequency deviations than steam generating units, the dominant source of generation in the NEM. This compounds the frequency deviation impacts caused by the high generator size to system load ratio. Providing sufficient frequency control ancillary services can be problematic in Tasmania;
- the geographic dispersion of a large number of smaller sized generating units means that relatively more transmission infrastructure, per MW generated, is required compared with other states; and
- Tasmania's electricity network has traditionally been energy constrained not capacity constrained. That is, there is always sufficient generation capacity available to meet short term load peaks, but sustained low rainfall can give rise to difficulties in meeting the state's long-term electric energy needs. The existence of Tamar Valley Power Station (natural gas fuelled), three wind farms and Basslink has alleviated the energy constraints in recent years.

3.1.1.4 Windy location

Tasmania is an inherently windy state, being located in the Roaring Forties latitudes. There is sufficient wind resource to suggest an expansion of wind generation in the state is possible. This needs to be balanced however against the technical difficulties associated with integrating wind generators into a small power system with the characteristics described above. Section 7.4 discusses the technical issues associated with connecting new generation technologies (notably wind generation) into the Tasmanian network.

3.1.1.5 Single non-regulated interconnector to other NEM regions

Tasmania's only connection to the remainder of the NEM is via Basslink, a privately owned HVDC market network service provider. This contrasts with mainland NEM regions, which are all interconnected via regulated interconnectors. Further details of Basslink are provided in Section 3.2.2.

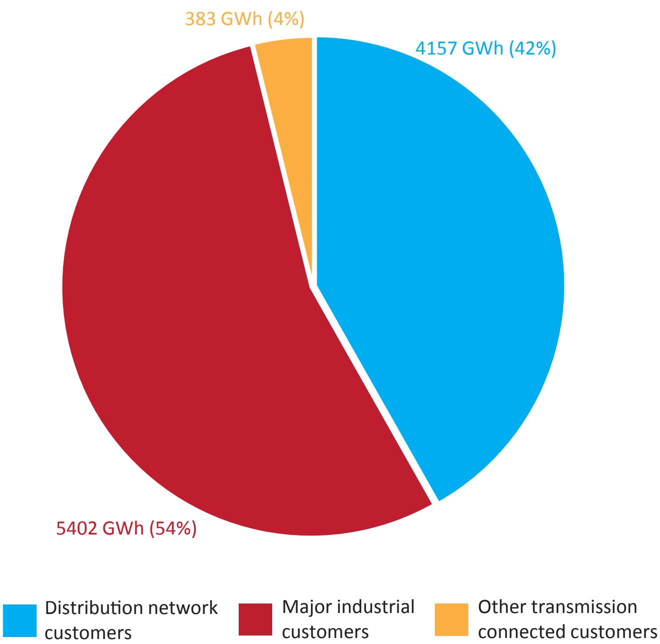
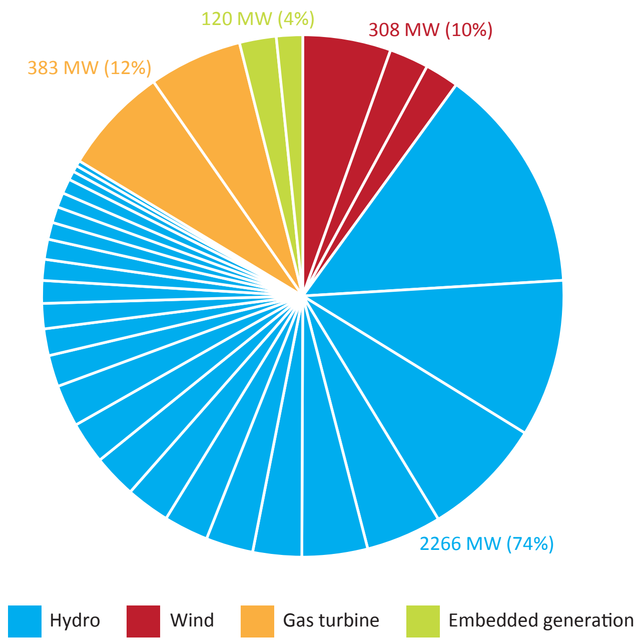


Figure 3-2: Relative energy consumption supplied from the transmission network in 2014



For embedded generation, the larger slice represents roof-top PV and the smaller slice represents all other embedded generation. For other generation types, each slice represents one power station or wind farm.

Figure 3-3: Generation capacity by type

3.2 Transmission network

3.2.1 Transmission network overview

Figure 3-4 presents a geographical overview of the Tasmanian transmission network, which 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 at which the lower voltage distribution network, and large industrial loads, are connected to the 110 kV or 220 kV transmission network.

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 coast), 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 peripheral transmission network.

A high-level summary of the composition of our transmission network infrastructure is presented in Table 3-1.

Table 3-1: Transmission network infrastructure

Asset	Quantity
Substations	49
Switching stations	6
Circuit kilometres of transmission lines	3,554
Route kilometres of transmission lines	2,344
Circuit kilometres of transmission cable	24
Transmission line support structures (towers and poles)	7,621
Easement area (Ha)	11,176

3.2.1.1 Substations

Substations in the Tasmanian transmission network transform voltages between transmission voltages, between transmission and distribution voltages, or both. Our substations also connect generators to the transmission network, provide network switching, and provide supply to those customers connected directly to the transmission network.

Connection points between our transmission and distribution networks are provided at 43 substations. These are known as terminal substations and supply the distribution network at 44, 33, 22, 11 and 6.6 kV.

3.2.1.2 Switching stations

Switching stations provide network switching capabilities, allowing the transfer of power throughout the transmission network. Some switching stations also connect generation to the network.

3.2.1.3 Transmission lines and circuits

Transmission lines connect generators to substations, and substations to each other, providing the mesh arrangement of the interconnected network. A transmission line may either carry one or two transmission circuits. A transmission circuit is the conductors that provide the physical delivery of electricity. A transmission line is the physical asset that includes the circuit(s), towers and other equipment that support the circuit(s), and the route that these take between two points.

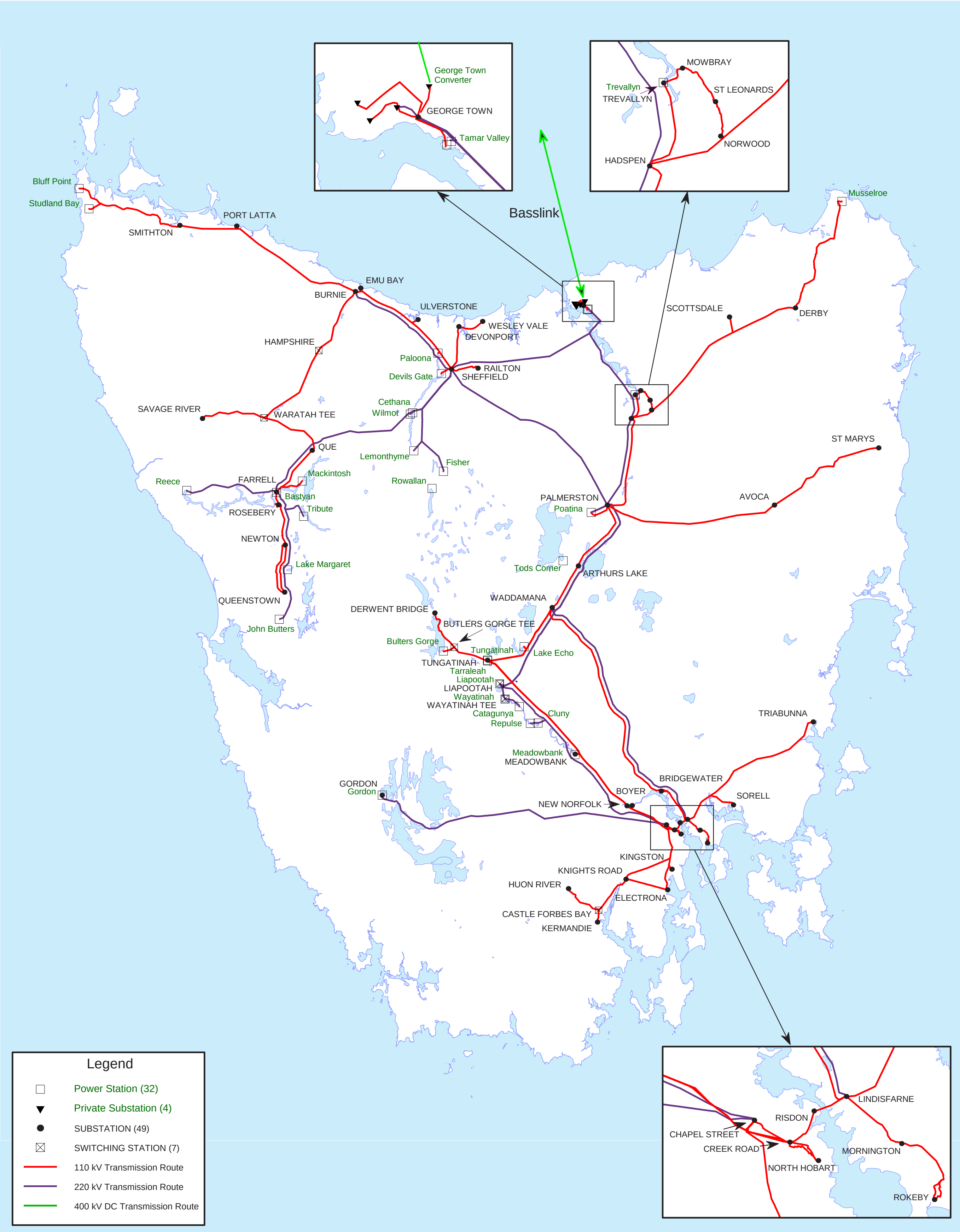


Figure 3-4: Tasmania's electricity transmission network

3.2.2 Basslink

Basslink Pty Ltd is a Market Network Service Provider in the NEM. Basslink Pty Ltd owns, operates and maintains the Basslink interconnector, a High Voltage Direct Current (HVDC) electrical interconnector between Victoria and Tasmania.

Basslink has a continuous sending end capacity of 500 MW and a short term sending end capacity of 630 MW when exporting electricity from Tasmania to Victoria. Power flow into Tasmania is limited to 478 MW. These figures are maximum limits. Basslink has a non-operational zone between 50 MW export and 50 MW import at all times.

Basslink is also able to transfer frequency control ancillary services (FCAS) between the mainland and Tasmania.

3.3 Distribution network

3.3.1 Distribution network overview

TasNetworks is responsible for the distribution of electricity to homes and businesses on mainland Tasmania and Bruny Island.[6]

The Tasmanian distribution network provides supply to over 280,000 customers and comprises:

- a sub-transmission network in greater Hobart, including Kingston, and one sub-transmission feeder on the west coast of Tasmania that provides connection points for the high voltage network in addition to terminal substations;
- a high voltage network of feeders[7] that distribute electricity from terminal 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 feeders providing supply to the majority of customers in Tasmania.

Figure 3-5 presents a geographical overview of the high-voltage distribution network by voltage, supplying rural and urban areas. Feeders are classified as supplying rural and urban areas, and these tend to have different characteristics.

Rural areas generally have low load, low customer connection density, and smaller rural population centres that are remote from supply points. Feeders supplying rural areas tend to cover wide geographic areas and can have a total route length between 50 km and 500 km. The significant route length creates a high exposure to external influences such as storm damage and lightning strikes. Additionally, rural feeders are generally radial in nature, with limited ability to interconnect with adjacent feeders. These two characteristics tend to result in more frequent and longer duration interruptions to supply. The majority of feeders supplying rural areas are operated at 22 kV. Rural areas supplied at 11 kV are generally those on the outer areas surrounding greater Hobart and Kingston. Planning issues on feeders supplying rural areas are characterised by voltage and power quality issues, due to the feeder length and disturbing loads eg pumping load.

Urban areas have high load and customer connection density. Feeders supplying urban areas are generally much shorter than rural feeders. They tend to have more underground distribution, and more interconnections with other urban feeders. Consequently, restoration following interruptions to supply is usually quicker than in rural areas. Feeders supplying urban areas of greater Hobart, Kingston and a pocket of the Burnie commercial area, are operated at 11 kV. Those in Launceston, Devonport and Burnie are operated at 22 kV. Feeders supplying urban areas are generally capacity constrained and have issues with high fault level.

6 The provision of electricity supplies on the Bass Strait Islands is managed by Hydro Tasmania.

7 The term 'feeder' is the common name used to describe distribution lines.

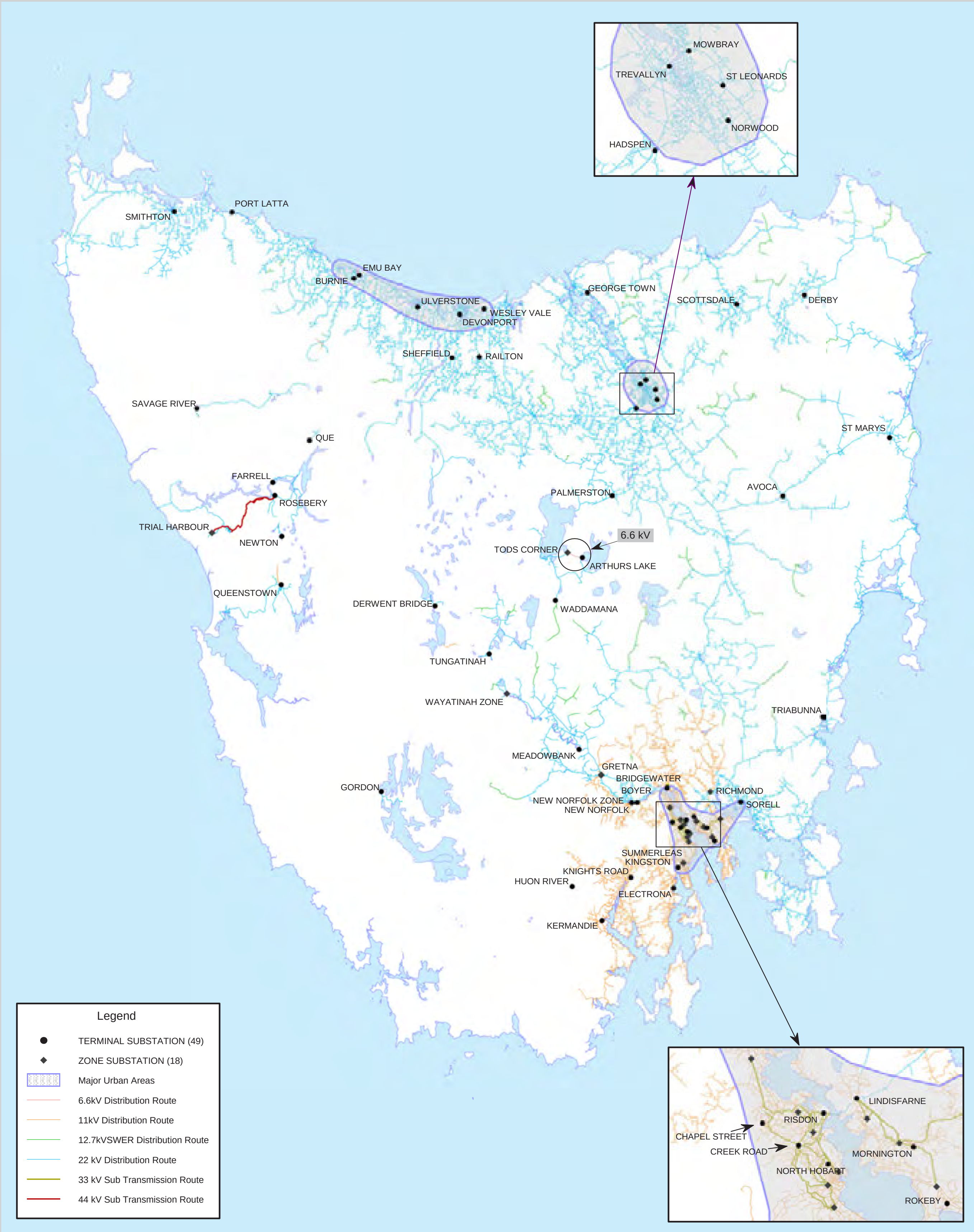


Figure 3-5: Tasmanian distribution voltage areas

A high-level summary of the composition of our distribution network infrastructure is presented in Table 3-2.

Table 3-2: Distribution network infrastructure[8]

Infrastructure	Nominal voltage (kV)	Quantity
Connection points		
Sites	44, 33, 22, 11 and 6.6	45
Sub-transmission feeders	44, 33 and 22	26
Minor zone source feeders[9]	22 and 11	6
Distribution feeders	22, 11 and 6.6	240
Zone substations		
Major	44, 33 and 22	13
Zone distribution feeders	22 and 11	117
Minor	22 and 11	3
Zone distribution feeders	22 and 11	7
Distribution substations		
Overhead		29,738
Ground-mounted		1,901
Route data[10]		
High voltage overhead	6.6 to 44	15,125 km
High voltage underground		1,222 km
Low voltage overhead[11]	0.4	4,959 km
Low voltage underground[11]		1,235 km
Poles	All voltages	221,405

8 At February 2015

9 Includes minor zone alternate-supply feeders

10 Includes TasNetworks owned assets only

11 Excludes customer service lines

3.3.1.1 Connection points

The distribution network is supplied from connection points at 45 connection sites. 43 of these are the terminal substation connections to the transmission network, and the remaining two directly from Hydro Tasmania generating sites at Gordon and Wayatinah power stations. These generally supply the high-voltage distribution feeders at 22 and 11 kV – there are also single 6.6 kV (from Arthurs Lake Substation) and 44 kV (from Rosebery Substation) feeders. Connections sites also supply the 33 kV sub-transmission network in greater Hobart and Kingston, and 44 kV (from Rosebery Substation) and 22 kV (from New Norfolk Substation) sub-transmission feeders.

3.3.1.2 Zone substations

Zone substations provide supply points for high-voltage feeders in addition to the connection points detailed above. We have 16 zone substations with 11 in greater Hobart and Kingston, and five in rural locations. We classify a zone substation with power transformers of aggregate capacity equal to or greater than 10 MVA as a major zone substation. A zone substation with power transformers of aggregate capacity less than 10 MVA is classified as a minor zone substation.

Zone substations in greater Hobart and Kingston reduce the voltage from 33 to 11 kV and are all major zones. Other major zones are Trial Harbour (44 to 22 kV) and New Norfolk (22 to 11 kV) zone substations. The remaining four zone substations in rural locations are minor zones; three transforming voltage from 22 to 11 kV and Wayatinah Zone Substation from 11 to 22 kV.

3.3.1.3 Sub-transmission feeders

Sub-transmission feeders directly supply major zone substations from terminal substations and generally have no direct customers connected. There are 26 sub-transmission feeders in the distribution network; 24 operate at 33 kV and one each at 44 kV and 22 kV, supplying the zone substations detailed above.

3.3.1.4 Minor Zone Source Feeders

Minor zone source feeders are high voltage distribution feeders that also provide supply to minor zone substations. These generally supply multiple distribution substations as well as minor zones.

3.3.1.5 High voltage distribution feeders

High voltage distribution lines (referred to as feeders) distribute electricity from connection points and zone substations. A small number of customers take supply directly from these feeders; however the majority of supply is to distribution substations for supply to the low voltage network.

3.3.1.6 Distribution substations and low voltage feeders

The low voltage network is operated at 230 Volts (single phase) and 400 Volts (three-phase). The majority of residential and business customers take a single-phase supply. The low voltage feeders are short (generally less than 300 m long) and are supplied through more than 30,000 distribution substations. Distribution substations have various arrangements (pole or ground-mounted, enclosed, or within a building) and sizes. Pole-mounted substations range in size from 25 kVA to 500 kVA and ground mounted substations from 100 kVA to 3,000 kVA. The majority of load customers are supplied from the low voltage network.

3.4 Telecommunications network

TasNetworks owns, operates, and maintains a telecommunications network within Tasmania. 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, digital microwave radios and associated repeater stations, and some power line carrier equipment.

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.

3.5 Planning areas

TasNetworks' annual planning review is performed based on geographical planning areas. For planning purposes, we divide Tasmania into seven areas and produce an area strategy for each of these, as well as a core-grid strategy for the transmission backbone and inter-area issues. The planning areas are designated based on the transmission network supplied through bulk supply points and the geographical coverage of the distribution network. Figure 3-6 shows the seven planning areas in Tasmania.

Chapter 6 of this APR has sections designated for each planning area. They describe the network in the area, the existing and forecast network issues, and information on where spare capacity is available that may allow simple connection of new loads to the network.

Section 6.2: West Coast
The west coast area of Tasmania, covering the area supplied from Farrell Substation

Section 6.3: North West
The north-west area of Tasmania from Deloraine and Port Sorell to Smithton and the far north-west. This area is supplied through major supply points at Burnie and Sheffield substations.

Section 6.4: Northern
The greater Launceston area, George Town and the far north-east. This area is supplied through major supply points at Hadspen, George Town and Palmerston (near Poatina) substations.

Section 6.5: Central
The Central Highlands and Derwent Valley areas of Tasmania. This area also includes the supply at Strathgordon. There is no major supply point in this area, with the area generally supplied from the 110 kV network between New Norfolk, Tungatinah (near Tarraleah) and Waddamana substations.

Section 6.6: Greater Hobart
Generally the areas covered by Hobart, Glenorchy, Brighton and Clarence council areas. High concentration of load within the Hobart CBD and eastern and western shore areas, however the area extends from Sandy Bay and South Arm to Brighton and Kempton. This area is supplied through major supply points at Chapel Street (in Glenorchy) and Lindisfarne substations.

Section 6.7: Eastern
The east coast of Tasmania from the Tasman Peninsula to St Helens and extending inland to Campbell Town, Oatlands and Richmond. The area is supplied through the peripheral 110 kV network, supplied from bulk supply points at Lindisfarne and Palmerston substations.

Section 6.8: Kingston-South
The Kingborough and Huon Valley area of Tasmania, including Bruny Island. The area is supplied through Chapel Street Substation (in Glenorchy).

Section 6.9: State-wide and inter-area planning
Details state-wide and inter-area issues and planning proposals and alignment of our proposals with national transmission planning performed by AEMO.

Figure 3-6: Geographical planning areas

Chapter 4

Overview

Chapter 4 focuses on the performance of the network in recent years. Firstly we present information about constraints which resulted in the power flow through the transmission network being altered to ensure the power system remained in a secure operating condition. We then present information about the reliability of the transmission and distribution networks, and our performance against our target standards. Finally, we include discussion on embedded generation and factors that have a material impact on the network.

4 Network performance

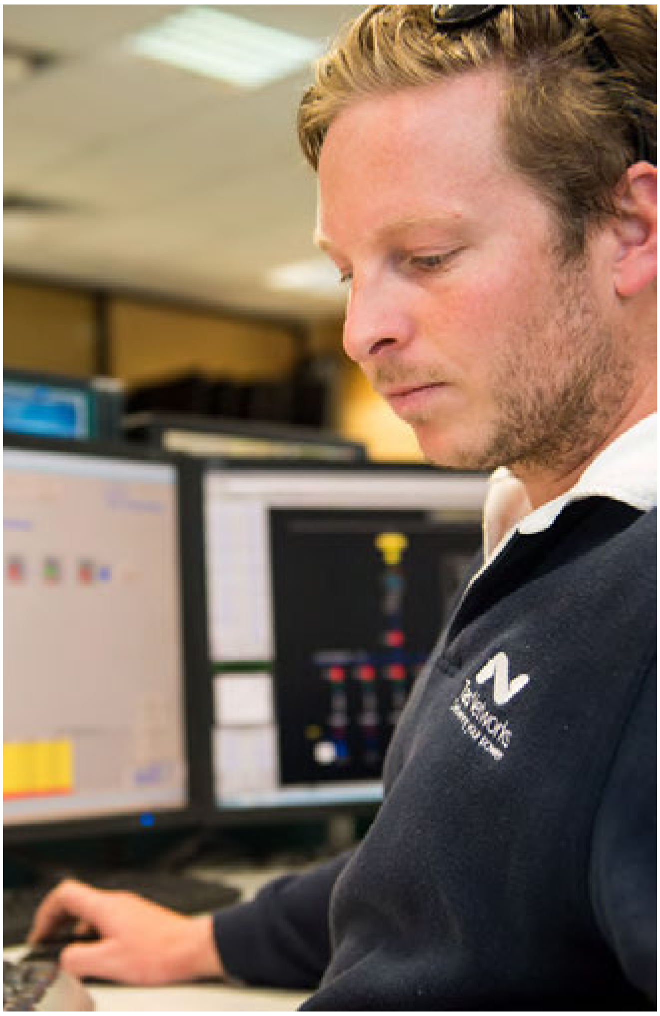
4.1 Transmission network constraints

A network constraint is a situation where the power flow through part of the transmission network must be restricted in order to avoid exceeding a known technical limit. In some such cases, it is possible to restrict the power flow by adjusting the output of generators and/or Basslink. A "constraint equation" is a mathematical equation that defines how generators' or Basslink's dispatch targets should be reduced to avoid exceeding a given technical limit. These constraint equations are developed by AEMO and are based on advice provided by TasNetworks. The constraint equations are then implemented in NEMDE[12], so that generators and/or Basslink can be re-dispatched automatically to prevent the relevant network limit from being exceeded.

Network limits are caused by equipment thermal ratings, operational voltage, network equipment protection settings, network stability limits and, in the case of Tasmania, the special operational requirements of Basslink. Some constraints can exist under normal conditions, when all transmission elements are in service. However, constraints are more likely to occur when some elements of the transmission network are out of service.

In the NEM the effect of every constraint is recorded. If power flow through part of a network is constrained to a particular limit, it is recorded as a binding constraint. If the limit is exceeded, it is recorded as a violating constraint.

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 that power system security is maintained and the available transmission capacity is maximised. Where a constraint is causing a significant increased cost to the electricity market, because more expensive generators must be dispatched as a result of the constraint, we may identify changes to our network to reduce or eliminate the constraint. In these cases, we must demonstrate that the cost of the network change is less than the increased market cost that the constraint is causing.



From 1 July 2014, the Market Impact Component of the AER's Service Target Performance Incentive Scheme (STPIS) applied to TasNetworks. This scheme created a financial incentive on us to minimise the impact of transmission constraints.

Figure 4-1 illustrates the occurrence of binding and violating constraints on the major Tasmanian transmission elements in 2014. It shows the number of NEM dispatch intervals[13] that constraints occurred for in various parts of the network. "Thermal limit – no outage" indicates that 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.

12 NEMDE, the National Electricity Market Dispatch Engine, is AEMO's computer system that calculates which generators should be dispatched to meet the current load demand, based on the current generator bid offers and network constraints. It controls generator dispatch in 5 minute intervals, and aims to ensure the lowest priced generators are dispatched, whilst not violating network constraints.

13 Dispatch intervals are 5-minutes.

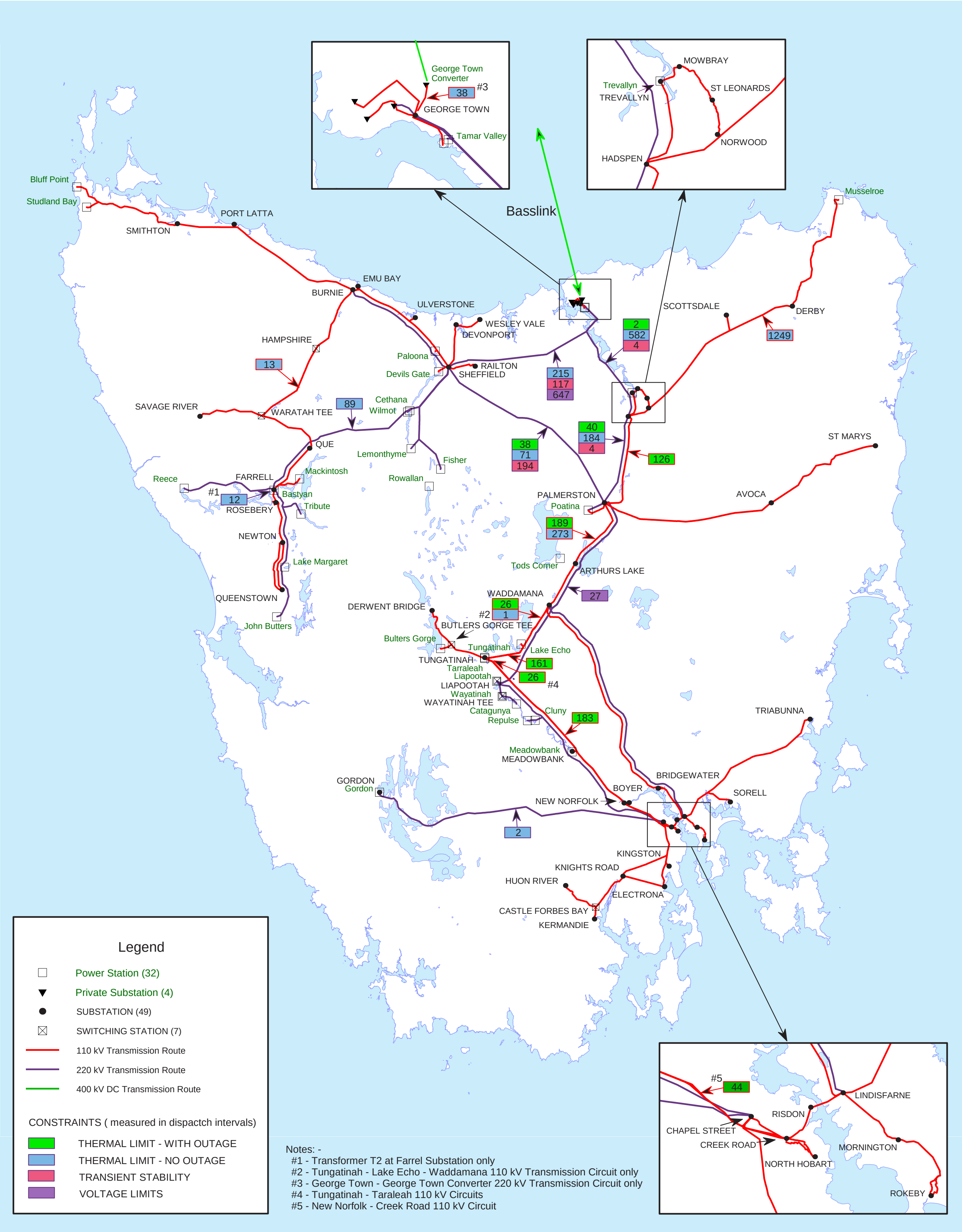


Figure 4-1: Recorded constraints for the 2014 calendar year

4.1.1 Existing constraints on major transmission network elements

Table 4-1 compares the number of dispatch intervals that constraint equations bound or violated on the major 220 kV transmission lines for 2012, 2013 and 2014. Detailed information on these constraints is provided in Appendix G; it contains the constraint IDs, detail of the constraints and the marginal cost of the constraints binding.

From April 2012 to the end of August 2014 Tasmania was a net exporter of electricity to the mainland. In the second half of 2014, aligned with the removal of the carbon tax, there was significant increase in Basslink import into Tasmania compared to the preceding two and a half years. Whilst still a net export month, August 2014 saw as much Basslink import into Tasmania as the whole of 2013. The majority of increased or decreased major binding constraints in 2014 was due to this change in Basslink flows.

The majority of increase in binding constraints was stability constraints in the Palmerston–Sheffield–George Town triangle. There was also an increase in thermal constraints on the Farrell–Sheffield 220 kV transmission line. These increases were all as a result of Basslink predominantly importing in 2014 compared with predominately exporting previously.

Similarly, the leading reason for a decrease in instances of constraint binding was due to the change in power flow across Basslink. The only exception was the thermal limit on the Palmerston–Sheffield 220 kV transmission line which reduced following installation of lightning protection on Palmerston–George Town and Sheffield–George Town 220 kV transmission lines, which resulted in more power flow through these corridors. The upgrade of transmission line dead-ends also contributed to decreased binding of the thermal limit on the Hadspen–George Town 220 kV transmission line.

Table 4-1: Comparison of major binding constraints from 2012 to 2014

Constraint	Number of dispatch intervals (and time period) bound or violated		
	2012	2013	2014
Constraints with increased incidence of binding in 2014			
Sheffield–George Town 220 kV voltage stability	0	202 (16.8 hrs)	647 (53.9 hrs)
Sheffield–George Town 220 kV transient stability	0	0	117 (9.8 hrs)
Palmerston–Sheffield 220 kV transient stability	0	0	194 (16.2 hrs)
Farrell–Sheffield 220 kV thermal limit with no outage	828 (2.9 days)	10 (50 mins)	89 (7.4 hrs)
Constraints with decreased incidence of binding in 2014			
Palmerston–Sheffield 220 kV thermal limit with no outage	177 (15 hrs)	324 (27 hrs)	71 (5.9 hrs)
Sheffield–George Town 220 kV thermal limit with no outage	2813 (9.8 days)	1038 (3.6 days)	215 (17.9 hrs)
Hadspen–George Town 220 kV thermal limit with no outage	362 (30 hrs)	7145 (24 days)	582 (48.5 hrs)
Gordon–Chapel Street 220 kV thermal limit with no outage	58 (5 hrs)	3939 (13.7 days)	2 (10 mins)
Palmerston–Hadspen 220 kV thermal limit with no outage	2 (10 mins)	1711 (5.9 days)	184 (15.3 hrs)
Palmerston–Waddamana 220 kV thermal limit with no outage	65 (5.4 hrs)	0	0

4.1.2 Constraint equations affecting Basslink dispatch

The Tasmanian network constraint equations that affected Basslink dispatch are presented in Table 4-2. More detailed information on these constraints is provided in Appendix G.

Similarly to the change in major binding constraints in 2014, the predominant reason for change in constraints affecting Basslink flows was due to the change in direction of the flows across Basslink.

The constraints with increased binding were primarily due to the unavailability of loads to participate in the system protection scheme during Basslink import.

Most of the Tasmanian network constraints that affect Basslink flows reduced in 2014. This was primarily evident on the Hadspen–George Town and Sheffield–George Town 220 kV transmission lines. The thermal rating increase in the Hadspen–George Town 220 kV transmission line as a result of conductor dead-end upgrade resulted in an increase in the allowable power flows in this corridor.

Table 4-2: Network constraint equations affecting Basslink flows

Constraint	Number of dispatch intervals (and time period) bound or violated		
	2012	2013	2014
Constraints with increased incidence of binding in 2014			
Basslink import limited due to load unavailability for FCSPS operation	3904 (13.6 days)	12 (60 minutes)	4014 (13.9 days)
Sheffield–Farrell 220 kV transmission line rating constraints with NCSPS operation	8 (40 minutes)	6 (30 minutes)	20 (2 hours)
Hadspen–Palmerston 220 kV transmission line rating constraints with NCSPS operation	Not available	21 (2 hours)	144 (12 hours)
Constraints with decreased incidence of binding in 2014			
Basslink export limited due to generation unavailability for FCSPS operation	24 (2 hours)	42 (4 hours)	28 (2 hours)
Palmerston–Sheffield 220 kV transmission line rating constraints with NCSPS operation	21 (2 hours)	91 (8 hours)	0
Hadspen–George Town 220 kV transmission line rating constraints with NCSPS operation	14 (70 minutes)	588 (2 days)	122 (10 hours)
Hadspen–Palmerston 110 kV transmission line rating constraints with NCSPS operation	9 (45 minutes)	0	0
Sheffield–George Town 220 kV transmission line rating constraints with NCSPS operation	1496 (5.2 days)	952 (3.3 days)	157 (13 hours)
Basslink rate-of-change limit	206 (17 hours)	159 (13 hours)	145 (12 hours)

4.1.3 Basslink performance and impact

Basslink imported heavily for the last four months of the 2014 calendar year. This is the first time in three years that Basslink has imported heavily and this has changed generation dispatch patterns dramatically. This is reflected in changes to constraints binding, as presented in Section 4.1.1 and 4.1.2. More binding constraints on Basslink import have occurred, especially due to load unavailability for FCSPS operation. Also Tasmania's new rate-of-change-of-frequency (RoCoF) equation bound for a cumulative 21 dispatch intervals (105 mins), which indicates small periods of high penetration of non-synchronous generation (from wind generators) coupled with low Tasmanian power system inertia due to low load and high Basslink import.[14]

Until December 2014 the loss of Basslink was treated as a single Tasmanian contingency. However, the loss of Basslink is now assumed credible during any Tasmanian transmission fault. This new assumption follows two events in December 2014 and one in February 2015 when Basslink tripped during Tasmanian transmission faults; normally Basslink would be expected to remain in service for faults within the Tasmanian transmission network. The main impact to the Tasmanian power system is that the local requirement for FCAS must be sourced from within Tasmania and it cannot be sourced from Basslink transferring FCAS from the mainland. All parties are working co-operatively to resolve this issue as quickly as possible.

During January 2015, the stochastic response of Basslink to sudden negative price excursions in Victoria led to insufficient reactive reserves being available at George Town Substation. The inability to bring in a capacitor bank due to discharge lockout and generators limited by their over excitation limits led to three dispatch intervals (15 minutes) with the voltage at George Town Substation 220 kV busbar as low as 210 kV (0.96 per cent of nominal). This under-voltage has been temporarily mitigated by applying constraints to Basslink transfer. However this constraint may have a large impact on Basslink transfer, and we will investigate the feasibility of installing additional reactive capability at George Town Substation.

14 *The RoCoF constraint is not shown in Table 4-1 as it shows only network constraints. The RoCoF constraint binding is determined by generation dispatch and Basslink flow, both of which are market outcomes over which we have no control.*

4.1.4 Performance of system protection schemes

The potential impact of Basslink's high transfer capabilities on the Tasmanian power system requires system protection schemes (SPS). Without these schemes, significant investment and augmentation to the transmission network would have been required to allow the present Basslink transfer capability. The SPS encompasses two separate schemes: the Frequency Control System Protection Scheme (FCSPS) and the Network Control System Protection Scheme (NCSPS).

The FCSPS is designed to ensure that, following the loss of Basslink, the Tasmanian frequency remains within the required frequency operating standards. This scheme is required because the loss of Basslink would have a much larger impact on frequency than loss of other elements in the Tasmanian network.[15] The FCSPS operates by providing high-speed tripping of generation if Basslink had been exporting prior to its loss, or disconnecting contracted customer loads if Basslink had been importing.

To facilitate large Basslink exports, transmission lines are operated up to 95 per cent of their thermal capacity to provide sufficient power transfer.[16] The NCSPS, which only operates when Basslink is exporting energy to Victoria, is designed to rapidly trip selected generators to remove a transmission line overload resulting from the trip of another transmission line. There is no requirement for the NCSPS when Basslink is importing, since much of the energy imported into Tasmania is directly consumed by the major industrial customers at George Town Substation. The SPS continuously monitors the power system to ensure that the correct response is delivered following a Basslink trip or loss of a critical network element.

Back-up protection schemes also form part of the SPS. These trip generators, loads or transmission elements should the NCSPS or FCSPS fail, or if multiple contingency events occur.

During 2014 the FCSPS was required to operate on six occasions: two events during Basslink export and four events during Basslink import. The FCSPS operated correctly on all occasions and the Tasmanian frequency remained within the specified frequency standards. There were no NCSPS events during the year. There were no significant periods of unavailability for either scheme.

15 *The impact on frequency of the loss of elements in the Tasmanian network is discussed in Section 3.1.1.1.*

16 *Transmission lines are normally operated at 50 per cent capacity to provide sufficient head-room to allow them to carry the additional power flow for the loss of a parallel transmission line.*

4.2 Tasmanian supply reliability

Reliability of supply is a key indicator in measuring network performance and is an indicator of the impact of supply interruptions to customers. We measure the duration, frequency and impact of supply interruptions, using different measures for the transmission and distribution networks. We continually analyse the performance of our electricity network and regularly report to OTTER and the AER against our measures. Our performance against the reliability targets set by the AER is a key component of our service target performance incentive scheme (STPIS).

The following sections provide information on network reliability targets and historical performance. More information on our network reliability performance is detailed in Appendix C.

4.2.1 Transmission reliability

Transmission network reliability is monitored and reported to the AER and OTTER in terms of the number of loss of supply (LOS) events that occurred during the year.[17] Loss of supply is measured in 'system minutes' and is calculated by dividing the total energy (MWh) not supplied to customers during an event by the energy supplied during one minute at the time of historical Tasmanian maximum demand.[18]

The AER sets our target for the number of loss of supply events allowed per year as part of each regulatory period. Since 2009 the target has been 15 or less events greater than 0.1 system minute and 2 or less events greater than 1.0 system minute. Table 4-3 presents the loss of supply performance of the transmission network over this period. We have only once, in 2011, failed to meet our target for number of loss of supply events greater than 1.0 system minute; we have never failed to meet our target of events greater than 0.1 system minute.

4.2.1.1 Significant network incidents

A significant network incident is defined as a loss of supply event exceeding 1.0 system minute. We did not incur any significant network incidents in 2014 – for the first time since 2008.

17 Transmission reliability is reported to the AER and OTTER by calendar and financial year, respectively.

18 An event of one system minute equates to approximately 31.2 MWh of unserved energy.

4.2.2 Distribution reliability

Reliability in the distribution network is measured in frequency and duration, and is reported as averages termed SAIFI and SAIDI totalled over a 12-month period. SAIFI is the System Average Interruption Frequency Index (measured in number of interruptions), and SAIDI is the equivalent measure for duration (measured in mins). A SAIFI of two indicates that, on average, all customers in an area of study experienced two loss of supply events during the year. A SAIDI of 10 minutes indicates that, on average, those customers experienced a cumulative loss of supply for 10 minutes during the year.

For the purposes of measuring distribution supply reliability, Tasmania has been divided into 101 supply reliability communities. Each community is categorised into one of five supply reliability categories:

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

The Tasmanian Electricity Code (the Code), enforced by OTTER, specifies the reliability performance standards for both the supply reliability communities and categories. We are required to use reasonable endeavours to ensure that each supply reliability community and category meets these standards. In addition, the AER sets standards for the supply reliability categories (not communities) each regulatory period as part of our performance incentive scheme. These are set based on our actual performance in the preceding five years, with the intention that we at least maintain our reliability performance.

The standards set out in the Code and by the AER have different exclusions. The standards set out in the Code exclude outages caused by third-party faults, customer plant, and the transmission network. The standards set by the AER, however, exclude planned outages to the network, major event days[19], and transmission network, customer plant, bushfire and total fire ban day related outages. The standards in the Code and set by the AER are presented in Table 4-4 and Table 4-5, respectively. We report distribution reliability on a financial year basis to OTTER and the AER, and additionally to OTTER on a quarterly basis.

We are pursuing aligning our different reliability requirements and reporting frequency to promote efficiency.

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

Table 4-3: Transmission network reliability performance

Performance measure	Target	2009	2010	2011	2012	2013	2014
Number of LOS events >0.1 system minute	≤15	8	9	11	10	10	3
Number of LOS events >1.0 system minute	≤2	2	2	6	2	1	0

In this section we present an overview of our distribution network reliability standards and performance. Our network reliability past performance and forecast data is detailed in Appendix C.

Table 4-4: Supply reliability category and community standards in the Code

Supply reliability category	Annual number of supply interruptions (on average) (SAIFI)		Annual duration of supply interruptions (on average) (SAIDI)	
	Category	Community	Category	Community
Critical infrastructure	0.2	0.2	30	30
High density commercial	1	2	60	120
Urban and regional centres	2	4	120	240
High density rural	4	6	480	600
Low density rural	6	8	600	720

Table 4-5: Supply reliability category standards set by the AER

Supply reliability category	Annual number of supply interruptions (on average) (SAIFI)	Annual duration of supply interruptions (on average) (SAIDI)
Critical infrastructure	0.22	20.79
High density commercial	0.49	38.34
Urban and regional centres	1.04	82.75
High density rural	2.79	259.48
Low density rural	3.20	333.16

4.2.2.1 Performance against Code standards

At a category level, our performance against SAIFI, the frequency measure, has generally been good and our recent SAIDI performance, the duration measure, has not met our target standards. Currently we are not meeting the SAIFI standard for the critical infrastructure supply reliability category and not meeting the SAIDI standard in any category except high density commercial.

At a community level, supply reliability was above target standards in 47 of the 101 communities in 2014. These were all in regards to duration of non-supply events (SAIDI), with 8 communities also not meeting the requirements for frequency of non-supply events (SAIFI). The number of communities not meeting their target standards has increased in each category in the past two years, except high density commercial.

Supply reliability communities that did not meet the standards in 2014 are detailed by planning area in Chapter 6. In this chapter we provide information on the communities, contributing factors to the poor performance in 2014, and planned actions.

4.2.2.2 Performance against AER standards

Similarly to our performance against standards in the Code, we are not meeting the SAIFI standard for the critical infrastructure supply reliability category. However our SAIDI performance is better than it is for the Code requirements. This suggests that events excluded from AER reporting are having an impact on our reliability performance under the Code. These are predominantly major event days, which typically affect a number of communities concurrently resulting in long restoration times and planned outages.

4.2.3 Tasmanian supply reliability summary

As detailed in Section 2.3.1, our reliability strategy includes maintaining overall network reliability performance while ensuring compliance with our relevant requirements. The strategy does not preclude enhancing network reliability where performance is inadequate or where asset risk is unacceptably high. We have maintained good reliability performance of the transmission network in recent years. This has resulted from a focus on continual service improvement with many initiatives included in operational and capital programs. This includes: improving our incident investigation and remediation process; incentive schemes to improve performance; improved maintenance practices; and targeted replacement of unreliable assets.

Reliability performance of the distribution network has been trending down in the last two years. Following investment in the 2007–12 regulatory period to improve reliability, we have limited our investment in recent years with a focus on maintaining reliability levels. However reliability in a number of communities and categories has not met the target standards in the last two years, predominantly due to a number of major event days and other weather events. The SAIDI measure is most affected by these events because they tend to affect a number of reliability communities and limits to the number of resources available to attend to these concurrent faults lengthen restoration times.

Initiatives to address areas of poor reliability are being investigated and implemented. Our proposed network augmentations to improve reliability are detailed by planning area in Chapter 6. Further to this, we are currently investigating the causes of poor reliability on our seven worst performing feeders, which between them affect 15 reliability communities. We also implement a number of asset management initiatives to ensure reliability is managed appropriately:

- vegetation management (trimmed or removed) to prevent contact with distribution lines resulting in supply interruptions;
- prioritised defect rectification programs to ensure assets posing a risk to reliability are repaired to reduce the likelihood of supply interruptions;
- protection settings are reviewed to ensure the fewest customers as possible lose supply following fault;
- targeted and specialised inspections programs, such as aerial and thermographic surveys, that focus on high risk assets or specific asset failure modes; and
- provision of new technologies, such as line fault indicators, to assist field crews in finding failed assets or restoring feeder sections more quickly, minimising duration of supply interruptions and assisting in root cause analysis and reducing recurrences.

These network augmentations and asset management initiatives will assist us in maintaining an appropriate level of reliability and improving the resilience of the network against extreme weather events, including major event days and high bushfire-risk events.

4.3 Embedded generation

There has been a continued increase in the number of customers wishing to generate electricity on their own premises.[20] Generally embedded generators fit into two broad categories: the larger systems tend to use rotating machines whereas low power generators are dominated by small-scale photovoltaic (PV) asynchronous installations (roof-top solar). To facilitate the connection of small embedded generators, exemption from full compliance with the Rules is granted by AEMO for small generators (less than 5 MW)[21] – although they must still have a connection agreement with TasNetworks. Currently Tasmania has approximately 120 MW of total embedded generating capacity connected, of which 70 MW is photovoltaic.

In 2014, we received 3,100 applications to connect embedded generation to the network. This was predominately applications for roof-top photovoltaic. The average time taken to connect was 32 days.

Whilst we support customers connecting embedded generators to our network, the recent proliferation of embedded generators has caused some technical challenges. The key issues arising from applications to connect embedded generating units received in the past year include:

- ensuring safe disconnection of embedded generation during faults that may lead to "island" conditions – especially for synchronous machines;
- ensuring that embedded synchronous generators are not exposed to auto-reclose events;
- ensuring that PV installations pose no state-wide threat to power system security – especially due to their frequency sensitivity;
- preventing PV systems from generating unsafe over-voltages; and
- maintaining stable voltages at weak connection points.

We are currently developing strategies to meet these challenges in the most cost-effective way for the Tasmanian community.

4.3.1 Rotating machines

Synchronous generators can pose risks to other network users (and the synchronous generator) during islanding type faults. An "island" is a situation in which part of the network, which contains a generator, becomes disconnected from the remainder of the network. Should that generator continue to operate, the islanded part of the network will still be live, with possibly minimal control over the voltage and frequency. This would pose a danger to customers, electrical equipment still connected and to service crews. It is therefore necessary to ensure embedded generators are equipped with anti-islanding protection devices.[22] TasNetworks must approve the anti-islanding protection device of the synchronous generator before network connection.

In 2014 four significant hydro generators were embedded into the distribution network:

- Tunbridge (6.0 MW);
- Herrick (0.9 MW);
- Nietta (1.0 MW); and
- Maydena (0.6 MW).

These machines increased the total capacity of rotating embedded generators to 42 MW.

4.3.2 Photovoltaic unit penetration

Historically PV uptake in Tasmania lagged behind that of the mainland states, although tariff incentives contributed to some minor surges in uptake. However, since 2012 there has been dramatic growth in installed capacity, primarily driven by falls in equipment cost. By the end of 2014, Tasmania had approximately 70 MW of registered PV at over 20,000 locations. Figure 4-2 presents the penetration of PV within the distribution network. It shows the amount of PV connected relative to the size of the distribution transformer in the area (each coloured dot represents one distribution transformer). At penetration above 100 per cent power flow at times may be from the low-voltage network back into the high-voltage network. However even at lower penetration, there is flow between customers within the low-voltage networks supplied from individual distribution transformers.

20 Generators connected within the distribution network are referred to as embedded generators.

21 http://www.aemo.com.au/Electricity/Network-Connections

22 An anti-islanding protection device will cause the generator to shut down should its part of the network become disconnected from the remainder of the network. All grid-connect PV inverters inherently contain anti-islanding protection.

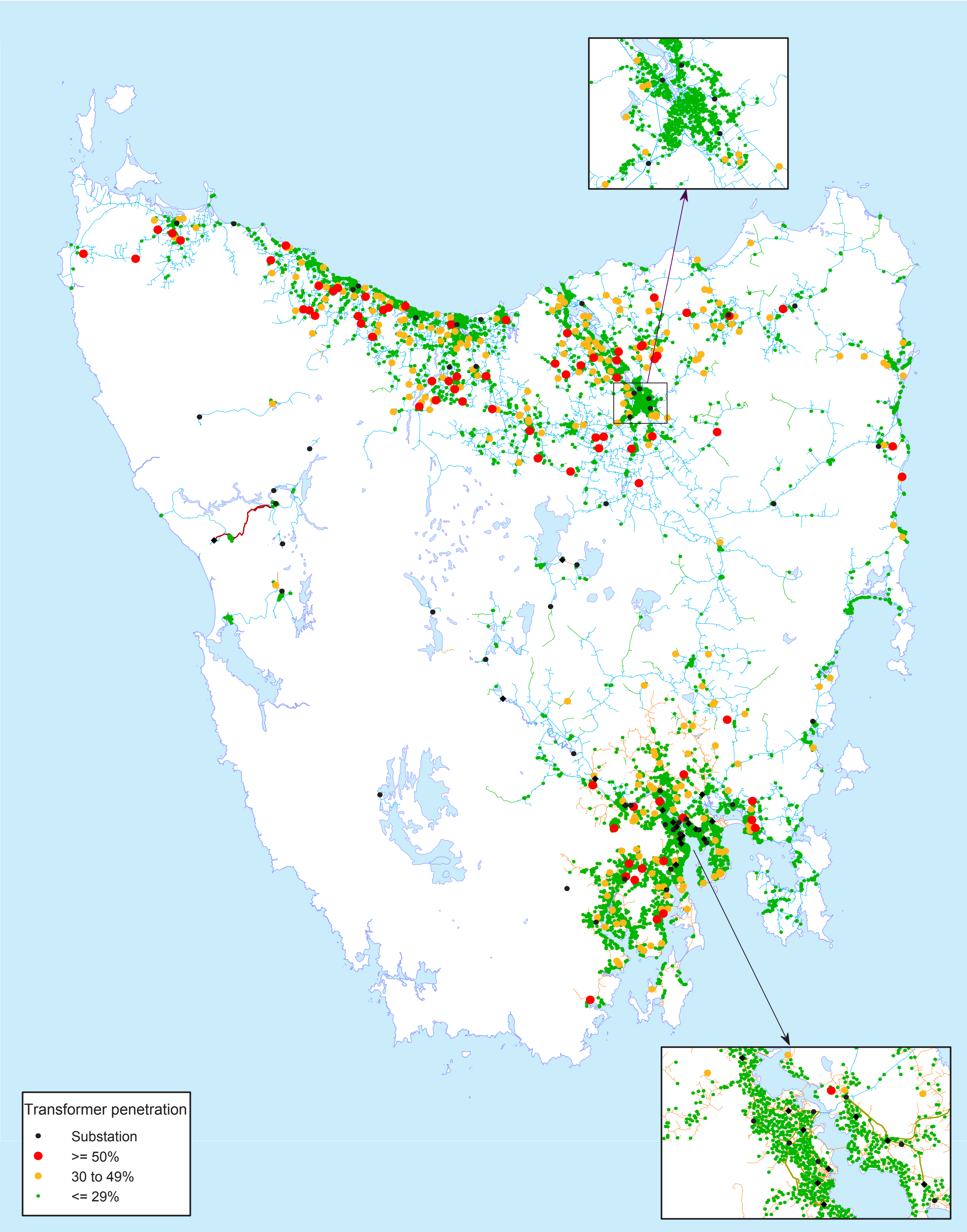


Figure 4-2: Distribution transformer photovoltaic penetration

AEMO forecasts PV uptake in Tasmania to follow the rapid growth of recent years; its forecast PV uptake is replicated in Figure 4-3. The expected continued strong growth in PV is reflected in the fact of the closeness of the moderate and rapid uptake forecasts. Under the moderate uptake scenario, the installed capacity of PV in Tasmania is forecast to exceed 270 MW by 2025.

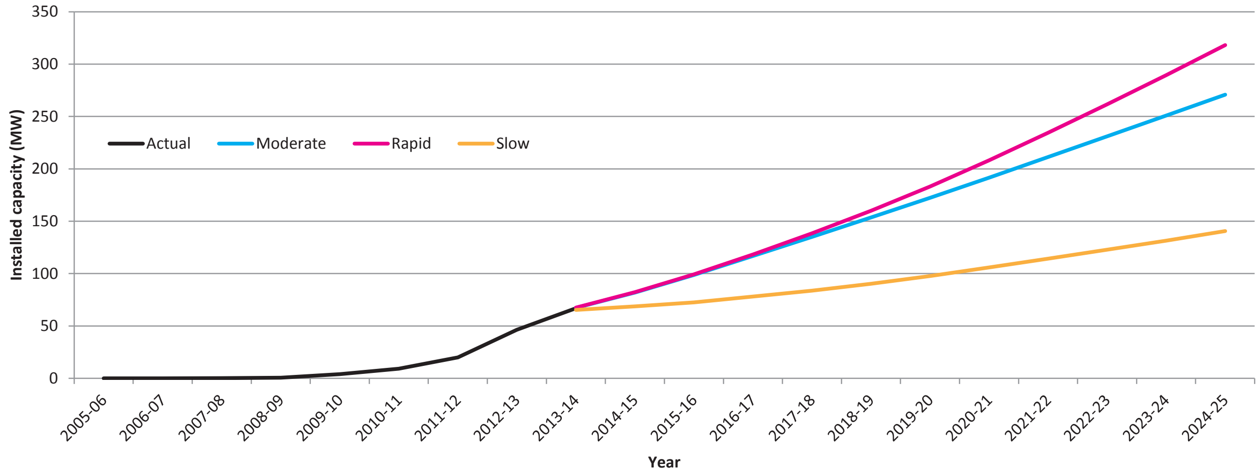


Figure 4-3: AEMO forecast PV uptake in Tasmania[23]

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, whereas the maximum demand in Tasmania occurs on early mornings in winter. In 2014 the maximum demand on the distribution network (ie excluding customer connected to the transmission network) occurred at 8:30 am on 22 July. PV output is very low at this time. Figure 4-4 provides an indication in the difference in solar radiation in winter and summer. The figure shows the measured solar radiation at Creek Road Substation for the day of the network maximum demand, and a mostly cloudless summer day. At the time of peak demand, solar radiation was measured at approximately 80 W/m^2, whereas the maximum on the summer day was almost 1,000 W/m^2. Despite rapid uptake of PV in Tasmania, the contribution to reduction in peak demand will remain negligible; however, as noted in this section, it presents a number of technical issues for the network.

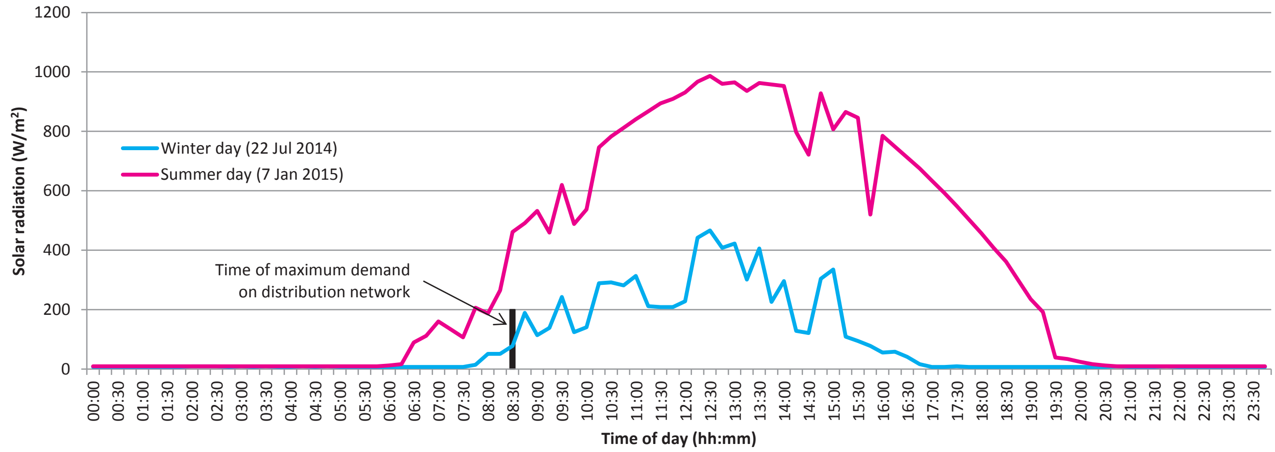


Figure 4-4: Solar radiation measured at Creek Road Substation

There are both network-wide and local issues associated with PV installations. From a network-wide perspective it is important that PV installations remain connected to the network following frequency disturbances. This is a major issue for Tasmania because:

- being a small power system, frequency disturbances are relatively common; and
- our operational frequency bands are significantly wider than mainland Australia (summarised in Section 7.2).

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 even in response to single contingency events, which would be unacceptable for customers and contravene the Rules.

23 *AEMO National Electricity Forecasting Report 2014, Supplementary Information, Rooftop PV: http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report/NEFR-Supplementary-Information*

Local issues mainly relate to voltage regulation in the distribution network. Historically the low voltage distribution circuits were optimised to supply customer load. The design ensured that standard voltages could be maintained above the allowable minimum voltage (during maximum winter load) and below the allowable maximum voltage (during minimum summer load). Essentially, PV penetration further depresses the summer minimum load and a number of low voltage circuits are becoming net generators. This has created an issue where existing distribution transformers and low voltage wires have insufficient thermal rating to cope with this increased power flow, and high voltages generated by PV inverters. WorkSafe Tasmania was forced to disconnect hundreds of PV installations in 2013–14 due to unsafe over-voltages generated by PV inverters and we have had to replace equipment that had insufficient rating for the increased solar penetration.

There are two possible outcomes if PV uptake continues at the current rate:

- many distribution circuits will "saturate" at relatively low penetration levels and we would be unable to connect further PV installations; or
- we would be forced to plan major infrastructure upgrades to facilitate further PV connections.

We don't consider either of these outcomes acceptable, and we are working on policy changes that will enable us to specify modern inverter technology that will contribute to voltage regulation. This approach will allow the network to accommodate the uptake in PV capacity more economically.

4.4 Fault levels

Fault level and fault current are used interchangeably to define the same power system quantity. Fault level is described in terms of apparent power (MVA) and fault current is defined in terms of current, typically expressed in kilo-amps (kA). The fault current, defined at a given point in the network, is the maximum current that would flow should a short-circuit fault occur at that particular point. Determining the maximum fault currents within the network is important for the appropriate selection of equipment such as circuit breakers, switchgear, cables and busbars. This equipment should be designed to withstand the thermal and mechanical stresses that would be experienced due to the high currents that occur under short circuit conditions.

We require that all new connecting circuit breakers to the network meet a minimum access standard. For all voltage levels, circuit breakers require a minimum symmetrical three phase fault current withstand of 25 kA for connection to the transmission network, and 16 kA for connection to the high voltage distribution network.

Within our network, the maximum allowable fault current contribution at the connection points between the transmission and distribution networks has historically been 13 kA. This was determined on the assumption that the distribution network design fault current is 16 kA, with a 3 kA margin for embedded generation. We have a number of transmission-distribution connection points where the maximum fault level exceeds 13 kA, as listed in Table 4-6, however we are currently reviewing this threshold. Our operational procedures in place to manage the fault level at these substations below 13 kA are as follows:

- At six of the substations with high fault level we operate the bus coupler circuit breaker normally open. Except for Electrona Substation, an auto-close scheme will immediately close the bus coupler to restore supply to the other busbar following a contingency on the connecting supply transformer.
- At two substations, we operate one supply transformer circuit normally open. At Trevallyn Substation we operate an auto-close scheme to bring in the transformer following a contingency on one of the other supply transformers. No such scheme is in place at Wesley Vale Substation, however the load connected to that substation is small.
- Creek Road Substation connection point is a critical point of supply in Hobart and therefore the busbar is operated normally-closed. We manually radialise the supply at times of high fault level.

Table 4-6: Transmission-distribution connection points with high fault current

Substation (connection voltage [kV])	Management strategy
Bridgewater (11)	Bus coupler operated normally-open, with auto-close scheme
Chapel Street (11)	Bus coupler operated normally-open, with auto-close scheme
Creek Road (33)	Busbars radialised when fault current exceeds 13 kA
Electrona (11)	Bus coupler operated normally-open
Emu Bay (11)	Bus coupler operated normally-open, with auto-close scheme
Kingston (11)	Bus coupler operated normally-open, with auto-close scheme
Rokeby (11)	Bus coupler operated normally-open, with auto-close scheme
Trevallyn (22)	Supply transformer incoming circuit breaker operated normally-open, with auto-close scheme
Wesley Vale (11)	Supply transformer incoming circuit breaker operated normally-open

Fault levels are also used to define the strength of the power system during normal operation. Minimum fault levels may be used to determine the appropriateness of a connection point to accommodate a new load or for planned switching in regards to voltage power quality. Connection points with higher fault levels experience lower levels of voltage flicker for load switching compared to those with low fault levels.

Appendix B provides a technical description of fault level quantities and our calculation methodology. Fault level data is provided in a Microsoft Excel file on our website, via the 2015 Annual Planning Report page. The file is available at http://apr.tasnetworks.com.au. The spreadsheet contains the existing maximum and minimum three-phase and single phase fault levels, and positive, negative and zero sequence impedances, at all transmission substation busbars.

4.5 Voltage management

Maintaining voltages within target ranges is important for ensuring the safety of people and equipment, the efficient and secure operation the power system, and quality of supply to 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. More detail on constraints and the voltage constraint equations that bound during 2014 is provided in Section 4.1.

The ranges of acceptable voltage limits are specified in the Rules and Australian Standards (AS), specifically:

- the Rules S5.1a.4 power frequency voltage (specifying maximum and minimum voltages in normal operation and following contingency);
- the Rules S5.3.5 power factor requirements (specifying permissible power factor range); and
- AS 60038-2012 Standard voltages (specifying maximum and minimum household supply and other voltages).

In the Tasmanian power system, voltage support is generally provided by generators and controlled reactive plant (such as capacitor banks). Some transformers can be ‘tapped’ to adjust voltages. As load in an area grows, the demands on voltage control increases. The first solution is usually to install reactive support such as capacitor banks, though this method becomes less effective with continued load growth. Eventually other solutions such as dynamic reactive plant, additional transmission lines or additional local generation will be needed.

We are currently experiencing difficulties in voltage management at George Town Substation. We have implemented constraint equations to manage the issue, however we are currently investigating the impact of this and potential solutions. This issue is discussed in Section 4.1.3.

Voltage management also forms a critical component of power quality, impacting all our customers. Voltage management in the distribution network is considered part of power quality. The network-wide and localised voltage issues from PV installations are detailed in Section 4.3.2, with other voltage-related power quality issues detailed in the following section.

4.6 Power quality

Power quality refers to the technical characteristics of the electricity supply received that ensure that the consumer can utilise electric energy from the network successfully, without interference to or mal-operation of electrical equipment. Power quality encompasses the following key areas:

- supply voltage;
- frequency departures;
- voltage disturbances;
- voltage dips; and
- distortion disturbances, including transients, waveform and harmonic distortion, and voltage/current differences between neutral and earth.

Generally, the quality of voltage is most important, because customers generally notice voltage deviations more than other power quality issues. The main categories of deviation are: temporary voltage variations, repeated voltage fluctuations (flicker), harmonic voltage distortions and voltage unbalance.

Schedules 5.1a, 5.1 and 5.3 of the Rules describe the planning, design and operating criteria that must be applied to transmission and distribution networks for power quality.

This section details our recent performance in power quality. More information, including performance criteria and planning levels, is included in Section 7.1 and Appendix H.

4.6.1 Performance monitoring (transmission)

We use an automated data management system to report against transmission network power quality performance. This system evaluates various characteristics against defined planning criteria.

Power quality monitoring meters are installed at the following substations: George Town (220 kV and 110 kV), New Norfolk (110 kV), Derby (110 kV and 22 kV) and Risdon (110 kV). We also have two portable monitoring units, for temporary installation at locations where power quality related issues require investigation. In addition, a portable optical current transformer is located at George Town Substation for high bandwidth harmonic current measurements.

We may expand the monitoring program for wider network coverage as new connection proposals are made. This will enable us to identify sources which inject additional flicker, harmonics or voltage unbalance into the power system.

The following paragraphs summarise our currently-known power quality issues. The power quality planning standards referenced here are detailed in Appendix H.

4.6.1.1 Temporary over voltage performance

Some remote parts of the 110 kV network are at risk of single phase temporary over voltage (TOV) during unbalanced line-ground faults. In particular, the transmission lines near Derby, Smithton, and St Marys substations could reach TOV levels of about 1.4 per unit during faults. Since these over-voltages are asymmetrical, with high zero phase sequence voltages, they do not penetrate into the distribution or customer voltage systems. However, we advise future connection applicants who may wish to connect to the 110 kV network, to liaise with us to ensure that suitable transformers are specified to block zero phase sequence voltages.

4.6.1.2 Voltage unbalance performance

Monitoring indicates 220 kV and 110 kV voltage unbalance is within the technical planning levels for at least 95 per cent of the time (annual probability) at all monitored busbars. For less than 5 per cent of the time, the 10 minute average values vary typically between 0.5 per cent and 1.35 per cent of nominal voltage, which is outside of the specified level of 1 per cent.

The most prominent voltage unbalance issues occur on the 110 kV busbars at George Town and Derby substations.

Voltage unbalance has not caused operational issues for either the transmission network or customer plant. We are continuing to monitor voltage unbalance at multiple locations to ensure that the transmission network continues to operate at or above historical performance levels. In doing so, we are ensuring that sufficient data is available to respond to any potential power quality concerns that may be identified in the future.

4.6.1.3 Voltage flicker performance

The short term voltage flicker indices are within the limits for at least 99 per cent of the time (annual probability) with some excursions above the planning levels noted for less than 1 per cent of the time.

The long term flicker indices are compliant for over 95 per cent of the time but have exceeded the planning levels when 99 per cent probability is considered.

4.6.1.4 Harmonic performance

Voltage harmonics are within limits for all measured harmonic frequencies for at least 95 per cent of the time (annual probability) at all monitored substations.

The 5th harmonic is of particular interest for the Tasmanian transmission network. To keep the harmonic voltages in southern Tasmania within the planning levels, the 2 x 40 MVAr 110 kV capacitor banks at Risdon Substation are tuned to 240 Hz. Since the installation of these capacitors, the 5th harmonic voltage level has been significantly below the specified limit and is expected to remain within the planning limits until approximately 2028.

The 110 kV capacitor banks at Chapel Street (tuned to 204 Hz) and Burnie (225 Hz) substations are two other capacitor banks in the transmission network that have been de-tuned for harmonic mitigation purposes. These optimisations have resulted in the transmission network being generally compliant with specified harmonic planning levels for the majority of the time, with only occasional excursions beyond the limits.

The harmonic performance of the network is influenced by the connected equipment of our customers. As customers' equipment changes over time, the harmonic performance of the network is likely to change also, which makes prediction of issues into the long term future somewhat difficult. Our power quality monitoring program allows us to actively keep abreast of any harmonic performance issues which may evolve.

4.6.2 Performance monitoring (distribution)

We have minimal power permanent quality measuring devices in the distribution network, and therefore the identification of issues is largely reactive. Where identified, we study these issues and address them, if appropriate. Issues with power quality are generally identified through the following methods:

- customer feedback
  We are regularly contacted by domestic, commercial and industrial customers in relation to quality of supply, generally relating to over or under voltages. The trend of customer feedback received in relation to over and under voltages is presented in Table 4-7.
- operational network issues
  As part of operating the network, we perform studies on alternative supply arrangements for different network configurations. This can identify power quality issues in the network, which limit our operational flexibility.
- load or voltage studies arising from new connections or limitations
  New and existing power quality issues can arise when performing studies to analyse new load connections or loading limitations in the network.

Table 4-7: Customer feedback on over and under voltage issues since 2010

Category	2010	2011	2012	2013	2014
Over-voltage	35	50	90	107	156
Under-voltage	21	40	39	34	26
Total	56	90	129	141	182

Table 4-7 shows there has been a continuing increase in the number of voltage issues experienced by customers. The number of over-voltage issues has increased significantly, while there has been a smaller decrease in the number of under-voltage issues. These trends are almost exclusively as a result of the increase in PV installations, with a number of the over-voltage issues reported as part of compliance testing process of PV installations. These issues and discussion on strategies to manage them are detailed in Section 4.3.2.

4.6.2.1 Compliance process

We continually undertake programs to address power quality issues. Compliance issues are generally addressed in two ways:

1. Confirmed major non-compliance
   We investigate and assess major non-compliances to identify likelihood of impact. Where we consider the level of risk (ie customer service, voltage, power factor etc) in continuing with the existing arrangement unacceptable, we rectify this variance; and
2. Confirmed minor non-compliance
   We monitor minor non-compliances over the forthcoming 12 months. We rectify these where the level of exceedance increases.

The corrective action to address non-compliances is generally through reconfiguration and reinforcement of distribution substations and low voltage networks. However, as discussed in Section 4.3.2, we are working on other solutions to address increasing issues as a result of PV installations that would otherwise force major infrastructure upgrades.

Chapter 5

Overview

Chapter 5 presents the electricity demand forecasts and the anticipated supply – demand balance of the Tasmanian power system. We present our forecasting methodology and key input data from state forecast to feeder forecasts and the process used for weather correction. Next we present the outcomes of this process, the 10-year energy and demand forecasts for Tasmania including what has changed since last year's forecast. Finally, this chapter includes the state level generation capacity forecast, including possible new generation developments, and present the generation capacity and energy adequacy over the forthcoming 10 years.

5 Regional demand and energy, and the supply-demand balance

5.1 Demand forecasts and the planning process

Each year we produce forecasts of the future use of our network. We prepare forecasts for the energy consumption and maximum demand at a state-level, and for maximum demand at each of our substations and distribution feeders.

The demand forecast is a key component of the network planning process. We use the demand forecast to identify the timing of capacity and other technical limitations in the network. This helps us in understanding the future challenges of the network and the areas which will be of particular interest moving forward; however it is not the only factor that drives network investment. As detailed in Section 2.3.2.3, we analyse potential network issues and consult with affected customers and stakeholders to ensure that an issue presents sufficient risk and the proposed solution provides sufficient benefit to justify any expenditure in investing in upgrading the network.

Electricity usage has declined in Tasmania since 2008. This coincided with the global financial crisis with a decrease in demand on both the distribution network and from transmission-connected customers. We forecast a modest increase in electricity consumption in the next 10 years, characterised by constant or decreased demand in the short-term before moderate increases aligned with forecast economic growth in Tasmania.

The results of the demand and energy forecasts are available to download from our website http://apr.tasnetworks.com.au. A summary of this information provided is available in Appendix I.1.

5.2 Forecasting methodology

The forecast results are a combination of the input data and the forecasting model. In this section we detail the key input data to the energy and demand forecasts and the results of the model verification process.

Our forecasts are based on three economic scenarios – medium, high and low. These scenarios are built on key energy market policies and economic conditions known at the time. We engage the National Institute of Economic and Industry Research (NIEIR) to prepare a forecast of economic variables and regional energy and demand forecasts for Tasmania for each scenario. The medium growth load forecast represents an estimate of how the future energy and demand may develop with known and anticipated economic changes that are considered most likely.

Temperature is the most important influence on daily maximum demand. In Tasmania, higher demands in winter occur at times of lower temperature. Our planning forecast is based on a probability of exceedance (POE) of temperature of 10 per cent – that is, the base temperature of the forecast (the effective temperature[24]) has a probability of occurring once in ten years. Variance in demand between different effective temperatures is minimal, with the forecast demand of the 10 and 90 per cent POE temperatures varying by less than four per cent. For demand forecasts within the distribution network, we plan on 50 per cent POE.

More detailed information on our forecasting process, at both state and connection point level, is presented in Appendix I.

24 The effective temperature is a weighted-average temperature calculation with weightings of 80 per cent for that day's minimum temperature and 20 per cent for the previous day's maximum temperature.

5.2.1 Factors affecting forecast

This section presents the economic variables and other factors that influence the energy and demand forecasts. There are four key economic indicators to the forecasts, of which gross state product is the primary. The forecast process accounts for a number of other indicators, however these have less influence on the forecast result than the four presented here. The other factors influencing the forecasts are changes in electricity prices, changes in usage from large customers (including new developments), and the impact of photovoltaic and other embedded generation.

5.2.1.1 Gross state product

Tasmanian gross state product (GSP) is one of the key inputs to the forecast. NIEIR's forecast model has a good correlation between GSP and electricity usage. However, the correlation mainly exists at the sector level between sectors of the economy and their relevant electricity usage. The GSP forecast includes three scenarios: base, high and low. The base scenario is considered most likely and drives the medium forecasts.

Figure 5-1 presents the historic and forecast Tasmanian overall GSP growth rate from 2007–08 to 2024–25 prepared by NIEIR. There has only been slight growth in the economy in Tasmania in recent years. Since 2009–10, the GSP growth has averaged only 0.4 per cent per annum, however growth significantly improved in 2013–14 compared to the preceding four years. Since 2007–08 it has averaged 1.0 per cent per annum and in the 10 years since 2003–04 has averaged 1.4 per cent per annum. The main factors that contributed to the weakness in the Tasmanian economy in recent years have been:

- falling private business investment expenditures;
- reductions in public sector capital expenditures; and
- relatively weak growth in private household expenditures.

Tasmanian GSP growth is forecast to average 0.8 per cent per annum to 2024–25 (including 2014–15). This is similar to the economic growth experienced since 2007–08. Tasmanian GSP growth to 2024–25 for high and low economic growth scenarios is forecast to average 1.3 and 0.3 per cent per annum, respectively.

5.2.1.2 Other economic inputs

The forecast considers three other economic inputs as material inputs to the load forecast: household consumption expenditure, private dwelling investment and population. These have less effect on the forecasts than GSP, and there are other economic inputs but are less correlated again.

Table 5-1 presents the three other material economic inputs to the forecast and their forecast growth rates to 2018–19 prepared by NIEIR. The growth rates presented are for the base (medium) scenario. The performance of both household consumption expenditure and private dwelling investment to is expected to improve over the next five years, due to lower interest rates and petrol prices. However, the rate of population growth is expected to remain constant at 0.5 per cent growth per annum.

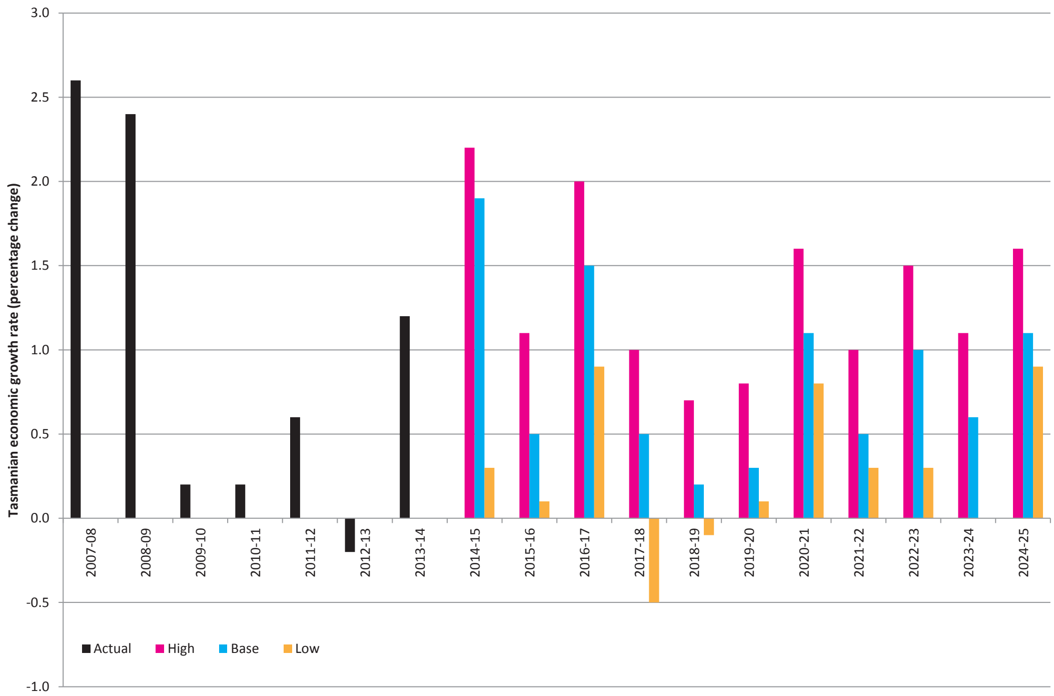


Figure 5-1: Tasmanian GSP growth

Table 5-1: Percentage growth of other economic inputs to load forecast

Economic input	2011–14 average	2014–15	2015–16	2016–17	2017–18	2018–19	2014–19 average
Household consumption expenditure	0.4	2.9	3.5	1.6	2.5	0.4	2.2
Private dwelling investment	-4.3	8.1	2.7	-1.0	2.3	-0.6	2.3
Population	0.2	0.6	0.6	0.5	0.5	0.5	0.5

5.2.1.3 Electricity prices

Electricity prices impact electricity consumption. As electricity prices increase, less electricity is consumed with the reverse also holding true. The forecasting model includes price elasticity by industry. The long run price elasticity implies effects over 15 to 20 years. In practice, most of the effect has occurred by year 4 or 5. Price elasticity applies to residential, commercial and industrial loads. Transmission-connected customers are treated on a customer-by-customer basis and do not include price effects.

The long-run own price elasticity of demand, measured as percentage change in electricity sales per percentage increase in price, is as follows:

- residential: -0.25;
- commercial: -0.20; and
- industrial: -0.30.

For clarity, the -0.25 for residential implies that a 10 per cent increase in residential prices will reduce residential sales by 2.5 per cent.

The NIEIR electricity price forecast indicates that the overall electricity price is expected to increase by 0.9 per cent per annum (in real terms) between 2013–14 and 2024–25.

5.2.1.4 Major new industrial, mining and commercial developments

The forecast growth of commercial electricity sales to 2025 is partly dampened by the substitution of natural gas for electricity in area heating and hot water, as well as cooking. Commercial sector electricity sales growth averages 2.4 per cent per annum between 2014 and 2025, 1.5 percentage points above the average total forecast electricity sales growth for Tasmania.

Industrial sales in Tasmania fell by 1.2 per cent in 2010–11 and by 3.2 per cent in 2011–12. Non-major industrial transmission-connected customer sales fell 34 per cent in 2010–11, mainly reflecting load loss at Emu Bay and Wesley Vale. It is forecast to rise by 0.9 per cent per annum to 2025. Major industrial transmission-connected customer sales have increased, on average, by 1.0 per cent per annum over the last 10 years in Tasmania. The forecasts for industrial load include additional new, or expansions in existing, load consistent with history. These are relatively small and can be seen in 2016–17 and 2021–22.

Major load energy (top four industrials) fell by 4.4 per cent in 2011–12, rose by 2.2 per cent in 2012–13 and rose again by 2.6 per cent in 2013–14. Analysis shows that three major customers have unstable loads (standard deviation of each customer various from 10 to 20 MW) when compared against the other major industrial customer (standard deviation around 4 MW). NIEIR identifies a possibility of major industrial development of about 30 MW in Tasmania under high growth forecast in 5 to 10 year period. Similarly, possibility of losing some industrial load of around 100 MW is identified by NIEIR under low growth forecast.

5.2.1.5 Roof-top photovoltaic generation

Roof-top photovoltaic (PV) are behind-the-meter generation systems offsetting energy consumption in the residential and business sectors. We have in excess of 20,000 PV systems installed in Tasmania, with an installed total capacity of over 70 MW.

Tasmanian winter and summer maximum demand days occur in mornings during cold weather conditions when the output from PV systems is low; hence PV penetration has more of an impact on reducing energy consumption than on reducing the maximum demand. NIEIR developed a growth forecast for PV penetration, which was included in the energy forecasting model.

5.2.1.6 Government policy

The forecast considers the impact of government policy on electricity consumption in Tasmania. The policies relate to both large industrial and domestic energy users. In summary, the policies considered the following:

- climate change, including impacts of future carbon pricing policy;
- renewable energy, including roof-top PV feed-in tariffs; and
- demand management, including smart meters, energy efficiency, electric vehicles and the State Renewable Energy Strategy.

5.2.2 Forecast model verification

To validate the econometric model used for maximum demand forecasting, a back cast (a backward looking forecast) of winter maximum demand has been conducted and compared with actual figures. The back cast is based on daily reference temperatures and actual economic conditions. Variations in transmission-connected customer loads between what is modelled and their actual contribution to maximum demand can contribute up to 40 MW back casting error, although more typically it is around 30 MW. The results of the model verification are presented in Figure 5-2.

The back casting indicates the model has produced forecasts that are representative of likely maximum demands when the economic conditions are known. The model is optimised annually to ensure it captures the changing drivers of maximum demand as technology and behaviour changes.

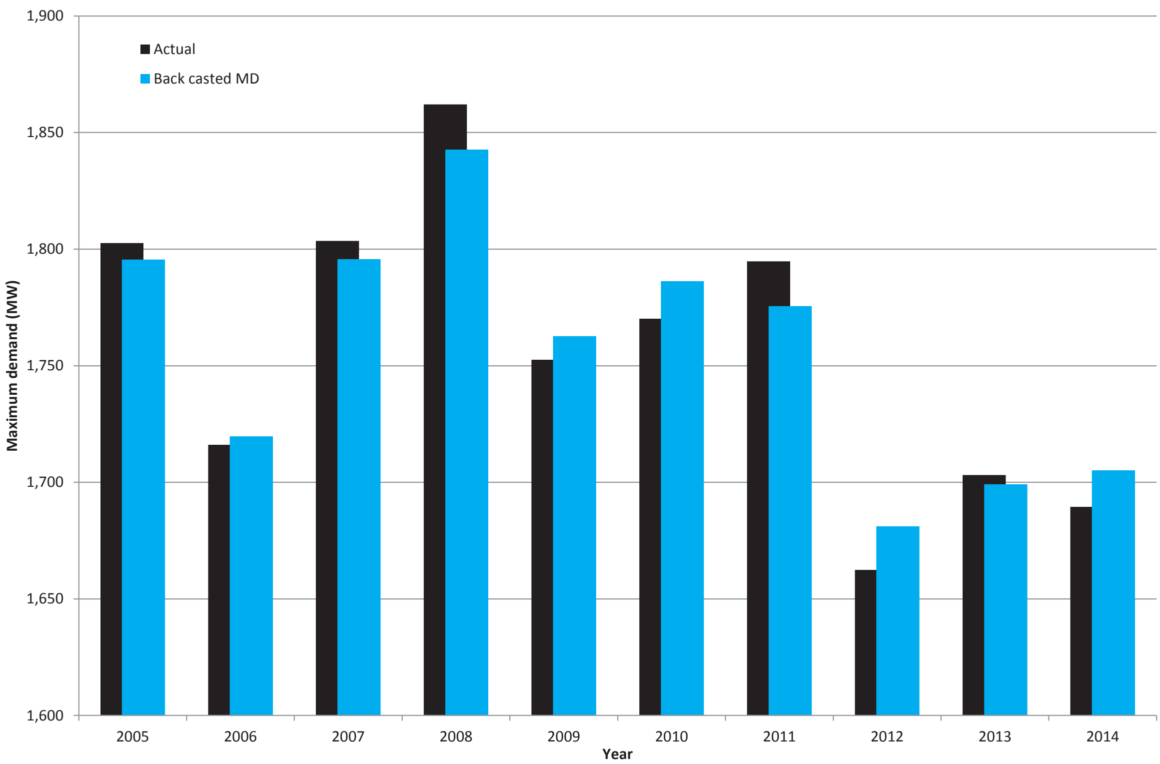


Figure 5-2: Back casting of Tasmania winter maximum demand

5.3 Tasmanian forecast maximum demand and energy

5.3.1 Tasmanian forecast energy

Figure 5-3 presents Tasmanian historic electricity energy sales data from 2005 to 2014 and the Tasmanian electrical energy sales forecast from 2015 to 2025 for the medium, high and low growth scenarios.

Energy sales have decreased since 2009–10; this is primarily due to the closure and suspension of operations of transmission-connected customers, closure of a number of timber mills, the connection of a large embedded generator at Ulverstone and the increase in roof-top photovoltaic. Despite this, energy sales are forecast to grow at 0.8 per cent per annum to 2025 in the medium growth forecast. This is similar to the forecast growth rate in Transend Networks' 2014 APR. In the short-term, we expect the trend remains within the medium and low forecast with an inclination towards the medium forecast.

The forecast average annual growth for the low scenario is 0.1 per cent – excluding the step-change from the loss of major industrial load between 2019 and 2021 assumed in this scenario. The forecast average annual growth for the high scenario is 1.6 per cent. This is based on more favourable economic conditions, including two hypothetical new large customers connecting to the transmission network.

As per the 2014 actual generation and sales data, annual energy losses (including distribution losses) were 4.2 per cent of the total generation.

5.3.2 Tasmanian forecast maximum demand

The maximum demand forecast represents the demand on generation (and Basslink import) to meet the maximum Tasmanian load (ie the load on the transmission network). This includes losses in the electricity network.

It is important to note that the differences between the high, medium and low growth scenarios reflect both different underlying economic growth and different load assumptions for Tasmanian industrial customers as detailed in Section 5.2.1.

Figure 5-4 and Figure 5-5 present winter and summer maximum demand respectively for each scenario. The following information is presented in these two graphs:

- the actual maximum demand recorded ("Actual");
- the maximum demand, temperature corrected to 10% POE ("Actual, 10% POE corrected"). This shows what we expect the maximum demand would have been if the weather conditions at the time corresponded to 10 per cent POE temperatures as used in the forecast[25];
- 2015 high growth ("High growth"), medium growth ("Medium growth") and low growth ("Low growth") forecasts. These are our current forecasts for these three economic scenarios, each at 10 per cent POE reference temperature;

25 10% POE implies a 1-in-10 probability of that demand being exceeded due to a cold day. Explanation of POE and the associated reference temperatures are presented in Appendix I.2.1

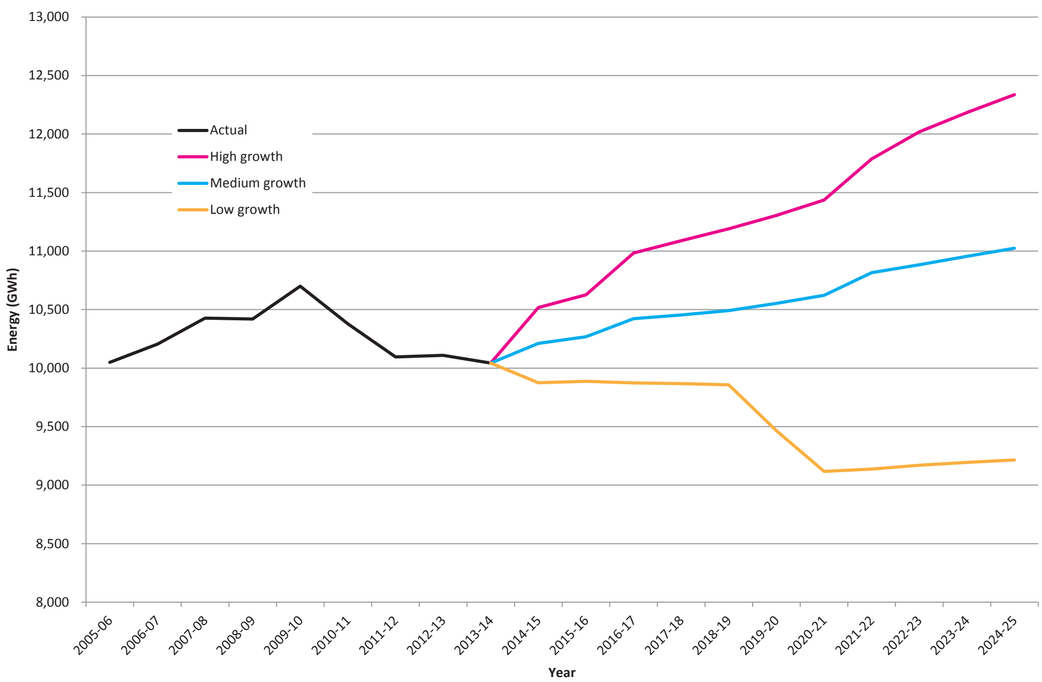


Figure 5-3: Forecast of total Tasmanian electrical energy sales

- our 2014 medium economic growth forecast ("2014 medium growth"). This was the forecast upon which Transend Networks' 2014 APR was developed, and is included for comparison purposes.

5.3.2.1 Winter maximum demand forecasts

Behaviour of historic data

Historic data shows a number of drops in maximum demand during the past 10 years. Unlike energy drops, which are mainly contributed by major changes in operations of the customers or economic factors, maximum demand drops can be observed due to short term changes in customer operations in addition to factors affecting energy drops.

There is a drop of maximum demand from 2005 to 2006. Our analysis indicates that this is mainly due to diversity of each connection point contribution to the maximum demand, especially major industrial customers. It was observed that a number of major industrial transmission-connected customers' contribution to the 2006 maximum demand is lower than their normal operating load. However, their individual maximum demands remained at 2005 levels.

A significant drop of maximum demand was observed in 2009. This coincides with the beginning of the global economic crisis. The drop was noticed both in the distribution network and transmission-connected customer loads.

The decrease in maximum demand in 2012 was mainly contributed to a transmission-connected customer, which temporarily closed its operation during that period. In addition, there was a 10 MW decrease in the distribution network loads. Though the customer resumed normal operations, the maximum demand in 2013 did not return to previous levels due to a further 45 MW decline in demand in the distribution network.

Another decrease in maximum demand was observed from 2013 to 2014. The 2014 maximum demand was recorded in August 2014 and coincided with transmission-connected customers' maximum demand – the first time such coincident was observed. In general, the transmission network maximum demand is recorded in late June or July and coincides with the distribution network maximum demand day (or a nearby day). The 2014 drop in transmission network maximum demand was mainly contributed to by this deviation of transmission network maximum demand from the distribution network maximum demand.

Forecast

The Tasmanian maximum demand forecast is presented in Figure 5-4. The forecast average growth rate in winter maximum demand is 1.1 per cent per annum for the medium scenario. The moderate forecast reflects the economic challenges in Tasmania outlined in Section 5.2.1. In the short-term, we do not forecast any growth in the Tasmanian maximum demand in the next two years and only 20 MW total growth within the next four years. We do not expect the Tasmanian maximum demand to again reach the 2008 historic peak within the planning period; even our second peak in 2011 is not expected to be again reached until 2024.

The forecast average winter growth rate for the high growth scenario is 2.3 per cent per annum. The better economic conditions are forecast to create an environment where two hypothetical new transmission-connected customers connect, in 2017 and 2022.

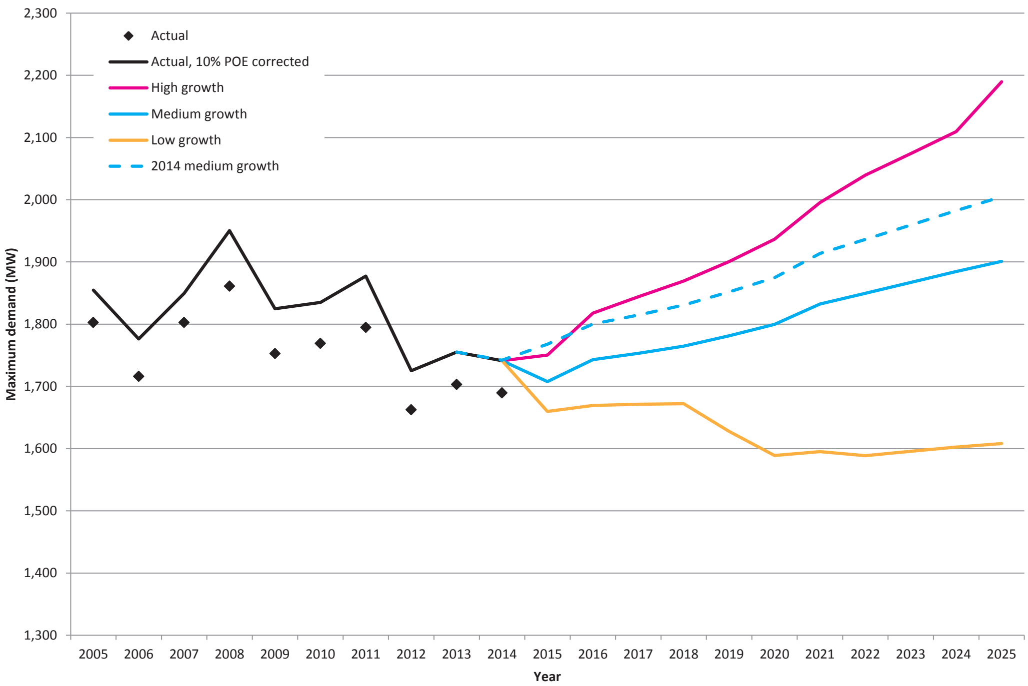


Figure 5-4: Forecast of total Tasmanian winter maximum demand

The forecast average winter growth rate for the low growth scenario is 0.25 per cent per annum. This is the growth rate excluding the step-change reduction in demand. This scenario predicts a drop in maximum demand from 2018 to 2020 due to a reduction in existing transmission-connected load, including the hypothetical closure of one customer.

5.3.2.2 Summer maximum demand forecasts

Behaviour of historic data

Historical maximum demand variations in summer are similar to the historic variations in winter data. The influential factors for these variations are discussed in 5.3.2.1.

Forecast

The summer maximum demand forecast is presented in Figure 5-5. It is forecast to grow at an average rate of 1.3 per cent per annum under the medium growth scenario, equivalent to the summer maximum demand forecast provided in the 2014 APR. The consistent forecast for the summer maximum demand, and that the growth rate is higher than winter, is evidenced by the fact of increasing irrigation demands amongst other things.

The average growth rate for the summer high growth scenario is 2.2 per cent per annum. The summer low growth rate is 0.4 per cent per annum, excluding the hypothetical loss of a major energy user, detailed previously.

5.3.3 Change in forecasts since last year

Due to the challenging economic conditions, the 2015 forecast GSP growth rate for Tasmania was revised downwards by NIEIR for the 2015–2025 period. As discussed earlier, GSP is one of the key input variables in the forecasting model; hence this decrease has been reflected in the 2015 electricity forecast.

The winter medium forecast produced in 2015 indicates a lower average growth rate than what was forecasted in 2014. The 2014 forecast indicated a slight decrease in winter maximum demand for 2014, and then an increase in demand for the forecast period. The latest forecast indicates this forecasted downturn will continue until 2015. As shown in Figure 5-4, the 2015 medium forecast shows an overall drop of around 60 MW in 2015 and around 100 MW in 2025 compared to the 2014 forecast.

The latest summer medium forecast also indicates a drop in the forecast load. But as shown in Figure 5-5, this drop is much less (around 10 MW) for the planning period. This is mainly due to the proposed increased in irrigation activities during summer (apart from the economic down turn).

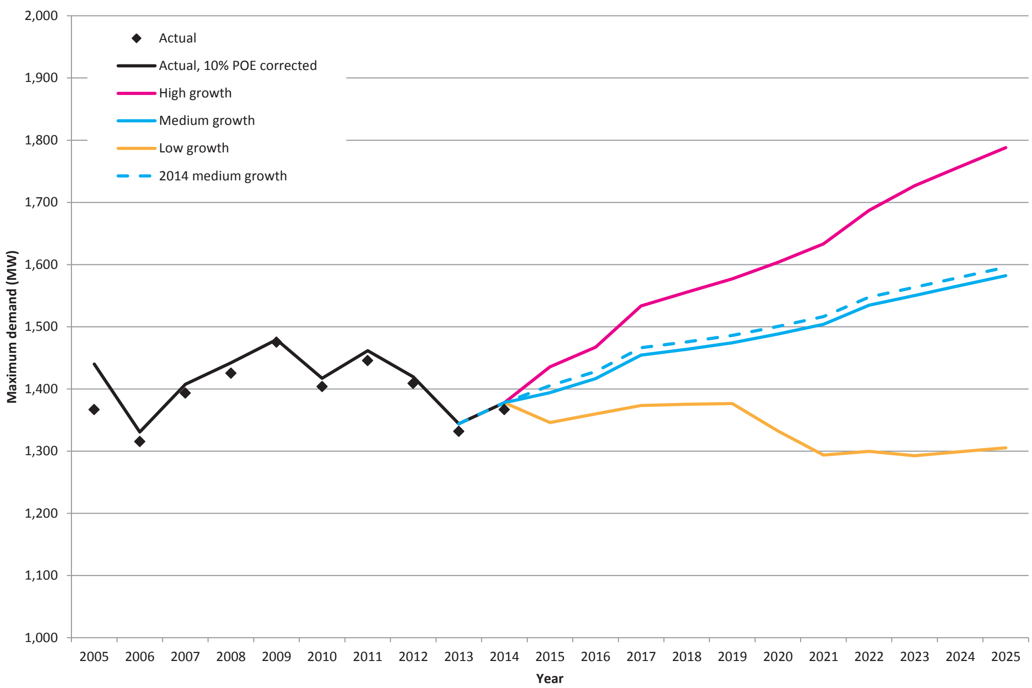


Figure 5-5: Forecast total Tasmanian summer maximum demand

5.3.3.1 Impact of changing forecast

Tasmanian maximum demand occurs in winter; hence the decrease in the winter medium demand forecast has meant a number of issues and proposals identified in the 2014 APR have been deferred. These are discussed by planning area in Chapter 6. The following proposed projects have been deferred past the 10-year planning period:

- Farrell Substation 220 kV security upgrade;
- load transfer between Burnie and Emu Bay substations;
- new zone substation at Austins Ferry or Brighton; and
- new zone substation at Margate.

5.4 Demand profile

Figure 5-6 presents the Tasmanian demand profiles on the maximum demand day in winter and summer for the past two years. The maximum demand curve illustrates the load profiles and the greater demand variability for electrical energy in winter compared with summer.

The overall demand curve on the maximum demand day of summer and winter has decreased from 2013 to 2014. That is, the overall energy consumption, as well as the day's maximum demand, decreased from 2013 to 2014, not just the peak loads.

The shape of the demand profile was very similar on the winter maximum demand days of both years. Notably, the peaks occurred at the same time. The same comment applies to the summer maximum demand days of both years.

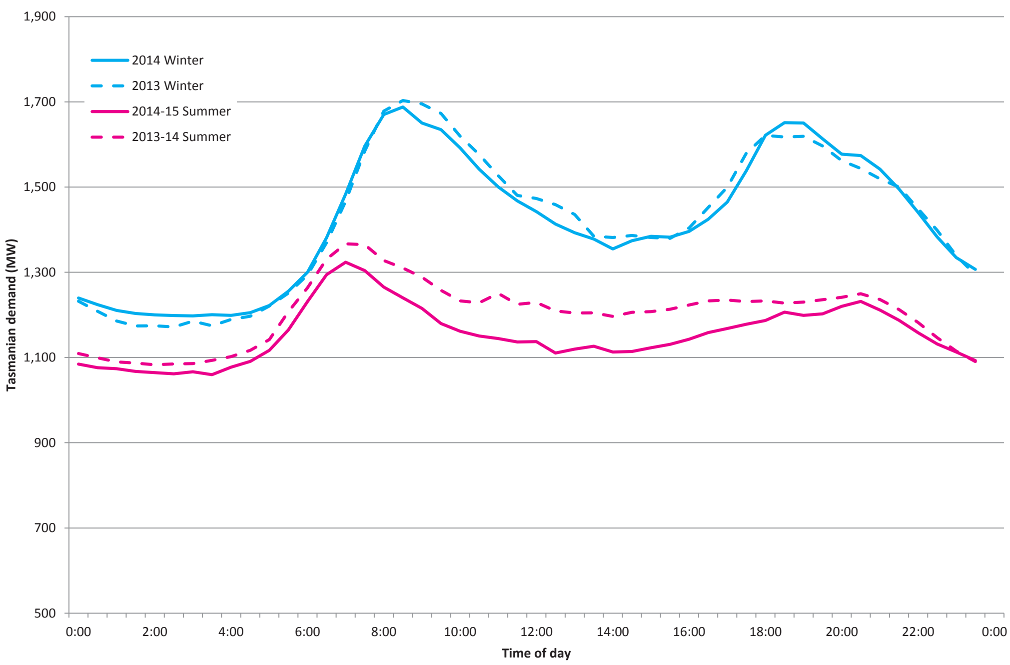


Figure 5-6: Winter and summer maximum demand curves

5.5 Intra-regional generation projections

This section presents a summary of our intra-regional (within Tasmania) generation projects. It includes our current generation capacity, type of generators and any forthcoming generation developments.

5.5.1 Generation capacity

Table 5-2 presents the total existing generation capacity, including Basslink import, connected to the transmission network as at June 2015. This excludes embedded generation in the distribution network. The details of individual generation sites are listed in Appendix F.

Table 5-2: Generation capacity

Generation type	Number of sites	Total name-plate rating (MW)
Hydro	25	2,266
Gas	1	383
Wind	3	308
Basslink imports	1	478
Total	29	3,435

5.5.1.1 Embedded generation

There are a number of embedded generators that are not directly connected to the transmission network and are not included in Table 5-2. Embedded generators are not directly modelled in planning studies of the transmission network, but their impact is indirectly incorporated as a reduction in connection point demand in future years' load forecasts based on historic performance of these generators. Details of these generators are given in Appendix F.

5.5.1.2 Generation developments and retirements

We are not currently processing any generation enquiries in Tasmania. However, we are aware of four publically announced generation development proposals. Table 5-3 presents their project names, proponent, capacity, type, status and their websites.

We are not aware of any planned retirements of transmission connected generation plant.

Table 5-3: Generation developments in Tasmania

Name	Proponent	Capacity (MW)	Type	Status	Website
Granville Harbour Wind Farm	West Coast Wind Pty Ltd	99	Wind	Publically announced	http://www.westcoastwind.com.au/
Cattle Hill Wind Farm	Cattle Hill Wind Farm Pty Ltd	240	Wind	Publically announced	http://www.onewindaustralia.com/
Low Head Wind Farm	Low Head Wind Farm Pty Ltd	30	Wind	Publically announced	http://www.lowheadwindfarm.com.au/
Bass Strait tidal energy	Tenax Energy	302[26]	Tidal	Publically announced	http://www.tenaxenergy.com.au/

26 Capacity sourced from AEMO generation information, TAS 10 December 2014: http://www.aemo.com.au/Electricity/Planning/Related-Information/Generation-Information

5.6 Supply demand balance assessment

This section investigates the energy balance between the forecast demand and the supply of generation, including potential future generation sources in Tasmania.

The supply–demand balance presented in this section indicates that the Tasmanian electricity demand will be met for at least the next 10 years.

The provision of electrical energy to Tasmanian users has been, and is expected to be for the foreseeable future, dominated by hydro generation. Hydro power stations provide 2,266 MW of the total 2,957 MW Tasmanian generation capacity connected to the transmission network, which is approximately 77 per cent of the generation capacity.

Hydro generation availability is affected by maintenance needs and the availability of water. Even with overall water storage at reasonable levels it is possible that some hydro generating plants associated with small and medium storages may not be available.

Tasmania's historic reliance on hydro generation has reduced in recent years through operation of the gas-fired Tamar Valley Power Station, establishment of the Bluff Point, Studland Bay and Musselroe wind farms, and the Basslink interconnector.

This section considers:

- capacity of the existing and future generation assets compared with the forecast maximum demand of Tasmanian electricity users; and
- electrical energy generation capacity compared with forecast electrical energy consumption.

5.6.1 Capacity balance

Generation capacity is the sum of the name-plate ratings of all available generators. The capacity balance determines the ability of the generating system to meet the maximum demand now and in future years.

As detailed in Section 5.5.1, the total capacity of generation connected to the transmission network is 3,435 MW, including Basslink import. The use of Basslink is dependent on market conditions and the availability of generation elsewhere in the NEM. Due to the intermittent nature of wind generation, the contribution from wind at the time of maximum demand is assumed to be five per cent of its peak capacity. Accordingly, the total capacity assumed for capacity balance studies is 3,142 MW.

This available capacity is compared against medium, low and high demand growth scenarios. Furthermore, the available excess capacity is tested for the following three outages:

- Basslink outage (loss of 478 MW);
- Gordon Power Station outage (loss of 432 MW); and
- total gas outage (Tamar Valley Power Station outage of 383 MW).

All three outages show that there is sufficient capacity until at least 2025. Among these outages, highest capacity impact is from a Basslink outage. The expected excess generation capacity under a Basslink outage against medium growth forecast is shown in Figure 5-7. Furthermore Figure 5-7 shows the possible excess capacity range as per low and high growth scenarios and excess capacity in medium growth scenarios. Excess capacity drops to about 950 MW under high growth scenario, while it will remain at around 1500 MW under low growth scenarios in 2025.

5.6.2 Energy balance

The energy balance considers the ability of Tasmania's generation sources, including Basslink, to meet future Tasmanian electrical energy needs for a range of generation and energy growth scenarios. As the main source of electrical energy in Tasmania is from hydro generation, the energy balance takes into account three rainfall scenarios (wet, medium and dry) which impact the amount of water available in hydro storages.

Historically we have performed the energy balance study annually for inclusion in the APR; however we have not performed the study this year. We forecast there will be less energy consumed than forecast in previous years and we are not aware of any generation retirements within the planning period. Due to the lower energy forecast in 2015, the energy balance will only improve on previous years. In this section we present the results of last year's studies, however in a simpler format to understand.

The methodology and assumptions used in this study are presented in Transend Networks' 2014 APR in its section on energy balance. The findings regarding the energy supply–demand balance investigations are dependent on the assumptions made about the demand, the forecast Victorian pool price and the heuristic controls in the model. The generation pattern assumption includes one proposed development, as included in Section 5.5.1.2 of this APR: the 240 MW Cattle Hill Wind Farm, from 2018.

5.6.2.1 Base case

The base case scenario estimates the future energy balance with respect to the 2014 medium energy growth forecast and the variation of hydro inflows. Figure 5-8 shows the variations in expected supply share from the available generation sources to meet the future energy demand for each of the three hydro storage projections. It presents the medium rainfall scenario as the shaded areas, with the short-dashed line representing the requirement under the dry scenario (low rainfall) and long-dashed line for the wet (heavy rainfall) scenario. The negative values for the Basslink import requirement represent energy is exported to Victoria.

Figure 5-8 presents the following observations:

- There is a steady growth in energy demand during the study period.
- Changes in energy supply patterns can be observed due to future commissioning of Cattle Hill Wind Farm. Note the expected reduction in thermal generation and increase in energy export to Victoria in 2018.
- All generation sources contribute to meeting the future energy demand. Meanwhile, it is expected a slight increase in export to Victoria during the study period with approximately 150 GWh more Basslink exports in 2025 than in 2015.

No unserved energy is expected during the 10-year planning horizon.

We also analysed this scenario considering no contribution from thermal generation. The thermal generation component represents the contribution from Tamar Valley Power Station; however the combined cycle component of the station has not operated in the past year. Should that continue to be the case, the analysis shows there is still sufficient generation to meet the energy requirements for the next 10 years. The absence of thermal generation would be largely accounted for by an increase in Basslink imports.

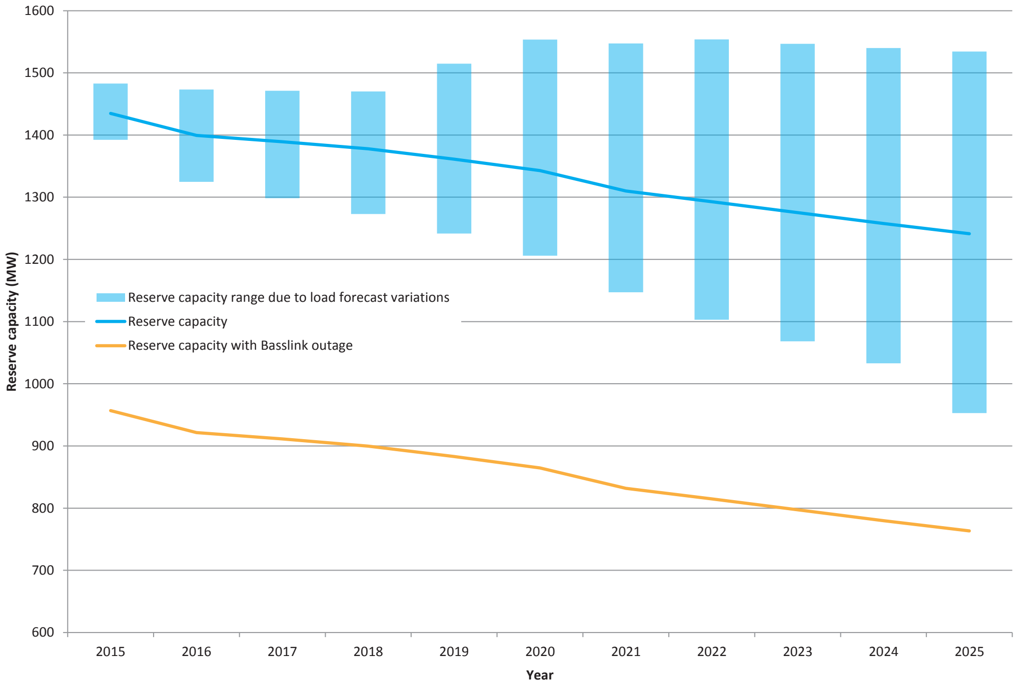


Figure 5-7: Reserve capacity variation due to load variations and severe outage

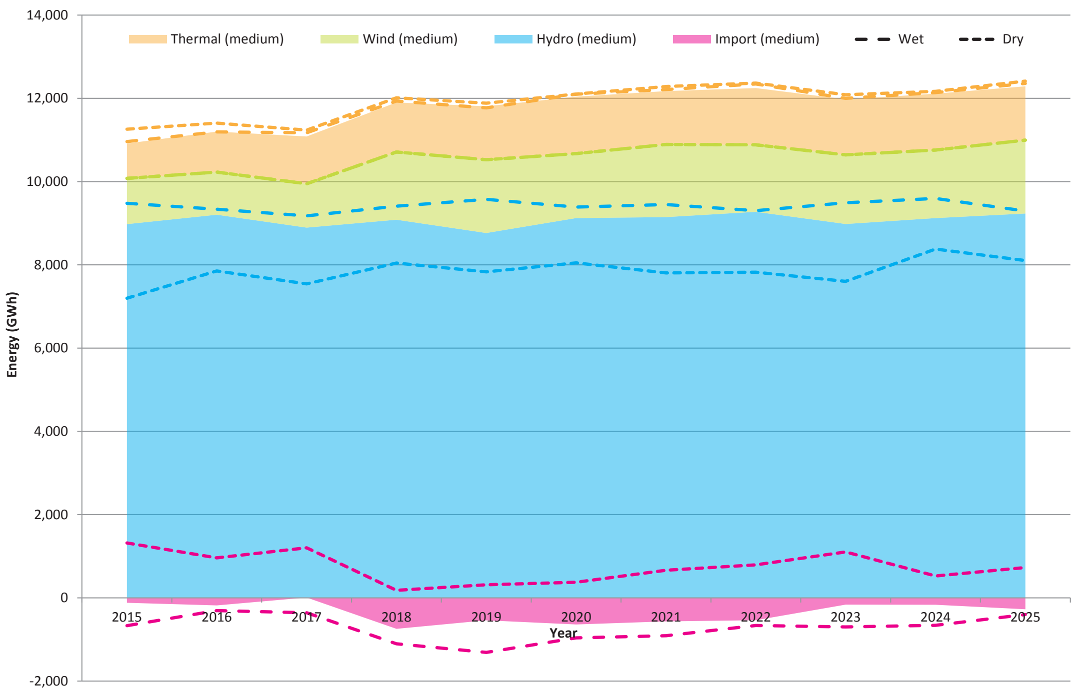


Figure 5-8: Supply balance to meet the energy demand under medium energy growth

5.6.2.2 High energy growth

This scenario uses the same hydro assumptions as the base case, but with a high energy growth scenario from 2014. It is assumed that the economic factors favouring a high growth in demand would also favour growth in industrial demand. Figure 5-9 shows the expected supply share to meet a high energy growth forecast.

The contribution from all generation sources, including Basslink imports from Victoria, is significant in meeting the future demand under a high energy growth scenario. The additional contribution to meet the energy requirement in this scenario compared to the base case is from hydro generation and Basslink imports. However, there is no unserved energy expected during the 10-year planning horizon under this scenario.

5.6.2.3 Extended failure of generation source

This scenario is comprised of three independent sub-scenarios. Each is a hypothetical six-month energy supply outage and its impact on the hydro system in Tasmania. The outages modelled include a major outage of:

- a large hydro generator (ie Gordon Power Station);
- the gas supply network (ie Tamar Valley Power Station); and
- Basslink.

The scenarios are analysed over 12 months: the six month outage, followed by a six month period to return the storage levels to their initial levels. As detailed in Section 5.6.2.1, Basslink is a net-importer of generation in the energy balance base case. The expected imports during the first six months are much higher than the second six months. Therefore, the outages from January to June were considered for the analysis, because these would have a greater adverse impact on water storages.

Figure 5-10 presents the monthly energy storage variations under the three different system outages, relative to the situation with no outage. A Basslink outage would result in the lowest hydro storage level at the end of the outage period with respect to the normal operation case. The expected energy storage drop due to a major Basslink outage is around 8.8 per cent of the total energy storage volume. A similar impact can be observed with the gas supply failure. The expected energy storage drop in this case would be around 5.2 per cent of the total energy storage volume. A Gordon Power Station outage would have virtually no impact on hydro storage levels with respect to the normal system operation case.

Hence if a major 6-month outage was to occur, the Tasmanian power system has sufficient energy capacity from non-hydro sources to allow hydro storage levels to return to the pre-outage levels, with all energy requirements able to be supplied during that time.

5.6.2.4 Summary of findings

The findings suggest that for medium and high energy growth scenarios there are no supply shortfall issues for the next 10 years. However, high energy imports from Victoria would be required to support continued limited contribution from thermal generation or for high energy growth.

Similarly, no unserved energy resulted from any of the major outages studied, although a major Basslink or gas supply outage could result in a reduction in hydro storage levels of up to nine per cent of the storage capacity.

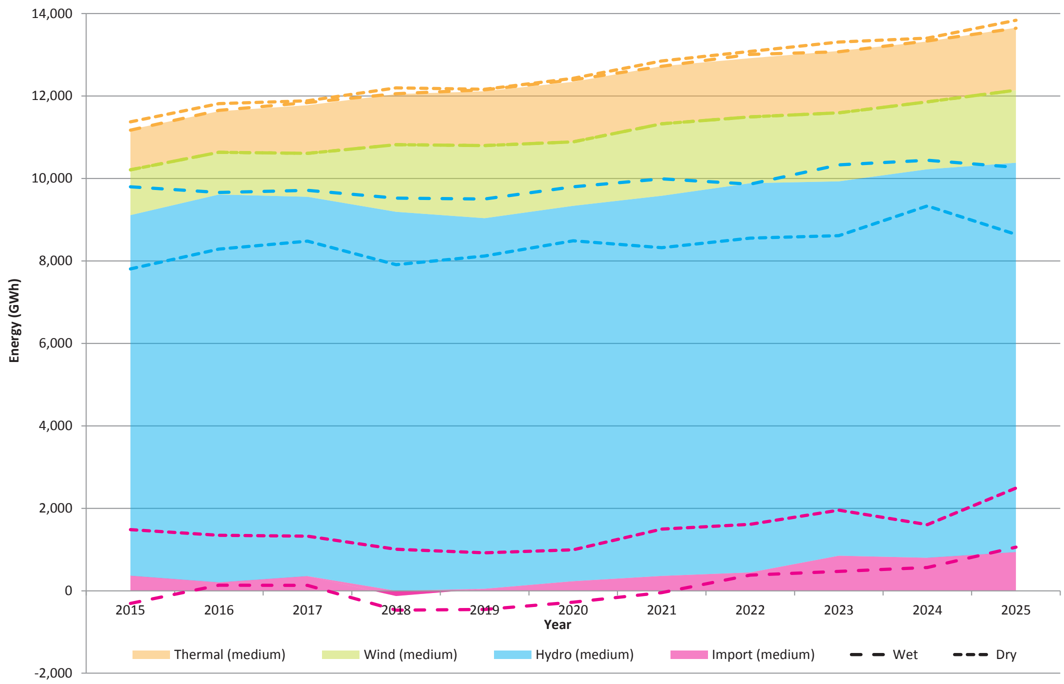


Figure 5-9: Supply balance to meet the energy demand under high energy growth

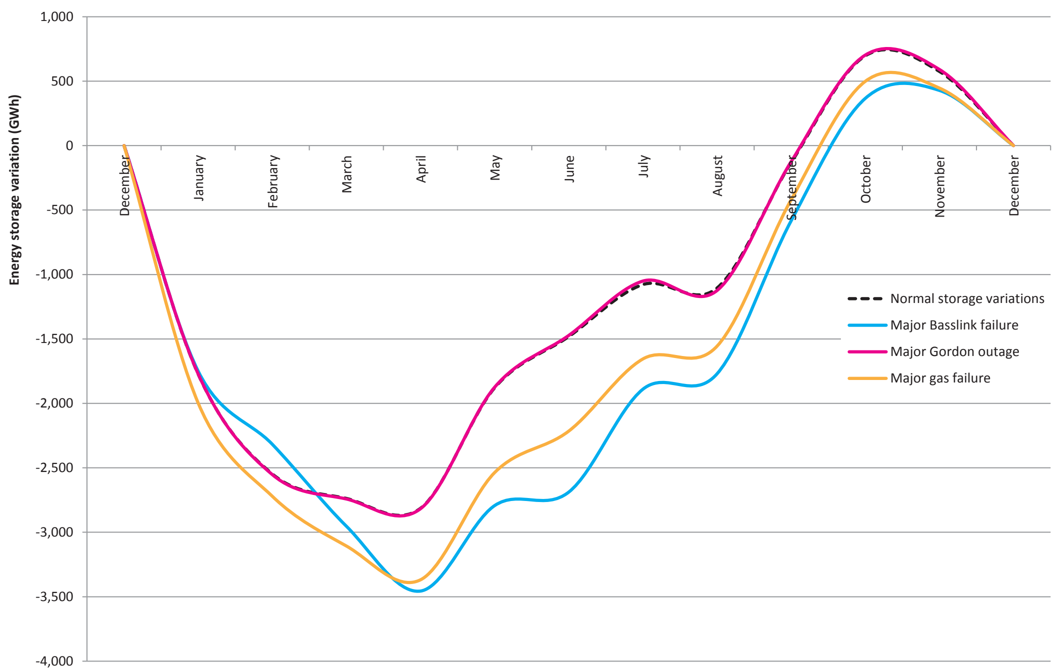


Figure 5-10: Monthly hydro storage variation due to selected outages

Chapter 6

Overview

Chapter 6 discusses the identified issues by planning area within the next 10 years. Depending on the nature and timing of the issue, we present options to relieve each issue along with proposed cost, timing and the load or generation support requirements to defer the issue. We present network planning, supply reliability and material asset condition issues. Also by planning area, this chapter provides an overview of the material current and recently completed projects, issues or proposed projects deferred in the last year, and information, intended for proponents of new load connections, about which connection points have existing available capacity.

This chapter also discusses the state-wide and inter-area planning issues, including as part of national transmission planning. We detail these issues and options to relieve them, and non-network projects we are investigating or undertaking. Also included is how the power system in Tasmania is considered as part of national transmission planning and a summary of the contents of AEMO's national transmission network development plan that relates to Tasmania.

6 Planning areas

6.1 Notes for all geographical planning areas

Sections 6.2 to 6.9 present the existing and forecast issues in the electricity network during the next ten years and the proposed solutions to relieve these constraints. It also includes other proposed projects to address asset condition and supply reliability issues, and to increase network capability.

Issues are identified from our regulatory obligations in planning and operating the electricity network, detailed in Section 2.1. The process we undertake for development, asset management and reliability is detailed in Section 2.3. Our technical assessment of emerging constraints is assessed against the following criteria:

- thermal overloading;
- voltage performance;
- stability;
- security and reliability;
- the Rules requirements, notably Schedules S5.1a and S5.1; and
- ESI Regulations.

The results of our studies are divided into seven geographical planning areas. The areas are detailed in Section 3.5 and our results are presented in Sections 6.2 to 6.8. There are also a number of state-wide and inter-area projects, which are included in Section 6.9.

We conduct our planning studies using the 2015 medium growth and 10 or 50 per cent POE maximum demand forecast for the transmission and distribution networks respectively. Section 5.1 of this APR discusses the load forecasting methodology, whilst Appendix I presents the maximum demand and energy forecasts. Substation load and rating information and generator information for each planning area is detailed in Appendix E and Appendix F, respectively.

The remainder of Section 6.1 presents an overview of the items that are common to all areas. To avoid repetition, they are discussed here.

6.1.1 Area issues and proposed solutions

This section provides an overview of the issue types relevant to each planning area. It provides a summary of the location of the issue, when the issue is forecast to occur, and our proposed solution.

The information is presented in four streams: constraints and inability to meet network performance requirements; asset replacements; network capability improvement parameter action plan; and supply reliability. Constraints and inability to meet network performance requirements are identified through analysis of the network and the load forecast. Asset replacement requirements are identified through condition assessments and risk analysis. Network capability improvement projects are those approved as part of our 2014–19 transmission regulatory period. Reliability requirements are identified through network performance metrics of the previous year.

6.1.1.1 Constraints and inability to meet network performance requirements

This section provides information on the constraints and inability to meet network performance requirements over the next ten years. The network performance requirements in Tasmania, relevant to the transmission network and referred to in this document as the ESI Regulations, are detailed in Section 2.1.2. The issues identified here are those that impact on our ability to transfer electrical power and where we do not meet our network performance requirements.

In each area section we present a summary table of the area of the identified issues, a brief description of the issue itself, the year in which the issue is forecast to materialise, the proposed solution. Further in the chapter we present the issue and potential/proposed solutions in more detail.

Table 6-1 presents a summary of the constraints and inability to meet network performance requirements where we have identified or are investigating a proposed augmentation solution. It also includes constraints where our current operating practice places customer supply at risk. These issues and proposed solutions are detailed further in this chapter. There are a number of other identified issues in this chapter; however we propose to manage these operationally with no capital expenditure.

Table 6-1: Summary of material constraints and inability to meet network performance requirements

Area of issue	Issue	Forecast year	Proposed solution (year)	Reference
Within one year				
Richmond Zone Substation	Supply transformers non-firm and regulating transformer overload	Current	Under investigation	6.7.3.5
St Marys Substation	Supply transformers non-firm	Current	Continue contingency load shedding scheme	6.7.3.6
Within one to three years				
Farrell–Que–Savage River–Hampshire 110 kV circuit	Above the 300 MWh unserved energy requirement of the ESI Regulations (constraint exists now, but at customer request we have an exemption until 2018)	2018	Re-assess options just prior to exemption expiry	6.2.4.3
Within three to five years				
None				
Within five to ten years				
None				

6.1.1.2 Asset replacements

This section presents the asset replacement projects identified over the next ten years. This section is limited to replacement transmission network assets and projects greater than $5 million, and replacement distribution network assets and projects greater than $2 million. However, we may include additional asset replacement projects where it includes material network assets (eg supply transformers), a material change to network arrangement, or where we identify projects that may be of specific interest to potential third-party providers.

In each area section we present a summary table of the identified issues over the next ten years, including the area and description of the issue, and the proposed solution. Table 6-2 presents a summary of the asset replacement projects included in this APR. These issues and proposed solutions are detailed further in this chapter.

Table 6-2: Summary of asset replacements

Area of issue	Issue	Proposed solution (year)	Reference
Within one year			
None			
Within one to three years			
Butlers Gorge–Derwent Bridge 110 kV transmission line	Transmission line condition	Replace transmission line with a 22 kV feeder from Butlers Gorge Power Station (2017)	6.5.3.7
Gretna Zone Substation	Condition of supply transformers	Replace transformers (2017)	6.5.3.5
Palmerston Substation	Condition of disconnectors and earth switches	Asset renewal (2017)	6.4.3.6
Queenstown–Newton 110 kV transmission line	Transmission line condition	Decommission transmission line and reconfigure supply to Newton Substation (2017)	6.2.3.5
Claremont Zone Substation	Condition of supply transformers	Replace transformers (2018)	6.6.3.7
New Norfolk Zone Substation	Condition of supply transformers	Replace transformers (2018)	6.5.3.6
North Hobart Substation	Condition of 11 kV switchboards	Switchboard replacement (2018)	6.6.3.11
Richmond Zone Substation	Condition of supply and regulating transformers	Replace transformers (2018)	6.7.3.5
Within three to five years			
All substation supply points	Risk of substation failure	Transportable substation (2019)	6.9.2.6
Derwent Park Zone Substation	Condition of supply transformers	Replace transformers (2019)	6.6.3.10
Lindisfarne Substation	Condition of supply transformers	Replace transformers (2019)	6.6.3.12
Triabunna Spur transmission line	Condition of Kay pole support structures	Replace structures (2019)	6.7.3.7
Waddamana–Bridgewater Junction 110 kV transmission line	Condition of transmission line	Asset renewal (2019)	6.9.2.4
Bellerive Zone Substation	Condition of supply transformers	Replace transformers (2020)	6.6.3.14
Geilston Bay Zone Substation	Condition of supply transformers	Replace transformers (2020)	6.6.3.13
Within five to ten years			
Upper Derwent 110 kV transmission lines	Condition of transmission lines	Issue currently under investigation	6.9.2.5

6.1.1.3 Network Capability Improvement Parameter Action Plan

The Network Capability Improvement Parameter Action Plan (NCIPAP) is a list of projects that forms the network capability component of the Service Target Performance Incentive Scheme (STPIS) that applies to our transmission revenue determination for the 2014–19 regulatory period. The intent of the NCIPAP is to incentivise projects that will increase transmission network capacity, availability or reliability.

NCIPAP projects provide an increased return on expenditure; however the amount we can allocate to these projects is capped. Projects are capped at a total of 1 per cent of our maximum allowable revenue (MAR) – for the transmission network – per year; approximately $2.2 million. For these projects we can earn up to 1.5 per cent of MAR for each year of the regulatory period; however in year five we may be penalised up to 2 per cent of MAR if the AER deems us to have not delivered or to have overspent on our program.

Our NCIPAP projects were reviewed by AEMO prior to our revenue proposal submission, and were approved by the AER as part of our transmission revenue determination for the 2014–19 regulatory period.

In each area section we present a table summarising the NCIPAP projects in each planning area, including the project name and its benefit, and the location, cost and timing of implementation. Project justification and other details were provided as part of the NCIPAP submission to the AER in our revenue determination process.[27]

Table 6-3 presents a summary of the NCIPAP projects and programs included in this APR and our 2014–19 regulatory period for transmission and approved by the AER. These projects and programs are separated by planning area further in this chapter.

27 *http://www.aer.gov.au/node/23140*

Table 6-3: Summary of NCIPAP projects and programs

Project or program	Benefit	Location	Timing
Transmission line substandard clearance compliance program	Reduced operational and safety risk and compliance with Australian Standards	Sheffield–Devonport and Wesley Vale Spur 110 kV transmission lines	2016
Transmission line substandard clearance compliance program	Reduced operational and safety risk and compliance with Australian Standards	Palmerston–Avoca 110 kV transmission line	2016
Power transformer dynamic rating program	Increased power flow capability and online condition monitoring	All 220/110 kV network transformers	2017
Transmission lines – dead end assembly rating upgrade program stage 2	Increased power flow capability	Liapootah–Chapel Street 220 kV and Hadspen–Norwood 110 kV transmission lines	2017
Transmission line lightning protection program	Minimise likelihood of flashover from lightning strike	Sheffield–Farrell, Farrell–Reece, Farrell–John Butters 220 kV and Farrell–Rosebery–Queenstown 110 kV transmission lines	2018
Chapel Street Substation 110 kV security augmentation	Installation of second 110 kV bus coupler circuit breaker to reduce impact of bus coupler fault	Chapel Street	2019
Transmission line substandard clearance compliance program	Reduced operational and safety risk and compliance with Australian Standards	Knights Road–Kermandie transmission line	2019
Weather station telemetry renewal program	Upgrade weather stations to BOM standard	State-wide (except Creek Road)	2019

6.1.1.4 Communities with poor reliability

This section provides a summary of the poor performing supply reliability communities. We focus on communities that are trending poor performing (where average performance has exceeded standards in last five years), however we also summarise communities that exceeded their reliability standards in 2014. As noted in Section 4.2.2, community reliability standards are specified in the Tasmanian Electricity Code.

In each area section we present the supply reliability communities, their supply reliability category, the measure exceeded, and our proposed actions. Where we identify specific projects for targeted reliability improvement, we elaborate on those projects in this chapter. We do not have proposals to address all poor-performing reliability communities; we target specific improvements in accordance with our network reliability strategy, detailed in Section 2.3.1. The performance of each reliability community by area is detailed in Appendix C.1.2.

Table 6-4 presents a summary of the communities with poor reliability where we have identified or are investigating a proposed solution. These communities and the proposed solutions are detailed further in this chapter. There are a number of other communities identified in this chapter that are not meeting their reliability standards; however we will continue to monitor the reliability in these communities and currently do not propose projects to improve their reliability.

Table 6-4: Summary of community supply reliability with proposed solutions

Reliability community	Category	Measure exceeded	Proposed solution	Reference
Bridport	Urban	SAIDI	Loop automation	6.4.3.7
Deloraine	Urban	SAIDI	Investigate loop automation	6.3.3.6
St Helens	Urban	SAIDI	Loop automation	6.7.3.8
Strahan	Urban	SAIDI	Automate existing stand-by generation	6.2.2.1
Zeehan	High density rural	SAIFI and SAIDI	Investigate options	6.2.3.6
Cressy–Blessington	Low density rural	SAIFI and SAIDI	Feeder rationalisation	6.4.3.8

6.1.2 Additional area information

In addition to the issues and proposed projects identified, in these sections we also detail any issues or proposed projects identified in the 2014 APRs that have been deferred or averted and the spare capacity available in the network. These sections are included for each planning area, and an overview of each is provided as follows.

6.1.2.1 Deferred or averted constraints

There are a number of constraints, or other issues, and proposed projects from the 2014 APRs that have been deferred or averted. These are no longer forecast to be required within the ten-year planning period, or their need is being re-assessed. Deferrals are predominantly due to the reduction in the load forecast, but are also due to project re-evaluation and material change in circumstances.

6.1.2.2 Availability to connect to the network

In this section we summarise the available capacity at existing substations by planning area. It is intended to provide prospective load customers introductory information on where, if they were to connect, the least network reinforcement work is required. The information provided is simply the available firm capacity at each substation; it does not consider other network limitations that may occur as a result of new load, or loads that may connect directly to the transmission network. We will work with proponents of any new load proposals to develop the optimal technical and cost-efficient solution.

We present the substations, connection voltage, existing firm capacity and maximum demand and resultant available firm capacity. These figures are given for 2014 actual demand and forecast for 2025 based on our load forecast for these substations.

6.2 West Coast planning area

6.2.1 Area network overview

The West Coast planning area covers the populated area of the West Coast council area. It extends from Strahan and Queenstown north to Savage River and Waratah. The area is characterised by mining loads, supplied from both the transmission and distribution networks, and tourism centres. Figure 6-1 presents a geographical diagram of the West Coast area.

The load in 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 alternate supply. Rosebery Substation is supplied by two transmission circuits, with other substations radially supplied. Distribution feeders in the area are supplied from four terminal substations and one zone substation. The majority of load in the area is to supply mining and minerals processing, with customers connected directly to the transmission network at three terminal substations. There is no interconnection between feeders within the distribution network.

There is a significant amount of transmission-connected generation in the West Coast area, mostly connected to the 220 kV busbar at Farrell Substation and exported to the bulk transmission network. We are aware of the proposed Granville Harbour Wind Farm, a publically announced project with an announced capacity of 99 MW.

There is no embedded generation unit over 0.5 MW, however Hydro Tasmania operates Upper Lake Margaret Power Station and Lower Lake Margaret mini hydro which connect directly to the Mt Lyell copper mine. There is approximately 0.5 MW of combined rooftop PV installed capacity in the West Coast area.

There has been no recent material investment to augment the network in the West Coast area, with the existing network generally sufficient.

6.2.2 Committed and completed projects

This section describes the material network projects that are committed (construction has begun or a firm date has been set) or have been completed in the West Coast area in the past year.

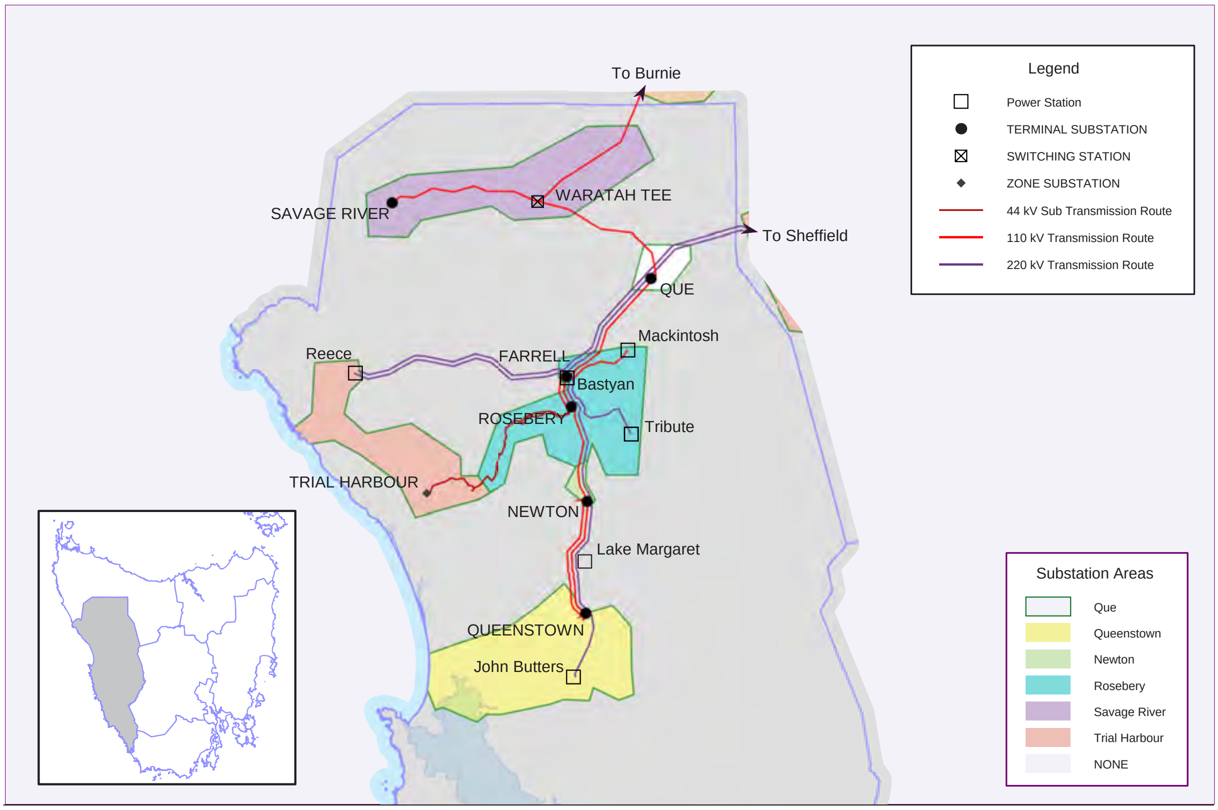


Figure 6-1: West Coast planning area network

6.2.2.1 Committed

Rosebery Substation transformer augmentation

Rosebery Substation provides supply to a transmission-connected customer and the distribution network in Rosebery and Zeehan. There are a number of mining customers supplied from this substation. The maximum demand at Rosebery Substation has exceeded the firm capacity of the transformers. In the event of the loss of one transformer, supply to some customers would be interrupted to prevent overloading of the remaining in-service transformer.

The Rosebery Substation transformer augmentation project is being implemented to provide additional capacity at Rosebery Substation. The project comprises the installation of cooling fans on the transformers, which will increase the continuous firm capacity of the substation from 30 MVA to 36 MVA. This will provide sufficient capacity to supply all customers in the event of the loss of one transformer.

This project is scheduled to be completed by the end of 2015.

Strahan distribution automation

The Strahan distribution automation project is being implemented to improve the reliability performance in Strahan. Supplied by a 35 km long single distribution feeder from Queenstown Substation, the Strahan urban reliability community has historically had poor reliability. It has failed to meet both its SAIFI and SAIDI measures in recent years.

In 2013 we installed two stand-by diesel generators in Strahan to restore supply to the community for loss of the feeder. The generators are remotely and manually operated. Reliability performance improved in 2014, however it still did not meet its performance standards. This project, further detailed in Section 6.9.4.3, will automate the operation of the generators. Upon loss of the feeder the generators will automatically start, greatly reducing the supply restoration time.

This project is scheduled to be completed in December 2015.

6.2.2.2 Completed

There were no material completed projects in the West Coast area in the last year.

6.2.3 Issues, solutions and developments

This section details the existing and forecast issues in the West Coast area. It also presents the potential and preferred solutions to alleviate these issues and any other proposed developments. Figure 6-2 presents a simplified diagram of the supply arrangement in the area. Only the relevant portion of the network is shown. The figure highlights the current and emerging constraint and asset condition issues in the area over the next ten years.

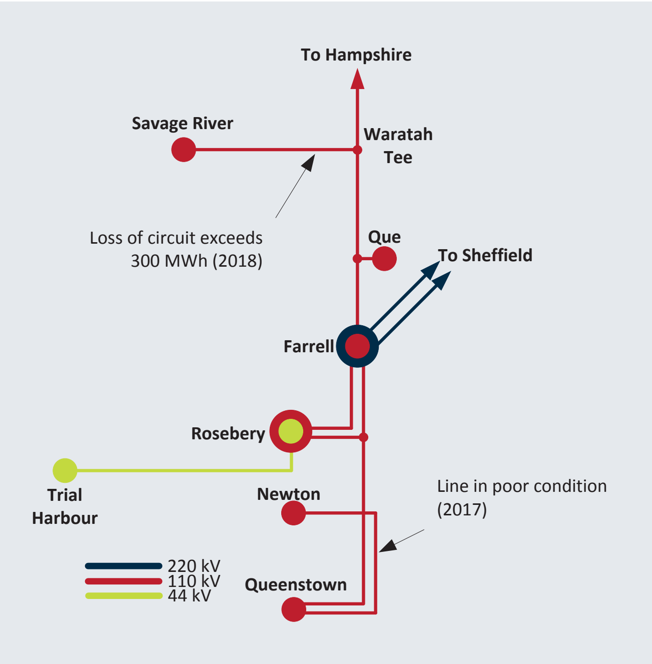


Figure 6-2: Current and emerging issues in the West Coast area

6.2.3.1 Constraints and inability to meet network performance requirements

Table 6-5 presents the area of the identified constraints and inability to meet network performance requirements, a brief description of the issue itself, the year in which the issue is forecast to materialise, the proposed solution and reference to further in the chapter where more detail is provided.

6.2.3.2 Asset replacement

Table 6-6 presents a summary of the identified asset condition issues over the next ten years, including the area and description of the issue, the proposed solution, and reference to further in the chapter where more information is provided.

6.2.3.3 Network capability improvement parameter action plan

There are no NCIPAP projects specific to the West Coast area in the 2014–19 transmission regulatory period. However there are other programs which include substations the West Coast area, listed in Section 6.9.2.3.

6.2.3.4 Communities with poor reliability

Table 6-7 summarises the communities with poor reliability in the West Coast area. There are two communities with trending poor reliability (5-year average).

As detailed in Section 6.2.2.1, we have installed stand-by generators in Strahan to improve reliability. Further, we are currently implementing a project to automate their operation to improve supply restoration times and further reduce the impact of faults. We are currently investigating options to improve the reliability at Zeehan, which may include a similar solution to the stand-by generators at Strahan.

Table 6-5: West Coast area constraints and inability to meet network performance requirements

Area of issue	Issue	Forecast year	Proposed solution (year)	Reference
Farrell–Que–Savage River–Hampshire 110 kV circuit	Above the 300 MWh unserved energy requirement of the ESI Regulations (constraint exists now, but with customer agreement we have an exemption until 2018)	2018	Re-assess options just prior to exemption expiry	6.2.4.3

Table 6-6: West Coast area asset replacements

Area of issue	Issue	Proposed solution (year)	Reference
Queenstown–Newton 110 kV transmission line	Transmission line condition	Decommission transmission line and reconfigure supply to Newton Substation (2017)	6.2.3.5

Table 6-7: West Coast area community supply reliability

Reliability community	Category	Measure exceeded	Proposed solution	Reference
Trending poor performing communities				
Strahan	Urban	SAIDI	Automate existing stand-by generation	6.2.2.1
Zeehan	High density rural	SAIFI and SAIDI	Investigate options	6.2.3.6

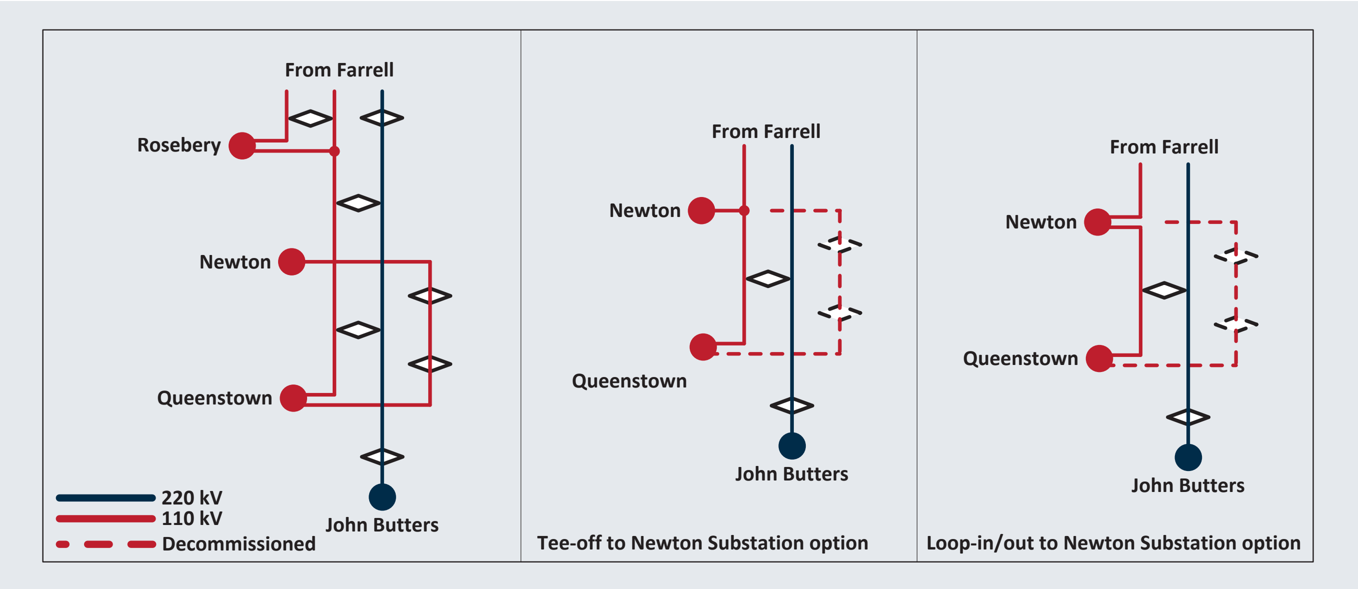


Figure 6-3: Newton Substation existing supply arrangement (left) and potential solutions (centre and right)

6.2.3.5 Queenstown–Newton 110 kV transmission line condition

Issue overview

The single-circuit radial 110 kV transmission line between Queenstown and Newton substations, commissioned in 1936, is in poor condition and would require extensive refurbishment to extend its service life. The tower members, bolts and foundations are all in poor condition and present a risk of failure in particularly severe weather conditions.

Proposed solution

We have assessed two options to provide supply from the Farrell–Rosebery–Queenstown 110 kV transmission circuit which runs adjacent to Newton Substation. Both options allow the decommissioning the Queenstown–Newton 110 kV transmission line, as options to maintain it in service are prohibitively expensive.

The options considered to address this issue were to decommission the affected line and provide a:

- tee-off from adjacent line to Newton Substation; or
- loop-in-and-out from adjacent line to Newton Substation.

The most economic option to address the identified constraint is to provide a tee-off arrangement. This option involves decommissioning the Queenstown–Newton 110 kV transmission line and providing a connection to the existing Farrell–Rosebery–Queenstown 110 kV transmission circuit to create a Farrell–Rosebery–Newton–Queenstown 110 kV transmission circuit.

The estimated cost of the project is $4.5 million and is proposed for implementation by June 2017.

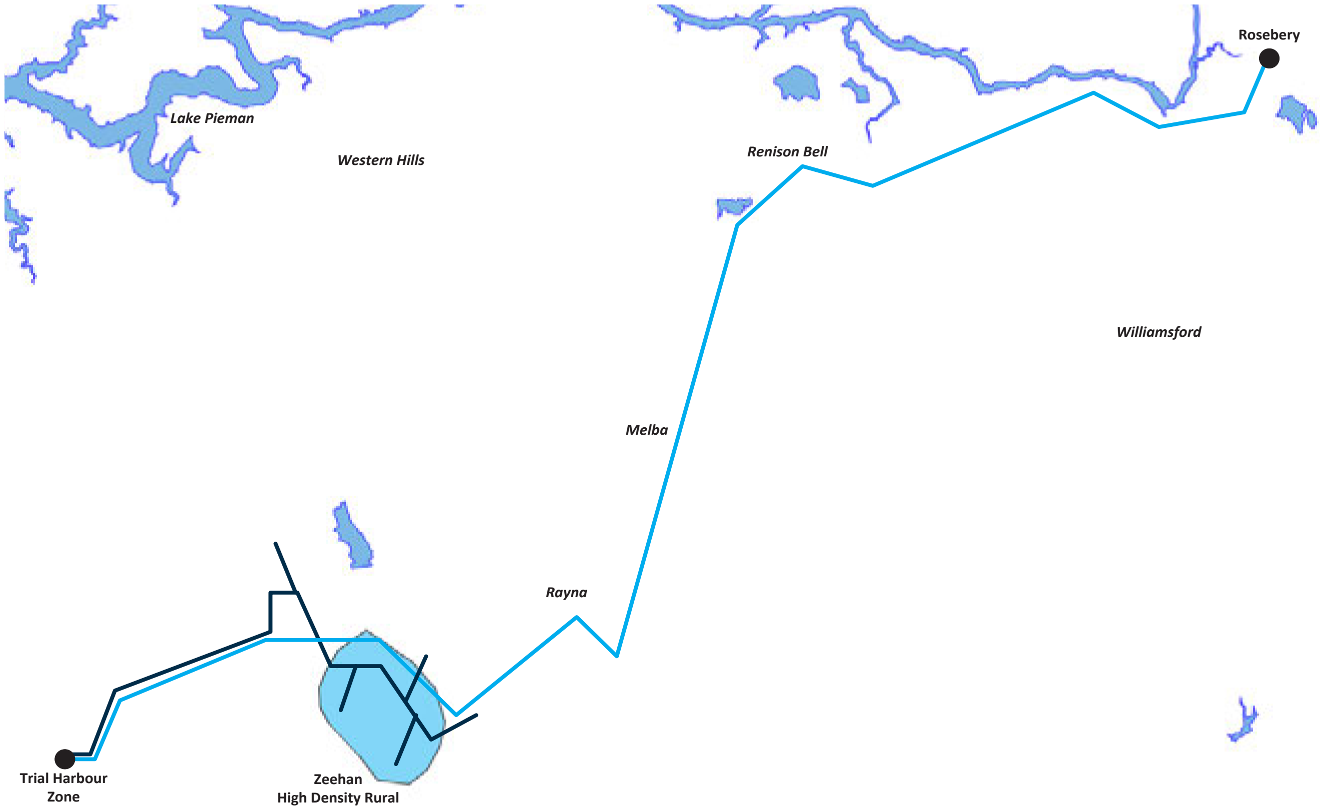


Figure 6-4: Zeehan high density rural reliability community

6.2.3.6 Zeehan reliability community

Issue overview

The Zeehan high density rural reliability community is supplied from a single 22 kV feeder from Trial Harbour Zone Substation, which itself is supplied via a single 44 kV sub-transmission feeder from Rosebery Substation. The Rosebery–Trial Harbour 44 kV sub-transmission feeder is approximately 35 km in length. Figure 6-4 presents the supply arrangement of the Zeehan reliability community.

Zeehan has had deteriorating reliability performance in recent years. It has not met the SAIFI or SAIDI standards in the last two years.

Potential solutions

We have identified three potential solutions to improve the reliability performance in Zeehan, as follows:

- distance-to-fault relay – installed on the 44 kV sub-transmission feeder at Rosebery Substation, this will reduce supply restoration times by allowing us to direct crews to the approximate location of a fault rather than needing to patrol the entire length of the line;
- remote load-break switches – stationed along the 44 kV feeder, these devices provide indication to the location of the fault, reducing restoration times, and will enable the feeder to be backed up by the second 44 kV feeder from Rosebery Substation which runs parallel to the feeder supplying Zeehan for the first 10 km from Rosebery Substation (if the fault occurs in this section of feeder); and
- stand-by generation – we will continue to monitor the performance of the generators installed at Strahan to assess whether a similar solution can be implemented at Zeehan;

We are investigating these three options and propose to implement the one, or a combination of, which is the most economic and provides the most benefit to Zeehan reliability community.

6.2.4 Deferred or averted issues in the West Coast planning area

6.2.4.1 Queenstown and Newton substations transmission security

Section 6.3.6.2 of Transend Networks' 2014 APR identified an existing issue of transmission security to Queenstown and Newton substations. Due to the load profile at the substations, it was expected that the loss of the Farrell–Rosebery–Queenstown 110 kV transmission circuit, supplying both substations, would result more than 300 MWh of unserved energy. It was proposed to establish a second 110 kV injection point to Queenstown Substation, via a 220/110 kV network transformer supplied from the Farrell–John Butters 220 kV transmission circuit.

Due to a major customer, taking the bulk of supply, entering care and maintenance mode, this issue and the proposed solutions have been deferred indefinitely. The asset condition issue, associated with this original proposal, is still required and is detailed in Section 6.2.3.5 of this APR.

6.2.4.2 Farrell Substation 220 kV security upgrade

We have identified that failure of the 220 kV bus coupler circuit breaker at Farrell Substation would result in loss of supply to the West Coast area and, during high generation in the West Coast area, may lead to power system instability and partial state-wide blackout. The preferred solution identified in Section 6.3.6.4 of Transend Networks' 2014 APR was to install a second bus coupler in series to create a double-circuit breaker arrangement.

Due to reduced demand in the West Coast area, as a result of reduced mining load, we do not expect this project will be required until after 2025. Preventing loss of supply to load in the West Coast area was the main economic benefit of this proposal; with reduced demand, there is reduced benefit in implementing this proposal. We have therefore deferred proposals for any remedial works in this area. We will continue to monitor this issue in future years.

6.2.4.3 Newton Substation supply transformer security

Section 6.3.6.3 of Transend Networks' 2014 APR identified an existing issue of the transformer security at Newton Substation. Due to the single transformer supply and load profile, it was expected loss of the transformer would result in more than 300 MWh of unserved energy. The solution identified was to utilise our existing fleet of mobile generators to provide backup supply in the event of loss of the transformer and to consult with the major customer supplied from the substation on transformer security.

This customer made a public announcement in July 2014 that it expected to close by the end of 2015 due to the lack of mineable reserves. As a result of this announcement, we have not proceeded with consultation and will not proceed further investigating existing transformer security for Newton Substation unless circumstances materially change.

6.2.4.4 Savage River and Que substations security

The Farrell–Que–Savage River–Hampshire 110 kV transmission circuit supplies a distribution load at Savage River Substation and transmission directly-connected customers at both Savage River and Que substations.

A contingency event occurring on this circuit between the Waratah Tee and Savage River Substation could result in more than 300 MWh of unserved energy at Savage River Substation, which does not meet the performance requirements of clause 5(1)(a)(iv) of the ESI Regulations. This situation applies now, and is not dependent on load growth.

We have an agreement under the ESI Regulations with the transmission customers supplied from Savage River Substation that there is insufficient benefit to undertake a network augmentation solution to address this issue. We are thus exempt under clause 8(4) of the ESI regulations, for the period 1 June 2013 until 30 June 2018, from planning the network to meet the requirement that no more than 300 MWh of unserved energy could occur at Savage River Substation following the loss of the Farrell–Que–Savage River–Hampshire 110 kV transmission circuit.

The exemption will cease from the date of expiry (June 2018), 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, but welcome affected customers to contact us if they now consider remedial action will have sufficient benefit.

6.2.5 Availability to connect in the network

Table 6-8 presents the spare capacity available at substations in the West Coast area. Newton Substation is effectively two single transformer substations, therefore inherently operates non-firm. For Newton and Que (also single transformer) substations, the available capacity given here is for the transformer capacity rather than the firm capacity. The actual maximum demand at Que, Rosebery and Savage River substations is not shown due to confidentiality, as all or the majority of load is taken by customers directly connected to the transmission network. However we welcome new connection enquiries for these substations, as we do for all others.

Table 6-8: West Coast area substation capacity availability

Substation	Connection voltage (kV)	Firm capacity	2014 (MVA)		2025 (MVA)	
			Actual MD	Available capacity	Forecast MD	Available capacity
Newton	11	15	5.5	9.5	5.5	9.5
	22	22.5	4.1	18.4	4.1	18.4
Que	22	50				
Queenstown	22	25	5.6	19.4	7.5	17.5
Rosebery	44	36				
Savage River	22	22.5				
Trial Harbour	22	20	3.6	16.4	3.4	16.6

6.3 North West planning area

6.3.1 Area network overview

The North West planning area covers the north-west geographic area of Tasmania. It extends from Port Sorell to Smithton and the far north-west, including the urban area of Burnie–Devonport, and inland to Deloraine, Sheffield and Hampshire. Most load in the area is residential, commercial, and small to medium industries. There are two customers connected directly to the transmission network. Figure 6-5 presents a geographical diagram of the North West area.

The area is supplied from the bulk 220 kV transmission network at Sheffield Substation. Distribution feeders in the North West area are supplied from eight terminal substations. Emu Bay and Wesley Vale substations are lightly loaded as they were built to serve paper manufacturing industries that have since closed. The distribution network in the area is predominately 22 kV, with pockets of 11 kV in Burnie CBD and to a single customer near Wesley Vale.

There is a significant amount of transmission-connected generation in the North West area. The majority of it is part of the Mersey-Forth power scheme and is connected to Sheffield Substation to provide power into the bulk transmission network. Bluff Point and Studland Bay wind farms connect to Smithton Substation at 110 kV. There are five embedded generators over 0.5 MW, including a 7.9 MW cogeneration plant in Ulverstone which can also provide supply into the network. There is approximately 15.0 MW of combined rooftop PV installed capacity in the North West area.

We haven't undertaken any significant development projects in the area in recent years. Demand in the North West area has been such that we have been able to maintain the network in its current arrangement.

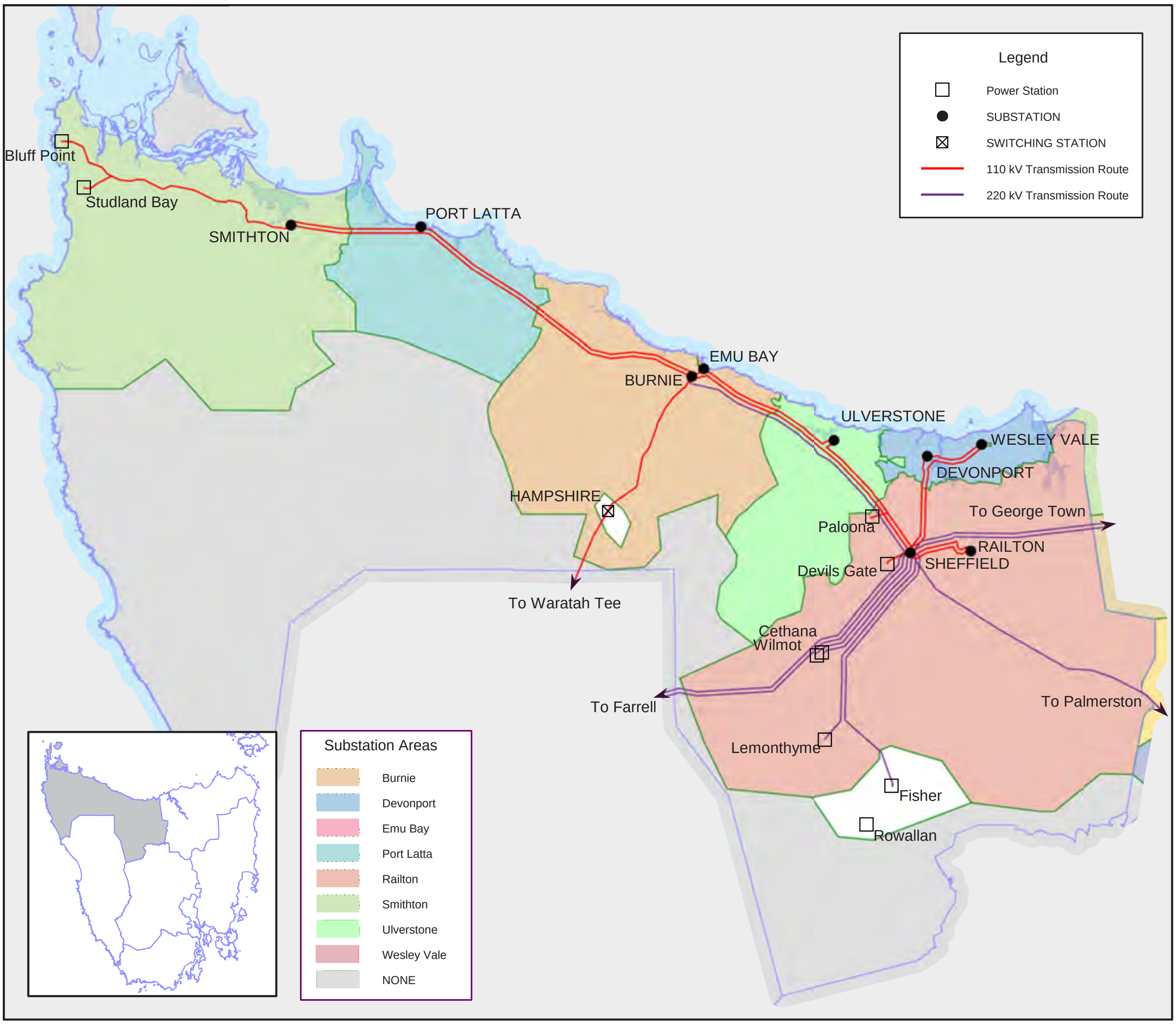


Figure 6-5: North West planning area network

6.3.2 Committed and completed projects

This section describes the material network projects that are committed (construction has begun or a firm date has been set) or have been completed in the area in the past year.

6.3.2.1 Committed

Sheffield Substation 220 kV K and L bay upgrades

The rating of the Sheffield–George Town 220 kV transmission circuits is limited by equipment within the bays at Sheffield Substation (bays K and L). This constrains the amount of power than can be transferred through this corridor. This project involves the replacement of selected assets within the K and L bays at Sheffield Substation. This will increase the rating of the Sheffield–George Town 220 kV transmission circuits, allowing more power to be transferred through this corridor. This project forms part of the NCIPAP projects in our 2014–19 transmission regulatory period.

This project is scheduled to be completed by June 2016.

6.3.2.2 Completed

Burnie Substation 110 kV redevelopment

This project comprised the replacement of the 110 kV circuit breakers, current transformers, protection and control equipment, and the installation of voltage transformers at Burnie Substation.

The substation redevelopment was driven by a need to replace assets in poor condition and susceptible to failure. The aim was to improve the reliability of electricity supply to customers supplied from Burnie Substation.

The project was completed in October 2014.

6.3.3 Issues, solutions and developments

This section details the existing and forecast issues in the North West area. It also presents the potential and preferred solutions to alleviate these issues and any other proposed developments. Figure 6-6 presents a simplified diagram of the supply arrangement in the area. Only the relevant portion of the network is shown. The figure highlights the current and emerging constraints and network development issues in the area over the next ten years.

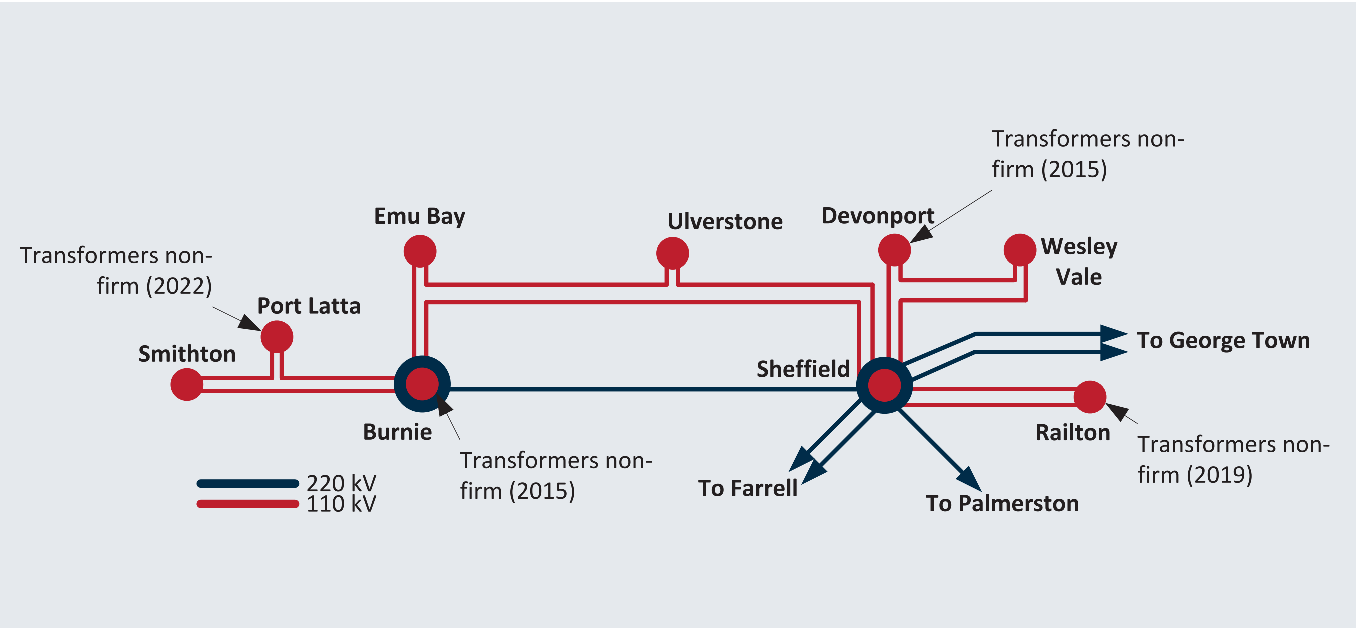


Figure 6-6: Current and emerging issues in the North West area

Table 6-9: North West area constraints and inability to meet network performance requirements

Area of issue	Issue	Forecast year	Proposed solution	Reference
Burnie Substation	Supply transformers non-firm	2015	Manage within short term ratings	6.3.3.5
Devonport Substation	Supply transformers non-firm	2015		
Railton Substation	Supply transformers non-firm	2019		
Port Latta Substation	Supply transformers non-firm	2022		

Table 6-10: North West area NCIPAP projects

Project	Benefit	Location	Cost ($000)	Timing
Transmission line substandard clearance compliance program	Reduced operational and safety risk and compliance with Australian Standards	Sheffield–Devonport and Wesley Vale Spur 110 kV transmission lines	279	August 2016

Table 6-11: North West area community supply reliability

Reliability community	Category	Measure exceeded	Proposed solution	Reference
Trending poor performing communities				
Deloraine	Urban	SAIDI	Investigate loop automation	6.3.3.6
Turners Beach	Urban	SAIDI	Monitor	N/A
Meander Valley Rural	High density rural	SAIDI	Under investigation	
Burnie Rural	Low density rural	SAIDI	Under investigation	
North Coast	Low density rural	SAIDI	Monitor	
North West	Low density rural	SAIDI	Monitor	
Railton Rural	Low density rural	SAIDI	Under investigation	
New poor performing communities in 2014				
Latrobe	Urban	SAIDI	Monitor	N/A

6.3.3.1 Constraints and inability to meet network performance requirements

Table 6-9 presents the area of the identified constraints and inability to meet the network performance requirements, a brief description of the issue itself, the year in which the issue is forecast to materialise, the proposed solution and reference to further in the chapter where more detail is provided.

6.3.3.2 Asset replacement

There are no material asset replacement projects identified for the North West area in the 2015 APR for the next ten years.

6.3.3.3 Network capability improvement parameter action plan

Table 6-10 summarises the remaining NCIPAP projects specific to the North West area to be completed in by the end of the 2014–19 transmission regulatory period. It lists the benefits, cost and timing of each project. There are other programs which include substations the North West area, listed in Section 6.9.2.3.

6.3.3.4 Communities with poor reliability

Table 6-11 summarises the communities with poor reliability in the North West area. There are seven communities with trending poor reliability (5-year average) plus the Latrobe community which is a newly poorly performing community in 2014.

The seven trending poorly performing communities, although the 5-year average is poor, have only not met reliability standards in the last two years. This is primarily due to major event days, where large storm events caused widespread interruptions to supply. Four of these six communities had more than 50 per cent contribution to SAIDI from major event days in 2014.

The primary contributing factors to poor reliability in the Latrobe community in 2014 was from major event days. Outages on these days contributed more than 50 per cent to the SAIDI measure. Otherwise this community has historically met its reliability standards and we expect that it will meet its reliability standards in 2015.

We propose a project to bring reliability up to standard in the Deloraine community. Further, we are investigating the causes of poor performance at an additional three poor performing communities in the North West area as part of our investigation into the seven worst performing feeders in the state.

For the remaining communities, we currently do not have propose any augmentation projects to improve reliability; however we will continue to implement operational measures as part of targeted reliability improvement programs. We will continue to monitor reliability performance and investigate solutions if performance deteriorates.

6.3.3.5 Substations exceeding firm capacity

Issue summary

There are four substations in the North West area forecast to become non-firm within the next 10 years. However the demand at all four is forecast to remain within the four-hour short-term rating of the transformers beyond 2025.

Table 6-12 presents these substations, their firm capacity, and forecast year of issue. The amount of load reduction or generation support required to defer the issues is not presented as the demand can be managed within the short-term firm rating of the transformers.

Table 6-12: North West area substations exceeding firm capacity

Substation	Firm capacity (MVA)		Year forecast non-firm	
	Continuous	Short-term	Continuous	Short-term
Burnie	60	72	2015	2025+
Devonport	60	72	2015	2025+
Railton	50	57	2019	2025+
Port Latta	22.5	27	2022	2025+

Potential solutions

In the short-to-medium term, loading at these substations will be managed within the short-term rating of the transformers and by load transfers within the existing network to neighbouring substations.

Aside from these operational measures, options we will consider for longer-term solutions are listed below. However these are not forecast to be required prior to 2025.

- demand-side management and generation support;
- transformer replacement with larger units; and
- the establishment of a new substation.

6.3.3.6 Deloraine reliability community

Issue overview

The Deloraine urban reliability community contains Deloraine township. It is supplied from Railton Substation by two feeders. The respective route length to Deloraine is approximately 30 and 35 km. Figure 6-7 presents the supply arrangement of the Deloraine reliability community. The community has had deteriorating reliability performance in recent years. It does not currently meet its SAIFI standard and has not met its SAIDI standard in the last two years.

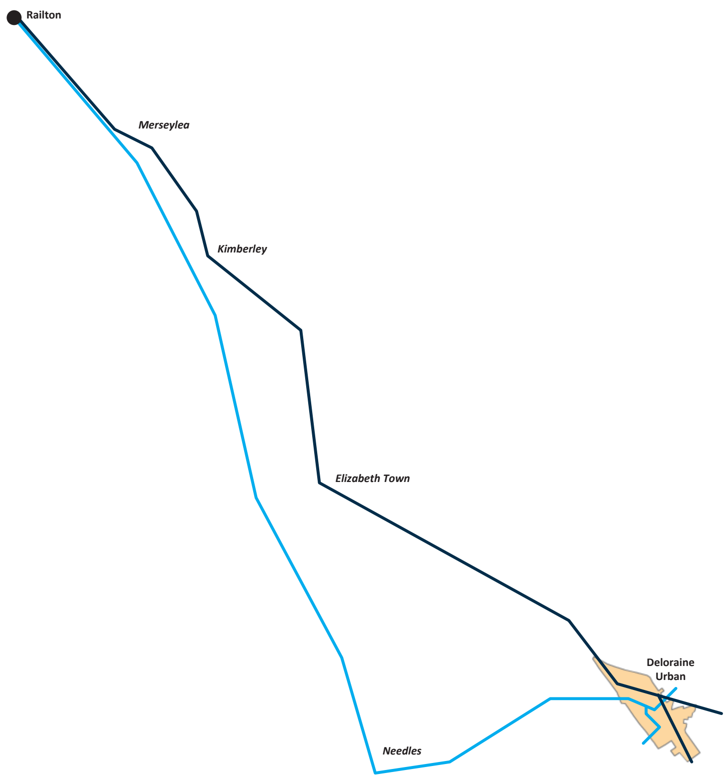


Figure 6-7: Deloraine urban reliability community

Potential solutions

We have identified reinforcement of supply to Deloraine as the likely solution to improve the reliability performance in this community. The reinforcement will come from Railton or Palmerston substations, or both, and in the form of one of more of the following:

- establishment of a new feeder to Deloraine;
- capacity upgrade of the existing feeder(s); and
- voltage improvement, allowing more power transfer, through installation of voltage regulators or capacitor banks.

The main benefit from implementing one or more of these solutions is the increase in transfer capability between feeders. This will allow restoration of supply following an outage. Coupled with the installation of reclosers and other equipment, this will allow the restoration to be performed remotely – significantly reducing supply restoration time.

6.3.4 Deferred or averted issues in the North West planning area

6.3.4.1 Conversion of Wesley Vale Substation from 11 kV to 22 kV

Both the 2014 APR of Aurora Energy (Section 11.2) and Transend Networks (Section 6.4.6.1) proposed the conversion of Wesley Vale Substation from an 11 kV to 22 kV supply point. The utilisation of this substation has been low since the paper mill, which it was built to supply, closed. This conversion would allow permanent load transfers away from Devonport and Railton substations to Wesley Vale Substation. This project was driven by supply reliability, power quality and substation loading issues.

We are currently re-analysing this proposal. This includes assessment of the cost of the substation conversion and the benefits of improved supply reliability to surrounding communities. In light of this, we have not included the proposal in this APR. However, following the outcomes of the analysis, we may again propose a project to convert Wesley Vale Substation to a 22 kV supply point.

6.3.4.2 Load transfer between Burnie and Emu Bay substations

Section 16.2.2 of Aurora Energy's 2014 APR proposed a development plan to transfer load from Burnie Substation (network operated at 22 kV) to Emu Bay Substation (network operated at 11 kV). It identified Burnie Substation would not meet its performance requirements in relation to unserved energy from 2024. The proposed solution involved the installation of 22/11 kV transformation within the distribution network to allow load to be transferred away from Burnie Substation to Emu Bay Substation.

Due to reduction in forecasted load at Burnie Substation, the network performance requirement issue at Burnie Substation has been deferred past 2025. As a result, we have deferred plans to undertake works associated with this proposal.

6.3.5 Availability to connect in the network

Table 6-13 presents the spare capacity available at substations in the North West area. Emu Bay and Wesley Vale substations can be converted to 22 kV with minor substation augmentation. Converting Wesley Vale, primarily, and Emu Bay substations to 22 kV operation is part our long term supply strategy to the North West area.

Table 6-13: North West area substation capacity availability

Substation	Connection voltage (kV)	Firm capacity (MVA)	2014 (MVA)		2025 (MVA)	
			Actual MD	Available capacity	Forecast MD	Available capacity
Burnie	22	60	57.0	3.0	71.4	0
Devonport	22	60	59.1	0.9	70.6	0
Emu Bay	11	38	10.0	28.0	18.1	19.9
Port Latta	22	22.5	20.5	2.0	23.8	0
Railton	22	50	46.1	3.9	57.0	0
Smithton	22	35	22.5	12.5	32.2	2.8
Ulverstone	22	45	27.3	17.7	31.7	13.3
Wesley Vale	11	25	0.4	24.6	0.5	24.5

6.4 Northern planning area

6.4.1 Area network overview

The Northern planning area covers the North and North East of Tasmania. It is centred around Launceston and the Tamar area, and extends to Poatina, Deloraine, George Town and the North East. The load profile in the 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 of Tasmania. Figure 6-8 presents a geographical diagram of the Northern area.

The area is supplied from the bulk 220 kV transmission network at Hadspen, George Town and Palmerston (near Poatina) substations. The connection from Hadspen Substation provides a 110 kV supply into Launceston and the North East, and Palmerton Substation provides supply in the northern midlands. George Town Substation predominantly supplies the industrial load in the area at both 220 kV and 110 kV, and it provides the connection point for the Basslink undersea cable to mainland Australia. The distribution network in the area is supplied from nine terminal substations and operates entirely at 22 kV. There are two major energy users and one other transmission connected customer in the Northern area. All three are supplied from George Town Substation.

There are three major transmission-connected generation sites in the Northern area: Poatina (300 MW – connected to Palmerston Substation), Tamar Valley (383 MW – connected to George Town Substation) and Musselroe (168 MW – connected to Derby Substation). These provide power into the bulk transmission network, although Musselroe Wind Farm is remotely connected. We are aware of the proposed Low Head Wind Farm, a publically announced project with an announced capacity of 30 MW.

Within the distribution network, there are four embedded generators over 0.5 MW. There is approximately 16.6 MW of combined rooftop PV installed capacity in the Northern area.

We have strengthened the network around Launceston in recent years, with the upgrade work completed in 2012. This has improved the reliability and security of supply to all customers in the area and relieved significant constraints at a number of supply points. This included development of the transmission and distribution networks and two new substations around Launceston.

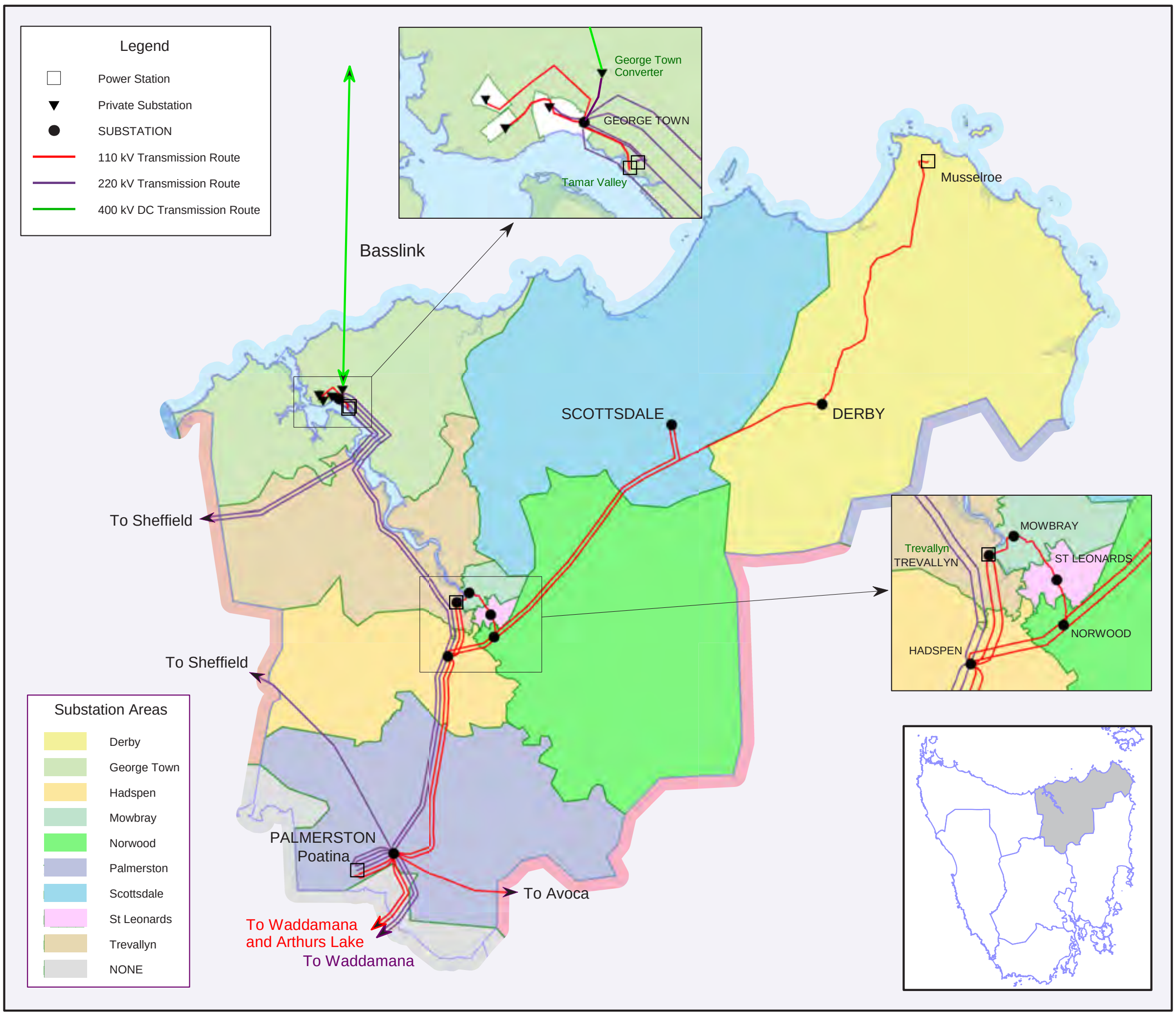


Figure 6-8: Northern planning area network

6.4.2 Committed and completed projects

This section describes the material network projects that are committed (construction has begun or a firm date has been set) or have been completed in the area in the past year.

6.4.2.1 Committed

George Town Substation 110 kV redevelopment

This project involves replacement of the 110 kV circuit breakers, current transformers, voltage transformers, disconnectors, and protection and control equipment at George Town Substation.

The substation redevelopment was driven by a need to replace assets that were in poor condition and susceptible to failure. The aim is to improve the reliability, security and performance of electricity supply to customers supplied from George Town Substation.

This project is scheduled for completion in August 2015.

Transmission line dead-end assembly rating upgrade (George Town–Comalco 220 kV transmission line)

In 2012 we identified a number of conductor dead-end assemblies had been installed on 220 kV transmission lines that imposed rating limits on the circuits. These circuits have been subsequently de-rated, which has imposed transmission constraints on these critical circuits. This project involves the upgrade of the assemblies on George Town–Comalco 220 kV transmission line to remove the rating limitation.

This project forms part of the NCIPAP projects in our 2014–19 transmission regulatory period.

This project is scheduled to be completed in March 2016.

6.4.2.2 Completed

George Town Automatic Voltage Control Scheme

This project involved the redesign of the George Town Automatic Voltage Control Scheme. The scheme was implemented to reduce the amount of manual intervention required to manage the voltage at the George Town Substation 220 kV busbar following the commissioning of Basslink. The redesign was required following the change to the normal operating patterns of local generators and the increased presence of non-synchronous generation (wind farms) to the network. This project formed part of the NCIPAP projects in our 2014–19 transmission regulatory period.

This project was completed in October 2014.

6.4.3 Issues, solutions and developments

This section details the existing and forecast issues in the Northern area. It also presents the potential and preferred solutions to alleviate these issues and any other proposed developments. Figure 6-9 presents a simplified diagram of the supply arrangement in the area. Only the relevant portion of the network is shown. The figure highlights the current and emerging constraints and asset condition issues in the area over the next ten years.

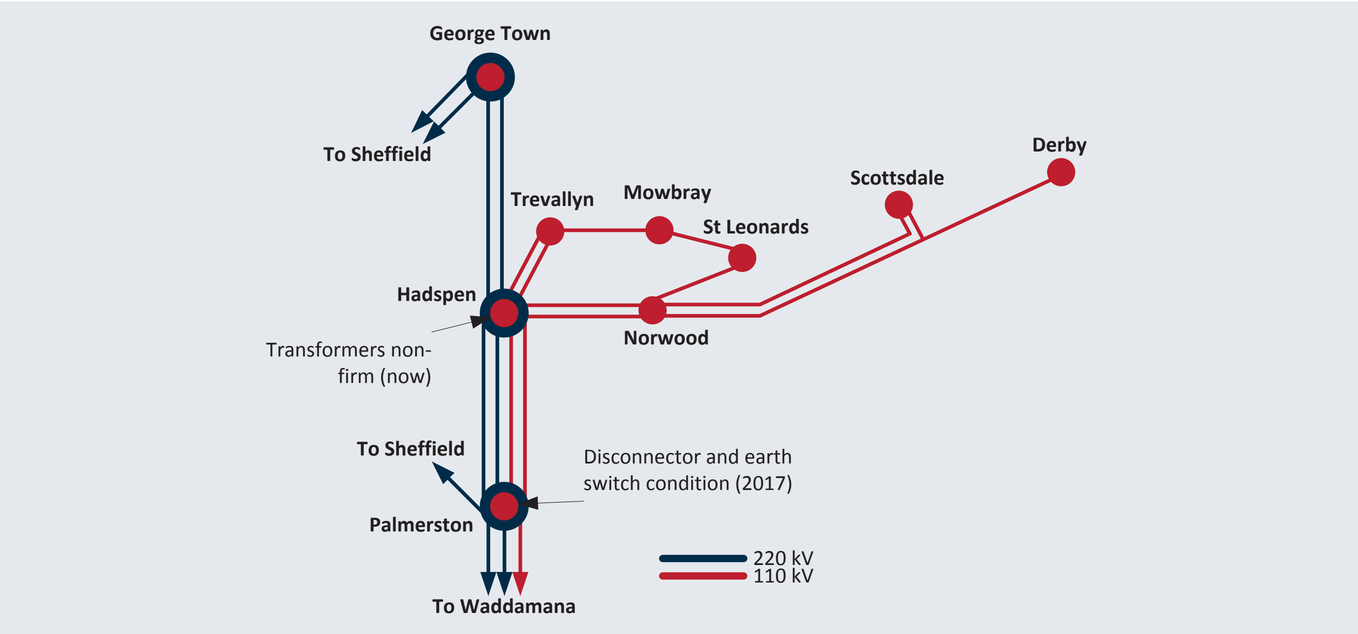


Figure 6-9: Current and emerging issues in the Northern area

Table 6-14: Northern area constraints and inability to meet network performance requirements

Area of issue	Issue	Forecast year	Proposed solution (year)	Reference
Hadspen Substation	Supply transformers non-firm	Current	Manage within short term rating	6.4.3.5

Table 6-15: Northern area asset condition issues

Area of issue	Issue	Proposed solution (year)	Reference
Palmerston Substation	Condition of disconnectors and earth switches	Asset renewal (2017)	6.4.3.6

Table 6-16: Northern area community supply reliability

Reliability community	Category	Measure exceeded	Proposed solution	Reference
Trending poor performing communities				
Bridport	Urban	SAIDI	Loop automation	6.4.3.7
George Town	Urban	SAIDI	Monitor	N/A
Tamar South	Urban	SAIFI and SAIDI	Monitor	N/A
Mid-Tamar (Exeter etc)	High density rural	SAIFI and SAIDI	Monitor	N/A
Winnaleah	High density rural	SAIDI	Monitor	N/A
Cressy–Blessington	Low density rural	SAIFI and SAIDI	Feeder rationalisation	6.4.3.8
Far North East Rural	Low density rural	SAIDI	Monitor	N/A
North East Rural	Low density rural	SAIDI	Under investigation	N/A
New poor performing communities in 2014				
Hadspen	Urban	SAIDI	Monitor	N/A
Perth	Urban	SAIDI	Monitor	N/A
Scottsdale	Urban	SAIDI	Under investigation	N/A
Derby–Ringarooma	High density rural	SAIDI	Monitor	N/A
Dilston–Windemere	High density rural	SAIFI and SAIDI	Monitor	N/A
Longford Rural	High density rural	SAIDI	Under investigation	N/A
Scottsdale Rural	High density rural	SAIDI	Under investigation	N/A
Tamar East Rural	Low density rural	SAIDI	Monitor	N/A
Tamar West	Low density rural	SAIDI	Monitor	N/A

6.4.3.1 Constraints and inability to meet network performance requirements

Table 6-14 presents the area of the identified constraints and inability to meet the network performance requirements, a brief description of the issue itself, the year in which the issue is forecast to materialise, the proposed solution and reference to further in the chapter where more detail is provided.

6.4.3.2 Asset replacement

Table 6-15 presents a summary of the identified asset condition issues over the next ten years, including the area and description of the issue, the proposed solution, and reference to further in the chapter where more information is provided.

6.4.3.3 Network capability improvement parameter action plan

There are no further NCIPAP projects to be completed in the Northern area within the 2014–19 transmission regulatory period. However there are other programs which include substations the Northern area, listed in Section 6.9.2.3.

6.4.3.4 Communities with poor reliability

Table 6-16 summarises the communities with poor reliability in the Northern area. There are eight communities with trending poor reliability (5-year average) and nine communities which are newly poor performing communities in 2014.

In the Tamar South, Winnaleah and Far North East Rural communities, the average poor performance is predominately due the high impact of major event days in recent years. George Town, despite having average poor performance, has actually met its reliability standards in the past three years. The Bridport, Cressy-Blessington, Mid-Tamar (Exeter etc) and North East Rural communities have generally experienced marginal and poor reliability performance.

The primary contributing factor to the newly poor performing communities in 2014 was major event days, where large storm events caused widespread interruptions to supply. Seven of these nine communities had more than 50 per cent contribution to SAIDI from major event days, and another more than 40 per cent. The poor reliability at Hadspen was largely due to planned work, which contributed 50 per cent to SAIDI. We expect that these communities will meet their standards in 2015.

We propose projects to bring reliability up to standard in two communities in the Northern area; at Bridport and Cressy-Blessington. Further, we are investigating the causes of poor performance at an additional four communities in the Northern area as part of our investigation into the seven worst performing feeders in the state.

For the remaining communities, we currently do not propose any augmentation projects to improve reliability; however we will continue to implement operational measures as part of targeted reliability improvement programs. We will continue to monitor reliability performance and investigate solutions if performance deteriorates.

6.4.3.5 Hadspen Substation transformer capacity

Issue overview

Hadspen Substation comprises two 50 MVA transformers, with a short term rating of 60 MVA. The maximum demand at Hadspen Substation in 2014 was 50.6 MVA, which exceeded the continuous firm rating of the substation. We forecast the maximum demand will exceed the four-hour short-term rating from winter 2024.

Limitation deferral

Table 6-17 presents the requirements to defer the identified non-firm issue at Hadspen Substation. The table presents the reduction in the forecasted load, or amount of generation support, required to defer the limitation by either one (to 2025) or five (to 2029) years. The reduction detailed is to maintain the load below 60 MVA, the short-term firm capacity of the transformers.

Table 6-17: Hadspen Substation limitation deferral

Deferral period	Maximum demand (2024) (MVA)	Generation support or reduction in forecasted load (MVA)
One year	60.8	1.6
Five years		5.6

Load transfer is available away from Hadspen Substation to Norwood, Palmerston, Trevallyn and Railton substations.

Potential solutions

The identified load transfer capabilities from Hadspen Substation may exceed 40 MW, depending on network loading. These transfer capabilities and utilisation of the transformer short-term rating are sufficient to delay in capital investment related to capacity issue beyond 2025.

6.4.3.6 Palmerston Substation disconnector and earth switch renewal

We have identified that our population of Stanger type DR1 and DR2 disconnectors need to be replaced. These disconnectors impact on transmission network reliability and availability, are unreliable, and are approaching the end of their service lives with spare parts no longer available. In addition, we propose to replace selected transmission line protection schemes.

As part of our renewal program for these disconnector types, we propose a project at Palmerston Substation to replace the 23 type DR1 and DR2 disconnectors, the associated earth switches, and the protection on the three Poatina–Palmerston 220 kV transmission lines. This will reduce the risk of failure of equipment due to poor condition, and increase transmission circuit availability.

The estimated cost of this project is $7.4 million and is scheduled to be implemented by June 2017.

6.4.3.7 Bridport reliability community

Issue overview

The Bridport urban reliability community is the small area around Bridport township. It is supplied via a single 22 kV overhead feeder from Scottsdale Substation. The feeder to Bridport is approximately 30 km long, and traverses through a low density rural community, with lower reliability standards, before supplying Bridport which is an urban community. The feeder into Bridport continues west and backup supply is available to this feeder and Bridport from a second feeder from Scottsdale Substation and from George Town Substation. Figure 6-10 presents the supply arrangement of the Bridport urban reliability community.

Supply reliability in Bridport has deteriorated in recent years, and the community has consistently not met its SAIDI standard.

Proposed solution

We propose to implement a loop automation scheme to improve the reliability to Bridport. This would allow supply to be automatically restored (less than one minute) following a sustained interruption to supply. Our proposal is to install a new recloser at the edge of the community on the primary feeder from Scottsdale Substation. For sustained faults within Bridport, this recloser will open and the normally-open point with the alternate feeder from Scottsdale Substation will close, restoring supply to Bridport.

The estimated cost of the loop automation scheme is $60,000 and it is scheduled to be implemented in 2016.

6.4.3.8 Cressy–Blessington reliability community

Issue overview

The Cressy–Blessington low density rural reliability community covers a large area including Cressy, Blessington and other townships such as Poatina and Epping Forrest. It is predominately supplied by the three 22 kV feeders from Palmerston Substation and one feeder from Norwood Substation. Figure 6-11 presents the supply arrangement of the Cressy–Blessington reliability community.

Cressy-Blessington is one of the worst performing reliability communities in the state, and the feeder from Palmerston Substation to Cressy and Epping Forest (feeder 3) is the worst performing feeder in the state in terms of reliability. This is due to the large exposure area and large amount of connected customer capacity relative to other low density rural communities.

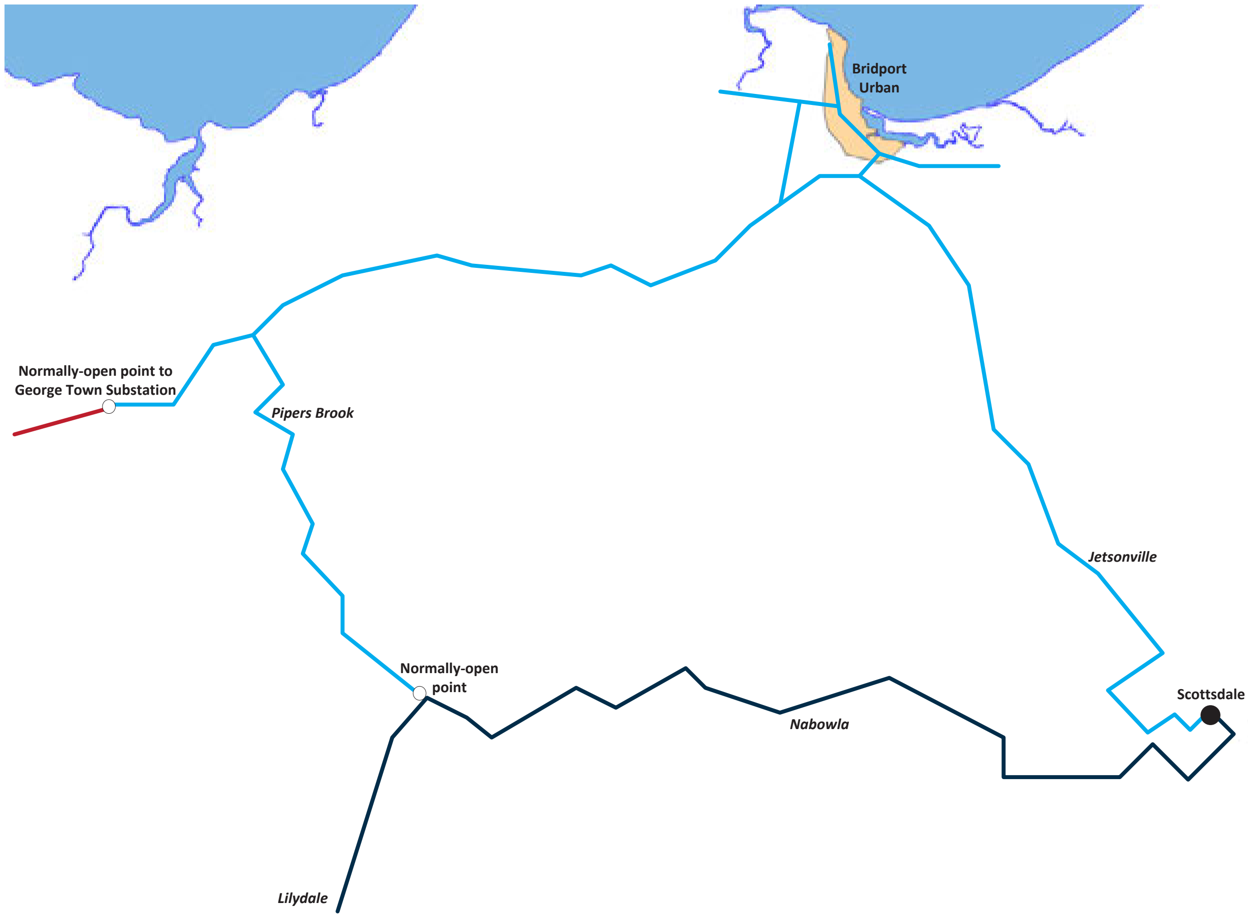


Figure 6-10: Bridport urban reliability community

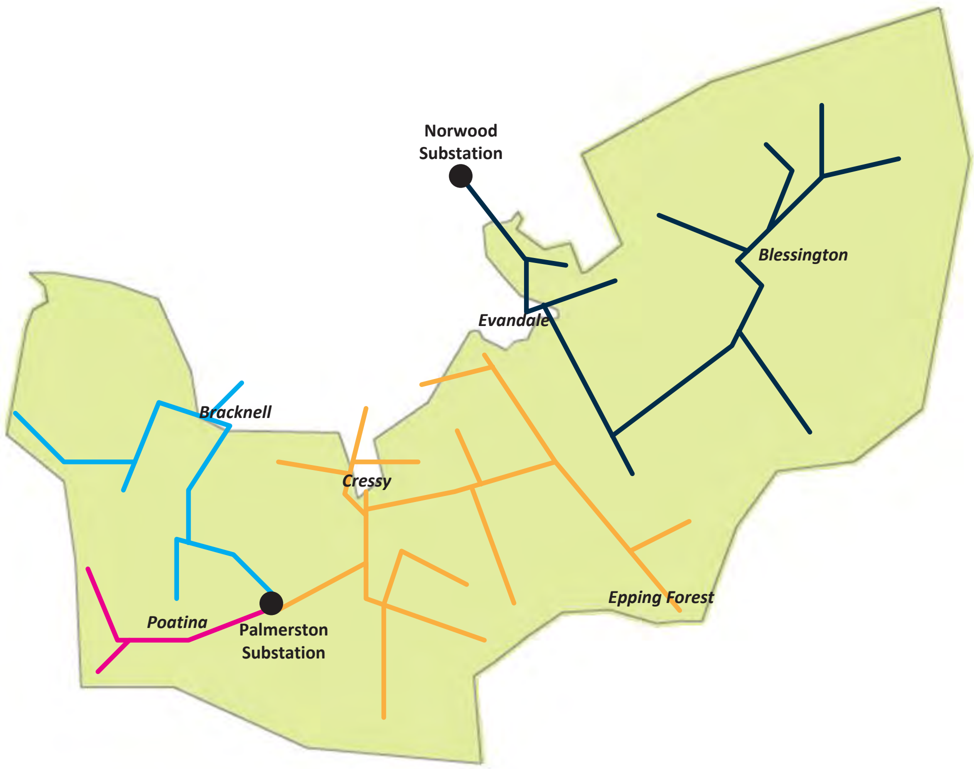


Figure 6-11: Cressy–Blessington low density rural reliability community

Proposed solution

We propose to provide an additional feeder from Palmerston Substation to improve reliability in this community. A new feeder will follow feeder 3 out of the substation then split feeder 3, reducing the length of the problem feeder. As well as reducing the exposure of the feeder to faults, it will increase the transfer capability between this feeder and other substations, thereby increasing the backup capability in case of faults.

The estimated cost of this solution is $800,000 and it is scheduled to be implemented in 2016.

6.4.4 Deferred or averted issues in the Northern area

6.4.4.1 Voltage control at George Town Substation

Section 6.5.6.1 of Transend Networks' 2014 APR discussed voltage control at George Town Substation. The load at George Town Substation is relatively constant, however generation output and Basslink operation varies widely. As a result, voltage control can be an issue and a failure of Basslink under some power system configurations could result in over-voltages at George Town Substation and other substations in the Northern area. This issue is managed by a constraint equation, as detailed in Section 4.1 of this APR.

In addition, under some operating scenarios, a double-circuit fault of either the Sheffield–George Town or Hadspen–George Town 220 kV transmission lines could result in significant interruption to supply or, in the worst case, a power system black out. This would not meet the requirements of the ESI Regulations.

Transend Networks identified in its 2014 APR that installing a dynamic reactive support device at George Town Substation could form part of a solution to these issues. However, the constraint equation has limited market impact and the scenarios that would not meet the requirements of the ESI Regulations are low probability events. Therefore there is currently no economic driver for dynamic reactive support at George Town Substation. We will continue to observe the market impact of the voltage constraint, and if a significant market impact is evident we will revisit this proposal. We welcome proposals from external parties regarding this issue.

6.4.4.2 Derby Substation transformer security

Section 6.6.6.3 of Transend Networks' 2014 APR discussed transformer security issues at Derby Substation. Based on the maximum demand forecast in 2014 and the possible load of a proposed development, by 2021 it was expected that the loss of the transformer would result in more than 300 MWh unserved energy, which does not meet the performance requirements of the ESI Regulations. Transend Networks identified in its 2014 APR the preferred solution was to construct a 22 kV 'super feeder' between Scottsdale and Derby substations to provide additional back up capacity to Derby Substation.

As the 22 kV 'super-feeder' proposal is dependent on the proposed development progressing, Derby Substation security is not expected to become problematic in the short-to-medium term. Therefore, we are not currently proceeding with this proposal. If the proposed development progresses to commitment stage, we will reassess the 22 kV 'super-feeder' proposal. In the meantime we will continue to monitor the maximum demand forecast at Derby Substation.

6.4.5 Availability to connect in the network

Table 6-18 presents the spare capacity available at substations in the Northern area. Derby Substation is a single transformer substation, therefore inherently operates non-firm. For this substation, the available capacity given here is for the transformer capacity rather than the firm capacity.

Table 6-18: Northern area substation capacity availability

Substation	Connection voltage (kV)	Firm capacity (MVA)	2014 (MVA)		2025 (MVA)	
			Actual MD	Available capacity	Forecast MD	Available capacity
Derby	22	0	5.9	19.1	10.8	14.2
George Town	22	50	20.0	30.0	23.3	26.7
Hadspen	22	50	50.6	0	61.5	0
Mowbray	22	50	32.2	17.8	39.8	10.2
Norwood	22	37.5	27.7	9.8	33.6	3.9
Palmerston	22	25	10.7	14.3	12.8	12.2
Scottsdale	22	31.5	10.9	20.6	12.9	18.6
St Leonards	22	60	29.9	30.1	36.2	23.8
Trevallyn	22	100	68.7	31.3	81.5	18.5

6.5 Central planning area

6.5.1 Area network overview

The Central planning area encompasses Tasmania's central highlands, the Derwent valley and part of the midlands. It also includes the supply at Strathgordon. Figure 6-12 presents a geographical diagram of the Central area.

Distribution feeders in the Central area are supplied from six terminal substations, New Norfolk Zone Substation and two other minor zone substations. The majority of the distribution-connected load is in the New Norfolk township. The remaining substations supply low load density areas in the highlands with limited, if any, transfer capability between feeders. There is one customer, a major energy user, supplied directly from the transmission network.

The transmission-connected generation in the Central area is critical to supplying southern Tasmanian load. The power stations form part of the Derwent and Gordon-Pedder hydro power schemes. The Derwent scheme has a capacity of more than 500 MW and is connected into the 110 kV and 220 kV networks in the area. Gordon Power Station has a capacity of 432 MW and connects to Chapel Street Substation at 220 kV. We are also aware of the proposed Cattle Hill Wind Farm, a publically announced project with an announced capacity of 240 MW.

There are two embedded generators over 0.5 MW. There is approximately 1.6 MW of combined rooftop PV installed capacity in the Central area.

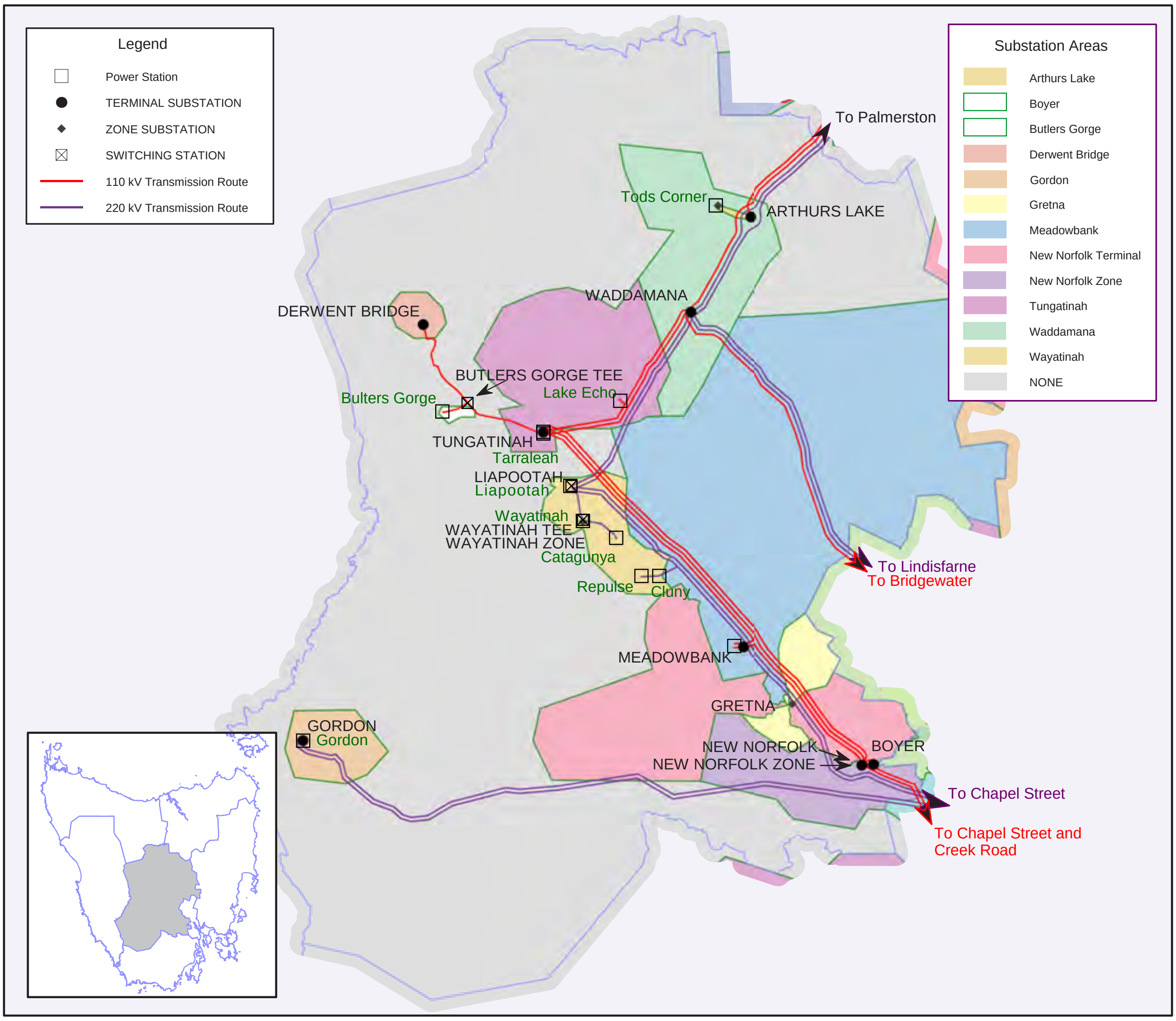


Figure 6-12: Central planning area network

6.5.2 Committed and completed projects

This section describes the material network projects that are committed (construction has begun or a firm date has been set) or have been completed in the area in the past year.

6.5.2.1 Committed

Dynamic rating of Boyer Substation supply transformers

The maximum demand at Boyer Substation exceeds the firm ratings of the supply transformers. This project involves the installation of remote monitoring equipment on the transformers. This will allow the transformers to be operated above their name-plate rating by monitoring the transformer temperature in real-time. This project forms part of the NCIPAP projects in our 2014–19 transmission regulatory period.

This project is scheduled to be completed in December 2015.

6.5.2.2 Completed

Tungatinah Substation 110 kV redevelopment

This project comprised redeveloping Tungatinah Substation and extending the 110 kV transmission circuits that connect Meadowbank and New Norfolk substations from Tarraleah Switching Station to Tungatinah Substation. The redevelopment was required as the majority of the primary assets at these sites were in poor condition and susceptible to failure.

The redevelopment project also provided the opportunity to rationalise the transmission network to remove line crossovers just south of Tarraleah Switching Station, and to bypass the Boyer Tee structure. The 110/22 kV supply transformer at Tungatinah Substation was replaced with a new unit.

The Tungatinah Substation redevelopment was completed in August 2014. The bypass of the Boyer Tee was completed in April 2015.

Meadowbank Substation redevelopment

This project included replacing 110 kV circuit breakers, installing a bus-coupler circuit breaker, current transformers, and protection and control equipment at Meadowbank Substation. The substation redevelopment was driven by the need to replace assets that were in poor condition and susceptible to failure. This aim of this project was to improve the reliability, security and performance of the electricity supply.

The supply arrangement of Meadowbank Substation was rearranged from a loop in-loop-out connection from one Tarraleah–New Norfolk 110 kV circuit to a double tee from the two Tungatinah–New Norfolk 110 kV circuits. This increased the transmission capacity in this corridor.

The project was completed in January 2015.

Westerway Zone Substation decommissioning

Westerway Zone Substation supplied a small pocket of 11 kV load around Westerway township. The supply transformers were in poor condition and replacing them was going to be expensive. As an alternative, the 11 kV network has been decommissioned and replaced with 22 kV infrastructure supplied directly from New Norfolk Substation.

This project was completed in March 2015.

6.5.3 Issues, solutions and developments

This section details the existing and forecast issues in the Central area. It also presents the potential and preferred solutions to alleviate these issues and any other proposed developments. Figure 6-13 presents a simplified diagram of the supply arrangement in the area. Only the relevant portion of the network is shown. The figure highlights the current and emerging constraints and asset condition issues in the area over the next ten years.

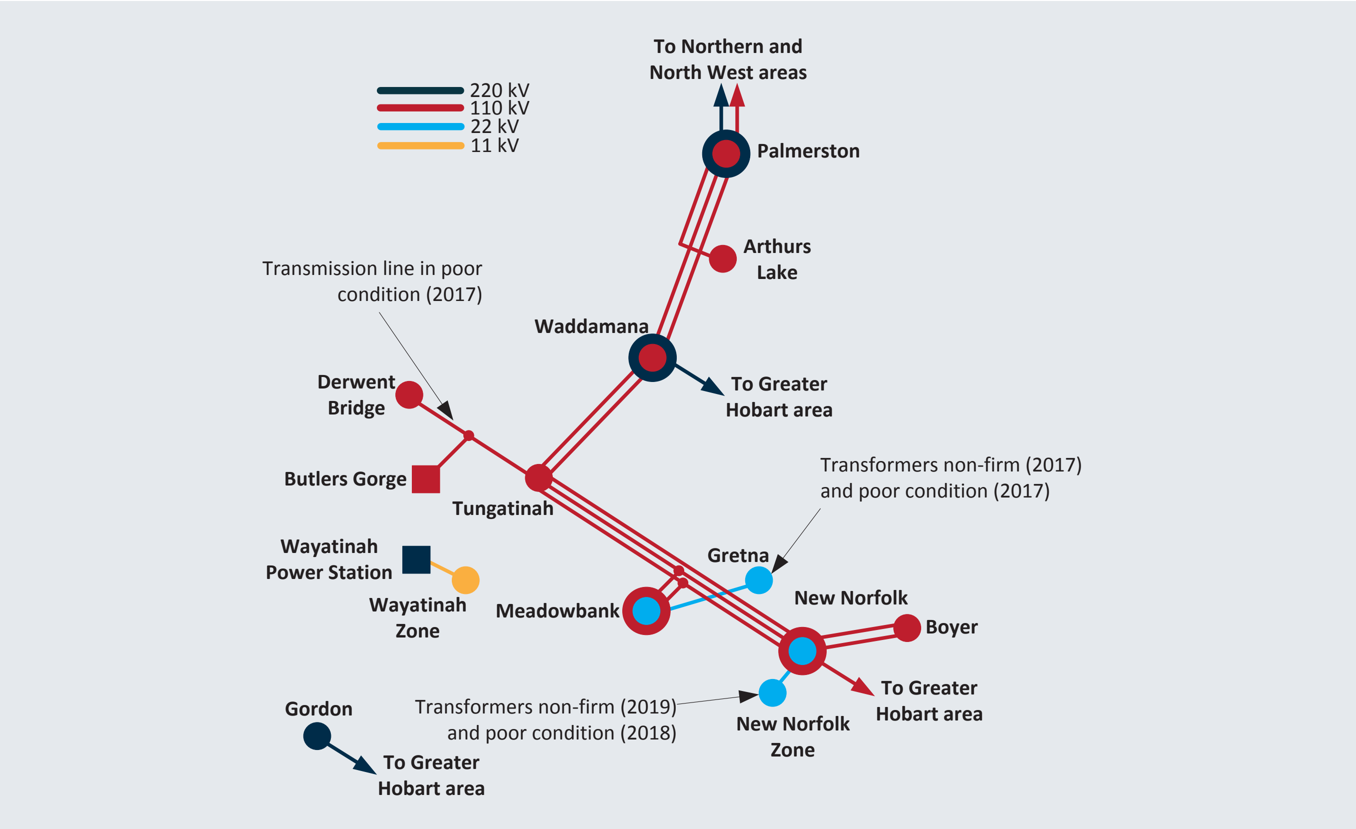


Figure 6-13: Current and emerging issues in the Central area

6.5.3.1 Constraints and inability to meet network performance requirements

Table 6-19 presents the area of the identified constraints and inability to meet network performance requirements, a brief description of the issue itself, the year in which the issue is forecast to materialise, the proposed solution and reference to further in the chapter where more detail is provided.

Table 6-19: Central area constraints and inability to meet network performance requirements

Area of issue	Issue	Forecast year	Proposed solution	Reference
Gretna Zone Substation	Supply transformers non-firm	2017	Replace transformers	6.5.3.5
New Norfolk Zone Substation	Supply transformers non-firm	2019	Replace transformers	6.5.3.6

6.5.3.2 Asset replacement

Table 6-20 presents a summary of the identified asset condition issues over the next ten years, including the area and description of the issue, the proposed solution, and reference to further in the chapter where more information is provided.

Table 6-20: Central area asset condition issues

Area of issue	Issue	Proposed solution (year)	Reference
Gretna Zone Substation	Condition of supply transformers	Replace transformers (2017)	6.5.3.5
New Norfolk Zone Substation	Condition of supply transformers	Replace transformers (2018)	6.5.3.6
Butlers Gorge–Derwent Bridge 110 kV transmission line	Transmission line condition	Replace transmission line with a 22 kV feeder from Butlers Gorge Power Station (2017)	6.5.3.7

6.5.3.3 Network capability improvement parameter action plan

There are no further NCIPAP projects to be completed in the Central area within the 2014–19 transmission regulatory period. However there are other programs which include substations the Central area, listed in Section 6.9.2.3.

6.5.3.4 Communities with poor reliability

Table 6-21 summarises the communities with poor reliability in the Central area. There are two communities with trending poor reliability (5-year average) plus the Bothwell Rural community which is a newly poorly performing community in 2014.

It is difficult to maintain reliability within standards in the Central area. There is limited, if any, inter-connection between feeders and load transfer capacity in the distribution network. This makes it difficult to restore supply until the fault is addressed and damage repaired. Major event days were the primary contributing factor to poor reliability in the Bothwell Rural community in 2014.

We currently do not propose any augmentation projects to improve reliability; however we will continue to implement operational measures as part of targeted reliability improvement programs. We will continue to monitor the reliability performance and investigate solutions if performance deteriorates.

6.5.3.5 Gretna Zone Substation transformer condition and capacity

Issue overview

Gretna Zone Substation has a single 1.0 MVA supply transformer and the substation maximum demand is forecast to exceed the transformer capacity by summer 2017. The existing transformer was manufactured in 1962, is in poor condition and nearing the end of its service life.

Proposed solution

Despite potential options available to defer the forecast loading issue at Gretna Zone Substation, we propose to replace the transformer due to its poor condition. Our proposal is to replace the transformer with a single standard 5 MVA unit to cater for the maximum demand on the substation.

The project is estimated to cost $1.0 million and proposed to be completed by June 2017.

6.5.3.6 New Norfolk Zone Substation transformer condition and capacity

Issue overview

New Norfolk Zone Substation has four 2.5 MVA supply transformers. The substation demand is forecast to exceed the 7.5 MVA firm rating by winter 2019. We apply a cyclic rating of 3.3 MVA to these units, providing a short-term firm rating of 9.8 MVA. The demand is forecast to remain within the short-term firm rating of the transformers past 2025.

The transformers were manufactured in 1960, are in poor condition and approaching the end of their service life.

Proposed solution

Despite potential options available to defer the forecast loading issue at New Norfolk Zone Substation, we propose to replace these transformers due to their poor condition. Our proposal is to replace the transformers with three standard 5 MVA units. This will increase the firm capacity of the substation to 10 MVA.

The project is estimated to cost $1.7 million and proposed to be completed by June 2018.

6.5.3.7 Supply to Derwent Bridge

Issue overview

The Butlers Gorge–Derwent Bridge 110 kV transmission line is among the oldest in Tasmania's transmission network. It was originally built in 1939, although some sections were replaced in the 1960s. This line is in generally poor condition and requires a significant capital investment to maintain. Similarly, in extreme summer conditions, the rating of the line drops to 0 MVA at 110 kV to maintain clearance, the design operating temperature of the circuit is 43˚C.

Table 6-21: Central area community supply reliability

Reliability community	Category	Measure exceeded	Proposed solution	Reference
Trending poor performing communities				
Wayatinah	High density rural	SAIDI	Monitor	N/A
Highlands	Low density rural	SAIDI		
New poor performing communities in 2014				
Bothwell Rural	Low density rural	SAIDI	Monitor	N/A

Table 6-22: Derwent Bridge Substation limitation deferral

Deferral period	Maximum demand (2015) (MVA)	Generation support or reduction in forecasted load	
		Load (MW)	Annual energy (MWh)
One year	0.25	0.25	1020
Five years		0.27	1070

Limitation deferral

Table 6-22 presents the requirements to provide an alternate supply to Derwent Bridge Substation load, if the transmission line is decommissioned. The table presents the reduction in the forecasted load, or amount of generation support, required to defer the limitation by either one or five years.

There is no feeder connection from Derwent Bridge Substation to rest of the network.

Potential solutions

The load at Derwent Bridge is connected at 22 kV. The load is small, with a maximum demand of only 250 kW. Rather than invest heavily in refurbishing the 110 kV transmission line for such a small load, we have investigated options to decommission this line and replace it with other services.

The following options are being considered to address the identified issue:

- decommission 110 kV transmission line and install diesel generator at Derwent Bridge;
- construct a 22 kV feeder from Butlers Gorge Power Station to Derwent Bridge Substation, install standby diesel generator at Derwent Bridge, decommission 110 kV transmission line, and decommission Derwent Bridge Substation; and
- establish a micro-grid at Derwent Bridge which could include a combination of mini-hydro and solar generation, battery storage, and standby diesel generator backup. Decommission 110 kV transmission line, and decommission Derwent Bridge Substation.

The current preferred option is to construct a new 22 kV distribution feeder from Butlers Gorge Power Station to supply the Derwent Bridge / Lake St Clair area, rather than implement a conventional asset replacement or network development option. However we intended to re-commence investigation into other options, including alternate supply arrangements to Derwent Bridge Substation, to determine if installing 22 kV feeder is the most appropriate solution. We have previously received interest from proponents for this service, who we will engage with in developing our strategy.

The estimated cost of constructing a new 22 kV feeder and associated other works is $1.2 million and proposed implementation is scheduled for completion by June 2017.

6.5.4 Deferred or averted issues in the Central planning area

No issues have been deferred beyond the current planning period in the last year.

6.5.5 Availability to connect to the network

Table 6-23 presents the spare capacity available at substations in the Central area. Aside from New Norfolk and New Norfolk Zone substations, all substations are single transformer substations. Therefore they inherently operate non-firm. For these substations, the available capacity given here is for the transformer capacity rather than the firm capacity. Rural zone substations are not included in this analysis.

Table 6-23: Central area substation capacity availability

Substation	Connection voltage (kV)	Firm capacity (MVA)	2014 (MVA)		2025 (MVA)	
			Actual MD	Available capacity	Forecast MD	Available capacity
Arthurs Lake	22	0	7.1	17.9	7.1	17.9
Derwent Bridge	22	0	0.2	9.8	0.3	9.7
Meadowbank	22	0	6.2	3.8	9.7	0.3
New Norfolk	22	30	16.1	13.9	18.9	11.1
Tungatinah	22	0	1.2	23.8	1.2	23.8
Waddamana	22	0	0.6	4.4	0.6	4.4
New Norfolk	22	7.5	7.1	0.4	8.4	0

6.6 Greater Hobart planning area

6.6.1 Area network overview

The Greater Hobart planning area covers the eastern and western shores of Hobart, predominately the Hobart CBD and the municipalities of Glenorchy, Clarence and much of Brighton. It also includes the supply area from Bridgewater Substation which extends north to Kempton. There area is mostly urban, with rural supply into the area extending north. The majority of the load in the Greater Hobart area is a mixture of commercial, industrial and urban residential load. The area north to Kempton and the south arm peninsula, supplied from Rokeby Substation, is a predominately rural load. Figure 6-14 presents a geographical diagram of the Greater Hobart area.

The area is generally supplied from the bulk transmission network at Chapel Street and Lindisfarne substations. There are eight terminal substations (four supplying the sub-transmission network and four directly supplying high voltage distribution feeders) and ten zone substations in the area. There is one major energy user directly connected to the transmission network. The area is supplied through a highly interconnected 11 kV 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 no transmission-connected generation in the Greater Hobart area, however there are two embedded generators larger than 0.5 MW. There is approximately 19.8 MW of combined rooftop PV installed capacity.

The Hobart eastern shore sub-transmission network has been strengthened in recent years. We implemented the Hobart eastern shore development project to relieve high loading on a number of existing substations. This has established a new terminal substation and two new zone substations. We are in the last stage of this project, with the new Rosny Park Zone Substation under construction.

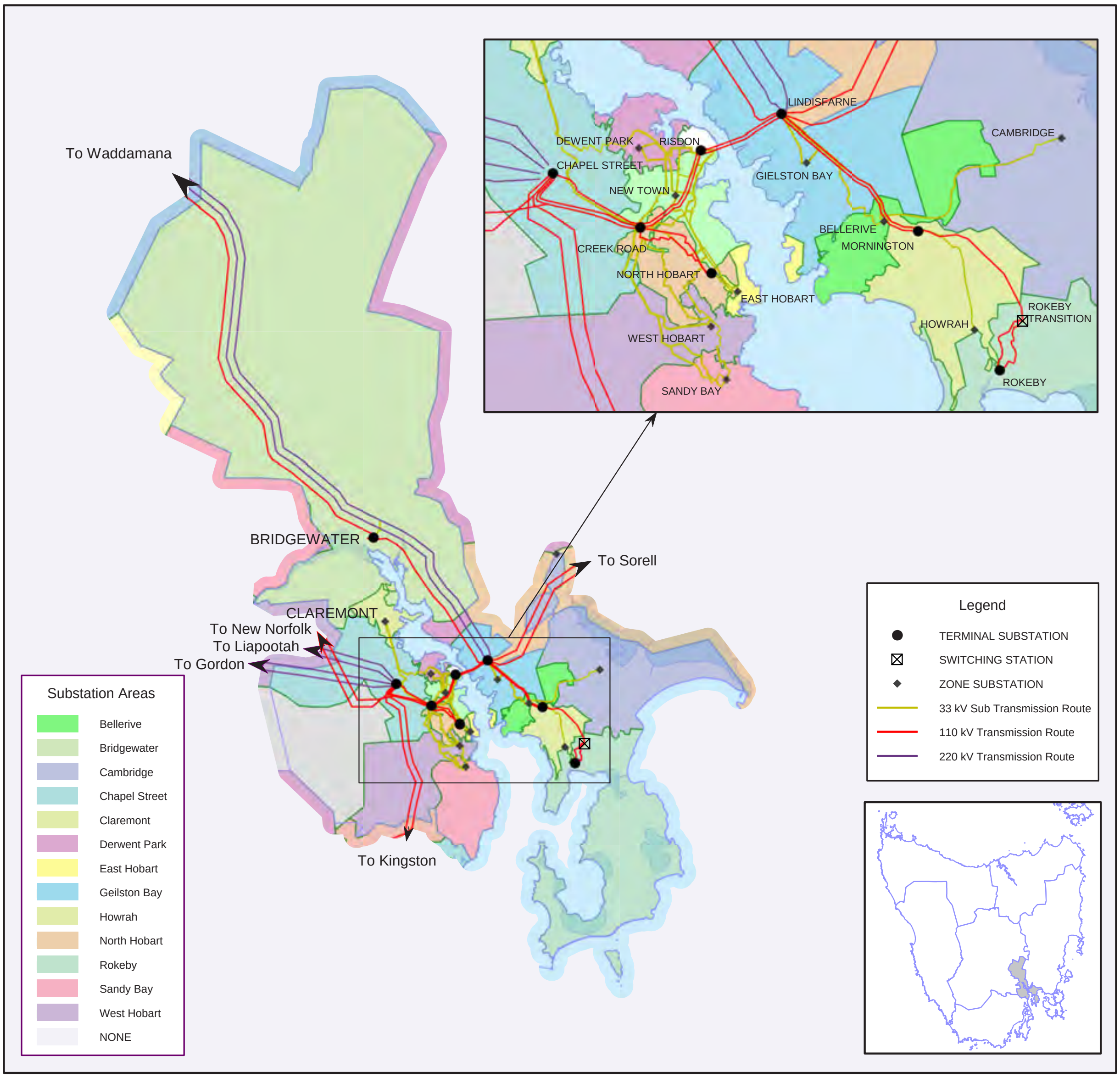


Figure 6-14: Greater Hobart planning area network

6.6.2 Committed and completed projects

This section describes the material network projects that are committed (construction has begun or a firm date has been set) or have been completed in the area in the past year.

6.6.2.1 Committed

Rosny Park Zone Substation

The establishment of Rosny Park Zone Substation is the final stage of our strategy to strengthen the network on Hobart's eastern shore. The initial stages of this project were the establishment of Mornington Substation and Howrah Zone Substation, both commissioned in 2011. This strategy was implemented to address the significant supply risks to customers on Hobart's eastern shore, which existed because the established substations were operated well above their firm ratings.

Rosny Park Zone Substation is being built as a single-transformer substation, supplied via a single 33 kV sub-transmission feeder from Mornington Substation. Rosny Park Zone Substation will initially take approximately 10 MVA of load from Bellerive and Geilston Bay zone substations, ensuring they are operated within their firm ratings.

This project is scheduled to be completed in May 2016.

6.6.2.2 Completed

Sandy Bay Zone Substation switchgear and protection replacement

This project involved the replacement of the high voltage circuit breakers and protection systems, and reconfiguration of the SCADA system at Sandy Bay Zone Substation. The high voltage switchgear and protection systems were installed in 1967 and had reached the end of their service life. The aim of this project was to reduce safety risks, increase asset reliability, and reduce operating and maintenance costs.

This project was completed in February 2015.

Weather station telemetry renewal program (Creek Road Substation)

Weather stations are an integral part of our real-time transmission line rating system. The weather station at Creek Road Substation was upgraded and relocated to bring it to Bureau of Meteorology standard and improve access. This project formed part of the NCIPAP projects in our 2014–19 transmission regulatory period and was completed in June 2015.

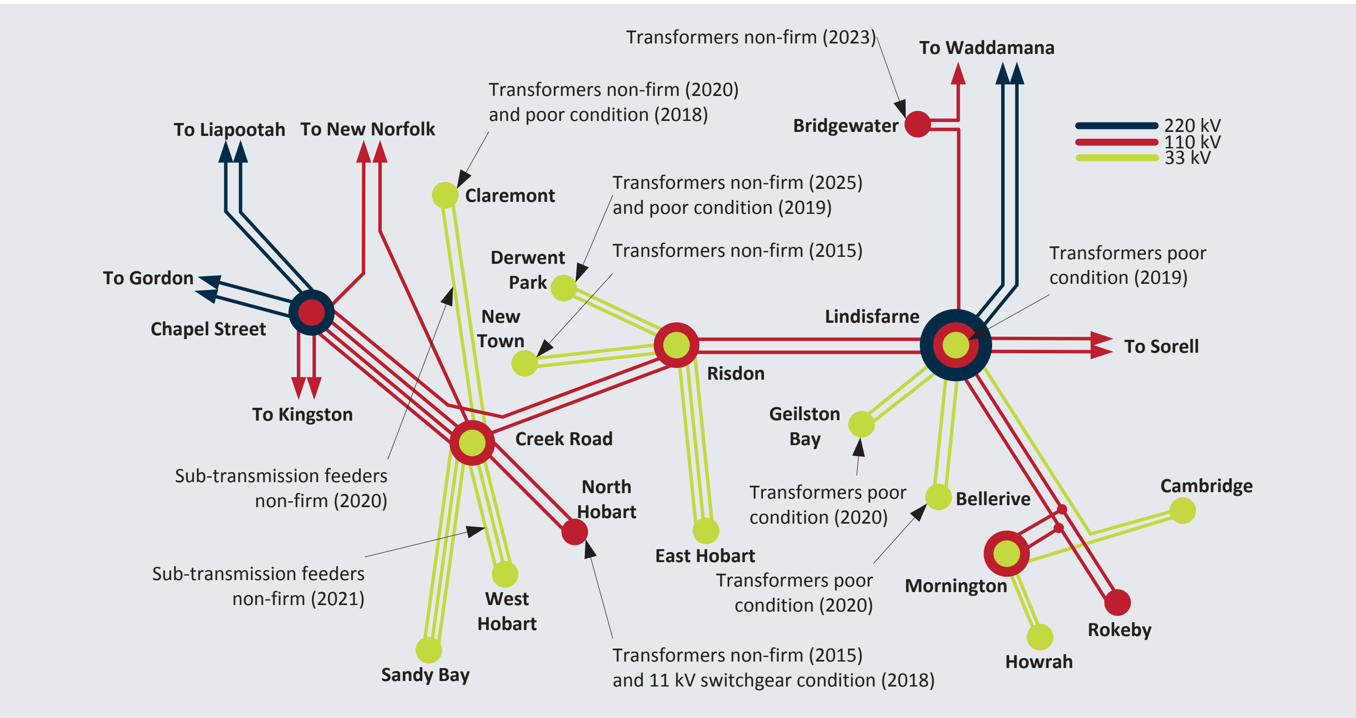


Figure 6-15: Current and emerging issues in the Greater Hobart area

6.6.3 Issues, solutions and developments

This section details the existing and forecast issues in the Greater Hobart area. It also presents the potential and preferred solutions to alleviate these issues and any other proposed developments. Figure 6-15 presents a simplified diagram of the supply arrangement in the area. Only the relevant portion of the network is shown. The figure highlights the current and emerging constraints and asset condition issues in the area over the next ten years.

6.6.3.1 Constraints and inability to meet network performance requirements

Table 6-24 presents the area of the identified constraints and inability to meet network performance requirements, a brief description of the issue itself, the year in which the issue is forecast to materialise, the proposed solution and reference to further in the chapter where more detail is provided.

6.6.3.2 Asset replacement

Table 6-25 presents a summary of the identified asset condition issues over the next ten years, including the area and description of the issue, the proposed solution, and reference to further in the chapter where more information is provided.

6.6.3.3 Network capability improvement parameter action plan

Table 6-26 summarises the NCIPAP projects to be completed in the Greater Hobart area by the end of the 2014–19 transmission regulatory period. It lists the benefits, cost and timing of each project. There are other programs which include substations the Greater Hobart area, listed in Section 6.9.2.3.

6.6.3.4 Communities with poor reliability

Table 6-27 summarises the communities with poor reliability in the Greater Hobart area. The Hobart critical extended community has trending poor reliability (5-year average) and the South Arm community is a newly poor performing community in 2014.

Reliability in the Hobart critical extended community has decreased in recent years, and not met its SAIFI and SAIDI standards. In 2014 the primary contributing factor was a single switchgear failure which contributed 40 per cent to both the SAIFI and SAIDI measure. The primary contributing factors to the South Arm community in 2014 was two major event days which contributed 85 per cent to the SAIDI measure. Otherwise this community has historically met its reliability standards and we expect it to meet its standards in 2015.

Table 6-24: Greater Hobart area constraints and inability to meet network performance requirements

Area of issue	Issue	Forecast year	Proposed solution	Reference
North Hobart Substation	Supply transformers non-firm	2015	Manage operationally (group firm rating)	6.6.3.5
New Town Zone Substation	Supply transformers non-firm	2015	Manage operationally (group firm rating)	6.6.3.6
Claremont Zone Substation	Supply transformers non-firm	2020	Replace transformers	6.6.3.7
Creek Road–Claremont sub-transmission feeders	Sub-transmission feeders non-firm	2020	Manage operationally (seasonal load transfers)	6.6.3.7
Creek Road–West Hobart sub-transmission feeders	Sub-transmission feeders non-firm	2021	Manage operationally (seasonal load transfers)	6.6.3.8
Bridgewater Substation	Supply transformers non-firm	2023	Manage within short term rating	6.6.3.9
Derwent Park Zone Substation	Supply transformers non-firm	2025	Replace transformers	6.6.3.10

Table 6-25: Greater Hobart area asset condition issues

Area of issue	Issue	Proposed solution (year)	Reference
North Hobart Substation	Condition of 11 kV switchboards	Switchboard replacement (2018)	6.6.3.11
Claremont Zone Substation	Condition of supply transformers	Replace transformers (2018)	6.6.3.7
Derwent Park Zone Substation	Condition of supply transformers	Replace transformers (2019)	6.6.3.10
Lindisfarne Substation	Condition of supply transformers	Replace transformers (2019)	6.6.3.12
Geilston Bay Zone Substation	Condition of supply transformers	Replace transformers (2020)	6.6.3.13
Bellerive Zone Substation	Condition of supply transformers	Replace transformers (2020)	6.6.3.14

Table 6-26: Greater Hobart area NCIPAP projects

Project	Benefit	Location	Cost ($000)	Timing
Chapel Street Substation 110 kV security augmentation	Installation of second 110 kV bus coupler circuit breaker to reduce impact of bus coupler fault	Chapel Street	450	January 2019

Currently we do not propose any augmentation projects to improve reliability in these communities; however we will continue to implement operational measures as part of targeted reliability improvement programs. We will continue to monitor reliability performance and investigate solutions if performance deteriorates.

6.6.3.5 North Hobart Substation transformer capacity

Issue overview

North Hobart Substation has two 45 MVA supply transformers, with a four-hour short-term firm rating of 50 MVA. The substation demand is forecast to exceed the continuous firm rating from winter 2015, and exceed the four-hour short-term firm rating of the transformers from 2016.

Limitation deferral

Table 6-28 presents the requirements to defer the identified non-firm issue at North Hobart Substation. The table presents the reduction in the forecasted load, or amount of generation support, required to defer the limitation by either one (to 2017) or five (to 2021) years. The reduction detailed is to maintain the load below 50 MVA, the short-term firm capacity of the transformers.

Potential solutions

The distribution network within Hobart is heavily interconnected; this means large portions of load can be transferred between substations. As such, for these substations we consider the "group firm" rating, and develop strategies to manage load across a number of substations, rather than as individual sites.

Therefore, we will operationally manage the loading at North Hobart Substation. This includes the utilisation of short-term ratings of the transformers and load transfers between this and other substations. These solutions will be investigated and implemented before projects with large-expenditure, such as transformer replacement or establishment of a new substation, are pursued.

6.6.3.6 New Town Zone Substation transformer capacity

Issue overview

New Town Zone Substation has two 22.5 MVA supply transformers, with a short-term firm rating of 22.9 MVA (limited by the rating of the 11 kV switchboard). The substation demand is forecast to exceed the continuous firm rating from winter 2015, and exceed the short-term firm rating of the transformers from 2016.

Limitation deferral

Table 6-29 presents the requirements to defer the identified non-firm issue at New Town Zone Substation. The table presents the reduction in the forecasted load, or amount of generation support, required to defer the limitation by either one (to 2017) or five (to 2021) years. The reduction detailed is to maintain the load below 22.9 MVA, the short-term firm capacity of the transformers.

Potential solutions

Similar to the loading issue at North Hobart Substation, the loading at New Town Zone Substation is managed with other inter-connecting substations. We will operationally manage the loading at New Town Zone Substation through the utilisation of short-term ratings and load transfers, with no proposals for large-expenditure, such as transformer or switchboard replacements at this time.

Table 6-27: Greater Hobart area community supply reliability

Reliability community	Classification	Limit exceeded	Proposed solution	Reference
Trending poor performing communities				
Hobart critical extended	Critical infrastructure	SAIFI and SAIDI	Monitor	N/A
Newly poor performing communities in 2014				
South Arm	High density rural	SAIDI	Monitor	N/A

Table 6-28: North Hobart Substation limitation deferral

Deferral period	Maximum demand (2016) (MVA)	Generation support or reduction in forecasted load (MVA)
One year	52.7	2.4
Five years		5.7

Table 6-29: New Town Zone Substation limitation deferral

Deferral period	Maximum demand (2016) (MVA)	Generation support or reduction in forecasted load (MVA)
One year	23.5	0.9
Five years		2.6

6.6.3.7 Claremont Zone Substation transformer condition, capacity and sub-transmission capacity

Issue overview

Claremont Zone Substation has two 22.5 MVA supply transformers, with a short-term firm rating of 30 MVA. The sub-transmission feeders supplying Claremont Zone Substation have also have a firm rating of 22.5 MVA. The substation demand is forecast to exceed the continuous firm rating of the transformers and sub-transmission feeders from winter 2020, however remain within the short-term firm rating of the transformers past 2025.

The transformers were manufactured in 1969. Their condition is deteriorating and they are approaching the end of their service life.

Proposed solution

Despite potential options available to defer the forecast loading issue at Claremont Zone Substation, we propose to replace these transformers due to their poor condition. Our proposal is to replace the transformers with two new standard 25 MVA units. This will defer the transformer loading issue past 2025.

The project is estimated to cost $3.0 million and is proposed to be completed by June 2018.

We will operationally manage the loading on the sub-transmission feeders. This will likely involve utilisation of short-term ratings of the feeders and seasonal load transfers to other substations.

6.6.3.8 West Hobart Zone Substation sub-transmission capacity

Issue overview

The sub-transmission feeders supplying Claremont Zone Substation have a firm rating of approximately 46 MVA. The substation demand is forecast to exceed the firm rating of the sub-transmission feeders from winter 2021.

Proposed solution

We will operationally manage the loading on the sub-transmission feeders. This will likely involve utilisation of short-term ratings of the feeders and seasonal load transfers to other substations.

6.6.3.9 Bridgewater Substation transformer capacity

Issue overview

Bridgewater Substation has two 35 MVA supply transformers, with a short-term firm rating of 38 MVA. The substation demand is forecast to exceed the continuous firm rating from winter 2023, however remain within the short-term firm rating of the transformers past 2025.

Proposed solution

We do not propose any investment at Bridgewater Substation as the load can be managed within the short-term ratings of the supply transformers.

6.6.3.10 Derwent Park Zone Substation transformer condition and capacity

Issue overview

Derwent Park Zone Substation has two 22.5 MVA supply transformers, with a short-term firm rating of 30 MVA. The substation demand is forecast to exceed the continuous firm rating from winter 2020, however remain within the short-term firm rating of the transformers past 2025.

The transformers were manufactured in 1969. Their condition is deteriorating and they are approaching the end of their service life.

Proposed solution

Despite potential options available to defer the forecast loading issue at Derwent Park Zone Substation, we propose to replace these transformers due to their poor condition. Our proposal is to replace the transformers with two new standard 25 MVA units. This will defer the transformer loading issue past 2025.

The project is estimated to cost $3.0 million and is proposed to be completed by June 2018.

6.6.3.11 North Hobart Substation 11 kV switchgear condition and configuration

Issue overview

The two 11 kV switchboards at North Hobart Substation comprise 6 feeder circuit breakers each, providing connection to 22 distribution feeders plus two local service station transformers. That is, 12 circuit breakers provide connection to 24 x 11 kV circuits. This arrangement reduces the reliability of supply to the Hobart CBD area, as a single feeder fault will trip its associated circuit breaker resulting in the loss of supply to both the faulty feeder and the healthy feeder connected to that circuit breaker.

The circuit breakers were manufactured in 1976 and are no longer supported by the manufacturer. We do not have this type of switchgear installed at any other site. The switchboards are not designed for arc containment and are not explosion proof. The circuit breakers also require manual spring charging after each operation, resulting in delays in restoring supply.

Proposed solution

The three arrangements we considered to address this issue were to replace the switchboard with:

- 24 kV air-insulated equipment (operated at 11 kV) to match our standard equipment;
- 12 kV air insulated equipment (operated at 11 kV) to fit in the existing station footprint, although non-standard within our network; and
- 24 kV gas-insulated equipment (operated at 11 kV) to fit in the existing station footprint, although non-standard within our network.

Our preferred option is to replace the 11 kV switchboards at North Hobart Substation with new 12 kV air-insulated switchboards (operated at 11 kV) that have sufficient circuit breakers to enable one feeder to be connected per circuit breaker. The new switchgear will have air-insulated busbars and vacuum circuit breakers. It will include arc containment facilities, be explosion proof, and be fully remote controllable.

The estimated cost of the project is $5.1 million and proposed implementation is scheduled for completion by June 2018.

6.6.3.12 Lindisfarne Substation supply transformer condition

Issue overview

Lindisfarne Substation has two 110/33 kV 45 MVA supply transformers, which were manufactured in 1964. These transformers receive regular condition-based testing and maintenance. In 2002 these transformers received refurbishment work that extended their useful service life. The condition of these transformers has continued to deteriorate and they are approaching the end of their service life. Furthermore, the maximum demand at Lindisfarne Substation exceeded the continuous firm rating of the transformers in 2014.

Proposed solution

We propose to replace these transformers with two new standard 110/33 kV 60 MVA units. Lindisfarne Substation is a critical node, providing supply to the 33 kV sub-transmission network on Hobart's eastern shore, and no other reasonable option to replacement of these units has been identified.

The estimated cost of the project is $7.2 million, with proposed implementation scheduled for completion by 2019.

6.6.3.13 Bellerive Zone Substation transformer condition

Issue overview

Bellerive Zone Substation has two 22.5 MVA supply transformers, which were manufactured in 1971. These transformers have been identified as approaching end of service life and may require replacement within the current planning period.

Proposed solution

We propose to replace these transformers with new standard 25 MVA units. As a consequence, the 11 kV switchboard (rated at 22.9 MVA) becomes the substation limiting factor; however the load is forecast to remain below this level until at least 2025.

The project is estimated to cost $3.0 million and is proposed to be completed by 2020.

6.6.3.14 Geilston Bay Zone Substation transformer condition

Issue overview

Geilston Bay Zone Substation has two 22.5 MVA supply transformers, which were manufactured in 1964. These transformers have been identified as approaching end of service life and may require replacement within the current planning period.

Proposed solution

We propose to replace these transformers with new standard 25 MVA units. As a consequence, the 11 kV switchboard (rated at 22.9 MVA) becomes the substation limiting factor. However following the transfer of load to the new Rosny Park Zone Substation, currently under construction, we forecast the load to remain below this level until at least 2025.

The project is estimated to cost $3.0 million and is proposed to be completed by 2020.

6.6.4 Deferred or averted issues in the Greater Hobart planning area

6.6.4.1 New zone substation at Austins Ferry or Brighton

The 2014 APRs of Aurora Energy (Section 10.1) and Transend Networks (Section 6.7.6.8) identified a new 33/11 kV zone substation at Austins Ferry or Brighton, supplied from a new 33 kV supply point at Bridgewater Substation, would likely be required in 2023. This was primarily to manage the loading of the 110/11 kV transformers at Bridgewater Substation, but also loading at Claremont Zone Substation and forecast issues within the distribution network. Due to reduction in forecasted load, we have suspended our analysis of this solution with the need for this new substation deferred past 2025.

6.6.4.2 Fault level mitigation at Creek Road Substation 33 kV bus

Section 6.7.6.2 of Transend Networks' 2014 APR identified an issue with the maximum fault level at the 33 kV busbar at Creek Road Substation. During times of high fault level, we manage the issue by manually opening the bus-tie circuit breakers and operating the supply transformers radially. This is undesirable as the loss of a single transformer will result in loss of supply to customers, including in the Hobart CBD area. The proposed solution was to install fault current limiters at Creek Road Substation.

The maximum allowable fault level was set in the connection agreement between Aurora Energy and Transend Networks. As detailed in Section 4.4 of this APR, we are investigating the maximum allowable fault level at this and other substations to see the practicality of increasing the maximum allowable fault level. If this proves insufficient, we may also investigate alternate solutions to this problem. Therefore the proposal to install fault current limiters at Creek Road Substation is deferred indefinitely.

6.6.5 Availability to connect in the network

Table 6-30 presents the spare capacity available at substations in the Greater Hobart area. It should be noted that our current load forecast does not include the changes that will occur following the establishment of Rosny Park Zone Substation. Supplied from Mornington Substation, Rosny Park Zone Substation will decrease load at Bellerive and Geilston Bay zone substations and Lindisfarne Substation. However it is unlikely to be sufficient to allow significant new load to be connected to these substations.

Table 6-30: Greater Hobart area substation capacity availability

Substation	Connection voltage (kV)	Firm capacity (MVA)	2014 (MVA)		2025 (MVA)	
			Actual MD	Available capacity	Forecast MD	Available capacity
Creek Road	33	120	86.8	33.2	109.0	11.0
Risdon	33	100	67.8	32.2	93.6	6.4
Bridgewater	11	35	30.1	4.9	36.0	0
Chapel Street	11	60	36.6	23.4	45.5	14.5
North Hobart	11	45	43.1	1.9	59.2	0
Claremont	11	22.5	21.7	0.8	24.4	0
Derwent Park	11	22.5	21.1	1.4	22.6	0
New Town	11	22.5	23.1	0	27.3	0
East Hobart	11	60	35.7	24.3	46.4	13.6
West Hobart	11	60	39.5	20.5	49.7	10.3
Sandy Bay	11	60	39.2	20.8	47.1	12.9
Lindisfarne	33	45	46.8	0	59.0	0
Mornington	33	60	21.9	38.1	26.9	33.1
Rokeby	11	35	20.1	14.9	24.5	10.5
Bellerive	11	22.5	18.8	3.7	21.2	1.3
Cambridge	11	20	15.3	4.7	15.1	4.9
Geilston Bay	11	22.5	25.4	0	29.9	0
Howrah	11	22.5	15.9	6.6	19.5	3.0

6.7 Eastern planning area

6.7.1 Area network overview

The Eastern planning area extends along Tasmania's east coast from the Tasman Peninsula to St Helens, and extends inland to Campbell Town, Oatlands and Richmond. The area is largely rural with low population density, and with the main economic activities being agriculture and tourism along the east coast. Figure 6-16 presents a geographical diagram of the Eastern area.

The area is supplied from the main transmission network at 110 kV from Palmerston (near Poatina) and Lindisfarne substations. The distribution network is supplied from four terminal substations and one rural zone substation. Sorell Substation is supplied by two circuits, with all other substations radially supplied. The distribution network in the Eastern area is characterised by overhead feeders supplying large areas, with limited interconnection.

There is no transmission-connected generation in the area, however there is one embedded generation unit larger than 0.5 MW. There is approximately 6.2 MW of combined rooftop PV installed capacity.

We recently undertook works to strengthen the distribution network interconnection in the Eastern area. Due to the general radial nature of the network, single contingencies can cause widespread loss of supply. We have upgraded the distribution network, including reinforcing feeders and installing remote switches, to allow us to restore supply to the majority of customers for a contingency on the transmission line from Palmerston Substation.

We also recently undertook work on the distribution network to the Tasman Peninsula. This area was severely affected by the Dunalley bushfires in January 2013. Following this we rebuilt the two distribution feeders to the area; one immediately to restore supply and the second rebuilt with concrete poles to bushfire proof the line.

There has been no material investment in the transmission network in the Eastern area in recent years, with the existing network being sufficient.

6.7.2 Committed and completed projects

This section describes the material network projects that are committed (construction has begun or a firm date has been set) or have been completed in the area in the past year.

6.7.2.1 Committed

There are no committed projects in the Eastern area in the 2015 APR.

6.7.2.2 Completed

Distribution network works supporting Avoca and St Marys substations

Avoca and St Marys substations are supplied via the single circuit Palmerston–Avoca and Avoca–St Marys 110 kV transmission lines. There is no redundant supply to these substations, and though some load could be supplied from other substations, a contingency on these lines will result in loss of supply to the majority of customers.

To reduce the impact of a fault on these lines, we have strengthened the distribution network in the area. The work included upgrading some feeders and installing remote switching. This allows us to supply most of the affected load to neighbouring substations for a contingency on these lines.

This project was completed in March 2015.

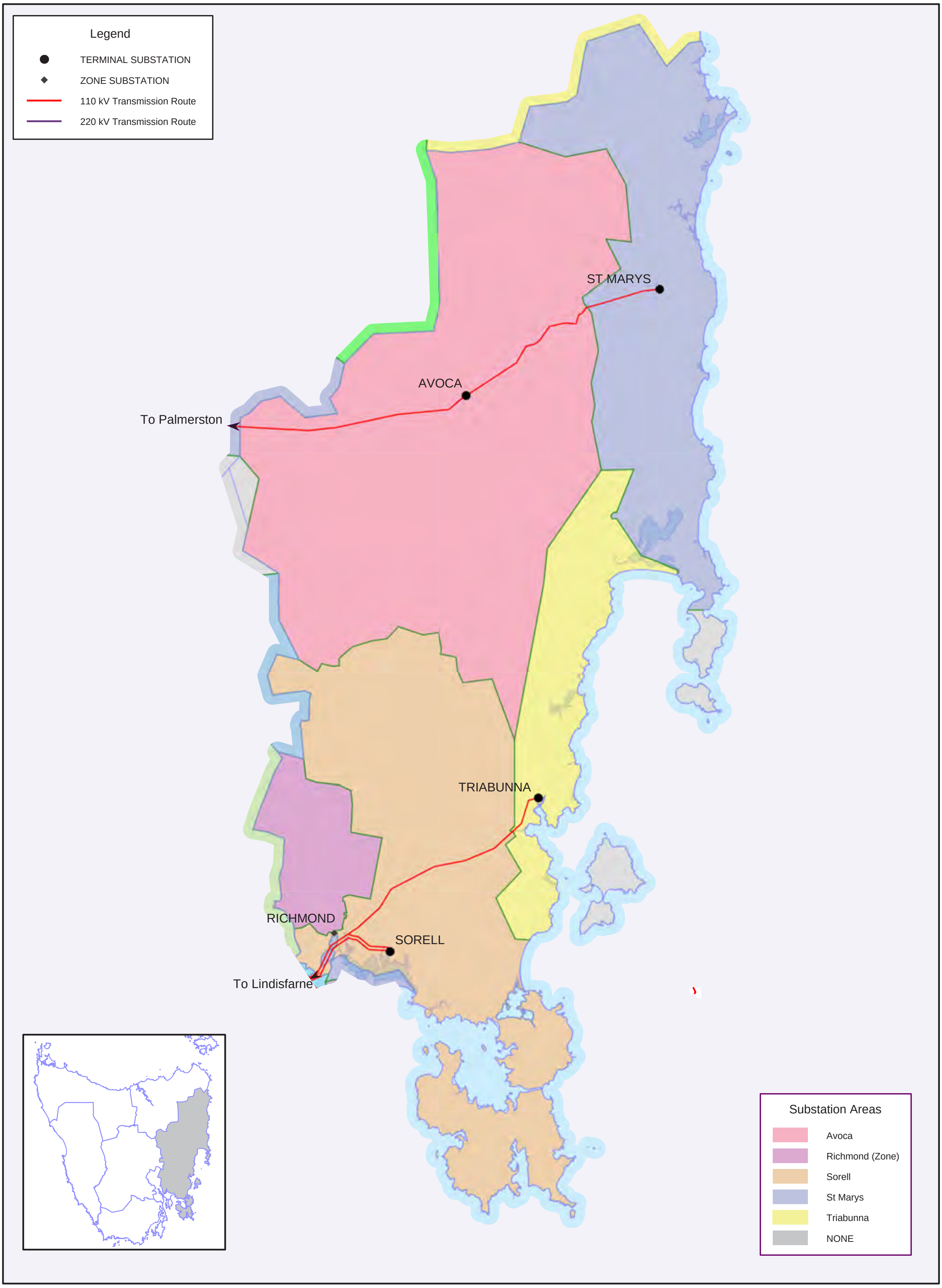


Figure 6-16: Eastern planning area network

6.7.3 Issues, solutions and developments

This section details the existing and forecast issues in the Eastern area. It also presents the potential and preferred solutions to alleviate these issues and any other proposed developments. Figure 6-17 presents a simplified diagram of the supply arrangement in the area. Only the relevant portion of the network is shown. The figure highlights the current and emerging constraints and asset condition issues in the area over the next ten years.

6.7.3.1 Constraints and inability to meet network performance requirements

Table 6-31 presents the area of the identified constraints and inability to meet network performance requirements, a brief description of the issue itself, the year in which the issue is forecast to materialise, the proposed solution and reference to further in the chapter where more detail is provided.

6.7.3.2 Asset replacement

Table 6-32 presents a summary of the identified asset condition issues over the next ten years, including the area and description of the issue, the proposed solution, and reference to further in the chapter where more information is provided.

6.7.3.3 Network capability improvement parameter action plan

Table 6-33 summarises the NCIPAP projects to be completed in the Eastern area by the end of the 2014–19 transmission regulatory period. It lists the benefits, cost and timing of each project. There are other programs which include substations the Eastern area, listed in Section 6.9.2.3.

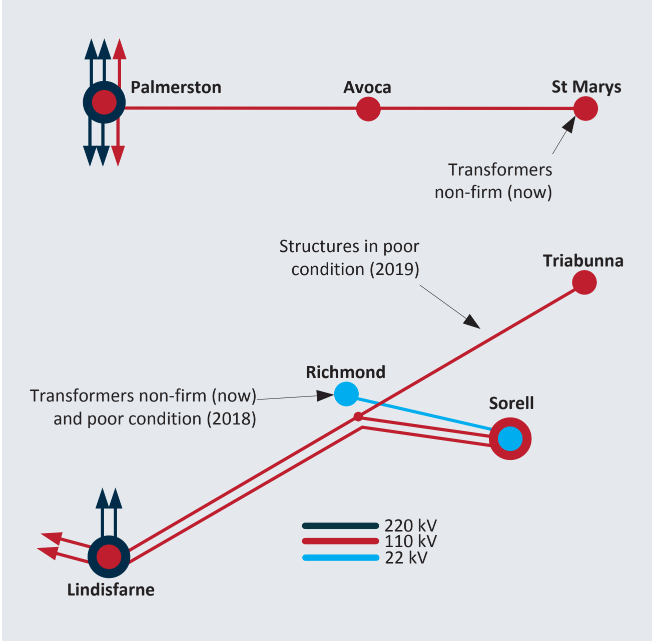


Figure 6-17: Current and emerging issues in the Eastern area

6.7.3.4 Communities with poor reliability

Table 6-34 summarises the communities with poor reliability in the Eastern area. There are eight communities with trending poor reliability (5-year average) plus the Sorell community which is a newly poor performing community in 2014.

The reliability of the four communities in and around the Tasman Peninsula (Copping-Dunalley, Forestier Peninsula, Pirates Bay-Nubeena-Port Arthur and Tasman Peninsular Rural) was severely affected by the January 2013 bushfire, then major event days in 2014. We rebuilt the distribution network in the area affected by the

Table 6-31: Eastern area constraints and inability to meet network performance requirements

Area of issue	Issue	Forecast year	Proposed solution	Reference
Richmond Zone Substation	Supply transformers non-firm and regulating transformer overload	Current	Under investigation	6.7.3.5
St Marys Substation	Supply transformers non-firm	Current	Continue emergency load shedding scheme	6.7.3.6

Table 6-32: Eastern area asset condition issues

Area of issue	Issue	Proposed solution (year)	Reference
Triabunna Spur transmission line	Condition of Kay pole support structures	Replace structures (2019)	6.7.3.7
Richmond Zone Substation	Condition of supply and regulating transformers	Replace transformers (2018)	6.7.3.5

Table 6-33: Eastern area NCIPAP projects

Project	Benefit	Location	Cost ($000)	Timing
Transmission line substandard clearance compliance program	Reduced operational and safety risk and compliance with Australian Standards	Palmerston–Avoca 110 kV transmission line	926	March 2016

Table 6-34: Eastern area community supply reliability

Reliability community	Category	Measure exceeded	Proposed solution	Reference
Trending poor performing communities				
Midway Point	Urban	SAIDI	Monitor	N/A
St Helens	Urban	SAIDI	Loop automation	6.7.3.8
Copping–Dunalley	High density rural	SAIDI	Monitor	N/A
Forestier Peninsula	High density rural	SAIDI	Monitor	
Pirates Bay–Nubeena–Port Arthur	High density rural	SAIFI and SAIDI	Monitor	
Fingal Valley Rural	Low density rural	SAIDI	Under investigation	
Ross Rural	Low density rural	SAIDI	Under investigation	
Tasman Peninsula Rural	Low density rural	SAIFI and SAIDI	Monitor	
New poor performing communities in 2014				
Sorell	Urban	SAIDI	Monitor	N/A

bushfire and, with a reduction in vegetation as a result of the bushfire, we expect the reliability to further improve in 2015, subject to no major event days.

St Helens community has not met its reliability standards in recent years; major event days were the main contributing factor in 2014, contributing more than 50 per cent towards the SAIDI measure. Midway Point community average reliability performance is marginally non-compliant, also predominantly affected by major event days in 2014 – the average prior to 2014 met standards. Fingal Valley Rural community SAIDI had more than 50 per cent contribution in 2014 from planned work, primarily associated with new and upgraded connections as part of the new irrigation scheme. However, Fingal Valley Rural and Ross Rural communities have had poor and marginal reliability performance in recent years.

The primary contributing factors to the Sorell community, newly poor performing in 2014, was a switchgear failure which contributed more than 50 per cent to the SAIDI measure. Otherwise this community has historically met its reliability standards and we expect it to again meet its standards in 2015.

We propose a project to bring reliability up to standard in the St Helens community. Further, we are investigating the causes of poor performance at an additional two communities in the Eastern area as part of our investigation into the seven worst performing feeders in the state.

For the remaining communities, we currently do not propose any augmentation projects to improve reliability; however we will continue to implement operational measures as part of targeted reliability improvement programs.

We will continue to monitor the reliability performance in these communities.

6.7.3.5 Richmond Zone Substation transformer condition and capacity

Issue overview

The two supply transformers at Richmond Zone Substation have a continuous firm rating of 2.5 MVA and cyclic rating of 3.3 MVA.[28] The regulating transformer T580144 has a continuous rating of 3 MVA. Figure 6-18 presents the arrangement of Richmond Zone Substation.

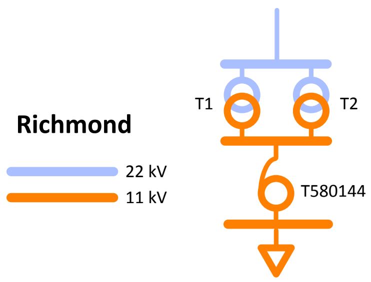


Figure 6-18: Richmond Zone Substation

The maximum demand at Richmond Zone Substation in 2014 was 3.1 MVA; as such the regulating transformer at Richmond Zone Substation is currently overloaded during times of maximum demand. The supply transformers are operated above their continuous firm rating, however the cyclic firm rating is forecast to be exceeded from winter 2021. The supply transformers are of star-delta winding arrangement, resulting in a phase shift which prevents live load transfers to adjacent substations.

In addition to the loading limitation, the transformers are approaching end of life. The supply transformers were manufactured in 1960, are in poor condition and are expected to reach end of life within the next five years.

28 Generic 30 per cent cyclic rating applied – no specific studies undertaken.

Table 6-35: St Marys Substation limitation deferral

Deferral period	Maximum demand (2014) (MVA)	Generation support or reduction in forecasted load (MVA)
One year	12.9	1.0
Five years		1.6

Potential solutions

Due to the poor condition of the transformers, we propose to replace the supply and regulating transformers. We will replace the transformers with larger units to cater for the maximum demand at the substation. We propose to replace these transformers by June 2018, and are considering two main options as follows:

- replace with two standard 5 MVA units; or
- replace with a single standard 5 MVA unit and invest in the distribution network to increase load transfer capability between Richmond Zone Substation and other substations.

Prior to the transformer replacement, we need to manage the loading limitations at Richmond Zone Substation. The following are some potential solutions we will investigate to manage this issue:

- provide further load transfers between Richmond and Cambridge zone substations;
- install 'smart' switches to provide fast load transfers;
- investigate cyclic rating of power transformers to confirm capability; and
- install peak-shaving generation to reduce peak load.

6.7.3.6 St Marys Substation transformer capacity

Issue overview

St Marys Substation comprises two 10 MVA transformers, each with a short term rating of 12 MVA. The maximum demand at St Marys Substation in 2014 was 12.9 MVA[29], currently exceeding the short-term firm rating of the substation.

To prevent overloading the remaining in-service transformer in the event of a fault on the other unit, we utilise an emergency load-shedding scheme. This scheme is armed when the load is above the firm rating of the transformers. In case of a fault on one transformer, the scheme will open distribution feeder circuit breakers until the load is within the rating of the remaining in-service transformer. This results in interruption to customer supply until supply can be restored either by transferring the interrupted feeders to adjacent substations or waiting until demand reduces and the interrupted feeder can be brought back into service.

Limitation deferral

Table 6-35 presents the requirements to defer the identified non-firm issue at St Marys Substation. The table presents the reduction in the forecasted load, or amount of generation support, required to defer the limitation by either one (to 2016) or five (to 2020) years. The reduction detailed is to maintain the load below 12 MVA, the four-hour short-term firm capacity.

Load transfer is available from St Marys Substation to Avoca, Triabunna and Derby substations.

Potential solution

Although St Marys Substation is operated non-firm, with the transformer short-term ratings and load transfer capabilities we do not currently propose to replace these transformers. We will continue to utilise the emergency load-shedding scheme and monitor this issue in future years.

29 This was during periods of load transfer to St Marys Substation. The maximum demand under normal network arrangement was 11.6 MVA.

6.7.3.7 Triabunna Spur transmission line Kay pole replacement program

Issue overview

A Kay pole is a transmission line support structure that consists of a single vertical steel pole supported by four, shorter, steel pole 'legs'. It is stabilised by guy wires attached between the base of each leg and the top of the vertical steel pole – see Figure 6-19. These poles were designed during the First World War when steel availability was limited.

We have 41 Kay pole support structures, reclaimed from a previous installation and now installed as part of the Triabunna Spur 110 kV transmission line. These structures were built in 1927, making them 88 years of age. They are approaching their end of service life and we are monitoring their condition.

The Triabunna Spur transmission line is a radial transmission line, a single asset failure will result in an immediate and sustained interruption to supply.

Figure 6-19: A Kay pole support structure

Proposed solution

Our current proposal is to replace the 41 Kay poles on the Triabunna Spur transmission line with new steel poles. However we are also investigating other options, including alternate supply arrangements to Triabunna Substation and the surrounding area, to determine if replacing these towers like-for-like is the most appropriate solution.

The estimated cost of these of the Kay pole replacement works is $3.7 million and implementation is scheduled for completion in 2019.

6.7.3.8 St Helens reliability community

Issue overview

The St Helens urban reliability community is the small area around St Helens township. It is supplied via a single 22 kV overhead feeder from St Marys Substation. This feeder is approximately 35 km long, and traverses through a low density rural community, with lower reliability standards, before supplying St Helens. Backup supply is provided via the parallel feeder from St Marys Substation and a feeder from Derby Substation. Figure 6-20 presents the supply arrangement of the St Helens reliability community.

Supply reliability in St Helens has deteriorated in the last four years. The community has not met its SAIDI standard in the past three years.

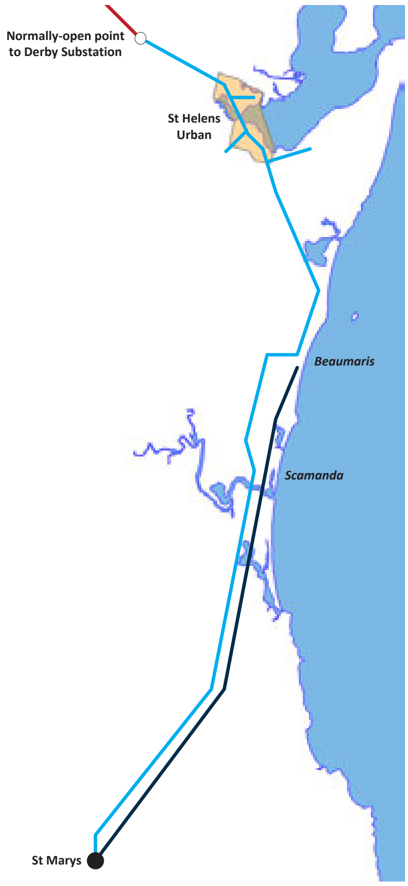


Figure 6-20: St Helens urban reliability community

Proposed solution

We propose to implement a loop automation scheme to improve the reliability to St Helens. This would allow supply to be automatically restored (less than one minute) following a sustained interruption to supply. Our proposal is to install a new recloser at the edge of the community on the feeder from St Marys Substation. For sustained faults affecting St Helens, this scheme will operate to transfer supply to Derby Substation, restoring supply to the St Helens community.

The estimated cost of the loop automation scheme is $60,000 and it is scheduled to be implemented in 2016.

6.7.4 Deferred or averted issues in the Eastern area

6.7.4.1 Smart grid controller for Palmerston–Avoca–St Marys supply security

Section 6.6.6.2 of Transend Networks' 2014 APR discussed supply security issues for customers supplied from the Palmerston–Avoca and Avoca–St Marys 110 kV transmission lines. It was identified the loss of the Palmerston–Avoca or Avoca–St Marys 110 kV transmission circuits or the supply transformer at Avoca Substation could result in more than 300 MWh of unserved energy. This would not meet the performance requirements of the ESI Regulations. The identified solution was to augment the distribution network to allow remotely-switched and increased load transfers away from the affected substations, and then implement a self-healing network. The self-healing network, implemented through a smart grid controller, would reduce the outage time following the outage to a few minutes with supply restoration provided through automatic switching in the distribution network.

As detailed in Section 6.7.2.2 of this APR, we have completed the distribution works in the area. This has increased the load transfer capacity between substations such that we now meet the 300 MWh performance requirement of the ESI Regulations. As such, there is no immediate requirement to implement a smart grid controller in the area to facilitate a self-healing network. We will continue to monitor this issue in future years.

6.7.4.2 St Marys Substation total transformer capacity

Section 6.6.6.1 of Transend Networks' 2014 APR discussed supply capacity issues at St Marys Substation. Based on the maximum demand forecast in 2014 and the possible connection of a new customer, the load at St Marys Substation was forecast to be such that there would be insufficient capacity to supply the connected load. Transend Networks identified in its 2014 APR the preferred solution was to replace the transformers with larger units recovered from the proposed transformer replacement at Rosebery Substation.

Due to reduced demand forecast and cognisant that the possible new customer connection is not committed, we do not expect the capacity at St Marys Substation to be exceeded until after 2024. We have therefore deferred proposals for any remedial works in this area. We will continue to monitor this issue in future years. The maximum demand at St Marys Substation remains above the firm rating of the transformers, as detailed in Section 6.7.3.6 of this APR, however it is manageable.

6.7.5 Availability to connect in the network

Table 6-36 presents the spare capacity available at substations in the Eastern area. Avoca Substation is a single transformer substation, therefore inherently operates non-firm. For this substation, the available capacity given here is for the transformer capacity rather than the firm capacity.

Table 6-36: Eastern area substation capacity availability

Substation	Connection voltage (kV)	Firm capacity (MVA)	2014 (MVA)		2025 (MVA)	
			Actual MD	Available capacity	Forecast MD	Available capacity
Sorell	22	60	29.3	30.7	34.0	26.0
Triabunna	22	25	7.0	18.0	10.3	14.7
Richmond	11	2.5	3.1	0	3.5	0
Avoca	22	0	7.9	9.1	14.1	2.9
St Marys	22	10	12.7	0	14.6	0

6.8 Kingston-South planning area

6.8.1 Area network overview

The Kingston-South planning area covers the area south of Hobart and includes the Kingborough and Huon Valley areas of Tasmania, including Bruny Island. The area is characterised by the urban area around Kingston, with the rest of the area predominantly rural. Figure 6-21 presents a geographical diagram of the Kingston-South area.

The area is supplied via a double-circuit 110 kV transmission line from Chapel Street Substation (in Glenorchy). The distribution network, operated at 11 kV, is supplied from four terminal substations and one zone substation. There is also one customer directly supplied from the transmission network at Huon River Substation. Summerleas Zone Substation, commissioned in 2014 to manage the supply issues around Kingston, is the most recent work to augment supply in the area.

There is no transmission-connected generation or embedded generation unit larger than 0.5 MW in the Kingston-South planning area. However there is approximately 8.4 MW of combined rooftop PV installed capacity.

6.8.2 Committed and completed projects

This section describes the material network projects that are committed (construction has begun or a firm date has been set) or have been completed in the Kingston-South area in the past year.

6.8.2.1 Committed

Castle Forbes Bay Tee Switching Station disconnector upgrade

A manually operated disconnector is located at Castle Forbes Bay Tee to facilitate the disconnection and reconnection of the Huon Valley Spur transmission line to the Knights Road–Kermandie 110 kV transmission circuit. This presents operational and reliability issues for supply to Huon River and Kermandie substations.

This project involves the replacement of the manually-operated disconnector with a remotely-operable unit, which will improve supply reliability to Kermandie Substation. It will reduce the time taken to restore supply following a fault and improve operational flexibility. This project forms part of the NCIPAP projects in our 2014–19 transmission regulatory period.

This project is scheduled to be completed in February 2016.

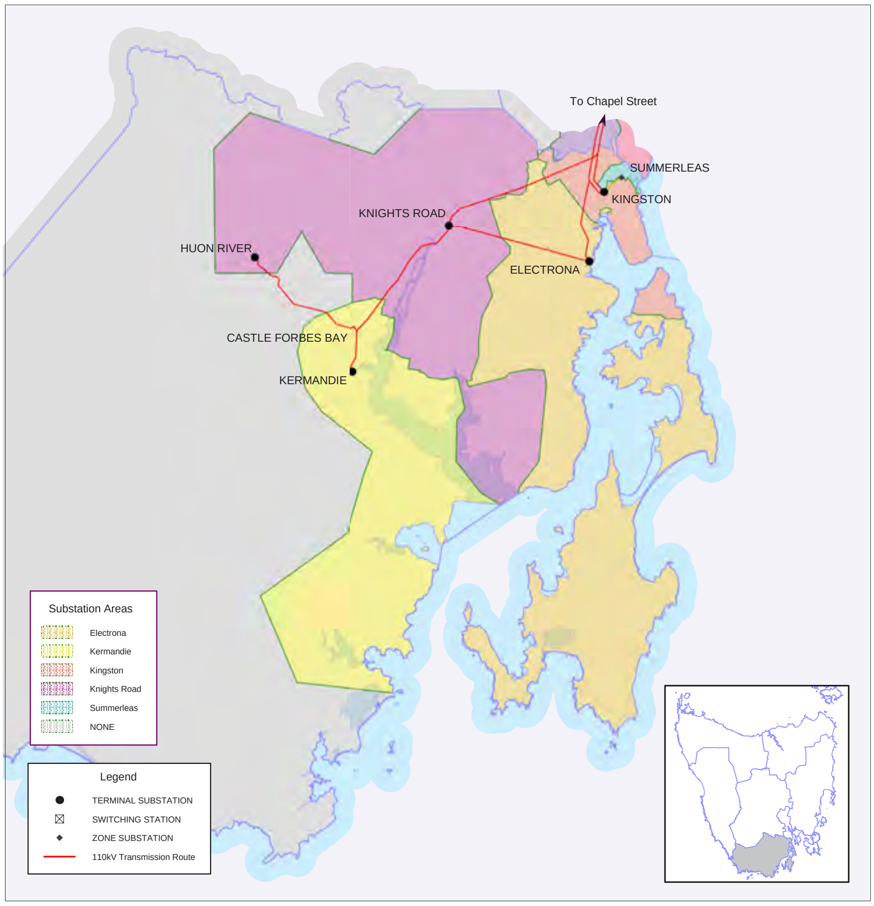


Figure 6-21: Kingston-South planning area network

Dynamic rating of Knights Road Substation supply transformers

The maximum demand at Knights Road Substation is approaching the continuous firm rating of the transformers. This project involves the installation of remote monitoring equipment on the transformers. This will allow the transformer to be operated above its name-plate rating by monitoring the transformer temperature in real-time. This project forms part of the NCIPAP projects in our 2014–19 transmission regulatory period.

This project is scheduled to be completed in February 2016.

Line fault indicator communications program (Castle Forbes Bay Tee Switching Station)

Following a fault on the Knights Road–Huon River–Kermandie 110 kV transmission circuit, crews are required to travel to the line fault indicator at Castle Forbes Bay Tee Switching Station to establish which section of the line received the fault. This project comprises the installation of remote fault indication at Castle Forbes Bay Tee Switching Station. This will allow the faulted section of the line to be determined remotely, thereby reducing the time to return the non-faulted section of line to service. This project forms part of the NCIPAP projects in our 2014–19 transmission regulatory period.

This project is scheduled to be completed in July 2015.

6.8.2.2 Completed

There were no material completed projects in the Kingston-South area in the last year.

6.8.3 Issues, solutions and developments

This section details the existing and forecast issues in the Kingston-South area. It also presents the potential and preferred solutions to alleviate these issues and any other proposed developments. Figure 6-22 presents a simplified diagram of the supply arrangement in the area. Only the relevant portion of the network is shown. However there are no current or emerging constraints and asset condition issues in the area over the next ten years.

6.8.3.1 Constraints and inability to meet network performance requirements

There are no constraints or inability to meet network performance requirements for the Kingston-South area in the 2015 APR for the next ten years.

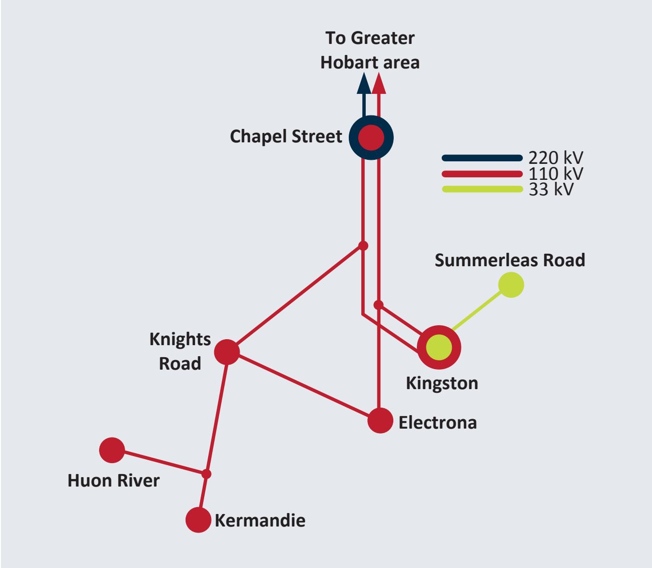


Figure 6-22: Current and emerging issues in the Kingston-South area

6.8.3.2 Asset replacement

There are no material asset replacement projects identified for the Kingston-South area in the 2015 APR for the next ten years.

6.8.3.3 Network capability improvement parameter action plan

Table 6-37 summarises the remaining NCIPAP projects to be completed in the Kingston-South area by the end of the 2014–19 transmission regulatory period. It lists the benefits, cost and timing of each project. There are other programs which include substations the Kingston-South area, listed in Section 6.9.2.3.

6.8.3.4 Communities with poor reliability

Table 6-38 summarises the communities with poor reliability in the Kingston-South area. There are three communities with trending poor reliability (5-year average) and four communities which are newly poor performing communities in 2014.

The three trending poor performing communities have not met their reliability standards on average in the past 5 years, however each has met their reliability standards in at least two of the past four years. The main cause of poor reliability in these communities in 2014 was major event days, which contributed at least 75 per cent towards the SAIDI measure.

Table 6-37: Kingston-South area NCIPAP projects

Project	Benefit	Location	Cost ($000)	Timing
Transmission line substandard clearance compliance program	Reduced operational and safety risk and compliance with Australian Standards	Knights Road–Kermandie transmission line	291	June 2019

The primary contributing factor to the four newly poor performing communities in 2014 was also major event days, where large storm events caused widespread interruptions to supply. We expect these communities will meet their standards in 2015, subject to no major event days.

We currently do not propose any augmentation projects to improve reliability in the Kingston-South area; however we will continue to implement operational measures as part of targeted reliability improvement programs. We will continue to monitor the reliability performance of these communities.

6.8.4 Deferred or averted issues in the Kingston-South area

6.8.4.1 Bruny Island submarine cable

Section 9.4.1 of Aurora Energy's 2014 APR described the supply arrangement to Bruny Island. The load on one of the two cables that supply the island has been overloaded during periods of maximum demand and there were concerns on the condition of the cable. It was proposed to utilise peak-shaving generation to manage loading issues and only replace the cable should it fail and be unable to be repaired.

We have recently completed a condition assessment of the cable. The assessment indicates the cable has at least 10 years of service life remaining. In addition, we are continuing to utilise peak-shaving generation on Bruny Island to manage loading on the cable of concern. As a result of these measures, this issue is no longer reported in the APR. We will continue to monitor the condition of the cable and utilise peak shaving.

6.8.4.2 New zone substation at Margate

Section 10.2 of Aurora Energy's 2014 APR identified a new 33/11 kV zone substation at Margate, supplied at 33 kV from Kingston Substation, would likely be required in 2021. This was primarily to manage the loading at Electrona Substation and forecast development around Margate. Due to reduction in forecast load, we have suspended our analysis of this solution with the need for this new substation being deferred past 2025.

6.8.5 Availability to connect in the network

Table 6-39 presents the spare capacity available at substations in the Kingston-South area. Summerleas Zone Substation is a single transformer substation, therefore inherently operates non-firm. For this substation, the available capacity given here is for the transformer capacity rather than the firm capacity.

Table 6-38: Kingston-South area community supply reliability

Reliability community	Category	Measure exceeded	Proposed solution	Reference
Trending poor performing communities				
Margate-Snug	Urban	SAIDI	Monitor	N/A
Bruny Island Rural	Low density rural	SAIDI		
Channel Rural	Low density rural	SAIDI		
New poor performing communities in 2014				
Huonville	Urban	SAIDI	Monitor	N/A
Huon-Channel	High density rural	SAIDI		
Huonville-Cygnet	High density rural	SAIDI		
Huonville Rural	Low density rural	SAIDI		

Table 6-39: Kingston-South area substation capacity availability

Substation	Connection voltage (kV)	Firm capacity (MVA)	2014 (MVA)		2025 (MVA)	
			Actual MD	Available capacity	Forecast MD	Available capacity
Electrona	11	25	13.3	11.7	15.5	9.5
Kermandie	11	10	6.0	4.0	6.9	3.1
Kingston (33 kV)	33	60	12.0	48.0	13.9	46.1
Kingston (11 kV)	11	35	26.9	8.1	28.2	6.8
Knights Road	11	20	16.5	3.5	19.4	0.6
Summerleas	11	0	12.0	13.0	13.9	11.1

6.9 State-wide and inter-area projects

This section discusses the proposed developments in the network that are state-wide or cross planning area boundaries.[30] It generally considers the issues and proposed projects in the bulk transmission network, made up of the 220 kV network and parallel 110 kV network that supports it.

6.9.1 Committed and completed projects

This section describes the material state-wide or inter-area network projects that are committed (construction has begun or a firm date has been set) or have been completed in the past year.

6.9.1.1 Committed

Fifteen minute short-term ratings

Short-term ratings allow assets to carry more power for a short period of time than they otherwise would. This project comprises the establishment of fifteen minute short-term ratings for parallel transmission circuits. This will allow higher power transfer with existing assets. Following a fault on a circuit, the power transfer through the circuit can be reduced to normal levels within fifteen minutes without causing damage or safety risk. This project forms part of the NCIPAP projects in our 2014–19 transmission regulatory period.

This project is scheduled to be completed in June 2016.

Installation of line fault location functionality

Palmerston–Hadspen, Palmerston–Sheffield and Sheffield–Burnie 220 kV transmission lines do not have fault location relay capability. This project comprises the installation of new protection relays on these transmission lines with modern units capable of fault location functionality. This will reduce the time taken to locate faults, allowing quicker restoration of the affected line. This project forms part of the NCIPAP projects in our 2014–19 transmission regulatory period.

This project is scheduled to be completed in June 2016.

Line fault indicator program

We have identified selected radial transmission circuits with no fault indication capability. These circuits all supply load in excess of 20 MW; extended outages of these circuits can impact our overall supply reliability. This project comprises the installation of line fault indicators on the Farrell–Que–Savage River–Hampshire, Lindisfarne–Sorell–Triabunna, Farrell–Rosebery–Queenstown and Norwood–Scottsdale–Derby 110 kV transmission circuits. This will allow shorter restoration time following the loss of these circuits due to a fault by providing indication of the fault location rather than a line patrol being required. This project forms part of the NCIPAP projects in our 2014–19 transmission regulatory period.

This project is scheduled to be completed in November 2016.

6.9.1.2 Completed

Transmission line dead-end assembly rating upgrade (Liapootah–Palmerston No. 1 220 kV transmission line)

In 2012 we identified a number of conductor dead-end assemblies on 220 kV transmission lines were not sufficiently rated. These circuits were de-rated, which imposed transmission constraints on these critical circuits. This project comprised the upgrade of the assemblies on Liapootah–Waddamana No.1 220 kV transmission line to remove the rating limitation. This project formed part of the NCIPAP projects in our 2014–19 transmission regulatory period and was completed in December 2014.

6.9.2 Issues, solutions and developments

This section details the existing and forecast issues that are state-wide or across planning areas. It also presents the potential and preferred solutions to alleviate these issues and any other proposed developments.

6.9.2.1 Constraints and inability to meet network performance requirements

There are no constraints or inability to meet network performance requirements that are state-wide or inter-area in the 2015 APR for the next ten years.

6.9.2.2 Asset replacement

Table 6-40 presents a summary of the identified asset condition issues over the next ten years, including the area and description of the issue, the proposed solution, and reference to further in the chapter where more information is provided.

30 *Planning areas detailed in Section 3.5 of this APR*

Table 6-40: State-wide and inter-area asset condition issues

Area of issue	Issue	Proposed solution (year)	Reference
Waddamana–Bridgewater Junction 110 kV transmission line	Condition of transmission line	Asset renewal (2019)	6.9.2.4
Upper Derwent 110 kV transmission lines	Condition of transmission lines	Issue currently under investigation	6.9.2.5
All substation supply points	Risk of substation failure	Transportable substation (2019)	6.9.2.6

Table 6-41: State-wide and inter-area NCIPAP projects

Project	Benefit	Location	Cost ($000)	Timing
Transmission lines – dead end assembly rating upgrade program stage 2	Increased power flow capability	Liapootah–Chapel Street 220 kV and Hadspen–Norwood 110 kV transmission lines	640	May 2017
Power transformer dynamic rating program	Increased power flow capability and online condition monitoring	All 220/110 kV network transformers	900	June 2017
Transmission line lightning protection program	Minimise likelihood of flashover from lightning strikes	Sheffield–Farrell, Farrell–Reece, Farrell–John Butters 220 kV and Farrell–Rosebery–Queenstown 110 kV transmission lines	550	March 2018
Weather station telemetry renewal program	Upgrade weather stations to BOM standard	State-wide (except Creek Road)	900	June 2019

6.9.2.3 Network capability improvement parameter action plan

Table 6-41 summarises the NCIPAP projects to be completed that are state-wide or inter-area by the end of our 2014–19 transmission regulatory period. It lists the benefits, cost and timing of each project.

6.9.2.4 Waddamana–Bridgewater 110 kV transmission line condition

Issue overview

The Waddamana–Bridgewater Junction 110 kV transmission line is a single circuit transmission line (single circuit strung both sides of double circuit tower, connected together to create one circuit) that was constructed in 1943. The circuit arrangement is shown in Figure 6-23. Due to its poor physical condition, significant refurbishment and increased operational and maintenance activities are required to sustain this as a safe and reliable transmission line. The Waddamana–Lindisfarne 220 kV double circuit transmission line, commissioned in 2011, now carries bulk power flow into Hobart's eastern shore.

Proposed solution

The options considered to address this issue were:

- local generation source at Bridgewater Substation; and
- circuit re-arrangement to create Waddamana–Bridgewater–Lindisfarne transmission circuit.

Our current preferred option is to create the Waddamana–Bridgewater–Lindisfarne 110 kV transmission circuit. We have not identified a credible option for the provision of local generation at Bridgewater Substation.

This new circuit arrangement will be achieved by re-connecting a currently unused 110 kV circuit in this corridor. This arrangement will allow transmission security to Bridgewater Substation to be maintained, via the double circuit Lindisfarne–Bridgewater transmission line, following the proposed decommissioning of the Waddamana–Bridgewater Junction section of the Waddamana–Lindisfarne 110 kV in the future. The proposed and future circuit arrangements are shown in Figure 6-23.

The estimated cost of the project is $1.9 million and proposed implementation is scheduled for completion by June 2019.

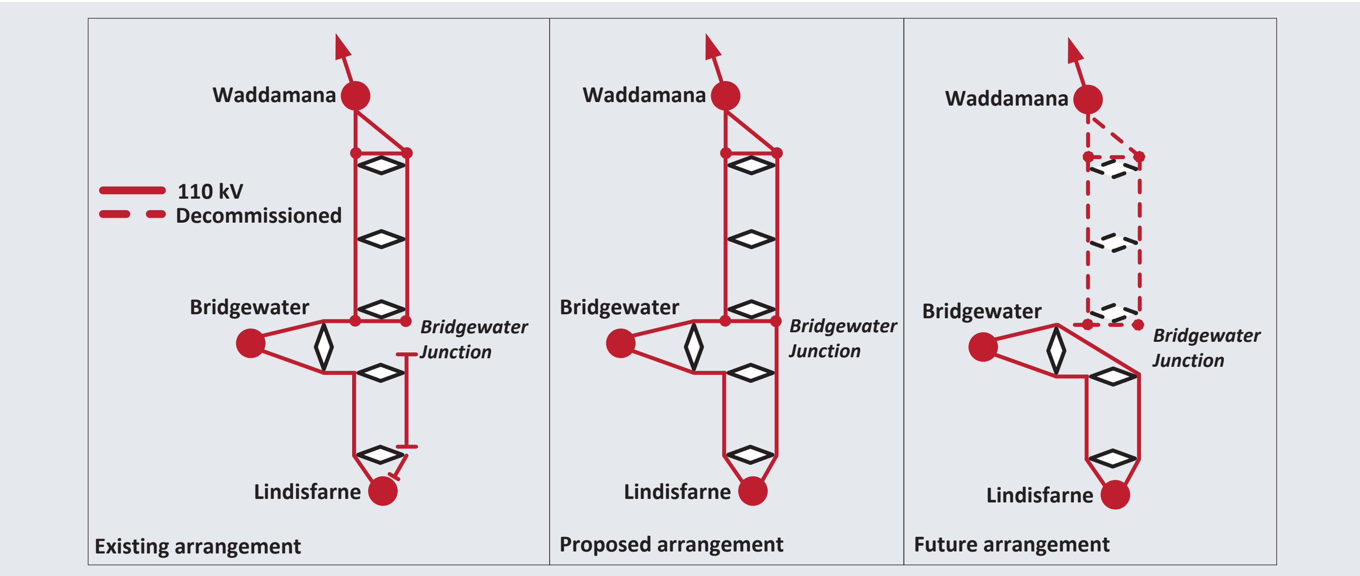


Figure 6-23: Waddamana–Bridgewater–Lindisfarne existing (left), proposed (centre) and future (right) supply arrangements

6.9.2.5 Southern Tasmanian transmission network rationalisation

Issue overview

The Upper Derwent 110 kV network has some of the oldest transmission lines in Australia. These lines were progressively commissioned from the mid-1930s to the mid-1950s, with some upgrades undertaken between 1999 and 2003. These lines are approaching the end of their service life are in poor condition.

The main purpose of the 110 kV transmission lines in the Upper Derwent area is to connect 300 MW of generation to the rest of the transmission network. The maintenance cost of these lines is becoming uneconomical due to the poor condition of the assets. The construction in 2011 of the double circuit Waddamana–Lindisfarne 220 kV transmission line has provided a secure 220 kV transmission network to southern Tasmania and has relieved constraints that existed on the Liapootah–Chapel Street 220 kV transmission corridor. This has reduced the requirement of the southern 110 kV network for bulk transmission purposes. The southern Tasmanian transmission network is presented in Figure 6-24.

Proposed solutions

With the majority of these 110 kV lines approaching their end of life, with asset health degrading and operational risks increasing, we are investigating whether we maintain the existing transmission lines in the Upper Derwent 110 kV or an alternate option. Alternate options to maintaining the existing network could include transferring all the generation in the area onto the 220 kV network, rationalising the supply through the 110 kV network, or a combination of these.

We have identified a number of options as an alternative to the existing network arrangement that we are investigating. These options were developed with the consideration of asset condition and available capacity of the existing network; available transmission line easements; possible access points to 220 kV network; and network requirements. However it is likely that any significant expenditure will not be required until at least the regulatory period commencing in 2019.

We are continuing studies to identify the possible non-network options available to maximize the benefits to the customers through this rationalisation process.

6.9.2.6 Transportable substation

Issue overview

We have identified advantages in holding a portable substation to enable time efficient customer connection. This would be available in situations such as mine site developments, where a rapid deployment is required within a minimal timeframe. Such a solution, being created from readily portable assets, could be re-deployed once the need for it at a particular location ceases.

A portable substation may also allow us to restore supply to communities following an extended interruption to supply. We may be able to use this to provide continuity of supply during planned and unplanned outages.

Proposed solution

To cater for these two scenarios it is prudent to hold a complete substation in a modular and portable format. The system will be modular in design, ie 110 kV switchgear and high voltage switchgear able to be transported individually (containerised). The transformer will be 110 kV to 22 and 11 kV and rated at 25 MVA.

The estimated cost of the project is $8.0 million, with proposed purchase by 2019.

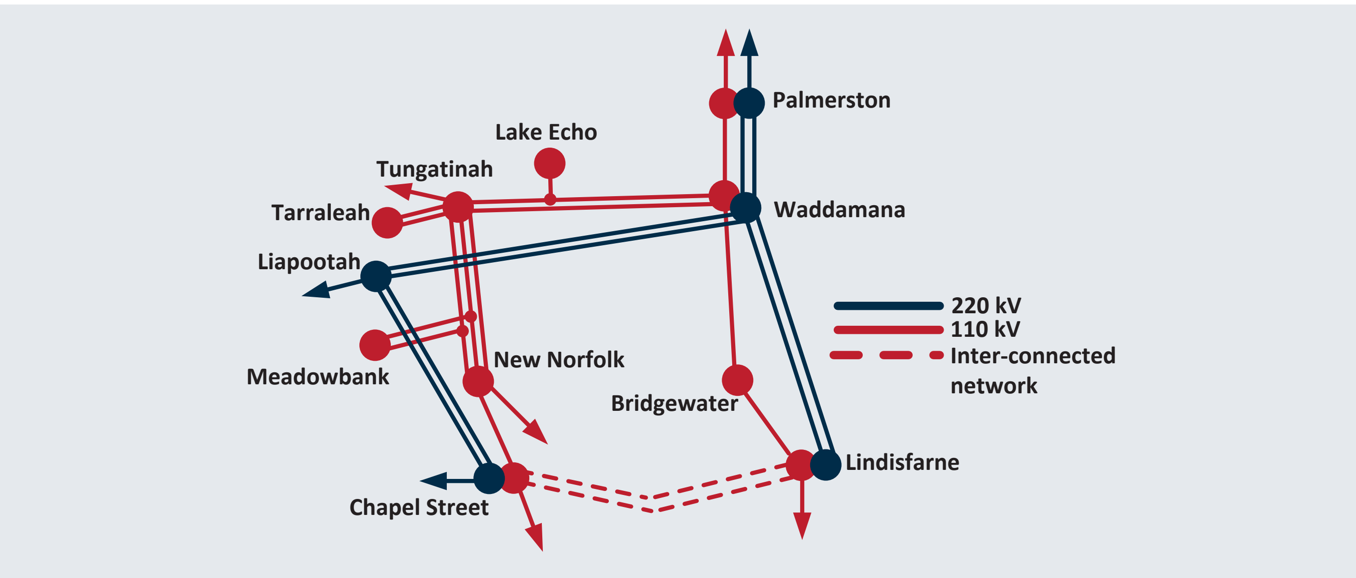


Figure 6-24: Southern transmission study network

6.9.3 Deferred or averted state-wide and inter-area issues

6.9.3.1 Waddamana–Palmerston 220 kV transmission security

Section 6.7.6.5 of Transend Networks' 2014 APR discussed power system security issues associated with the transmission corridor between Waddamana and Palmerston substations. This corridor provides the link between northern and southern sections of the Tasmanian transmission network. Under some generation dispatch conditions, loss of the double circuit 220 kV transmission line between Waddamana and Palmerston substations could cause the Tasmanian power system to split into two electrical islands. In turn, at times of insufficient generation in the area, this could result in a black out and loss of supply to all customers in southern Tasmania. Even if the southern Tasmania power system did not completely black out, there would be significant customer load loss as the result of under frequency load shedding. Our preferred option to address this issue was to augment the Waddamana–Palmerston 110 kV transmission line to 220 kV. This would provide three 220 kV circuits between Waddamana and Palmerston substations, strengthening the transmission network between northern and southern Tasmania.

Our economic evaluation of this issue, using probabilistic contingency and unserved energy analysis, showed that a positive market benefit would result from the proposed project when load in southern Tasmania reaches 726 MW. This was forecast for winter 2019.

Due to reduced demand forecast, the year at which this project becomes economically viable is deferred. We have therefore deferred proposals for any augmentation in the Waddamana–Palmerston transmission corridor. We will continue to monitor this issue in future years, including further exploring non-network and other innovate solutions which may be viable at lower demand levels to address this issue.

6.9.3.2 Voltage support for Hobart and surrounding areas

Section 6.7.6.7 of Transend Networks' 2014 APR discussed the voltage support required in Hobart and surrounding areas. At a southern Tasmanian load of 800 MW, we would not be able to meet Schedule S5.1.8 of the Rules for a Liapootah–Cluny–Repulse–Chapel Street 220 kV transmission circuit fault. This requires a reactive margin of 1 per cent of the maximum fault level at each bus to be maintained to ensure voltage stability. The preferred option to address this issue was to install two 40 MVAr 110 kV capacitor banks at Creek Road Substation.

A southern Tasmanian load of 800 MW was forecast to occur in 2021. Due to reduced demand forecast, this is now forecast to occur in 2028. This is past our planning period of 10 years and therefore we have deferred proposals to address this issue. We will continue to monitor the issue in future years.

6.9.4 Network innovation and trial projects

We have investigated and implemented a number of projects that are alternatives to traditional investment in poles and wires. Such projects are termed "non-network" projects. This section details a selection of the non-network solutions we have investigated or implemented, and trial projects either underway or recently completed.

Aside from our own process of developing non-network solutions, we welcome feedback and invite proposals on approaches to managing our network issues. We welcome feedback to particular issues raised in this APR or proposals at any time.

6.9.4.1 Mesh radio

Much of TasNetworks' communication with field devices such as reclosers and voltage regulators utilises commercially available mobile network. These communications arrangements do not have the reliability and expansion capability that is required in the longer term. We are currently trialling an alternative mesh radio system, which could be wholly owned by TasNetworks and scalable as needed. If successful, such a communications system will:

- reduce cost of communications to TasNetworks field devices;
- be less vulnerable to bad weather or congestion; and
- allow more economic communications with more field devices.

We have awarded a contract for the mesh radio trial, which is planned to be implemented in the Bridgewater/Brighton area. The trial should be completed by the end of 2015.

6.9.4.2 Virtual network monitoring

Virtual network monitoring uses mathematical techniques to estimate the load in parts of the distribution network where no monitoring exists. This allows us to study potential problems in the distribution network more accurately than would otherwise be possible, without the cost of installing monitoring equipment.

TasNetworks completed the first stage of the virtual network monitoring project in 2014. This system is estimating load in urban areas, and has proven successful. We intend to extend the system to other parts of Tasmania.

6.9.4.3 Advanced distribution management system

Currently, many switching elements in the distribution network are remotely controlled. This will increase with the mesh radio system as more devices become capable of remote control. These devices are still manually controlled by control room operators in most cases.[31] An advanced distribution management system would place an automation layer over the top of the remote control. This allows faster fault finding and faster load restoration.

31 Excluding 'loop automation' sites. This style of automation can only be implemented in specific circumstances.

We are planning a trial of the advanced distribution management system at Strahan. Strahan's power is supplied from Queenstown, via a single 30 km 22 kV feeder. A fault on this feeder will result in a blackout of Strahan. TasNetworks has installed two backup diesel generators at Strahan, which can provide power to the town if the feeder is faulty. However, the process of starting these generators following a feeder fault currently requires operator intervention. The advanced distribution management system will automate the generator start-up and supply restoration following a feeder fault, which will reduce the time which Strahan is without power.

6.9.4.4 Remote area power supplies

Some parts of the distribution network are underutilised because there are long sections of feeders supplying very small loads. These sections of the network are expensive to maintain. Some of these loads can be supplied more economically using a Remote Area Power Supply (RAPS). We have implemented a hybrid diesel/battery RAPS at Crotty Dam, allowing a long feeder to be decommissioned. Currently the Crotty Dam RAPS system is operating at a reliability level exceeding that of the original overhead line supply.

We are in the process of investigating a RAPS to supply our Mt Tim Shea radio communications site. This will likely be a hybrid solar/diesel/battery and may also include a small wind turbine.

There are several other candidate sites in Tasmania for RAPS installations. The experience we gain from these initial RAPS solutions will guide our future deployment of RAPS in other locations.

6.9.4.5 FuseSavers

FuseSavers are devices which protect an Expulsion Drop Out (EDO) fuse. These fuses are usually used to protect the main distribution feeder from tripping as a result of faults on a spur or a single transformer.

When an EDO fuse blows due to a temporary fault (for instance, debris blowing across the lines) an operator must drive to the site to replace it. This incurs labour costs, and customers are left without supply until the fuse is replaced. FuseSavers protect the fuse from transient faults, by opening before the fuse blows. They then automatically close after around 20 seconds. If the fault no longer exists, supply is restored. If the fault still exists, the fuse will then blow and an operator will rectify the fault before replacing the fuse and restoring supply.

We have trialled FuseSavers at 29 sites and are currently evaluating the next step in the trial.

6.9.4.6 Residential demand management

Section 20.3.1 of Aurora Energy's 2014 APR discussed the *Peak Performer Initiative*, a residential demand management program intended to achieve peak demand reduction via control of residential loads such as hot water heaters and heat pumps. Further work has shown that currently (i) there is unlikely to be sufficient customer participation in such a demand management scheme to achieve the intended outcomes, and (ii) even if 100 per cent participation in the scheme could be achieved, the cost of implementing widespread remote control of residential devices is likely to outweigh the potential benefits that could be achieved. Because of these factors, coupled with the low forecast of peak demand growth, we are not currently developing the Peak Performer Initiative further; however we remain open to developing it should opportunities present.

6.9.4.7 Commercial and industrial demand management

TasNetworks has been evaluating the viability of a program to reduce peak demand by engaging commercial and industrial distribution customers to reduce load during times of high demand. A customer's participation in such a scheme would be voluntary and under commercial terms acceptable to the customer. Only commercial and industrial customers in areas where demand reductions would be beneficial would be approached to participate in the program.

TasNetworks has undertaken a state-wide commercial and industrial distribution-connected load survey to identify the characteristics of the principal customers (and customer groups) across Tasmania, and the demand management potential that may be realised by such customers. The conclusion from this survey was that sufficient load reduction and customer participation is likely to be available for demand management, and further detailed investigation is warranted.

We are scoping a pilot project to prove the technical feasibility of this demand management concept. In the first instance this is expected to include demand management within selected commercial buildings. This project will involve the establishment of the necessary systems to support any subsequent program.

Assuming the pilot project proves successful, formal demand management programs with specific customers could then be implemented as needed, in particular locations where peak demand reduction would be beneficial.

6.9.5 Tariff changes

The default residential electricity tariff in Tasmania does not include any time-of-use pricing. Aurora Energy's 2014 Annual Planning Report included a discussion of proposed residential time-of-use tariff trial, followed by ongoing analysis to determine whether a residential time-of-use tariff should be introduced more broadly.

In late 2014, the Australian Energy Markets Commission made a rule which requires network tariffs to "reflect the efficient cost of providing network services to individual consumers so that they can make more informed decisions about their electricity usage." We are therefore taking a holistic review of our tariffs for all customer classes. Our main considerations in this assessment are that tariffs can be understood by customers, that the tariffs should encourage customers to use energy in a way that does not drive up network costs, and that, in the long run, optimised energy use by customers results in lower network charges being borne by the customers. We will be consulting with customers extensively during this tariff review process.

Any resulting tariff changes will be phased in gradually over a number of years, to ensure customers do not experience sudden changes in charges.

6.10 Regulatory investment tests

As detailed in Sections 5.16.3(2) and 5.17.3(2) of the Rules, we are required to undertake a regulatory investment test for all capital works projects where the augmentation component is estimated to cost more than $5 million. The regulatory investment test requires us to consult with AEMO and all interested parties; however we continue to consult with all stakeholders as part of our normal planning process. Our requirements under the regulatory investment test are detailed in Section 2.1.4.

We did not complete any regulatory investment tests in the past year, nor do we have any in progress. In addition, we do not propose any projects in this APR that will likely be subject to the regulatory investment test.

The project specification consultation report stage of the regulatory investment test will constitute our formal request for proposals under clause 5.12.2(c)(4)(iv) of the Rules. However, we welcome feedback from interested parties at any time regarding feasible options that may provide cost-effective solutions to the network issues presented in this APR.

6.11 National transmission planning

As the national transmission network planner, AEMO annually produces a National Transmission Network Development Plan (NTNDP). AEMO's web-site[32] summarises the purpose of the NTNDP as:

> *The NTNDP provides an independent, strategic view of the efficient development of the National Electricity Market transmission network over a 20-year planning horizon. The 2014 NTNDP considers the challenges and opportunities for transmission network development over the next 20 years. It focusses on the transmission network assets connecting large-scale generation to population and industrial centres in the National Electricity Market.*

The NTNDP's analysis focuses on the adequacy of the main transmission network and national transmission flow paths in a 20-year study period (to 2034). In Tasmania, the main transmission network is the 220 kV bulk transmission network and the portion of 110 kV transmission network that operates in parallel to and supports the 220 kV network. National transmission flow paths support major power transfers between zones of generation and demand centres in the NEM. Tasmania is considered a single zone and therefore there are no national transmission flow paths in Tasmania, however Basslink is a national transmission flow path linking the Tasmania and Latrobe Valley (in Victoria) zones.

The NTNDP also reports on AEMO's assessment of the needs for Network Support and Control Ancillary Services (NSCAS) in a five-year period. NSCAS relate to the capability to control active and reactive power flow into or out of the transmission network.

This section details the manner in which our proposed augmentations to the transmission network relate to the NTNDP, the development strategies for national transmission flow paths specified in the NTNDP, and the impact our proposed augmentations may have on other transmission networks. The most recent NTNDP was published in December 2014.[32]

32 *Available at http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan*

Table 6-42: Proposed augmentations to the main transmission network

Proposal	Comment on relationship to NTNDP	APR reference
Voltage control at George Town Substation	The 2014 NTNDP identified the voltage control issue reported in the 2013 NTNDP and in Transend Networks' 2014 APR has been resolved following commissioning of two new voltage control schemes. However we are monitoring the operational performance of these schemes and continue to monitor the market impact of the constraints.	6.4.4.1
	However in January 2015 we experienced a further voltage control issue at George Town Substation. This has been mitigated by an additional constraint equation; however, we are currently investigating its impact and the potential need for a network solution.	4.1.3

6.11.1 Relationship of our proposals to the NTNDP

The 2014 NTNDP did not identify any emerging limitations or NSCAS gaps on the main transmission network in Tasmania.[33] However we have identified a voltage issue at George Town Substation, which we and AEMO are currently monitoring. The relationship between our proposed augmentations to the main transmission network in this APR and the NTNDP is presented in Table 6-42.

6.11.2 Development strategies for national transmission flow paths

There are no national transmission flow paths in Tasmania. However Basslink is a national transmission flow path, connecting the Tasmania and Latrobe Valley (in Victoria) zones. There is no development proposal in the 2014 NTNDP to increase the Tasmania–Victoria transfer capacity.

6.11.3 Material inter-network impact

We are required to identify whether our proposed augmentations in the APR have a material inter-network impact. This is the impact a development in a transmission network may have on another transmission network. This may include the imposition of constraints on power transfer or an adverse impact on quality of supply.

None of the proposed augmentations in our APR will have a material inter-network impact.

33 *Ref. AEMO 2014 NTNDP, Figure 8: http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan*

Chapter 7

Overview

Chapter 7 presents information which would be of interest to owners of generators or large loads that are connected to, or are considering connecting to, our transmission network. The Tasmanian power system has some characteristics which make it unique in the NEM. These characteristics can have an impact on the connection of generating systems or large loads.

7 Information for new transmission network connections

7.1 Power quality

Power quality refers to the technical characteristics of the electricity supply received, such as voltage levels, fluctuations and disturbances, that ensure that the consumer can utilise electric energy from the transmission system successfully, without interference or mal-operation of electrical equipment.

Generally, the quality of voltage is most important, because customers generally notice voltage deviations more than other power quality issues. The main categories of deviation are: temporary voltage variations, repeated voltage fluctuations (flicker), harmonic voltage distortions and voltage unbalance.

7.1.1 Objectives

Our transmission network power quality objectives are to:

- comply with regulatory obligations as stipulated in Schedule 5.1 of the Rules;
- apply appropriate planning criteria to minimise the risk of non-compliance with power quality standards following the connection of new participants to the network;
- work in a collaborative manner with affected parties, continue to develop knowledge and understanding of power quality issues and assist with identifying mitigating measures, where appropriate; and
- monitor power system performance and assess compliance in accordance with defined planning criteria.

7.1.2 Performance criteria (transmission)

The power system standards stipulated in Schedule 5.1a of the Rules include separate technical performance criteria, which we address collectively under the broader heading of power quality. These are:

- S5.1a.4 power frequency voltage (which deals with over & under voltage);
- S5.1a.5 voltage fluctuations (which deals with flicker);
- S5.1a.6 voltage waveform distortion (which deals with harmonics); and
- S5.1a.7 voltage unbalance.

In line with our stated objectives outlined above, we address the power system performance criteria by continuously monitoring power quality at key substations.

7.1.3 Performance criteria (distribution)

The power quality standards relevant to the distribution network are detailed in AS 61000 Electromagnetic capability and chapter 8 of the Tasmanian Electricity Code. The specific standards for each element of power quality are:

- voltage
  - SA/SNZ TS IEC 61000.3.5:2013 Electromagnetic capability (EMC) –Limits – Limitation of voltage fluctuations and flicker in low-voltage power supply systems for equipment with rated current greater than 75 A;
  - AS/NZS 61000.3.6:2001 Electromagnetic capability (EMC) – Limits – Assessment of emission limits for distorting loads in MV and HV power systems (IEC 61000-3-6:1996);
  - AS 61000.3.100-2011 Electromagnetic capability (EMC) – Limits – Steady state voltage limits in public electricity systems; and
  - Section 8.6.4 of Tasmanian Electricity Code.
- harmonics
  - AS/NZS 61000.2.2:2003 (R2013) Electromagnetic compatibility (EMC) – Environment – Compatibility levels for low-frequency conducted disturbances and signalling in public low-voltage power supply systems;
  - AS/NZS 61000.2.4:2009 Electromagnetic compatibility (EMC) – Environment – Compatibility levels in industrial plants for low-frequency conducted disturbances;
  - AS/NZS 61000.2.12:2003 (R2013) Electromagnetic compatibility (EMC) – Environment – Compatibility levels for low-frequency conducted disturbances and signalling in public medium-voltage power supply systems; and
  - TR IEC 61000.3.7:2012 Electromagnetic compatibility (EMC) – Limits – Assessment of emission limits for the connection of fluctuating installations to MV, HV and EHV power systems.
- power factor
  - Section 8.6.3 of Tasmanian Electricity Code.

7.1.4 Planning levels and strategies

7.1.4.1 Voltage fluctuations and voltage waveform distortion

Schedules 5.1.5 and 5.1.6 of the Rules require a Network Service Provider to determine 'planning levels' for connection points in its network. We have calculated these planning levels, which are presented in Appendix H.

When processing a new connection application, we will allocate a proportion of these planning levels to each connection applicant to define their maximum emission limits. The allocated limits will be a function of the applicant's maximum agreed demand and the connection point's firm MVA capability.

Our planning studies take into account the typical increased levels of harmonic voltages resulting from load growth, and we implement mitigation measures as required to keep the harmonic content within the specified limits. The planning process does not take into account high levels of harmonic injection from single connection points. We would require the causer to implement mitigation measures in such situations.

7.1.4.2 Under voltage performance

The Rules do not contain a system standard for under-voltage recovery. We have therefore developed an under-voltage recovery guideline, which we use as the basis for assessing whether the voltage recovery performance of equipment is acceptable. This guideline is included in Appendix H.

Whilst not strictly enforceable under either the Rule or Tasmanian regulations, this guideline does provide connecting parties with an indication of the post-fault voltage recovery profile which we are endeavouring to meet in our transmission network.

7.2 Frequency control ancillary services

For any power system to operate stably there must be a continuous and close balance between the power generated and the power consumed. FCAS is the mechanism by which this balance is maintained. The power system needs sufficient power reserves to offset the continually fluctuating loads with supply side adjustments. The supply side adjustments are usually provided by generators. There must also be sufficient reserves to cope with contingencies that cause major loss of generation or load.

The provision of FCAS in Tasmania is not the responsibility of the transmission network service provider; it is a service supplied by the market and thus AEMO is responsible for ensuring that sufficient FCAS is dispatched. During each dispatch interval, AEMO must enable sufficient FCAS to meet system requirements.

There are eight different categories of FCAS (refer Appendix 11.3 for details). In Tasmania, it is generally the provision of the Fast Raise and Fast Lower services (formerly known as 6-second raise and lower) that are the most challenging to provide. This is because of the inherent response characteristics of hydro generators. The provision of FCAS in the longer time frames of 60 seconds and 5 minutes is easier to achieve, as hydro generators are generally unhindered by temperature and fuel supply issues that tend to constrain the ramping capability of thermal generators.

To limit the requirement for Fast Raise FCAS, the Tasmanian Frequency Operating Standards[34] limit the maximum credible generator contingency size to 144 MW. Generating units operating above this output must implement suitable measures to effectively limit the maximum generator contingency to 144 MW. This may be accomplished via a tripping scheme to quickly disconnect an appropriately sized load in response to the generator's own trip event, resulting in a net generation loss of 144 MW or less. The commercial negotiations with a suitable network load owner are the responsibility of the generator. TasNetworks is able to provide and maintain the tripping scheme as part of our connection service.

The tripping of Basslink is the largest single contingency risk in Tasmania. It is mitigated by the FCSPS. The FCSPS acts to limit frequency deviations in Tasmania by rapidly disconnecting appropriate generators if Basslink trips while exporting; it will disconnect loads if Basslink trips while importing. Participation of new loads or generators in the FCSPS is not mandatory, and is commercially negotiated through a Participation Agreement. TasNetworks owns and maintains the FCSPS hardware, and we are able to extend the scheme to include new participants following agreement by all parties.

The ability of Basslink and the other non-synchronous generators (mainly windfarms) to supply an increasing proportion of Tasmanian load increases the chances of the power system having too little inertia. We have mitigated this risk by implementing the NEM's first Rate of Change of Frequency (RoCoF) constraint equation. The constraint equation will limit generation and/or Basslink, to contain the rate of change of frequency following a credible contingency event. This will achieve two outcomes:

1. Ensure generating systems that are sensitive to RoCoF are not disconnected from the power system due to operation of their protection systems following credible contingency events.

2. Ensure that RoCoF elements forming part of the existing design of the Tasmanian Under Frequency Loading Shedding Scheme do not operate for credible contingency events.

34 The Tasmanian Frequency Operating Standards: http://www.aemc.gov.au/Media/docs/Final%20Report-83b9ab86-e33f-463a-bc29-f3d62a74b0fb-0.pdf

7.3 Tasmanian developments that could impact on Basslink energy transfer

Basslink is Tasmania's only interconnection to the remainder of the NEM. New developments that affect the energy transfer across Basslink could therefore have a material impact on the economic efficiency of the NEM, as well as constraining the energy production from Tasmanian based generators.

Basslink requires a certain level of support from the network in order to maintain its energy transfer. To date, this has been provided by synchronous generation. The design and performance characteristics of many new forms of renewable generation (most notably wind and solar photovoltaic) are such that they are not equivalent and cannot be directly substituted in place of synchronous machines. Two characteristics which are relevant to the operation of Basslink, and the Tasmanian power system more broadly, are the limited contribution of inertia and fault level coming from solar photovoltaic and wind generation technologies. Other network performance aspects, including voltage and frequency control capability, can also indirectly affect Basslink's ability to operate unconstrained.

The capacity of wind generation in Tasmania now exceeds 300 MW. This has provided the first insight to the types of new operational constraints that can result from the connection of non-synchronous generation en masse. Modifications to FCAS calculations, and the implementation of the first rate-of-change-of-frequency constraint in the NEM, are two notable examples.

There is potential for further operating constraints to be imposed, which could limit the dispatch targets of Basslink and/or Tasmanian wind farms, if mechanisms are not identified to ensure the dispatch of sufficient inertia and fault level. There are three key aspects to this issue, which we are pursuing as part of ongoing investigations linked to the integration of large scale renewables:

- determining the minimum level of synchronous machine support required to support various combinations of Basslink power transfer (import and export), wind generation and Tasmanian load demand;
- determining the appropriate form of constraints to maintain the security of the power system if sufficient synchronous machine support is not available through normal market processes; and
- identifying alternative mechanisms that may reduce or eliminate constraints through the use of commercial instruments (e.g. network support agreements with generators) or other engineering solutions (e.g. installation of equipment such as synchronous condensers).

We are committed to understanding the issues outlined above. We are actively working with AEMO and network users to develop credible and practical solutions that maximise the capability of existing and potential new assets, without compromising power system security and reliability standards.

7.4 Connection and integration of additional wind generation

The issues Tasmania faces in connecting additional wind generation can be classified into two broad categories: connection issues and integration issues.

Connection issues can be considered the local issues that a wind farm may face when connecting to a specific location in the network, whereas integration issues are the system wide issues associated with accommodating higher levels of wind generation. Integration issues apply more broadly to any type of non-synchronous generation.

7.4.1 Connection issues

7.4.1.1 Short circuit ratio

Most wind farms require a certain level of power system support at their connection point to enable them to connect to the network in a stable and reliable manner. Larger wind farms require stronger power systems, and the accepted way of defining this relative strength is by defining the short circuit ratio at the connection point. The short circuit ratio is calculated by dividing the MVA fault level at the connection point by the MW rating of the wind farm. Many of Tasmania's best wind resource areas are often remote from the main network and have inherently low short circuit ratios. Existing wind farms may have already absorbed much of the available MVA fault level in their locality, meaning that future wind farms will connect to an effectively weaker power system.

7.4.1.2 Reactive power requirements

The reactive power capability (i.e. its size and response characteristics) that a wind farm requires to meet network access standards is heavily influenced by the network location at which the wind farm is to be connected.

7.4.2 Integration issues

7.4.2.1 Displacement of synchronous generators

At a higher level, consideration must be given to the impact that wind generation will have on the overall power system and in particular the displacement of traditional synchronous generators that could occur. Since synchronous generators supply the power system with the bulk of its FCAS and the bulk of its inertia, their displacement makes these services scarcer. Further displacement of synchronous generation by non-synchronous generation could ultimately place constraints upon the level of wind generation that could be securely dispatched. In Tasmania this is exacerbated by the presence of Basslink which, like wind farms, can cause large energy deficits (and hence frequency dips) when recovering from system faults.

Voltage control at George Town Substation can be challenging at times (refer to Sections 4.1.3 and 6.4.4.1). Displacement of synchronous generators by nonsynchronous generation will reduce the fault level at George Town, making the George Town voltage more difficult to control.

7.4.2.2 Isolated operation

If the wind farm is located where it, along with other loads or generators, could become isolated from the main network, the wind farm must incorporate an anti-islanding protection scheme.

Appendices

Appendix A Glossary, abbreviations and technical terms

A.1 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 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.

Basslink	a privately owned undersea cable connecting the Tasmanian electricity network to that of mainland Australia. Basslink is described in Section 3.2.2.
bay	the suite of electrical infrastructure installed within a substation to connect a transmission line, distribution feeder, transformer or generator to substation busbars.
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.
coincident maximum demand	the highest amount of electricity delivered, or forecast to be delivered, simultaneously at a set of connection points.
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.
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. See also: trading interval. [R]
diversity	the ratio of demand of the particular load at the time of maximum demand of the group of loads considered to the maximum demand of the particular load.
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.
energy sales:	the total amount of electrical energy consumed in Tasmania for a particular period.
ESI Regulations	reference to the *Electricity Supply Industry (Network Planning Requirements) Regulations 2007.* ESI Regulations are described in Section 2.1.2.
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.
guaranteed service level scheme	a payment scheme where our distribution customers are compensated for prolonged and excessive interruptions to their supply.
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 those 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.
kilo-Volt	one kilo-Volt equals 1,000 Volts. See also: voltage.

load factor	the ratio of average demand to maximum demand over the same period.
market network service provider	a network service provider whose network links two connection points located in different NEM regions, the power transfer between which can be independently controlled and dispatched via the central dispatch process. The network must not be the subject of a revenue determination by the Australian Energy Regulator. Basslink is the only MNSP in the NEM. [R]
N, N-1, N-2	N refers to the state of the network (or portion of the network) where all network elements are in service. N-1 refers to the state of the network (or a portion of the network) where there is one element out of service, either following a planned outage or a contingency event. An "N-1 secure" network is a network which will continue to provide supply even with one element out of service. N-2 refers to the state of the network when two elements are out of service. See also: firm, non-firm.
native electrical energy	the electrical energy supplied by scheduled, semi-scheduled, and significant non-scheduled and small non-scheduled generating units within Tasmania.
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 issue that does not require the construction of a network augmentation. Examples include electronic control schemes and demand side management.
non-synchronous generator	refer to Appendix A.3 for a detailed explanation. For the purposes of this APR, non-synchronous generators include Basslink, solar photovoltaic (PV) panels, wind farms, and some mini-hydro or micro-hydro generators. See also: synchronous generator.
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.
primary	the assets through which the electricity being carried by the network flows. See also: secondary.
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
Rules	the National Electricity Rules
secondary	assets within an electricity network that do not convey the electrical energy, but which are required for control, protection or operation of assets which carry such energy. [R]
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	a substation without transformers, operating at a single voltage level.
synchronous generator	refer to Appendix A.3 for a detailed explanation. For the purposes of this APR, synchronous generators refer to generators driven by hydro, gas, or steam (i.e. coal-fired) turbines. NB: There are no coal-fired power stations in Tasmania. See also: non-synchronous generator. [R]
trading interval	a 30 minute period ending on the hour or on the half hour and, where identified by a time, means the 30 minute period ending at that time. Financial settlement in the NEM takes place by trading interval. See also: dispatch interval. [R]
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 or load or transmission circuit from the remainder of the network.
voltage	the force which causes electrical current to flow. [R]

A.2 Abbreviations

AC	Alternating Current
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
APR	Annual Planning Report
AS	Australian Standards
CB	Circuit Breaker
CBD	Central Business District
CCGT	Combined Cycle Gas Turbine
DC	Direct Current
EDO	Expulsion Drop Out
EHV	Extra High Voltage
EMC	Electromagnetic Capability
ESI	Electricity Supply Industry
FCAS	Frequency Control Ancillary Services
FCSPS	Frequency Control System Protection Scheme
FOC	Fibre Optic Cable
GIS	Geographic Information System
GSL	Guaranteed Service Level
GSP	Gross State Product
GWh	Gigawatt-hour
Ha	Hectare
HV	High Voltage
HVDC	High Voltage Direct Current
Hz	Hertz
IEC	International Electrotechnical Commission
kA	Kiloamps
kV	Kilovolts
LEOY	Likely End of Year
LOS	Loss of Supply
MAIFI	Momentary System Average Interruption Frequency Index
MD	Maximum Demand
MNSP	Market Network Service Provider
MV	Medium Voltage
MVA	Megavolt-amperes
MVAr	Megavolt-amperes reactive
MW	Megawatts
MWh	Megawatt-hour
NBN	National Broadband Network
NCSPS	Network Control System Protection Scheme
NEM	National Electricity Market
NEMDE	National Electricity Market Dispatch Engine
NER	National Electricity Rules
NIEIR	National Institute of Economic and Industry Research
NSCAS	Network Support and Control Ancillary Services
NTNDP	National Transmission Network Development Plan
NZS	New Zealand Standards
OCGT	Open Cycle Gas Turbine
OTTER	Office of the Tasmanian Energy Regulator
POE	Probability of Exceedance
PU	per unit
PV	photovoltaic [solar generation system]
RIT	Regulatory Investment Test
RoCoF	Rate of Change of Frequency
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SPS	System Protection Scheme
STPIS	Service Target Performance Incentive Scheme
TOV	Temporary Over Voltage
TR	Technical Report
TS	Technical Specifications

A.3 Explanations of technical terms

The sections below provide a more detailed explanation of terms and concepts that are commonly used within the electricity industry.

A.3.1 MW and MWh

MW (or MegaWatt) is the *rate* at which electrical energy is transferred through the electricity network. It can be thought of as defining how quickly the energy flows through the network.

From a network design perspective, the rate at which electrical energy flows is more critical than the total amount of energy transferred, because transferring energy at a faster rate will generate more heat within electrical equipment. Dissipating this heat is a key factor in operating network equipment, and it is ultimately the ability of network equipment to dissipate heat that limits the rate of electrical energy transfer through the equipment. For this reason, transmission equipment has a maximum transfer limit, in MW.

MWh (or MegaWatt-hour) is measure of the total electric energy transferred, normally during a stated time. This is the unit in which electricity is sold to most customers, because customers pay for how much energy they use, not how quickly they use it.

A.3.2 Frequency, inertia and FCAS

Electricity is the flow of sub-atomic particles, usually electrons, through a conductive object. In an electricity network, this flow of particles is not a constant flow in one direction, but rather the flow reverses direction many times per second (hence the term "alternating current", or AC). This flow reversal stems from the design of generators, and electrical equipment such as transformers and motors requires this continuous flow reversal in order to operate.

Electric current flowing in one direction, and then flowing in the reverse direction, is termed a "cycle". "Frequency" refers to the number of cycles which occur in one second, and is measured in Hertz (Hz). The Australian standard frequency is 50 Hz, which means there should be 50 cycles, or 100 flow reversals, every second.

This phenomenon of continually reversing electrical current is caused by the rotation of generators. To maintain the power system frequency at a fixed value, all generators[35] must spin at a precisely constant speed. If all generators within the power system were to slow down, the power system frequency will drop. Conversely, if generators were to speed up, the frequency would increase. User equipment is designed to operate at a particular frequency (e.g. 50 Hz), and equipment damage could result if the power system frequency deviated significantly from this value. Power system operators (AEMO, in Australia) are therefore required to maintain the power system frequency within a tight tolerance. To prevent equipment damage, power systems are designed to black out rather than operate outside the frequency limits.

Because alternating current electricity cannot be stored, there is a need to continually balance the amount of electricity generated with the amount used by loads. If there is excess generation, frequency will rise. If there is insufficient generation, frequency will fall. This balance is maintained by dispatching additional generators as the load increases. Should a contingency event occur, such as one generator unexpectedly disconnecting due to a fault, this load-generation balance will be disturbed. If one generator disconnects, the remaining generators will slow down and frequency will fall. If, on the other hand, a load was to suddenly disconnect, there would be excess generation and the power system frequency would rise. The balance can be restored by increasing or reducing (as appropriate) the power outputs of all remaining generators.

The ability of a generator to change output suddenly in response to a frequency deviation is termed its frequency control capability. Differing generators have differing frequency control capabilities. In the NEM, frequency control capability is assigned a commercial value, via the Frequency Control Ancillary Services (FCAS) market. In addition to bidding to generate electricity, generators also bid to provide their frequency control capability. Frequency control capability is considered an ancillary function – the core function being to produce electrical energy – hence the term "ancillary service".

In the Tasmanian context, Basslink is effectively a generator when it is importing electricity into Tasmania, or a load when it is exporting electricity from Tasmania. Basslink is able to rapidly change its power transfer (whether importing or exporting) in response to frequency deviations, so as to restore a load-generation imbalance. Basslink is therefore able to provide frequency control services.

The rate at which frequency deviates, following an unexpected generator or load trip, is influenced by (i) the size of the generator or load lost, and (ii) the spinning mass of the generators remaining in the power system. This spinning mass is termed a generator's inertia. The greater the total inertia in a power system, the more slowly frequency will deviate following a contingency event. Inertia in a power system can be increased by either dispatching more generators, or dispatching physically larger generators ahead of smaller generators. In the NEM, there is no commercial value placed on inertia.

35 *Strictly speaking, it is only the synchronous generators which spin at a precisely constant speed.*

A.3.3 Synchronous and non-synchronous generation

Synchronous generators spin at a precisely constant speed, which causes the phenomenon of electrical frequency described above. These generators' speed is directly proportional to the power system frequency. The vast majority of large generators in the world, and all Tasmanian transmission-connected hydro and gas turbine generators, are synchronous generators.

Non-synchronous generators do not rotate at a constant speed. They may either rotate at some different speed (e.g. most wind turbines), or they may have no rotating parts at all (e.g. solar photovoltaic generation and Basslink). Other than hydro and solar thermal generators, most renewable generation technologies utilise non-synchronous generation.

From a power system planning and operation perspective, a significant difference between synchronous and non-synchronous generation is their response following a fault on the power system. Due to their inherent design, synchronous generators will continue to operate during a fault, and actually force electrical current to flow through the faulted part of the network. (This high current allows the protection system to sense the fault, and rapidly disconnect the faulty equipment.) Non-synchronous generators react differently during fault condition: some will cease generating altogether, others reduce their output significantly.

Traditionally, power systems have been dominated by synchronous generators. The design of large power systems has traditionally relied on the presence of synchronous generators to maintain stable operation. Inclusion of small quantities of non-synchronous generators in power systems has not been problematic. Future displacement of synchronous generation by non-synchronous generation has the potential to cause power system control and stability problems. Technology is rapidly changing, and manufacturers of non-synchronous generation are examining how non-synchronous generators can be made to act similarly to synchronous generators. Power system operators are examining how power systems can be made to withstand a greater penetration of non-synchronous generation.

A.3.4 Transmission line ratings

Transmission line conductors (that is, the wires) will heat up, and therefore expand, as electricity flows through them. Because they are suspended on towers, the conductors will sag towards the ground as they expand. If the conductors heat too much, they will sag too close to the ground, which creates a danger to the public, as well as the possibility of an electrical fault occurring. The sag effect is not permanent: as the conductors cool down they contract and therefore lift back up again.

The amount of heating – and resulting sag – depends on the material of which the conductor is made, the amount of electrical current flowing, and external factors such as the surrounding air temperate, wind (which has a cooling effect), and the heating effects of sun shining directly on the conductor. Because these weather-related factors are continually changing, transmission line designers need to make reasonable "worst case" assumptions about these conditions. The transmission line is designed so that, under these "worst case" conditions, the ground clearance is compliant with statutory safety standards. The electrical current which can flow under these worst case conditions, without the sag exceeding limits, is known as the transmission line's "static rating". Transmission system operators can therefore know that, providing the electrical current flowing through a transmission line is less than the static rating, the ground clearance will be compliant.

When a transmission line is operating, the worst case weather conditions will only occur a small fraction of the time. Typically, the weather conditions are more favourable, and the transmission line would be at a lower temperature – and be sagging less – than it was designed for, even if it was carrying the full static rating current. Under these conditions (for example, if it is windy and therefore the conductors are being cooled), it may be possible to allow *more* current than the static rating to flow through the conductor and still maintain a safe ground clearance.

A transmission line rating which is based on actual weather conditions is called a dynamic rating. Dynamic ratings can be used when actual information about the weather conditions along the length of the transmission line is known. This can be obtained, for example, from weather stations mounted on selected transmission towers. The use of dynamic transmission line ratings normally allows the line to carry more current than if the static rating was used, thereby utilising otherwise wasted transmission line capacity.

Appendix B Fault level and sequence impedances

We calculate fault currents at substations in the transmission network in accordance with the recommendations of Australian Standard AS 3851-1991 The calculation of short-circuit currents in three-phase AC systems. From this, the maximum fault currents calculated at 1.1 pu voltage and the minimum at 0.9 pu voltage. The Thevenin impedance is defined as the source impedance back to the generators, and large motors where considered. This method thus defines the extreme envelope for all fault currents and is appropriate to be used for future planning. We recognise that at particular network locations the actual envelope could be smaller but this would need confirmation with detailed local studies.

Figure B-1 illustrates the AC and DC components that make up fault currents. The size and rate of decay of the DC component is a function of the ratio between the reactance (X) and the resistance (R) of the impedance between the faulted point of the system and the generation feeding the fault. This ratio is defined as the X/R ratio of the system, with the DC component decaying with time constant $X/2\Pi fR$.

The maximum current that a circuit breaker will be exposed to is defined as the Peak Make Current. During fault conditions, the current a circuit breaker is expected to break is known as the RMS Break Current. This is defined as the RMS of the symmetrical AC component of the fault current plus the offset by the DC component at that point.

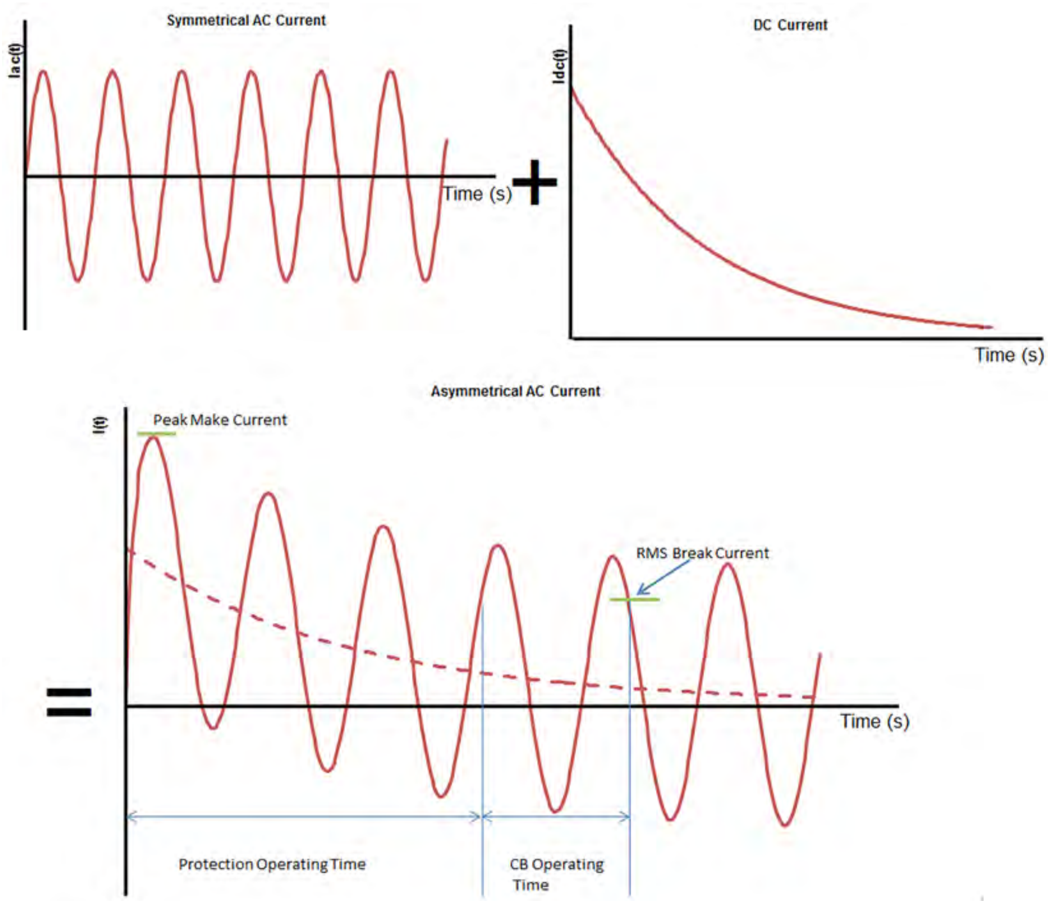


Figure B-1: Components of AC fault current

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 4.2.2 and Chapter 6 of this APR. The information presented here is our performance against the standards set out in the Tasmanian Electricity Code (the Code) and by the AER since 2009–10.

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 SAIFI and SAIDI, respectively, against the standards specified in the Code. The performance presented here is what we provide to OTTER as part of our normal reporting process. The standards exclude outages caused by third-party faults and customer plant, and the transmission network.

This information is provided up to 31 December 2014, with the last column of the tables presenting calendar year information to provide the most recent data. Consequently, there is a six-month cross-over in reporting periods between the 2013–14 financial and 2014 calendar years; however trends in performance between 2013–14 and 2014–15 financial years can be identified.

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

Supply reliability category	Standard (interruptions)	2009–10	2010–11	2011–12	2012–13	2013–14	2014
Critical infrastructure	0.2	0.19	0.18	0.22	0.27	0.21	0.40
High density commercial	1	0.76	0.44	0.27	0.43	0.47	0.17
Urban and regional centres	2	1.38	1.01	1.03	0.92	0.85	0.58
High density rural	4	3.69	2.59	2.29	2.36	2.18	1.49
Low density rural	6	4.16	3.51	3.72	3.49	3.11	2.17

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

Supply reliability category	Standard (mins)	2009–10	2010–11	2011–12	2012–13	2013–14	2014
Critical infrastructure	30	21	15	25	30	16	49
High density commercial	60	80	31	32	77	43	15
Urban and regional centres	120	209	114	85	94	164	97
High density rural	480	798	341	259	269	521	424
Low density rural	600	992	575	498	547	740	684

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. Similarly to Section C.1.1, the final column of the chart details reliability in 2014, compared with financial year data for the remainder.

We classify poor performing communities in this APR as 'trending' and 'newly poorly performing'. Trending poor performing communities are those whose five-year average performance exceeds their reliability standard. Newly poor performing are those who exceeded their reliability standards in 2014, but their five-year average meets the standard. Of the poor performing communities summated in Table C-3 and Table C-4, six of the eight SAIFI communities and 30 of the 47 SAIDI communities are trending poor performing. The following figures (Figure C-1 to Figure C-7) show maps by planning areas of trending and newly poor performing reliability communities.

Supply reliability communities that did not meet the standards in 2014 are detailed by planning area in Chapter 6. In the chapter we list the communities that have trending poor reliability and those that are newly poor performing in 2014. We present potential solutions for those communities where we proposals to improve reliability. Our network reliability strategy is presented in Section 2.3.1.

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

Supply reliability category (number of communities)	Standard (interruptions)	2009–10	2010–11	2011–12	2012–13	2013–14	2014
Critical infrastructure (1)	0.2	0	0	1	1	0	1
High density commercial (8)	2	1	0	0	0	0	0
Urban and regional centres (32)	4	1	1	1	2	3	2
High density rural (33)	6	4	0	3	2	6	4
Low density rural (27)	8	2	0	2	1	2	1
Total (101)		8	1	7	6	11	8

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

Supply reliability category (number of communities)	Standard (mins)	2009–10	2010–11	2011–12	2012–13	2013–14	2014
Critical infrastructure (1)	30	0	0	0	1	0	1
High density commercial (8)	120	1	0	1	3	0	0
Urban and regional centres (32)	240	11	5	5	5	12	14
High density rural (33)	600	11	2	3	4	11	15
Low density rural (27)	720	10	9	6	6	14	17
Total (101)		33	16	15	19	37	47

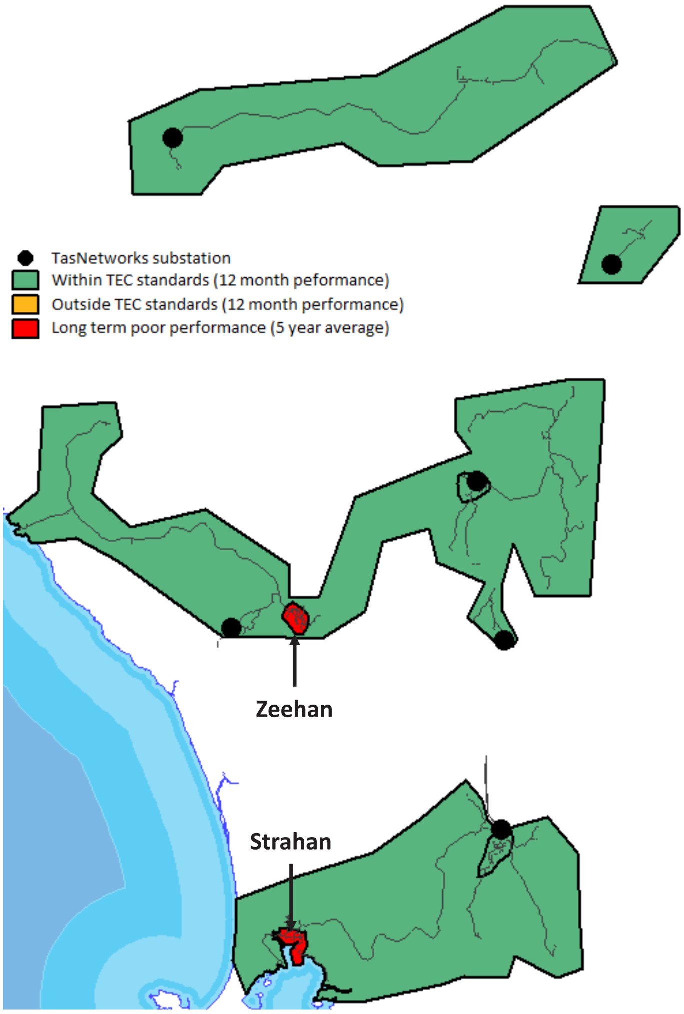


Figure C-1: West Coast area community reliability performance

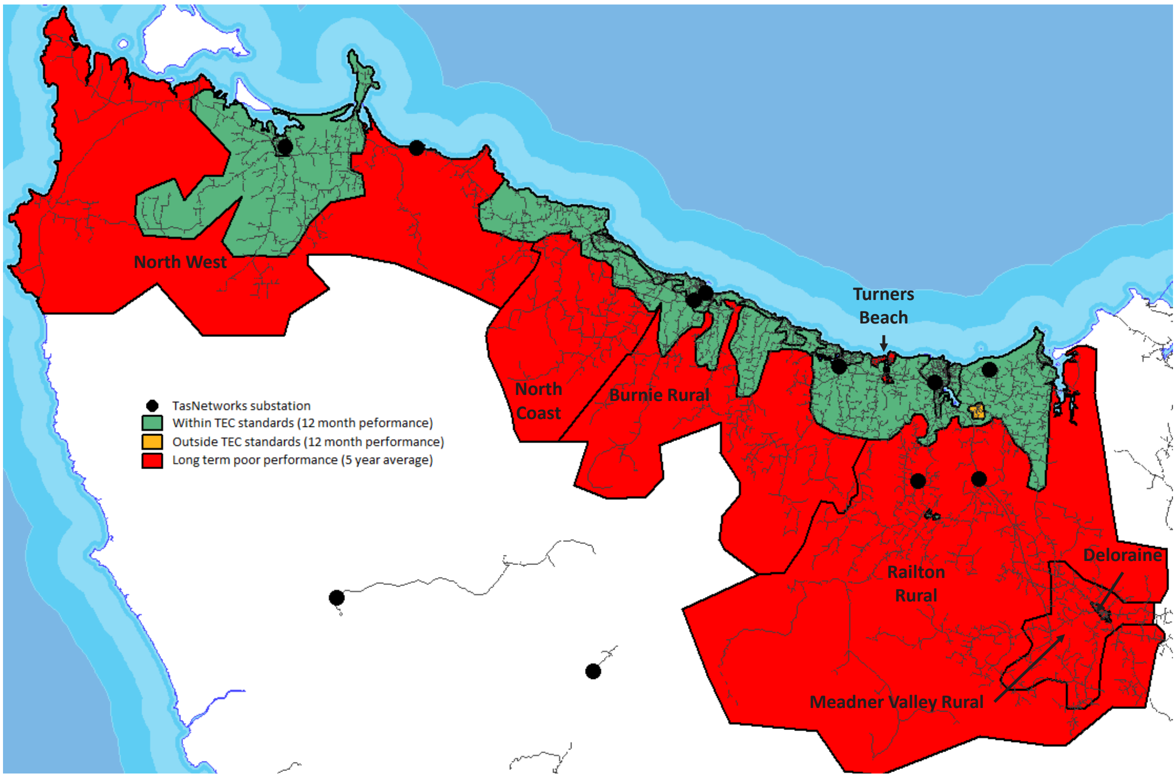


Figure C-2: North West area community reliability performance

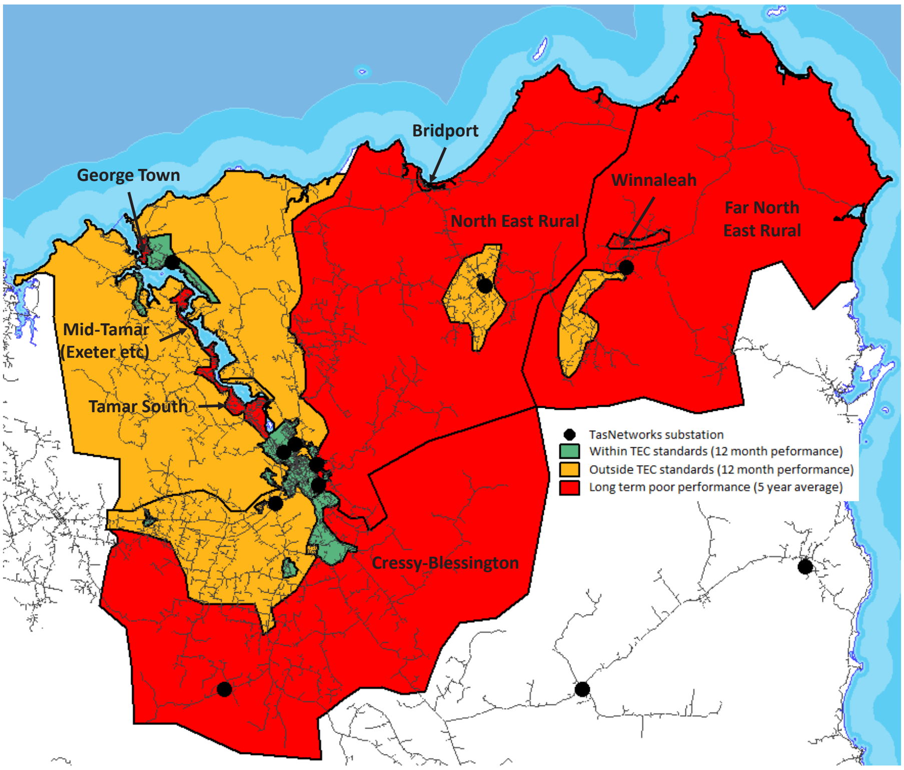


Figure C-3: Northern area community reliability performance

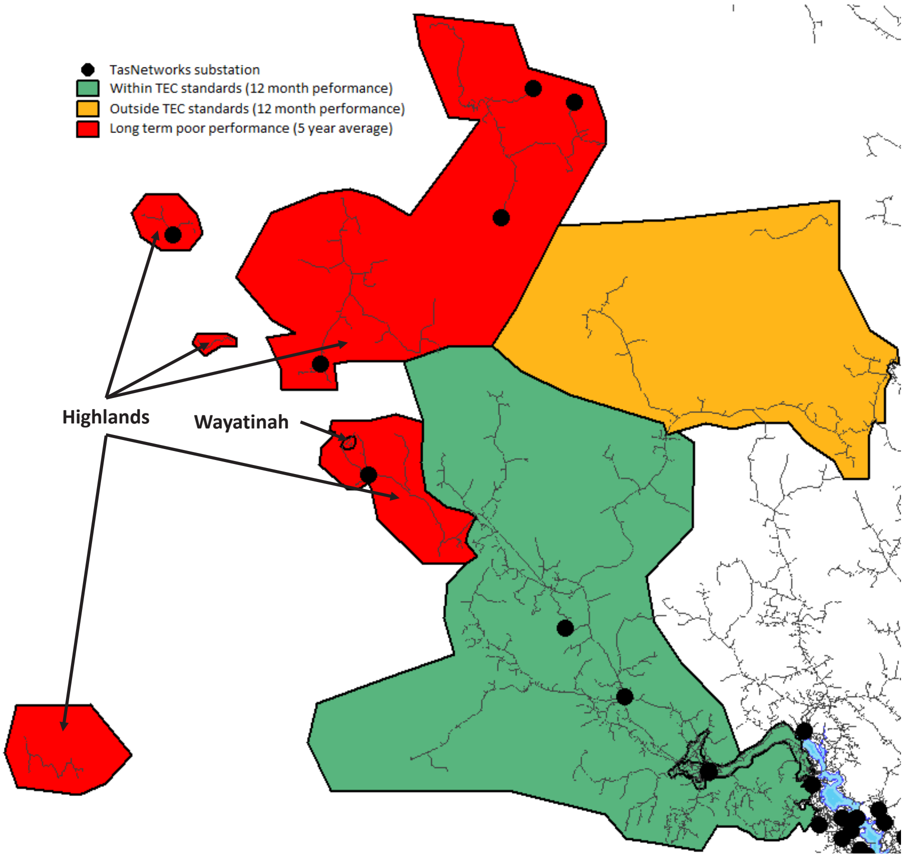


Figure C-4: Central area community reliability performance

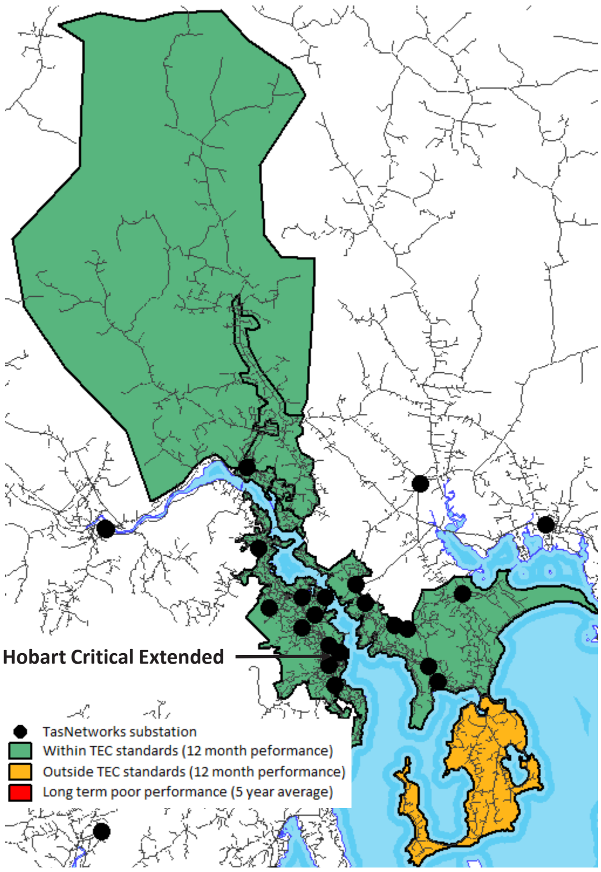


Figure C-5: Greater Hobart area community reliability performance

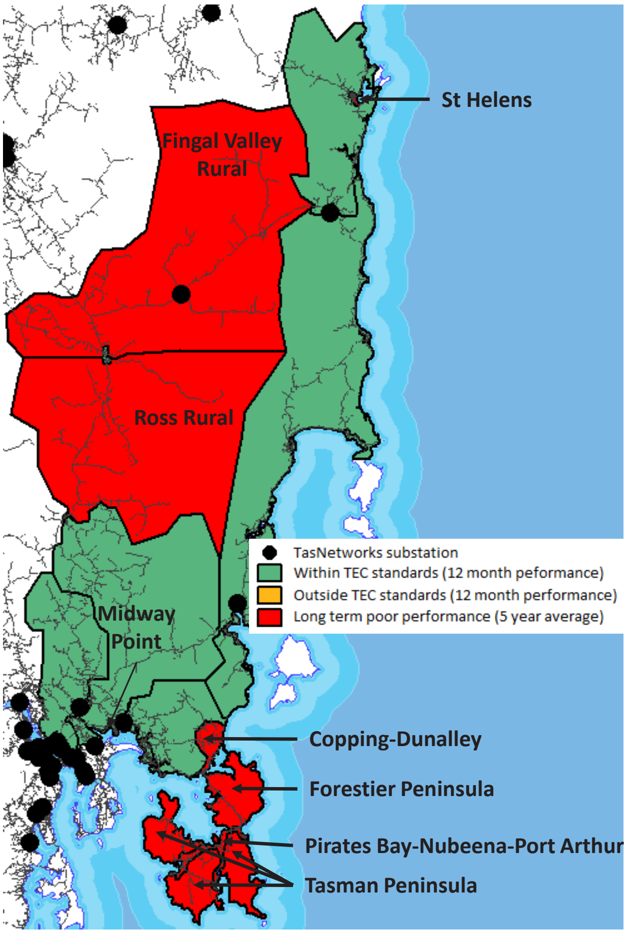


Figure C-6: Eastern area community reliability performance

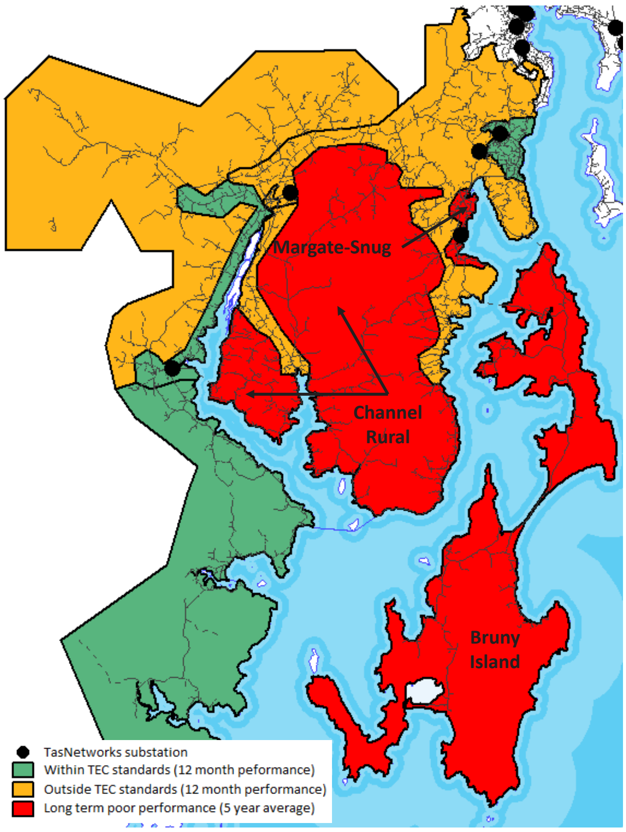


Figure C-7: Kingston-South area community reliability performance

C.2 Performance against AER standards

At the commencement of each distribution regulatory period, the AER, as part of our revenue determination, sets standards for distribution network reliability. These standards form part of our service target performance incentive scheme (STPIS) and are calculated on our actual performance for the preceding five years. The standards set by the AER exclude planned outages to the network, major event days, outages caused by customer plant and certain third-party faults.

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. These standards have been set for our 2012–17 distribution regulatory period. Although performance prior to 2012–13 is shown, we were not subject to the standards presented in these tables as reliability did not form part of the STPIS for the distribution network at that time.

In these tables, the 2009–10 and 2010–11 data formed part of what was provided to the AER in setting our standards for 2012–2017. The 2011–12 data is estimated; it was unpublished to the AER and uses our current network capacity as basis for the performance calculations in conjunction with actual outage data. The information for the 2014–15 year is forecast based actual data for the six months to 31 December 2014, and historical averages for the subsequent six months to 30 June 2015.

The table also show our forecast reliability performance for the remainder of the regulatory period. In forecasting our performance, we use the method the AER uses to calculate our reliability standards. That is, we extrapolate our performance using our average performance during the preceding five years (including 2014–2015). We forecast reliability performance to generally align with our current STPIS standards. The low density rural supply reliability category is the only category forecast to perform worse than the current standard, in both measures, though only marginally. This is as a result of a particularly poor year experienced in 2013–14. It also reflects the continued challenges in maintaining reliability in the communities in this category, due to the large geographical areas covered by the high voltage feeders and limited alternate supply options.

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

Supply reliability category	Standard (2012–17) (interruptions)	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15 (forecast)	Forecast to 2016–17
Critical infrastructure	0.22	0.09	0.19	0.26	0.17	0.13	0.25	*0.20*
High density commercial	0.49	0.63	0.33	0.21	0.30	0.32	0.40	*0.31*
Urban and regional centres	1.04	1.09	0.78	1.01	0.82	1.21	0.88	*0.94*
High density rural	2.79	2.86	2.10	2.20	2.21	3.00	2.23	*2.35*
Low density rural	3.20	3.18	2.90	3.36	3.00	4.65	2.95	*3.37*

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

Supply reliability category	Standard (2012–17) (mins)	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15 (forecast)	Forecast to 2016–17
Critical infrastructure	20.79	5.01	11.72	16.90	4.65	6.83	29.18	*13.86*
High density commercial	38.34	63.79	18.62	13.57	33.61	27.66	35.00	*25.69*
Urban and regional centres	82.75	86.00	58.76	67.55	64.19	101.89	74.60	*73.40*
High density rural	259.48	283.60	169.86	206.15	203.25	289.29	257.36	*225.18*
Low density rural	333.16	360.75	287.84	383.44	358.41	533.00	385.82	389.70

Appendix D Metering and information technology systems

D.1 Metering programs

An electricity meter is a device that records the amount of electrical energy consumed at a customer installation. The energy consumption data is in turn used to invoice customers for the amount of energy they use. Meters can record and display data as either cumulative total energy used or as energy consumed over shorter periods of time (known as intervals). Meters that record cumulative data are typically read manually on site by a meter reader whereas meters that record interval data are remotely read via a communications link.

Capital investment in metering is driven by new installations and meter replacement. Table D-1 presents our 2014–15 and forecast investment in metering programs.

From 1 July 2017, metering services will become contestable and unregulated and our expenditure no longer subject to regulation by the AER.

Table D-1: Investment in metering programs

Year	Investment ($m)	
	New installations	Meter replacements
2014–15 (LEOY)	1.74	1.77
2015–16	1.80	1.70
2016–17	1.80	1.70

D.1.1 New installations

The installation program is driven by customer requirements. In accordance with our metering management plans, all new meters installed will be electronic meters.

Investment in new installations is based on historical volumes with an allowance made for customer growth.

D.1.2 Meter replacement

There are two key drivers for meter replacement:

- meters found to be non-compliant from testing regimes must be replaced to ensure compliance with Chapter 7 of the Rules; and
- planned replacement to address specific business needs such as access, obsolete technologies, obsolete network tariffs and safety issues.

The replacement program is designed to rationalise the meter fleet by removing meter types with small populations and to future-proof the meter fleet by installing electronic type meters. New meters have on-board contactors for time of use type loads, allowing reduced use of time switches.

Electronic meters will also allow communications to be installed for remote sites to reduce the cost of meter reading in these locations. New technology will also allow for monitoring power quality, can be capable of remote disconnect/reconnect and can allow for retail products for customers without changing the meter.

Compliance driven replacements are projected to maintain existing levels.

D.2 Information systems programs

Information systems programs are critical in enabling us to increase our performance, efficiencies and effectiveness in asset management. Elements of focus for successful information systems programs are people, processes, technology. The objectives of the programs are:

- reduction in business risk;
- enhanced network system performance;
- enhanced standards compliance;
- effective knowledge management;
- effective resource utilisation; and
- optimum infrastructure investment.

This section details our investments in Information Systems programs in the distribution network.

D.2.1 Investment in 2014–15

This section details our investments in Information systems programs in 2014–15. The investment is summarised in Table D-2 and presented in more detail below.

Table D-2: Information systems investment in 2014–15[36]

Project	Investment ($000)
SCADA uplift	1,960
Substation data upgrade	350
NBN Spatial Data, Smart Assets and Ground Mounted Substation data capture	390
G-Tech and WebMap Upgrade	550
Drawing Management System	250

SCADA uplift

Our current distribution SCADA system was identified as not meeting business requirement for dynamic and real time visibility of distribution assets to support more cost effective, safe and reliable outage management. In addition, the current SCADA iFIX system had reached the limits of its performance and could not support the installation of more smart assets (reclosers, fuse savers, load break switches, mobile generators).

36 *Likely end of year figures as at end of February 2014.*

This project has successfully migrated the distribution SCADA network onto a standardised OSI platform which has included the following:

- commissioning of smart field assets to OSI Monarch;
- SCADA reports to provide data to the engineering, SCADA, operations and field teams; and
- virtualisation of the paper-based pinboards.

Substation data upgrade

We identified our single line diagrams for a number of critical ground mounted substations were out of date or not approved. In addition, there was a low level of confidence in the asset attribute data that the business stores across multiple locations (WASP[37], draft drawings, static site audit database).

To assist in achieving our high level strategic objectives, we needed to improve the accuracy of our distribution asset data, increase business confidence in our as-built single line diagrams, and the processes for maintaining the asset data is accurate and complete.

This project improved the capture and data quality of ground mounted substation asset information and has developed a suite of supporting single line diagrams.

NBN spatial data, smart assets and ground mounted substation

The National Broadband Network (NBN) fibre optic network is currently being rolled out around Australia. When setting out the fibre optic cable (FOC), continuous underground cabling is not always an option. In Tasmania where Telstra underground infrastructure is not available, the secondary option is to utilise the existing TasNetworks distribution overhead network assets (poles) to facilitate the NBN FOC network.

To facilitate the transfer of information between NBNCo and TasNetworks, a technology solution was required to record and display the NBNCo FOC attributes on distribution poles. This included the ability to record attributes including pole construction data, associate FOC attributes to poles, and to manage and display the data within the TasNetworks network information systems environment and systems.

This project increased TasNetworks' asset information holdings by:

- registering NBNCo asset data that utilises existing TasNetworks distribution assets (poles) to facilitate the NBN network;
- registering telemetered devices; and
- increasing the data holdings pertaining to ground mounted substations.

Geographic information systems consolidation

This project consolidated the duplicated Webmap environments onto the new WebMap 2015 platform, reducing costs (licencing, support and operational expenditure) and providing a modern consolidated location intelligence platform for the integrated business. The Webmap platform update will impact the Dial Before You Dig system, where additional significant operational expenditure benefits can be realised.

An upgrade of the GeoMedia Smart Client software which hosts the Request Alteration to Distribution System process allows us to consolidate our geographic information system (GIS) software on the one platform, and leverage the software more effectively.

Finally, a maintenance upgrade to the G/Tech core GIS enabled the system to work correctly under a consolidated business systems environment (Windows 7) and provides future options for the schematic representation of the network model.

This project upgraded the core components of TasNetworks' GIS to the current release.

Drawing management system

A requirement existed to manage transmission drawings in-house as the outsourced management of the drawings was no longer available due to the service provider's change in system.

The drawing management project delivered an integrated platform for transmission technical drawings.

D.2.2 Investment in 2015–16

This section details our investments in Information systems programs in the forward planning period. This only includes our investment in 2015–16 as we are currently developing our investment plan for the remainder of the planning period. The investment is summarised in Table D-3 and presented in more detail below.

Table D-3: Information systems expected investment in 2015–16

Project	Investment ($000)
Asset information management standards	200
Asset register	150
Asset technical, financial, geospatial and operational information	300
Asset technical drawings	250
External systems integration	250

37 *Works, Assets Solutions and People database*

Asset information management standards

This project will deliver a suite of integrated standards required to support our asset management information system.

Asset register

This project will consolidate existing transmission and distribution asset registers to provide a single source of asset information.

Asset technical, financial, geospatial and operation information

This project will assess the requirements for asset management information (including core asset attribution, SCADA and other real-time systems). A determination of data deficiencies will be made and processes implemented to collect missing requisite data.

Asset technical drawings

This project will consolidate our distribution drawing repository and significantly increase data quality and accessibility to critical distribution drawings.

External systems integration

This project considers the integration of core asset information to and from other business systems.

Appendix E Substation information

This appendix presents the supply transformer information and 2014 load data for each substation. Presented by planning area, each table presents the substations, total and firm capacities (both continuous and short-term), maximum demand and loading performance in 2014. The performance details the hours that demand at each substation exceeded 95 per cent of its maximum demand and the number of hours the substation exceeded its firm capacity. Some substations are single supply transformers; therefore the load supplied is always non-firm and short-term ratings and hours exceeding firm not listed here. Hours exceeding is shown as blank for radial substations or those where the demand was within the firm rating of the substation.

Substations marked with an asterisk (*) supply both distribution and transmission-connected customers. For these sites, the distribution component of the load only is shown, with the transmission-connected customer component excluded. However, substation total load has been used for purposes of calculating hours exceeding 95% substation peak load and firm ratings. For all substations, the 2014 power factor is at the time of mega-watt maximum demand.

Table E-1: West Coast area substation load data

Substation	Capacity (MVA)			2014 MD		Hours exceeding:		
	Total	Firm (cont.)	Firm (short term)	MW	pf	95% of substation peak load	Firm (cont.)	Firm (short term)
Terminal substations								
Newton (22 kV)	22.5	0		4.7	0.842	49.0		
Newton (11 kV)	15	0		4.1	0.995	18.5		
Queenstown	50	25	30	5.5	0.995	6.5		
Rosebery (44 kV)*	60	30	36	15.9	0.943	73.0	132.5	0
Rosebery (22 kV)	19	9	9	2.4	0.931	0.5		
Savage River*	45	22.5	27	1.2	1.000	1990.5	858.0	0
Zone substations								
Trial Harbour	40	20		3.2		1.5		

Table E-2: North West area substation load data

Substation	Capacity (MVA)			2014 MD		Hours exceeding:		
	Total	Firm (cont.)	Firm (short term)	MW	pf	95% of substation peak load	Firm (cont.)	Firm (short term)
Terminal substations								
Burnie	120	60	72	56.5	0.992	6.5		
Devonport	90	60	72	58.9	0.996	3.0		
Emu Bay	76	38	38	9.3	0.926	7.5		
Port Latta*	45	22.5	27	8.3	0.917	11.0		
Railton	100	50	57	44.6	0.990	36.5		
Smithton	70	35	42	21.4	0.978	4.0		
Ulverstone	90	45	54	27.2	0.996	3.5		
Wesley Vale	50	25	28	0.3	0.908	4.5		

Table E-3: Northern area substation load data

Substation	Capacity (MVA)			2014 MD		Hours exceeding:		
	Total	Firm (cont.)	Firm (short term)	MW	pf	95% of substation peak load	Firm (cont.)	Firm (short term)
Terminal substations								
Derby	25	0	0	7.2	0.997	1.5		
George Town	96	48	48	19.8	0.991	6.5		
Hadspen	100	50	60	50.5	0.998	6.5	0.5	0
Mowbray	100	50	60	31.7	0.984	10.0		
Norwood	100	50	60	27.6	0.995	8.5		
Palmerston	50	25	30	10.9	0.917	20.5		
Scottsdale	63	31.5	36	12.3	0.974	0.5		
St Leonards	120	60	78	29.7	0.993	4.0		
Trevallyn	150	100	130	68.6	0.999	10.0		

Table E-4: Central area substation load data

Substation	Capacity (MVA)			2014 MD		Hours exceeding:		
	Total	Firm (cont.)	Firm (short term)	MW	pf	95% of substation peak load	Firm (cont.)	Firm (short term)
Terminal substations								
Arthurs Lake	25	0	0	6.6	0.992	8457.0[38]		
Derwent Bridge	10	0	0	0.2	1.000	1.0		
Meadowbank	10	0	0	5.4	0.923	6.5		
New Norfolk	60	30	30	15.5	0.974	7.0		
Tungatinah	25	0	0	1.1	0.982	3.0		
Waddamana	5	0	0	0.7	1.000	1.0		
Zone substations								
Gretna	1	0		0.8		4.0		
New Norfolk	10	7.5		7.1		2.0		
Wayatinah	2	0		0.9		17.5		

38 Arthurs Lake load is mainly a large pump, a single load which is either on or off.

Table E-5: Greater Hobart area substation load data

Substation	Capacity (MVA)			2014 MD		Hours exceeding:		
	Total	Firm (cont.)	Firm (short term)	MW	pf	95% of substation peak	Firm (cont.)	Firm (short term)
Terminal substations								
Bridgewater	70	35	38	30.0	0.996	4.5		
Chapel Street	120	60	60	36.4	0.995	7.0		
Creek Road	180	120	144	84.8	0.977	8.0		
Lindisfarne	90	45	54	46.2	0.988	5.5	3.5	0
Mornington	120	60	72	21.9	0.997	12.5		
North Hobart	90	45	50	41.6	0.965	5.5		
Risdon	150	100	120	65.1	0.960	19.5		
Rokeby	70	35	38	20.0	0.993	5.5		
Zone substations								
Bellerive	45	22.5	22.9[39]	16.6	0.986	8.5		
Cambridge	40	20	20	12.4	0.998	8.0		
Claremont	45	22.5	22.5	18.6	0.984	7.0		
Derwent Park	45	22.5	22.9[39]	17.1	0.944	8.0		
East Hobart	90	60	60	29.1	0.957	11.0		
Geilston Bay	45	22.5	22.9[39]	23.4	0.985	8.5	8.5	4.0
Howrah	50	25	25	15.9	1.000	8.0		
New Town	45	22.5	22.9[39]	20.8	0.973	7.5		
Sandy Bay	90	60	60	35.9	0.984	5.5		
West Hobart	90	60	60	37.9	0.966	7.5		

Table E-6: Eastern area substation load data

Substation	Capacity (MVA)			2014 MD		Hours exceeding:		
	Total	Firm (cont.)	Firm (short term)	MW	pf	95% of substation peak load	Firm (cont.)	Firm (short term)
Terminal substations								
Avoca	17	0		7.7	0.931	3.5		
St Marys	20	10	12	12.8	0.994	7.0	176.0	10.5
Sorell	120	60	61	29.3	0.999	7.0		
Triabunna	50	25	30	6.9	0.986	1.0		
Zone substations								
Richmond	5	2.5	3	3.0		4.0	96.0	0.5

Table E-7: Kingston-South area substation load data

Substation	Capacity (MVA)			2014 MD		Hours exceeding:		
	Total	Firm (cont.)	Firm (short term)	MW	pf	95% of substation peak load	Firm (cont.)	Firm (short term)
Terminal substations								
Electrona	50	25	30	16.0	0.990	1.5		
Kermandie	20	10	10	5.9	0.986	12.5		
Kingston (33 kV)	120	60	72	11.8	0.974	1.0		
Kingston (11 kV)	70	35	38	26.8	0.996	3.0		
Knights Road	40	20	23	16.5	1.000	5.0		
Zone substations								
Summerleas	25	0		11.8		1.0		

39 Limited by 11 kV switchboard emergency rating.

Appendix F Generator information

Table F-1 lists the Tasmanian power stations connected to the transmission network.

Table F-1: Transmission-connected generation

Generator	Source	Capacity (MW)	TasNetworks planning area	Connecting substation or transmission line
Bastyan	Hydro	79.9	West Coast	Farrell
Bluff Point	Wind	64.75	North West	Smithton
Butlers Gorge and Nieterana[40]	Hydro	14.4	Central	Tungatinah
Catagunya	Hydro	48	Central	Liapootah
Cethana	Hydro	85	North West	Sheffield
Cluny	Hydro	17	Central	Liapootah–Chapel Street 220 kV
Devils Gate	Hydro	60	North West	Sheffield
Fisher	Hydro	43.2	North West	Sheffield
Gordon	Hydro	432	Central	Chapel Street
John Butters	Hydro	144	West Coast	Farrell
Lake Echo	Hydro	32.4	Central	Tungatinah–Waddamana 110 kV
Lemonthyme	Hydro	51	North West	Sheffield
Liapootah	Hydro	83.7	Central	Liapootah
Mackintosh	Hydro	79.9	West Coast	Farrell
Meadowbank	Hydro	40	Central	Meadowbank
Paloona	Hydro	28	North West	Sheffield–Ulverstone 110 kV
Musselroe	Wind	168	Northern	Derby
Poatina	Hydro	300	Northern	Palmerston
Reece	Hydro	231.2	West Coast	Farrell
Repulse	Hydro	28	Central	Liapootah–Chapel Street 220 kV
Rowallan	Hydro	10.45	North West	Sheffield
Studland Bay	Wind	75	North West	Smithton
Tamar Valley	Gas	178 (OCGT) 205 (CCGT)	Northern	George Town
Tarraleah	Hydro	90	Central	Tungatinah
Trevallyn	Hydro	93	Northern	Trevallyn
Tribute	Hydro	82.8	West Coast	Farrell
Tungatinah	Hydro	125	Central	Tungatinah
Wayatinah	Hydro	38.25	Central	Liapootah
Wilmot	Hydro	30.6	North West	Sheffield

40 *Nieterana is a mini-hydro power station, which is connected to Butlers Gorge Power Station. The total power generated by Buters Gorge (capacity 12.2 MW) and Nieterana (2.2 MW) flows through this connection point to the network.*

Table F-2 lists the embedded generation sites within the distribution network. Hydro Tasmania also operates two power stations, Upper Lake Margaret Power Station (8.4 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 F-2: Embedded generation over 0.5 MW

Location	Source	Capacity (MW)	Export (MW)	TasNetworks planning area	Connecting feeder
Parangana Lake	Hydro	0.65	0.65	North West	Railton feeder 85001
Glenorchy	Biomass	1.7	1.5	Greater Hobart	Chapel Street feeder 20551
South Hobart	Biomass	1.1	1.1	Greater Hobart	West Hobart feeder 13045
Mowbray	Biomass	2.2	1.1	Northern	Mowbray feeder 62006
Meander	Hydro	2.1	1.9	North West	Railton feeder 85006
Launceston	Natural gas	2.0	2.0	Northern	Trevallyn feeder 61026
Ulverstone	Natural gas	7.9	2.0	North West	Ulverstone feeder 82006
Tods Corner	Hydro	1.6	1.6	Central	Arthurs Lake feeder 49101
Tunbridge	Hydro	6.0	4.9	Easters	Avoca feeder 56004
Derby	Hydro	1.12	1.12	Northern	Derby feeder 55001
Wynyard	Natural gas	2.0	0	North West	Burnie feeder 91004
Nietta	Hydro	1.0	1.0	North West	Ulverstone feeder 82004
Herrick	Hydro	0.9	0.9	Northern	Derby feeder 55002
Maydena	Hydro	0.55	0.55	Central	New Norfolk feeder 39571

Appendix G Transmission network constraints supplementary material

This appendix provides more information on the binding transmission network constraints summarised in Section 4.1. The tables presented here detail the constraint ID(s) that are included under the general constraint, the reason for and impact of these constraints, the cumulative duration the constraints bound for, the summated marginal cost of the constraint, and an explanation of the reason for increase or decrease in the amount the constraint bound and/or actions to reduce this number.

The marginal cost of binding constraint is calculated by AEMO for every dispatch interval during which a binding constraint occurs. It is the change in market cost that would occur if the constraint could be relieved by one MW. This is not the same as the cost difference that would occur if the constraint could be removed completely. Full market simulations would be required to understand the potential market benefit of completely eliminating a constraint. Comparing the marginal cost of constraints does, however, give some indication of the relative impact that constraints are having on the market.

As detailed in Section 4.1, the primary reason for the changes in binding constraints in 2014 was due to the change of direction of power flows across Basslink. In the last half of 2014, Basslink was largely importing energy in to Tasmania, whereas in the previous 2–3 years it had largely been exporting energy to the mainland.

Table G-1: Comparison of major binding constraints from 2012 to 2014

Constraint	Constraint ID	Reason for constraint	Impact of constraint	Number of dispatch intervals (and tine period) bound or violated			Summated marginal cost of constraint (binding only) ($)		Explanation
				2012	2013	2014	2013	2014	
Constraints with increased incidence of binding in 2014									
Sheffield–George Town 220 kV voltage stability	T^V_NIL_8	To prevent voltage collapse at George Town Substation for the loss of a Sheffield–George Town 220 kV transmission line	Limiting Tasmanian generation and power flows on Basslink during export.	0	202 (16.8 hrs)	647 (53.9 hrs)	1,568	11,988	This voltage stability constraint limits Tasmanian generation and the amount of Basslink export by taking into account local George Town area load, synchronised generation and the action of the NCSPS and George Town Reactive Power Special Protection Scheme (GTRSPS). This constraint can be relieved through the increase in generation from George Town, West Coast, Mersey Forth, Poatina power stations and the switching of local George Town capacitor banks and Basslink harmonic filters
Sheffield–George Town 220 kV transient stability	V:T_SHGT_BL_1	Invoked during a single Sheffield–George Town 220 kV circuit out of service. Basslink import into Tasmania will be limited at low George Town fault levels while Tamar Valley Combine Cycle Gas Turbine is out of service. Acts to prevent Basslink inverter commutation instability for loss of remaining Sheffield–George Town 220 kV line.	Limiting power flows on Basslink during import.	0	0	117 (9.8 hrs)	0	2,047	An increase in 2014 when compared to the previous two years due to Basslink predominantly importing into Tasmania during the second half of the year while coinciding with a SH-GT 220 kV line outage. Generation dispatch can improve fault level at George Town for Basslink import conditions.
Palmerston–Sheffield 220 kV transient stability	T::T_NIL_4	To prevent poorly damped Tasmania North–South oscillations following a trip of the Palmerston–Sheffield 220 kV transmission line while Tamar Valley Combine Cycle Gas Turbine is out of service.	Limiting generation from West Coast and Mersey Forth during Basslink import	0	0	194 (16.2 hrs)	0	1,853	An increase in 2014 when compared to the previous two years due to Basslink predominantly importing into Tasmania during the second half of the year. Reducing the generation dispatched from Sheffield and Farrell during high Basslink import will reduce the number of binding intervals.
Farrell–Sheffield 220 kV thermal limit with no outage	T>>T_NIL_BL_EXP_7C T>T_NIL_BL_IMP_7CC	To prevent overloading of one of the Farrell–Sheffield 220 kV lines for loss of the other line.	Constrain generation in West Coast area	828 (2.9 days)	10 (50 mins)	89 (7.4 hrs)	201	1,787	An increase in 2014 when compared to the previous two years due to Basslink predominantly importing into Tasmania during the second half of the year. During Basslink import the NCSPS is not available and this corridor is required to operate firm during that time.

Constraint	Constraint ID	Reason for constraint	Impact of constraint	Number of dispatch intervals (and tine period) bound or violated			Summated marginal cost of constraint (binding only) ($)		Explanation
				2012	2013	2014	2013	2014	
Constraints with reduced incidence of binding in 2014									
Palmerston–Sheffield 220 kV thermal limit with no outage	T>T_NIL_BL_220_6B	To prevent overloading of the Palmerston–Sheffield 220 kV line for loss one Sheffield – George Town line.	Limiting the generation from the West Coast and Mersey Forth.	177 (15 hrs)	324 (27 hrs)	71 (5.9 hrs)	25,279	2,122	Reduced in 2014 due to a decrease in instances where the Hadspen – George Town transmission corridor was declared a credible contingency as a result lightning activity.
	T>T_GT_HA_3A_N-2	The loss of both Hadspen–George Town 220 kV transmission lines being declared a credible contingency and avoid overloading the Palmerston–Sheffield 220 kV line	Limiting the total sum of power flows on Palmerston - Sheffield and Hadspen – George Town 220 kV corridors to below the thermal rating of the Palmerston – Sheffield 220 kV line. Reduce generation from the south of Palmerston and the north east including Trevallyn and Musselroe.						The installation of optical fibre ground wires on the Palmerston–Hadspen–George Town and Sheffield–George Town 220 kV transmission lines (completed in March 2014) is expected to alleviate this issue.
Sheffield–George Town 220 kV thermal limit with no outage	T>>T_NIL_BL_EXP_6E	To prevent overloading of one Sheffield–George Town 220 kV line for loss of the other line during insufficient Basslink export levels to compensate for NCSPS action.	Limiting power flows on the SH-GT 220 kV corridor by constraining West Coast and Mersey Forth generation.	2813 (9.8 days)	1038 (3.6 days)	215 (17.9 hrs)	263,487	3,089	Reduced in 2014 due to Basslink predominantly importing into Tasmania during the second half of the year. The constraint can be reduced by having generation dispatched through the HA-GT 220 kV corridor to increase the Basslink export headroom. This will allow for increased power flows on the SH-GT 220 kV corridor once higher Basslink headroom is available.
	T>T_NIL_BL_IMP_6E (#1 circuit) T>T_NIL_BL_IMP_6EE (#2 circuit)	To avoid overloading one Sheffield–George Town 220 kV line (flow to George Town) for trip of the other circuit with no SPS action.							
	T>T_SHGT_HAGT_N-2	Avoid overloading the Sheffield–George Town 220 kV lines for the loss of both Hadspen–George Town 220 kV lines after being declared credible.							

Constraint	Constraint ID	Reason for constraint	Impact of constraint	Number of dispatch intervals (and tine period) bound or violated			Summated marginal cost of constraint (binding only) ($)		Explanation
				2012	2013	2014	2013	2014	
Hadspen–George Town 220 kV thermal limit with no outage	T>>T_NIL_BL_EXP_5F (1) T>T_NIL_BL_5C (2)	To prevent the overloading of one Hadspen–George Town 220 kV line for the loss of the other line whilst considering NCSPS action. Ensures that Basslink can fully compensate NCSPS action (1) and that sufficient NCSPS generation is dispatched (2).	Constrain power flow from south of Palmerston and the north east including Trevallyn and Musselroe.	362 (30 hrs)	7145 (24 days)	582 (48.5 hrs)	571,880	15,995	Reduced in 2014 due to Basslink predominantly importing into Tasmania during the second half of 2014 along with a decrease in the Basslink headroom requirement following the removal of fast action NCSPS on the Hadspen–George Town corridor. Reduced in 2014 due to Basslink predominantly importing into Tasmania during the second half of the year and a more conducive dispatch of NCSPS generation during export.
	T>T_NIL_BL_IMP_5F (HA-GT #1) T>T_NIL_BL_IMP_5FF (HA-GT #2)	To avoid the overloading of Hadspen–George Town No. 1 or 2 220 kV line (flow to GT) for the loss of other line with no SPS action	The power flow on Hadspen–George Town 220 kV corridor is restricted						The reduced frequency of T>T_NIL_BL_IMP_5F and T>T_NIL_BL_IMP_5FF constraints was due to the thermal rating of the line being increased following the augmentation of the conductor dead-ends which restored the previous thermal rating of the transmission lines.
	T>T_HAGT_N-2	To prevent voltage collapse at George Town, if the loss of both Hadspen–George Town 220 kV lines or Palmerston–Hadspen 220 kV lines is declared a credible contingency							
	T>T_NIL_TOV_5F (HA-GT #1) T>T_NIL_TOV_5FF (HA-GT #2)	To avoid temporary over voltages following NCSPS slow/fast action for the overloading of Hadspen–George Town No. 1/No. 2 220 kV line (flow to North) for the loss of the other line.							
Gordon–Chapel Street 220 kV thermal limit with no outage	T>T_NIL_BL_IMP_1B T>T_NIL_NCSPS5_1B	To prevent overloading of one of the Gordon–Chapel Street 220 kV lines for the loss of the other line.	Constrain generation at Gordon Power Station	58 (5 hrs)	3939 (13.7 days)	2 (10 mins)	109,715	1	Reduced due to the lower level of generation at Gordon Power Station in 2014 which rarely exceeded the Gordon–Chapel Street 220 kV transmission line thermal rating.

Constraint	Constraint ID	Reason for constraint	Impact of constraint	Number of dispatch intervals (and tine period) bound or violated			Summated marginal cost of constraint (binding only) ($)		Explanation
				2012	2013	2014	2013	2014	
Palmerston–Hadspen 220 kV thermal limit with no outage	T>>T_NIL_BL_EXP_3F	To prevent overloading of one of the Palmerston–Hadspen 220 kV lines for the loss of the other line. Ensures that Basslink can fully compensate NCSPS action.		2 (10 mins)	1711 (5.9 days)	184 (15.3 hrs)	42,140	2,023	Reduce in 2014 due to Basslink predominantly importing into Tasmania during the second half of the year and a more conducive dispatch of NCSPS generation during export. Generation re-dispatched to increase the generation available for NCSPS tripping and a reduction of non-NCSPS generation would reduce the number of binding constraints.
	T>T_NIL_BL_3C (1) T>T_NIL_BL_IMP_3F (2)	To prevent overloading of one of the Palmerston–Hadspen 220 kV lines for loss of the other lines. Ensures sufficient NCSPS generation is dispatched (1) or no NCSPS action (2).							
Palmerston–Waddamana 220 kV thermal limit with no outage	T>T_NIL_BL_IMP_8C	To prevent overloading either Palmerston to Waddamana Tee 220 kV line section (flow to South) for trip of the other Liapootah to Waddamana Tee to Palmerston 220 kV line		65 (5.4 hrs)	0	0	0	0	This constraint did not bind in 2014 primarily due to generation dispatch outcomes. This constraint typically binds during high north to south power flow conditions. In 2014 power flow was both northwards and southwards to support both Basslink export and import conditions.

Table G-2: Network constraint equations affecting Basslink flows

Constraint	Constraint ID	Reason for constraint	Impact of constraint	Number of dispatch intervals (and tine period) bound or violated			Summated marginal cost of constraint (binding only) ($)		Explanation
				2012	2013	2014	2013	2014	
Constraints with increased incidence of binding in 2014									
Basslink import limited due to load unavailability for FCSPS operation	V_T_NIL_FCSPS	To protect the Tasmanian system frequency following FCSPS action during Basslink import by ensuring sufficient availability of FCSPS load for tripping.	Limit power flow on Basslink import from Victoria to Tasmania	3904 (13.6 days)	12 (60 mins)	4014 (13.9 days)	331	59,536	An increase in 2014 due to Basslink predominantly importing into Tasmania during the second half of 2014. There was also a change in the FCSPS load arming algorithm for Basslink during import which required more load being armed which resulted in an increase of insufficient FCSPS load available.
Sheffield–Farrell 220 kV transmission line rating constraints with NCSPS operation	T>>T_NIL_BL_EXP_7C	To avoid overloading one of the Farrell–Sheffield 220 kV lines for the loss of the other line considering NCSPS action. Ensures that Basslink can fully compensate NCSPS action.	Limit generation from West Coast area and force higher Basslink export level.	8 (40 mins)	6 (30 mins)	20 (2 hrs)	172	634	There was a small increase in the number of binding intervals for this constraint due to the change in generation dispatch which caused insufficient Basslink headroom to compensate for NCSPS arming of West Coast generation.
Hadspen–Palmerston 220 kV transmission line rating constraints with NCSPS operation	T>T_NIL_BL_3C T>>T_NIL_BL_EXP_3F	To avoid overloading one of the Hadspen–Palmerston 220 kV lines (flow to Hadspen) for the loss of the other line. Ensures that Basslink can fully compensate NCSPS action.	Force more NCSPS generation to be dispatched together with higher Basslink export level while limiting generation from non NCSPS generators.	Not avail-able	21 (2 hrs)	144 (12 hrs)	7,671	1,810	An increase in 2014 due to the change in generation dispatch which resulted in more non-NCSPS generation being dispatched for this particular corridor.
Constraints with decreased incidence of binding in 2014									
Basslink export limited due to generation unavailability for FCSPS operation	T_V_NIL_FCSPS	To protect the Tasmanian system frequency following FCSPS action on Basslink export by ensuring sufficient availability of FCSPS generation for tripping.	Limit power flow on Basslink export from Tasmania to Victoria.	24 (2 hrs)	42 (4 hrs)	28 (2 hrs)	616	143	A small reduction in the number of binding intervals in 2014 due to more conducive dispatches of NCSPS generation during export conditions.
Palmerston–Sheffield 220 kV transmission line rating constraints with NCSPS operation				21 (2 hrs)	91 (8 hrs)	0	5,485	0	

Constraint	Constraint ID	Reason for constraint	Impact of constraint	Number of dispatch intervals (and tine period) bound or violated			Summated marginal cost of constraint (binding only) ($)		Explanation
				2012	2013	2014	2013	2014	
Hadspen–George Town 220 kV transmission line rating constraints with NCSPS operation	T>>T_NIL_BL_EXP_5F T>T_NIL_BL_5C	To avoid overloading one of the Hadspen–George Town 220 kV lines (flow to George Town) for the loss of the other line. Ensures that Basslink can fully compensate NCSPS action.	Force more NCSPS generation to be dispatched together with higher Basslink export level while limiting generation from non NCSPS generators.	14 (70 mins)	588 (2 days)	122 (10 hrs)	434,888	6,817	A reduction in 2014 due to the change in generation dispatch which resulted in more NCSPS generation being dispatched for this particular corridor.
Hadspen–Palmerston 110 kV transmission line rating constraints with NCSPS operation	T>>T_NIL_BL_EXP_4F	To avoid overloading the Hadspen–Palmerston No. 3 110 kV line (flow to Hadspen) for the loss of the Palmerston 220/110 kV transformer considering NCSPS action. Ensures that Basslink can fully compensate NCSPS action.	Force higher Basslink export level to fulfil the Basslink headroom requirement.	9 (45 mins)	0	0	0	0	This constraint has not bound since 2013 due to the changes in generation dispatch which always fulfil the Basslink headroom requirement during export.
Sheffield–George Town 220 kV transmission line rating constraints with NCSPS operation	T>>T_NIL_BL_EXP_6E	To avoid overloading one of the Sheffield–George Town 220 kV lines (flow to George Town) for loss of other line. Ensures that Basslink can fully compensate NCSPS action.	Force higher Basslink export level to ensure that Basslink can fully compensate NCSPS action.	1496 (5.2 days)	952 (3.3 days)	157 (13 hrs)	25,469	2,393	The number of binding intervals was reduced significantly due to Basslink predominantly importing into Tasmania during the second half of 2014. There was also a more conducive generation dispatch scheduled to provide sufficient Basslink headroom to compensate NCSPS action on the Sheffield–George Town 220 kV circuits.
Basslink rate-of-change limit	TVBL_ROC	To constraint the rate of change of power flows on Basslink.	Limit the rate of change (Tasmania to Victoria) of 200 MW per 5 minutes for Basslink.	206 (17 hrs)	159 (13 hrs)	145 (12 hrs)	2,637	3,167	

Appendix H Power quality planning levels

This appendix provides TasNetworks' planning levels for over/under voltage, voltage unbalance, harmonic voltage content and voltage fluctuation.

The actual emission level allocated to any particular connection will be less than the planning level given below. We will allocate emission levels for particular connections at the time of assessing a connection application.

H.1 Planning levels for over and under voltages

The Rules illustrate the allowable Temporary Over Voltage (TOV) envelope in S5.1a.4 (the Rules Figure S-5.1a.1), which is reproduced in Figure H-1 below.

The Rules do not specify a standard for transient voltage recovery following under voltage events. We have compiled the under-voltage characteristic in Figure H-2 largely from performance standards applicable to generating units. We consider this to be a reasonable guide to the required voltage recovery characteristics that would enable the power system to adequately recover, following a network event. We will use Figure H-2 for general assessment of under voltage performance, but we reserve the right to apply alternate performance metrics as required.

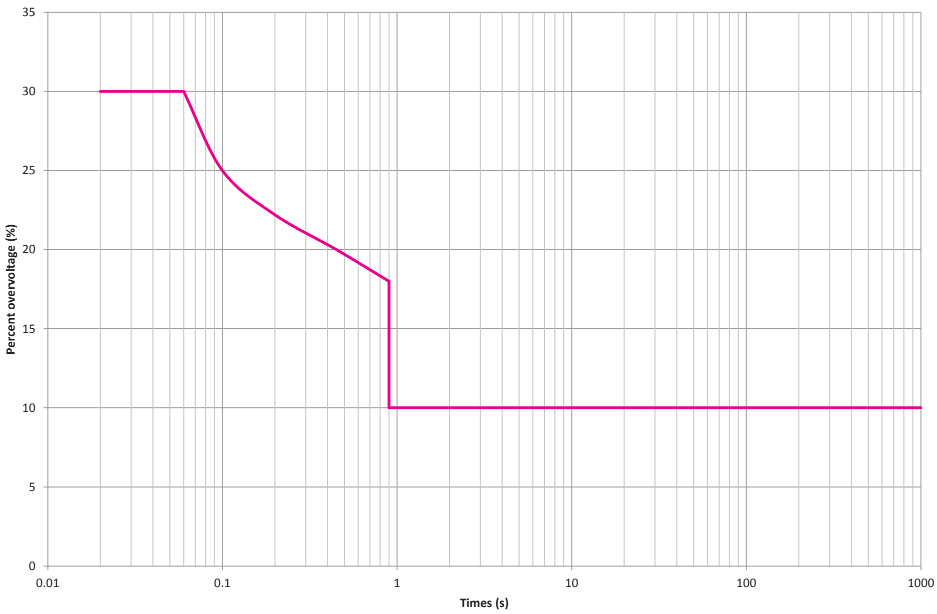


Figure H-1: The Rules over-voltage requirements (reproduced from the Rules S5.1a.1)

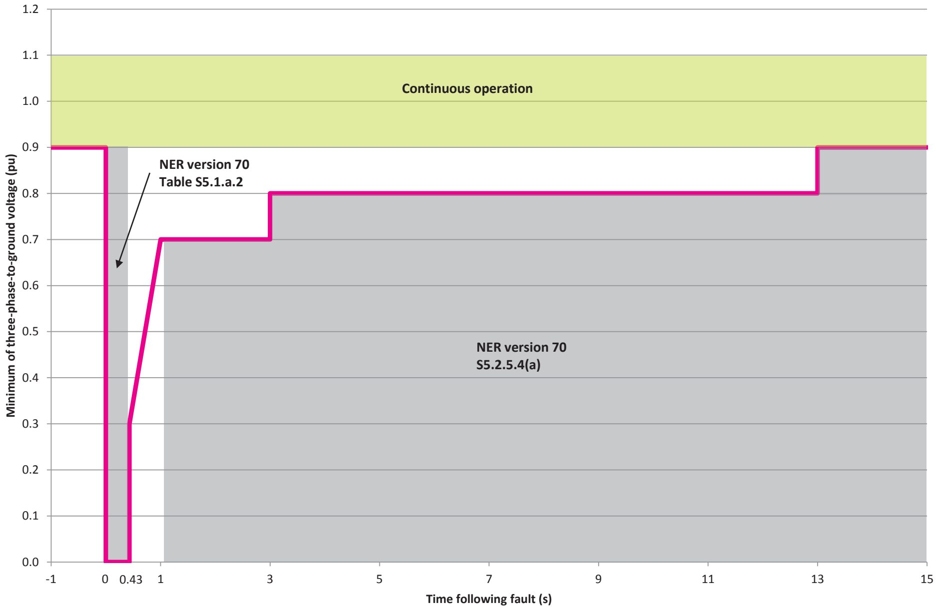


Figure H-2: Compilation of the Rules under-voltage recovery requirements

H.2 Planning levels for voltage fluctuation

Voltage fluctuations are defined as repetitive or random variations in the magnitude of the supply voltage. The magnitudes of these variations do not usually exceed 10 per cent of the nominal supply voltage. However, small magnitude changes occurring at particular frequencies can give rise to an effect called flicker.

There are two important parameters to voltage fluctuations: the frequency of fluctuation and the magnitude of fluctuation. Voltage fluctuations may cause spurious tripping of relays, interference with communications equipment, and may trip out electronic equipment.

With respect to planning levels for voltage fluctuations, Table H-1 has been derived and adopted for the Tasmanian transmission network. Note that TR IEC 61000.3.7:2012 should be referenced for further details.[41]

Table H-1: Voltage fluctuation planning levels

Flicker level	Bus voltage	
	HV[42]	MV[43]
PST	0.8	0.9
PLT	0.6	0.7

PST Short-term flicker level

This is a measure of the change in relative voltage magnitude versus the frequency of the voltage changes, calculated on a 10-minute basis. An index level of less than 1.0 is considered acceptable.

PLT Long-term flicker level

This is an average of PST values evaluated over a period of two hours. An index level of less than 0.9 is considered acceptable.

H.3 Planning levels for harmonic voltage

With respect to planning levels for harmonic voltages, Table H-2has been derived and adopted for the Tasmanian transmission network. Note that TR IEC 61000.3.6:2012 should be referenced for further details.[44]

41 The Rules S5.1a.5 refers to AS/NZS 61000.3.7:2001. This standard has been superseded by TR IEC 61000.3.7:2012

42 HV: 35 kV < Un ≤ 230 kV

43 MV: 1 kV < Un ≤ 35 kV

44 The Rules S5.1a.6 refers to AS/NZS 61000.3.6:2001. This standard has been superseded by TR IEC 61000.3.6:2012

Table H-2: Harmonic planning levels for the Tasmanian network

Harmonic number	Permissible voltage level (% of the nominal voltage)			
	Transmission or sub-transmission busbars		Load busbars	
	220 kV / 110 kV	44 kV / 33 kV	33 kV / 22 kV / 11 kV	6.6 kV
2	1.14	1.37	1.84	1.87
3	2.00	2.75	4.27	4.39
4	0.60	0.72	0.96	0.98
5	2.00	3.01	5.12	5.31
6	0.27	0.32	0.43	0.44
7	2.00	2.69	4.19	4.34
8	0.27	0.32	0.43	0.44
9	0.81	0.95	1.27	1.31
10	0.29	0.34	0.46	0.47
11	1.50	1.94	2.97	3.11
12	0.27	0.31	0.41	0.43
13	1.50	1.80	2.53	2.64
14	0.25	0.29	0.38	0.40
15	0.21	0.24	0.32	0.34
16	0.23	0.27	0.36	0.38
17	1.11	1.27	1.69	1.77
18	0.22	0.25	0.34	0.36
19	0.98	1.11	1.48	1.56
20	0.22	0.24	0.33	0.34
21	0.15	0.17	0.23	0.24
22	0.21	0.23	0.31	0.33
23	0.78	0.87	1.17	1.24
24	0.20	0.23	0.30	0.32
25	0.71	0.79	1.05	1.12
26	0.20	0.22	0.29	0.31
27	0.12	0.13	0.18	0.19
28	0.19	0.21	0.28	0.30
29	0.59	0.65	0.86	0.93
30	0.19	0.21	0.28	0.30
31	0.55	0.59	0.79	0.85
32	0.19	0.20	0.27	0.29
33	0.12	0.13	0.17	0.19
34	0.19	0.20	0.26	0.29
35	0.47	0.50	0.66	0.72
36	0.18	0.19	0.26	0.28
37	0.43	0.46	0.61	0.67
38	0.18	0.19	0.25	0.28
39	0.12	0.13	0.17	0.18
40	0.18	0.19	0.25	0.27
41	0.38	0.39	0.53	0.58
42	0.18	0.18	0.24	0.27
43	0.35	0.36	0.49	0.54
44	0.18	0.18	0.24	0.27
45	0.12	0.12	0.16	0.18
46	0.17	0.18	0.24	0.26
47	0.31	0.32	0.42	0.47
48	0.17	0.17	0.23	0.26
49	0.29	0.29	0.39	0.44
50	0.17	0.17	0.23	0.26
THD[45]	3.00	4.36	6.61	6.93

Planning levels at generator busbars (terminal connection voltage) are to be taken as half of these values, recognising that there is a cost associated with specifying a higher level of required harmonic immunity for such plant.

45 Total harmonic distortion.

H.4 Planning levels for voltage unbalance

The planning levels for voltage unbalance are summarised in Table S-5.1a.1 of the Rules, being part of Schedule 5.1a (System Standards). This table is replicated in Table H-3.

Table H-3: Planning levels for voltage unbalance (from the Rules Table S-5.1a.1)

Nominal supply voltage (kV)	Maximum negative sequence voltage (% of nominal voltage)			
Column 1	Column 2	Column 3	Column 4	Column 5
	No contingency event	Credible contingency event	General	Once per hour
	30 minute average	30 minute average	10 minute average	1 minute average
More than 100	0.5	0.7	1.0	2.0
More than 10 but not more than 100	1.3	1.3	2.0	2.5
10 or less	2.0	2.0	2.5	3.0

Appendix I Chapter 5 supplementary material

I.1 Results of demand and energy forecasts

Load forecast data is provided in a number of Microsoft Excel file on the TasNetworks web sites, via the 2015 Annual Planning Report page. The file is available at http://apr.tasnetworks.com.au.

The following load forecast information is provided:

- *Annual energy, Total winter maximum demand, Total summer maximum demand*: these data are total forecast energy use or maximum demand, based on generation sent out. These are the energy/maximum demand required to support all Tasmanian load, including network losses. Data are given for each of the low, medium and high economic growth forecasts.
- *Substation winter MD forecast, Substation summer MD forecast*: present the load forecast used by TasNetworks for individual substations from 2015 to 2025. The values present include maximum active power (MW) and coincident reactive power (MVAr). These values are based on medium growth with 10 per cent POE. The loads shown are for distribution connection point load only and exclude directly transmission connected and auxiliary loads.
- *Substation winter diversity forecast, Substation summer diversity forecast*: present the forecast diversity factors used by TasNetworks for individual substations from 2015 to 2020.
- *Zone sub summer maximum demand, Zone sub winter maximum demand*: present the load forecast used by TasNetworks for zone substations from 2015 to 2025. The values are presented as apparent power (MVA).
- *Zone feeder summer maximum demand, Zone feeder winter maximum demand*: present the load forecast used by TasNetworks for feeders from zone substations from 2015 to 2025. The values are presented as amperes (A).
- *Subtransmission feeder summer maximum demand, Subtransmission feeder winter maximum demand*: present the load forecast used by TasNetworks for subtransmission feeders from terminal substations to zone substations from 2015 to 2025. The values are presented as amperes (A).
- *Connection point feeder summer maximum demand, Connection point feeder winter maximum demand*: present the load forecast used by TasNetworks for feeders from terminal substations from 2015 to 2025. The values are presented as amperes (A).
- *Minor zone source feeder maximum demand*: present the load forecast used by TasNetworks for feeders connecting to rural zone substations from 2015 to 2025. The values are presented as amperes (A).
- *Forecast coincident maximum demand profiles*: present the forecast of the load profiles of each terminal substation at the time of total state peak demand from 2015 to 2020. The values are presented as maximum active power (MW) and coincident reactive power (MVAr).
- *Forecast maximum demand profiles*: present the forecast of the load profiles of each terminal substation from 2015 to 2020. The values are presented as maximum active power (MW) and coincident reactive power (MVAr).
- *Forecast Average Profiles*: present the forecast of the load profiles from a selection of day types (weekday, Saturday and Sunday/public holiday) and a selection of months (January, April, July and October) for each terminal substation from 2015 to 2020. The values are presented as maximum active power (MW) and coincident reactive power (MVAr).
- *Load transfer capacities:* present the known load transfer capacities between terminal and urban zone substations. The values presented are in MVA.

I.2 State forecasting methodology

TasNetworks state forecast is based on three economic scenarios (medium, high and low). These scenarios are built on key energy market policies and economic conditions known at the time. For each of these scenarios our forecaster, NIEIR, prepares a forecast of economic variables and regional energy and demand forecasts for Tasmania. We engage NIEIR to develop state energy and maximum demand forecasts because NIEIR is recognised as an independent expert in this field.

The medium growth load forecast represents an estimate of how the future energy and demand may develop with known and anticipated economic changes considered most likely. The high and the low growth forecasts are based on alternative economic growth scenarios.

NIEIR develops an econometric model for Tasmanian energy and maximum demand forecasts. The following factors are incorporated for the forecasting model:

- gross state product and real incomes;
- weather conditions; • electricity prices;
- average consumption per dwelling; and
- major new industrial, mining and commercial developments.

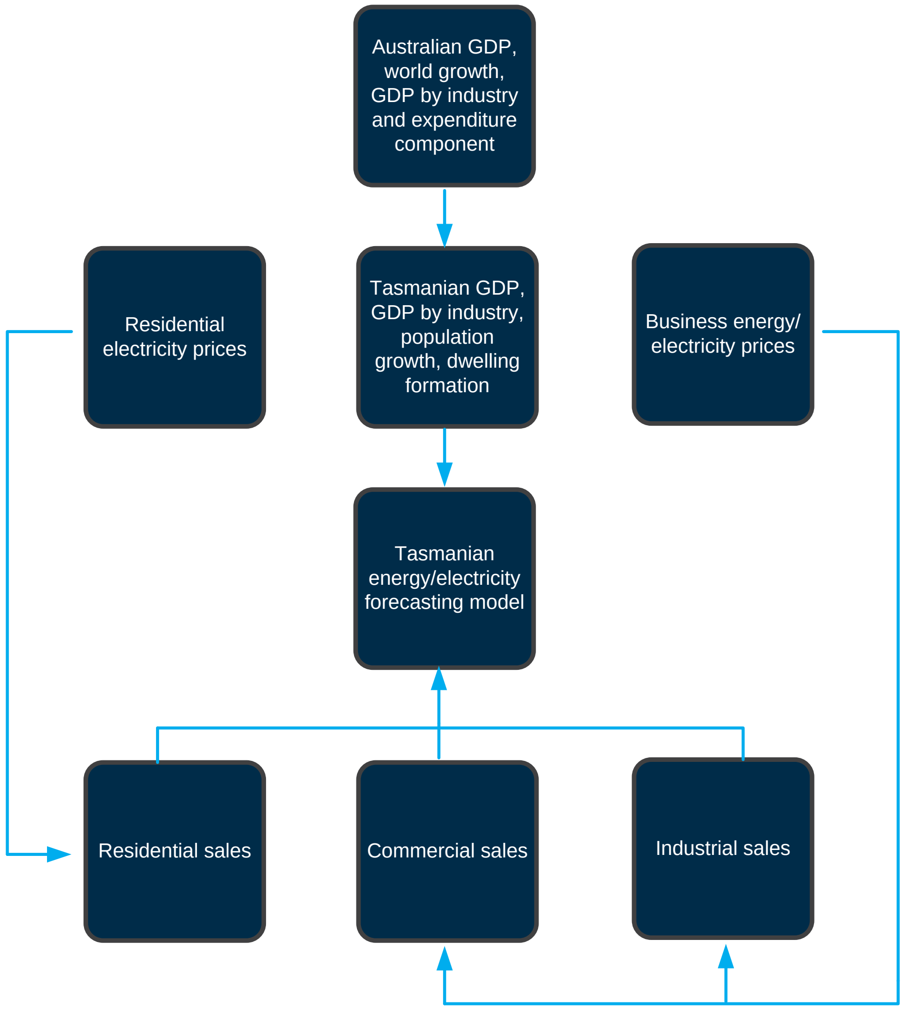


Figure I-1: Schematic of energy/electrical forecasting model

Energy sales forecasts are based on econometric models. In modelling, Tasmanian energy sales by industry are linked to real output growth by industry, electricity prices, and weather conditions. Business energy sales in Tasmania are linked directly to business prices. Business sales by industry are also linked to real output growth by industry for Tasmania. Residential sales are determined from a model including average consumption per dwelling, weather, real income, and electricity prices. The schematic of the forecasting model is presented in Figure I-1.

Forecasts of summer and winter maximum demands for Tasmania were developed using econometric regression equations based on historic data. These winter and summer maximum demand equations are estimated as a load factor equation. The load factor equation effectively means the forecast maximum demands for Tasmania indirectly reflects the impact of GSP and real electricity price changes. These maximum demand equations include Tasmanian GSP as an independent explanatory variable. A price variable is difficult to justify in any maximum demand forecast equation until customers are interval metered and/or face peak power pricing/ tariff structures. Price is excluded from the maximum demand model but included in the energy models as discussed above. Furthermore, these equations were derived excluding the impact of the top four transmission connected major industrial customers which are assumed to be weather/temperature insensitive and added to maximum demand outside the model.

As temperature variations are incorporated into the forecasting process, the maximum demand forecasts are prepared on a probability of exceedance (POE) basis relating to temperature for each high, medium, and low growth scenarios. Three conditions have been developed for Tasmania at 10, 50 and 90 per cent POE, which indicate the probability of the temperature dropping below the reference temperature – as maximum demand variation is inversely proportionate to temperature, the changes of the maximum demand exceeding the forecast.[46]

Transmission-connected customers provide their own demand forecasts. Transmission-connected customer demand forecasts are reconciled with NIEIR's forecast and combined with connection point projected demand forecast to produce a consolidated connection point and regional demand forecast for Tasmania.

46 10 per cent POE represents a 10 per cent chance the actual temperature on the day dropping below the reference temperature in a given year.

I.2.1 Weather conditions

Daily electricity maximum demand in winter and summer depends on:

- the ambient minimum temperature during the day; and
- the ambient maximum temperature on the previous day.

The approach developed by NIEIR was to calculate the probabilities associated with different average daily temperatures. The average temperature was defined as the weighted average of the overnight minimum and the previous daily maximum. The daily minimum was assigned a weight of 0.8, while the previous day's maximum a weight of 0.2 in this calculation.

Based on historic data, the following temperature percentiles were derived for maximum demand forecasts:

- 10th percentile: temperature met once in every ten years;
- 50th percentile: temperature met once in every two years; and
- 90th percentile: temperature met nine out of ten years.

Temperature exercises the most important influence on peak demands. Other weather variables, such as humidity, rainfall and wind, were not considered in the POE calculations for Tasmania.

Table I-1: Tasmanian reference temperatures at associated POE

POE	Winter (°C at Hobart)	Summer (°C at Hobart)
10%	0.9	7.0
50%	2.1	8.7
90%	3.2	9.8

As per the historic data analysis, sensitivity of maximum demand in winter and summer are around 25 to 30 MW per degree and 12 to 15 MW per degree respectively. These sensitivities are dependent upon how cool each season actually is.

I.3 Connection site forecasting methodology

The underlying approach is to project load for each connection site at a rate that is consistent with recent history, using weather corrected data. The sources of input information for the approach are as follows:

- State maximum demand forecast produce by NIEIR;
- Temperature data retrieved from the Bureau of Meteorology web site;
- Terminal substation active and reactive power data from metering data;
- Zone substations and feeder data from TasNetworks SCADA system; and
- Load adjustments information received from internal process associated with new or augmented customer connections. Only committed connections, over 500 kW, are used.

Historic data at each connection site is to be corrected for the temperature (weather correction, which is described in Appendix I.2.1). Temperature of the connection site is obtained from the nearest weather station of Bureau of Meteorology. Weather corrected data are then adjusted for large block loads and permanent transfers.

The basic approach is to extrapolate from recent history using linear time trends (over varying time frames) or applying growth rates based on historical behaviour to the most recent temperature corrected observation. This is applied to non-coincident peak demands for each substation.

Similarly, our directly transmitted connected customer forecasts (provided by each customer) are reconciled with NIEIR produced directly transmitted connected customer forecasts.

The spatial forecasts for each connection site (i.e., distribution and directly transmitted connected customers) are aggregated together, using diversity factors, to a system level forecast (bottom-up). This is then compared to, and reconciled with the system level forecast produced by NIEIR (top-down).

Connection site maximum demand forecasts are prepared for both summer (December-February) and winter (June-August) periods.

I.3.1 Weather correction

TasNetworks weather corrects the data to the 10, 50 and 90 per cent POE load levels.

The random nature of weather means that any comparison of historical electricity loads over time requires these loads to be adjusted to standardised weather conditions.

Long term trending data are generated from temperature data retrieved from the Bureau of Meteorology web site. Accordingly, respective temperatures for each POE levels are generated for each weather station for each season based on annual minimum effective temperatures for the period from 1970 to date.

Load sensitivity for the temperature is calculated by generating a liner relationship between daily maximum demand and the daily effective temperature for each season for each connection point. In this regard, weekends and public holidays are excluded.

I.3.2 Adjusting for significant block loads, permanent transfers and other factors

Before applying any form of analysis or growth factor to historical weather corrected peak demands, these are adjusted for transfers to and from the substation as well as significant block loads that comprise a large proportion of the loads at the specific connection site. The effects of transfers and large block loads are removed from the historical data series before any trends are fitted or growth rates are determined. These are later added back to the forecasts.

Forecasts are also adjusted for predicted transfers and large block loads that are expected to arise during the forecast period.

I.3.3 Embedded generation

Embedded generation units are not specifically allocated load within the connection point feeder, zone substation and zone substation feeder load forecast.

Generation units connected to the distribution network are not required to be scheduled, in accordance with the Rules, however there are two registered generation units in the distribution network; a 6 MW mini-hydro generating unit (non-market, non-scheduled) and 2.2 MW natural gas unit (market, non-scheduled) embedded within the distribution networks supplied from Avoca and Mowbray substations, respectively. As a result, the load data used assumes that the generating units were displaying their normal operating pattern. The methodology does not take into account abnormal patterns of usage either generating or not generating during the load forecast periods.

Based on the nature of the input data the forecast of generation load is unavailable and is not provided. Therefore, the historic net load of the feeders were taken for analysis and forecasting as embedded generation acts as a 'negative load' when seen from the network. Appendix E provides the details of embedded generators connected within the distribution network.

I.3.4 Zone and feeder forecasts

Maximum demand for summer and winter for each feeder is extracted from 'PI' Historian (information technology storage system for transformer and cable loads and voltages) and the data is processed to remove spikes and erroneous data points.

The maximum demand data is manually examined to ensure that switching of any feeder has been correctly accounted for.

Actual maximum demand for each feeder is determined and that figure is extrapolated on an annual basis using the output of its station maximum demand forecasts.

Maximum demand forecasts of zone substations are determined based on the historic maximum demand of each zone substation and it contribution to the maximum demand of the relevant terminal substation.

The forecasts are then adjusted for any confirmed switching arrangements in the near future and/or the confirmed establishment of new feeders that would take load from the existing feeder.

Appendix J Service target performance incentive scheme submission

The following information was provided to the AER as part of the service target performance incentive scheme for the 2013–14 year.

1. Supply reliability category:
   - System Average Interruption Duration Index (SAIDI);
   - System Average Interruption Frequency Index (SAIFI); and
   - Momentary System Average Interruption Frequency Index (MAIFI) (under 60 seconds)
2. Average distribution customer numbers.
3. Daily performance for supply reliability category, with and without excluded events for:
   - SAIDI;
   - SAIFI; and
   - MAIFI
4. Total number of calls per day after removal of excluded events.
5. Total number of calls not answered within 30 seconds after removal of excluded events.
6. Value of major event days threshold for year.
7. Dates of major event days.
8. Statistical information for major event day threshold for year.
9. Daily performance for „customer minutes off" after removal of excluded events.
10. Interruption events, both planned and unplanned covering:
    - Supply reliability area;
    - Category of are;
    - Cause of event;
    - kVA interrupted;
    - Number of customer interrupted; and
    - Duration of interruption.