Powerlink Queensland

Transmission Annual Planning Report

2017

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Executive summary

Planning and development of the transmission network is integral to Powerlink Queensland meeting its obligations under the National Electricity Rules (NER), *Queensland's Electricity Act 1994* and its Transmission Authority.

The Transmission Annual Planning Report (TAPR) is a key part of the planning process. It provides information about the Queensland electricity transmission network to everyone interested or involved in the National Electricity Market (NEM) including the Australian Energy Market Operator (AEMO), Registered Participants and interested parties. The TAPR also provides broader stakeholders with an overview of Powerlink's planning processes and decision making on potential future investments.

The TAPR includes information on electricity energy and demand forecasts, committed generation and network developments. It also provides estimates of transmission grid capability and potential network and non-network developments required in the future to continue to meet electricity demand in a timely manner.

Overview

The 2017 TAPR outlines the key factors impacting Powerlink's transmission network development and operations. The forecasts presented in this TAPR indicate relatively flat growth for energy, summer maximum demand and winter maximum demand in the first half of the 10-year outlook period, with moderate growth in the latter half of the 10-year outlook period.

An amended planning standard for the transmission network also came into effect from July 2014 which allows the network to be planned and developed with up to 50MW or 600MWh at risk of being interrupted during a single network contingency. This provides more flexibility in the cost-effective development of network and non-network solutions to meet future demand.

The Queensland transmission network experienced significant growth in the period from the 1960s to the 1980s. The capital expenditure required to manage emerging risks related to assets now reaching the end of technical or economic life represents the majority of Powerlink's program of work over the outlook period. Considerable emphasis is placed on ensuring that asset reinvestment is not just on a like-for-like basis. Network planning studies have focused on evaluating the enduring need for existing assets in the context of a subdued demand growth outlook and the potential for network reconfiguration, coupled with alternative non-network solutions.

Powerlink's focus on stakeholder engagement has continued over the last year, with a range of engagement activities undertaken to seek stakeholder feedback and input into our network investment decision making. This included the Powerlink Queensland Transmission Network Forum incorporating related break-out sessions, encompassing large-scale variable renewable electricity (VRE) generation in Queensland and improving stakeholder engagement when developing non-network solutions.

Electricity energy and demand forecasts

The energy and demand forecasts presented in this TAPR consider the following factors:

- continued growth of solar photovoltaic (PV) installations, including solar PV farms connecting to the distribution network
- changing Queensland economic growth conditions over the outlook period
- continued consumer response to high electricity prices
- the impact of energy efficiency initiatives, battery storage technology and tariff reform.

In preparing its demand and energy forecasts, Powerlink conducted a forum for industry experts to share insights and build on our knowledge relating to emerging technologies. As a result several enhancements were made to how these emerging technologies are forecast within this TAPR. These forecasts are obtained through a reconciliation of two separate processes, namely top-down econometric forecasts derived from externally provided forecasts of economic indicators, and bottom-up forecasts from Distribution Network Service Providers (DNSPs) and directly connected customers at each transmission connection supply point.

Key economic inputs to Powerlink's econometric model include population growth, retail turnover and the price of electricity. DNSP customer forecasts are reconciled to meet the totals obtained from this model.

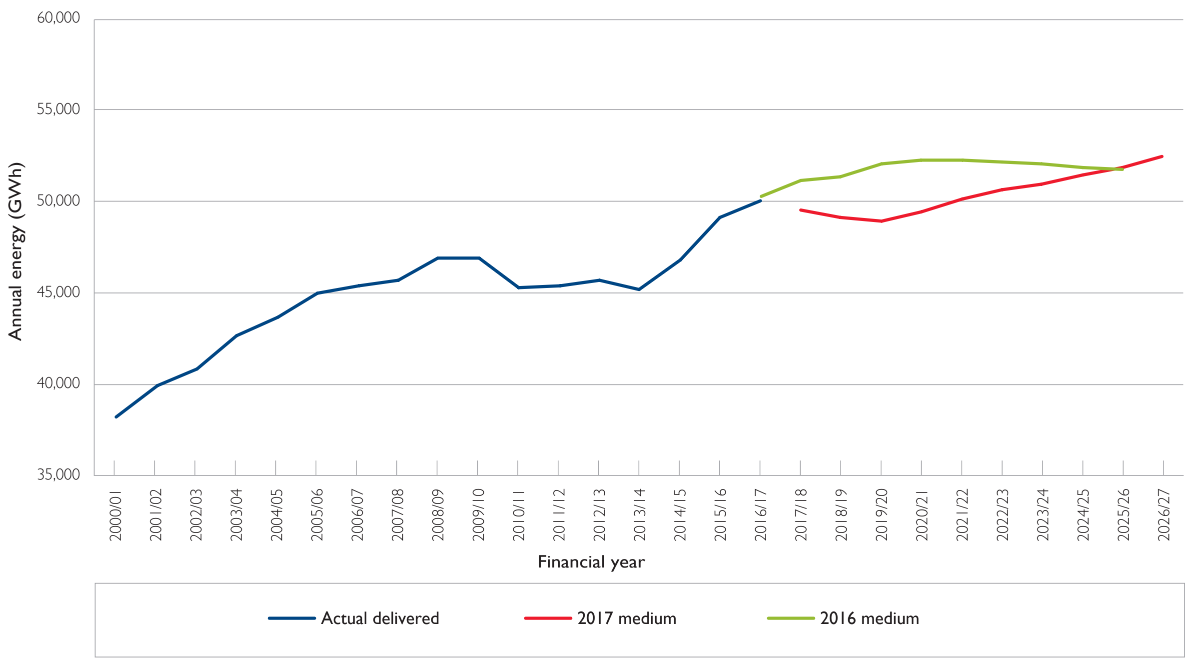
The 2016/17 summer in Queensland was hot and long lasting with particularly high electricity demand on the transmission network on 18 January and 12 February. A new record demand was recorded at 6:00pm on 18 January, when 8,401MW was delivered from the transmission grid. Scheduled as generated and native demand records were recorded at 5:30pm on 12 February, with scheduled as generated reaching 9,369MW and native demand reaching 8,756MW. The corresponding delivered demand on 12 February was 8,392MW, slightly lower than 18 January record. The scheduled as generated record of 9,369MW exceeded the previous record of 9,097MW from February 2016. After temperature correction, the 2016/17 summer demand exceeded the 2016 Transmission Annual Planning Report forecast by around 2%.

Electricity energy forecast

Based on the medium economic outlook, Queensland's delivered energy consumption is forecast to increase at an average of 0.4% per annum over the next 10 years from 50,190GWh in 2016/17 to 52,459GWh in 2026/27. The delivered energy forecast in the 2017 TAPR shows a reduction compared to the 2016 TAPR. The reduction to 2020 is largely due to forecast increases in the capacity of distribution connected solar PV farms and a forecast reduction in energy usage by a major transmission connected customer.

A comparison of the 2016 and 2017 TAPR forecasts for energy delivered from the transmission network is displayed in Figure 1. Energy delivered from the transmission network for 2016/17 is expected to be within 1% of the 2016 TAPR forecast.

Figure 1 Comparison of the medium economic outlook energy forecasts



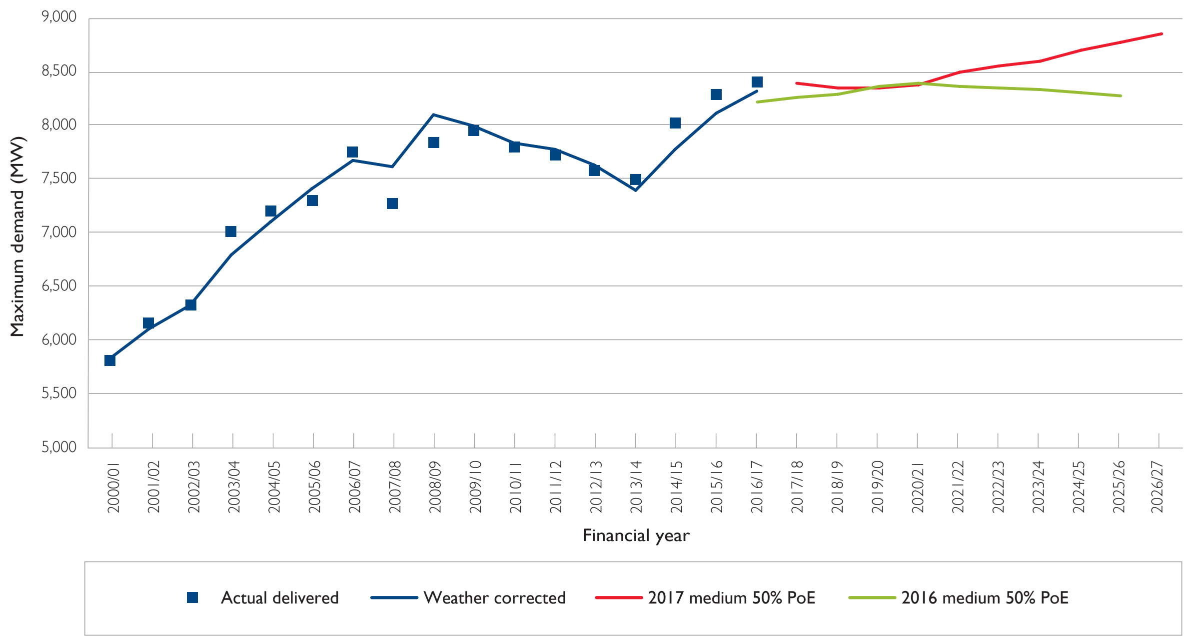
Electricity demand forecast

Based on the medium economic outlook, Queensland's transmission delivered summer maximum demand is forecast to increase at an average rate of 0.6% per annum over the next 10 years, from 8,302MW (weather corrected) in 2016/17 to 8,790MW in 2026/27.

The transmission delivered maximum demand for summer 2016/17 of 8,401MW was a new record for Queensland.

A comparison of 2016 and 2017 summer maximum demand forecasts for the medium economic outlook, based on a 50% probability of exceedance (PoE) is displayed in Figure 2. As with the energy forecasts, the 2017 demand forecast has been adjusted to take account of actual consumption over the 2016/17 period and updated to reflect the latest economic projections for the State. The increase from 2020 is largely due to an expectation that electricity prices will remain flat and then fall and that the Queensland state economy will return to solid growth.

Figure 2 Comparison of the medium economic outlook demand forecasts



Powerlink's asset planning criteria

There is a significant focus on striking the right balance between reliability and cost of transmission services. In response to these drivers, the Queensland Government amended Powerlink's N-1 criterion to allow for increased flexibility from July 2014. The planning standard permits Powerlink to plan and develop the transmission network on the basis that load may be interrupted during a single network contingency event, within limits of unsupplied demand and energy that may be at risk for the contingency event.

Powerlink is required to implement appropriate network or non-network solutions in circumstances where the limits of 50MW or 600MWh are exceeded or when the economic cost of load which is at risk of being unsupplied justifies the cost of the investment. Therefore, the application of the planning standard has the effect of deferring or reducing the extent of investment in network or non-network solutions required in response to demand growth. Powerlink will continue to maintain and operate its transmission network to maximise reliability to consumers.

Future network development

The energy industry is going through a period of transformation driven by changes in economic outlook, electricity consumer behaviour, government policy and regulation and emerging technologies. These fundamental shifts, including the upturn in VRE developments in Queensland, are reshaping the operating environment in which Powerlink delivers its transmission services.

Powerlink is responding to these fundamental shifts by:

- adapting its approach to investment decisions
- placing considerable emphasis on an integrated and flexible analysis of future reinvestment needs
- supporting diverse generation connection

- continuing to focus on developing options that deliver a secure, reliable and cost effective transmission network.

Based on the medium economic forecast outlook, the planning standard and committed network and non-network solutions, network augmentations are not forecast to occur as a result of network limitations within the five-year outlook period of this TAPR.

There are proposals for large mining, metal processing and other industrial loads that have not reached a committed development status. These new large loads are within the resource rich areas of Queensland and associated coastal port facilities. These loads have the potential to significantly impact the performance of the transmission network supplying, and within, these areas. Within this TAPR, Powerlink has outlined the potential network investment required in response to these loads emerging in line with the high economic outlook forecast.

As previously mentioned, the Queensland transmission network experienced significant growth in the period from the 1960s to the 1980s. The capital expenditure needed to manage the emerging risks related to this asset base which is now reaching end of technical or economic life, represents the majority of Powerlink's program of work within the outlook period. The reinvestment program is particularly focused on transmission lines where condition assessment has identified emerging risks requiring action within the outlook period.

Considerable emphasis has been given to an integrated approach to the analysis of future reinvestment needs and options. Powerlink has systematically assessed the enduring need for assets at the end of their technical or economic life and considered a broad range of options including network reconfiguration, asset retirement, non-network solutions or replacement with an asset of lower capacity. An example of this is the strategy to undertake minor works from Central Queensland to Southern Queensland to align the technical and economic end of life of the 275kV transmission lines. This incremental development approach defers large capital investment and has the benefit of maintaining the existing topology, transfer capability and operability of the transmission network.

The integrated planning approach has revealed a number of potential reconfiguration opportunities in the Ross, Central West, Gladstone and Moreton zones within the outlook period. Powerlink has also included additional information in this TAPR relating to long-term network reconfiguration strategies that in future years are likely to require further stakeholder engagement and consultation.

Renewable energy

Over the past year, Powerlink has supported a high level of connection activity, responding to more than 80 connection enquiries comprising over 15,000MW of potential VRE generation. In 2016/17, Powerlink finalised seven VRE generator Connection and Access Agreements totalling 718MW.

Powerlink is also working with the Queensland Government to progress two initiatives:

- Economic Development Queensland on the Aldoga Renewable Energy Zone project; and
- the Powering North Queensland Plan.

Powerlink will continue to engage with market participants and interested parties across the renewables sector to better understand the potential for VRE generation in Queensland.

Committed and commissioned projects

During 2016/17, the majority of committed projects provided for reinvestment in transmission lines and substations across Powerlink's network.

Reinvestment projects completed in 2016/17 include major replacement works at Rockhampton Substation and line refit works on 110kV transmission lines in Brisbane between Belmont, Runcorn and Algester substations.

Powerlink is currently finalising the last of its minor transmission augmentation projects to manage localised voltage limitations in the Northern Bowen Basin, with the installation of a 132kV capacitor bank at Moranbah Substation.

Grid section and zone performance

During 2016/17, the Powerlink transmission network supported the delivery of a record summer maximum demand of 8,401MW, 130MW higher than that recorded in summer 2015/16. Record transmission delivered demands were recorded for Ross, Surat, Bulli and Moreton zones.

The Central Queensland to Southern Queensland grid section showed greater levels of utilisation during 2016/17, predominantly due to lower gas fired generation in the Bulli Zone and greater output from central and north Queensland generators.

The transmission network in the Queensland region performed reliably during the 2016/17 year, including during the summer maximum demand. Queensland grid sections were largely unconstrained due in part to the absence of high impact events on the transmission network, effective emergency response and prudent scheduling of planned transmission outages. Central Queensland to North Queensland grid section experienced 3.58 hours of constrained operation associated with the reclassification of double circuit events due to increased risk during the Tropical Cyclone Debbie weather event. Subsequent flooding damaged 19 towers between Broadsound and Nebo substations which are scheduled for rectification during 2017.

Additional stakeholder consultation for non-network solutions

Powerlink is continuing to build its engagement processes with non-network providers and expand the use of non-network solutions to address the future needs of the transmission network, as an alternative option to like-for-like replacements or to complement an overall network reconfiguration strategy, where technically and economically feasible.

In August 2016, Powerlink concluded the first Non-network Solution Feasibility Study to further improve communication with non-network providers. Such studies are intended to seek potential alternate solutions for future network developments resulting from augmentation and reinvestments needs which currently fall outside of NER consultation requirements. Powerlink will continue to request non-network solutions from market participants as part of the Regulatory Investment Test for Transmission (RIT-T) process.

In May 2017, Powerlink held a Future Transmission Network webinar, the first in a series of webinars which are intended to inform non-network providers, and other stakeholders unfamiliar with Powerlink's transmission network, with an overview of the history, characteristics, most recent understanding of asset condition and ongoing requirements of the transmission network. Each webinar will focus on transmission assets in specific geographic regions within Queensland which are approaching their anticipated end of technical or economic life in the medium to longer term, sharing our most recent information well in advance of the commencement of any NER consultation process.

The Future Transmission Network webinar series in conjunction with the Non-network Feasibility Study process will assist in achieving the right balance between reliability and cost by providing opportunities to exchange early information on the viability and potential of non-network solutions and how they may integrate with the transmission network.

Customer and consumer engagement

Powerlink continues to implement its Stakeholder Engagement Framework, supporting the considerable work already being undertaken to engage with stakeholders and seek their input into Powerlink's business focus and objectives.

The framework aims to build greater stakeholder engagement and contribution, inform consumers and encourage feedback, and appropriately incorporate that input into Powerlink's business decision making to improve planning and operational activities. A primary aim is to ensure Powerlink's services better reflect consumer values, priorities and expectations.

Powerlink undertakes a biannual survey across its stakeholder groups, including customers, consumer advocates, government, regulators and industry, to gain a stronger understanding of stakeholder perceptions of performance. The survey completed in 2016 sought views from over 100 key stakeholders and highlighted improvements in reputation and social licence to operate for Powerlink.

Powerlink's Customer and Consumer Panel also continued to meet throughout the year, providing input and feedback on Powerlink's decision making processes and methodologies. Comprised of members from a range of sectors including energy industry, resources, community advocacy groups, consumers and research organisations, the panel provides an important avenue to keep our stakeholders better informed about operational and strategic topics of relevance.

Since 2016, Powerlink has engaged with key stakeholders in a number of ways, including its Transmission Network Forum, Demand and Energy Forecasting Forum, North Queensland Area Forum and Future Transmission Network webinar – all proving to be valuable avenues to exchange information and gather feedback on a range of investment and forecasting considerations.

Focus on continuous improvement in the TAPR

As part of Powerlink's commitment to continuous improvement, the 2017 TAPR focuses on an integrated approach to future network development and contains detailed discussion on key areas of future expenditure.

The 2017 TAPR:

- continues the discussion on the potential for generation developments (in particular VRE generation) first introduced in 2016 (refer to Chapter 7)
- includes updated information on Powerlink's approach to assisting the development of non-network solutions – specifically through the ongoing improvement of engagement practices for non-network solution providers and provision of information (refer to Section 1.8.1 and Section 4.2).

Chapter 1:

Introduction

Introduction

Key highlights

- The purpose of Powerlink's Transmission Annual Planning Report (TAPR) under the National Electricity Rules (NER) is to provide information about the Queensland electricity transmission network.
- Powerlink is responsible for planning the shared transmission network within Queensland.
- Since publication of the 2016 TAPR, Powerlink has continued to proactively engage with stakeholders and seek their input into Powerlink's objectives, network operations and investment decisions.
- The 2017 TAPR contains detailed discussion on key areas of the transmission network requiring future expenditure.

1.1 Introduction

Powerlink Queensland is a Transmission Network Service Provider (TNSP) in the National Electricity Market (NEM) and owns, develops, operates and maintains Queensland's high voltage electricity transmission network. It has also been appointed by the Queensland Government as the Jurisdictional Planning Body (JPB) responsible for transmission network planning for the national grid within the State.

As part of its planning responsibilities, Powerlink undertakes an annual planning review in accordance with the requirements of the NER and publishes the findings of this review in its TAPR.

This 2017 TAPR includes information on electricity energy and demand forecasts, the existing electricity supply system including committed generation and transmission network reinvestments and developments, and forecasts of network capability. Risks associated with the condition and performance of existing assets, as well as emerging limitations in the capability of the network, are identified and possible solutions to address these are discussed. Interested parties are encouraged to provide input to identify the most economical solution (including non-network solutions provided by others) that satisfies the required reliability standard to customers into the future. This 2017 TAPR explores the potential for the connection of variable renewable electricity (VRE) generation to Powerlink's transmission network.

Powerlink's annual planning review and TAPR play an important part in planning Queensland's transmission network and helping to ensure it continues to meet the needs of participants in the NEM and Queensland electricity consumers.

1.2 Context of the TAPR

All bodies with jurisdictional planning responsibilities in the NEM are required to undertake the annual planning review and reporting process prescribed in the NER[1].

Information from this process is also provided to the Australian Energy Market Operator (AEMO) to assist in the preparation of its National Electricity Forecasting Report (NEFR), Electricity Statement of Opportunities (ESOO) and National Transmission Network Development Plan (NTNDP).

The ESOO is the primary document for examining electricity supply and demand issues across all regions in the NEM. The NTNDP provides information on the strategic and long-term development of the national transmission system under a range of market development scenarios. The NEFR provides independent electricity demand and energy forecasts for each NEM region over a 10-year outlook period. The forecasts explore a range of scenarios across high, medium and low economic growth outlooks.

The primary purpose of the TAPR is to provide information on the short-term to medium-term planning activities of TNSPs, whereas the focus of the NTNDP is strategic and long-term. The NTNDP and TAPR are intended to complement each other in informing stakeholders, promoting efficient outcomes and investment decisions. In supporting this complementary approach, information from the NTNDP is considered in this TAPR, and more generally in Powerlink's planning activities.

1 For the purposes of Powerlink's 2017 TAPR, Version 91 of the NER in place from 2 May 2017.

Interested parties may benefit from reviewing Powerlink's 2017 TAPR in conjunction with AEMO's 2017 NEFR, ESOO and NTNDP, which are anticipated to be published in June, August and December 2017 respectively.

1.3 Purpose of the TAPR

The purpose of Powerlink's TAPR under the NER is to provide information about the Queensland electricity transmission network to everyone interested/involved in the NEM including AEMO, Registered Participants and interested parties. The TAPR also provides broader stakeholders with an overview of Powerlink's planning processes and decision making on future investment.

It aims to provide information that assists to:

- identify locations that would benefit from significant electricity supply capability or demand side management initiatives
- identify locations where major industrial loads could be connected
- identify locations where capacity for new generation developments exist (in particular VRE generation)
- understand how the electricity supply system affects their needs
- understand the transmission network's capability to transfer quantities of bulk electrical energy
- provide input into the future development of the transmission network.

Readers should note this document is not intended to be relied upon explicitly for the evaluation of participants' investment decisions.

1.4 Role of Powerlink Queensland

Powerlink has been nominated by the Queensland Government as the entity with transmission network planning responsibility for the national grid in Queensland, known as the JPB as outlined in Clause 5.20.5 of the NER.

As the owner and operator of the electricity transmission network in Queensland, Powerlink is registered with AEMO as a TNSP under the NER. In this role, and in the context of this TAPR, Powerlink's transmission network planning and development responsibilities include:

- ensuring the network is able to operate with sufficient capability and if necessary, is augmented, to provide network services to customers in accordance with Powerlink's Transmission Authority and associated reliability standard
- ensuring the risks associated with the condition and performance of existing assets are appropriately managed
- ensuring the network complies with technical and reliability standards contained in the NER and jurisdictional instruments
- conducting annual planning reviews with Distribution Network Service Providers (DNSPs) and other TNSPs whose networks are connected to Powerlink's transmission network, that is, Energex, Ergon Energy[2], Essential Energy and TransGrid
- advising AEMO, Registered Participants and interested parties of asset reinvestment needs within the time required for action
- advising AEMO, Registered Participants and interested parties of emerging network limitations within the time required for action
- developing recommendations to address emerging network limitations through joint planning with DNSPs and consultation with AEMO, Registered Participants and interested parties, with potential solutions including network upgrades or non-network options such as local generation and demand side management initiatives

[2] Energex and Ergon Energy merged under the parent company of Energy Queensland on 1 July 2016.

- examining options and developing recommendations to address transmission constraints and economic limitations across interconnectors through joint planning with other TNSPs and network service providers, and consultation with AEMO, Registered Participants and interested parties, with potential solutions including network upgrades, development of new interconnectors or non-network options
- assessing whether or not a proposed transmission network augmentation has a material impact on networks owned by other TNSPs, and in assessing this impact Powerlink must have regard to the objective set of criteria published by AEMO in accordance with Clause 5.21 of the NER
- undertaking the role of the proponent for regulated transmission augmentations in Queensland.

In addition, Powerlink participates in inter-regional system tests associated with new or augmented interconnections.

1.5 Overview of approach to asset management

Powerlink's asset management framework captures significant internal and external drivers on the business and sets out initiatives to be adopted. The Asset Management Policy forms the foundation of the Asset Management Strategy as discussed below.

The principles set out in these documents guides Powerlink's analysis of future network investment needs and key investment drivers. Other factors that influence network development, such as energy and demand forecasts, generation development (including potential generation withdrawal), and risks related to the condition and performance of the existing asset base are also analysed collectively in order to form an integrated network investment plan over a 10-year outlook period.

1.5.1 Asset Management Policy

Powerlink's Asset Management Policy sets out a commitment to sustainable asset management practices that ensures Powerlink provides a valued transmission service to its customers by managing risk, optimising performance and managing expenditure on assets through the whole of asset life cycle. The policy includes the principles that are applied to manage Powerlink's entire transmission network, as well as telecommunications and business infrastructure assets.

1.5.2 Asset Management Strategy

Powerlink's Asset Management Strategy identifies the systems and processes that guide the development of investment plans for the network, including such factors as expected service levels, investment policy and risk management.

1.5.3 Asset risk management

Powerlink's approach to risk management requires a structured approach, applying contemporary and best practice asset risk management practices.

As the reinvestment in assets approaching end of technical or economic life forms a substantial part of Powerlink's future network investment plans, the assessment of emerging risks related to the condition and performance of these assets is of particular importance. Such assessments are underpinned by Powerlink's corporate risk management framework and the application of a range of risk assessment methodologies set out in AS/NZS ISO31000:2009 Risk Management[3]. In order to inform risk assessments, Powerlink undertakes a periodic review of network assets which considers a broad range of factors, including physical condition, capacity constraints, performance and functionality, statutory compliance and ongoing supportability.

1.6 Overview of planning responsibilities and processes

1.6.1 Planning criteria and processes

Powerlink has obligations that govern how it should address forecast network limitations. These obligations are prescribed by *Queensland's Electricity Act 1994* (the Act), the NER and Powerlink's Transmission Authority.

[3] AS/NZS ISO 31000:2009 is an international Risk Management standard.

The Act requires that Powerlink "ensure as far as technically and economically practicable, that the transmission grid is operated with enough capacity (and if necessary, augmented or extended to provide enough capacity) to provide network services to persons authorised to connect to the grid or take electricity from the grid".

It is a condition of Powerlink's Transmission Authority that it meets licence and NER requirements relating to technical performance standards during intact and contingency conditions. The NER sets out minimum performance requirements of the network and connections, and requires that reliability standards at each connection point be included in the relevant connection agreement.

New network developments and reinvestments are proposed to meet these legislative and NER obligations. Powerlink may also propose transmission investments that deliver a net market benefit when assessed in accordance with the Regulatory Investment Test for Transmission (RIT-T).

The requirements for initiating solutions to forecast network limitations, including new regulated network developments or non-network solutions, are set down in Clauses 5.14.1, 5.16.4 and 5.20.5 of the NER. These clauses apply to different types of proposed transmission investments.

While each of these clauses prescribes a slightly different process, at a higher level the main steps in network planning for transmission investments subject to the RIT-T can be summarised as follows:

- publication of information regarding the nature of the network limitation and need for action which examines demand growth and its forecast exceedance of the network capability
- consideration of generation and network capability to determine when additional capability is required
- consultation on assumptions made and credible options, which may include network augmentation, local generation or demand side management initiatives, and classes of market benefits considered to be material which should therefore be taken into account in the comparison of options
- analysis and assessment of credible options, which include costs, market benefits and material internetwork impact
- identification of the preferred option that satisfies the RIT-T, which maximises the present value of the net economic benefit to all those who produce, consume and transport electricity in the market
- consultation and publication of a recommended course of action to address the identified future network limitation.

1.6.2 Integrated planning of the shared network

Powerlink is responsible for planning the shared transmission network within Queensland, and inter-regionally. The NER sets out the planning process and requires Powerlink to apply the RIT-T promulgated by the Australian Energy Regulator (AER) to transmission investment proposals. The planning process requires consultation with AEMO, Registered Participants and interested parties, including customers, generators, DNSPs and other TNSPs. Section 4.4 discusses current consultations, as well as anticipated future consultations, that will be conducted in line with the processes prescribed in the NER.

Significant inputs to the network planning process are the:

- forecast of customer electricity demand (including demand side management) and its location
- location, capacity and arrangement of new and existing generation (including embedded generation)
- condition and performance of assets and an assessment of the risks associated in allowing assets to remain in-service
- assessment of future network capacity to meet the required planning criteria and efficient market outcomes.

The 10-year forecasts of electrical demand and energy across Queensland are used, together with forecast generation patterns, to determine potential flows on transmission network elements. The location and capacity of existing and committed generation in Queensland is sourced from AEMO, unless modified following advice from relevant participants and is provided in Table 5.1. Information about existing and committed embedded generation and demand management within distribution networks is provided by DNSPs.

Powerlink examines the capability of its existing network and the future capability following any changes resulting from committed network projects. This involves consultation with the relevant DNSP in situations where the performance of the transmission network may be affected by the distribution network, for example where the two networks operate in parallel.

Where potential flows could exceed network capability, Powerlink notifies market participants of these forecast emerging network limitations. If the capability violation exceeds the required reliability standard, joint planning investigations are carried out with DNSPs (or other TNSPs if relevant) in accordance with Clause 5.14.1 of the NER. The objective of this joint planning is to identify the most cost effective solution, regardless of asset boundaries, including potential non-network solutions.

In addition to meeting the forecast demand, Powerlink must maintain its current network so that the risks associated with the condition and performance of existing assets is appropriately managed. Powerlink routinely undertakes an assessment of the condition of assets to identify emerging asset related risks.

As assets approach the end of their technical or economic life, Powerlink examines a range of options to determine the most appropriate reinvestment strategy. Consideration is given to optimising the topography and capacity of the network, taking into account current and future network needs. In many cases, power system flows and patterns have changed over time. As a result, the ongoing network capacity requirements need to be re-evaluated. Individual asset reinvestment decisions are not made in isolation, and assets are not necessarily replaced on a like-for-like basis. Rather, asset reinvestment strategies and decisions are made taking into account the inter-related connectivity of the high voltage system, and are often considered across an area or transmission corridor. The consideration of potential non-network solutions forms an important part of this integrated planning approach.

The integration of condition and demand based limitations delivers cost effective solutions that address both reliability of supply and risks associated with assets approaching end of technical or economic life. Powerlink considers a range of strategies and options to address emerging asset related condition and performance issues. These strategies include:

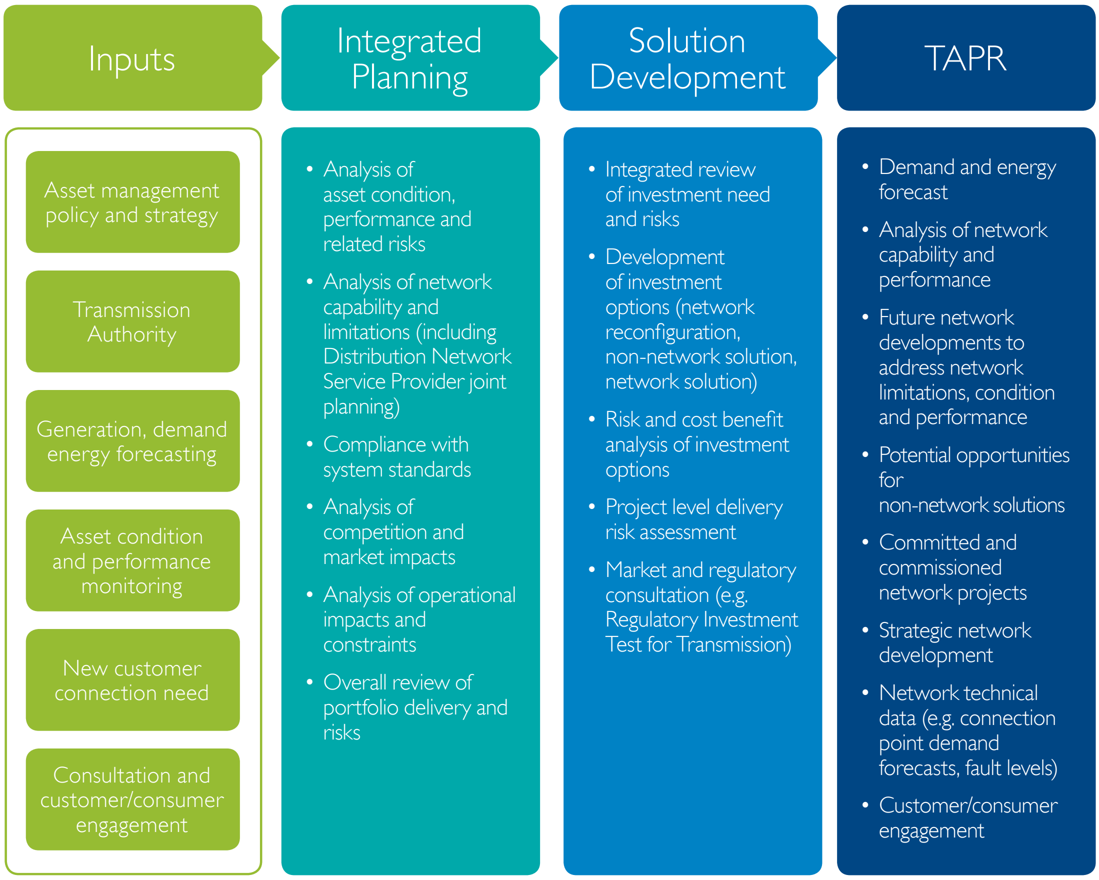
- retiring or decommissioning assets where there is unlikely to be an ongoing future need
- refurbishing to extend the technical life of assets
- replacing assets of different capacity or type
- changing the topography and configuration of the network
- implementing non-network solutions.

Each of these options is considered in the context of future capacity needs.

Furthermore, in accordance with the NER, information regarding proposed transmission reinvestments within the five-year outlook period which meet the required cost threshold of $6 million must be published in the TAPR. More broadly, this provides information to the NEM, including AEMO, Registered Participants and interested parties (including non-network providers) on Powerlink's planning processes and decision making relating to potential future reinvestments. Further information is provided in Section 4.2.

A summary of Powerlink's integrated planning approach that takes into account both network capacity needs and end of technical or economic life related issues is presented in Figure 1.4.

Figure 1.4 Overview of Powerlink's TAPR planning process



1.6.3 Planning of connections

Participants wishing to connect to the Queensland transmission network include new and existing generators, major loads and DNSPs. Planning of new connections or alterations to existing connections involves consultation between Powerlink and the connecting party to negotiate a Connection and Access Agreement (CAA). Negotiation of the CAA requires the specification and then compliance assessment of the required technical standards. This process also involves AEMO. The services provided can be prescribed (regulated), negotiated or non-regulated services in accordance with the definitions in the NER or the framework for provision of such services. Investments in new prescribed connections, or augmentations to existing prescribed connections costing more than the threshold specified in the NER (currently $6 million[4]), may be subject to the RIT-T.

1.6.4 Planning of interconnectors

Development and assessment of new or augmented interconnections between Queensland and other States, is the responsibility of the respective TNSPs. Information on the analysis of potential interconnector upgrades and new interconnectors is provided in Chapter 6.

[4] Following the Australian Energy Regulator's 2015 Cost Threshold Review, from 1 January 2016, the $5 million cost thresholds referred to in clauses 5.15.3(b)(1),(2),(3)(4) and (6) of the National Electricity Rules increased from $5 million to $6 million.

1.7 Powerlink's asset planning criteria

There is a significant focus on striking the right balance between reliability and cost of transmission services. In response to these drivers, the Queensland Government amended Powerlink's N-1 criterion to allow for increased flexibility from July 2014. The planning standard permits Powerlink to plan and develop the transmission network on the basis that load may be interrupted during a single network contingency event. The following limits are placed on the maximum load and energy that may be at risk of not being supplied during a critical contingency:

- will not exceed 50MW at any one time
- will not be more than 600MWh in aggregate.

The risk limits can be varied by:

- a connection or other agreement made by the transmission entity with a person who receives or wishes to receive transmission services, in relation to those services or
- agreement with the Queensland Energy Regulator (QER).

Powerlink is required to implement appropriate network or non-network solutions in circumstances where the limits set out above are exceeded or when the economic cost of load which is at risk of being unsupplied justifies the cost of the investment. Therefore, the planning standard has the effect of deferring or reducing the extent of investment in network or non-network solutions required in response to demand growth. Powerlink will continue to maintain and operate its transmission network to maximise reliability to consumers.

Powerlink's transmission network planning and development responsibilities include developing recommendations to address emerging network limitations through joint planning. The objective of joint planning is to identify the most cost effective solution, regardless of asset boundaries, including potential non-network solutions. Joint planning - while traditionally focused on the DNSPs (Energex, Ergon Energy and Essential Energy) and TransGrid - can also include consultation with AEMO, other Registered Participants, load aggregators and other interested parties.

Energex and Ergon Energy were issued amended Distribution Authorities from July 2014. The service levels defined in their respective Distribution Authority differ to that of Powerlink's authority. Joint planning accommodates these different planning standards by applying the planning standard consistently with the owner of the asset which places load at risk during a contingency event.

Powerlink has established policy frameworks and methodologies to support the implementation of this standard. These are being applied in various parts of the Powerlink network where possible emerging limitations are being monitored. For example, based on the medium economic forecast in Chapter 2, voltage stability limitations occur in the Proserpine area within the outlook period. However, the load at risk of not being supplied during a contingency event does not exceed the risk limits of the planning standard. In this instance the planning standard is deferring investment and delivering savings to customers and consumers.

The planning standard will deliver further opportunities to defer investment if new mining, metal processing or other industrial loads develop (discussed in Table 2.1 of Chapter 2). These new loads are within the resource rich areas of Queensland or at the associated coastal port facilities but have not yet reached the development status necessary to be included (either wholly or in part) in the medium economic forecast. The loads have the potential to significantly impact the performance of the transmission network supplying, and within, these areas. The possible impact of these loads is discussed in Section 6.2. The planning standard may not only affect the timing of required investment but also in some cases affords the opportunity for incremental solutions that would not have otherwise met the original N-1 criterion.

1.8 Stakeholder engagement

Powerlink shares effective, timely and transparent information with its stakeholders using a range of engagement methods. Two key stakeholder groups for Powerlink are customers and consumers. Customers are defined as those who are directly connected to Powerlink's network, while consumers are electricity end-users, such as households and businesses, who primarily receive electricity from the distribution networks. There are also stakeholders who can provide Powerlink with non-network solutions. These stakeholders may either connect directly to Powerlink's network, or connect to the distribution networks. The TAPR is just one avenue that Powerlink uses to communicate information about transmission planning in the NEM. Through the TAPR, Powerlink aims to increase understanding and awareness of some of our business practices including load forecasting and transmission network planning.

1.8.1 Customer and consumer engagement

Powerlink is committed to proactively engaging with stakeholders and seeking their input into Powerlink's business processes and objectives. All engagement activities are undertaken in accordance with our Stakeholder Engagement Framework that sets out the principles, objectives and outcomes Powerlink seeks to achieve in our interactions with stakeholders. The framework aims to build greater stakeholder trust and social licence to operate, support better business decision making and improve the management of corporate risks and reputation.

A number of key performance indicators are used to monitor progress towards achieving Powerlink's stakeholder engagement performance goals. In particular, Powerlink undertakes a bi-annual stakeholder survey to gain insights about stakeholder perceptions of Powerlink, its social licence to operate and reputation. Most recently completed in November 2016, the survey provides an evidence base to support the Stakeholder Engagement Framework and inform engagement strategies with individual stakeholders.

2016/17 Stakeholder engagement activities

Since the publication of the 2016 TAPR, Powerlink has engaged with stakeholders in various ways through a range of forum and panels as outlined below.

Transmission Network Forum

In July 2016, more than 100 customer, consumer, government and industry representatives attended Powerlink's second annual Transmission Network Forum. The forum began with a presentation on Powerlink's 2016 TAPR, followed by interactive breakout sessions on how the transmission network can support large-scale VRE generation and exploring opportunities for improved engagement in developing non-network solutions.

Customer and Consumer Panel

Powerlink hosts a Customer and Consumer Panel that provides a face-to-face forum for our stakeholders to give input and feedback to Powerlink regarding our decision making, processes and methodologies. Comprised of members from a range of sectors including energy industry, resources, community advocacy groups, consumers and research organisations, the panel provides an important avenue to keep our stakeholders better informed about operational and strategic topics of relevance. The panel met in October 2016 and May 2017 to discuss and explore topics including the AER's Draft and Final Decisions for Powerlink's transmission determination, opportunities to strengthen Powerlink's customer focus and the application of relevant key insights from the Energy Networks Australia and CSIRO's Electricity Network Transformation Roadmap.

Demand and Energy Forecasting Forum

In April 2017, Powerlink held a Demand and Energy Forecasting Forum attended by a wide range of experts from a variety of stakeholder groups. The forum examined the impact of new technologies and tariff reform on demand and energy forecasting on the Queensland transmission network. The forum also explored possible themes for the development of load forecast scenarios. The information provided as a result of this forum has supported the development of this TAPR load forecast and is detailed further in Chapter 2 and Appendix B.

North Queensland Area Plan Forum

Powerlink also hosted a North Queensland Area Plan Forum in April 2017. Held in Townsville, the forum provided the opportunity for Powerlink to gather strategic input from local stakeholders on views and factors to consider when planning reinvestment in the North Queensland transmission network. Forum participants workshopped the factors that have the potential to impact Powerlink's network in the next 10 years, as well as the key drivers Powerlink should consider when assessing network or non-network solutions for the region. Feedback received will assist with guiding future planning and investment decisions.

Future Transmission Network webinar

The Future Transmission Network webinar was held in May 2017 for non-network providers. This was the first in a series of webinars intended to inform non-network providers and other stakeholders unfamiliar with Powerlink's transmission network, with an overview of the history, characteristics, most recent understanding of asset condition and ongoing requirements of the transmission network. It is anticipated that the provision and exchange of early information through engagement activities such as this will generate more opportunities for interactions with non-network providers during formal or informal consultation processes.

More information on Powerlink's stakeholder engagement activities is available on our website.

1.8.2 Non-network solutions

Powerlink has established processes for engaging with stakeholders for the provision of non-network services in accordance with the requirements of the NER. These engagement processes centre on publishing relevant information on the need and scope of viable non-network solutions to emerging network limitations. For a given network limitation, the viability and specification of non-network solutions are first introduced in the TAPR. Further opportunities are then explored in the consultation and stakeholder engagement processes undertaken as part of any subsequent RIT-T.

In the past, these processes have been successful in delivering non-network solutions to emerging network limitations. As early as 2002, Powerlink engaged generation units in North Queensland to maintain reliability of supply and defer transmission projects between central and northern Queensland. More recently Powerlink entered into network support services as part of the solution to address emerging limitations in the Bowen Basin area which have now ended. This is outlined in Section 4.2.

Powerlink is committed to the ongoing development of its non-network engagement processes and where possible and economically viable, expand the use of non-network solutions:

- to address future network limitations within the transmission network or
- more broadly, in combination with network developments as part of an integrated solution to complement an overall network reconfiguration strategy.

In August 2016, Powerlink concluded the first Non-network Solution Feasibility Study[5] with a focus on further improving consultation with non-network providers and seeking potential alternate solutions for network developments (augmentations and reinvestments) which fall outside of NER consultation requirements. In particular, where technically feasible, the Non-network Solution Feasibility Study process is intended to be applied to augmentations which are below the RIT-T cost threshold of $6 million and to further explore the potential to expand the use of non-network solutions in relation to network reinvestments which currently do not require RIT-T consultation. This process will assist in achieving the right balance between the reliability and cost of transmission services by providing a mechanism to exchange early information on the viability and potential of non-network solutions and how they may be utilised to integrate with the transmission network to meet current and future capacity needs. Powerlink will also continue to request non-network solutions from market participants as part of the RIT-T process defined in the NER.

[5] Refer to Powerlink's website.

Feedback received from non-network providers during 2016 indicated that the propose/respond model of the Non-network Solution Feasibility Study, while beneficial, could be further enhanced by:

- the provision of very early advice of possible non-network opportunities outside of a defined process
- ensuring that any process implemented was iterative in nature.

As mentioned in Section 1.8.2, a Future Transmission Network webinar was held in May 2017 for non-network providers. Future webinars will also focus on transmission assets approaching their anticipated end of technical or economic life in the medium to longer term in order to share our most up-to-date information with non-network providers as early as possible. The information provided is indicative only and provided in good faith, as confirmation of the investment need and any potential solutions (network and non-network) are tested robustly closer to the anticipated end of technical or economic life of the asset.

Since publication of the 2016 TAPR, Powerlink has continued its collaboration with the Institute for Sustainable Futures[6] and other Network Service Providers regarding the Network Opportunity Mapping project. This project aims to provide enhanced information to market participants on network constraints and the opportunities for demand side solutions. These collaborations further demonstrate Powerlink's commitment to using a variety of platforms to broaden stakeholder awareness regarding possible commercial opportunities for non-network solutions and provide technical information which historically has only been discussed in the TAPR.

The Non-network Solution Feasibility Study process, in conjunction with the publicly available data provided via the Network Opportunities Mapping project and informal information sessions such as the Future Transmission Network webinar, responds to previous feedback Powerlink has received from a number of stakeholders about the need to provide enhanced and earlier information on the potential value and timing of non-network solutions.

Non-network Engagement Stakeholder Register

In 2014 Powerlink established the Non-network Engagement Stakeholder Register (NNESR) to give non-network providers the details of emerging network limitations and other future transmission network needs which may have the potential for non-network solutions. The NNESR is comprised of a variety of interested stakeholders who have the potential to offer network support through existing and/or new generation or demand side management initiatives (either as individual providers or aggregators).

The NNESR was introduced to serve as a communication tool to achieve the following outcomes:

- leveraging off the knowledge of participants to seek input on process enhancements that Powerlink can adopt to increase the potential uptake of non-network solutions
- to provide interested parties with information prior to the commencement of formal public consultation as part of the RIT-T
- in relation to other augmentation network investments which may fall outside of NER consultation requirements
- with respect to network reinvestments which may have the potential to use non-network solutions.

Potential non-network providers are encouraged to register their interest in writing to networkassessments@powerlink.com.au to become a member of Powerlink's NNESR.

[6] Information available at Network Opportunity Mapping

1.8.3 Focus on continuous improvement

As part of Powerlink's commitment to continuous improvement, the 2017 TAPR focuses on an integrated approach to future network development and contains detailed discussion on key areas of future expenditure.

In conjunction with condition assessments and risk identification, as assets approach their anticipated replacement dates, possible reinvestment alternatives undergo detailed planning studies to confirm alignment with future reinvestment and optimisation strategies. These studies have the potential to deliver new information and may provide Powerlink with an opportunity to:

- improve and further refine options under consideration or
- consider other options from those originally identified which may deliver a greater benefit to stakeholders.

Information regarding possible reinvestment alternatives is updated annually within the TAPR and includes discussion on the latest information as planning studies mature.

The 2017 TAPR:

- continues the discussion on the potential for generation developments (in particular VRE generation) first introduced in 2016 (refer to Chapter 7)
- includes updated information on Powerlink's approach to assisting the development of non-network solutions – specifically, through the ongoing improvement of engagement practices for non-network solution providers and provision of information (refer to Section 1.81 and Section 4.2).

Chapter 2:

Energy and demand projections

2 Energy and demand projections

Key highlights

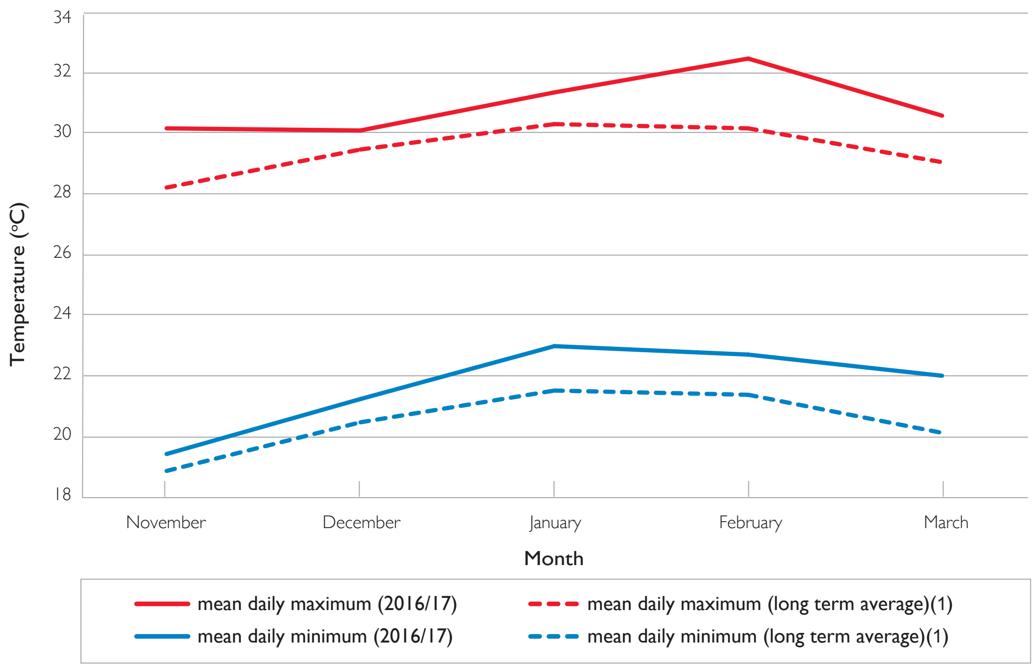
- This chapter describes the historical energy and demand performance of Powerlink's transmission network and provides forecast data separated by zone.
- The 2016/17 summer in Queensland was hot and long lasting with a new maximum delivered demand recorded at 6:00pm on 18 January, when 8,401MW was delivered from the transmission network.
- Scheduled as generated and native demand records were reached at 5:30pm on 12 February. The scheduled as generated reached 9,369MW and the native demand reached 8,756MW.
- Powerlink develops its energy and demand forecasts using both a top-down econometric model and bottom-up forecasts from the distribution businesses and direct connect customers.
- Based on the medium economic outlook, Queensland's delivered energy consumption and demand is expected to remain relatively flat, with average annual increases of 0.4% and 0.6% per annum over the next 10 years.
- Powerlink is focused on understanding the potential future impacts of emerging technologies so transmission network services are developed in a way valued by customers. For example, future developments in battery storage technology coupled with small-scale solar photovoltaic (PV) could see significant changes to future electricity usage patterns. This could reduce the need to develop transmission services to cover short duration peaks.

2.1 Overview

The 2016/17 summer in Queensland was hot and long lasting with two days of particularly high electricity demand on the transmission network on 18 January and 12 February. A new delivered maximum demand was recorded at 6:00pm on 18 January, when 8,401MW was delivered from the transmission network. Scheduled as generated and native demand records were recorded at 5:30pm on 12 February, with scheduled as generated reaching 9,369MW and native demand reaching 8,756MW. The corresponding delivered demand on 12 February was 8,392MW, slightly lower than 18 January record. The scheduled as generated record of 9,369MW exceeded the previous record of 9,097MW recorded in February 2016. After temperature correction, the 2016/17 summer demand exceeded the 2016 Transmission Annual Planning Report (TAPR) forecast by around 2%.

Figure 2.1 shows observed temperatures for Brisbane during summer 2016/17 compared with long-term averages.

Figure 2.1 Brisbane weather over summer 2016/17



Note:

(1) Based on years 2000 to 2017

Energy delivered from the transmission network for 2016/17 is expected to be within 1% of the 2016 TAPR forecast.

The CSG (coal seam gas) industry continues to ramp up with observed demands close to those forecast in the 2016 TAPR. By 2018/19, CSG demand is forecast to exceed 750MW. No new CSG loads have committed to connect to the transmission network since the publication of 2016 TAPR.

During the 2016/17 summer, Queensland had around 1,700MW of installed rooftop PV capacity. This rate of increase has slowed to around 15MW per month. An important impact of the rooftop PV has been to delay the time of state peak, which now occurs around 5:30pm. As more rooftop PV is installed, future summer maximum demands are likely to occur in the early evening.

The Queensland Government's Solar 150 initiative to support up to 150MW of solar generation in Queensland in collaboration with the Australian Renewable Energy Agency (ARENA) has been a key driver in the number of solar PV farms now committed and under construction in Queensland. The Federal Government's large-scale renewable energy target of 33,000GWh per annum by 2020 is also expected to drive future renewable capacity in the form of solar PV farms seeking to connect to the Queensland transmission and distribution networks over the next two to three years.

Solar PV farms connecting directly to the distribution network will reduce the amount of energy being delivered through the transmission network and accelerate the delay of the state peak from around 5:30pm to an evening peak. No distribution connected solar PV farms were included in the 2016 TAPR. Additional distribution connected solar PV farm capacity has been included further into the 10-year outlook period to align with Australia's obligations under the Paris Agreement on climate change. Further details on interest from potential variable renewable electricity (VRE) proponents is included in Chapter 7.

2 Energy and demand projections

The forecasts presented in this TAPR indicate relatively flat growth for energy, summer maximum demand and winter maximum demand in the first half of the 10-year outlook period, with moderate growth in the latter half of the 10-year outlook period. While there has been significant investment in the resources sector, global price signals for resources such as coal and gas are unlikely to result in further developments in the short-term. Independent economic outlook is that Queensland, on the whole, is still experiencing slow economic growth, however this is expected to return to solid growth for the second half of the forecasting period. The lower Australian dollar has improved growth prospects in areas such as tourism and foreign education while sustained low interest rates are providing a boost in the housing industry. Queensland's population growth has slowed following the resources boom and is expected to increase by around 15% to around 5.6 million over the 10-year forecast period.

The consumer response to electricity prices is expected to have a continued dampening effect on electricity usage. Future developments in battery storage technology coupled with rooftop PV could see significant changes to future electricity usage patterns. In particular, developments in battery storage technology have the potential to flatten electricity usage, reducing the need to develop transmission services to cover short duration peaks and put downward pressure on transmission costs.

Powerlink is committed to understanding the future impacts of emerging technologies so that transmission network services are developed in a way most valued by customers. Driven by this commitment, Powerlink has again hosted a forum in April 2017 to share and build on knowledge related to emerging technologies. As a result, several enhancements were made to the forecasting methodology associated with emerging technologies in this TAPR. Details of Powerlink's forecasting methodology can be found in Appendix B.

The delivered demand forecast in the 2017 TAPR shows an increase compared to the 2016 TAPR. The increase from 2020 is largely due to an expectation that electricity prices will remain flat and then fall and that the Queensland state economy will return to solid growth. Figure 2.2 shows a comparison of the delivered summer maximum demand forecast with the 2016 TAPR, based on a 50% probability of exceedance (PoE) and medium economic outlook.

The delivered energy forecast in the 2017 TAPR shows a reduction compared to the 2016 TAPR. The reduction to 2020 is largely due to the forecast of distribution connected solar PV farms and a forecast reduction in energy by a major transmission connected customer. Figure 2.3 shows a comparison of the delivered energy forecast with the 2016 TAPR, based on the medium economic outlook.

Figure 2.2 Comparison of the medium economic outlook demand forecasts

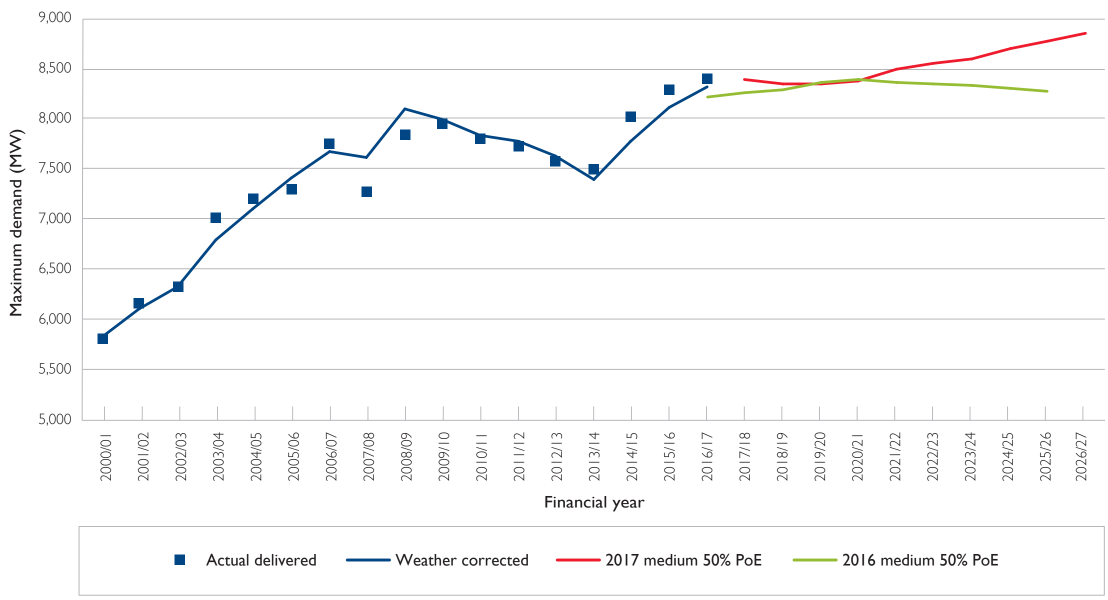
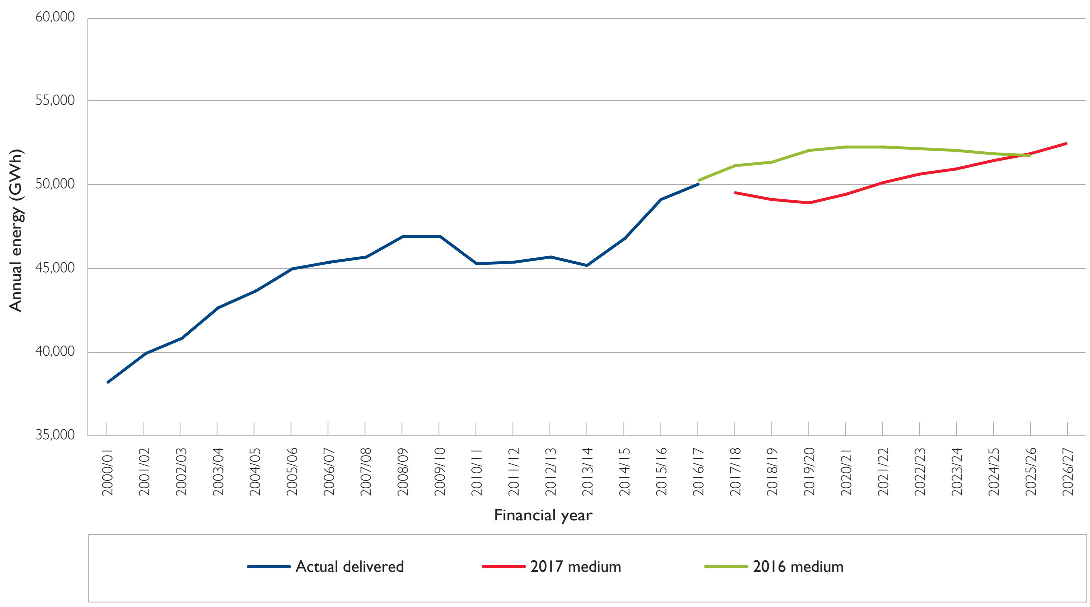


Figure 2.3 Comparison of the medium economic outlook energy forecasts



2.2 Customer consultation

In accordance with the National Electricity Rules (NER), Powerlink has obtained summer and winter maximum demand forecasts over a 10-year outlook period from Queensland's Distribution Network Service Providers (DNSPs), Energex and Ergon Energy. These connection supply point forecasts are presented in Appendix A. Also in accordance with the NER, Powerlink has obtained summer and winter maximum demand forecasts from other customers that connect directly to the transmission network. These forecasts have been aggregated into demand forecasts for the Queensland region and for 11 geographical zones, defined in Table 2.12 in Section 2.4, using diversity factors observed from historical trends.

2 Energy and demand projections

Energy forecasts for each connection supply point were obtained from Energex, Ergon Energy and other transmission connected customers. These have also been aggregated for the Queensland region and for each of the 11 geographical zones in Queensland.

Powerlink works with Energex, Ergon Energy, Australian Energy Market Operator (AEMO), customer and consumer representatives, and the wider industry to refine its forecasting process and input information. This takes place through ongoing engagement activities and forums such as the Demand and Energy Forecasting Forum and Powerlink Queensland Transmission Network Forum undertaken prior to and shortly after the release of the TAPR.

Powerlink, Energex and Ergon Energy jointly conduct the Queensland Household Energy Survey to improve understanding of consumer behaviours and intentions. This survey provides air conditioning penetration forecasts that feed directly into the demand forecasting process plus comprehensive insights on consumer intentions on electricity usage.

Powerlink's forecasting methodology is described in Appendix B.

Transmission customer forecasts

New large loads

No new large loads have connected or have committed to connect in the outlook period.

Possible new large loads

There are several proposals under development for large mining, metal processing and other industrial loads. These are not yet at a stage that they can be included (either wholly or in part) in the medium economic forecast. These developments, totalling nearly 900MW, are listed in Table 2.1.

Table 2.1 Possible large loads excluded from the medium economic outlook forecast

Zone	Description	Possible load
North	Further port expansion at Abbot Point	Up to 100MW
North	CSG load (Bowen Basin area)	Up to 80MW
North and Central West	New coal mining load (Galilee Basin area)	Up to 400MW
Surat	CSG load and coal mining projects (Surat Basin area)	Up to 300MW

2.3 Demand forecast outlook

The following sections outline the Queensland forecasts for energy, summer demand and winter demand.

All forecasts are prepared for three economic outlooks, high, medium and low. Demand forecasts are also prepared to account for seasonal variation. These seasonal variations are referred to as 10% PoE, 50% PoE and 90% PoE forecasts. They represent conditions that would expect to be exceeded once in 10 years, five times in 10 years and nine times in 10 years respectively.

The forecast average annual growth rates for the Queensland region over the next 10 years under low, medium and high economic growth outlooks are shown in Table 2.2. These growth rates refer to transmission delivered quantities as described in Section 2.3.2. For summer and winter maximum demand, growth rates are based on 50% PoE corrected values for 2016/17.

Table 2.2 Average annual growth rate over next 10 years

	Economic growth outlooks		
	Low	Medium	High
Delivered energy	-0.4%	0.4%	1.4%
Delivered summer maximum demand (50% PoE)	-0.1%	0.6%	1.5%
Delivered winter maximum demand (50% PoE)	0.0%	0.6%	1.5%

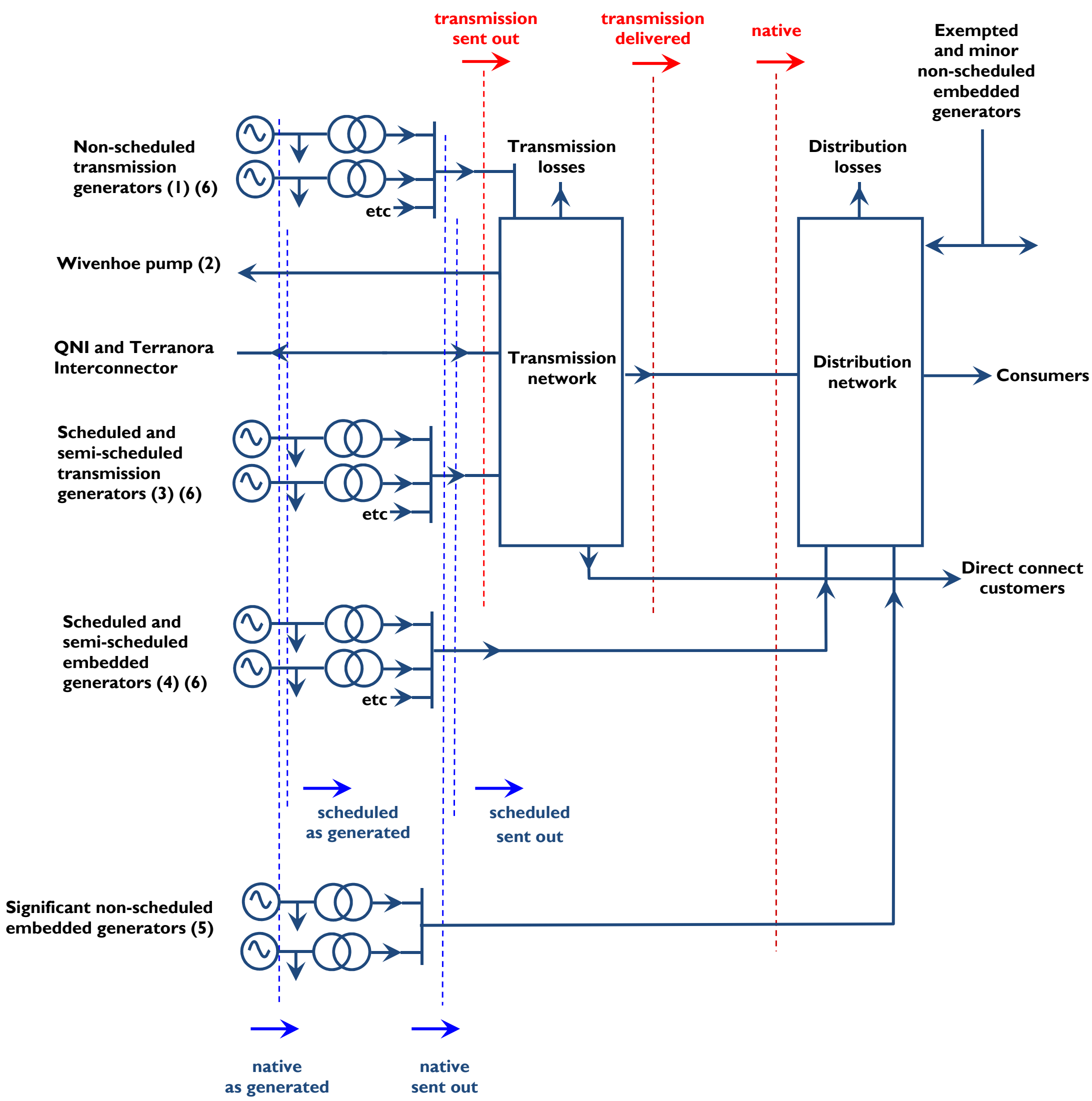
2.3.1 Future management of maximum demand

The installation of additional rooftop PV systems and distribution connected solar PV farms is expected to delay the current time of the maximum demand from around 5:30pm to an evening peak and reduce the delivered demand and energy during daylight hours. The latter half of the 10-year demand forecast shows some growth in the maximum demand (refer to Figure 2.2). If the trend continues, Powerlink will need to consider if the network needs to be augmented to meet these evening peaks at a future point. However, there is an opportunity for new technology and non-network solutions to deliver cost efficiencies and negate the need to build new transmission assets by assisting in the management of evening maximum demand. The successful integration of non-network solutions has the potential to shift and reduce maximum demand back to daylight hours where demand levels are reduced due to embedded solar generation.

2.3.2 Demand and energy terminology

The reported demand and energy on the network depends on where it is being measured. Individual stakeholders have reasons to measure demand and energy at different points. Figure 2.4 shows the common ways to measure demand and energy, with this terminology used consistently throughout the TAPR.

Figure 2.4 Load forecast definitions



Notes:

(1) Includes Invicta and Koombooloomba

(2) Depends on Wivenhoe generation

(3) Includes Yarwun which is non-scheduled

(4) Barcaldine, Roma, Mackay and Townsville Power Station 66kV component

(5) Pioneer Mill, Racecourse Mill, Moranbah North, Moranbah, Barcaldine Solar Farm, German Creek, Oaky Creek, Isis Central Sugar Mill, Daandine, Bromelton and Rocky Point

(6) For a full list of transmission network generators and scheduled and semi-scheduled embedded generators refer to Table 5.1

2.3.3 Energy forecast

Historical Queensland energies are presented in Table 2.3. They are recorded at various levels in the network as defined in Figure 2.4.

Transmission losses are the difference between transmission sent out and transmission delivered energy. Scheduled power station auxiliaries are the difference between scheduled as generated and scheduled sent out energy.

Table 2.3 Historical energy (GWh)

Year	Scheduled as generated	Scheduled sent out	Native as generated	Native sent out	Transmission sent out	Transmission delivered	Native	Native plus solar PV
2007/08	51,337	47,660	52,268	48,711	47,177	45,653	47,188	47,188
2008/09	52,591	48,831	53,638	50,008	48,351	46,907	48,563	48,580
2009/10	53,150	49,360	54,419	50,753	48,490	46,925	49,187	49,263
2010/11	51,381	47,804	52,429	48,976	46,866	45,240	47,350	47,531
2011/12	51,147	47,724	52,206	48,920	46,980	45,394	47,334	47,813
2012/13	50,711	47,368	52,045	48,702	47,259	45,651	47,090	48,129
2013/14	49,686	46,575	51,029	47,918	46,560	45,145	46,503	47,894
2014/15	51,855	48,402	53,349	50,047	48,332	46,780	48,495	49,952
2015/16	54,238	50,599	55,752	52,223	50,573	49,094	50,744	52,546
2016/17 (1)	55,593	51,808	57,213	53,562	51,745	50,190	52,007	53,861

Note:

(1) These projected end of financial year values are based on revenue and statistical metering data until March 2017.

The forecast transmission delivered energy forecasts are presented in Table 2.4 and displayed in Figure 2.5. Forecast native energy forecasts are presented in Table 2.5.

Table 2.4 Forecast annual transmission delivered energy (GWh)

Year	Low growth outlook	Medium growth outlook	High growth outlook
2017/18	49,161	49,560	50,584
2018/19	48,553	49,171	51,695
2019/20	48,123	48,924	51,958
2020/21	48,210	49,414	52,713
2021/22	48,541	50,144	53,782
2022/23	48,644	50,669	54,558
2023/24	48,530	51,001	55,180
2024/25	48,615	51,520	56,300
2025/26	48,475	51,858	57,044
2026/27	48,076	52,459	57,404

Figure 2.5 Historical and forecast transmission delivered energy

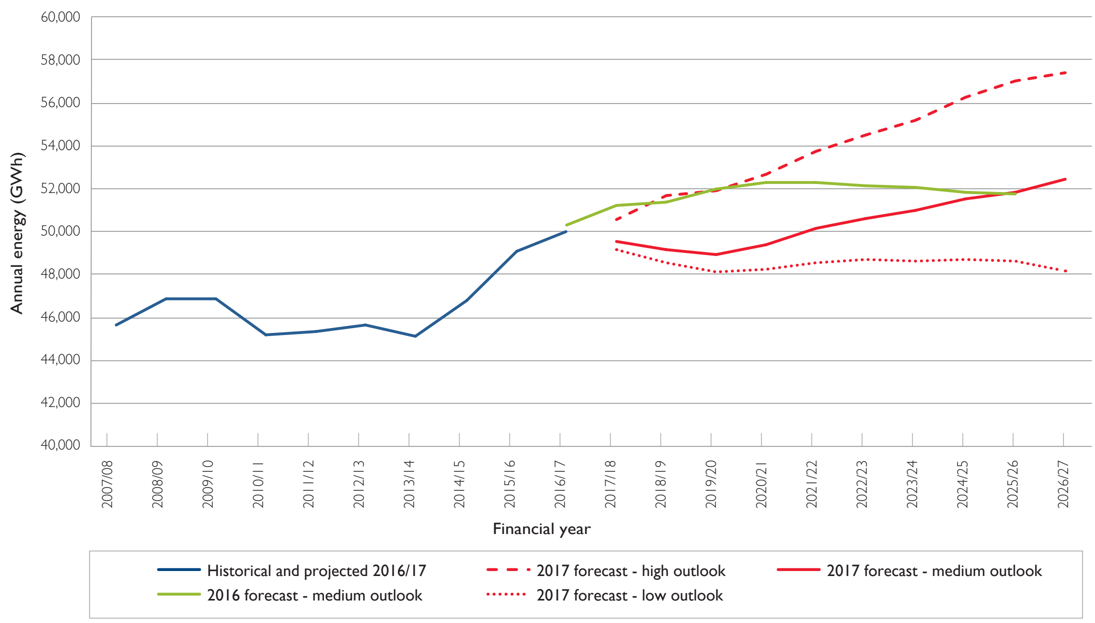


Table 2.5 Forecast annual native energy (GWh)

Year	Low growth outlook	Medium growth outlook	High growth outlook
2017/18	50,997	51,395	52,419
2018/19	50,745	51,363	53,887
2019/20	50,641	51,442	54,476
2020/21	50,890	52,095	55,394
2021/22	51,221	52,823	56,462
2022/23	51,323	53,347	57,237
2023/24	51,262	53,734	57,913
2024/25	51,511	54,416	59,196
2025/26	51,644	55,026	60,213
2026/27	51,573	55,956	60,901

2.3.4 Summer maximum demand forecast

Historical Queensland summer maximum demands at time of native peak are presented in Table 2.6.

Table 2.6 Historical summer maximum demand (MW)

Summer	Scheduled as generated	Scheduled sent out	Native as generated	Native sent out	Transmission sent out	Transmission delivered	Native	Native plus solar PV	Native corrected to 50% PoE
2007/08	8,082	7,603	8,178	7,713	7,425	7,281	7,569	7,569	7,893
2008/09	8,677	8,135	8,767	8,239	8,017	7,849	8,070	8,078	8,318
2009/10	8,891	8,427	9,053	8,603	8,292	7,951	8,321	8,355	8,364
2010/11	8,836	8,299	8,895	8,374	8,020	7,797	8,152	8,282	8,187
2011/12	8,707	8,236	8,769	8,319	7,983	7,723	8,059	8,367	8,101
2012/13	8,453	8,008	8,691	8,245	7,920	7,588	7,913	8,410	7,952
2013/14	8,365	7,947	8,531	8,114	7,780	7,498	7,831	8,378	7,731
2014/15	8,809	8,398	9,000	8,589	8,311	8,019	8,326	8,512	8,084
2015/16	9,094	8,668	9,272	8,848	8,580	8,271	8,539	8,783	8,369
2016/17	9,369	8,886	9,541	9,062	8,698	8,392	8,756	8,899	8,666

The transmission delivered summer maximum demand forecasts are presented in Table 2.7 and displayed in Figure 2.6. Forecast summer native demand is presented in Table 2.8.

Table 2.7 Forecast summer transmission delivered demand (MW)

Summer	Low growth outlook			Medium growth outlook			High growth outlook		
	90% PoE	50% PoE	10% PoE	90% PoE	50% PoE	10% PoE	90% PoE	50% PoE	10% PoE
2017/18	7,877	8,317	8,881	7,931	8,372	8,938	8,113	8,558	9,127
2018/19	7,806	8,244	8,805	7,898	8,339	8,905	8,163	8,612	9,188
2019/20	7,758	8,199	8,763	7,887	8,332	8,902	8,240	8,698	9,284
2020/21	7,747	8,194	8,768	7,914	8,368	8,949	8,356	8,827	9,430
2021/22	7,781	8,236	8,820	8,015	8,479	9,075	8,505	8,989	9,610
2022/23	7,772	8,232	8,822	8,070	8,542	9,148	8,600	9,095	9,729
2023/24	7,736	8,201	8,796	8,095	8,575	9,191	8,686	9,192	9,840
2024/25	7,767	8,239	8,844	8,190	8,682	9,312	8,867	9,387	10,053
2025/26	7,763	8,243	8,857	8,249	8,752	9,396	9,001	9,535	10,219
2026/27	7,744	8,230	8,852	8,300	8,813	9,471	9,103	9,650	10,351

Figure 2.6 Historical and forecast transmission delivered summer demand

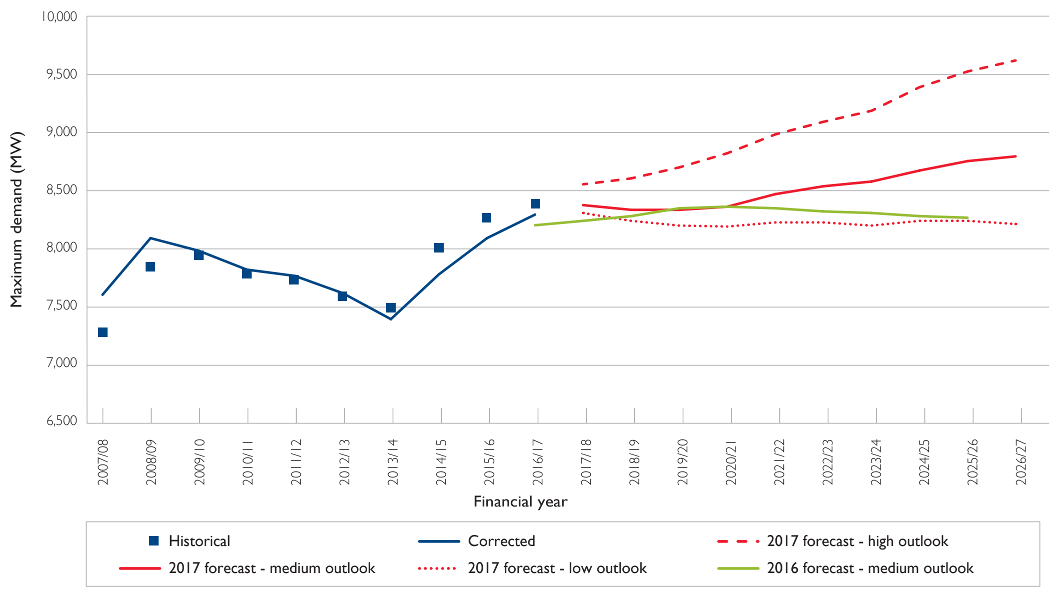


Table 2.8 Forecast summer native demand (MW)

Summer	Low growth outlook			Medium growth outlook			High growth outlook		
	90% PoE	50% PoE	10% PoE	90% PoE	50% PoE	10% PoE	90% PoE	50% PoE	10% PoE
2017/18	8,203	8,643	9,207	8,256	8,698	9,263	8,439	8,883	9,452
2018/19	8,131	8,570	9,131	8,224	8,665	9,230	8,488	8,938	9,513
2019/20	8,084	8,524	9,089	8,213	8,658	9,227	8,566	9,024	9,610
2020/21	8,072	8,520	9,094	8,239	8,693	9,275	8,681	9,152	9,756
2021/22	8,107	8,562	9,145	8,340	8,805	9,400	8,830	9,315	9,935
2022/23	8,098	8,558	9,147	8,396	8,868	9,473	8,925	9,421	10,055
2023/24	8,062	8,527	9,122	8,420	8,901	9,516	9,012	9,518	10,166
2024/25	8,092	8,565	9,170	8,516	9,008	9,638	9,192	9,712	10,379
2025/26	8,089	8,569	9,183	8,575	9,077	9,722	9,327	9,861	10,545
2026/27	8,070	8,556	9,178	8,626	9,139	9,797	9,429	9,976	10,677

2.3.5 Winter maximum demand forecast

Historical Queensland winter maximum demands at time of native peak are presented in Table 2.9. As winter demand normally peaks after sunset, solar PV has no impact on winter maximum demand.

Table 2.9 Historical winter maximum demand (MW)

Winter	Scheduled as generated	Scheduled sent out	Native as generated	Native sent out	Transmission sent out	Transmission delivered	Native	Native plus solar PV	Native corrected to 50% PoE
2007	7,837	7,416	7,893	7,481	7,298	7,166	7,350	7,350	7,026
2008	8,197	7,758	8,283	7,858	7,612	7,420	7,665	7,665	7,237
2009	7,655	7,158	7,756	7,275	7,032	6,961	7,205	7,205	7,295
2010	7,313	6,885	7,608	7,194	6,795	6,534	6,933	6,933	6,942
2011	7,640	7,207	7,816	7,400	7,093	6,878	7,185	7,185	6,998
2012	7,490	7,081	7,520	7,128	6,955	6,761	6,934	6,934	6,908
2013	7,150	6,753	7,345	6,947	6,699	6,521	6,769	6,769	6,983
2014	7,288	6,895	7,470	7,077	6,854	6,647	6,881	6,881	6,999
2015	7,816	7,369	8,027	7,620	7,334	7,126	7,411	7,412	7,301
2016	8,020	7,513	8,191	7,686	7,439	7,207	7,454	7,454	7,480

The transmission delivered winter maximum demand forecasts are presented in Table 2.10 and displayed in Figure 2.7. Forecast winter native demand is presented in Table 2.11.

Table 2.10 Forecast winter transmission delivered demand (MW)

Winter	Low growth outlook			Medium growth outlook			High growth outlook		
	90% PoE	50% PoE	10% PoE	90% PoE	50% PoE	10% PoE	90% PoE	50% PoE	10% PoE
2017	7,077	7,263	7,534	7,118	7,304	7,575	7,176	7,363	7,635
2018	7,048	7,232	7,500	7,117	7,302	7,571	7,373	7,561	7,834
2019	7,039	7,224	7,493	7,131	7,317	7,587	7,452	7,642	7,920
2020	7,043	7,231	7,505	7,159	7,348	7,624	7,557	7,753	8,037
2021	7,072	7,263	7,541	7,241	7,434	7,716	7,664	7,864	8,156
2022	7,083	7,276	7,558	7,303	7,500	7,786	7,746	7,951	8,248
2023	7,060	7,256	7,540	7,327	7,527	7,817	7,812	8,020	8,324
2024	7,079	7,278	7,567	7,395	7,600	7,898	7,940	8,155	8,466
2025	7,095	7,297	7,592	7,461	7,670	7,975	8,070	8,290	8,610
2026	7,058	7,263	7,562	7,480	7,694	8,005	8,130	8,354	8,682

Figure 2.7 Historical and forecast winter transmission delivered demand

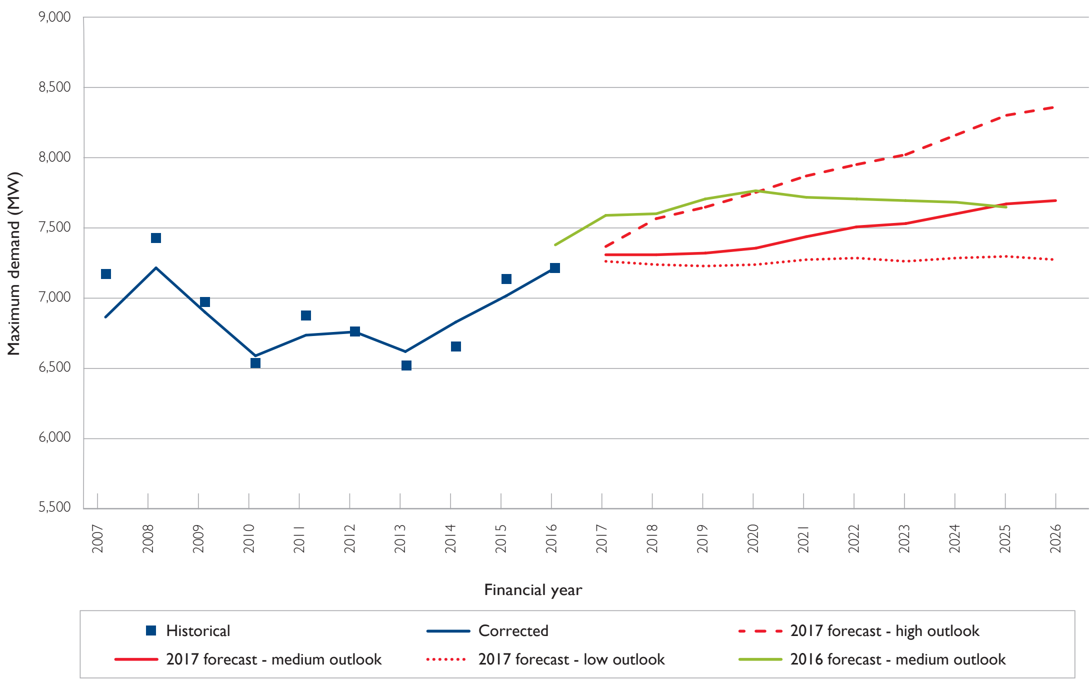


Table 2.11 Forecast winter native demand (MW)

Winter	Low growth outlook			Medium growth outlook			High growth outlook		
	90% PoE	50% PoE	10% PoE	90% PoE	50% PoE	10% PoE	90% PoE	50% PoE	10% PoE
2017	7,322	7,508	7,778	7,363	7,549	7,820	7,420	7,607	7,880
2018	7,292	7,477	7,745	7,361	7,546	7,816	7,617	7,805	8,079
2019	7,284	7,468	7,737	7,376	7,562	7,832	7,696	7,887	8,164
2020	7,288	7,476	7,749	7,404	7,593	7,868	7,802	7,997	8,282
2021	7,317	7,508	7,786	7,486	7,679	7,960	7,908	8,109	8,401
2022	7,328	7,521	7,802	7,548	7,744	8,030	7,991	8,195	8,493
2023	7,305	7,500	7,785	7,572	7,771	8,062	8,056	8,265	8,568
2024	7,323	7,522	7,812	7,640	7,844	8,142	8,185	8,399	8,711
2025	7,339	7,542	7,836	7,705	7,915	8,220	8,315	8,534	8,854
2026	7,304	7,509	7,808	7,726	7,940	8,251	8,375	8,600	8,927

2.4 Zone forecasts

The 11 geographical zones referred to throughout this TAPR are defined in Table 2.12 and are shown in the diagrams in Appendix C. In the 2008 Annual Planning Report (APR) Powerlink split the South West zone into Bulli and South West zones, and in the 2014 TAPR Powerlink split the South West zone into Surat and South West zones.

Table 2.12 Zone definitions

Zone	Area covered
Far North	North of Tully, including Chalumbin
Ross	North of Proserpine and Collinsville North, excluding the Far North zone
North	North of Broadsound and Dysart, excluding the Far North and Ross zones
Central West	South of Nebo, Peak Downs and Mt McLaren, and north of Gin Gin, but excluding the Gladstone zone
Gladstone	South of Raglan, north of Gin Gin and east of Calvale
Wide Bay	Gin Gin, Teebar Creek and Woolooga 275kV substation loads, excluding Gympie
Surat	West of Western Downs and south of Moura, excluding the Bulli zone
Bulli	Goondiwindi (Waggamba) load and the 275/330kV network south of Kogan Creek and west of Millmerran
South West	Tarong and Middle Ridge load areas west of Postmans Ridge, excluding the Bulli and Surat zones
Moreton	South of Woolooga and east of Middle Ridge, but excluding the Gold Coast zone
Gold Coast	East of Greenbank, south of Coomera to the Queensland/New South Wales border

Each zone normally experiences its own maximum demand, which is usually greater than that shown in tables 2.16 to 2.19.

Table 2.13 shows the average ratios of forecast zone maximum transmission delivered demand to zone transmission delivered demand at the time of forecast Queensland region maximum demand. These values can be used to multiply demands in tables 2.16 and 2.18 to estimate each zone's individual maximum transmission delivered demand, the time of which is not necessarily coincident with the time of Queensland region maximum transmission delivered demand. The ratios are based on historical trends.

Table 2.13 Average ratios of zone maximum delivered demand to zone delivered demand at time of Queensland region maximum demand

Zone	Winter	Summer
Far North	1.19	1.19
Ross	1.50	1.60
North	1.15	1.18
Central West	1.10	1.18
Gladstone	1.03	1.05
Wide Bay	1.03	1.13
Surat	1.13	1.14
Bulli	1.15	1.30
South West	1.04	1.19
Moreton	1.01	1.01
Gold Coast	1.02	1.01

Tables 2.14 and 2.15 show the forecast of transmission delivered energy and native energy for the medium economic outlook for each of the 11 zones in the Queensland region.

Table 2.14 Annual transmission delivered energy (GWh) by zone

Year	Far North	Ross	North	Central West	Glad-stone	Wide Bay	Surat	Bulli	South West	Moreton	Gold Coast	Total
Actuals												
2007/08	1,818	2,719	2,728	3,165	10,058	1,399		87	1,712	18,684	3,283	45,653
2008/09	1,851	2,772	2,779	3,191	10,076	1,430		94	1,774	19,532	3,408	46,907
2009/10	1,836	2,849	2,719	3,300	10,173	1,427		84	1,442	19,619	3,476	46,925
2010/11	1,810	2,791	2,590	3,152	10,118	1,308		95	1,082	18,886	3,408	45,240
2011/12	1,792	2,723	2,611	3,463	10,286	1,323		105	1,196	18,629	3,266	45,394
2012/13	1,722	2,693	2,732	3,414	10,507	1,267		103	1,746	18,232	3,235	45,651
2013/14	1,658	2,826	2,828	3,564	10,293	1,321	338	146	1,304	17,782	3,085	45,145
2014/15	1,697	2,977	2,884	3,414	10,660	1,266	821	647	1,224	18,049	3,141	46,780
2015/16	1,724	2,944	2,876	3,327	10,721	1,272	2,633	1,290	1,224	17,944	3,139	49,094
2016/17	1,738	2,715	2,677	3,130	10,219	1,326	4,049	1,521	1,312	18,315	3,188	50,190
Forecasts												
2017/18	1,683	2,818	2,908	3,352	9,489	1,278	4,267	1,518	1,178	17,715	3,354	49,560
2018/19	1,647	2,736	2,850	3,217	9,490	1,209	4,428	1,566	1,132	17,562	3,334	49,171
2019/20	1,631	2,720	2,871	3,054	9,499	1,057	4,515	1,596	1,117	17,529	3,335	48,924
2020/21	1,655	2,766	2,915	3,045	9,528	1,001	4,542	1,608	1,130	17,831	3,393	49,414
2021/22	1,678	2,814	2,968	3,103	9,549	1,034	4,662	1,598	1,144	18,142	3,452	50,144
2022/23	1,695	2,854	3,064	3,147	9,567	1,061	4,681	1,569	1,152	18,382	3,497	50,669
2023/24	1,707	2,889	3,152	3,156	9,584	1,085	4,680	1,497	1,129	18,587	3,535	51,001
2024/25	1,741	2,951	3,172	3,207	9,610	1,127	4,624	1,413	1,061	19,000	3,614	51,520
2025/26	1,777	3,017	3,068	3,289	9,639	1,122	4,463	1,326	1,022	19,438	3,697	51,858
2026/27	1,782	3,061	2,993	3,420	9,679	1,138	4,303	1,077	1,060	20,120	3,826	52,459

Table 2.15 Annual native energy (GWh) by zone

Year	Far North	Ross	North	Central West	Glad-stone	Wide Bay	Surat	Bulli	South West	Moreton	Gold Coast	Total
Actuals												
2007/08	1,818	3,371	2,771	3,528	10,058	1,413		87	2,039	18,819	3,283	47,188
2008/09	1,851	3,336	2,950	3,481	10,076	1,437		94	2,265	19,665	3,408	48,563
2009/10	1,836	3,507	3,070	3,635	10,173	1,447		84	2,193	19,766	3,476	49,187
2010/11	1,810	3,220	2,879	3,500	10,118	1,328		95	2,013	18,979	3,408	47,350
2011/12	1,792	3,217	2,901	3,710	10,286	1,348		105	2,014	18,695	3,266	47,334
2012/13	1,722	3,080	3,064	3,767	10,507	1,292		103	1,988	18,332	3,235	47,090
2013/14	1,658	3,067	3,154	3,944	10,293	1,339	402	146	1,536	17,879	3,085	46,503
2014/15	1,697	3,163	3,434	3,841	10,660	1,285	1,022	647	1,468	18,137	3,141	48,495
2015/16	1,724	3,141	3,444	3,767	10,721	1,293	2,739	1,290	1,475	18,011	3,139	50,744
2016/17	1,738	3,066	3,364	3,569	10,219	1,354	4,096	1,521	1,551	18,341	3,188	52,007
Forecasts												
2017/18	1,697	3,135	3,574	3,731	9,489	1,298	4,352	1,518	1,457	17,789	3,355	51,395
2018/19	1,675	3,127	3,562	3,702	9,491	1,295	4,513	1,566	1,438	17,659	3,335	51,363
2019/20	1,660	3,127	3,583	3,685	9,499	1,297	4,612	1,596	1,424	17,624	3,335	51,442
2020/21	1,683	3,174	3,627	3,742	9,528	1,328	4,651	1,608	1,437	17,924	3,393	52,095
2021/22	1,707	3,222	3,680	3,800	9,549	1,361	4,771	1,598	1,450	18,234	3,451	52,823
2022/23	1,723	3,262	3,776	3,843	9,567	1,388	4,790	1,569	1,458	18,474	3,497	53,347
2023/24	1,736	3,297	3,864	3,880	9,584	1,412	4,789	1,497	1,463	18,677	3,535	53,734
2024/25	1,769	3,359	3,933	3,958	9,610	1,454	4,733	1,413	1,483	19,090	3,614	54,416
2025/26	1,805	3,425	3,993	4,041	9,638	1,498	4,573	1,326	1,504	19,526	3,697	55,026
2026/27	1,865	3,524	4,087	4,171	9,679	1,564	4,413	1,077	1,542	20,208	3,826	55,956

Tables 2.16 and 2.17 show the forecast of transmission delivered winter maximum demand and native winter maximum demand for each of the 11 zones in the Queensland region. It is based on the medium economic outlook and average winter weather.

Table 2.16 State winter maximum transmission delivered demand (MW) by zone

Winter	Far North	Ross	North	Central West	Glad-stone	Wide Bay	Surat	Bulli	South West	Moreton	Gold Coast	Total
Actuals												
2007	219	309	286	442	1,165	297			410	3,451	587	7,166
2008	216	285	361	432	1,161	253		17	374	3,655	666	7,420
2009	210	342	328	416	1,125	218		19	341	3,361	601	6,961
2010	227	192	325	393	1,174	179		18	269	3,173	584	6,534
2011	230	216	317	432	1,155	222		22	376	3,303	605	6,878
2012	214	212	326	426	1,201	215		20	346	3,207	594	6,761
2013	195	249	348	418	1,200	190	23	17	263	3,039	579	6,521
2014	226	346	359	463	1,200	204	16	51	257	2,974	551	6,647
2015	192	289	332	429	1,249	203	172	137	258	3,268	597	7,126
2016	216	278	341	451	1,229	193	467	193	280	3,009	550	7,207
Forecasts												
2017	202	283	388	388	1,062	208	476	195	252	3,274	576	7,304
2018	203	278	398	380	1,064	204	504	202	246	3,251	572	7,302
2019	203	278	401	380	1,063	203	511	205	247	3,258	568	7,317
2020	206	278	406	387	1,064	202	509	195	247	3,283	571	7,348
2021	212	280	414	393	1,065	203	521	198	249	3,324	575	7,434
2022	211	278	444	402	1,066	201	531	198	246	3,346	577	7,500
2023	212	266	462	404	1,066	201	527	196	247	3,366	580	7,527
2024	216	270	468	410	1,068	204	517	188	251	3,418	590	7,600
2025	219	274	474	416	1,070	206	516	180	254	3,464	597	7,670
2026	221	276	477	422	1,071	208	496	169	256	3,497	601	7,694

Table 2.17 State winter maximum native demand (MW) by zone

Winter	Far North	Ross	North	Central West	Glad-stone	Wide Bay	Surat	Bulli	South West	Moreton	Gold Coast	Total
Actuals												
2007	219	309	292	520	1,165	297			485	3,476	587	7,350
2008	216	362	365	470	1,161	253		17	479	3,676	666	7,665
2009	210	425	372	466	1,125	218		19	407	3,362	601	7,205
2010	227	319	363	484	1,174	186		18	380	3,198	584	6,933
2011	230	339	360	520	1,155	222		22	428	3,304	605	7,185
2012	214	289	360	460	1,201	215		20	375	3,206	594	6,934
2013	195	291	374	499	1,200	195	89	17	290	3,040	579	6,769
2014	226	369	420	509	1,200	204	90	51	286	2,975	551	6,881
2015	192	334	404	518	1,249	203	208	137	288	3,281	597	7,411
2016	216	358	419	504	1,229	200	467	193	310	3,008	550	7,454
Forecasts												
2017	202	336	450	449	1,063	210	511	195	281	3,276	576	7,549
2018	203	332	460	440	1,063	206	539	202	275	3,254	572	7,546
2019	203	332	462	441	1,064	205	547	205	275	3,260	568	7,562
2020	206	332	467	447	1,064	205	544	195	276	3,286	571	7,593
2021	212	333	475	454	1,066	206	557	198	277	3,326	575	7,679
2022	211	331	505	463	1,066	203	566	198	275	3,349	577	7,744
2023	212	319	524	465	1,066	204	562	196	275	3,368	580	7,771
2024	216	323	530	471	1,068	206	552	188	280	3,420	590	7,844
2025	219	327	535	477	1,070	209	551	181	283	3,466	597	7,915
2026	221	329	539	483	1,071	210	531	170	285	3,500	601	7,940

2 Energy and demand projections

Tables 2.18 and 2.19 show the forecast of transmission delivered summer maximum demand and native summer maximum demand for each of the 11 zones in the Queensland region. It is based on the medium economic outlook and average summer weather.

Table 2.18 State summer maximum transmission delivered demand (MW) by zone

Summer	Far North	Ross	North	Central West	Gladstone	Wide Bay	Surat	Bulli	South West	Moreton	Gold Coast	Total
Actuals												
2007/08	292	296	386	476	1,193	243		15	314	3,466	600	7,281
2008/09	280	350	317	459	1,178	278		19	367	3,934	667	7,849
2009/10	317	394	415	505	1,176	268		11	211	3,919	735	7,951
2010/11	306	339	371	469	1,172	274		18	175	3,990	683	7,797
2011/12	296	376	405	525	1,191	249		18	217	3,788	658	7,723
2012/13	277	303	384	536	1,213	232		14	241	3,754	634	7,588
2013/14	271	318	353	493	1,147	260	30	21	291	3,711	603	7,498
2014/15	278	381	399	466	1,254	263	130	81	227	3,848	692	8,019
2015/16	308	392	412	443	1,189	214	313	155	231	3,953	661	8,271
2016/17	269	291	392	476	1,088	276	447	175	309	3,957	712	8,392
Forecasts												
2017/18	323	374	411	463	1,038	208	471	179	255	3,971	679	8,372
2018/19	322	371	407	458	1,041	205	486	181	253	3,947	668	8,339
2019/20	322	368	407	463	1,040	204	489	178	252	3,944	665	8,332
2020/21	327	368	417	463	1,040	203	488	174	252	3,968	668	8,368
2021/22	331	371	422	479	1,043	204	504	174	253	4,022	676	8,479
2022/23	333	358	453	486	1,045	204	507	173	254	4,049	680	8,542
2023/24	335	358	467	485	1,045	204	503	171	253	4,070	684	8,575
2024/25	341	365	474	493	1,047	207	503	163	258	4,137	694	8,682
2025/26	347	371	479	499	1,049	209	489	155	261	4,192	701	8,752
2026/27	353	376	482	504	1,053	211	474	150	263	4,237	710	8,813

Table 2.19 State summer maximum native demand (MW) by zone

Summer	Far North	Ross	North	Central West	Glad-stone	Wide Bay	Surat	Bulli	South West	Moreton	Gold Coast	Total
Actuals												
2007/08	292	404	390	533	1,193	243		15	387	3,512	600	7,569
2008/09	280	423	331	510	1,178	278		19	421	3,963	667	8,070
2009/10	317	500	453	539	1,176	268		11	361	3,961	735	8,321
2010/11	306	412	408	551	1,172	274		18	337	3,991	683	8,152
2011/12	296	449	434	598	1,191	249		18	378	3,788	658	8,059
2012/13	277	417	422	568	1,213	241		14	328	3,799	634	7,913
2013/14	271	423	386	561	1,147	260	88	21	316	3,755	603	7,831
2014/15	278	399	479	548	1,254	263	189	81	254	3,889	692	8,326
2015/16	308	423	491	519	1,189	214	370	155	257	3,952	661	8,539
2016/17	269	364	512	559	1,088	276	498	175	329	3,974	712	8,756
Forecasts												
2017/18	324	449	490	524	1,038	210	532	179	281	3,992	679	8,698
2018/19	322	446	486	519	1,040	208	547	181	279	3,969	668	8,665
2019/20	322	443	486	524	1,040	206	550	179	278	3,965	665	8,658
2020/21	327	443	497	524	1,040	205	548	174	278	3,989	668	8,693
2021/22	331	447	501	541	1,043	206	564	174	279	4,044	675	8,805
2022/23	333	433	532	547	1,045	207	568	173	280	4,070	680	8,868
2023/24	335	434	546	546	1,045	206	563	171	279	4,091	685	8,901
2024/25	341	441	553	554	1,047	209	564	163	284	4,158	694	9,008
2025/26	347	446	558	560	1,049	211	550	155	287	4,213	701	9,077
2026/27	353	452	561	566	1,052	213	534	149	290	4,259	710	9,139

2.5 Daily and annual load profiles

The daily load profiles (transmission delivered) for the Queensland region on the days of 2016 winter and 2016/17 summer maximum native demands are shown in Figure 2.8.

The annual cumulative load duration characteristic for the Queensland region transmission delivered demand is shown in Figure 2.9.

Figure 2.8 Daily load profile of winter 2016 and summer 2016/17 maximum native demand days

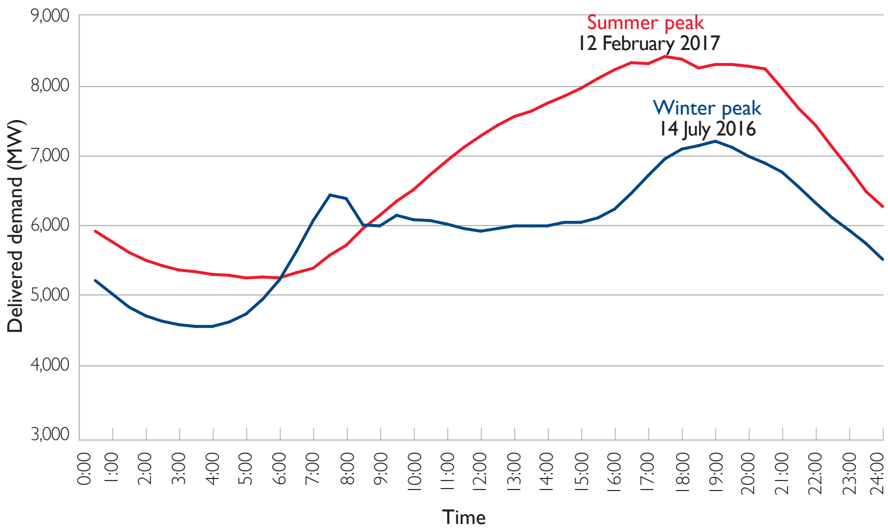
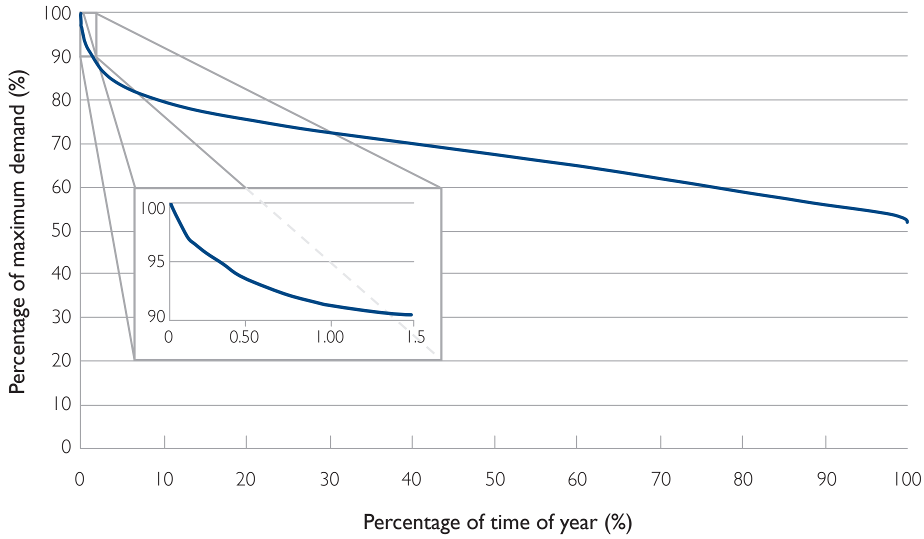


Figure 2.9 Normalised cumulative transmission delivered load duration from 1 April 2016 to 31 March 2017



Chapter 3:
Committed and commissioned network developments

3 Committed and commissioned network developments

Key highlights

- During 2016/17, Powerlink's efforts have been predominantly directed towards reinvestment in transmission lines and substations across Powerlink's network.
- Powerlink's reinvestment program is focused on reducing the identified risks associated with assets reaching the end of technical or economic life.
- A major project for Powerlink has been the Rockhampton Substation replacement which ensures a safe, reliable and secure electricity supply for the region.

3.1 Transmission network

Powerlink Queensland's network traverses 1,700km from north of Cairns to the New South Wales (NSW) border. The Queensland transmission network comprises transmission lines constructed and operated at 330kV, 275kV, 132kV and 110kV. The 275kV transmission network connects Cairns in the north to Mudgeeraba in the south, with 110kV and 132kV systems providing transmission in local zones and providing support to the 275kV network. A 330kV network connects the NSW transmission network to Powerlink's 275kV network at Braemar and Middle Ridge substations.

A geographic representation of Powerlink's transmission network is shown in Figure 3.1. Single line diagrams showing network topology and connections may be made available upon request.

3.2 Committed and commissioned transmission projects[1]

Table 3.1 lists transmission network developments which are committed at June 2017.

Table 3.2 lists network reinvestments commissioned since Powerlink's 2016 TAPR was published.

Table 3.3 lists network reinvestments which are committed at June 2017.

Table 3.4 lists network assets which are committed for retirement at June 2017.

Table 3.1 Committed transmission developments at June 2017

Project	Purpose	Zone location	Proposed commissioning date
Moranbah area 132kV capacitor banks (1)	Increase supply capability in the North zone	North	Progressively from winter 2013 to summer 2017/18

Note:

(1) Refer to Section 4.2.3

[1] There have been no transmission network developments commissioned since June 2016. Powerlink received and processed numerous connection enquiries since the 2016 TAPR was published, however none proceeded to connection works for commissioning during the 2016/17 financial year.

Table 3.2 Commissioned network reinvestments since June 2016

Project	Purpose	Zone location	Date commissioned
Rockhampton Substation replacement	Maintain supply reliability in the Central West zone	Central West	September 2016
Upper Kedron secondary systems replacement	Maintain supply reliability in the Moreton zone	Moreton	December 2016
Line refit works on 110kV transmission lines between Runcorn and Algester	Maintain supply reliability in the Moreton zone	Moreton	December 2016
Line refit works on 110kV transmission lines between Belmont and Runcorn	Maintain supply reliability in the Moreton zone	Moreton	December 2016
Blackwall IPASS secondary systems replacement	Maintain supply reliability in the Moreton zone	Moreton	June 2017

Table 3.3 Committed network reinvestments at June 2017

Project	Purpose	Zone location	Proposed commissioning date
Turkinje secondary systems replacement	Maintain supply reliability in the Far North zone	Far North	Summer 2018/19
Garbutt to Alan Sherriff 132kV line replacement	Maintain supply reliability in the Ross zone	Ross	Summer 2017/18
Garbutt transformers replacement	Maintain supply reliability in the Ross zone	Ross	Winter 2019
Ingham South 132/66kV transformers replacement	Maintain supply reliability in the Ross zone	Ross	Summer 2019/20
Nebo 275/132kV transformer replacements	Maintain supply reliability in the North zone (1)	North	Progressively from summer 2013/14 to summer 2017/18
Proserpine Substation replacement	Maintain supply reliability in the North zone	North	Summer 2017/18
Moranbah 132/66kV transformer replacement	Maintain supply reliability in the North zone	North	Winter 2018
Line refit works on the 132kV transmission line between Collinsville North and Proserpine substations	Maintain supply reliability to Proserpine	North	Summer 2018/19
Mackay Substation replacement	Maintain supply reliability in the North zone	North	Summer 2018/19
Line refit works on the 132kV transmission line between Eton Tee and Alligator Creek Substation	Maintain supply reliability in the North zone	North	Summer 2020/21
Nebo primary plant and secondary systems replacement	Maintain supply reliability in the North zone	North	Summer 2022/23
Calvale 275/132kV transformer reinvestment	Maintain supply reliability in the Central West zone (2)	Central West	Summer 2017/18
Blackwater Substation replacement	Maintain supply reliability in the Central West zone	Central West	Summer 2017/18
Baralaba secondary systems replacement	Maintain supply reliability in the Central West zone	Central West	Summer 2017/18
Moura Substation replacement	Maintain supply reliability in the Central West zone	Central West	Summer 2017/18
Stanwell secondary systems replacement	Maintain supply reliability in the Central West zone	Central West	Summer 2018/19
Dysart Substation replacement	Maintain supply reliability in the Central West zone	Central West	Summer 2019/20
Dysart transformer replacement	Maintain supply reliability in the Central West zone	Central West	Summer 2019/20
Calvale and Callide B secondary systems replacement	Maintain supply reliability in the Central West zone (3)	Central West	Winter 2021
Line refit works on 132kV transmission lines between Calliope River and Boyne Island	Maintain supply reliability in the Central West zone	Gladstone	Summer 2017/18

Table 3.3 Committed network reinvestments at June 2017 *(continued)*

Project	Purpose	Zone location	Proposed commissioning date
Wurdong secondary systems replacement	Maintain supply reliability in the Gladstone zone	Gladstone	Summer 2018/19
Line refit works on 275kV transmission line between Woolooga and Palmwoods	Maintain supply reliability in the Wide Bay zone	Wide Bay	Winter 2019
Tennyson secondary systems replacement	Maintain supply reliability in the Moreton zone	Moreton	Summer 2018/19
Rocklea secondary systems replacement	Maintain supply reliability in the Moreton zone	Moreton	Summer 2018/19
Mudgeeraba 110kV Substation primary plant and secondary systems replacement	Maintain supply reliability in the Gold Coast zone	Gold Coast	Summer 2017/18
Mudgeeraba 275/110kV transformer replacement	Maintain supply reliability in the Gold Coast zone	Gold Coast	Summer 2017/18

Note:

(1) The first transformer was commissioned in August 2013.

(2) Approved works were rescoped as part of the Callide A/Calvale 132kV transmission reinvestment, previously named Callide A Substation replacement. Refer to Section 4.2.4.

(3) The majority of Powerlink's staged works are anticipated for completion by summer 2018/19. Remaining works associated with generation connection will be coordinated with the customer.

Table 3.4 Committed asset retirement works at June 2017

Project (1)	Purpose	Zone location	Proposed retirement date
Proserpine to Glenella 132kV transmission line retirement	Removal of assets at the end of technical and economic life in the North zone	North	Winter 2017

Note:

(1) Operational works, such as asset retirements, do not form part of Powerlink's capital expenditure budget.

3 Committed and commissioned network developments

Figure 3.1 Existing Powerlink Queensland transmission network June 2017

Chapter 4:
Future network development

4 Future network development

Key highlights

- Powerlink is responding to fundamental shifts in its operating environment by adapting its approach to investment decisions. In particular, assessing whether an enduring need exists for key assets and investigating alternate network reconfiguration opportunities and/or non-network solutions, where feasible, to manage asset risks.
- The Ross, Central West, Gladstone and Moreton zones have potential reconfiguration opportunities during the five-year outlook period from 2017 to 2022.
- Additional commitment of generating capacity in north or central west Queensland is expected to lead to a rise in congestion on the Gladstone or CQ-SQ grid sections. This will likely result in material constraint durations and levels for generators in north or central west Queensland.

4.1 Introduction

The National Electricity Rules (NER) (Clause 5.12.2(c)(3)) requires the Transmission Annual Planning Report (TAPR) to provide "a forecast of constraints and inability to meet the network performance requirements set out in schedule 5.1 or relevant legislation or regulations of a participating jurisdiction over one, three and five years". In addition, there is a requirement (Clause 5.12.2(c)(4)) of the NER to provide estimated load reductions that would defer forecast limitations for a period of 12 months and to state any intent to issue request for proposals for augmentation or non-network alternatives. The NER (clauses 5.12.2(c)(7) and 5.15.3(b)(1)) requires the TAPR to include information pertinent to transmission network replacements where the capitalised expenditure is estimated to be more than $6 million.

This chapter on proposed future network developments contains:

- discussion on Powerlink's integrated planning approach to network development
- information regarding assets reaching the end of their technical or economic life and options to address identified asset risks, including potential network reconfigurations, asset retirements or de-ratings
- identification of emerging future limitations[1] with potential to affect supply reliability including estimated load reductions required to defer these forecast limitations by 12 months (NER Clause 5.12.2(c)(4)(iii))
- a statement of intent to issue request for proposals for augmentation or non-network alternatives (NER Clause 5.12.2(c)(4)(iv))
- a table summarising the outlook for network limitations over a five-year outlook period and their relationship to the Australian Energy Market Operator (AEMO) 2016 National Transmission Network Development Plan (NTNDP)
- details of those limitations for which Powerlink Queensland intends to address or initiate consultation with market participants and interested parties
- a table summarising possible connection point proposals.

Where appropriate all transmission network, distribution network or non-network (either demand management or local generation) alternatives are considered as options for investment or reinvestment. Submissions for non-network alternatives are invited by contacting networkassessments@powerlink.com.au.

[1] Identification of forecast limitations in this chapter does not mean that there is an imminent supply reliability risk. The NER requires identification of limitations which are expected to occur some years into the future, assuming that demand for electricity grows as forecast in this TAPR. Powerlink regularly reviews the need and timing of its projects, primarily based on forecast electricity demand, to ensure solutions are not delivered too early or too late to meet the required network reliability.

4.1.1 Integrated approach to network development

Powerlink's planning for future network development focuses on optimising the network topology based on consideration of future network needs due to:

- forecast demand
- new customer supply requirements
- existing network configuration
- condition based risks related to existing assets.

This planning process includes consideration of a broad range of options to address identified needs described in Table 4.1.

Table 4.1 Examples of planning options

Option	Description
Augmentation	Increases the capacity of the existing transmission network, e.g. the establishment of a new substation, installation of additional plant at existing substations or construction of new transmission lines. This is driven by the need to meet prevailing network limitations and customer supply requirements.
Reinvestment	Asset reinvestment planning ensures that existing network assets are assessed for their enduring network requirements in a manner that is economic, safe and reliable. This may result in like-for-like replacement, network reconfiguration, asset retirement, line refit, operational refurbishment or replacement with an asset of lower capacity. Condition and risk assessment of individual components may also result in the staged replacement of an asset where it is technically and economically feasible.
Network reconfiguration	The assessment of future network requirements may identify the reconfiguration of existing assets as the most economical option. This may involve asset retirement coupled with the installation of plant or equipment at an alternative location that offers a lower cost substitute for the required network functionality.
Asset retirement	May include strategies to disconnect, decommission and/or demolish an asset and is considered in cases where needs have diminished or can be deferred in order to achieve long-term economic benefits.
Line refit	Powerlink also utilises a line reinvestment strategy called line refit to extend the technical life of a transmission line and provide cost benefits through the deferral of future transmission line rebuilds. Line refit may include structural repairs, foundation works, replacement of line components and hardware and the abrasive blasting of tower steelwork followed by painting.
Operational refurbishment	Operational refurbishment includes the replacement of a part of an asset which restores the asset to a serviceable level and does not significantly extend the life of the asset.
Additional maintenance	Additional maintenance is maintenance undertaken at elevated levels in order to keep assets at the end of their life in a safe and reliable condition.
Non-network alternatives	Non-network solutions are not limited to, but may include network support from existing and/or new generation or demand side management initiatives (either from individual providers or aggregators) which may reduce, negate or defer the need for network investment solutions.
Operational measures	Network constraints may be managed during specific periods using short-term operational measures, e.g. switching of transmission lines or redispatch of generation in order to defer or negate network investment.

4.1.2 Forecast capital expenditure

The energy industry is going through a period of transformation driven by fundamental shifts in economic outlook, electricity consumer behaviour, government policy and regulation and emerging technologies that have reshaped the environment in which Powerlink delivers its transmission services.

As a result Powerlink's capital expenditure program of work for the five-year outlook period is considerably less than that of previous years. The load driven capital expenditure originally forecast in the 2013/17 regulatory period will not be realised due to these fundamental shifts in Powerlink's business and operating environment which contributed to a downturn in commodity prices. This significantly reduced resource sector investment, underlying economic growth and the associated demand for electricity. Similarly distribution load demand remained relatively flat driven by consumer response to high electricity prices, increased focus on energy efficiency and the uptake of distributed solar PV installations.

In this changed environment, the reduction in forecast demand growth also had an impact on Powerlink's planned reinvestment program. Powerlink has adapted its approach to reinvestment decisions, with a particular focus on assessing whether there is an enduring need for key assets and seeking alternative investment options through network reconfiguration to manage asset condition and/or non-network solutions where feasible.

Also, Powerlink has taken a cautious approach in determining when it is appropriate to refit or replace ageing transmission line assets and how to implement these works cost effectively. This approach is aimed at delivering better value to consumers.

The five-year outlook period discussed in the 2017 TAPR runs from 2017/18 to 2022/23 and discusses potential transmission network projects where the estimated cost is over $6 million.

4.1.3 Forecast network limitations

As outlined in Section 1.6.1, under its Transmission Authority, Powerlink Queensland must plan and develop its network so that it can supply the forecast maximum demand with the system intact. The planning standard, which came into effect from July 2014, permits Powerlink to plan and develop the network on the basis that some load may be interrupted during a single network contingency event. Forward planning allows Powerlink adequate time to identify emerging limitations and to implement appropriate network and/or non-network solutions to maintain transmission services which meet the planning standard.

Emerging limitations may be triggered by thermal plant ratings (including fault current ratings), protection relay load limits, voltage stability and/or transient stability. Appendix E lists the indicative maximum short circuit currents and fault rating of the lowest rated plant at each Powerlink substation and voltage level, accounting for committed projects listed in Chapter 3.

Assuming that the demand for electricity remains relatively flat in the five-year outlook period, Powerlink does not anticipate undertaking any significant augmentation works during this outlook period other than those which could potentially be triggered from economic drivers and/or the commitment of mining or industrial block loads (refer to Table 4.2). In Powerlink's Revenue Determination 2017-2022, the projects that would be triggered by these large loads were identified as contingent projects. These contingent projects and their triggers are discussed in detail in Section 6.2.

Table 4.2: Potential contingent projects

Potential project	Indicative cost
Northern Bowen Basin area	$56m
Bowen Industrial Estate	$43m
Central to North Queensland reinforcement	$55m
Central West to Gladstone area reinforcement	$105m
QNI upgrade (Queensland component)	$67m
Queensland to South Australia interconnection (Queensland component)	$120m

In accordance with the NER, Powerlink undertakes consultations with AEMO, Registered Participants and interested parties on feasible solutions to address forecast network limitations through the Regulatory Investment Test for Transmission (RIT-T) process. Solutions may include provision of network support from existing and/or new generators, demand side management initiatives (either from individual providers or aggregators) and network augmentations.

4.2 Proposed network developments

As the Queensland transmission network experienced considerable growth in the period from 1960 to 1980, there are now many transmission assets between 35 and 55 years old. It has been identified that a number of these assets are approaching the end of their technical or economic life and reinvestment in some form is required within the five-year outlook period in order to manage emerging risks related to safety, reliability and other factors. Reinvestment in the transmission network to manage identified risks associated with these assets will form the majority of Powerlink's capital expenditure program of work moving forward.

In conjunction with condition assessments and risk identification, as assets approach their anticipated end of technical or economic life, possible reinvestment options undergo detailed planning studies to confirm alignment with future reinvestment and optimisation strategies. These studies have the potential to provide Powerlink with an opportunity to:

- improve and further refine options under consideration or
- consider other options from those originally identified which may deliver a greater benefit to customers and consumers.

Information regarding possible reinvestment alternatives is updated annually within the TAPR and includes discussion based on the latest information available at the time.

Proposed network developments within the five-year outlook period are discussed below. The developments are the most likely solution, but as mentioned may change with ongoing detailed analysis of asset condition and network requirements.

For clarity, an analysis of this program of work has been performed across Powerlink's standard geographic zones.

4.2.1 Far North zone

Existing network

The Far North zone is supplied by a 275kV transmission network with major injection points at the Chalumbin and Woree substations into the 132kV transmission network. This 132kV network supplies the Ergon Energy distribution network in the surrounding areas of Tully, Innisfail, Turkinje and Cairns, and connection to the hydro power stations at Barron Gorge and Kareeya.

Transmission network overview

There are no network limitations forecast to occur in the Far North zone within the five-year outlook period.

Transmission lines

Kareeya to Chalumbin 132kV transmission line

The 132kV transmission line was constructed in the mid 1980s and provides connection to the Kareeya Power Station from the Chalumbin Substation. It operates in an environmentally sensitive world heritage area in the Wet Tropics with extremely high humidity conditions impacting on the life of its galvanised components. After detailed assessment of the condition of the line and analysis of the available options, including consideration of the the inherent constraints of working within the Wet Tropics Management Authority area, Powerlink has committed an operational project to address corrosion on the structures of the transmission line by summer 2017/18.

Substations

Powerlink's routine program of condition assessments has identified primary plant and secondary systems assets within the Far North zone with emerging safety, reliability and obsolescence risks that may require reinvestment within the five-year outlook period. Planning analysis confirms these assets are required to provide a reliable supply into the future (except where potential retirement has been identified) and the related investment needs are outlined in Table 4.3.

Table 4.3 Possible reinvestment works in the Far North zone within five years

Potential project	High level scope	Purpose	Possible commissioning date	Alternatives	Indicative cost
Substations					
Kamerunga Substation replacement	Full replacement of 132kV substation	Maintain supply reliability to the Far North zone	Summer 2019/20	Staged replacement of 132kV primary plant and secondary systems	$25m
Woree secondary systems replacement	Staged replacement of the 132kV secondary systems equipment	Maintain supply reliability to the Far North zone	Summer 2020/21	Full replacement of 132kV secondary systems	$10m
Retirement of one 132/22kV Cairns transformer	Retirement of one 132kV Cairns transformer including primary plant reconfiguration works (1)	Maintain supply reliability to the Far North zone	Summer 2021/22	Replacement of the transformer	$0.5m
Cairns secondary systems replacement	Full replacement of 132kV secondary systems	Maintain supply reliability to the Far North zone	Summer 2022/23	Staged replacement of the 132kV secondary systems equipment	$9m

Note:

(1) There may be additional works and associated costs required by Ergon Energy that need to be economically evaluated in relation to reconfiguration of the 22kV switchyard.

4.2.2 Ross zone

Existing network

The 132kV network between Collinsville and Townsville was developed in the 1960s and 1970s to supply mining, heavy commercial and residential loads. The 275kV network within the zone was developed more than a decade later to reinforce supply into Townsville. Parts of the 132kV network are located closer to the coast in a high salt laden wind environment leading to accelerated structural corrosion (refer to figures 4.1 and 4.2).

Figure 4.1 Northern Ross zone transmission network

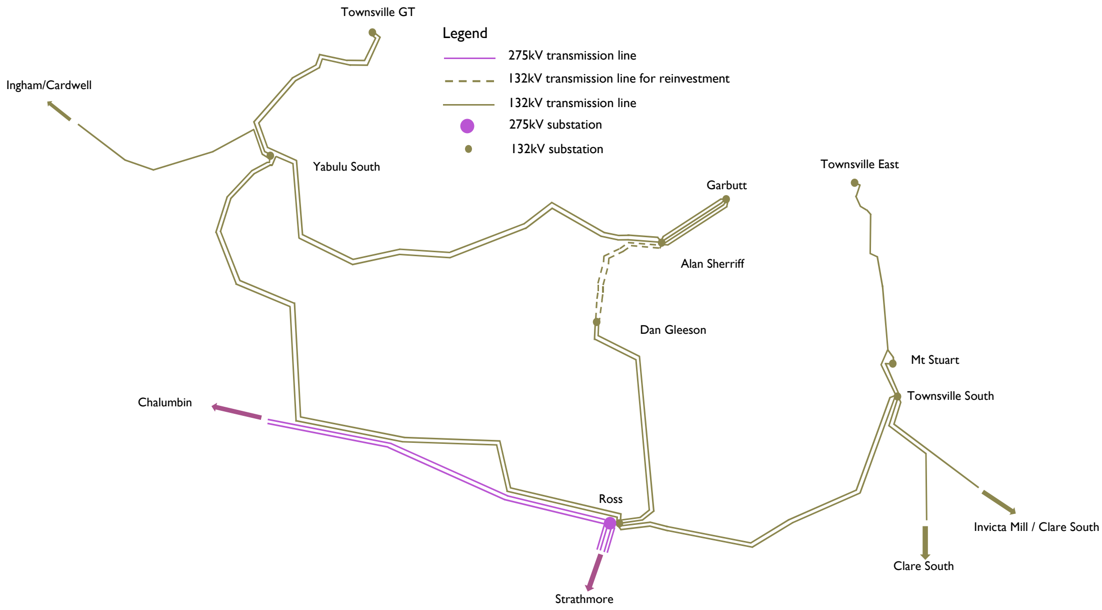
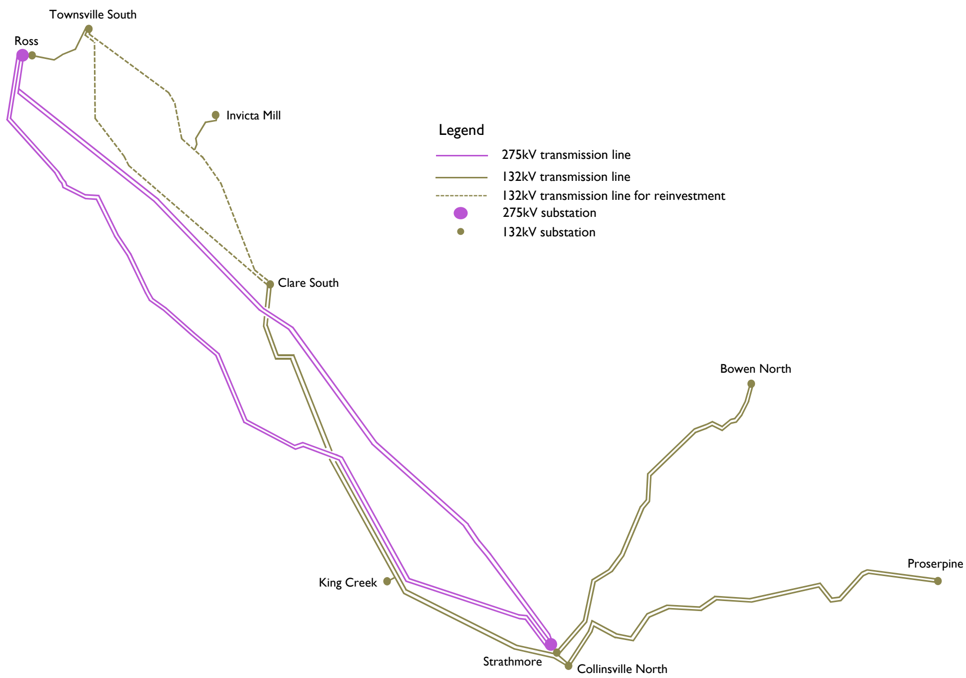


Figure 4.2 Southern Ross zone transmission network



Transmission network overview

There are no network limitations forecast to occur in the Ross zone within the five-year outlook period.

Transmission lines

Dan Gleeson to Alan Sherriff 132kV transmission line

The 132kV line between Dan Gleeson and Alan Sherriff substations was constructed in the 1960s and is located in the south-western suburbs of Townsville. Foundation repair on this transmission line was completed in 2016 to allow the continued safe and economic operation of this line in the medium term. The condition assessment indicates moderate levels of structural corrosion and end of technical or economic life is expected within the next five to 10 years. Possible strategies for this transmission line may include line refit, replacement or retirement at the end of its technical life.

Clare South to Townsville South 132kV transmission lines

The 275kV and 132kV network which operates in parallel between Collinsville and Townsville has developed over many years. The 132kV lines are reaching end of technical or economic life within the next five to 10 years, while the earliest end of technical or economic life trigger for the 275kV lines is beyond the 10-year outlook of this TAPR.

Two 132kV lines traverse separate easements between Clare South and Townsville South substations, whereas a double circuit 132kV line connects Clare South to Collinsville North substations with one circuit switched at Strathmore Substation.

The inland Clare South to Townsville South transmission line consists of 230 structures and is approximately 69km in length. It is forecast that the above ground corrosion on these structures will require line refit in the five to 10-year outlook period.

The near term driver is to confirm the below ground condition that is particular to 156 structures with grillage foundations. Work is underway to conduct non-invasive testing on these grillage foundations, and based on this testing, it is expected that Powerlink will be able to confirm below ground conditions along this transmission line. Hence, reinvestment timing and scope is uncertain at this stage within the five-year outlook.

Once the below ground condition is known, Powerlink will consider a number of end of life strategies for this transmission line, whilst holistically considering future capacity requirements in the area. This will include an assessment of the cost associated with keeping this line in safe operation below and above the ground, and the costs and network requirements associated with removing it.

It has been identified that removal of this transmission line would require a substitute network or non-network solution to remain within mandated supply requirements. A possible solution to the voltage limitation could be the installation of a transformer at Strathmore Substation, network reconfiguration, network support or non-network alternative (refer to Section 6.3.1).

A condition assessment has confirmed that the coastal circuit has experienced higher rates of structural corrosion and as such, Powerlink is proposing to undertake line refit works on the coastal transmission line by around 2019/20. Once the below ground condition is known for the inland transmission line, the possible scope of works, reinvestment options and timing at the end of its technical life will be confirmed.

Collinsville North/Strathmore to Clare South 132kV transmission lines

The 132kV line between Collinsville North/Strathmore and Clare South was constructed in the 1960s and is located in the Houghton and Burdekin catchment basins, with the northern section dominated by sugar cane and cattle grazing pastures. A recent condition assessment identified levels of structural corrosion with end of technical or economic life expected to occur within the next five to 10 years.

As such, Powerlink is proposing to undertake line refit works on the transmission line commencing around 2022/23. Powerlink will consider a number of end of life strategies for this transmission line, whilst holistically considering future capacity requirements in North Queensland over the entire transmission corridor.

Substations

Powerlink's routine program of condition assessments has identified transformer, primary plant and secondary systems assets within the Ross zone with emerging reliability, safety and obsolescence risks that may require reinvestment within the five-year outlook period. Planning analysis confirms these assets are required to provide ongoing reliable supply and the related investment needs are outlined in Table 4.4.

Non-network solutions

In Powerlink's 2015 and 2016 TAPR a potential non-network solution was identified as an alternative option to the replacement of both of the 132/66kV transformers at Garbutt. In March 2016, Powerlink initiated a Non-network Solution Feasibility Study to provide non-network service providers and interested parties with technical information regarding Powerlink's requirements and for the purpose of inviting information, comment and discussion as part of the "concept" phase of project development. The information received from possible non-network solution providers during the study process supported the replacement of both of the 50/70MVA 132/66kV transformers at Garbutt as the lowest cost solution to address the need and deliver the lowest long run cost to consumers. The findings of the feasibility study were published on Powerlink's website in August 2016[2].

2 Details of the Non-network Feasibility Study are available on Powerlink's website.

Table 4.4 Possible reinvestment works in the Ross zone within five years

Potential project	High level scope	Purpose	Possible commissioning date	Alternatives	Indicative cost
Transmission lines					
Line refit works on the coastal 132kV transmission line between Clare South and Townsville South substations	Line refit works on steel lattice structures	Maintain supply reliability in the Ross zone	Summer 2019/20	Line refit works on 132kV transmission line between Townsville South and Invicta, and additional reinforcement at Strathmore. New 132kV transmission line.	$20m
Retirement of the inland 132kV transmission line between Clare South and Townsville South substations	Retirement of the transmission line including non-network support, voltage support or network reconfiguration in the Strathmore area (1) (2)	Maintain supply reliability in the Ross zone	Summer 2019/20	Targeted foundation repair on the 132kV transmission line, followed by line refit or decommissioning in five to 10 years. New 132kV transmission line.	$10m
Line refit works on the 132kV transmission line between Strathmore/ Collinsville North and Clare South substations	Line refit works on steel lattice structures	Maintain supply reliability in the Ross zone	Progressively from Summer 2022/23	Line refit works on 132kV transmission line Strathmore and King Creek, and additional reinforcement at Clare South. New 132kV transmission line.	$45m
Substations					
Dan Gleeson secondary systems replacement	Full replacement of 132kV secondary systems	Maintain supply reliability to the Ross zone	Summer 2019/20	Staged replacement of 132kV secondary systems equipment	$7m
Townsville South	Staged replacement of 132kV primary plant and secondary systems	Maintain supply reliability to the Ross zone	Summer 2021/22	Full replacement of 132kV primary plant and secondary systems	$16m

Note:

(1) Modification and installation of system integrity protection schemes may be required to manage system security during system normal and during outages. The retirement of these transmission lines may also require establishment of an alternate telecommunications network.

(2) Non-network solutions to remain within Powerlink's planning standard may include up to 10MW and 1,000MWh in the Proserpine or Collinsville area.

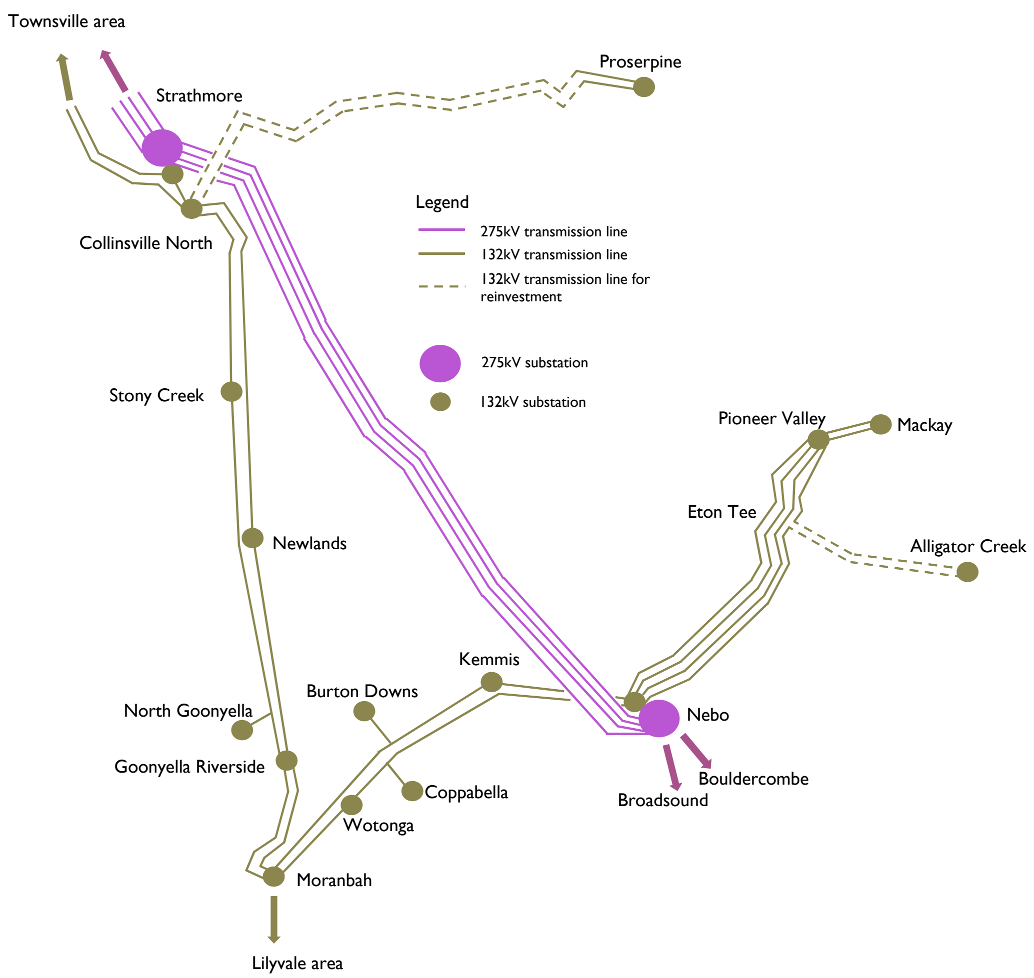
4.2.3 North zone

Existing network

Three 275kV circuits between Nebo (in the south) and Strathmore (in the north) substations form part of the 275kV transmission network supplying the North zone. Double circuit inland and coastal 132kV transmission lines supply regional centres and infrastructure related to mines, coal haulage and ports associated with the Bowen Basin mines (refer to Figure 4.3).

The coastal network in this zone is characterised by transmission line infrastructure in a corrosive environment which make it susceptible to premature ageing.

Figure 4.3 North zone transmission network



Transmission network overview

There are no network limitations forecast to occur in the North zone within the five-year outlook period.

The combination of increasing local demand in the Proserpine area, along with assets in the area reaching the end of their technical life, is expected to lead to some load at risk under Powerlink's planning standard within the five-year outlook period.

The critical contingency is an outage of the 275/132kV Strathmore transformer. Based on the medium economic forecast of this TAPR, this places load at risk of 10MW from summer 2020/21, which is within the 50MW and 600MWh limits established under Powerlink's planning standard (refer to Section 1.7).

Substations

Powerlink's routine program of condition assessments has identified transformer, primary plant and secondary systems assets within the North zone with emerging reliability, safety and obsolescence risks that may require reinvestment within the five-year outlook period. Planning analysis confirms these assets are required to provide ongoing reliable supply and the related investment needs are outlined in Table 4.5.

Table 4.5 Possible reinvestment works in the North zone within five years

Potential project	High level scope	Purpose	Possible commissioning date	Alternatives	Indicative cost
Substations					
Kemmis 132kV secondary systems replacement	Full replacement of 132kV secondary systems	Maintain supply reliability to the North zone	Summer 2022/23	Staged replacement of 132kV secondary systems equipment	$8m

Supply to Bowen Basin coal mining area

The Bowen Basin area is defined as the area of 132kV supply north of Lilyvale Substation, west of Nebo Substation and south and east of Strathmore Substation.

In August 2013, Powerlink completed a RIT-T consultation to address voltage and thermal limitations[3] forecast to occur in the Bowen Basin coal mining area from summer 2013/14. As part of this process, Powerlink identified the installation of 132kV capacitor banks at Dysart, Newlands, and Moranbah substations, and entered into a non-network arrangement as the preferred option to address the emerging network limitations.

Powerlink has completed the installation of the capacitor banks at Moranbah, Dysart and Newland substations. However, the installation of a second capacitor bank at Moranbah Substation has been deferred in order to optimise project staging with other works planned at the substation (refer to Table 3.1). The Moranbah capacitor bank is expected to be commissioned by summer 2017/18. The non-network agreement that Powerlink entered following completion of the RIT-T process came to an end in December 2016.

There have been several proposals for new coal mining, coal seam gas (CSG) and port expansion projects in the Bowen Basin area whose development status is not yet at the stage that they can be included (either wholly or in part) in the medium economic forecast of this TAPR. These loads could be up to 80MW (refer to Table 2.1) and cause voltage and thermal limitations impacting network reliability. Possible network solutions to these limitations are provided in Section 6.2.1. The timing of any emerging limitations will be subject to commitment of additional demand.

4.2.4 Central West and Gladstone zones

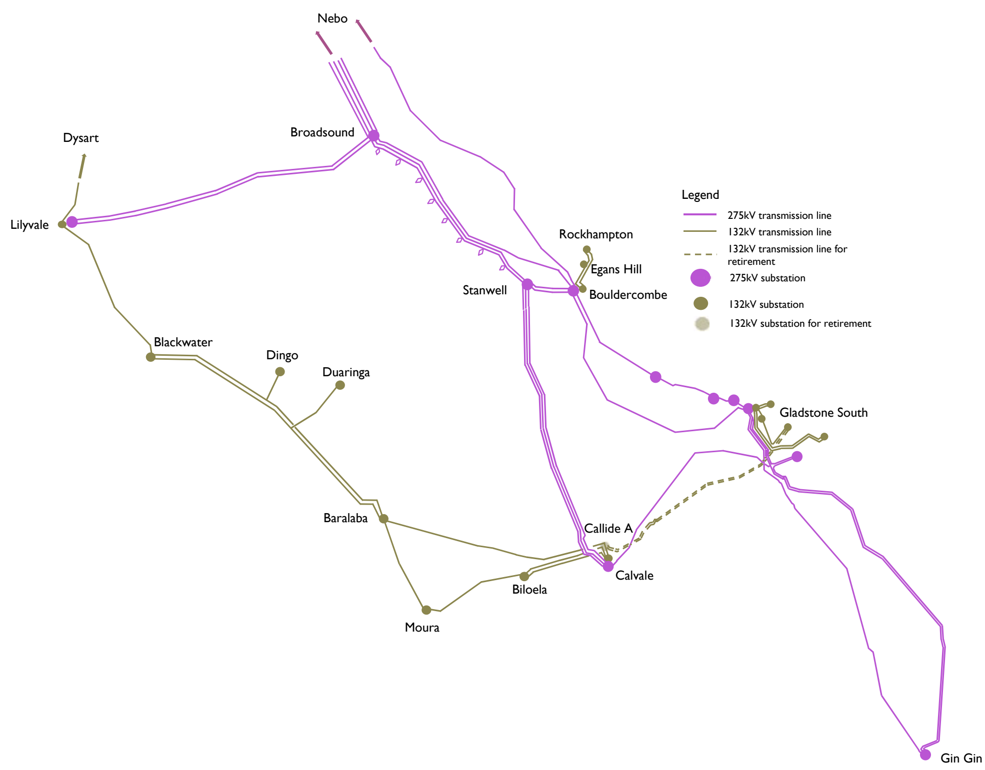
Existing network

The Central West 132kV network was developed between the mid 1960s to late 1970s to meet the evolving requirements of mining activity in the southern Bowen Basin. The 132kV injection points for the network are taken from Calvale and Lilyvale 275kV substations. The network is located more than 150km from the coast in a dry environment making infrastructure less susceptible to corrosion. As a result transmission lines and substations in this region have met (and in many instances exceeded) their anticipated technical life but will require replacement or rebuilding in the near future.

The Gladstone 275kV network was initially developed in the 1970s with the Gladstone Power Station and has evolved over time with the addition of the Wurdong Substation and supply into the Boyne Island smelter in the early 1990s (refer to Figure 4.4).

[3] Details of this consultation and the relevant technical information are available on Powerlink's website Maintaining a Reliable Electricity Supply to the Bowen Basin coal mining area

Figure 4.4 Central West and Gladstone transmission network



Transmission network overview

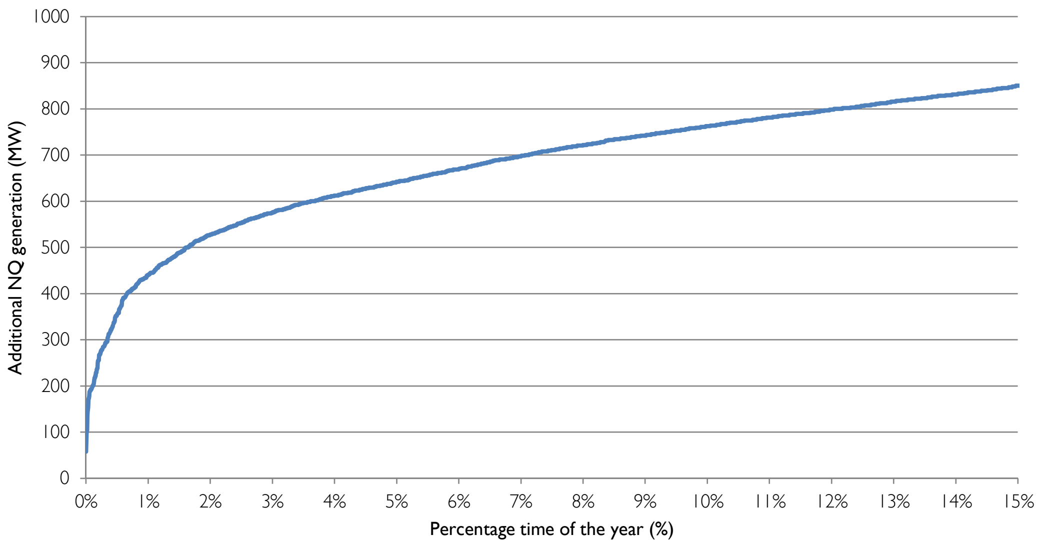
There are no network limitations forecast to occur in the Central West or Gladstone zones within the five-year outlook period.

In the NEM, generators compete for dispatch. Briefly, a generator's dispatch level depends on its bid in relation to other generators' bids, demand and available transmission capacity. Congestion occurs when transmission capacity prevents the optimum economic dispatch. Affected generators are said to be constrained by the amount unable to be economically dispatched. Forecast of constraint durations and levels are sensitive to highly uncertain variables including changes in bidding behaviour, environmental conditions, demand levels, etc. The use of historical conditions can serve to inform possible future outcomes.

Based on historical conditions and information on the expected operation of the committed generation, Powerlink's assessment indicates north and central west generators will continue to operate mostly unconstrained. However, additional generating capacity above committed levels in north or central west Queensland is expected to lead to a rise in congestion on the Gladstone or CQ-SQ grid sections. This will likely result in material constraint durations and levels for generators in north or central west Queensland. There is no load at risk associated with these constraints.

Figure 4.5 shows the percentage of time the Gladstone or CQ-SQ grid section could be congested as a function of the net increase of additional generation in north or central west Queensland above currently committed generation. Although high constraint times may not be indicative of the cost of market impact, they serve as a trigger for the analysis of the economics for overcoming the congestion.

Figure 4.5 Constraint outlook on Gladstone/CQ-SQ grid section for additional (above committed levels) NQ generation (based on 1 April 2016 to 31 March 2017 conditions)



Transmission lines

Egans Hill to Rockhampton 132kV transmission line

Rockhampton is supplied via a 132kV transmission line from Bouldercombe Substation. The section from Egans Hill to Rockhampton was constructed in the early 1960s and there is an ongoing need for this asset to supply the Rockhampton region. A recent condition assessment identified levels of structural corrosion with end of technical or economic life expected to occur within the next five years. Powerlink is proposing to undertake line refit works on the transmission line by around 2018/19.

Callide A to Moura 132kV transmission line

The 132kV transmission line was constructed in the early 1960s and there is an ongoing need for this asset to supply the Biloela and Moura substations. The condition assessment indicates moderate levels of structural corrosion, along with design limitations and degraded condition of the existing foundations, end of technical or economic life is expected to occur within the next five to 10 years. Detailed analysis is underway to evaluate foundation, repair and line refit or a staged replacement of this transmission line progressively from 2020 to 2025.

Callide A to Gladstone South 132kV transmission double circuit line

The 132kV transmission line was constructed in the mid 1960s to support the loads in the Gladstone area. A recent condition assessment identified high levels of structural corrosion with end of technical or economic life expected to occur within the next five years. Planning analysis has identified the possibility of reconfiguring the network in the area to achieve the lowest run cost of the 132kV reinvestment, and it is likely this line will be retired from service at the end of its technical life, expected within the next five to 10 years.

Substations

Powerlink's routine program of condition assessments has identified transformers, primary plant and secondary systems assets within the Central West and Gladstone zone with emerging safety, reliability and obsolescence risks that may require reinvestment within the five-year outlook period.

Powerlink has identified opportunities to reconfigure the network by summer 2018/19 to provide efficiencies and cost savings by:

- reducing the number of transformers within the zone, particularly at Lilyvale and Bouldercombe

- re-arrangement of the 132kV network around Callide A Substation by the establishment of a second transformer at Calvale Substation and retirement of Callide A Substation and the Callide A to Gladstone South transmission line. A committed project is underway to establish a second transformer at Calvale Substation.

The planning analysis also confirms the balance of substation assets are required to provide an ongoing reliable supply and the related investment needs are outlined in Table 4.6.

Table 4.6 Possible replacement works in the Central West and Gladstone zones within five years

Potential project	High level scope	Purpose	Possible commissioning date	Alternatives	Indicative cost
Transmission lines					
Line refit of the 132kV transmission line between Egans Hill and Rockhampton substations	Line refit works on steel lattice structures	Maintain supply reliability in the Central West zone	Winter 2019	New 132kV transmission line	$18m
Line replacement of the 132kV transmission line between Callide A and Moura substations	Staged replacement of 132kV transmission line between Callide A and Moura substations on a new easement	Maintain supply reliability to Biloela and Moura in the Central West zone	Progressively from 2020	Foundation repair and line refit works	$68m
Substations					
Lilyvale transformers replacement	Replacement of two of the three 132/66kV transformers (1)	Maintain supply reliability in the Central West zone	Winter 2020	Replacement of three 132/66kV transformers. Retire two of three 132/66kV transformers and implement non-network solution. (2)	$10m
Lilyvale primary plant replacement	Staged replacement of 275kV and 132kV primary plant	Maintain supply reliability in the Central West zone	Summer 2020/21	Full replacement of 275/132kV substation	$8m
Bouldercombe primary plant replacement	Staged replacement of 275kV and 132kV primary plant	Maintain supply reliability in the Central West zone	Summer 2020/21	Full replacement of 275/132kV substation	$26m
Bouldercombe transformer replacement	Replacement of one 275/132kV transformer with a larger unit, and retirement of the other	Maintain supply reliability in the Central West zone	Summer 2022/23	Replacement of two 275/132kV transformers	$7m

Note:

(1) Due to the extent of available headroom, the retirement of this transformer does not bring about a need for non-network solutions to avoid or defer load at risk or future network limitations, based on Powerlink's demand forecast outlook.

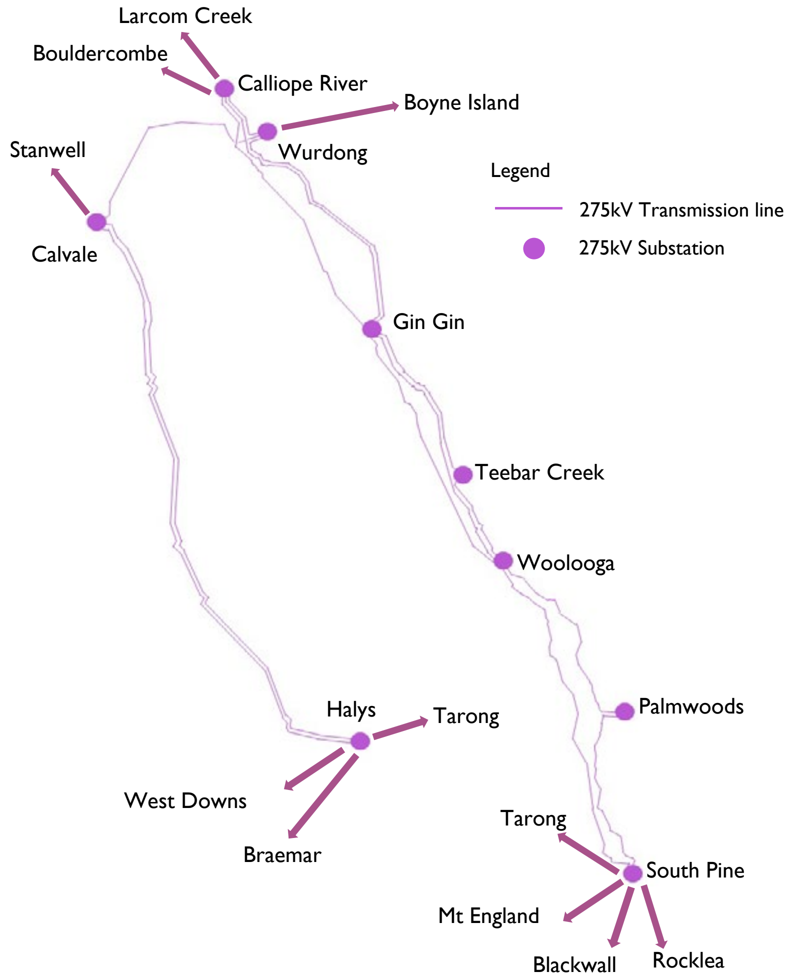
(2) Non-network solutions are not limited to, but may include network support from existing and/or new generation or demand side management initiatives (either from individual providers or aggregators).

4.2.5 Wide Bay zone

Existing network

The Wide Bay zone supplies loads in the Maryborough and Bundaberg region and also forms part of Powerlink's eastern CQ-SQ transmission corridor. This corridor was constructed in the 1970s and 1980s and consists of single circuit 275kV transmission lines between Calliope River and South Pine (refer to Figure 4.6). These transmisison lines traverse a variety of environmental conditions and as a result exhibit different corrosion rates and risk profiles.

Figure 4.6 CQ-SQ transmission network



Transmission network overview

There are no network limitations forecast to occur in the Wide Bay zone within the five-year outlook period.

Substations

Powerlink's routine program of condition assessments has identified primary plant and secondary systems assets within the Wide Bay zone with emerging safety, reliability and obsolescence risks that may require reinvestment within the five-year outlook period. Planning analysis confirms these substation assets are required to provide ongoing reliable supply and the related investment needs are outlined in Table 4.7.

Table 4.7 Possible reinvestment works in the Wide Bay zone within five years

Potential project	High level scope	Purpose	Possible commissioning date	Alternatives	Indicative cost
Substations					
Gin Gin Substation rebuild	Staged replacement of 275kV and 132kV primary plant	Maintain supply reliability in the Wide Bay zone	Summer 2019/20	Full replacement of 275/132kV substation. In-situ replacement of the 275/132kV substation.	$18m

4.2.6 South West zone

Existing network

The South West zone is defined as the Tarong and Middle Ridge areas west of Postman's Ridge.

Transmission network overview

There are no network limitations forecast to occur within the South west zone within the five-year outlook period.

Substations

Powerlink's routine program of condition assessments has identified primary plant and secondary systems assets within the South West zone with emerging safety, reliability and obsolescence risks that may require reinvestment within the five-year outlook period. Planning analysis confirms these substation assets are required to provide ongoing reliable supply and the related investment needs are outlined in Table 4.8.

Table 4.8 Possible reinvestment works in the South West zone within five years

Potential project	High level scope	Purpose	Possible commissioning date	Alternatives	Indicative cost
Substations					
Tarong secondary systems replacement	In situ staged replacement of secondary systems equipment	Maintain supply reliability in the South West zone	Summer 2021/22	Full replacement of 275kV secondary systems	$11m

4.2.7 Moreton zone

Existing network

The Moreton zone includes a mix of 110kV and 275kV transmission networks servicing a number of significant load centres in SEQ, including the Sunshine Coast, greater Brisbane, Ipswich and northern Gold Coast regions.

Future investment needs in the Moreton zone are substantially associated with the condition and performance of 110kV and 275kV assets in the greater Brisbane area. The 110kV network in the greater Brisbane area was progressively developed from the early 1960s and 1970s, with the 275kV network being developed and reinforced in response to load growth from the early 1970s. Multiple Powerlink 275/110kV injection points now interconnect with the Energex network to form two 110kV rings supplying the Brisbane CBD.

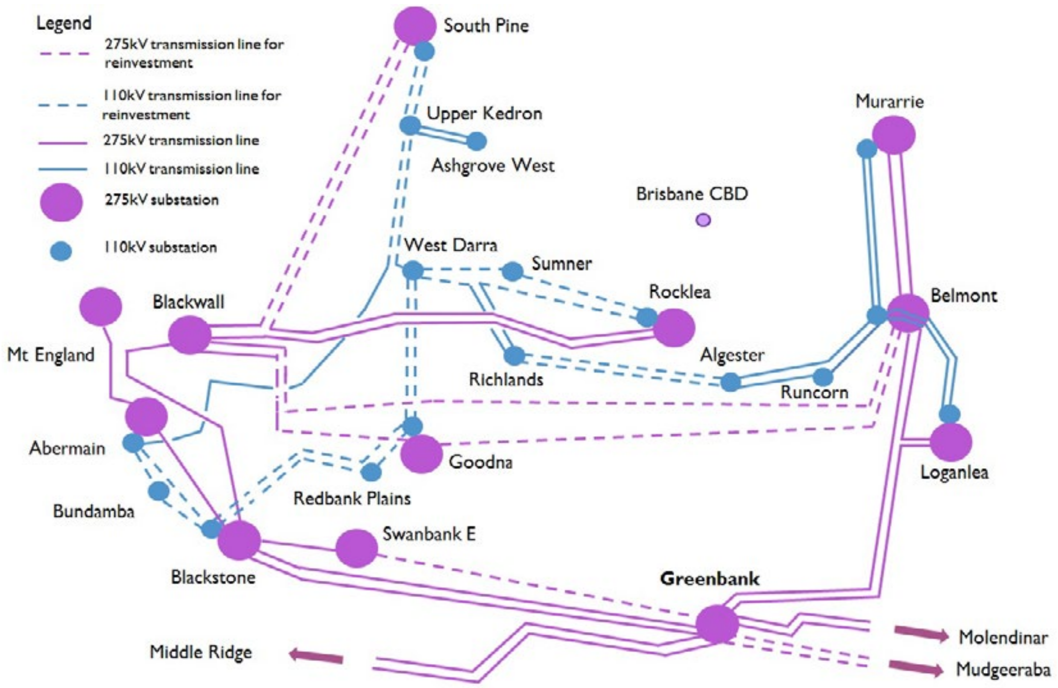
Transmission network overview

There are no network limitations forecast to occur in the Moreton zone within the five-year outlook period.

Transmission lines

The 110kV and 275kV transmission lines in the greater Brisbane area are located between 20km and 40km from the coast, traversing a mix of industrial, high density urban and semi-urban areas. The majority of assets are reasonably protected from the prevailing coastal winds and are exposed to moderate levels of pollution related to the urban environment. These assets have, over time, experienced structural corrosion at similar rates, with end of technical or economic life for most transmission line assets expected to occur between 2020 and 2025. Figure 4.7 illustrates the assets that are approaching end of technical or economic life over this period.

Figure 4.7 Greater Brisbane transmission network



With the maximum demand forecast relatively flat in the five-year outlook period, and based on the development of the network over the last 40 years, planning studies have identified a number of 110kV and 275kV transmission line assets that could potentially be retired. Given the uncertainty in future demand growth, Powerlink proposes to implement low cost maintenance strategies to keep the transmission lines in-service for a reasonable period. Future decommissioning remains an option once demand growth is better understood. As such, detailed analysis will be ongoing to evaluate the possible retirement of the following transmission lines at the end of technical or economic life:

- West Darra to Upper Kedron
- West Darra to Goodna
- Richlands to Algester.

This ongoing review, together with further joint planning with Energex, may result in a future investment recommendation in the 2020s and would involve further consultation with impacted parties.

For the balance of transmission line assets with an enduring need, Powerlink is progressively analysing options and is proposing a program of line refit works between winter 2016 and summer 2020/21 as the most cost effective solution to manage the safety and reliability risks associated with these assets remaining in-service.

Substations

Powerlink's routine program of condition assessments has identified transformers, primary plant and secondary systems assets within the Moreton zone with emerging safety, reliability and obsolescence risks that may require reinvestment within the five-year outlook period. Planning analysis confirms these assets are required to provide ongoing reliable supply and the related investment needs are outlined in Table 4.9.

Table 4.9 Possible reinvestment works in the Moreton zone within five years

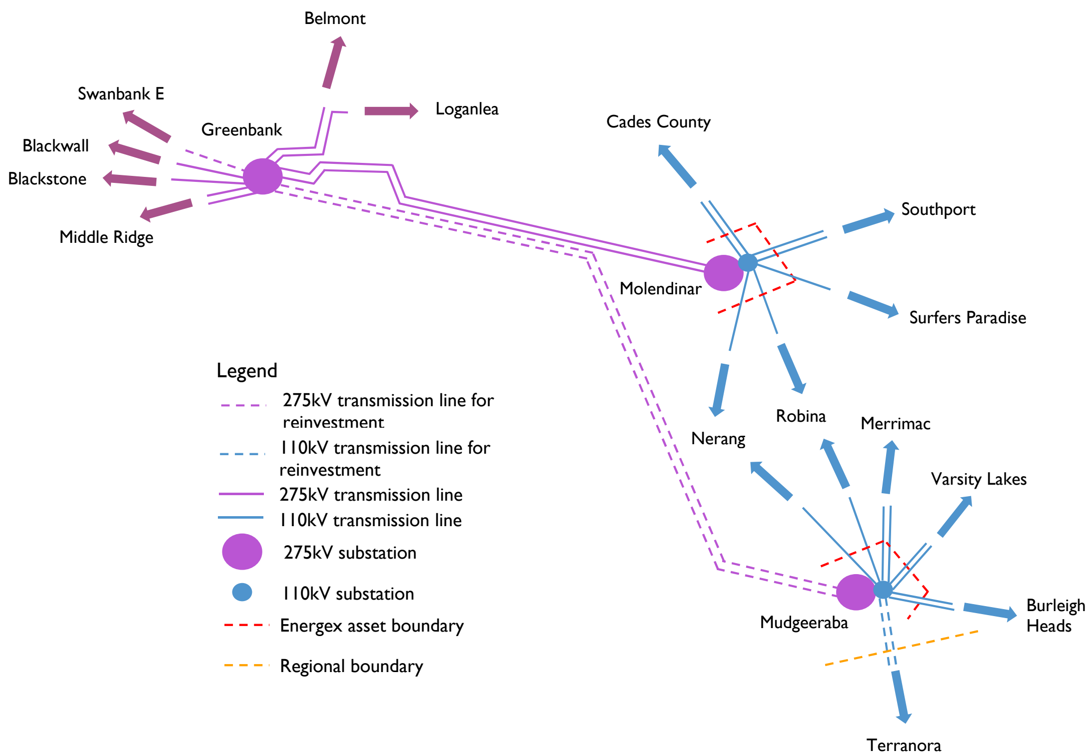
Potential project	High level scope	Purpose	Possible commissioning date	Alternatives	Indicative cost
Transmission Lines					
Line refit works on 110kV transmission lines between South Pine to Upper Kedron	Line refit works on steel lattice structures	Maintain supply reliability in the CBD and Moreton zone	Summer 2021/22	New 110kV transmission line/s	$9m
Line refit works on 110kV transmission lines between Sumner to West Darra	Line refit works on steel lattice structures	Maintain supply reliability in CBD and Moreton zone	Summer 2021/22	New 110kV transmission line/s	$7m
Line refit works on 110kV transmission lines between Rocklea to Sumner	Line refit works on steel lattice structures	Maintain supply reliability in CBD and Moreton zone	Summer 2021/22	New 110kV transmission line/s	$9m
Line refit works on 275kV transmission lines between South Pine to Karana Tee	Line refit works on steel lattice structures	Maintain supply reliability in the Moreton zone	Summer 2022/23	New 275kV transmission line/s	$19m
Substations					
Ashgrove West Substation replacement	Full replacement of 110kV substation	Maintain supply reliability in the Moreton zone	Summer 2019/20	Staged replacement of 110kV primary plant and secondary systems	$13m
Abermain secondary systems replacement	Full replacement of 110kV secondary systems	Maintain supply reliability in the Moreton zone	Winter 2020	Staged replacement of 110kV secondary systems equipment	$7m
Palmwoods 275kV secondary systems replacement	Full replacement of 275kV secondary systems	Maintain supply reliability in the Moreton zone	Summer 2020/21	Full replacement of 275/132kV substation	$7m
Belmont 275kV secondary system replacement	Full replacement of 275kV secondary systems	Maintain supply reliability in the CBD and Moreton zone	Winter 2021	Staged replacement of 275kV secondary systems equipment	$9m

4.2.8 Gold Coast zone

Existing network

The Powerlink transmission system in the Gold Coast was originally constructed in the 1970s and 1980s. The Molendinar and Mudgeeraba substations are the two major injection points into the area (refer to Figure 4.8) via a double circuit 275kV transmission line between Greenbank and Molendinar substations, and two single circuit 275kV transmission lines between Greenbank and Mudgeeraba substations.

Figure 4.8 Gold Coast transmission network



Transmission network overview

There are no network limitations forecast to occur in the Gold Coast zone within the five-year outlook period.

Transmission lines

Greenbank to Mudgeeraba 275kV transmission lines

The two 275kV single circuit transmission lines were constructed in the mid 1970s and are exposed to high rates of corrosion due to proximity to the coast and the prevailing salt laden coastal winds. The extent of corrosion observed during condition assessments requires that Powerlink consider options for targeted line refit of these lines in the five to 10-year outlook period for continued safe operation. Due to outage impacts of removal of one or both lines, a staged approach will need to be considered. Alternatively a new transmission line would be required beyond the outlook of the TAPR (refer to Section 6.3.4). Planning studies have confirmed the need to preserve the 275kV injection into Mudgeeraba.

Mudgeeraba to Terranora 110kV transmission lines

The 110kV line was constructed in the mid 1970s and forms an essential part of the interconnection between Powerlink and Essential Energy's network in northern New South Wales (NSW), with 13km of the transmission line owned by Powerlink. The transmission line operates in a metropolitan/semi-coastal environment with moderate rates of atmospheric pollution impacting on the life of its galvanised components and is subject to prevailing salt laden coastal winds. Based on Powerlink's most recent condition assessment, line refit or replacement of the 13km transmission line section will be required beyond the five-year outlook period.

Substations

Powerlink's routine program of condition assessments has identified transformers, primary plant and secondary systems assets at Mudgeeraba with emerging safety, reliability and obsolescence risks that may require reinvestment within the five-year outlook period.

The condition of two 275/110kV transformers at Mudgeeraba Substation requires action within the five-year outlook period. A committed project is underway to replace one of these transformers and planning studies have identified the potential to subsequently retire the other transformer. This option is considered feasible under the current demand forecast outlook. However, the reliability and market impacts of this option under a broader range of demand forecast scenarios need to be analysed in further detail and Powerlink anticipates the commencement of a RIT-T consultation (refer to Section 4.4.2).

Planning analysis confirms the balance of assets in this zone are required to provide ongoing reliable supply and the related investment needs are outlined in Table 4.10.

Table 4.10 Possible replacement works in the Gold Coast zone within five years

Potential project	High level scope	Purpose	Possible commissioning date	Alternatives	Indicative cost
Transmission lines					
Targeted line refit works on sections of the 275kV transmission lines between Greenbank and Mudgeeraba substations	Line refit works on steel lattice structures	Maintain supply reliability to the Gold Coast zone	Progressively Summer 2021/22	New 275kV transmission line/s. Full line refit on one or both 275kV single circuit transmission lines.	$20m
Substations					
Retirement of one Mudgeeraba 275/110kV transformer	Retirement of the transformer (1)	Maintain supply reliability to the Gold Coast zone	Summer 2019/20	New 275/110kV transformer	$1.5m
Mudgeeraba 275kV secondary systems replacement	Full replacement of 275kV secondary systems	Maintain supply reliability to the Gold Coast zone	Summer 2021/22	Staged replacement of 275kV secondary systems equipment	$11m

Note:

(1) Due to the extent of available headroom, the retirement of this transformer does not bring about a need for non-network solutions to avoid or defer load at risk or future network limitations, based on Powerlink's demand forecast outlook of the TAPR.

4.3 Summary of forecast network limitations

There are no network limitations forecast to occur in Queensland within the five-year outlook period.

4.4 Consultations

Network development to meet forecast demand is dependent on the location and capacity of generation developments and the pattern of generation dispatch in the competitive electricity market. Uncertainty about the generation pattern creates uncertainty about the power flows on the network and subsequently, which parts of the network will experience limitations. This uncertainty is a feature of the competitive electricity market and historically has been particularly evident in the Queensland region. Nothwithstanding the discussion in Section 4.2.4, Powerlink has not anticipated any material changes to network power flows which may require any major augmentation driven network development. This is due to a combination of several factors including a relatively flat energy and demand forecast in the five-year outlook period and Powerlink's planning criteria (refer to Chapters 1 and 2).

Proposals for transmission investments over $6 million to address forecast limitations are progressed under the provisions of Clause 5.16.4 of the NER. Accordingly, and where action is considered necessary, Powerlink will:

- notify of anticipated limitations within the timeframe required for action
- seek input, generally via the TAPR, on potential solutions to network limitations which may result in transmission network or non-network investments
- issue detailed information outlining emerging network limitations to assist non-network solutions as possible genuine alternatives to transmission investments to be identified
- consult with AEMO, Registered Participants and interested parties on credible options (network or non-network) to address anticipated constraints
- carry out detailed analysis on credible options that Powerlink may propose to address identified network constraints
- consult with AEMO, Registered Participants and interested parties on all credible options (network and non-network) and the preferred option
- implement the preferred option in the event an investment (network and non-network) is found to satisfy the RIT-T.

Alternatively, transmission investments may be undertaken under the "funded augmentation" provisions of the NER.

It should be noted that the information provided regarding Powerlink's network development plans may change and should therefore be confirmed with Powerlink before any action is taken based on the information contained in this TAPR.

4.4.1 Current consultations – proposed transmission investments

Proposals for transmission investments over $6 million that address limitations are progressed under the provisions of Clause 5.16.4 of the NER. Powerlink carries out separate consultation processes for each proposed new transmission investment by utilising the RIT-T consultation process.

There are currently no consultations underway.

4.4.2 Future consultations – proposed transmission investments

Powerlink anticipates the commencement of a RIT-T consultation for the replacement or removal of the Mudgeeraba 275/110kV transformer during 2018.

4.4.3 Summary of forecast network limitations beyond the five-year outlook period

The timing of forecast network limitations may be influenced by a number of factors such as load growth, industrial developments, new generation, the planning standard and joint planning with other network service providers. As a result of these variants, it is possible for the timing of forecast network limitations identified in a previous year's TAPR to shift beyond the five-year outlook period. However, there were no forecast network limitations identified in Powerlink's transmission network in the 2016 TAPR which fall into this category in 2017.

4.4.4 Connection point proposals

Table 4.11 lists connection works that may be required within the five-year outlook period. Planning of new or augmented connections involves consultation between Powerlink and the connecting party, determination of technical requirements and completion of connection agreements. New connections can result from joint planning with the relevant Distribution Network Service Provider (DNSP) or be initiated by generators or customers.

Table 4.11 Connection point proposals

Potential project	Purpose	Zone	Possible commissioning date
Mt Emerald Wind Farm	New wind farm near Atherton (1)	Far North	Quarter 2 2018
Clare Solar PV	New solar farm near Clare	Ross	Quarter 2 2017
Ross Solar PV	New solar farm near Ross	Ross	Quarter 2 2017
Genex Kidston Hydro/Solar PV	New hydro generator with solar PV near Kidston	Ross	Mid 2019
Whitsunday Solar PV	New solar farm near Strathmore	North	Quarter 1 2018
Hamilton Solar PV	New solar farm near Strathmore	North	Quarter 1 2018
Teebar Solar PV	New solar farm near Teebar Creek	Wide Bay	Quarter 1 2018
Lower Wonga Solar PV	New solar farm near Woolooga	Wide Bay	Quarter 4 2018
Coopers Gap Wind Farm	New wind farm near Halys	South West	Quarter 2 2018
Darling Downs Solar PV	New solar farm near Braemar	Bulli	Quarter 1 2018
Bulli Creek Solar PV	New solar farm near Bulli Creek	Bulli	Mid 2019

Note:

(1) When Powerlink constructs a new line or substation as a non-regulated customer connection (e.g. generator, renewable generator, mine or industrial development), the costs of acquiring easements, constructing and operating the transmission line and/or substation are paid for by the company making the connection request.

4.5 NTNDP alignment

The 2016 NTNDP was published by AEMO in December 2016. The focus of the NTNDP is to provide an independent, strategic view of the efficient development of the National Electricity Market (NEM) transmission network over a 20-year planning horizon.

Modelling for the 2016 NTNDP included as its starting point the completed and committed projects defined in Section 3.2. The NTNDP transmission development analysis was based on the 2016 National Electricity Forecasting Report (NEFR) and focused on assessing the adequacy of the main transmission network to reliably support major power transfers between NEM generation and demand centres (referred to as NTNDP zones).

The NEFR forecasts slowing maximum demand growth. This is broadly aligned with Powerlink's medium economic forecast in Chapter 2. The slowing forecast maximum demand growth results in fewer network limitations in all regions. In fact, the 2016 NTNDP did not identify any emerging reliability limitations across the main transmission network within the Queensland region due to load growth. However, the NTNDP identified a potential reliability limitation when some Central Queensland black coal generating units are projected to retire in 2021[4] under the generation outlook in the neutral scenario. The Calvale to Wurdong 275kV line is projected to overload under some system normal conditions. The extent of the potential overload, and the economic impact, would depend on any changes to the generation dispatch pattern. This outlook is consistent with Powerlink's expectations under a similar generation scenario.

Consistent with the above, the 2016 NTNDP identified potential economic dispatch limitations across the Central West to Gladstone grid section under the neutral scenario. Again the trigger for this congestion is the retirement of some Central Queensland black coal generating units. As discussed in Section 6.2.5 Powerlink recognised the vulnerability of this grid section to the commitment of renewable generation in North Queensland and in general the dispatch of generation in the Queensland region.

The 2016 NTNDP also identified potential economic dispatch limitations across the South West Queensland and South East Queensland grid section under the neutral scenario. The trigger for this congestion is the retirement of some Central Queensland local black coal generating units and additional new generation in SWQ. The subsequent high power transfers from SWQ to SEQ potentially overload a 275kV circuit between Mt England to South Pine without constraining generation. This outlook is consistent with Powerlink's expectations under similar generation scenarios.

Both the NTNDP and this TAPR acknowledge that asset reinvestment will be the focus within the five-year outlook period and continue in the longer term. Planning for the future network will include optimising the network topology as assets reach the end of their technical and economic life so that the network is best configured to meet current and future needs.

The NTNDP and this TAPR also recognise there is a shift from large-scale, synchronous, centrally dispatched generation towards distributed and intermittent (or variable) non-synchronous generation, connected to the power system through inverter-based technology as the electricity industry transitions to a low carbon future. Transmission networks will increasingly be needed for system support services, such as frequency and voltage support, to maintain a reliable and secure supply.

The 2016 NTNDP projects that Australia's 2030 emissions reductions target[5] will be met mostly by large-scale variable renewable electricity (VRE) generation replacing coal generation as it withdraws from service. Gas powered generation will be required to support intermittent renewable generation unless alternate technologies become cost competitive.

4 No such retirements have been announced or confirmed as at early June 2017.

5 Australia committed at the 21st Conference of Parties to reduce greenhouse gas emissions (COP21). The Council of Australian Governments (CoAG) recommended that the NTNDP assume a 26% to 28% of emissions reduction below 2005 levels by 2030.

This energy transformation is likely to impact existing and future transmission needs. Transmission development will be required over the next 20 years to:

- connect up to 22GW of new large-scale wind and solar generation
- integrate this intermittent generation while maintaining a reliable and secure power system.

The transmission network was historically designed to transport electricity from large-scale synchronous generation to load centres located close to major energy reserves. In contrast, renewable generation is expected to connect to the transmission network from more remote areas which have access to high wind and solar resources. These outlying grid sections have been designed to supply only local load and consequently have a lower power transfer capability compared to other parts of the transmission network. For this reason, the specific locations and capacity of large scale renewable generation has the potential to impact the utilisation of grid sections within the Queensland region.

Further, concentration of generation in the same location may cause local transmission congestion due to network limitations. These outcomes will also be influenced by any subsequent withdrawal of thermal synchronous generation. This changing generation mix in the NEM may require new power system infrastructure to provide frequency control and network support services.

Powerlink will proactively monitor this changing outlook for the Queensland region and take into consideration the impact of emerging technologies, withdrawal of gas and coal-fired generation and the integration of VRE in future transmission plans. These plans may include:

- reinvesting in assets to extend their end of technical or economic life
- removing some assets without replacement
- determining optimal sections of the network for new connection (in particular renewable generation) as discussed in detail in Chapter 7
- replacing existing assets with assets of a different type, configuration or capacity or
- non-network solutions.

The NTNDP also presents results of analysis into the need for Network Support and Control Ancillary Services (NSCAS). NSCAS are procured to maintain power system security and reliability, and to maintain or increase the power transfer capabilities of the network. The 2016 NTNDP reported that no NSCAS gaps of any type were identified in the Queensland region over the next five years. However, both the NTNDP and this TAPR reported that operational strategies, including transmission line switching, may be required to manage high voltages under light load conditions in SEQ. AEMO and Powerlink will continue to monitor this situation.

4 Future network development

Chapter 5:

Network capability and performance

5 Network capability and performance

Key highlights

- Semi-scheduled wind farm Mt Emerald (180MW) and solar farms Kidston (50MW), Ross River (125MW), Clare (136MW), Whitsunday (57MW), Hamilton (57MW), Collinsville (42MW), Teebar (53MW), Darling Downs (110MW) and Oakey (25MW) have committed during 2016/17.
- The range of generators connected to the Powerlink network is diversifying with the connection of variable renewable electricity generators.
- During 2016/17, the CQ-SQ grid section was highly utilised reflecting higher CQ and NQ generator scheduling. The utilisation of this grid section is expected to increase with the connection of variable renewable electricity generators in NQ.
- Committed generation is expected to alter power transfers, particularly during daylight hours, increasing the likelihood of congestion across the Gladstone, CQ-SQ and Queensland/New South Wales Interconnector (QNI) grid sections.
- During 2016/17, record peak transmission delivered demands were recorded in the Ross, Surat, Bulli and Moreton zones.
- The transmission network has performed reliably during 2016/17, with Queensland grid sections largely unconstrained.

5.1 Introduction

This chapter on network capability and performance provides:

- a table of existing and committed generation capacity over the next three years
- sample power flows at times of forecast Queensland maximum summer and winter demands under a range of interconnector flows and generation dispatch patterns
- background on factors that influence network capability
- zonal energy transfers for the two most recent years
- historical constraint times and power flow duration curves at key sections of Powerlink Queensland's transmission network
- a qualitative explanation of factors affecting power transfer capability at key sections of Powerlink's transmission network
- historical system normal constraint times and load duration curves at key zones of Powerlink's transmission network
- double circuit transmission lines categorised as vulnerable by the Australian Energy Market Operator (AEMO)
- a summary of the management of high voltages associated with light load conditions.

The capability of Powerlink's transmission network to meet forecast demand is dependent on a number of factors. Queensland's transmission network is predominantly utilised more during summer than winter. During higher summer temperatures, reactive power requirements are greater and transmission plant has lower power carrying capability. Also, higher demands occur in summer as shown in Figure 2.8.

The location and pattern of generation dispatch influences power flows across most of the Queensland network. Future generation dispatch patterns and interconnector flows are uncertain in the deregulated electricity market and will also vary substantially due to the effect of planned or unplanned outages of generation plant. Power flows can also vary substantially with planned or unplanned outages of transmission network elements. Power flows may also be higher at times of local area or zone maximum demands (refer to Table 2.13) and/or when embedded generation output is lower.

Years referenced in this chapter correspond to the period from April to March of the following year, capturing a full winter and summer period.

5.2 Existing and committed scheduled, semi-scheduled and transmission connected generation

Scheduled generation in Queensland is principally a combination of coal-fired, gas turbine and hydro electric generators.

New generators are regarded as committed (incorporated into future studies) when a Connection and Access Agreement (CAA) has been signed. The semi-scheduled solar farms Kidston, Ross River, Clare, Whitsunday, Hamilton, Collinsville, Teebar, Darling Downs and Oakey and Mt Emerald wind farm have reached committed status since the 2016 Transmission Annual Planning Report (TAPR).

In December 2014, Stanwell Corporation withdrew Swanbank E Power Station (PS) from service for up to three years. In June, the Queensland Government announced that it will be brought back online by the first quarter of 2018.

Table 5.1 summarises the available capacity of power stations connected, or committed (as of 1st May) to be connected to Powerlink's transmission network including the non-scheduled market generators at Yarwun, Invicta and Koombooloomba. This table also includes scheduled and semi-scheduled existing embedded generators at Mackay, Barcaldine, Roma and the Townsville PS 66kV component, and committed embedded generators Kidstone SF, Collinsville SF and Oakey SF.

Information in this table has been provided to AEMO by the owners of the generators. Details of registration and generator capacities can be found on AEMO's website. In accordance with Clause 5.18A of the NER, Powerlink's Register of Large Generator Connections with information on generators connecting to Powerlink's network can be found on Powerlink's website.

5 Network capability and performance

Table 5.1 Available generation capacity

Existing and committed plant connected to the Powerlink transmission network and scheduled or semi-scheduled embedded generators.

Generator	Location	Available capacity MW generated (1) Winter 2017	Summer 2017/18	Winter 2018	Summer 2018/19	Winter 2019	Summer 2019/20
Coalfired							
Stanwell	Stanwell	1,460	1,460	1,460	1,460	1,460	1,460
Gladstone	Calliope River	1,680	1,680	1,680	1,680	1,680	1,680
Callide B	Calvale	700	700	700	700	700	700
Callide Power Plant	Calvale	900	900	900	900	900	900
Tarong North	Tarong	443	443	443	443	443	443
Tarong	Tarong	1,400	1,400	1,400	1,400	1,400	1,400
Kogan Creek	Kogan Creek Power Station Switchyard	744	730	744	730	744	730
Millmerran	Millmerran	852	760	852	760	852	760
Total coalfired		**8,179**	**8,073**	**8,179**	**8,073**	**8,179**	**8,073**
Combustion turbine							
Townsville (Yabulu) (2)	Townsville GT Switchyard	243	233	243	233	243	233
Mt Stuart (3)	Townsville South	419	379	419	379	419	379
Mackay (2)(4)	Mackay	34	34	34	34	34	34
Barcaldine (2)	Barcaldine	37	34	37	34	37	34
Yarwun (5)	Yarwun	160	155	160	155	160	155
Roma (2)	Roma	68	54	68	54	68	54
Condamine	Columboola	144	144	144	144	144	144
Braemar 1	Braemar	504	471	504	471	504	471
Braemar 2	Braemar	519	504	519	504	519	504
Darling Downs	Braemar	633	580	633	580	633	580
Oakey (6)	Oakey GT Power Station	340	282	340	282	340	282
Swanbank E (7)	Swanbank E			365	365	365	365
Total combustion turbine		**3,101**	**2,870**	**3,466**	**3,235**	**3,466**	**3,235**
Hydro electric							
Barron Gorge	Barron Gorge PS	66	66	66	66	66	66
Kareeya (including Koombooloomba) (8)	Kareeya PS	93	93	93	93	93	93
Wivenhoe (9)	Mt England	500	500	500	500	500	500
Total hydro electric		**659**	**659**	**659**	**659**	**659**	**659**

Table 5.1 **Available generation capacity** *(continued)*

Generator	Location	Available capacity MW generated (1) Winter 2017	Summer 2017/18	Winter 2018	Summer 2018/19	Winter 2019	Summer 2019/20
Solar PV (10)							
Kidston (2)	Kidston		50	50	50	50	50
Ross River	Ross		125	125	125	125	125
Clare	Clare South		136	136	136	136	136
Whitsunday	Strathmore		57	57	57	57	57
Hamilton	Strathmore		57	57	57	57	57
Collinsville (2)	Collinsville North			42	42	42	42
Teebar	Teebar Creek		53	53	53	53	53
Darling Downs	Braemar		110	110	110	110	110
Oakey (2)	Oakey			25	25	25	25
Total solar			**588**	**655**	**655**	**655**	**655**
Wind (10)							
Mt Emerald	Walkamin			180	180	180	180
Sugar mill							
Invicta (8)	Invicta Mill	34	0	34	0	34	0
Total all stations		**11,973**	**12,190**	**13,173**	**12,802**	**13,173**	**12,802**

Notes:

(1) The capacities shown are at the generator terminals and are therefore greater than power station net sent out nominal capacity due to station auxiliary loads and step-up transformer losses. The capacities are nominal as the generator rating depends on ambient conditions. Some additional overload capacity is available at some power stations depending on ambient conditions.

(2) Townsville PS 66kV component, Mackay, Barcaldine, Roma, Kidston, Collinsville and Oakey Solar Farm are embedded scheduled and semi-scheduled generators. Assumed generation is accounted in the transmission delivered forecast.

(3) Origin Energy has advised AEMO of its intention to retire Mt Stuart at the end of 2023.

(4) Stanwell Corporation has advised AEMO of its intention to retire Mackay GT at the end of financial year 2020/21.

(5) Yarwun is a non-scheduled generator, but is required to comply with some of the obligations of a scheduled generator.

(6) Oakey Power Station is an open-cycle, dual-fuel, gas-fired power station. The generated capacity quoted is based on gas fuel operation.

(7) The Queensland Government announced that Swanbank E is expected to be brought online in the first quarter of 2018.

(8) Koombooloomba and Invicta are transmission connected non-scheduled generators.

(9) Wivenhoe Power Station is shown at full capacity (500MW). However, output can be limited depending on water storage levels in the dam.

(10) Intermittent generators shown at full capacity.

5.3 Sample winter and summer power flows

Powerlink has selected 18 sample scenarios to illustrate possible power flows for forecast Queensland region summer and winter maximum demands. These sample scenarios are for the period winter 2017 to summer 2019/20 and are based on the 50% probability of exceedance (PoE) medium economic outlook demand forecast outlined in Chapter 2. These sample scenarios, included in Appendix C, show possible power flows under a range of import and export conditions on the QNI transmission line. The dispatch assumed is broadly based on historical observed dispatch of generators.

Power flows in Appendix C are based on existing network configuration and committed projects (listed in tables 3.1, 3.3 and 3.4), and assume all network elements are available. In providing this information Powerlink has not attempted to predict market outcomes.

5.4 Transfer capability

5.4.1 Location of grid sections

Powerlink has identified a number of grid sections that allow network capability and forecast limitations to be assessed in a structured manner. Limit equations have been derived for these grid sections to quantify maximum secure power transfer. Maximum power transfer capability may be set by transient stability, voltage stability, thermal plant ratings or protection relay load limits. AEMO has incorporated these limit equations into constraint equations within the National Electricity Market Dispatch Engine (NEMDE). Figure C.2 in Appendix C shows the location of relevant grid sections on the Queensland network.

5.4.2 Determining transfer capability

Transfer capability across each grid section varies with different system operating conditions. Transfer limits in the NEM are not generally amenable to definition by a single number. Instead, Transmission Network Service Providers (TNSPs) define the capability of their network using multiterm equations. These equations quantify the relationship between system operating conditions and transfer capability, and are implemented into NEMDE, following AEMO's due diligence, for optimal dispatch of generation. In Queensland the transfer capability is highly dependent on which generators are in-service and their dispatch level. The limit equations maximise transmission capability available to electricity market participants under prevailing system conditions.

Limit equations derived by Powerlink which are current at the time of publication of this Transmission Annual Planning Report (TAPR) are provided in Appendix D. Limit equations will change over time with demand, generation and network development and/or network reconfiguration. Such detailed and extensive analysis on limit equations has not been carried out for future network and generation developments for this TAPR. However, expected limit improvements for committed works are incorporated in all future planning. Section 5.5 provides a qualitative description of the main system conditions that affect the capability of each grid section.

5.5 Grid section performance

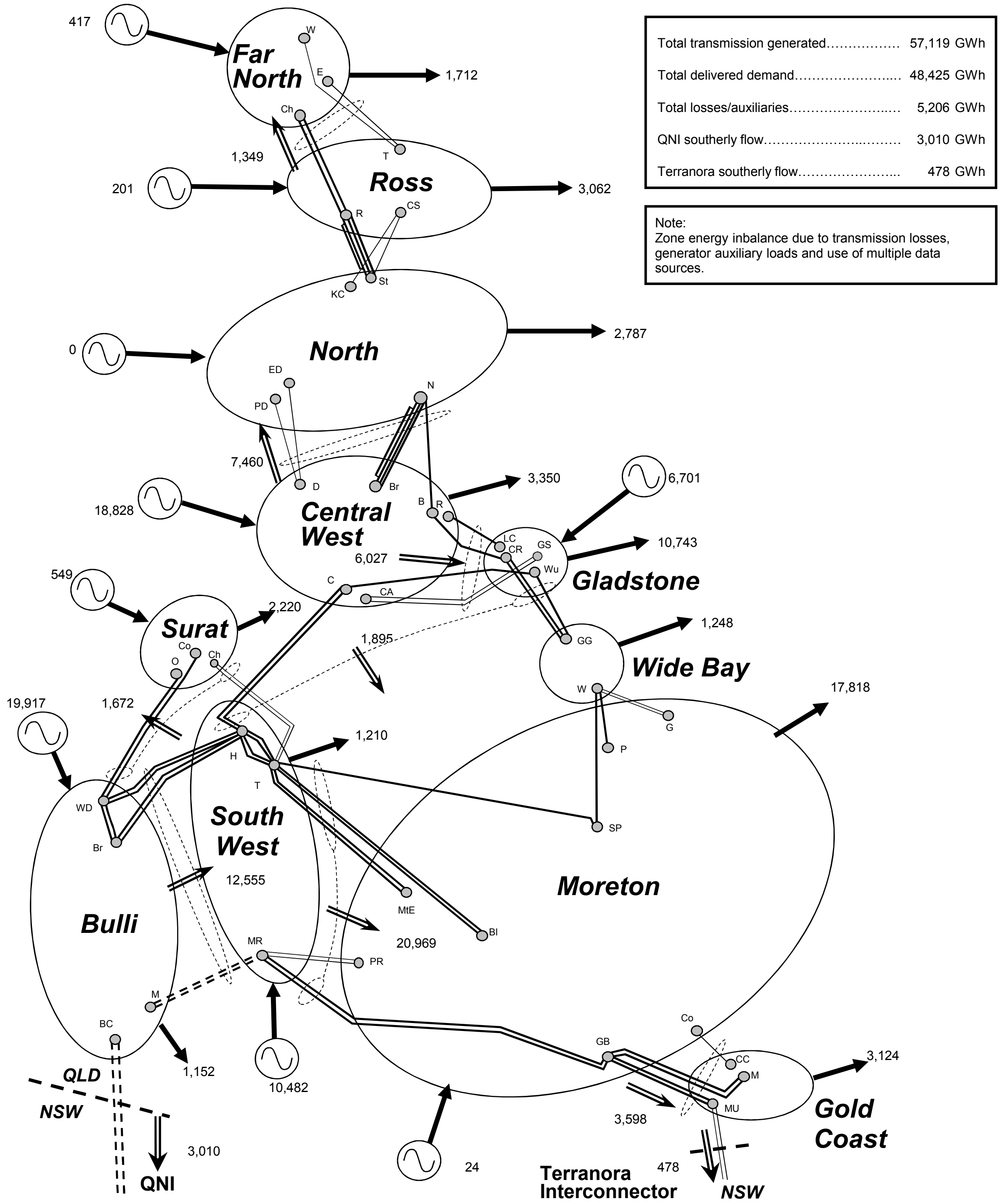
This section is a qualitative summary of system conditions with major effects on transfer capability across key grid sections of the Queensland network.

For each grid section, the time that the relevant constraint equations have bound over the last 10 years is provided. Constraint times can be associated with a combination of generator unavailability, network outages, unfavourable dispatches and/or high loads. Constraint times do not include occurrences of binding constraints associated with network support agreements. Binding constraints whilst network support is dispatched are not classed as congestion. Although high constraint times may not be indicative of the cost of market impact, they serve as a trigger for the analysis of the economics for overcoming the congestion.

Binding constraint information is sourced from AEMO. Historical binding constraint information is not intended to imply a prediction of constraints in the future.

Historical transfer duration curves for the last five years are included for each grid section. Grid section transfers are predominantly affected by load, generation and transfers to neighbouring zones. Figures 5.1 and 5.2 provide 2015 and 2016 zonal energy as generated into the transmission network (refer to Figure C.1 in Appendix C for generators included in each zone), transmission delivered energy to Distribution Network Service Providers (DNSPs) and direct connect customers and grid section energy transfers. Figure 5.3 provides the changes in energy transfers from 2015 to 2016. These figures assist in the explanation of differences between 2015 and 2016 grid section transfer duration curves.

Figure 5.1 2015[1] zonal electrical energy transfers (GWh)



[1] Consistent with this chapter, time periods are from April 2015 to March 2016.

Figure 5.2 2016[2] zonal electrical energy transfers (GWh)

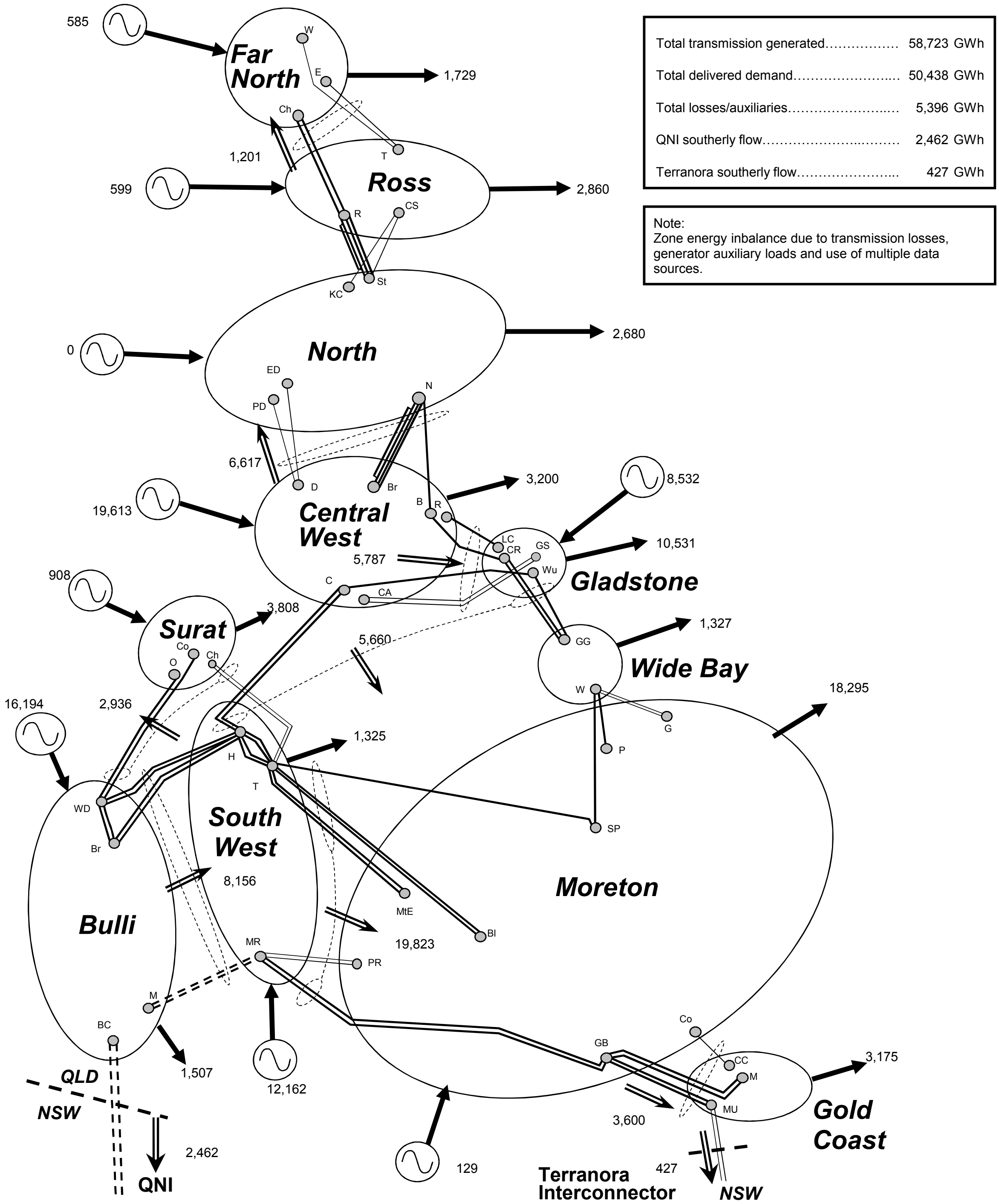
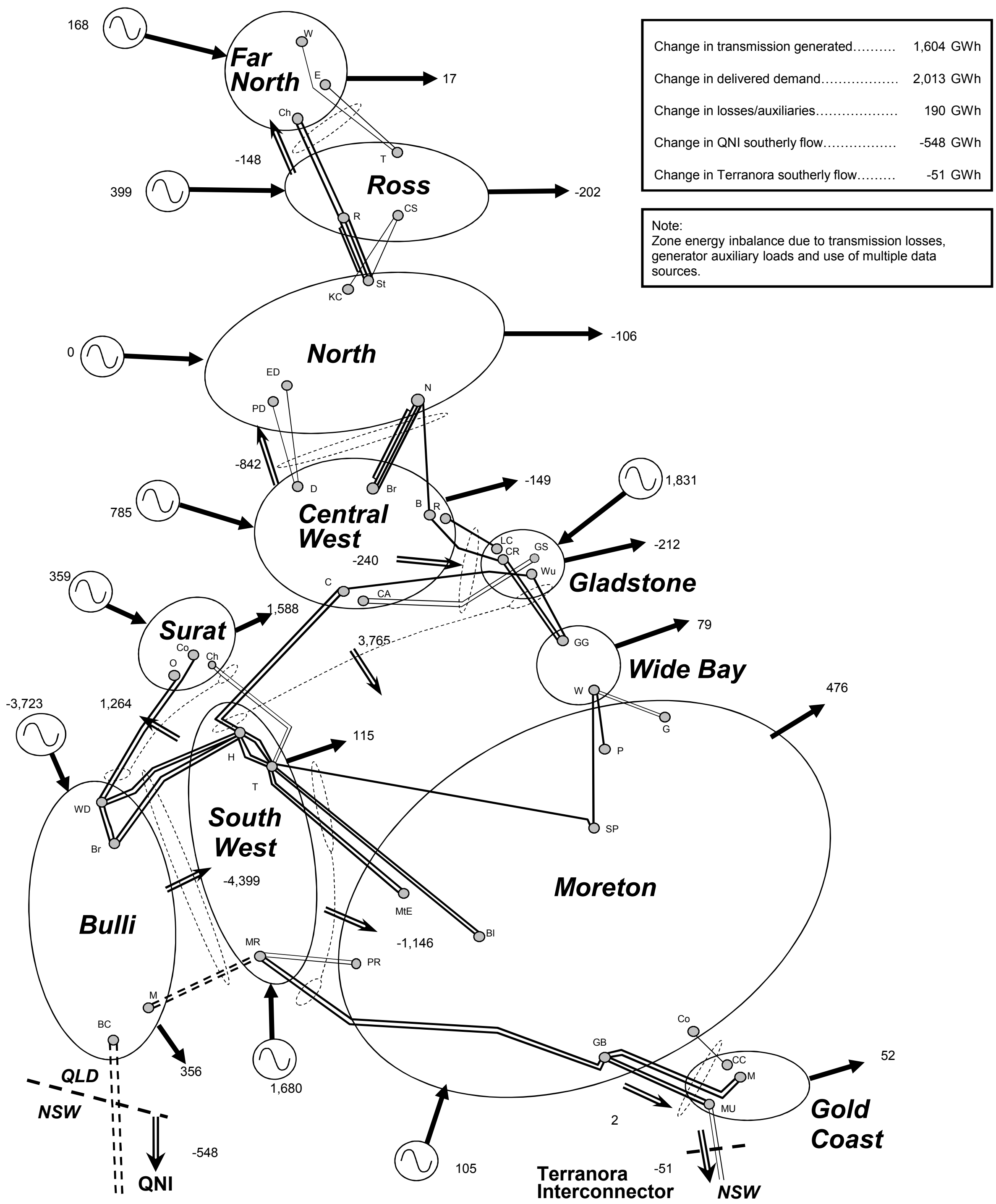


Figure 5.3 Change[3] in zonal electrical energy transfers (GWh)



3 Consistent with this chapter, time periods for the comparison are from April 2016 to March 2017 and April 2015 to March 2016.

Table C.1 in Appendix C shows power flows across each grid section at time of forecast Queensland region maximum demand, corresponding to the sample generation dispatch shown in figures C.3 to C.20. It also identifies whether the maximum power transfer across each grid section is limited by thermal plant ratings, voltage stability and/or transient stability. Power transfers across all grid sections are forecast to be within transfer capability of the network for these sample generation scenarios. This outlook is based on 50% PoE medium economic outlook demand forecast conditions.

Power flows across grid sections can be higher than shown in figures C.3 to C.20 in Appendix C at times of local area or zone maximum demands. However, transmission capability may also be higher under such conditions depending on how generation or interconnector flow varies to meet higher local demand levels.

5.5.1 Far North Queensland grid section

Maximum power transfer across the Far North Queensland (FNQ) grid section is set by voltage stability associated with an outage of a Ross to Chalumbin 275kV circuit.

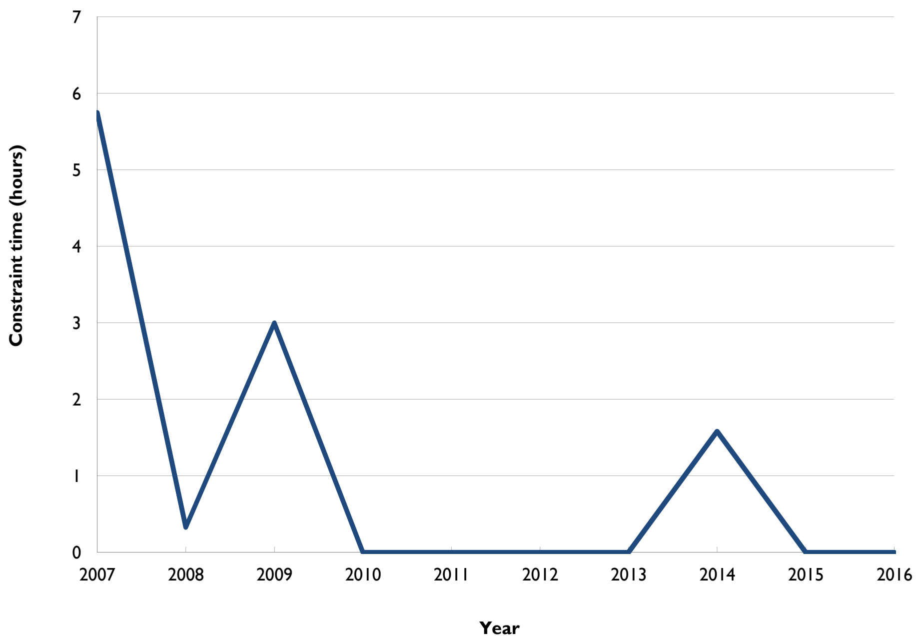
The limit equation in Table D.1 of Appendix D shows that the following variables have a significant effect on transfer capability:

- Far North zone to northern Queensland area[4] demand ratio
- Far North and Ross zones generation.

Local hydro generation reduces transfer capability but allows more demand to be securely supported in the Far North zone. This is because reactive margins increase with additional local generation, allowing further load to be delivered before reaching minimum allowable reactive margins. However, due to its distributed and reactive nature, increases in delivered demand erode reactive margins at greater rates than they were created by the additional local generation. Limiting power transfers are thereby lower with the increased local generation but a greater load can be delivered.

The FNQ grid section did not constrain operation during April 2016 to March 2017. Information pertaining to the historical duration of constrained operation for the FNQ grid section is summarised in Figure 5.4.

Figure 5.4 Historical FNQ grid section constraint times

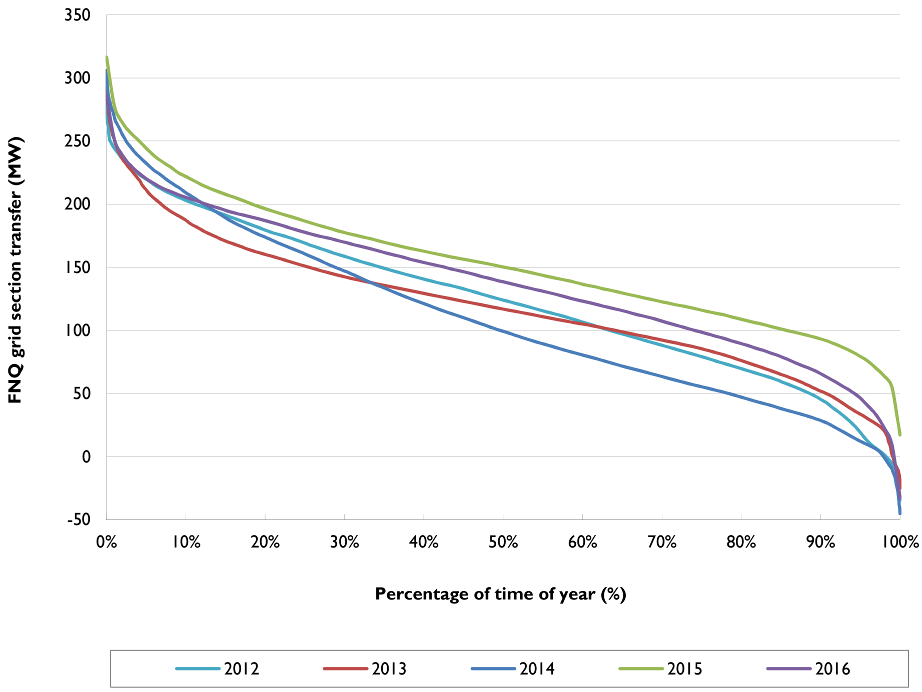


[4] Northern Queensland area is defined as the combined demand of the Far North, Ross and North zones.

Constraint durations have reduced over time due to the commissioning of various transmission projects[5]. There have been minimal constraints in this grid section since 2008.

Figure 5.5 provides historical transfer duration curves showing small annual differences in grid section transfer demands and energy. The peak flow and energy delivered to the Far North zone by the transmission network is not only dependant on the Far North zone load, but also generation from the hydro generating power stations at Barron Gorge and Kareeya. These vary depending on rainfall levels in the Far North zone. The capacity factor of the hydro generating power stations increased from approximately 30% in 2015 to approximately 40% in 2016 (refer to figures 5.1, 5.2 and 5.3).

Figure 5.5 Historical FNQ grid section transfer duration curves



No network augmentations are planned to occur as a result of network limitations across this grid section within the five-year outlook period.

5.5.2 Central Queensland to North Queensland grid section

Maximum power transfer across the Central Queensland to North Queensland (CQ-NQ) grid section may be set by thermal ratings associated with an outage of a Stanwell to Broadsound 275kV circuit, under certain prevailing ambient conditions. Power transfers may also be constrained by voltage stability limitations associated with the contingency of the Townsville gas turbine or a Stanwell to Broadsound 275kV circuit.

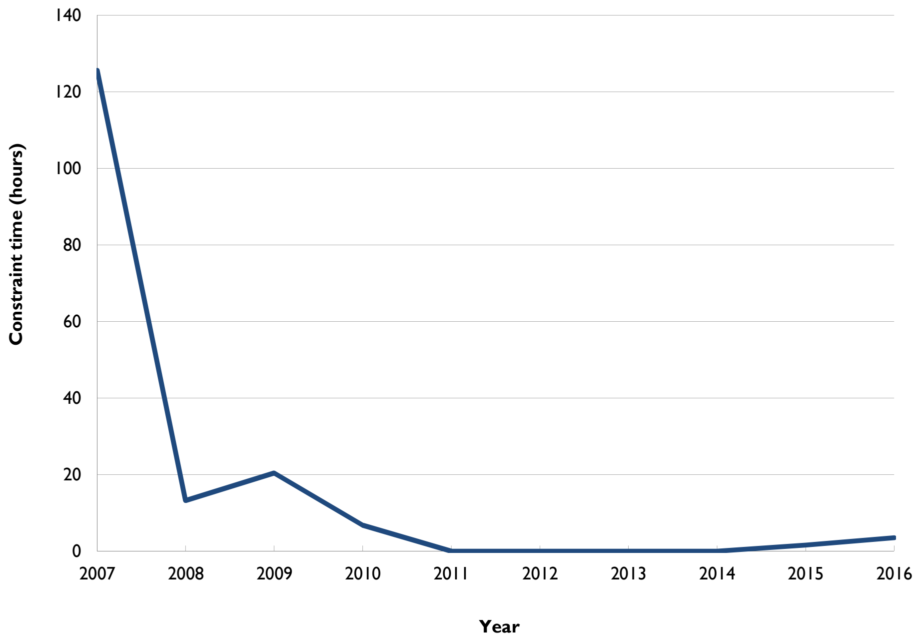
The limit equations in Table D.2 of Appendix D show that the following variables have a significant effect on transfer capability:

- level of Townsville gas turbine generation
- Ross and North zones shunt compensation levels.

[5] For example, the second Woree 275/132kV transformer commissioned in 2007/08.

Information pertaining to the historical duration of constrained operation for the CQ-NQ grid section is summarised in Figure 5.6. During 2016, the CQ-NQ grid section experienced 3.58 hours of constrained operation. These constraints were associated with the reclassification of a double circuit between Strathmore and Ross substations as credible due to increased risk during the Tropical Cyclone (TC) Debbie weather event.

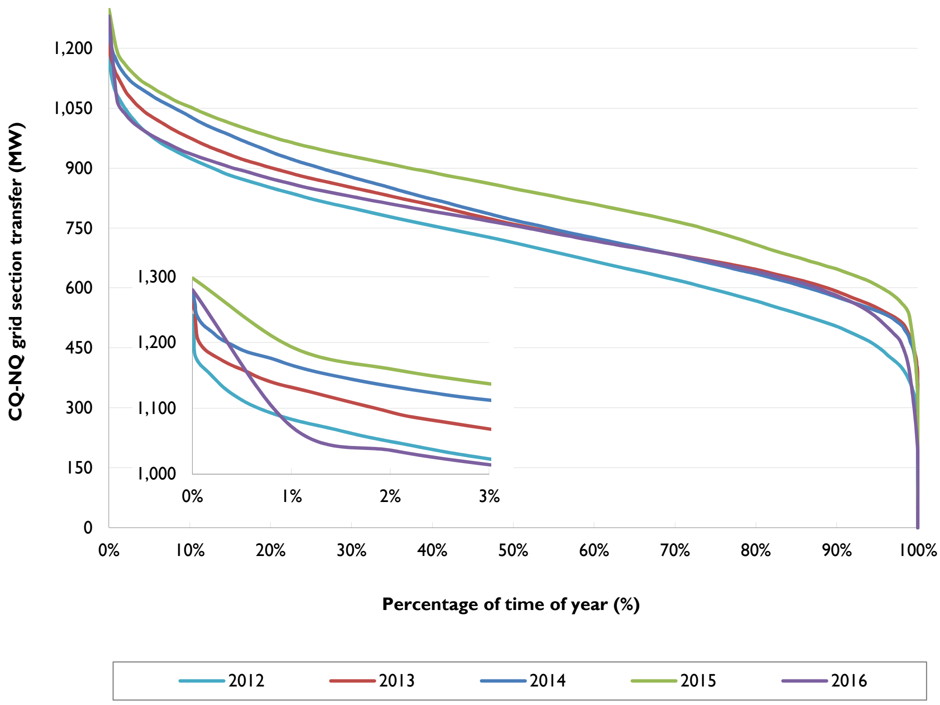
Figure 5.6 Historical CQ-NQ grid section constraint times



Historically, the majority of the constraint times were associated with thermal constraint equations ensuring operation within plant thermal ratings during planned outages. The staged commissioning of double circuit lines from Broadsound to Ross completed in 2010/11 provided increased capacity to this grid section. There have been minimal constraints in this grid section since 2008.

Figure 5.7 provides historical transfer duration curves showing small annual differences in grid section transfer demands and energy. Utilisation of the grid section was lower in 2016 compared to 2015 predominantly due to the higher capacity factor of the generators in FNQ and Ross zones (refer to figures 5.1, 5.2 and 5.3).

Figure 5.7 Historical CQ-NQ grid section transfer duration curves



Flooding associated with TC Debbie caused collapse and damage to 19 towers on one of the paralleled 275kV single circuit lines between Broadsound and Nebo. The transmission line was subsequently returned to service with a large section unparalleled. The system normal capacity of the grid section is not impacted. The damaged towers are scheduled for rectification during 2017.

The recent commitment of variable renewable electricity (VRE) generators (refer to Table 5.1) in north Queensland are expected to reduce CQ-NQ transfers, especially during daylight hours. CQ-NQ transfer duration curves in future years are expected to reflect these new transfer patterns with a downward trend as more energy is supplied locally. The development of large loads in central or northern Queensland (additional to those included in the forecasts), on the other hand, can significantly increase the levels of CQ-NQ transfers. This is discussed in Section 6.2.4.

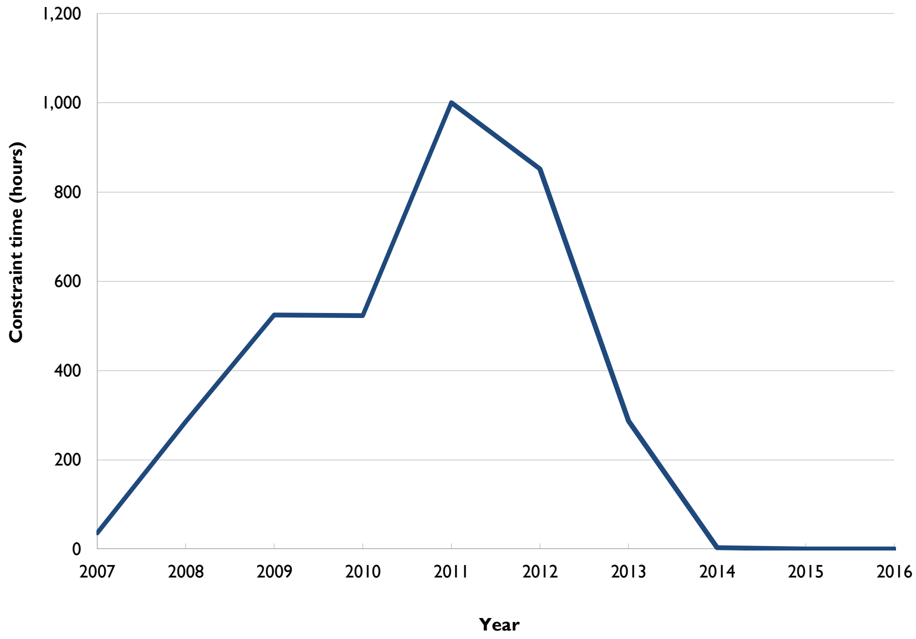
5.5.3 Gladstone grid section

Maximum power transfer across the Gladstone grid section is set by the thermal rating of the Bouldercombe to Raglan, Larcom Creek to Calliope River, Calvale to Wurdong or the Calliope River to Wurdong 275kV circuits, or the Calvale 275/132kV transformer.

If the rating would otherwise be exceeded following a critical contingency, generation is constrained to reduce power transfers. Powerlink makes use of dynamic line ratings and rates the relevant circuits to take account of real time prevailing ambient weather conditions to maximise the available capacity of this grid section and, as a result, reduce market impacts. The appropriate ratings are updated in NEMDE.

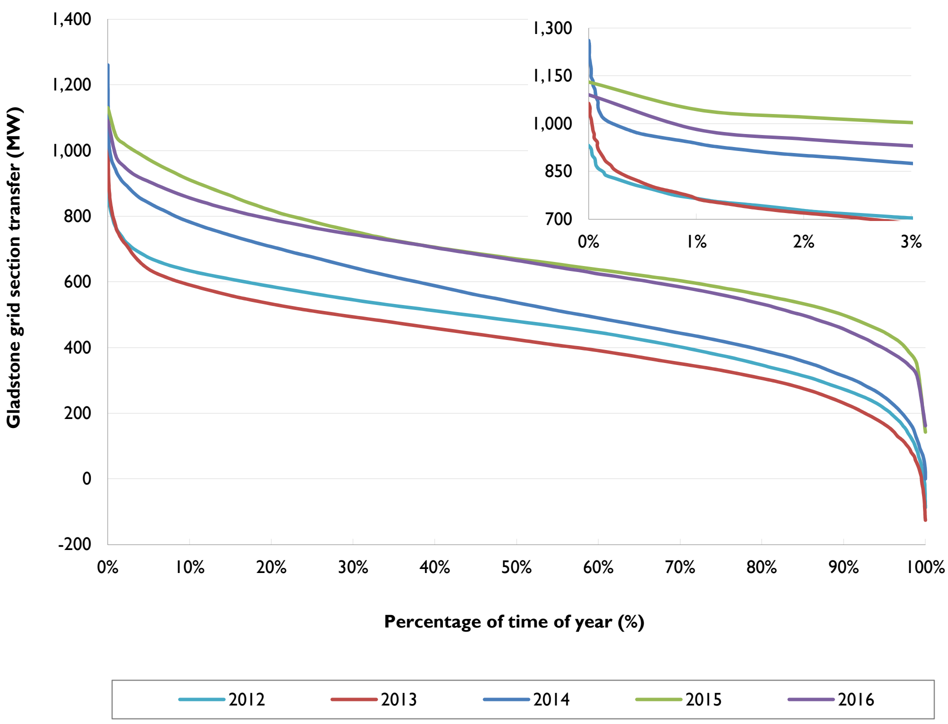
Information pertaining to the historical duration of constrained operation for the Gladstone grid section is summarised in Figure 5.8. During 2016, the Gladstone grid section experienced 0.42 hours of constrained operation.

Figure 5.8 Historical Gladstone grid section constraint times



Power flows across this grid section are highly dependent on the dispatch of generation in Central Queensland and transfers to northern and southern Queensland. Figure 5.9 provides historical transfer duration curves showing a slight decrease in utilisation in 2016 compared to 2015. This reduction in transfer is predominantly associated with a significant increase in Gladstone zone generation (refer to figures 5.1, 5.2 and 5.3).

Figure 5.9 Historical Gladstone grid section transfer duration curves



The utilisation of the Gladstone grid section is expected to increase if the newly committed generators in the north displace Gladstone zone or southern generators as this incremental power makes its way to the load in the Gladstone and/or southern Queensland zones. A project to increase the design temperature of Bouldercombe to Raglan and Larcom Creek to Calliope River 275kV transmission lines, approved by the AER under the Network Capability Incentive Parameter Action Plan (NCIPAP), will assist in relieving this congestion.

5.5.4 Central Queensland to South Queensland grid section

Maximum power transfer across the Central Queensland to South Queensland (CQ-SQ) grid section is set by transient or voltage stability following a Calvale to Halys 275kV circuit contingency.

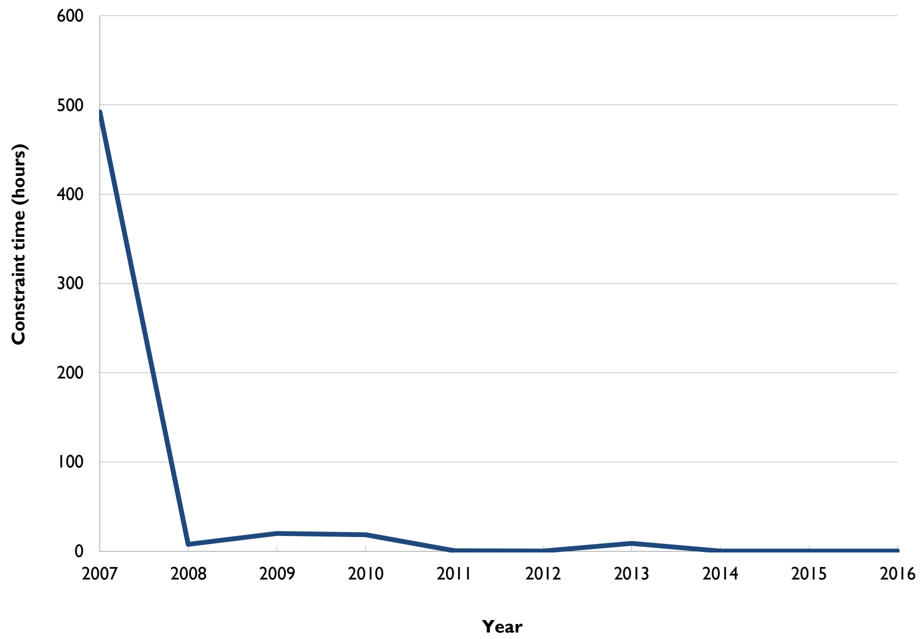
The voltage stability limit is set by insufficient reactive power reserves in the Central West and Gladstone zones following a contingency. More generating units online in these zones increase reactive power support and therefore transfer capability.

The limit equation in Table D.3 of Appendix D shows that the following variables have significant effect on transfer capability:

- number of generating units online in the Central West and Gladstone zones
- level of Gladstone Power Station generation.

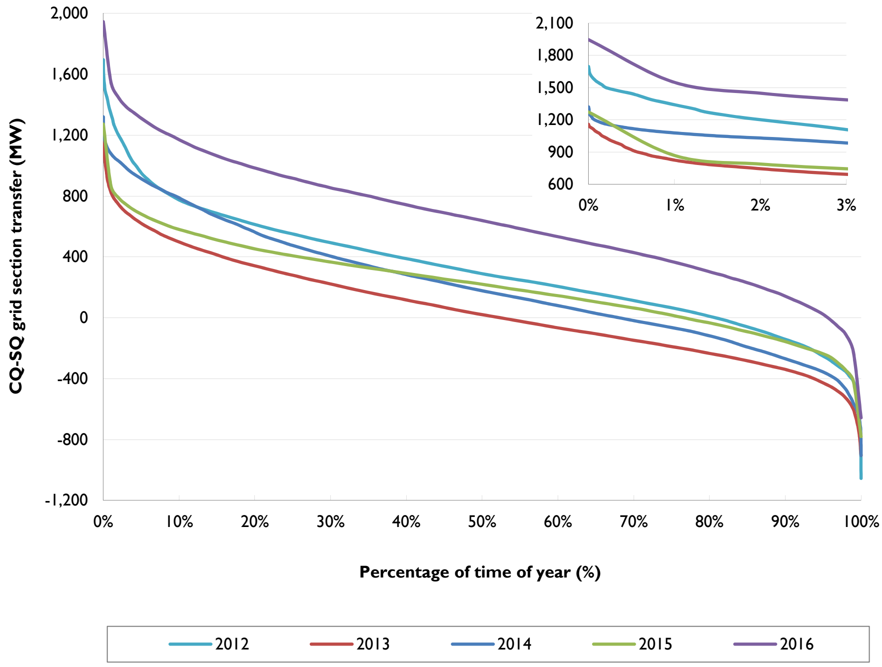
The CQ-SQ grid section did not constrain operation during April 2016 to March 2017. Information pertaining to the historical duration of constrained operation for the CQ-SQ grid section is summarised in Figure 5.10.

Figure 5.10 Historical CQ-SQ grid section constraint times



The reduction in constraint times since 2007 to near zero levels can be attributed to lower central to southern Queensland transfers. Central to southern Queensland energy transfers have seen a sharp decline following the commissioning of significant levels of generation in the South West Queensland (SWQ) area between 2006 and 2010. Figure 5.11 provides historical transfer duration curves showing a large increase in utilisation in 2016. This increase in transfer is predominantly due to a significant reduction in generation from the gas fuelled generators in the Bulli zone substituted by generation in central and north Queensland (refer to figures 5.1, 5.2 and 5.3). The utilisation of the CQ-SQ grid section is expected to further increase over time if the newly committed generators in the north displace southern generators.

Figure 5.11 Historical CQ-SQ grid section transfer duration curves



The eastern single circuit transmission lines of CQ-SQ traverse a variety of environmental conditions that have resulted in different rates of corrosion resulting in varied risk levels across the transmission lines. Depending on transmission line location, it is expected that sections of lines will be at end of technical or economic life from the next five to 10 years. This is discussed in Section 6.3.3.

5.5.5 Surat grid section

The Surat grid section was introduced in the 2014 TAPR in preparation for the establishment of the Columboola to Western Downs 275kV transmission line[6], Columboola to Wandoan South 275kV transmission line and Wandoan South and Columboola 275kV substations. These network developments were completed in September 2014 and significantly increased the supply capacity to the Surat Basin north west area.

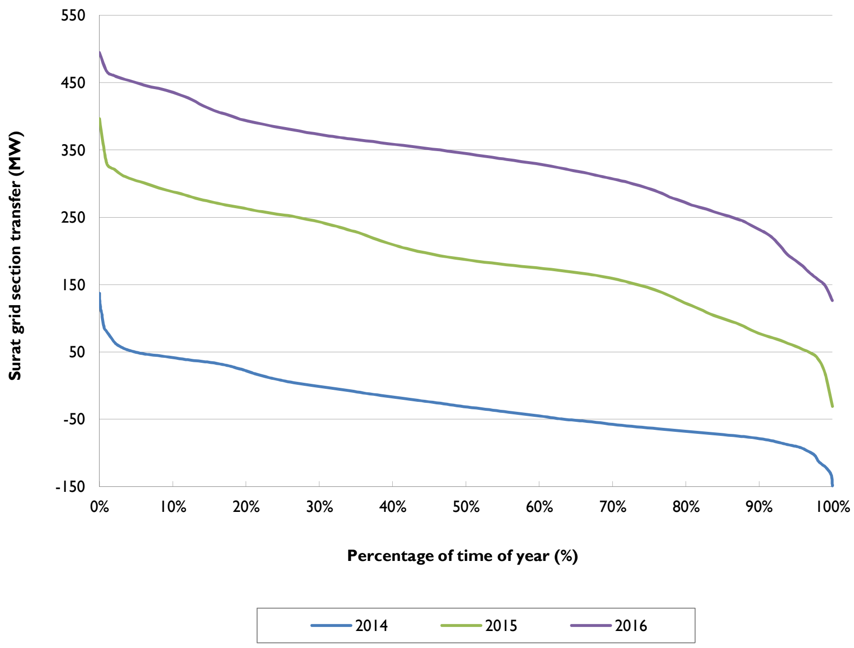
The maximum power transfer across the Surat grid section is set by voltage stability associated with insufficient reactive power reserves in the Surat zone following an outage of a Western Downs to Orana 275kV circuit. More generating units online in the zone increases reactive power support and therefore transfer capability. Local generation reduces transfer capability but allows more demand to be securely supported in the Surat zone. This is because the reduction in power transfer due to increased local generation is greater than the reduction in grid section transfer capability.

There have been no constraints recorded over the brief history of the Surat grid section.

Figure 5.12 provides the transfer duration curve since the zone's creation. Grid section transfers depict the ramping of coal seam gas (CSG) load. The zone has transformed from a net exporter to a net importer of energy.

[6] The Orana Substation is connected to one of the Columboola to Western Downs 275kV transmission lines.

Figure 5.12 Historical Surat grid section transfer duration curve



Network augmentations are not planned to occur as a result of network limitations across this grid section within the five-year outlook period.

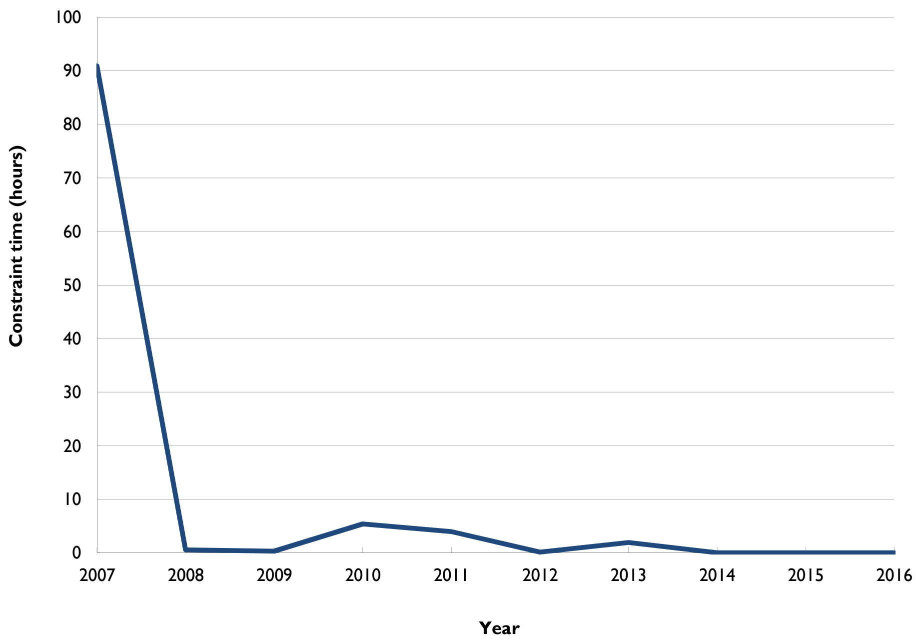
The development of large loads in Surat (additional to those included in the forecasts), without corresponding increases in generation, can significantly increase the levels of Surat grid section transfers. This is discussed in Section 6.2.4.

5.5.6 South West Queensland grid section

The SWQ grid section defines the capability of the transmission network to transfer power from generating stations located in the Bulli zone and northerly flow on QNI to the rest of Queensland. The grid section is not expected to impose limitations to power transfer under intact system conditions with existing levels of generating capacity.

The SWQ grid section did not constrain operation during April 2016 to March 2017. Information pertaining to the historical duration of constrained operation for the SWQ grid section is summarised in Figure 5.13.

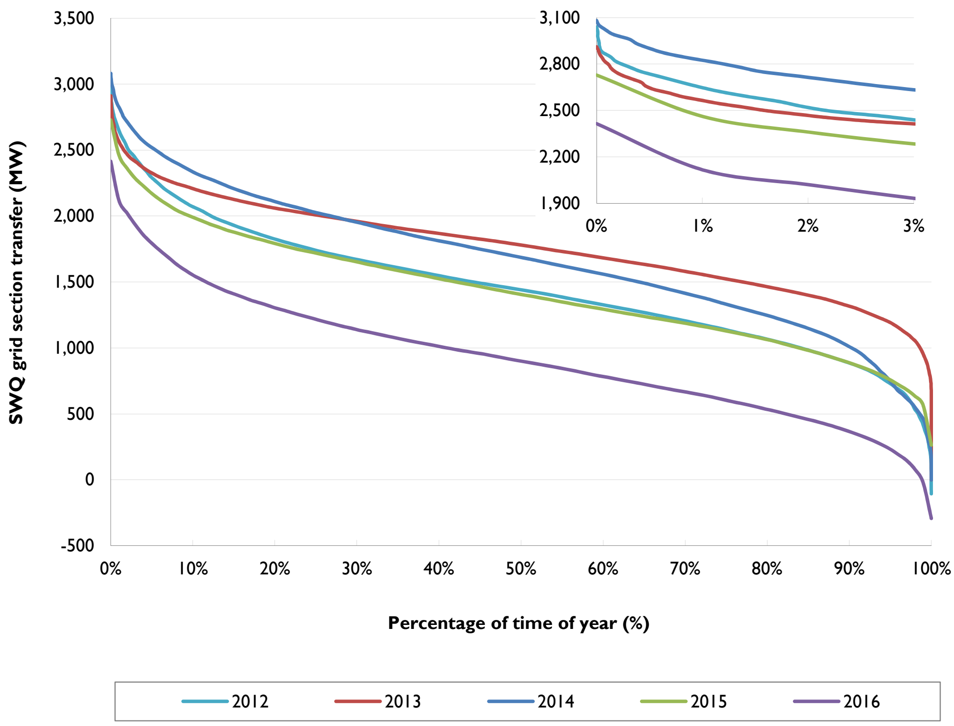
Figure 5.13 Historical SWQ grid section constraint times



The commissioning of significant levels of base load generation in the SWQ area between 2006 and 2010 increased the utilisation of this grid section. The majority of constraint times in the 2007 period were due to thermal constraint equations ensuring operation within plant thermal ratings during planned outages.

Figure 5.14 provides historical transfer duration curves showing a reduction in 2016 energy transfer to levels compared to 2015. Reductions in gas fuelled generation in the Bulli zone, increases in SW zone generation and CQ-SQ transfers (refer to figures 5.1, 5.2 and 5.3) are predominantly responsible for the reduction in SWQ utilisation.

Figure 5.14 Historical SWQ grid section transfer duration curves



Network augmentations are not planned to occur as a result of network limitations across this grid section within the five-year outlook period.

5.5.7 Tarong grid section

Maximum power transfer across the Tarong grid section is set by voltage stability associated with the loss of a Calvale to Halys 275kV circuit. The limitation arises from insufficient reactive power reserves in southern Queensland.

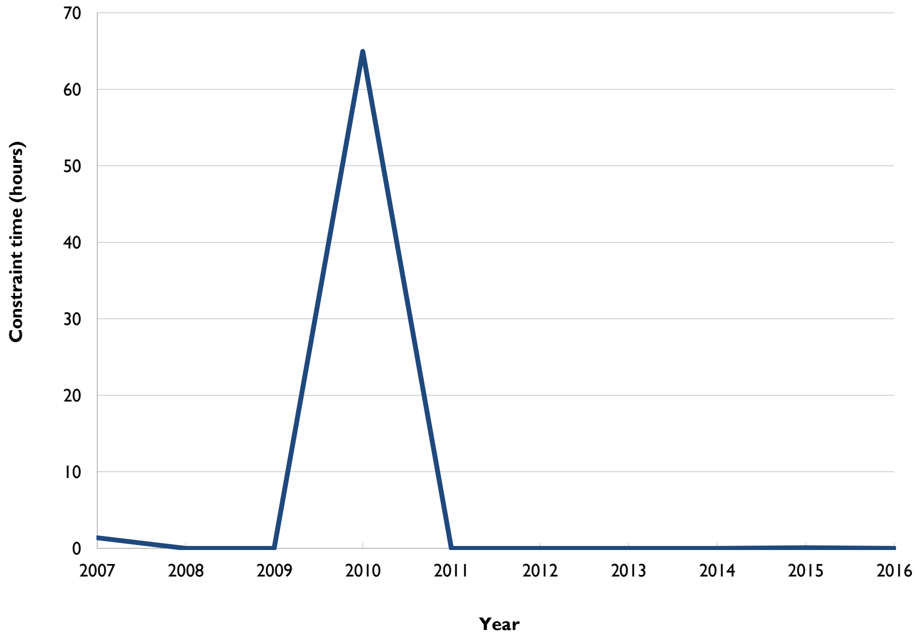
Limit equations in Table D.4 of Appendix D show that the following variables have a significant effect on transfer capability:

- QNI transfer and South West and Bulli zones generation
- level of Moreton zone generation
- Moreton and Gold Coast zones capacitive compensation levels.

Any increase in generation west of this grid section, with a corresponding reduction in generation north of the grid section, reduces the CQ-SQ power flow and increases the Tarong limit. Increasing generation east of the grid section reduces the transfer capability, but increases the overall amount of supportable South East Queensland (SEQ) demand. This is because reactive margins increase with additional local generation, allowing further load to be delivered before reaching minimum allowable reactive margins. However, due to its distributed and reactive nature, increases in delivered demand erode reactive margins at greater rates than they were created by the additional local generation. Limiting power transfers are thereby lower with the increased local generation but a greater load can be delivered.

The Tarong grid section did not constrain during April 2016 to March 2017. Information pertaining to the historical duration of constrained operation for the Tarong grid section is summarised in Figure 5.15.

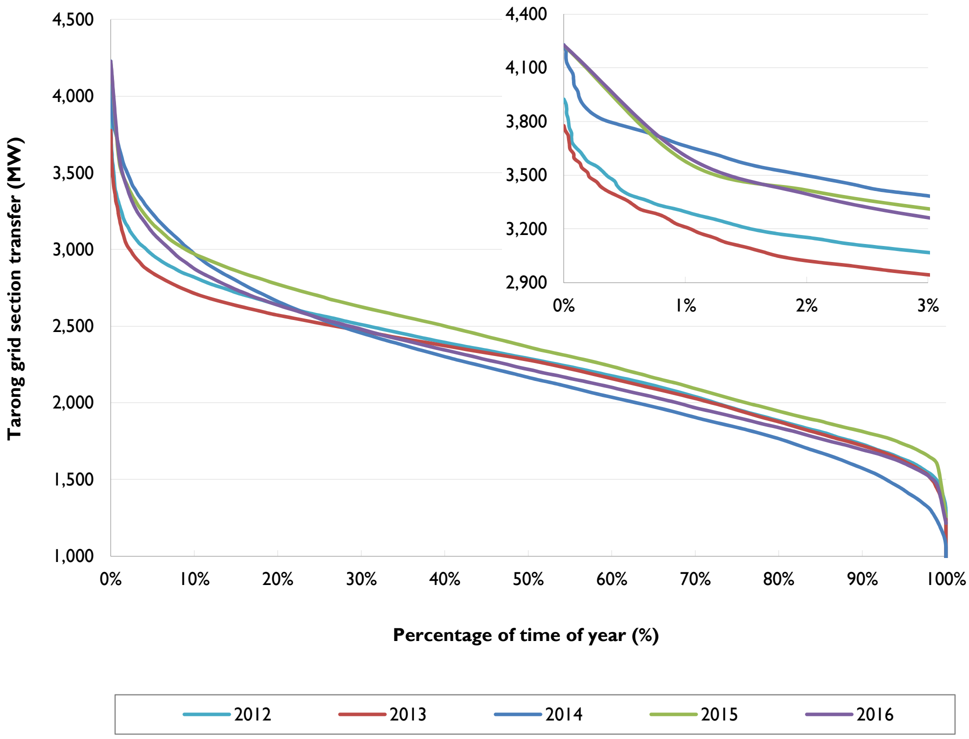
Figure 5.15 Historical Tarong grid section constraint times



Constraint times have been minimal over the last 10 years, with the exception of 2010/11 where constraint times are associated with line outages as a result of severe weather events in January 2011.

Figure 5.16 provides historical transfer duration curves showing small annual differences in grid section transfer demands. The increase in transfer between 2014 and 2015 is predominantly attributed to Swanbank E being placed into cold storage in December 2014. The 2016 trace reflects high transfers associated with high summer demand (refer to figures 5.1, 5.2 and 5.3).

Figure 5.16 Historical Tarong grid section transfer duration curves



Network augmentations are not planned to occur as a result of network limitations across this grid section within the five-year outlook period.

5.5.8 Gold Coast grid section

Maximum power transfer across the Gold Coast grid section is set by voltage stability associated with the loss of a Greenbank to Molendinar 275kV circuit, or Greenbank to Mudgeeraba 275kV circuit.

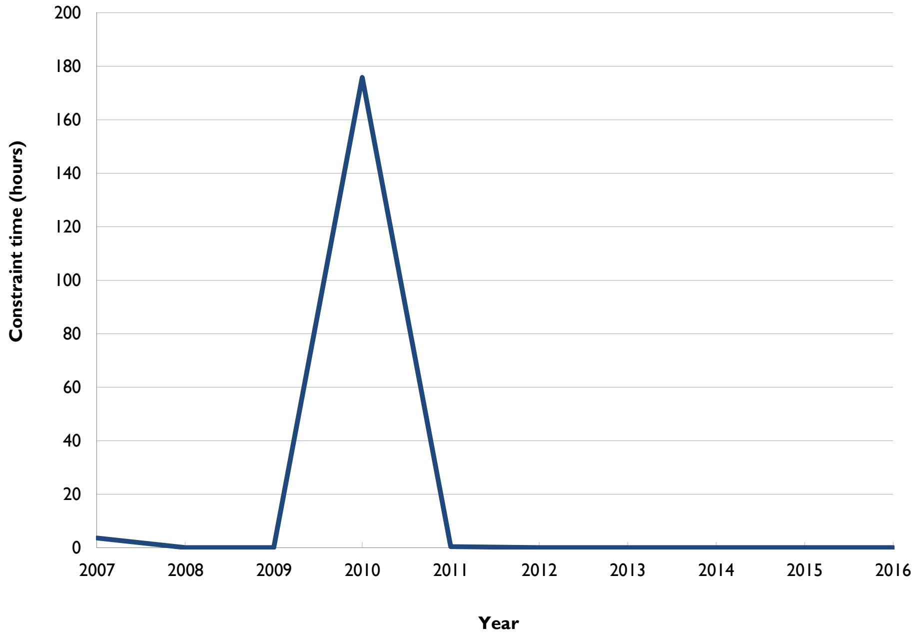
The limit equation in Table D.5 of Appendix D shows that the following variables have a significant effect on transfer capability:

- number of generating units online in Moreton zone
- level of Terranora Interconnector transmission line transfer
- Moreton and Gold Coast zones capacitive compensation levels
- Moreton zone to the Gold Coast zone demand ratio.

Reducing southerly flow on Terranora Interconnector reduces transfer capability, but increases the overall amount of supportable Gold Coast demand. This is because reactive margins increase with reductions in southerly Terranora Interconnector flow, allowing further load to be delivered before reaching minimum allowable reactive margins. However, due to its distributed and reactive nature, increases in delivered demand erode reactive margins at greater rates than they were created by the reduction in Terranora Interconnector southerly transfer. Limiting power transfers are thereby lower with reduced Terranora Interconnector southerly transfer but a greater load can be delivered.

The Gold Coast grid section did not constrain operation during April 2015 to March 2016. Information pertaining to the historical duration of constrained operation for the Gold Coast grid section is summarised in Figure 5.17.

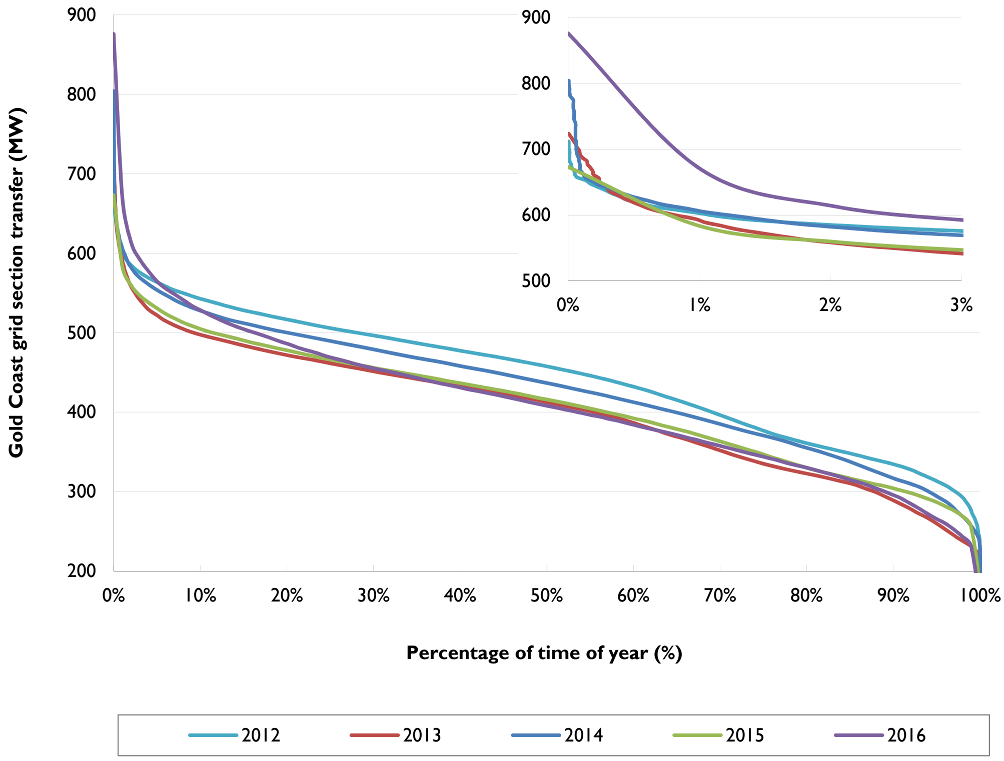
Figure 5.17 Historical Gold Coast grid section constraint times



Powerlink delivered increases to the Gold Coast grid section transfer capacity with projects including the establishment of the Greenbank Substation in 2006/07 and Greenbank SVC in 2008/09. Constraint times have been minimal since 2007, with the exception of 2010 where constraint times are associated with the planned outage of one of the 275kV Greenbank to Mudgeeraba feeders.

Figure 5.18 provides historical transfer duration curves showing changes in grid section transfer demands and energy in line with changes in transfer to northern New South Wales (NSW) and changes in Gold Coast loads. Gold Coast zone demand was higher in 2016 compared to 2015 (refer to figures 5.1, 5.2 and 5.3).

Figure 5.18 Historical Gold Coast grid section transfer duration curves



The condition of two 275/110kV transformers at Mudgeeraba Substation requires action within the five-year outlook. An approved project is underway to replace one of transformer. This is discussed in Section 4.2.8.

5.5.9 QNI and Terranora Interconnector

The transfer capability across QNI is limited by voltage stability, transient stability, oscillatory stability, and line thermal rating considerations. The capability across QNI at any particular time is dependent on a number of factors, including demand levels, generation dispatch, status and availability of transmission equipment, and operating conditions of the network.

AEMO publish an annual NEM Constraint Report which includes a chapter examining each of the NEM interconnectors, including QNI and Terranora Interconnector. Information pertaining to the historical duration of constrained operation for QNI and Terranora Interconnector is contained in these Annual NEM Constraint Reports. The NEM Constraint Report can be found on AEMO's website.

For intact system operation, the southerly transfer capability of QNI is most likely to be set by the following:

- transient stability associated with transmission faults near the Queensland border
- transient stability associated with the trip of a smelter potline load in Queensland
- transient stability associated with transmission faults in the Hunter Valley, NSW
- transient stability associated with a fault on the Hazelwood to South Morang 500kV transmission line in Victoria
- thermal capacity of the 330kV transmission network between Armidale and Liddell in NSW
- oscillatory stability upper limit of 1,200MW.

For intact system operation, the combined northerly transfer capability of QNI and Terranora Interconnector is most likely to be set by the following:

- transient and voltage stability associated with transmission line faults in NSW
- transient stability and voltage stability associated with loss of the largest generating unit in Queensland
- thermal capacity of the 330kV and 132kV transmission network within northern NSW
- oscillatory stability upper limit of 700MW.

In 2014, Powerlink and TransGrid completed a Regulatory Investment Test for Transmission (RIT-T) consultation which described the outcomes of a detailed technical and economic assessment into the upgrade of QNI. This is discussed further in Section 6.5.2.

AEMO's 2016 National Transmission Development Plan (NTNDP) indicated net positive market benefits in increasing the capability of QNI from 2026/27. This is discussed further in Section 6.5.2.

5.6 Zone performance

This section presents, where applicable, a summary of:

- the capability of the transmission network to deliver 2016 loads
- historical zonal transmission delivered loads
- intra-zonal system normal constraints
- double circuit transmission lines categorised as vulnerable by AEMO
- Powerlink's management of high voltages associated with light load conditions.

Double circuit transmission lines that experience a lightning trip of all phases of both circuits are categorised by AEMO as vulnerable. A double circuit transmission line in the vulnerable list is eligible to be reclassified as a credible contingency event during a lightning storm if a cloud to ground lightning strike is detected close to the line. A double circuit transmission line will remain on the vulnerable list until it is demonstrated that the asset characteristics have been improved to make the likelihood of a double circuit lightning trip no longer reasonably likely to occur or until the Lightning Trip Time Window (LTTW) from the last double circuit lightning trip. The LTTW is three years for a single double circuit trip event or five years where multiple double circuit trip events have occurred during the LTTW.

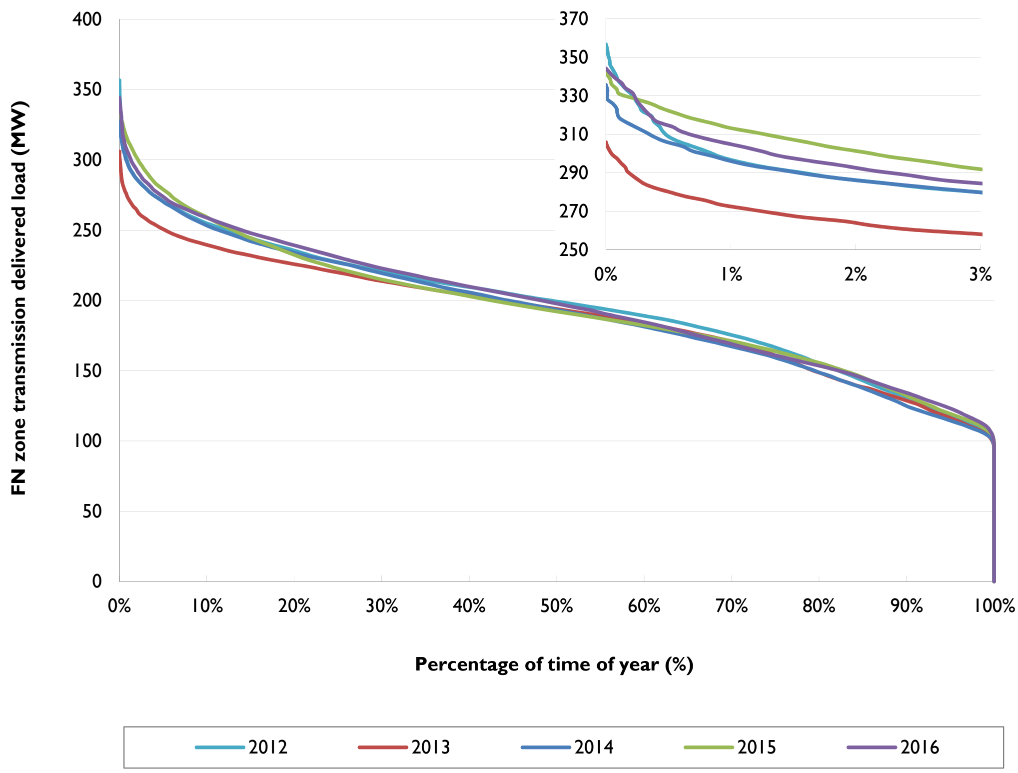
5.6.1 Far North zone

The Far North zone experienced no load loss for a single network element outage during 2016.

The Far North zone contains no scheduled/semi-scheduled embedded generators or significant non-scheduled embedded generators as defined in Figure 2.4.

Figure 5.19 provides historical transmission delivered load duration curves for the Far North zone. Energy delivered from the transmission network has increased by 1.0% between 2015 and 2016. The maximum transmission delivered demand in the zone was 344MW which is below the highest maximum demand over the last five years of 357MW set in 2012.

Figure 5.19 Historical Far North zone transmission delivered load duration curves



As a result of double circuit outages associated with lightning strikes, AEMO have included Chalumbin to Turkinje 132kV in the vulnerable list. This double circuit tripped due to lightning in January 2016.

High voltages associated with light load conditions are managed with existing reactive sources. The need for voltage control devices increased with the reinforcements of the Strathmore to Ross 275kV double circuit transmission line and the replacement of the coastal 132kV transmission lines between Yabulu South and Woree substations. Powerlink relocated a 275kV reactor from Braemar to Chalumbin Substation in April 2013. Generation developments in the Braemar area resulted in underutilisation of the reactor, making it possible to redeploy. No additional reactive sources are required in the Far North zone within the five-year outlook period for the control of high voltages.

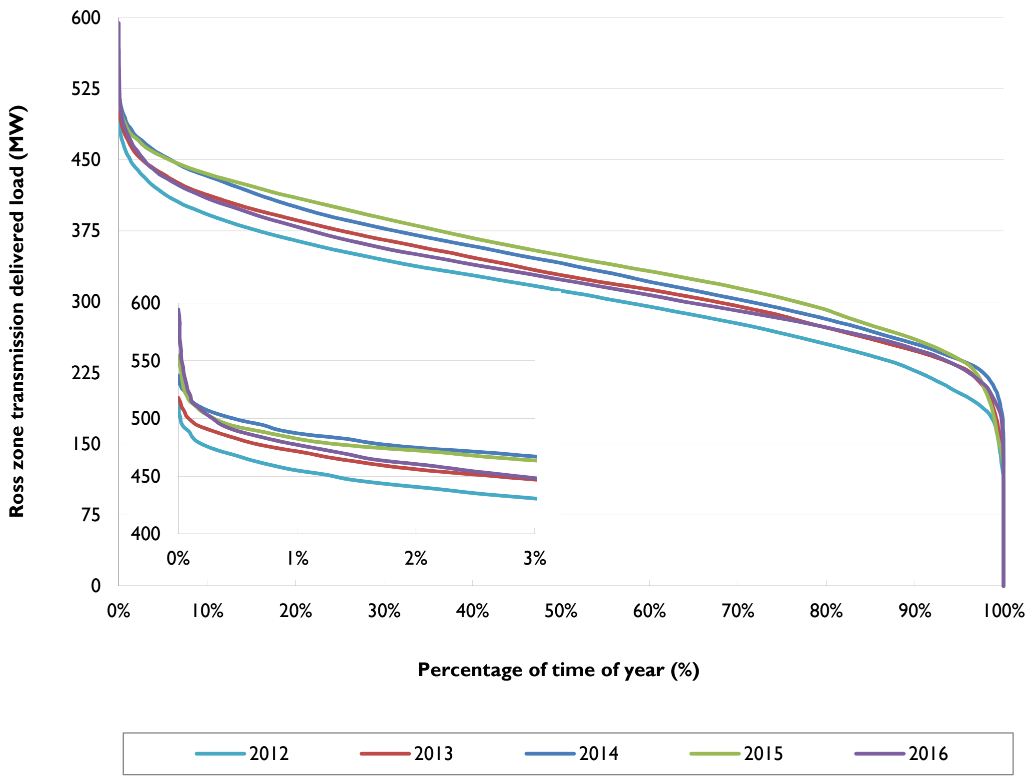
5.6.2 Ross zone

The Ross zone experienced no load loss for a single network element outage during 2016.

The Ross zone includes the scheduled embedded Townsville Power Station 66kV component and the significant non-scheduled embedded generator at Pioneer Mill as defined in Figure 2.4. These embedded generators provided approximately 309GWh during 2016.

Figure 5.20 provides historical transmission delivered load duration curves for the Ross zone. Energy delivered from the transmission network has reduced by 6.6% between 2015 and 2016 predominantly due to the increase in embedded generation. The peak transmission delivered demand in the zone was 594MW which is the highest maximum demand for the zone.

Figure 5.20 Historical Ross zone transmission delivered load duration curves



As a result of double circuit outages associated with lightning strikes, AEMO have included the Ross to Chalumbin 275kV double circuit transmission line in the vulnerable list. This double circuit tripped due to lightning in January 2015.

High voltages associated with light load conditions are managed with existing reactive sources. Two tertiary connected reactors at Ross Substation were replaced by a bus reactor in August 2015.

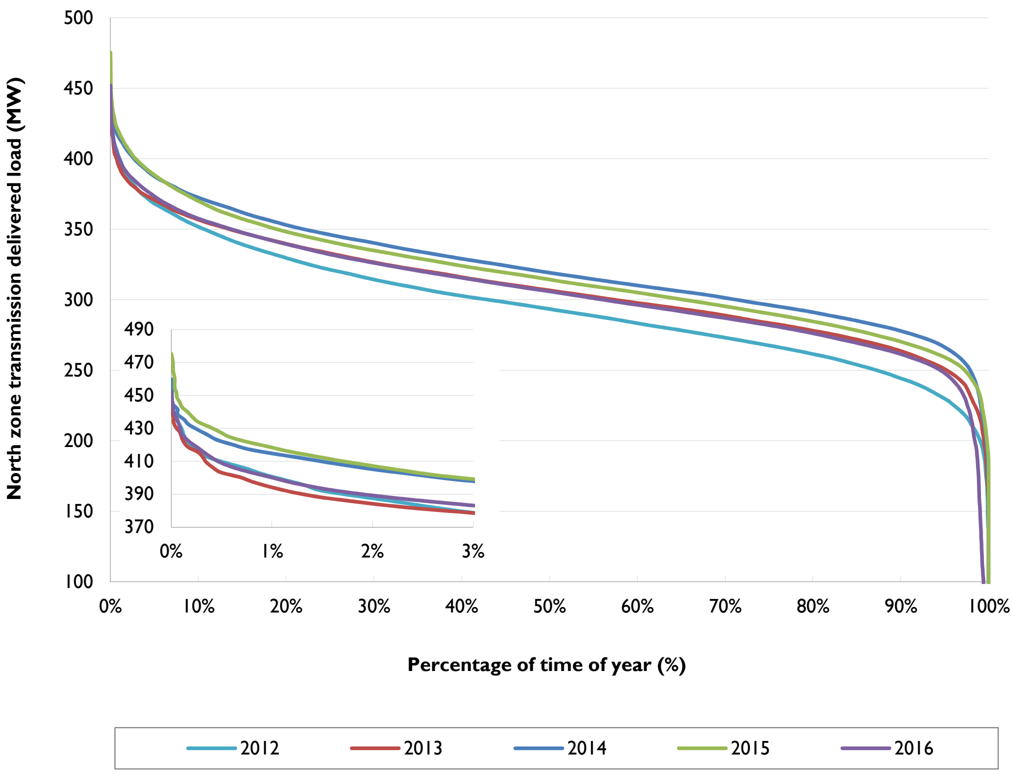
5.6.3 North zone

The North zone experienced no load loss for a single network element outage during 2016.

The North zone includes the scheduled embedded Mackay generator and significant non-scheduled embedded generators Moranbah North, Moranbah and Racecourse Mill as defined in Figure 2.4. These embedded generators provided approximately 679GWh during 2016.

Figure 5.21 provides historical transmission delivered load duration curves for the North zone. Energy delivered from the transmission network has reduced by 3.8% between 2015 and 2016 predominantly due to the increase in embedded generation. The peak transmission delivered demand in the zone was 452MW which is below the highest maximum demand over the last five years of 475MW set in 2015.

Figure 5.21 Historical North zone transmission delivered load duration curves



As a result of double circuit outages associated with lightning strikes, AEMO include the following double circuits in the North zone in the vulnerable list:

- Collinsville to Proserpine 132kV double circuit transmission line, last tripped February 2016
- Collinsville North to Stony Creek and Collinsville North to Newlands 132kV double circuit transmission line last tripped February 2016
- Moranbah to Goonyella Riverside 132kV double circuit transmission line, last tripped December 2014.

High voltages associated with light load conditions are managed with existing reactive sources. A Braemar 275kV reactor was relocated to replace two transformer tertiary connected reactors decommissioned due to condition at Nebo Substation in August 2013. Generation developments in the Braemar area resulted in underutilisation of the reactor, making it possible to redeploy. No additional reactive sources are required in the North zone within the five-year outlook period for the control of high voltages.

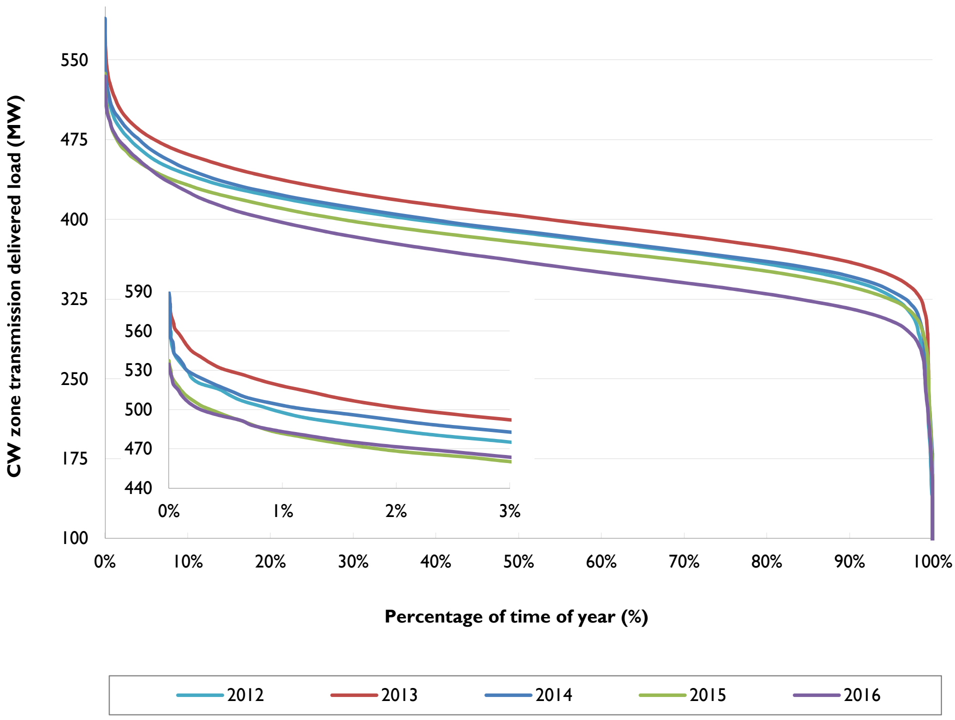
5.6.4 Central West zone

The Central West zone experienced no load loss for a single network element outage during 2016.

The Central West zone includes the scheduled embedded Barcaldine generator and significant non-scheduled embedded generators Barcaldine SF, German Creek and Oaky Creek as defined in Figure 2.4. These embedded generators provided approximately 439GWh during 2016.

Figure 5.22 provides historical transmission delivered load duration curves for the Central West zone. Energy delivered from the transmission network has reduced by 4.5% between 2015 and 2016. The peak transmission delivered demand in the zone was 535MW which is below the highest maximum demand over the last five years of 589MW set in 2014.

Figure 5.22 Historical Central West zone transmission delivered load duration curves



As a result of double circuit outages associated with lightning strikes, AEMO include the Bouldercombe to Rockhampton and Bouldercombe to Egans Hill 132kV double circuit transmission line in the vulnerable list. This double circuit tripped due to lightning in February 2016.

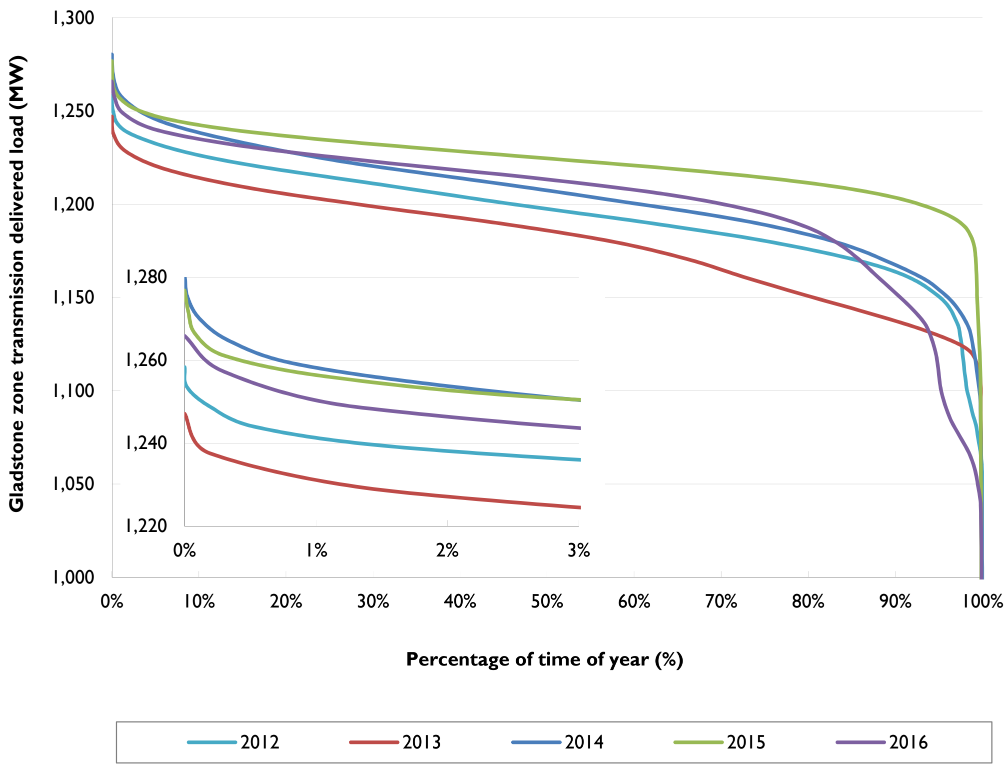
5.6.5 Gladstone zone

The Gladstone zone experienced no load loss for a single network element outage during 2016.

The Gladstone zone contains no scheduled/semi-scheduled embedded generators or significant non-scheduled embedded generators as defined in Figure 2.4.

Figure 5.23 provides historical transmission delivered load duration curves for the Gladstone zone. Energy delivered from the transmission network has reduced by 2.0% between 2015 and 2016. The peak transmission delivered demand in the zone was 1,266MW which is below the highest maximum demand over the last five years of 1,280MW set in 2014.

Figure 5.23 Historical Gladstone zone transmission delivered load duration curves

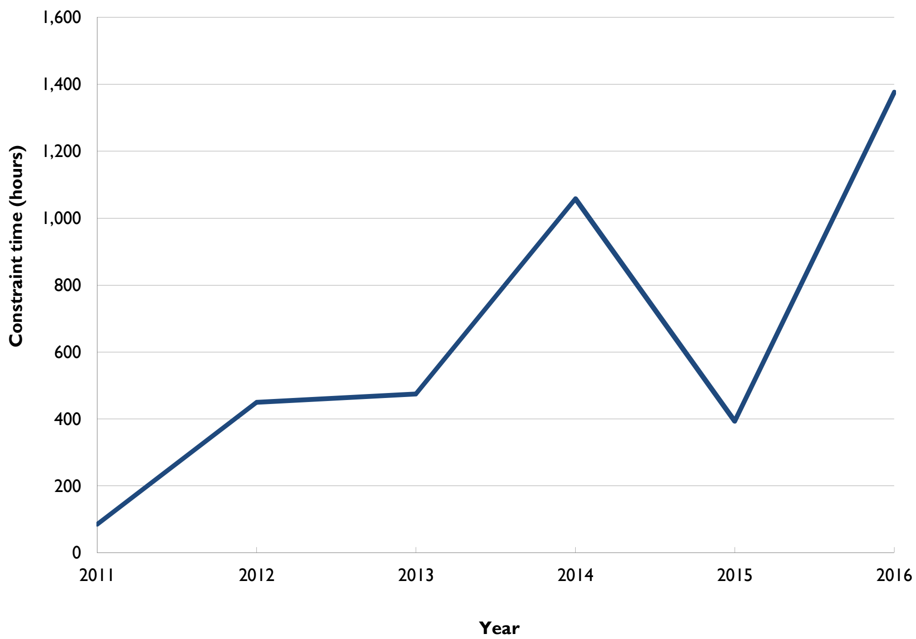


Constraints occur within the Gladstone zone under intact network conditions. These constraints are associated with maintaining power flows within the continuous current rating of a 132kV feeder bushing within Boyne Smelters Limited's substation. The constraint limits generation from Gladstone Power Station, mainly from the units connected at 132kV. AEMO identify this constraint by constraint identifier Q>NIL_BI_FB. This constraint was implemented in AEMO's market system from September 2011. During the 2016 period, 1,377 hours were recorded against this constraint.

A project was considered by Powerlink and AEMO under the NCIPAP to address this congestion. The project was found not to be economically feasible at this time.

Information pertaining to the historical duration of constrained operation due to this constraint is summarised in Figure 5.24. The trend is reflective of the operation of the two 132kV connected Gladstone Power Station units. The annual energy production from Gladstone PS 132kV connected units in the 2016 period was the highest in the six year period.

Figure 5.24 Historical Q>NIL_BI_FB constraint times



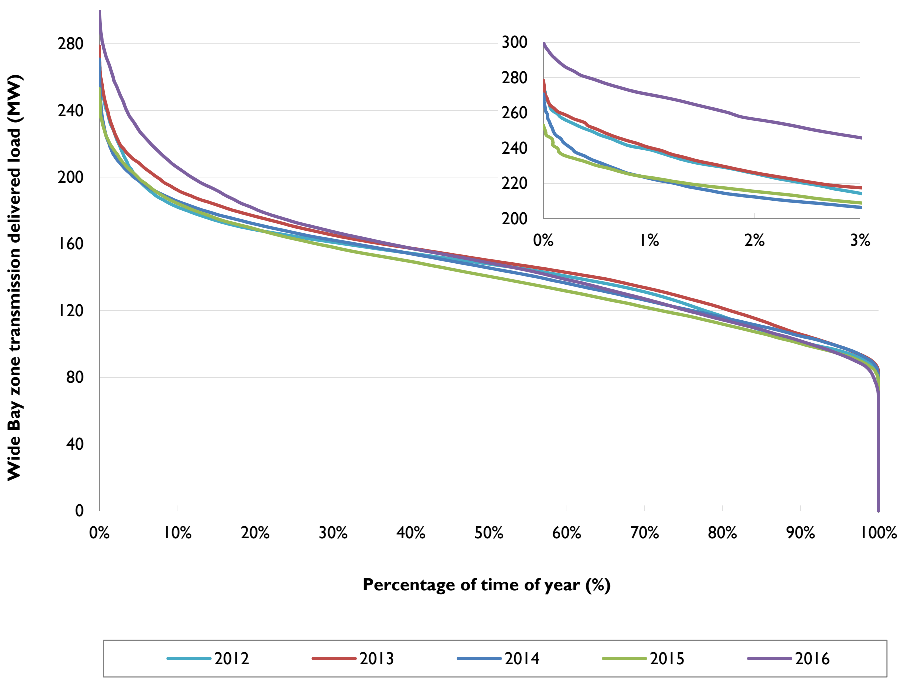
5.6.6 Wide Bay zone

The Wide Bay zone experienced no load loss for a single network element outage during 2016.

The Wide Bay zone includes the non-scheduled embedded Isis Central Sugar Mill as defined in Figure 2.4. This embedded generator provided approximately 23GWh during 2016.

Figure 5.25 provides historical transmission delivered load duration curves for the Wide Bay zone. Energy delivered from the transmission network increased by 6.4% between 2015 and 2016 predominantly due to summer 2016/17 being hot and long lasting (refer to Section 2.1). The peak transmission delivered demand in the zone was 300MW which is the highest maximum demand over the last five years.

Figure 5.25 Historical Wide Bay zone transmission delivered load duration curves



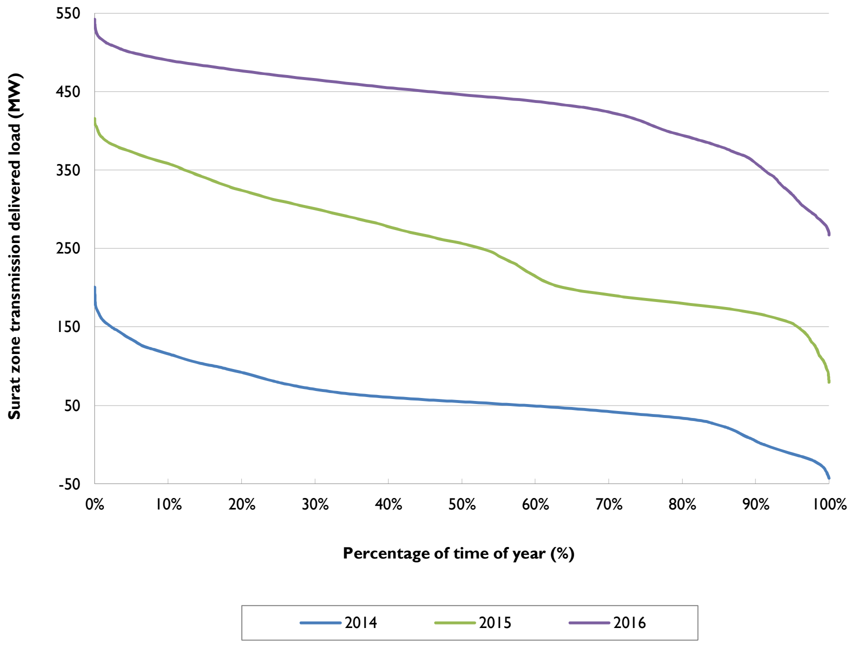
5.6.7 Surat zone

The Surat zone experienced no load loss for a single network element outage during 2016.

The Surat zone includes the scheduled embedded Roma generator as defined in Figure 2.4. This embedded generator provided approximately 71GWh during 2016.

The Surat zone was introduced in the 2014 TAPR, Figure 5.26 provides transmission delivered load duration curve since its introduction. The curves reflect the ramping of CSG load in the zone.

Figure 5.26 Historical Surat zone transmission delivered load duration curves



As a result of double circuit outages associated with lightning strikes, AEMO include the following double circuits in the Surat zone in the vulnerable list:

- Chinchilla to Columboola 132kV double circuit transmission line, last tripped October 2015
- Tarong to Chinchilla 132kV double circuit transmission line, last tripped March 2015.

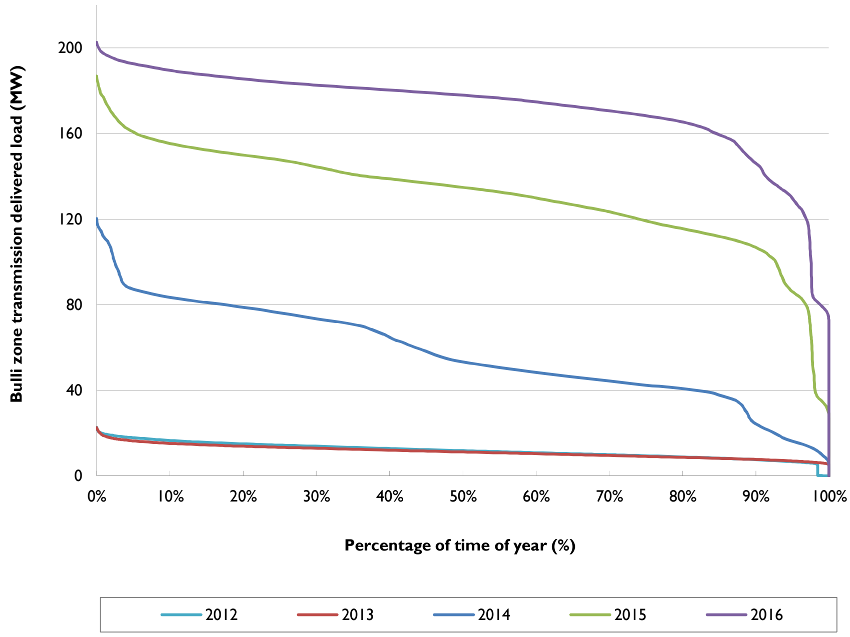
5.6.8 Bulli zone

The Bulli zone experienced no load loss for a single network element outage during 2016.

The Bulli zone contains no scheduled/semi-scheduled embedded generators or significant non-scheduled embedded generators as defined in Figure 2.4.

Figure 5.27 provides historical transmission delivered load duration curves for the Bulli zone. Energy delivered from the transmission network has increased by approximately 30.9% between 2015 and 2016. The peak transmission delivered demand in the zone was 203MW. The significant increase is due to the ramping up of CSG load in the zone.

Figure 5.27 Historical Bulli zone transmission delivered load duration curves



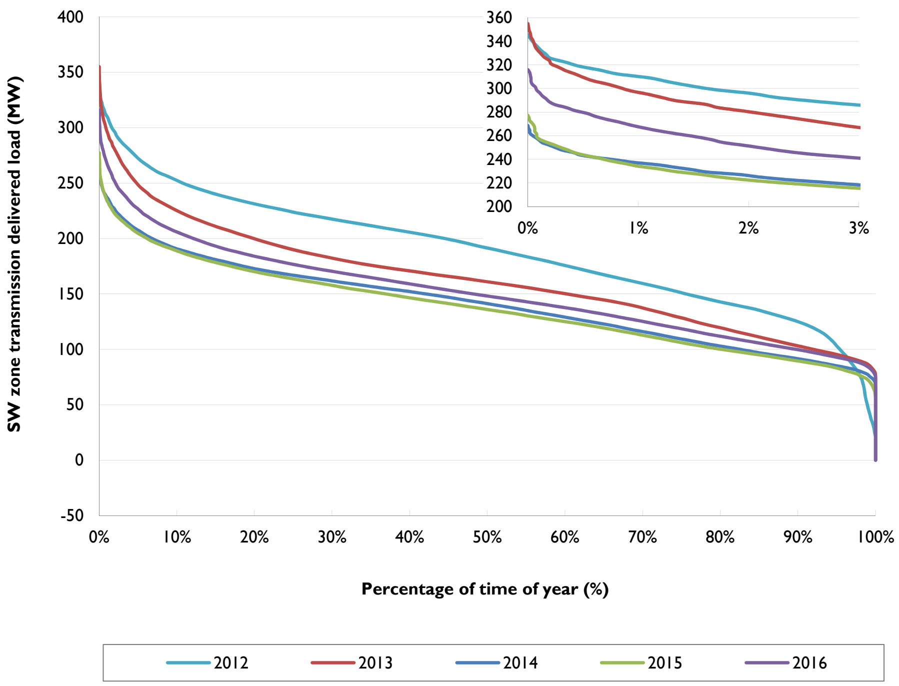
5.6.9 South West zone

The South West zone experienced no load loss for a single network element outage during 2016.

The South West zone includes the significant non-scheduled embedded Daandine Power Station as defined in Figure 2.4. This embedded generator provided approximately 241GWh during 2016.

Figure 5.28 provides historical transmission delivered load duration curves for the South West zone. Energy delivered from the transmission network has increased by 9.5% between 2015 and 2016. The peak transmission delivered demand in the zone was 316MW.

Figure 5.28 Historical South West zone transmission delivered load duration curves



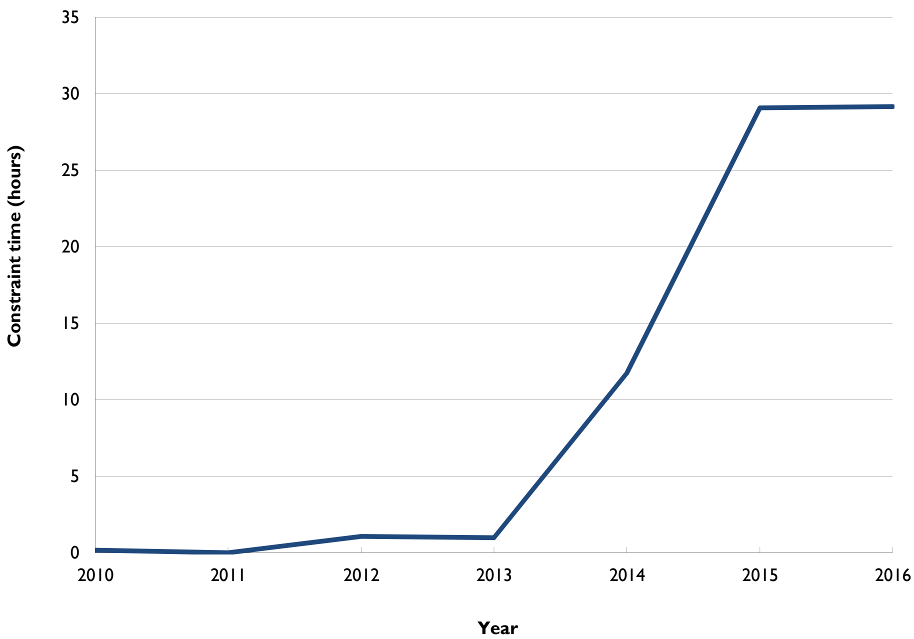
Constraints occur within the South West zone under intact network conditions. These constraints are associated with maintaining power flows of the 110kV transmission lines between Tangkam and Middle Ridge substations within the feeder's thermal ratings at times of high Oakey Power Station generation. Powerlink maximises the allowable generation from Oakey Power Station by applying dynamic line ratings to take account of real time prevailing ambient weather conditions. AEMO identify these constraints with identifiers Q>NIL_MRTA_A and Q>NIL_MRTA_B. These constraints were implemented in AEMO's market system from April 2010. During the 2016 period, 29.17 hours of constraints were recorded against this constraint.

Projects were considered by Powerlink and AEMO under the NCIPAP to address this congestion. These projects were found not to be economically feasible at this time.

Energy Infrastructure Investments (EII) has advised AEMO of its intention to retire Daandine Power Station in June 2022.

Information pertaining to the historical duration of constrained operation due to these constraints is summarised in Figure 5.29.

Figure 5.29 Historical Q>NIL_MRTA_A and Q>NIL_MRTA_B constraint times



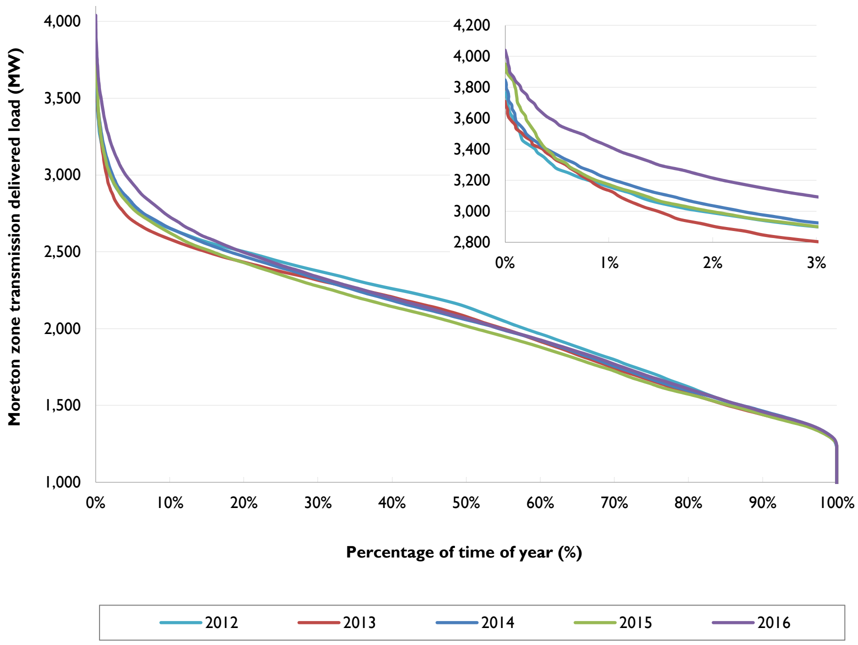
5.6.10 Moreton zone

The Moreton zone experienced no load loss for a single network element outage during 2016.

The Moreton zone includes the significant non-scheduled embedded generators Bromelton and Rocky Point as defined in Figure 2.4. These embedded generators provided approximately 18GWh during 2016.

Figure 5.30 provides historical transmission delivered load duration curves for the Moreton zone. Energy delivered from the transmission network has increased by 2.7% between 2015 and 2016 predominantly due to summer 2016/17 being hot and long lasting (refer to Section 2.1). The peak transmission delivered demand in the zone was 4,040MW which exceeds the previous transmission delivered demand of 4,023MW set in 2009/10.

Figure 5.30 Historical Moreton zone transmission delivered load duration curves



High voltages associated with light load conditions are managed with existing reactive sources. In preparation for the withdrawal of Swanbank E, Powerlink and AEMO agreed on a procedure to manage voltage controlling equipment in SEQ. The agreed procedure uses voltage control of dynamic reactive plant in conjunction with Energy Management System (EMS) online tools prior to resorting to network switching operations. No additional reactive sources are forecast in the Moreton zone within the five-year outlook period for the control of high voltages.

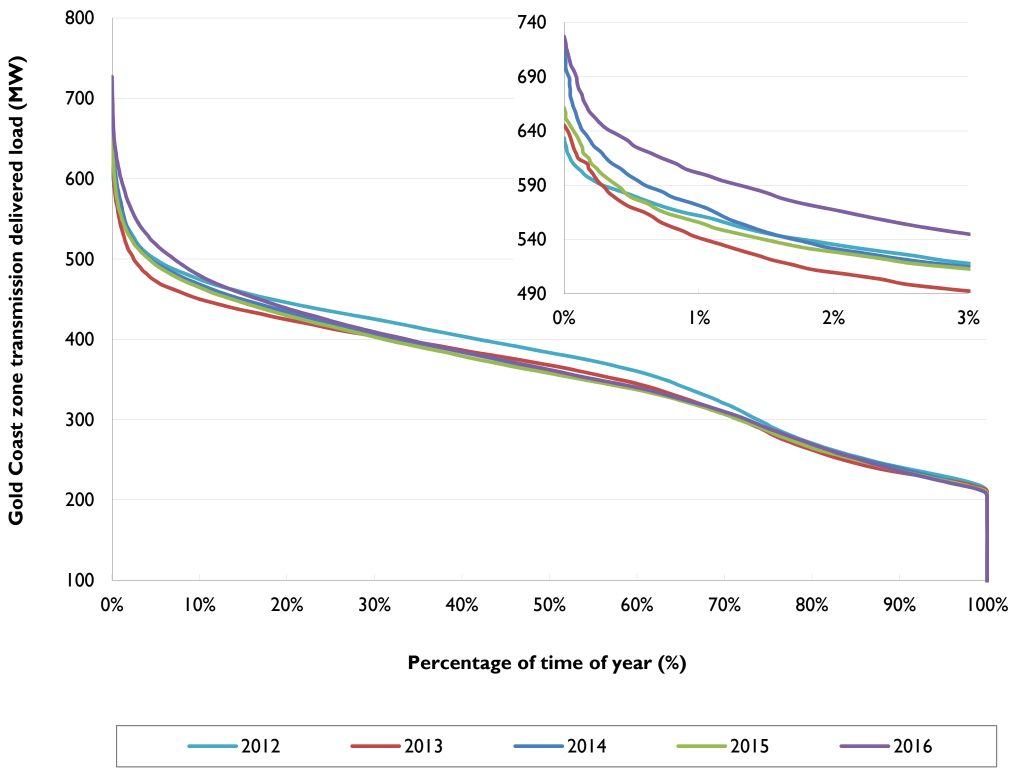
5.6.11 Gold Coast zone

The Gold Coast zone experienced no load loss for a single network element outage during 2016.

The Gold Coast zone contains no scheduled/semi-scheduled embedded generators or significant non-scheduled embedded generators as defined in Figure 2.4.

Figure 5.31 provides historical transmission delivered load duration curves for the Gold Coast zone. Energy delivered from the transmission network has increased by 1.7% between 2015 and 2016 predominantly due to summer 2016/17 being hot and long lasting (refer to Section 2.1). The peak transmission delivered demand in the zone was 727MW which is the highest maximum demand over the last five years.

Figure 5.31 Historical Gold Coast zone transmission delivered load duration curves



Chapter 6:
Strategic planning

6 Strategic planning

Key highlights

- This chapter identifies possible network limitations which may arise between the five and 10-year outlook period and provides potential network solutions.
- Long-term planning takes into account:
  - the role network is to play in enabling the transition to a lower carbon future while continuing to balance the economic and efficient development of the network; and
  - uncertainties in load growth and sources of generation, and the condition and performance of existing assets to optimise the network that is best configured to meet current and a range of plausible future capacity needs.
- Plausible new loads within the resource rich areas of Queensland or at the associated coastal port facilities may cause network limitations to emerge within the 10-year outlook period. Possible network options are provided for Bowen Basin coal mining area, Bowen Industrial Estate, Galilee Basin coal mining area, CQ-NQ grid section, Central West to Gladstone and the Surat Basin north west area.
- Assets where reinvestment will need to be made in the next five to 10-year period where there may be opportunities for reconfiguration include Ross, Central West and Gladstone zones and CQ-SQ grid section.

6.1 Background

Powerlink Queensland as a Transmission Network Service Provider (TNSP) in the National Electricity Market (NEM) and as the appointed Jurisdictional Planning Body (JPB) by the Queensland Government is responsible for transmission network planning for the national grid within Queensland. Powerlink's obligation is to plan the transmission system to reliably and economically supply load while managing risks associated with the condition and performance of existing assets in accordance with the requirements of the National Electricity Rules (NER), *Queensland's Electricity Act 1994* (the Act) and its Transmission Authority.

A key step in this process is the development of long-term strategic plans for both the main transmission network and supply connections within the zones. These long-term plans take into consideration uncertainties in the future. This can impact potential sources of generation and load growth. Uncertain load growth can occur due to different economic outlooks, emergence of new technology and the commitment and/or retirement of large industrial and mining loads.

There is also considerable uncertainty in generation. Queensland is experiencing a high level of growth in variable renewable electricity (VRE) generation, in particular small and large-scale solar photovoltaic (PV) and wind farm generation, either being connected or proposing to connect to the transmission and distribution networks. This new generation, together with generation that may be displaced in or outside Queensland, has the potential to significantly impact the utilisation and flow patterns of the transmission network including major grid sections. Long-term plans need to take into account the role network is to play in enabling the transition to a lower carbon future while continuing to balance the economic and efficient development of the network.

Long-term plans also take into consideration the condition and performance of existing assets. As assets reach the end of technical or economic life, reinvestment decisions are required. These decisions are made in the context of the required reliability standards, load forecast and generation outlook. Reinvestment decisions also need to be cognisant of the uncertainties that exist in the generation and load growth outlooks.

As assets reach the end of technical or economic life, opportunities may emerge to retire without replacement, initiate non-network alternatives, extend technical life or replace with assets of a different type, configuration or capacity. Powerlink considers options to integrate demand based limitations and condition based risks of assets to ensure an optimised network that is best configured to meet current and a range of plausible future capacity needs.

Information in this chapter is organised in two parts. Section 6.2 discusses the possible impact uncertain load growth may have on the performance and adequacy of the transmission system. This discussion is limited to the impact possible new large loads may have on the network (refer to Table 2.1). Section 6.3 provides a high-level outline of the possible network development plan for investments required to manage risks related to the condition and performance of existing assets. This high-level outline is discussed for parts of the main transmission system and within regional areas where the risks based on the condition and performance of assets may initiate investment decisions in the five to 10-year outlook period of this Transmission Annual Planning Report (TAPR). Information on reinvestment decisions within the current five-year outlook period of this TAPR is detailed in Chapter 4.

Powerlink considers it important to identify these long-term development options so that analyses using a scenario based approach, such as the Australian Energy Market Operator's (AEMO) National Transmission Network Development Plan (NTNDP), are consistent. In this context the longer-term plans only consider possible network solutions. However, this does not exclude the possibility of non-network solutions or a combination of both. As detailed planning studies are undertaken around the future network need and possible reinvestment options, Powerlink will identify the requirements a non-network solution would need to offer in order for it to be a genuine alternative to network investment. Subject to the cost threshold of $6 million, these non-network options will be fully evaluated as part of the Regulatory Investment Test for Transmission (RIT-T) process.

6.2 Possible network options to meet reliability obligations for potential new loads

Chapter 2 provides details of several proposals for large mining, metal processing and other industrial loads whose development status is not yet at the stage that they can be included (either wholly or in part) in the medium economic forecast. These load developments are listed in Table 2.1.

The new large loads in Table 2.1 are within the resource rich areas of Queensland or at the associated coastal port facilities. The relevant resource rich areas include the Bowen Basin, Galilee Basin and Surat Basin. These loads have the potential to significantly impact the performance of the transmission network supplying, and within, these areas. The degree of impact is also dependent on the location and capacity of new or withdrawn generation in the Queensland region.

The commitment of some or all of these loads may cause limitations to emerge on the transmission network. These limitations could be due to plant ratings, voltage stability and/or transient stability. Options to address these limitations include network solutions, demand side management (DSM) and generation non-network solutions. Feasible network projects can range from incremental developments to large-scale projects capable of delivering significant increases in power transfer capability.

As the strategic outlook for non-network options is not able to be clearly determined, this section focuses on strategic network developments only. This should not be interpreted as predicting the preferred outcome of the RIT-T process. The recommended option for development is the credible option that maximises the present value of the net economic benefit to all those who produce, consume and transport electricity in the market.

The emergence and magnitude of network limitations resulting from the commitment of these loads will also depend on the location, type and capacity of new or withdrawn generation. For the purpose of this assessment the existing and committed generation in Table 5.1 has been taken into account when discussing the possible network limitations and options. However, where current interest in connecting further VRE generation has occurred, that has the potential to materially impact the magnitude of the emerging limitation, this is also discussed in the following sections.

For the transmission grid sections potentially impacted by the possible new large loads in Table 2.1, details of feasible network options are provided in sections 6.2.1 to 6.2.6. Formal consultation via the RIT-T process on the network and non-network options associated with emerging limitations will be subject to commitment of additional demand.

6.2.1 Bowen Basin coal mining area

Based on the medium economic forecast defined in Chapter 2, the committed network described in Table 3.1, and the committed generation described in Table 5.1 network limitations exceeding the limits established under Powerlink's planning standard may occur following the possible retirement of assets described in Section 4.2.2. A possible solution to the voltage limitation could be the installation of a transformer at Strathmore Substation, network reconfiguration works, or a non-network solution.

In addition, there has been a proposal for the development of coal seam gas (CSG) processing load of up to 80MW (refer to Table 2.1) in the Bowen Basin. These loads have not reached the required development status to be included in the medium economic forecast for this TAPR.

The new loads within the Bowen Basin area would result in voltage and thermal limitations on the 132kV transmission system upstream of their connection points. Critical contingencies include an outage of the Strathmore 275/132kV transformer, a 132kV circuit between Nebo and Moranbah substations, the 132kV circuit between Strathmore and Collinsville North substations, or the 132kV circuit between Lilyvale and Dysart substations (refer to Figure 4.3).

The impact these loads may have on the Central Queensland to North Queensland (CQ-NQ) grid section and possible network solutions to address these is discussed in Section 6.2.4.

Possible network solutions

Feasible network solutions to address the limitations are dependent on the magnitude and location of load. The location, type and capacity of future VRE generation connections in North Queensland may also impact on the emergence and severity of network limitations. The type of VRE generation interest in this area is predominately large-scale solar PV. Given that the Bowen Basin coal mining area has a predominately flat profile it is unlikely that the daytime PV generation profile will be able to successfully address all emerging limitations.

Possible network options may include one or more of the following:

- second 275/132kV transformer at Strathmore Substation
- turn-in to Strathmore Substation the second 132kV circuit between Collinsville North and Clare South substations
- 132kV phase shifting transformers to improve the sharing of power flow in the Bowen Basin within the capability of the existing transmission assets.

6.2.2 Bowen Industrial Estate

Based on the medium economic forecast defined in Chapter 2, no additional capacity is forecast to be required as a result of network limitations within the five-year outlook period of this TAPR.

However, electricity demand in the Abbot Point State Development Area (SDA) is associated with infrastructure for new and expanded mining export and value adding facilities. Located approximately 20km west of Bowen, Abbot Point forms a key part of the infrastructure that will be necessary to support the development of coal exports from the northern part of the Galilee Basin. The loads in the SDA could be up to 100MW (refer to Table 2.1) but have not reached the required development status to be included in the medium economic forecast for this TAPR.

The Abbot Point area is supplied at 66kV from Bowen North Substation. Bowen North Substation was established in 2010 with a single 132/66kV transformer and supplied from a double circuit 132kV line from Strathmore Substation but with only a single circuit connected. During outages of the single supply to Bowen North the load is supplied via the Ergon Energy 66kV network from Proserpine, some 60km to the south. An outage of this single connection will cause voltage and thermal limitations impacting network reliability.

Possible network solutions

A feasible network solution to address the limitations comprises:

- installation of a second 132/66kV transformer at Bowen North Substation
- connection of the second Strathmore to Bowen North 132kV circuit
- second 275/132kV transformer at Strathmore Substation
- turn-in to Strathmore Substation the second 132kV circuit between Collinsville North and Clare South substations.

6.2.3 Galilee Basin coal mining area

There have been proposals for new coal mining projects in the Galilee Basin. Although these loads could be up to 400MW (refer to Table 2.1) none have reached the required development status to be included in the medium economic forecast for this TAPR. If new coal mining projects eventuate, voltage and thermal limitations on the transmission system upstream of their connection points may occur.

Depending on the number, location and size of coal mines that develop in the Galilee Basin it may not be technically or economically feasible to supply this entire load from a single point of connection to the Powerlink network. New coal mines that develop in the southern part of the Galilee Basin may connect to Lilyvale Substation via an approximate 200km transmission line. Whereas coal mines that develop in the northern part of the Galilee Basin may connect via a similar length transmission line to the Strathmore Substation.

Whether these new coal mines connect at Lilyvale and/or Strathmore Substation, the new load will impact the performance and adequacy of the CQ-NQ grid section. Possible network solutions to the resultant CQ-NQ limitations are discussed in Section 6.2.4.

In addition to these limitations on the CQ-NQ transmission system, new coal mine loads that connect to the Lilyvale Substation may cause thermal and voltage limitations to emerge during an outage of a 275kV circuit between Broadsound and Lilyvale substations.

Possible network solutions

For supply to the Galilee Basin from Lilyvale Substation, feasible network solutions to address the limitations are dependent on the magnitude of load and may include one or both of the following options:

- installation of capacitor bank/s at Lilyvale Substation
- third 275kV circuit between Broadsound and Lilyvale substations.

The location, type and capacity of future VRE generation connections in Lilyvale, Blackwater and Bowen Basin areas may also impact on the emergence and severity of this network limitation. The type of VRE generation interest in this area is predominately large-scale solar PV. Given that the coal mining load in the area has a predominately flat profile it is unlikely that the daytime PV generation profile will be able to successfully address all emerging limitations.

6.2.4 Central Queensland to North Queensland grid section transfer limit

Based on the medium economic forecast outlined in Chapter 2 and the committed generation described in Table 5.1, network limitations impacting reliability or the efficient economic operation of the NEM are not forecast to occur within the five-year outlook of this TAPR.

However, as discussed in sections 6.2.1, 6.2.2 and 6.2.3 there have been proposals for large coal mine developments in the Galilee Basin, and development of CSG processing load in the Bowen Basin and associated port expansions. The loads could be up to 580MW (refer to Table 2.1) but have not reached the required development status to be included in the medium economic forecast of this TAPR.

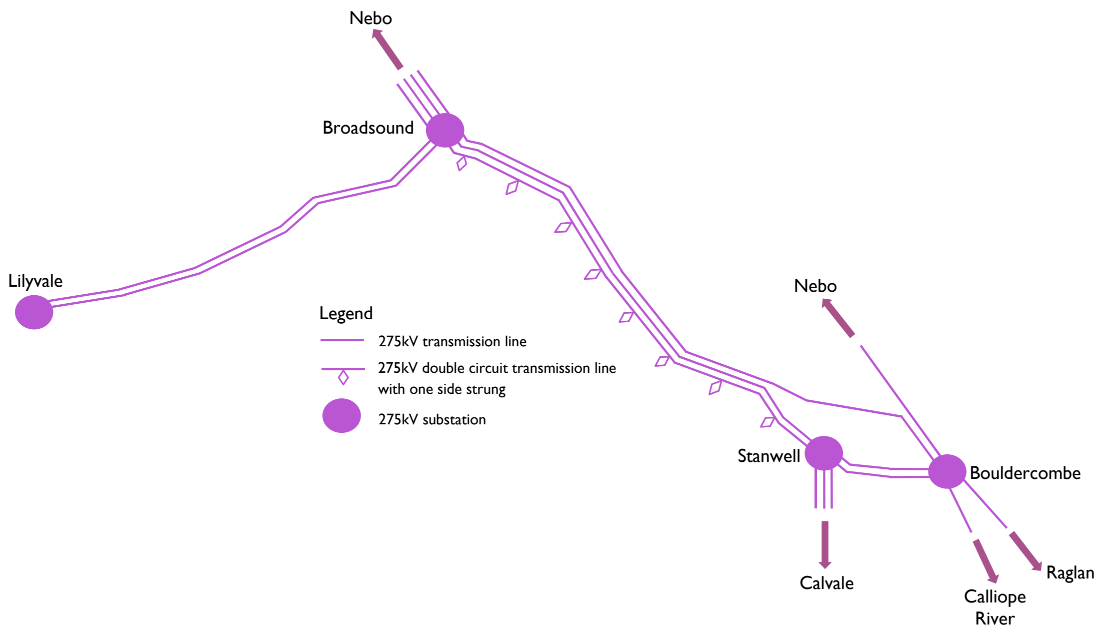
Network limitations on the CQ-NQ grid section may occur if a portion of these new loads commit. Power transfer capability into northern Queensland is limited by thermal ratings or voltage stability limitations. Thermal limitations may occur on the Bouldercombe to Broadsound 275kV line during a critical contingency of a Stanwell to Broadsound 275kV circuit. Voltage stability limitations may occur during the trip of the Townsville gas turbine or 275kV circuit supplying northern Queensland.

Currently generation costs are higher in northern Queensland due to reliance on liquid fuels, and there may be positive net market benefits in augmenting the transmission network. The recent uptake of VRE generation connections in North Queensland would be taken into account in any market benefit assessment, including consideration of the location, type and capacity of these future connections.

Possible network solutions

In 2002, Powerlink constructed a 275kV double circuit transmission line from Stanwell to Broadsound with one circuit strung (refer to Figure 6.1). A feasible network solution to increase the power transfer capability to northern Queensland is to string the second side of this transmission line.

Figure 6.1 Stanwell/Broadsound area transmission network



6.2.5 Central West to Gladstone area reinforcement

The 275kV network forms a triangle between the generation rich nodes of Calvale, Stanwell and Calliope River substations. This triangle delivers power to the major 275/132kV injection points of Calvale, Bouldercombe (Rockhampton), Calliope River (Gladstone) and Boyne Island substations.

Since there is a surplus of generation within this area, this network is also pivotal to supply power to northern and southern Queensland. As such, the utilisation of this 275kV network depends not only on the generation dispatch and supply and demand balance within the Central West and Gladstone zones, but also in northern and southern Queensland.

Based on the medium economic forecast defined in Chapter 2 and the existing and committed generation in Table 5.1, network limitations impacting reliability are not forecast to occur within the five-year outlook period of this TAPR. This assessment also takes into consideration the possible retirement of the Callide A to Gladstone South 132kV double circuit transmission line within the next five years (refer to Section 4.2.4).

The committed generation in Table 5.1 in North Queensland has the potential to increase the utilisation of this transmission network. As detailed in Section 4.2.4, based on the expected operation of the committed VRE generators, the north and central west generators should continue to operate mostly unconstrained.

Notwithstanding the connection of this committed VRE generation, Powerlink recognised the vulnerability of this grid section to congestion and proposed a network project under the Network Capability Incentive Parameter Action Plan (NCIPAP) for the 2018-22 Revenue Reset period. This project involves increasing the ground clearance of 11 spans on Bouldercombe to Raglan 275kV and three on Larcom Creek to Calliope River 275kV transmission lines to increase the thermal rating of these lines. This project was accepted by the Australian Energy Regulator (AER) and Powerlink will seek final approval, as per the NER, before implementing these improvements.

In addition, there are several developments in the Queensland region that would change not only the power transfer requirements between the Central West and Gladstone zones but also on the intra-connectors to northern and southern Queensland. These developments include new loads in the resource rich areas of the Bowen Basin, Galilee Basin and Surat Basin and also the connection of VRE energy generation, in particular large-scale solar PV and wind farm generation. Such generation, together with what it displaces, has the potential to further significantly increase the utilisation of this grid section. This may lead to significant limitations within this 275kV triangle impacting efficient market outcomes despite the uprating from the NCIPAP project. Network limitations would need to be addressed by dispatching out-of-merit generation and the technical and economic viability of increasing the power transfer capacity would need to be assessed under the requirements of the RIT-T.

Possible network solutions

Depending on the emergence of network limitations within the 275kV network it may become economically viable to increase its power transfer capacity to alleviate constraints. A feasible network solution to facilitate efficient market operation may include transmission line augmentation between:

- Calvale and Larcom Creek substations
- Larcom Creek and Calliope River substations.

6.2.6 Surat Basin north west area

Based on the medium economic forecast defined in Chapter 2, network limitations impacting reliability are not forecast to occur within the five-year outlook period of this TAPR.

However, there have been several proposals for additional CSG upstream processing facilities and new coal mining load in the Surat Basin north west area. These loads have not reached the required development status to be included in the medium economic forecast for this TAPR. The loads could be up to 300MW (refer to Table 2.1) and cause voltage limitations impacting network reliability on the transmission system upstream of their connection points.

Depending on the location and size of additional load, voltage stability limitations may occur following outages of the 275kV circuits between Western Downs and Columboola, and between Columboola and Wandoan South substations (refer to Figure 6.2).

Possible network solutions

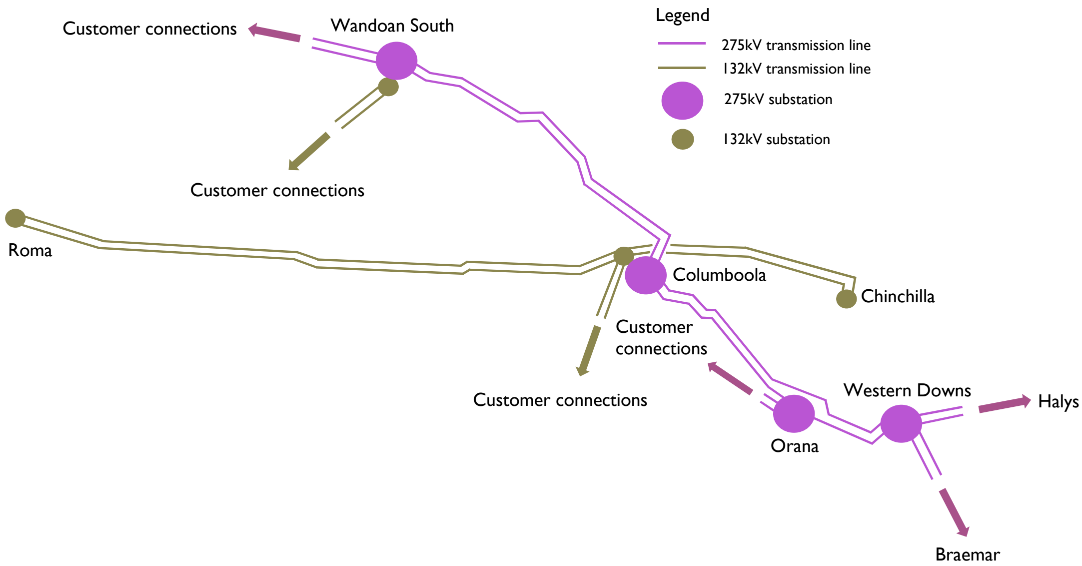
Due to the nature of the voltage stability limitation, the size and location of load and the range of contingencies over which the instability may occur, it may not be possible to address this issue by installing a single SVC at one location.

The location, type and capacity of future VRE generation connections in the Surat Basin north west area may also impact on the emergence and severity of these voltage limitations. The type of VRE generation interest in this area is large-scale solar PV. Given that the CSG upstream processing facilities and new coal mining load has a predominately flat profile it is unlikely that the daytime PV generation profile will be able to successfully address all emerging voltage limitations. However, voltage limitations may be ameliorated by these renewable plants, particularly if they are designed to provide voltage support 24 hours a day.

To address the voltage stability limitation the following network options are viable:

- SVCs, STATCOMs or SynCons at both Columboola and Wandoan South substations
- additional circuits between Western Downs, Columboola and Wandoan South substations to increase fault level and transmission strength, or
- a combination of the above options.

Figure 6.2 Surat Basin north west area transmission network



6.3 Possible reinvestment options initiated within the five to 10-year outlook period

In addition to meeting the forecast demand, Powerlink must maintain existing assets to ensure the risks associated with condition and performance are appropriately managed. To achieve this Powerlink routinely undertakes an assessment of the condition of assets and identifies potential emerging risks related to such factors as reliability, physical condition, safety, performance and functionality, statutory compliance and obsolescence.

Based on these assessments a number of assets have been identified as approaching the end of technical or economic life. This section focuses on those assets where reinvestment will need to be made in the next five to 10-year period of this TAPR and where there may be opportunities for network reconfiguration. Information on reinvestment decisions within the current five-year outlook period is detailed in Chapter 4.

The parts of the main transmission system and regional areas for which Powerlink has identified opportunities for reconfiguration in the five to 10-year outlook period of this TAPR include:

- Ross zone
- Central West and Gladstone zones
- Central Queensland to South Queensland grid section
- Gold Coast zone.

Powerlink will also continue to investigate opportunities for reconfiguration in other parts of the network where assets are approaching the end of technical or economic life and demand and generation developments evolve.

Reinvestment decisions in these areas aim to optimise the network topology to ensure the network is best configured to meet current and a range of plausible future capacity needs. As assets reach the end of technical or economic life, consideration is given to a range of options to manage the associated risks. These options include asset retirement, network reconfiguration, partial or full replacement (possibly with assets of a different type, configuration or capacity), extend technical life, and/or non-network alternatives.

Individual asset investment decisions are not determined in isolation. An integrated planning process is applied to take account of both future load and generation, and the condition based risks of related assets in the network. The integration of condition and demand based limitations delivers cost effective solutions that manage both reliability of supply obligations, efficient market operation and the risks associated in allowing assets to remain in-service.

A high-level outline of the possible network development plan for these identified areas that manage risks related to the condition and performance of the existing assets is given in sections 6.3.1 to 6.3.4.

6.3.1 Ross zone

The network from the Strathmore area to Townsville South and Ross substations in North Queensland has developed over many years. It comprises a 132kV network and a 275kV network which operate in parallel. As detailed in Section 4.2.2, the 132kV lines are forecast to approach end of technical or economic life in the five to 10-year outlook period.

The establishment of the 275kV network has reduced the reliance on these 132kV transmission lines for intra-network transfers. However, two single circuit 275kV transmission lines, that form part of this network which are paralleled and operate as one circuit, are also reaching the end of technical or economic life in the 10 to 20-year horizon.

The end of technical or economic life decisions for these 275kV single circuit transmission lines may present an opportunity to reshape the transmission footprint to better support the evolving requirements of the transmission system in North Queensland. In particular, by aligning the reinvestment needs on the 275kV and 132kV network, the long-term network strategy may help to address issues originating from:

- the potential for a number of large VRE generators to connect
- the relatively low thermal capacity of the existing 132kV transmission system; and
- the connection large industrial block load increases above forecast levels (refer to sections 6.2.1 to 6.2.4).

The first stage of this strategy will require taking the lowest cost approach to maintain the required network reliability and connectivity of the 132kV transmission lines between Collinsville North and Townsville South substations until the 275kV transmission network requires major investment. It is expected that in most cases targeted maintenance or an extension of life by a 'fit for purpose' refit will be the most economic network option.

Beyond this, there are a number of technically feasible options for the end of technical or economic life strategies for the 132kV transmission line assets within this area. Planning studies have indicated the potential to reconfigure the 132kV network whilst still maintaining the required reliability and connectivity, including an option to retire the inland 132kV transmission line from Townsville South to Clare South substations. If this retirement were to eventuate, and based on the medium economic forecast defined in Chapter 2, network limitations exceeding the limits under Powerlink's planning standard are forecast to occur. Possible solutions to the limitation include the installation of the second 275/132kV transformer at Strathmore (refer to Section 4.2.2) or network support.

If 132kV network reconfiguration is the most technical and economic end of life option in the 10-year outlook period, it is still aligned with the longer term strategy to maintain flexibility to reshape the transmission footprint at a later date, whilst:

- maintaining geographic diversity of transmission supply into North Queensland
- meeting existing network requirements, including connectivity to Clare South, King Creek and Invicta Mill and for potential new loads and/or generation
- providing flexibility to adapt to meet various scenarios for network requirements in the future, including rationalisation of the number of transmission lines in this corridor
- allowing rationalisation of the 132kV switchyards at Collinsville North and Strathmore substations in 15 to 20 years when the primary plant at Strathmore is predicted to reach end of technical or economical life and

- installation of a second 275/132kV injection at Strathmore will provide higher headroom to allow 132kV optimisation to one higher capacity circuit in the future and potential connection of more renewable generation.

6.3.2 Central West and Gladstone zones

The 275kV network in the Gladstone area was constructed in the 1970s with the exception of the transmission line to Boyne Island via Wurdong which was constructed in the 1990s. All the 1970s lines are expected to require reinvestment within the next 10 years.

The 132kV lines from Calliope River to Boyne Island, Calliope River to Gladstone Power Station, Calliope River to Gladstone North and Calliope River to Gladstone South were built prior to 1982. The 132kV lines from Gladstone South to QAL were built prior to 1970 and Gladstone South to Callide in the mid 1960s. As outlined in Section 4.2.4 it is likely this line will be retired from service at the end of its technical or economic life within the next five to 10 years.

The two single 275kV circuits between Calliope River Substation and Bouldercombe Substation (one via Larcom Creek and Raglan) are showing signs of deteriorated galvanising of structures, nuts and bolts and hardware. These lines will exceed an acceptable risk profile and require some reinvestment in the next five to 10 years.

Planning assessments confirm the need to retain two 275kV circuits between Calliope River and Bouldercombe substations. The long-term strategy is to perform targeted maintenance or an extension of life by a 'fit for purpose' refit to align the end of technical and economic life of these two 275kV lines. High-level assessments indicate it may be of more benefit to replace these circuits in the late 2020s with a new high capacity double circuit line between Calliope River and Bouldercombe that would also supply Larcom Creek and Raglan substations.

6.3.3 Central Queensland to South Queensland grid section

Three single circuit 275kV transmission lines operate between Calliope River and South Pine substations and form the coastal corridor of the Central Queensland to South Queensland (CQ-SQ) grid section. These transmission lines were constructed in the 1970s and 1980s. The lines traverse a variety of environmental conditions that have resulted in different rates of corrosion. The risk levels therefore vary across the transmission lines. More detailed condition assessments have been completed for those sections of the lines where the environmental conditions are more onerous.

Based on these detailed assessments the 275kV single circuit lines in the most northern and southern end will reach end of technical or economic life in the five to 10-year outlook of this TAPR. Powerlink expects to require some form of investment in the remainder of the transmission lines over the next 10 to 20 years.

The 275kV lines at the northern end of this coastal corridor are currently experiencing an accelerated rate of corrosion. It is expected that the risks, primarily driven by the 275kV single circuit transmission lines between Calliope River and Wurdong substations, will exceed acceptable corrosion levels by approximately 2021. The higher rate of corrosion is due to the proximity to the coast and exposure to salt laden coastal winds. The Calliope River to Wurdong line also traverses two tidal crossings and operates in a heavy industrial area.

Risks on the section between Calliope River and Wurdong may be managed through maintenance works, with minimal work required over the next five years. This strategy is economic and will allow the technical end of life of the 275kV single circuits between Calliope River to Wurdong to be aligned with those from Wurdong to Gin Gin.

The 275kV transmission lines between South Pine and Woolooga substations are also experiencing a higher rate of corrosion and will exceed acceptable risk levels in the next five years. The higher rate of corrosion is due to a localised wet weather environment in the hinterland regions of Mapleton and Maleny.

Similar to the strategy in the northern section, it is considered economic to align the technical and economic end of life of the South Pine to Woolooga and Palmwoods to Woolooga transmission lines. This will require a moderate amount of maintenance or refurbishment on the South Pine to Woolooga 275kV transmission line in the next five to 10 years. A transmission line refit project is underway for completion in the next five years to manage the risks of the 275kV single circuit transmission line between Palmwoods and Woolooga substations.

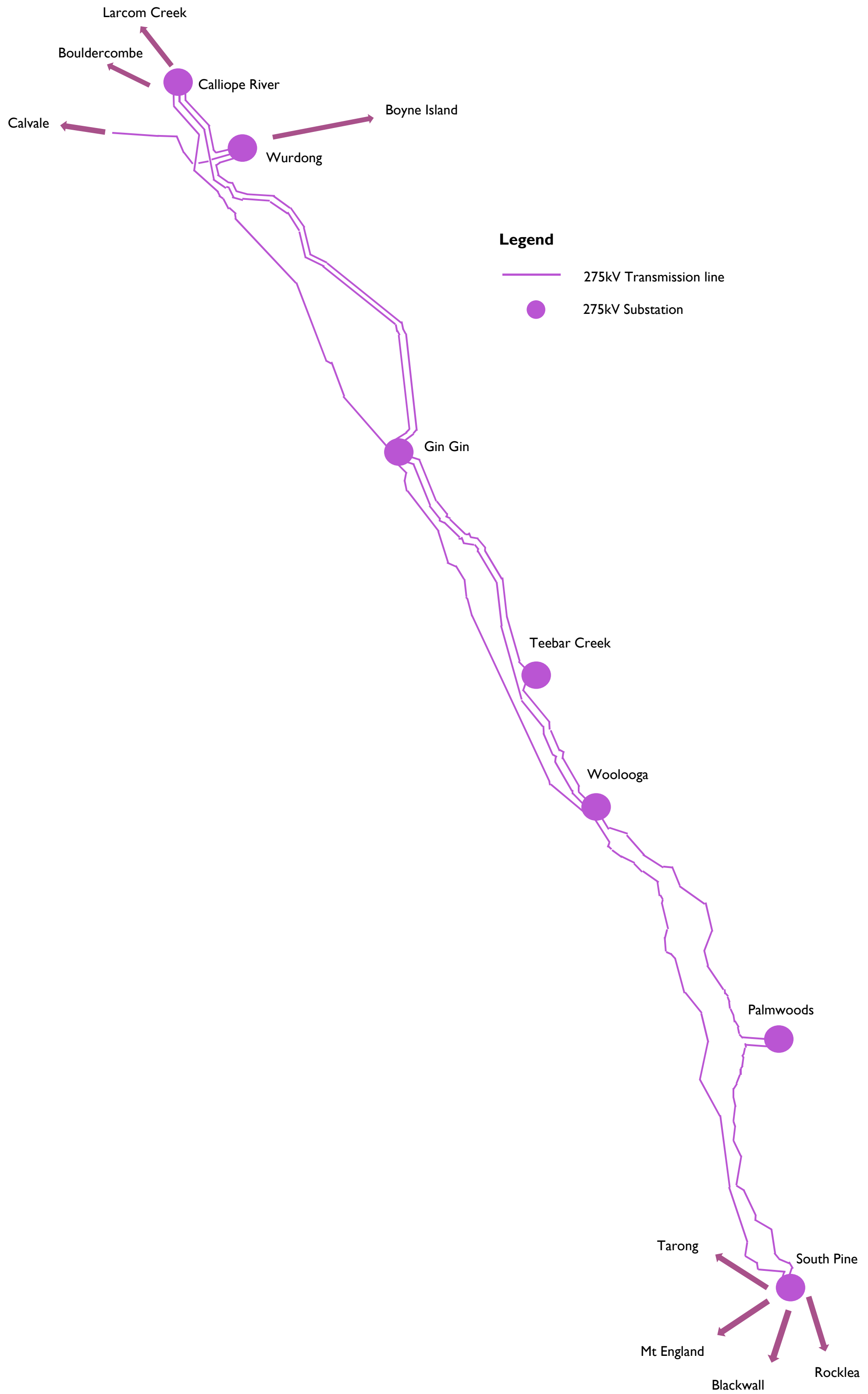
These strategies have the benefit of maintaining the existing topology, transfer capability and operability of the network. The strategies provide for an incremental development approach and defer large capital investment.

The incremental approach to reinvesting in the existing assets is both economic over the 10-year outlook period of this TAPR and is fully aligned with providing time to better understand the impact that a lower carbon (higher renewable) electricity generation future may have on the required transfer capability of this grid section.

The CQ-SQ grid section is an important intra-connector for the efficient operation of the NEM. Based on the medium economic forecast defined in Chapter 2 and the existing and committed generation in Table 5.1, network limitations impacting reliability or efficient market outcomes are not forecast to occur within the 10-year outlook period of this TAPR. However, potential investment in VRE generation in central and north Queensland, coupled with the possible displacement and/or retirement of existing thermal plant, may significantly increase the utilisation of the grid section and potentially cause congestion.

Powerlink will take these developments into account when formulating the strategies to meet the future emerging market requirements.

Figure 6.3 Coastal Central Queensland to South Queensland area transmission network



6.3.4 Gold Coast zone

The main transmission system into the Gold Coast area is via the Greenbank to Molendinar double circuit 275kV transmission line and the two Greenbank to Mudgeeraba 275kV single circuit transmission lines.

The Greenbank and Mudgeeraba substations are located approximately 40km and 8km respectively from the coast. Given this, the south eastern end of the single circuit 275kV lines are subjected to higher rates of corrosion due to the prevailing salt laden coastal winds.

The single circuit 275kV lines consist of around 160 galvanized steel lattice towers that have been subject to above ground corrosion. A condition assessment concludes that these lines are currently tracking to a standard rate of corrosion. It is expected that these lines will exceed an acceptable risk profile within 10 to 20 years. To defer a major rebuild these lines will need targeted maintenance or refit in the five to 10-year outlook period.

The reinvestment options that would be considered include refit of one or both single circuit transmission lines, a new double circuit transmission line, decommissioning with consideration to any non-network alternatives. Due to potentially complex staging and deliverability requirements, the end of technical or economic life strategy should be reviewed within the next five years (refer to Section 4.2.8).

Any major reinvestment in the Greenbank to Mudgeeraba single circuit 275kV transmission lines will require extensive joint planning with Energex, Essential Energy, TransGrid and Directlink. Following more detailed analysis, Powerlink will undertake a RIT-T at the appropriate time when impacts on power transfer limits, power quality and efficient market outcomes will be assessed.

The Tweed region in Northern NSW is supplied by the double circuit 110kV Mudgeeraba to Terranora transmission line and the Directlink HVDC link to Lismore. A condition assessment of the double circuit line concludes that this line will exceed an acceptable risk profile within 10 to 20 years. To defer a major rebuild of this line targeted maintenance or refit in the five to 10-year outlook period will be required.

The capacity on the 132kV network supplying northern NSW is limited, and operation of Directlink must be taken into account when considering reinvestment in this area. Outages on or removal of any of these circuits will have market impacts. As such, it is expected that any major reinvestment in the 10 to 20-year horizon for the Mudgeeraba to Terranora double circuit transmission line would require extensive joint planning and consultation with Energex, Essential Energy, TransGrid and Directlink. Following more detailed analysis, Powerlink will undertake a RIT-T at the appropriate time when impacts on power transfer limits, power quality and efficient market outcomes will be assessed.

6.4 Supply demand balance

The outlook for the supply demand balance for the Queensland region was published in the AEMO 2016 Electricity Statement of Opportunities (ESOO)[1]. Interested parties who require information regarding future supply demand balance should consult this document.

6.5 Interconnectors

6.5.1 Existing interconnectors

The Queensland transmission network is interconnected to the New South Wales (NSW) transmission system through the Queensland/New South Wales Interconnector (QNI) transmission line and Terranora Interconnector transmission line.

The QNI maximum southerly capability is limited by thermal ratings, transient stability and oscillatory stability (as detailed in Section 5.5.9).

The combined QNI plus Terranora Interconnector maximum northerly capability is limited by thermal ratings, voltage stability, transient stability and oscillatory stability (as detailed in Section 5.5.9).

[1] Published by AEMO in July 2016.

The capability of these interconnectors can vary significantly depending on the status of plant, network conditions, weather and load levels in both Queensland and NSW. It is for these reasons that interconnector capability is regularly reviewed, particularly when new generation enters the market or transmission projects are commissioned in either region.

6.5.2 Interconnector upgrades

Powerlink and TransGrid have assessed whether an upgrade of QNI could be technically and economically justified on several occasions since the interconnector was commissioned in 2001. Each assessment and consultation was carried out in accordance with the relevant version of the AER's Regulatory Investment Test in place at the time.

The most recent assessment was carried out as part of the joint Powerlink and TransGrid regulatory consultation process which concluded in December 2014. At that time, in light of uncertainties, Powerlink and TransGrid considered it prudent not to recommend a preferred upgrade option, however continue to monitor market developments to determine if any material changes could warrant reassessment of an upgrade to QNI. Relevant changes may include:

- changes in generation and large-scale load developments in Queensland and the NEM (including CSG, coal developments, VRE generation, retirement of generation) and
- NEM-wide reductions in forecast load and energy consumption.

There is considerable uncertainty in both load and generation development/retirement in the Queensland region. This uncertainty also extends to the southern States, perhaps not to the same extent for new large-scale load developments, but certainly for new generation development and/or retirements. The impact this may have on the congestion and incidence of constraints on QNI is complex and varied. Depending on the emergence of these changes, QNI congestion may increase in the northerly or southerly direction. The different investments in load and investments and retirements in generation across the NEM may also impact on the location and scope of viable network upgrade options.

Augmentation to QNI was also considered in AEMO's 2016 National Transmission Network Development Plan (NTNDP)[2]. The merits of increasing QNI capacity were assessed across a number of scenarios. For each of the scenarios the generation outlooks were co-optimised with interconnector augmentation, as increased interconnection has the potential to provide a range of benefits, including increased efficiency in generation production costs, greater reliability and security outcomes, and reduction in capital investment related to new generation. AEMO's modelling indicated that bi-directionally increasing the capability of QNI may deliver net positive market benefits from 2026–27 depending on the scenario. AEMO modelled controllable series compensation on QNI to achieve this bi-directional increase in QNI power transfer capability. To manage the voltage profile a part of this series compensation could be installed in the Queensland region. The AER accepted this as a contingent project in Powerlink's 2018-22 Revenue Reset period.

Possible network solutions

The National Electricity Market (NEM) is moving into a new era with transformation of the generation mix to meet climate change policy objectives. There is a shift from large-scale, synchronous, centrally dispatched generation towards distributed and VRE generators, connected to the power system through inverter-based technology as the electricity industry transitions to a low carbon future.

The Electricity Network Transformation Roadmap[3] and AEMO's 2016 NTNDP both suggest that transmission interconnections will play a stronger role in the future. Greater levels of interconnection allows the diversity of VRE generation, particularly wind generation, across regions during summer and winter peaking conditions, to deliver fuel cost savings by improving utilisation of renewable generation and reducing reliance on higher-cost gas generation.

2 2016 National Transmission Network Development Plan
3 Electricity Network Transformation Roadmap – Final Report, April 2017 (page 99)

Transmission networks, including interconnection, will also be increasingly needed for system support services, such as frequency and voltage support, to maintain a reliable and secure supply. For example, a more interconnected NEM can improve system resilience to high impact, low probability events such as interconnector failures.

Powerlink will proactively monitor this changing outlook for the Queensland region and take into consideration the impact of emerging technologies, withdrawal of gas and coal-fired generation and the integration of VRE in future transmission plans. Options that increase interconnector capacity will not be constrained to upgrades to the existing QNI, but will look holistically at the potential market benefits of solutions required to maintain reliable, secure energy supply over the next 20 years and beyond.

This may involve consideration of the technical and economic benefits of establishing diversity in the interconnection paths. Options include developing additional circuits between Queensland and New South Wales or establishing an alternative inter-state connection. Powerlink is contributing to the South Australian Energy Transformation RIT-T. One of the network options being assessed in this RIT-T is the development of a High Voltage Direct Current-Voltage Source Converter (HVDC–VSC) ~1,500km connection between South West Queensland and South Australia. This option also has the potential benefit of increasing the QNI limit, and other interstate limits, by implementing special control schemes with the HVDC-VSC link. Increases in the QNI limit of approximately 300MW may be possible by quickly changing the dispatched power on the HVDC-VSC link following the initial critical contingency.

Powerlink will monitor the progress of this RIT-T, and AEMO's 2017 NTNDP, and use these results to further inform the prudent timing and form of further interconnector studies.

Powerlink will also consider smaller-scale network or non-network alternatives that in combination may deliver a more cost-effective range of future reliability, security, and efficiency benefits for consumers. With respect to this, Powerlink continues to encourage expressions of interest for potential non-network solutions which may be capable of increasing the transfer capability across the interconnector and hence deliver market benefits[4]. This is part of a broader strategy Powerlink is implementing to further develop, expand and capture economically and technically feasible non-network solutions. This strategy is based on enhanced collaboration with stakeholders (refer to Section 1.8.2).

[4] Information on non-network solutions may be found at QNI Upgrade consultation.

6 Strategic planning

Chapter 7:

Renewable energy

7 Renewable energy

Key highlights

- This chapter explores the potential for the connection of variable renewable electricity generation to Powerlink's transmission network.
- Due to fundamental shifts in the external environment, Powerlink has a key role in enabling the connection of variable renewable electricity infrastructure in Queensland.
- Over the past year, Powerlink has supported a high level of connection activity, responding to more than 80 connection enquiries comprising over 15,000MW of potential variable renewable electricity generation.
- In 2016/17, Powerlink finalised seven renewable renewable electricity generator Connection and Access Agreements totalling 718MW.

7.1 Introduction

Queensland is rich in a diverse range of variable renewable electricity (VRE) resources – solar, wind, geothermal, biomass, and hydro. This makes Queensland an attractive location for large-scale VRE generation development projects.

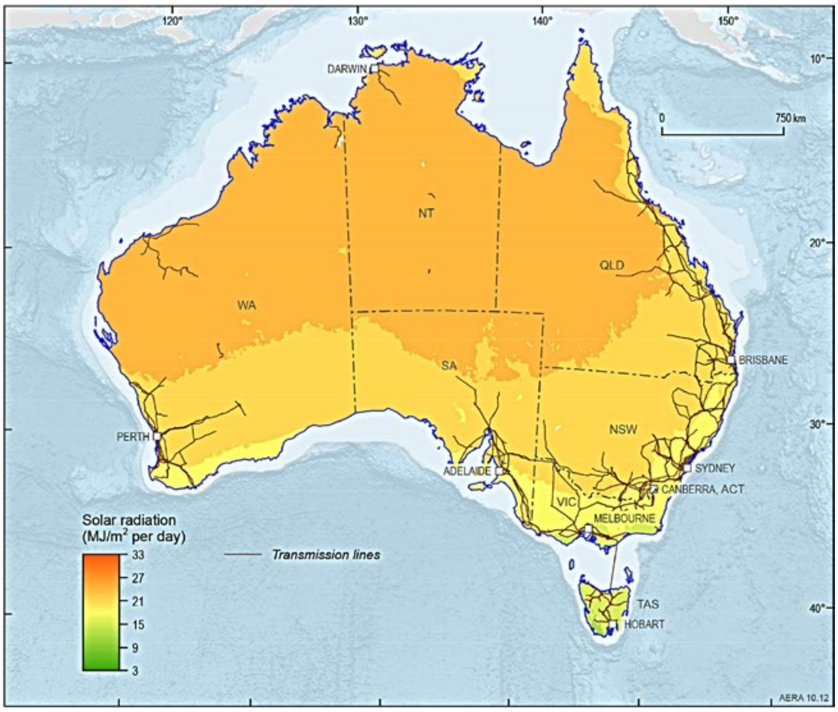
In February 2017, the level of roof top solar installations in Queensland exceeded 1,700MW, and is presently increasing at approximately 15MW each month. This uptake provides a strong indication that Queensland consumers are no longer meeting their energy requirements entirely through conventional means. The development of complementary technologies, such as energy storage, smart appliances, and electric vehicles are changing the way customers consume and produce energy. During the past year there has been a significant increase in the development of large-scale solar and wind generation farms. Fundamental external shifts such as these are shaping the operating environment in which Powerlink delivers its transmission services.

Powerlink is committed to supporting the development of all types of energy projects requiring connection to the transmission network. In addition, due to these fundamental shifts in the external environment, Powerlink will also have a key role in enabling the connection of VRE infrastructure developments which aim to provide a sustainable, low carbon future for electricity producers and users in Queensland. The network capacity information presented in this chapter is applicable to all forms of generation including energy storage[1].

The Australian Government Department of Geoscience has published an assessment of Australia's energy resource. The report acknowledges that Australia's potential for VRE generation is very large and widely distributed across the country. Figures 7.1 and 7.2 highlight Queensland's solar and wind energy potential and the proximity of Powerlink's high voltage transmission infrastructure to this energy resource.

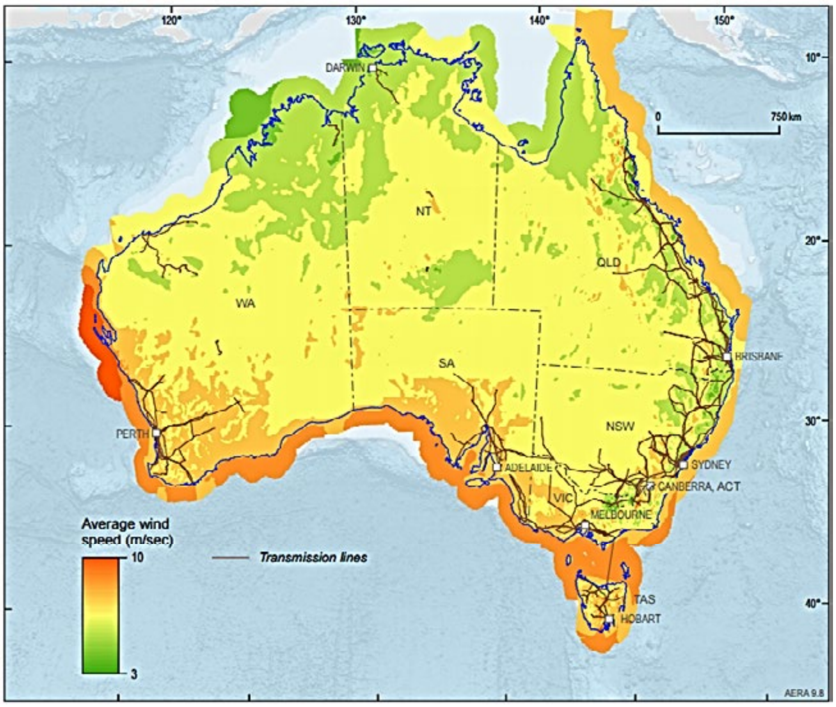
[1] The impact of new synchronous generator connections on existing fault levels has not been considered in the assessments conducted in this chapter. For further information on existing fault levels and equipment rating, please refer to Appendix E.

Figure 7.1 Australian annual average solar radiation



Source: Geoscience Australia and Bureau of Meteorology[2]

Figure 7.2 Australian annual average wind speed



Source: Geoscience Australia and Windlab Systems Pty Ltd[2]

2 Geoscience Australia and BREE, 2014, Australian Energy Resource Assessment. 2nd Ed. This product is released under the Creative Commons Attribution 3.0 International Licence. http://creativecommons.org/licenses/by/3.0/legalcode

7.2 Connection activity during 2016/17

Powerlink is currently managing a high level of interest in transmission connections for VRE projects. In 2016/17, Powerlink received more than 80 new connection enquiries totalling in excess of 15,000MW.[3]

Figures 7.3 and 7.4 illustrate record levels of connection enquiries over the last year.

Figure 7.3 Historical number of variable renewable electricity generation connection enquiries[3]

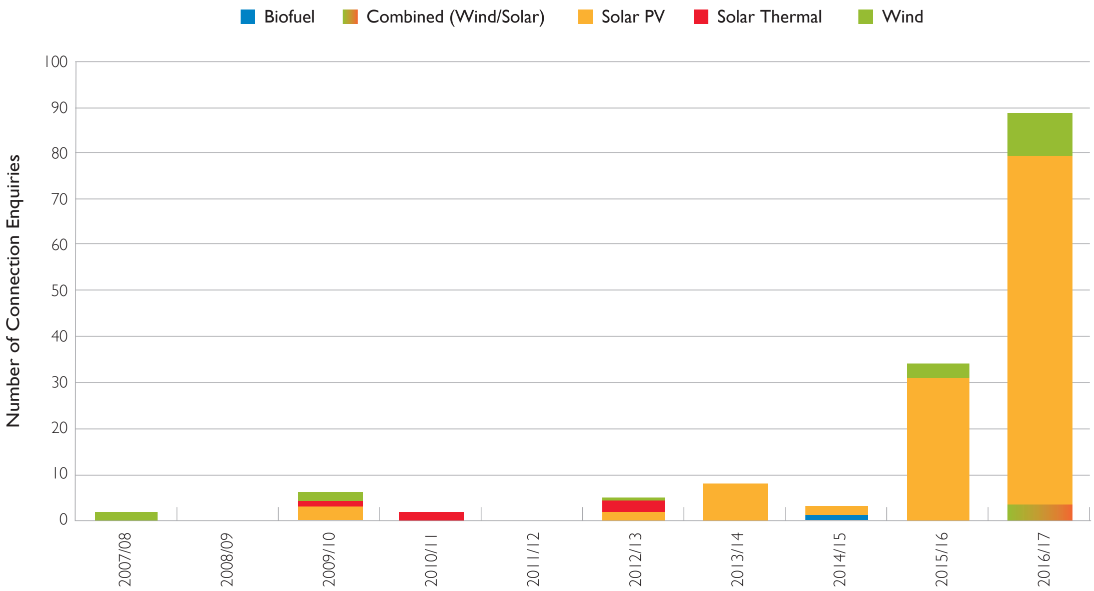
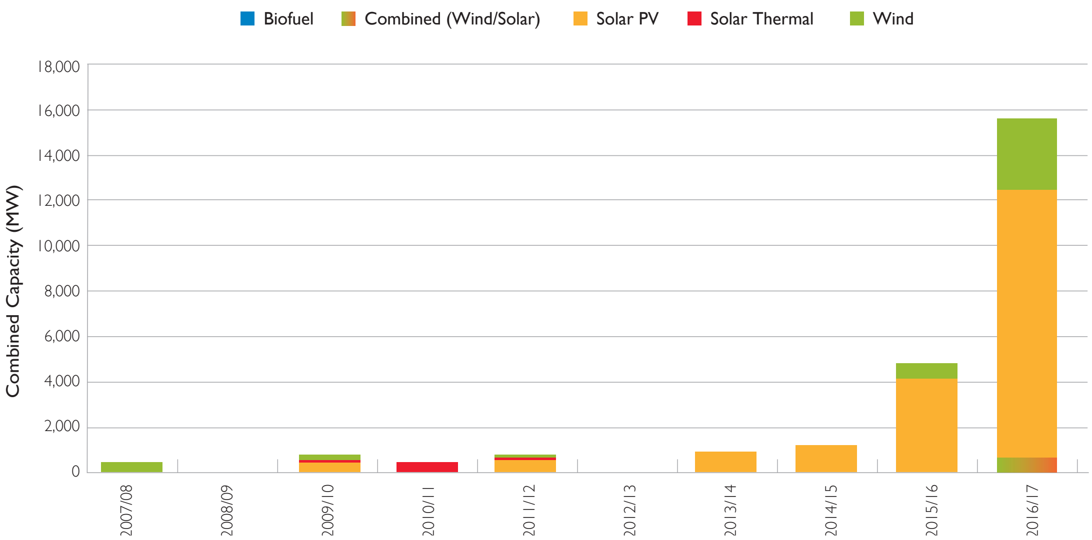


Figure 7.4 Historical capacity of variable renewable electricity generation connection enquiries[3]



During 2016/17, Powerlink finalised seven connection and access agreements for new non-scheduled generation, totalling 718MW[3] (refer to Table 7.1).

[3] Connection activity details as at 1 June 2017

Table 7.1 Transmission connected VRE generation projects committed during 2016/17

Zone	Project	Registered capacity (MW)	Connection location
Far North	Mt Emerald Wind Farm	180	New Walkamin Substation near Chalumbin
Ross	Ross River Solar Farm	125	Ross
Ross	Clare Solar Farm	136	Clare South
North	Hamilton Solar Farm	57	Strathmore
North	Whitsunday Solar Farm	57	Strathmore
Wide Bay	Teebar Solar Farm	53	Teebar Creek
Bulli	Darling Downs Solar Farm	110	Darling Downs

Additionally, Powerlink has been advised of 117MW of committed semi-scheduled renewable projects connecting downstream within the distribution network.

7.3 Network capacity for new generation

Powerlink has assessed the potential generation capacity which could be accommodated at various locations across the transmission network. This information is available on Powerlink's website. The data presented is not comprehensive, and is not intended to replace the existing processes that must be followed to seek connection to Powerlink's transmission network.

7.3.1 Calculation methodology

Powerlink has assessed the available generation connection capacity at 60 locations across the network. Locations close to major urban areas were considered unlikely to host a large VRE project and were excluded from the assessment. In addition, substations operating at 275kV and 330kV were excluded from this study as connections at these voltages will generally accommodate generation levels in excess of 400MW.

Thermally Supportable Generation

A connection point's thermal capacity relates to the highest level of generation that can be injected into a connection point without exceeding the rating of a transmission circuit following the loss of a network element. It may be possible for generation to be installed in excess of this level if a fast generation run-back scheme is implemented to limit generation output following the relevant network contingency events.

Each connection point's thermal capacity was calculated by applying generation of increasing levels to a connection point, displacing QNI transfer, and performing contingency analysis. The thermal limit of a connection point was assessed as being reached when a rating breach was identified.

System Strength Supportable Generation

A connection point's network strength capacity relates to the ability of power electronic connected systems to maintain stable operation. Short Circuit Ratio (SCR) is a commonly used metric for quantifying the power system's strength at a connection point, and is calculated by dividing the short circuit power (in MVA) at a connection point by the installed level of power electronic connected generation (also in MVA). The SCR at the connection point strongly influences a plant's ability to operate satisfactorily both in steady state and following a system disturbance[4]. Powerlink has assumed a SCR of two to determine generation capacity.

Multiple independent power electronic connected systems in an area can interact with each other. Any interaction between such systems, including non-synchronous generation and certain network infrastructure[5], may reduce the system strength capacity available at that location.

[4] "Connection of wind farms to weak AC networks", CIGRE WG B4.62, December 2016.
[5] Including Static VAr Compensators (SVCs) and Static Synchronous Compensators (STATCOMs)

Overall Non-Synchronous Supportable Generation

The overall non-synchronous supportable generation is the lower of the thermally supportable generation and the system strength supportable generation at each location.

7.3.2 Network capacity results

As mentioned in Section 7.2, Powerlink has received more than 80 new connection enquiries and finalised seven connection agreements for new VRE generation since publication of the 2016 TAPR. As a consequence, the capacity results calculated via the methodology described in Section 7.3.1 are continually changing. On this basis, the revised approach is to present the detailed calculation results on Powerlink's website in order to more efficiently address the dynamics of this evolving environment and best serve the needs of customers (refer to Powerlink's Generation Capacity Guide). Powerlink expects to maintain this data as required and encourages proponents to make informed investment decisions through the established connection enquiry process. This process includes the provision of detailed capacity and congestion information for customers seeking to connect to Powerlink's transmission network. To join Powerlink's Non-network Engagement Stakeholder Register (NNESR) and be notified of any updates to this data, please email networkassessments@powerlink.com.au.

The calculation methodology assumes the existing configuration of the transmission network and the technical standards that currently apply to transmission network design and power system operation. Changes to either of these have the potential to change the network capacity available to generators. The analysis also assumes that the proposed generation facility will comply with the NER's automatic access standard for reactive power capability.

Under the open access regime which applies in the National Electricity Market (NEM), it is possible for generation to be connected to a connection point in excess of the network's capacity, or for the aggregate generation within a zone to exceed the capacity of the main transmission backbone. Where this occurs, this dispatch of generation may need to be constrained. This 'congestion' is managed by AEMO in accordance with the procedures and mechanisms of the NEM. It is the responsibility of each generator proponent to assess and consider the consequences of potential congestion, both immediate and into the future.

Powerlink proactively monitors the potential for congestion to occur, and will assess the potential network augmentations to maximise market benefits using the Australian Energy Regulator's (AER) Regulatory Investment Test for Transmission (RIT-T)[6]. Where augmentations are found to be economic, Powerlink may augment the network to ensure that the electricity market operates efficiently and at the minimum overall long run cost to consumers. Generator proponents are encouraged to refer to other sections of this document which provide more detail.

As a transmission network service provider, the scheduling of generation does not form part of Powerlink's role and as such, the indicative connection point generation capacity limits are not related to the scheduling and dispatch of generation in the NEM.

7.4 Potential changes in technical standards

As higher levels of non-synchronous VRE sources are introduced into the NEM, new technical and regulatory challenges arise. The characteristics of the power system vary as synchronous generators, which inherently provided services such as inertia and system strength are displaced. Impacts such as the management of frequency and performance standards under weak system conditions require different approaches. This section summarises a number of initiatives in response to these challenges.

[6] Details of the RIT-T, including the market benefits which can be considered, are available on the Australian Energy Regulator's website: Regulatory investment test for transmission (RIT-T) and application guidelines 2010

New Rules[7] have been created that include a new classification of contingency event, known as the protected event, which allows power system security under particular non-credible event circumstances to be managed using a combination of ex-ante and ex-post actions. The new rules include a framework to regularly review current and emerging power system frequency risks, both under and over frequency risks, and to identify and implement the most efficient means for their management.

The Australian Energy Market Commission (AEMC) is also conducting a review into regulatory frameworks that affect system security in the NEM. This system security review addresses two key issues:

- the management of frequency following contingency events and
- system strength in a power system with reduced levels of synchronous generation.

A directions paper[8], published in March, details the AEMC's proposed approach and measures, which include potential obligations on new non-synchronous generators to:

- be capable of providing a fast frequency response
- withstand higher rates of change of frequency (RoCoF) and
- improve system strength at its connection point for existing generators to continue to meet their performance standard.

The "Independent Review into the Future Security of the National Electricity Market"[9] published in June 2017 also recommends a review of the connection standards. In particular, the connection standards review is to focus on system strength, reactive power, voltage control, generator performance and active power control. Powerlink will continue to monitor changes in technical standards as they develop.

7.5 Supporting variable renewable electricity infrastructure development

As part of Powerlink's commitment to innovation and responding effectively to the needs of customers, Powerlink has made a number of refinements to its connection process during 2016/17.

At Powerlink's Transmission Network Forum held in July 2016, an interactive breakout session was held to seek input and feedback from stakeholders on how the transmission network can enable large-scale VRE generation. A summary of the feedback received is available on Powerlink's website[10], and the following sections outline the specific measures Powerlink has implemented in response. Powerlink will continue to seek and respond to feedback throughout 2017/18.

7.5.1 Connection cost

Proponents highlighted the cost of grid connection is a critical factor in progressing VRE generation projects. In response to the range of measures proposed to reduce or defer the cost of connection, Powerlink has implemented targeted changes that provide strategic benefits for proponents, including plant with asset lives matched to the 25 year project life and shortening of lead times and cost through standardisation.

7 Emergency frequency control schemes for excess generation
8 System Security Market Frameworks Review
9 Independent Review into the Future Security of the National Electricity Market
10 Stakeholder Engagement/Engagement Forums

7.5.2 Provision of information

Considerable stakeholder feedback related to Powerlink providing additional information to proponents regarding connection opportunities and the connections process, including:

- cost estimates being provided earlier in the process
- greater transparency on other connection enquiries active in an area
- establishing the information proponents will be required to provide earlier in the process and
- provision of site-specific information to enable proponents to determine site viability in a Geospatial Information Systems (GIS) format, which could then be updated in 'real time'.

In response, Powerlink has established a process to provide proponents, in a timely way, with project specific details of:

- connection options available, including viable connection locations, and cable/overhead infrastructure options
- network capacity, constraints and operational issues
- easement issues, including existing easements and Powerlink-owned land, as well as potential consultation requirements and
- capital cost and connection charge estimates.

In relation to details of active connection enquiries, Powerlink is limited by the confidentiality requirements of the National Electricity Rules (NER). Powerlink has provided overviews in engagement forums and in Section 7.2 to communicate aggregate metrics regarding connection activities.

7.5.3 Shared network connections

There was also significant feedback relating to shared network connections, including the concept of 'Renewable Energy Zones' (REZs). In particular, proponents highlighted the need for active involvement from a range of stakeholders (including Government) for the concept to generate value. Stakeholders enquired about the potential for different funding models to incentivise clustering and overcome 'first mover' risk. Some raised concerns about aggregating high volumes of a single form of generation at a single point, with a potential impact upon intermittency, the risk of land banking, and the potential for additional delays in the connection process.

In response to this feedback, Powerlink is working with the Queensland Government on two initiatives, which are discussed in Section 7.5.4.

Powerlink acknowledges the potential for issues to arise from co-locating large volumes of homogeneous intermittent generation. The REZs concept works most efficiently when used to connect diverse forms of generation that are unlikely to achieve maximum output coincidently. The impact of increasing levels of generation intermittency on Frequency Control Ancillary Services (FCAS) requirements has recently been investigated by the Australian Energy Market Operator's (AEMO) Future Power System Security Program. AEMO has presented on the results of this study, with a final report yet to be published.

7.5.4 Renewable Energy Zones (REZs)

Powerlink is committed to supporting the development of VRE projects in Queensland. Where economies of scale can be achieved through project clusters, Powerlink may consider the development of Renewable Energy Zones (REZs), subject to regulatory approvals and the conditions of its Transmission Authority.

The implementation of a REZ would require that consideration be given to a range of criteria, including economic benefit to customers, energy resource potential, infrastructure availability and access, stakeholder and local authority support, environmental suitability, and where possible, opportunity for deferral or replacement of planned network investment projects.

A REZ may be viewed as a network expansion into the zone of interest, as a high capacity transmission line or a connection hub, either of which would be aimed at supporting clusters of diverse VRE projects. These arrangements are generally more cost effective than the creation of multiple connection paths to the grid as infrastructure sharing reduces the need for asset duplication. Although this concept is aimed at identifying priority areas for development, it is not intended to preclude the development of VRE projects outside the targeted zones.

While the majority of recent interest focuses on solar related activity, Powerlink recognises considerable opportunity also exists for wind, biomass, geothermal and hydroelectric projects in Queensland. Powerlink believes the REZ concept works most efficiently when used to connect diverse forms of generation unlikely to achieve maximum output coincidently, allowing a portion of the infrastructure's capacity to be shared between parties with limited congestion.

As illustrated in figures 7.5 and 7.6, a REZ may involve:

- the establishment of a centralised hub, from which radial connections to individual renewable projects emanate
- a high-capacity radial transmission line, with renewable projects connecting along the length of this line
- a hybrid of these two options, with hub substations placed along the length of a new high-capacity transmission line.

Figure 7.5: REZ with high capacity transmission line

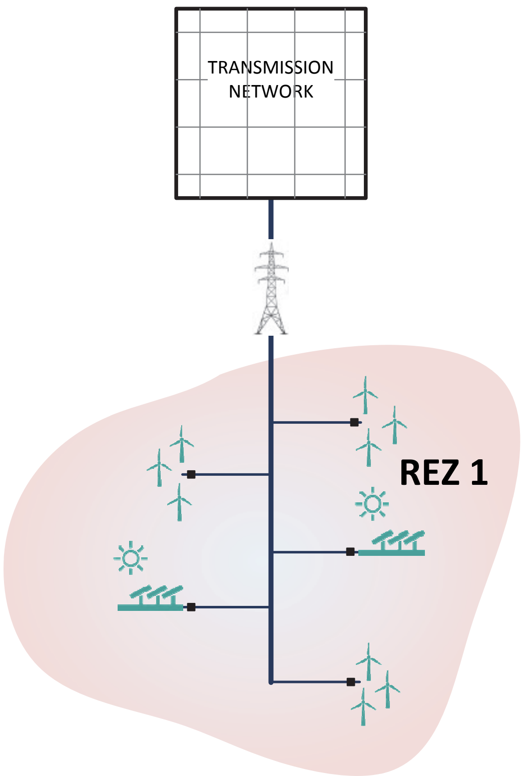
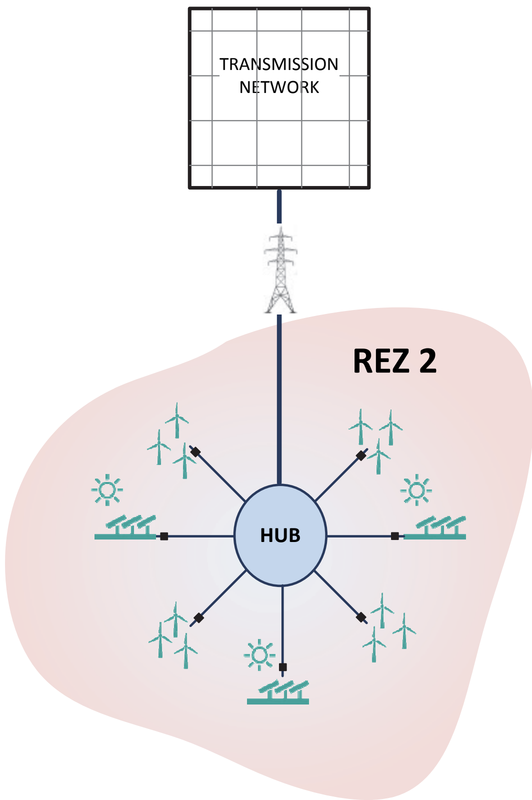


Figure 7.6: REZ with dedicated connection hub



Powerlink is working with the Queensland Government to progress two initiatives:

- Economic Development Queensland (EDQ) on the Aldoga Renewable Energy Zone project

  This project involves utilising a 1,250 hectare site adjacent to Powerlink's Larcom Creek Substation, with the potential to support up to 450MW of generation capacity. As a flagship project, it is envisaged that the Aldoga development will act as a catalyst for further opportunities. More information about this project is available on the website of the Queensland Department of Infrastructure, Local Government and Planning (DILGP).

- Powering North Queensland Plan (DEWS)

  This project includes a feasibility study into the development of strategic transmission infrastructure in north and north-west Queensland to support a clean energy hub. More information about this project is available on the Department of Energy and Water Supply (DEWS) website.

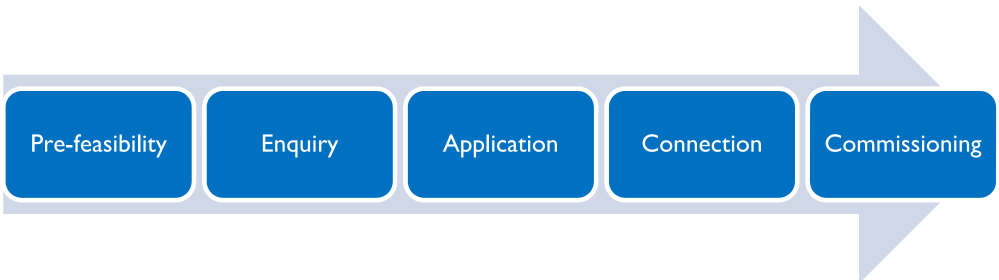
7.5.5 Proposed renewable connections in Queensland

DEWS provide mapping information on proposed (future) VRE projects, together with existing generation facilities (and other information) on its website. For the latest information on proposed VRE projects and locations in Queensland, please refer to DEWS website.

7.5.6 Further information

Powerlink will continue to work with market participants and interested parties across the renewables sector to better understand the potential for VRE, and to identify opportunities and emerging limitations as they occur. The National Electricity Rules (Clause 5.3) prescribes procedures and processes that Network Service Providers must apply when dealing with connection enquiries. Powerlink uses a five-stage approach as illustrated in Figure 7.7 below to facilitate this process.

Figure 7.7: Overview of Powerlink's existing network connection process



Proponents who wish to connect to Powerlink's transmission network are encouraged to contact BusinessDevelopment@powerlink.com.au. For further information on Powerlink's network connection process please refer to Powerlink's website[11] www.powerlink.com.au.

[11] Refer to Connecting to Powerlink's Network on the Powerlink website.

Appendices

Appendix A – Forecast of connection point maximum demands

Appendix B – Powerlink's forecasting methodology

Appendix C – Estimated network power flows

Appendix D – Limit equations

Appendix E – Indicative short circuit currents

Appendix F – Abbreviations

Appendix A – Forecast of connection point maximum demands

Tables A.1 to A.6 show 10-year forecasts of native summer and winter demand at connection point peak. These forecasts have been supplied by Powerlink customers.

The connection point reactive power (MVAr) forecast includes the customer's downstream capacitive compensation.

Groupings of some connection points are used to protect the confidentiality of specific customer loads.

In tables A.1 to A.6 the zones in which connection points are located are abbreviated as follows:

FN	Far North zone
R	Ross zone
N	North zone
CW	Central West zone
G	Gladstone zone
WB	Wide Bay zone
S	Surat zone
B	Bulli zone
SW	South West zone
M	Moreton zone
GC	Gold Coast zone

Table A.1 Ergon Energy connection point forecast of summer native maximum demand

Connection point	Voltage (kV)	Zone	2017/18		2018/19		2019/20		2020/21		2021/22		2022/23		2023/24		2024/25		2025/26		2026/27(1)	
			MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Alan Sherriff	132	R	26	13	26	13	26	13	26	13	27	13	27	13	27	13	27	13	27	13	28	14
Aligator Creek (Louisa Creek)	132	N	39	12	39	12	38	11	38	11	38	11	37	11	37	11	36	11	36	11	36	11
Alligator Creek	33	N	38	14	38	14	38	14	38	14	38	14	38	14	37	14	38	14	38	14	38	14
Biloela	66	CW	32	6	32	6	32	6	32	6	32	6	32	6	32	6	32	6	32	6	32	6
Blackwater	132	CW	29	17	29	17	28	17	28	17	28	17	27	17	27	16	27	16	27	16	26	16
Blackwater	66	CW	98	11	98	11	95	11	95	11	98	11	100	12	98	12	98	11	97	11	97	11
Bowen North	66	R	23	8	23	8	23	8	31	11	31	11	31	10	30	10	30	10	30	10	30	10
Bulli Creek (Waggamba)	132	B	19	3	19	3	19	3	19	3	19	3	19	3	18	3	18	3	18	3	18	3
Cairns	22	FN	47	0	47	0	46	0	46	0	45	0	45	0	44	0	44	0	44	0	44	0
Cairns City	132	FN	58	30	58	30	57	30	57	30	56	29	56	29	55	29	54	28	54	28	54	28
Calliope River	132	G	40	20	47	24	44	22	43	22	43	22	43	22	42	21	42	21	41	21	41	21
Cardwell	22	R	5	3	5	3	5	3	5	3	5	3	5	3	5	3	5	3	5	3	5	3
Chinchilla	132	SW	18	9	18	9	18	9	18	9	18	9	18	9	18	9	18	9	18	9	18	9
Clare South	66	R	81	26	82	26	80	26	81	26	80	26	77	25	76	24	76	24	76	24	76	24
Collinsville	33	N	15	8	15	8	15	8	16	8	16	8	16	8	16	8	16	8	16	8	16	8
Columboola	132	SW	60	9	61	9	60	9	60	9	59	9	59	9	58	8	58	8	58	8	58	8
Dan Gleeson	66	R	111	35	113	35	111	35	112	35	112	35	107	32	106	31	107	31	107	31	107	31
Dysart	66	CW	47	8	47	8	46	8	46	8	46	8	45	8	45	8	44	8	44	8	44	8
Edmonton	22	FN	46	10	47	10	47	10	47	10	48	10	48	10	48	10	48	10	49	10	49	10
Egans Hill	66	CW	70	13	71	13	71	13	72	13	72	13	72	13	72	13	72	13	73	13	73	14
El Arish	22	FN	5	1	5	1	5	1	5	1	6	1	6	1	6	1	6	1	6	1	6	1
Garbutt	66	R	105	33	106	33	105	33	106	33	106	33	101	30	100	29	100	29	101	29	101	29

Table A.1 Ergon Energy connection point forecast of summer native maximum demand *(continued)*

Connection point	Voltage (kV)	Zone	2017/18		2018/19		2019/20		2020/21		2021/22		2022/23		2023/24		2024/25		2025/26		2026/27(1)	
			MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Gin Gin	132	WB	135	16	135	16	133	16	133	16	131	16	131	16	129	16	128	15	128	15	127	15
Gladstone South	66	G	59	22	60	22	61	23	62	23	62	23	63	23	63	23	63	23	64	24	65	24
Ingham	66	R	19	5	19	5	19	5	19	5	19	5	19	5	18	5	18	5	18	5	18	5
Innisfail	22	FN	28	14	28	14	27	14	27	14	27	14	27	14	26	13	26	13	26	13	26	13
Kamerunga	22	FN	62	21	63	21	62	21	63	21	63	21	63	22	62	21	63	22	63	22	64	22
Lilyvale (Barcaldine & Clermont)	132	CW	34	6	34	6	34	5	34	5	33	5	33	5	33	5	33	5	33	5	33	5
Lilyvale	66	CW	138	60	139	60	144	63	145	63	152	66	152	66	150	65	149	65	149	65	149	65
Mackay	33	N	88	36	88	36	87	36	87	36	87	36	87	36	86	35	85	35	85	35	85	35
Middle Ridge	110	SW	207	30	208	30	205	30	206	30	204	30	204	30	201	29	200	29	200	29	200	29
Middle Ridge (Postmans Ridge)	110	M	9	4	9	4	9	4	9	4	9	4	9	4	9	4	9	4	9	4	9	4
Moranbah (Broadlea)	132	N	38	12	38	12	37	12	37	12	37	12	39	13	41	13	40	13	40	13	40	13
Moranbah	66 and 11	N	123	37	123	37	120	36	120	36	118	36	136	41	152	46	150	45	150	45	149	45
Moura	66	CW	58	19	58	19	57	19	57	19	57	19	57	19	56	19	56	18	56	18	56	18
Nebo	11	N	3	1	3	1	3	1	3	1	3	1	3	1	3	1	3	1	3	1	3	1
Newlands	66	N	33	13	33	13	34	14	37	15	37	14	36	14	36	14	35	14	35	14	35	14
Oakey	110	SW	28	6	28	6	28	6	28	6	27	5	27	5	27	5	26	5	26	5	26	5
Pandoin	66	CW	41	8	42	8	42	8	42	8	42	8	43	8	42	8	42	8	43	8	43	8
Pioneer Valley	66	N	62	28	62	28	61	27	61	27	61	27	61	27	60	27	60	27	60	27	60	27
Proserpine	66	N	48	17	48	17	48	17	48	17	48	17	48	17	47	16	47	16	47	16	47	16

Table A.1 Ergon Energy connection point forecast of summer native maximum demand *(continued)*

Connection point	Voltage (kV)	Zone	2017/18		2018/19		2019/20		2020/21		2021/22		2022/23		2023/24		2024/25		2025/26		2026/27(1)	
			MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Rockhampton	66	CW	98	18	98	18	96	18	96	18	95	18	95	18	93	17	93	17	93	17	93	17
Ross (Kidston, Milchester and Georgetown)	132	R	40	15	41	15	40	15	41	15	41	15	41	15	41	15	41	15	41	15	41	15
Stony Creek	132	N	6	3	6	3	6	3	6	3	6	3	6	3	6	3	6	3	6	3	6	3
Tangkam	110	SW	82	26	84	26	84	26	85	27	84	26	85	27	84	26	84	26	84	26	85	27
Tarong	66	SW	40	16	40	16	39	16	39	16	39	16	39	16	38	15	38	15	38	15	38	15
Teebar Creek (Isis and Maryborough)	132	WB	117	37	118	37	116	36	116	36	115	36	115	36	113	35	113	35	113	35	113	35
Townsville East	66	R	48	15	49	15	48	15	49	15	48	15	46	14	46	13	46	13	46	13	46	13
Townsville South	66	R	104	33	103	32	101	32	100	31	99	31	94	28	91	27	91	26	90	26	89	26
Tully	22	R	15	7	15	7	14	7	14	7	14	7	14	7	14	7	14	7	14	7	14	7
Turkinje (Craiglie and Lakeland)	132	FN	20	6	20	6	20	6	20	6	20	6	20	6	20	6	19	6	20	6	20	6
Turkinje	66	FN	60	16	60	16	62	16	68	18	67	18	67	18	66	17	65	17	65	17	65	17
Woolooga (Kilkivan)	132	WB	25	3	25	3	25	3	25	3	25	3	25	3	24	3	24	3	24	3	24	3
Woree (Cairns North)	132	FN	47	21	49	21	50	22	51	23	53	23	54	24	55	24	56	25	58	25	59	26
Yarwun (Boat Creek)	132	G	39	23	39	23	38	22	38	22	38	23	39	23	39	23	38	23	38	23	38	23
Hail Creek and King Creek	Various	Various	40	9	40	9	39	9	39	9	39	9	39	9	38	9	38	9	38	9	37	9

Note:

(1) Connection point loads for summer 2026/27 have been extrapolated.

Table A.2 Ergon connection point forecast of winter native maximum demand

Connection point	Voltage (kV)	Zone	2017		2018		2019		2020		2021		2022		2023		2024		2025		2026	
			MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Alan Sherriff	132	R	23	12	23	12	23	12	23	12	23	12	23	12	23	12	23	12	23	12	23	12
Alligator Creek (Louisa Creek)	132	N	41	13	41	13	41	13	39	13	40	13	39	13	39	13	39	12	39	12	38	12
Alligator Creek	33	N	37	14	37	14	37	14	36	13	37	14	36	13	36	13	36	13	36	13	36	13
Biloela	66	CW	32	4	32	4	32	4	31	4	31	4	31	4	31	4	31	4	31	4	30	4
Blackwater	132	CW	34	24	34	23	34	23	33	23	33	23	32	22	33	22	32	22	32	22	32	22
Blackwater	66	CW	102	14	100	14	101	14	98	14	102	14	104	15	104	15	103	15	103	15	105	15
Bowen North	66	R	23	8	24	8	24	8	30	10	33	11	32	11	32	11	32	11	32	11	32	11
Bulli Creek (Waggamba)	132	B	21	11	21	11	21	11	21	10	21	10	21	10	21	10	21	10	21	10	21	10
Cairns	22	FN	45	6	44	6	45	6	43	5	43	5	43	5	43	5	42	5	42	5	42	5
Cairns City	132	FN	52	29	51	28	52	29	50	28	50	28	50	27	50	27	49	27	49	27	49	27
Calliope River	132	G	40	20	46	23	46	23	42	21	43	21	42	21	42	21	42	21	41	21	41	21
Cardwell	22	R	5	3	5	3	5	3	4	3	4	3	4	3	4	3	4	3	4	3	4	3
Chinchilla	132	SW	20	5	19	5	20	5	19	5	19	5	19	5	19	5	19	5	19	5	19	5
Clare South	66	R	66	18	65	18	66	18	64	17	65	18	64	17	64	17	64	17	64	17	64	17
Collinsville	33	N	16	7	15	7	16	7	15	7	15	7	15	7	15	7	15	6	15	6	15	6
Columboola	132	SW	112	27	111	27	112	27	109	26	110	27	108	26	108	26	107	26	107	26	106	26
Dan Gleeson	66	R	90	50	90	50	91	50	89	49	91	50	90	49	84	43	84	42	84	42	84	43
Dysart	66	CW	49	8	49	8	49	8	48	8	48	8	47	8	47	8	47	8	46	8	46	8
Edmonton	22	FN	33	6	33	6	33	6	32	6	32	6	32	6	32	6	31	6	31	6	31	6
Egans Hill	66	CW	73	15	73	15	74	16	72	15	73	15	73	15	73	15	73	15	73	15	74	15
El Arish	22	FN	4	1	4	0	4	1	4	0	4	0	4	0	4	0	4	0	4	0	4	0
Garbutt	66	R	75	41	75	41	76	42	74	41	75	41	74	41	69	35	69	35	69	35	70	35

Table A.2 Ergon connection point forecast of winter native maximum demand *(continued)*

Connection point	Voltage (kV)	Zone	2017		2018		2019		2020		2021		2022		2023		2024		2025		2026	
			MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Gin Gin	132	WB	118	16	117	16	117	16	114	15	115	15	113	15	113	15	112	15	111	15	111	15
Gladstone South	66	G	58	19	58	19	59	19	59	20	60	20	59	20	60	20	60	20	60	20	60	20
Ingham	66	R	38	7	38	7	38	7	37	6	37	6	37	6	37	6	36	6	36	6	36	6
Innisfail	22	FN	22	11	22	11	22	11	22	11	22	11	21	11	21	11	21	11	21	11	21	10
Kamerunga	22	FN	47	14	47	14	47	14	46	14	46	14	45	13	45	13	45	13	44	13	44	13
Lilyvale (Barcaldine & Clermont)	132	CW	30	2	30	2	30	2	29	2	30	2	29	2	29	2	29	2	29	2	29	2
Lilyvale	66	CW	142	60	140	59	143	60	146	61	147	62	155	65	155	65	153	64	152	64	152	64
Mackay	33	N	71	42	70	42	71	43	69	42	70	42	70	42	70	42	70	42	70	42	70	42
Middle Ridge	110	SW	261	24	259	23	261	24	255	23	257	23	253	23	254	23	252	23	252	23	251	23
Middle Ridge (Postmans Ridge)	110	M	11	4	11	4	12	4	11	4	12	4	11	4	12	4	12	4	12	4	12	4
Moranbah (Broadlea)	132	N	46	15	46	15	46	15	45	15	45	15	47	15	50	16	49	16	49	16	49	16
Moranbah	66 and 11	N	104	30	119	34	119	34	116	33	116	33	134	39	154	44	152	44	151	44	151	43
Moura	66	CW	60	19	59	19	60	19	58	18	59	18	58	18	59	18	58	18	58	18	58	18
Nebo	11	N	3	1	3	1	3	1	3	1	3	1	3	1	3	1	3	1	3	1	3	1
Newlands	66	N	35	13	35	13	37	14	39	15	39	15	39	15	39	15	38	15	38	15	38	15
Oakey	110	SW	21	4	21	4	21	4	20	4	20	4	20	4	20	4	20	4	20	4	19	4
Pandoin	66	CW	38	8	37	8	38	8	37	8	38	8	37	8	38	8	38	8	38	8	38	8
Pioneer Valley	66	N	54	22	54	22	54	23	53	22	54	22	53	22	53	22	53	22	53	22	53	22

Table A.2 Ergon connection point forecast of winter native maximum demand *(continued)*

Connection point	Voltage (kV)	Zone	2017		2018		2019		2020		2021		2022		2023		2024		2025		2026	
			MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Proserpine	66	N	49	18	48	18	49	18	47	18	48	18	47	18	48	18	47	17	47	17	47	17
Rockhampton	66	CW	90	19	89	19	89	19	86	18	87	18	85	18	85	18	84	18	84	17	83	17
Ross (Kidston, Milchester and Georgetown)	132	R	61	20	61	20	62	20	60	20	61	20	61	20	61	20	61	20	61	20	61	20
Stony Creek	132	N	6	3	6	3	6	3	6	3	6	3	6	3	6	3	6	3	6	3	6	3
Tangkam	110	SW	85	21	84	21	85	21	83	21	84	21	83	21	83	21	82	20	81	20	81	20
Tarong	66	SW	42	13	41	13	41	13	40	13	40	13	40	12	40	12	39	12	39	12	39	12
Teebar Creek (Isis and Maryborough)	132	WB	99	13	98	13	99	13	96	12	97	13	95	12	95	12	95	12	94	12	94	12
Townsville East	66	R	34	19	34	19	35	19	34	19	34	19	34	19	32	16	32	16	32	16	32	16
Townsville South	66	R	65	36	64	35	63	35	61	34	61	33	59	33	55	28	54	27	53	27	52	27
Tully	22	R	12	5	12	5	12	5	11	5	11	5	11	5	11	5	11	5	11	5	11	5
Turkinje (Craiglie and Lakeland)	132	FN	19	6	19	6	19	6	19	6	19	6	18	6	18	6	18	6	18	6	18	6
Turkinje	66	FN	59	13	63	14	63	14	64	15	71	16	70	16	70	16	69	16	69	16	69	16
Woolooga (Kilkivan)	132	WB	23	4	23	4	23	4	22	4	22	4	22	4	22	4	22	4	22	4	22	4
Woree (Cairns North)	132	FN	39	7	40	7	42	8	42	8	44	8	44	8	46	8	47	8	48	9	49	9
Yarwun (Boat Creek)	132	G	43	23	43	22	43	22	42	22	43	23	44	23	44	23	43	23	43	23	43	22
Hail Creek and King Creek	Various	N	44	9	43	9	44	9	42	9	43	9	42	9	42	9	42	8	41	8	41	8

Table A.3 Energex connection point forecast of summer native maximum demand

Connection point	Voltage (kV)	Zone	2017/18		2018/19		2019/20		2020/21		2021/22		2022/23		2023/24		2024/25		2025/26		2026/27	
			MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Abermain	110	M	58	20	58	20	58	20	58	20	59	20	59	20	59	20	59	20	58	20	58	20
Abermain	33	M	93	15	94	15	97	16	98	16	99	16	100	16	102	16	103	18	104	18	105	19
Algester	33	M	66	16	66	16	65	16	65	16	65	16	65	16	65	16	64	16	63	16	63	16
Ashgrove West	110	M	130	14	130	14	130	14	131	14	131	14	131	14	131	14	131	14	130	14	130	14
Ashgrove West	33	M	73	6	73	6	73	6	73	6	73	6	74	6	74	6	75	6	75	6	76	6
Belmont	110	M	425	257	425	256	426	257	436	263	439	265	444	268	446	269	445	269	434	262	434	262
Blackstone (Raceview)	110	M	92	13	94	13	95	13	95	13	95	14	96	14	96	14	96	14	96	14	97	14
Bundamba	110	M	36	23	36	23	36	23	36	23	37	23	37	23	37	23	37	23	37	23	37	23
Goodna	33	M	108	13	109	13	113	13	115	13	117	14	119	14	121	14	123	14	124	15	126	15
Loganlea	110	M	285	116	283	116	282	115	285	117	289	118	291	119	292	119	292	119	290	119	289	118
Loganlea	33	M	90	16	90	16	90	16	90	16	90	16	90	16	90	16	90	16	90	16	91	16
Middle Ridge (Postmans Ridge and Gatton)	110	M	112	15	112	15	112	15	113	15	113	15	114	15	114	15	114	15	114	15	114	15
Molendinar	110	GC	413	52	414	52	416	52	420	53	423	53	425	53	428	54	429	54	428	54	430	54
Mudgeeraba	110	GC	341	91	339	90	340	90	340	90	342	91	344	91	346	92	348	93	350	93	352	94
Mudgeeraba	33	GC	19	7	19	7	19	7	19	7	19	7	19	7	19	7	19	7	19	7	18	7
Murarrie	110	M	415	94	421	95	427	96	429	97	431	97	431	97	437	98	451	102	461	104	475	118
Palmwoods	110 & 132	M	361	176	361	176	363	177	367	179	375	183	380	185	386	188	387	189	389	190	391	190
Redbank Plains	11	M	23	8	23	8	24	8	24	8	25	8	25	8	26	9	26	9	27	9	27	9
Richlands	33	M	125	34	125	34	125	34	125	34	125	34	125	34	125	34	124	34	123	34	123	34
Rocklea	110	M	159	65	159	64	160	65	160	65	161	65	162	66	162	66	168	69	185	76	185	75

Table A.3 Energex connection point forecast of summer native maximum demand *(continued)*

Connection point	Voltage (kV)	Zone	2017/18		2018/19		2019/20		2020/21		2021/22		2022/23		2023/24		2024/25		2025/26		2026/27	
			MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Runcorn	33	M	50	7	50	7	50	7	50	7	50	7	50	7	50	7	49	7	49	7	49	7
South Pine	110	M	882	180	878	180	881	180	883	181	891	182	895	183	899	184	899	184	898	184	900	184
Sumner	110	M	34	16	34	16	33	16	33	15	33	15	33	15	33	15	33	15	32	15	32	15
Tennyson	33	M	168	27	171	28	176	29	176	29	178	29	175	29	172	28	174	28	175	29	176	29
Wecker Road	33	M	133	23	133	23	133	23	133	23	133	23	133	23	133	23	133	23	132	23	132	23
Woolooga (Gympie)	132	M	180	23	179	23	180	23	180	23	181	23	182	23	183	23	184	24	185	24	186	24

Table A.4 Energex connection point forecast of winter native maximum demand

Connection point	Voltage (kV)	Zone	2017		2018		2019		2020		2021		2022		2023		2024		2025		2026	
			MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Abermain	110	M	51	20	52	21	52	21	52	21	52	21	53	21	53	21	53	21	53	21	53	21
Abermain	33	M	69	6	71	6	72	6	75	6	76	6	78	6	79	6	81	7	83	7	84	7
Algester	33	M	58	30	59	31	59	31	58	30	58	30	58	30	58	30	58	30	58	30	58	30
Ashgrove West	110	M	135	13	137	13	137	13	136	13	137	13	138	13	138	13	139	13	141	13	141	13
Ashgrove West	33	M	58	7	59	7	59	7	58	7	59	7	59	7	60	7	61	7	62	7	62	7
Belmont	110	M	319	53	323	54	323	54	322	54	331	55	332	56	336	56	340	57	343	57	338	57
Blackstone (Raceview)	110	M	66	13	67	13	70	14	70	14	70	14	71	14	71	14	72	14	73	14	74	15
Bundamba	110	M	31	17	31	17	31	17	31	17	31	17	31	17	31	17	31	17	32	18	32	18
Goodna	33	M	85	7	89	8	92	8	93	8	95	8	97	8	100	9	103	9	105	9	107	9
Loganlea	110	M	289	85	291	86	290	86	289	85	295	87	297	88	299	88	303	89	305	90	307	91
Loganlea	33	M	78	11	79	11	79	11	78	11	79	11	79	11	79	11	80	12	81	12	81	12
Middle Ridge (Postmans Ridge and Gatton)	110	M	48	6	48	6	48	6	48	6	49	6	49	6	49	6	49	6	50	6	50	6
Molendinar	110	GC	371	27	375	28	379	28	379	28	382	28	384	28	387	28	392	29	398	29	402	29
Mudgeeraba	110	GC	245	68	249	69	248	69	246	69	249	69	250	70	251	70	255	71	259	72	263	73
Mudgeeraba	33	GC	19	6	19	6	19	6	19	6	19	6	19	6	19	6	19	6	19	6	19	6
Murarrie	110	M	323	70	330	71	334	72	338	73	341	74	344	74	349	75	355	77	367	79	377	81
Palmwoods	110 & 132	M	333	132	337	134	337	134	339	135	343	136	350	139	356	142	364	145	368	146	375	149
Redbank Plains	11	M	17	4	17	4	18	4	18	4	18	4	19	4	19	4	20	5	20	5	21	5

Table A.4 Energex connection point forecast of winter native maximum demand *(continued)*

Connection point	Voltage (kV)	Zone	2017		2018		2019		2020		2021		2022		2023		2024		2025		2026	
			MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Richlands	33	M	77	13	78	13	77	13	77	13	77	13	77	13	77	13	78	13	78	13	79	13
Rocklea	110	M	157	40	155	39	154	39	154	39	156	40	157	40	158	40	159	40	168	43	188	48
Runcorn	33	M	47	9	50	9	50	9	49	9	49	9	49	9	49	9	50	9	50	9	50	9
South Pine	110	M	707	96	715	98	714	97	711	97	718	98	723	99	727	99	734	100	741	101	748	102
Sumner	110	M	24	8	24	8	24	8	24	7	24	7	24	7	24	7	24	7	24	7	24	7
Tennyson	33	M	134	13	136	13	140	13	143	14	144	14	145	14	143	14	141	14	144	14	147	14
Wecker Road	33	M	100	10	101	10	101	10	100	10	101	10	101	10	101	10	102	10	103	10	104	10
Woolooga (Gympie)	132	M	184	10	187	10	187	10	186	10	188	10	189	10	190	10	193	11	195	11	198	11

Table A.5 Sum of individual summer native peak forecast demands for the transmission connected loads

Connection point (1)	2017/18		2018/19		2019/20		2020/21		2021/22		2022/23		2023/24		2024/25		2025/26		2026/27	
	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Transmission connected industrial loads (2)	1,130	366	1,130	366	1,130	366	1,130	366	1,130	366	1,130	366	1,130	366	1,130	366	1,130	366	1,130	366
Transmission connected mining loads (3)	67	26	68	26	70	27	72	27	76	29	101	37	103	38	104	38	104	38	104	38
Transmission connected CSG loads (4)	797	262	819	269	820	269	811	267	831	273	832	274	824	271	814	267	783	257	754	248
Transmission connected rail supply substations (5)(6)	257	-255	257	-255	257	-255	257	-255	257	-255	257	-255	257	-255	257	-255	257	-255	257	-255

Notes:

(1) Transmission connected customers supply 10-year active power (MW) forecasts. The reactive power (MVAr) forecasts are calculated based on historical power factors at each connection point. The new CSG connection points have been assigned a power factor based on customer agreement of 0.95 power factor (or better) for 132kV and 0.96 power factor (or better) for 275kV connection point voltage.

(2) Industrial loads include:

- Ross zone – Townsville Nickel, Sun Metals and Invicta Mill
- Gladstone zone – RTA, QAL and BSL.

(3) Mining loads include:

- North zone – Burton Downs, North Goonyella, Goonyella Riverside and Eagle Downs.

(4) CSG loads include:

- Bulli zone – Kumbarilla Park
- Surat zone – Wandoan South, Orana and Columboola.

(5) Rail supply substations include:

- North zone – Mackay Ports, Oonooie, Bolingbroke, Wandoo, Mindi, Coppabella, Wotonga, Peak Downs and Mt McLaren
- Central West zone – Norwich Park, Gregory, Blackwater, Bluff, Wycarbah, Duaringa, Grantleigh and Raglan
- Gladstone zone – Callemondah.

(6) There are a number of connection points that supply the Aurizon rail network and these individual connection point peaks have been summated. Due to the load diversity between the connection points, the real and reactive power (MW and MVAr) coincident peak is significantly lower.

Table A.6 Sum of individual winter native peak forecast demands for the transmission connected loads

Connection point (1)	2016		2017		2018		2019		2020		2021		2022		2023		2024		2025	
	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Transmission connected industrial loads (2)	1,135	371	1,135	371	1,135	371	1,135	371	1,135	371	1,135	371	1,135	371	1,135	371	1,135	371	1,135	371
Transmission connected mining loads (3)	65	25	67	25	69	26	70	26	75	28	99	36	100	36	100	36	100	36	100	36
Transmission connected CSG loads (4)	770	253	815	268	828	272	812	267	830	273	842	277	834	274	812	267	801	263	762	250
Transmission connected rail supply substations (5)(6)	257	-255	257	-255	257	-255	257	-255	257	-255	257	-255	257	-255	257	-255	257	-255	257	-255

Notes:

(1) Transmission connected customers supply 10-year active power (MW) forecasts. The reactive power (MVAr) forecasts are calculated based on historical power factors at each connection point. The new CSG connection points have been assigned a power factor based on customer agreement of 0.95 power factor (or better) for 132kVand 0.96 power factor (or better) for 275kV connection point voltage.

(2) Industrial loads include:

- Ross zone – Townsville Nickel, Sun Metals and Invicta Mill
- Gladstone zone – RTA, QAL and BSL.

(3) Mining loads include:

- North zone – Burton Downs, North Goonyella, Goonyella Riverside and Eagle Downs.

(4) CSG loads include:

- Bulli zone – Kumbarilla Park
- Surat zone – Wandoan South, Orana and Columboola.

(5) Rail supply substations include:

- North zone – Mackay Ports, Oonooie, Bolingbroke, Wandoo, Mindi, Coppabella, Wotonga, Peak Downs and Mt McLaren
- Central West zone – Norwich Park, Gregory, Blackwater, Bluff, Wycarbah, Duaringa, Grantleigh and Raglan
- Gladstone zone – Callemondah.

(6) There are a number of connection points that supply the Aurizon rail network and these individual connection point peaks have been summated. Due to the load diversity between the connection points, the real and reactive power (MW and MVAr) coincident peak is significantly lower.

Appendix B – Powerlink's forecasting methodology

A discussion of Powerlink's forecasting methodology is presented below. Powerlink is publishing its forecasting model with the 2017 TAPR (Transmission Annual Planning Report) which should be reviewed in conjunction with this description.

Powerlink's forecasting methodology for energy, summer maximum demand and winter maximum demand comprises the following three steps:

1. Transmission customer forecasts

   The loads of customers other than Energex and Ergon that connect directly to Powerlink's transmission network are assessed based on their forecasts, recent history and through direct consultation. Only committed load is included in the medium economic outlook forecast while some speculative load is included in the high economic outlook forecast.

2. Econometric regressions

   Forecasts are developed for Energex and Ergon based on relationships between past usage patterns and economic variables where reliable forecasts for these variables exist.

3. New technologies

   The impact of new technologies such as rooftop solar PV, distribution connected PV solar farms, battery storage, electric vehicles and demand side management (DSM) are factored into the forecasts for Energex and Ergon.

The discussion below provides further insight to steps 2 and 3, where DNSP (Distribution Network Service Provider) forecasts are developed.

Econometric regressions

DNSP forecasts are prepared for summer maximum demand, winter maximum demand and annual energy.

To prepare these forecasts, regression analysis is carried out using native demand and energy plus distribution connected solar photovoltaic (PV) which includes rooftop PV and distribution connected solar PV farms as this represents the total underlying Queensland DNSP load. This approach is necessary as the regression process needs to describe all electrical demand in Queensland, irrespective of the type or location of generation that supplies it.

Data Preparation

The first step in the regression analysis is to assemble historical native energy and maximum demand values as follows:

- Energy

  Determine DNSP native energy for each year from 2000/01. As this work is done in March, an estimation is prepared for the current financial year which will be updated with actual totals 12 months later when preparing the next TAPR.

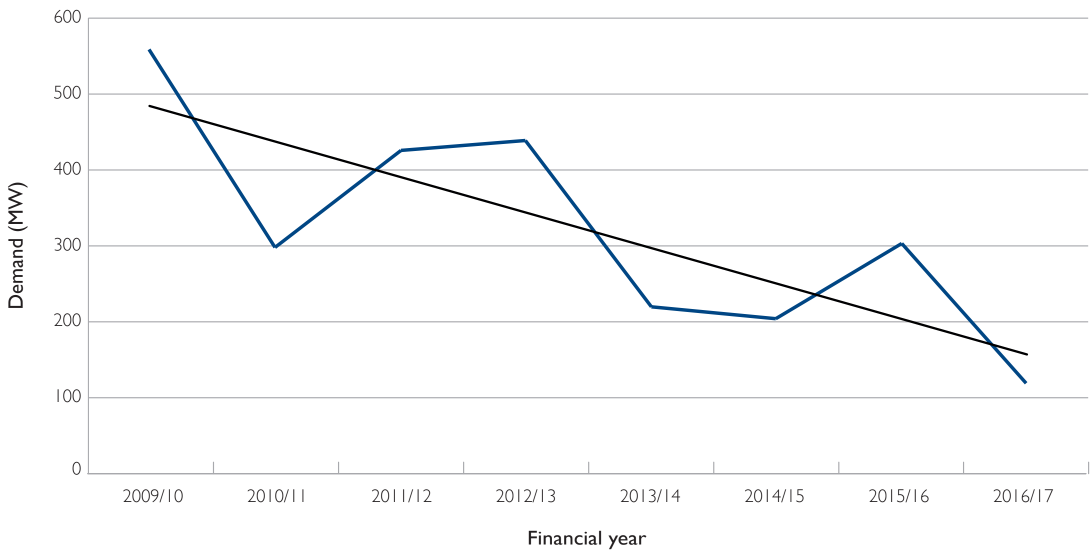
- Winter maximum demand

  The DNSP native demand at the time of winter state peak is collated for each year from winter 2000. Each of these demands are then normalised to average weather conditions (50% probability of exceedance (PoE)). Powerlink's method for weather correction is described later in this appendix.

- Summer maximum demand

  The DNSP native demand at the time of summer state peak is collated for each year from summer 2000/01. Each of these demands are then normalised to average weather conditions (50% PoE). DNSP native demand at the time of summer state evening peak (after 6pm) is also collated for each year from summer 2000/01. These demands are also corrected to average weather conditions. This evening series is used as the basis for regressing as evidence supports Queensland moving to a summer evening peak due to the increasing impact of distribution connected solar PV. This move to an evening peak by 2020/21 is supported through analysis of day and evening trends for corrected maximum demand as illustrated in Figure B.1.

Figure B.1 Difference in summer day and summer evening normalised maximum demand



Before the energy data can be used in a regression, it is necessary to make appropriate adjustments to account for distribution connected solar PV. This ensures that the full underlying DNSP load is being regressed. This energy adjustment assumes that rooftop solar PV, on average, has a 13% capacity factor. This 13% figure is based on observations through the Australian PV Institute.

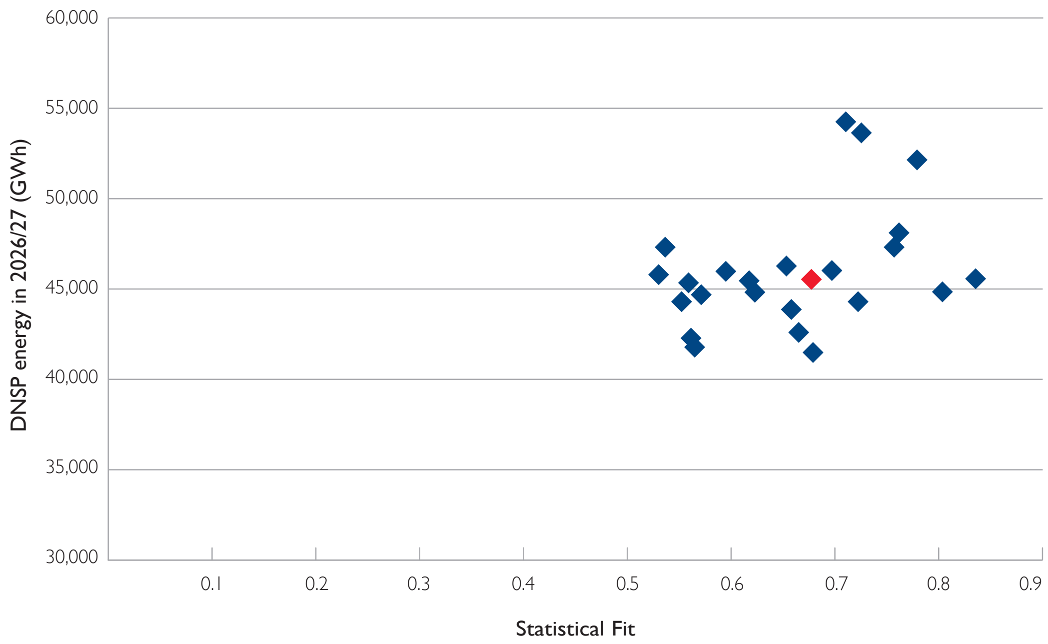
Following the regression for energy, the forecast is then adjusted to take into account future distribution connected solar PV contributions based on forecast distribution connected solar PV capacity. Forecast summer maximum demand is now based on an evening regression adjusted for the transition to an evening peak. Winter maximum demand has historically occurred in the evening, so no PV adjustment needs to be applied to the winter maximum demand forecast.

Energy regression

An energy regression is developed using historical energy data (described above) as the output variable and a price and economic variable for inputs. A logarithmic relationship between the input and output variables is used in keeping with statistical good practice.

Input variables are selected from two price variables (supplied by the Australian Energy Market Operator) and 16 economic variables (supplied by Deloitte Access Economics). This provides 32 combinations. For each of these 32 combinations the option of a one year delay to either or both input variables is also considered leading to a total of 128 regressions being assessed. Of these, the top 25 are selected and placed on a scatter plot as shown in Figure B.2 where the statistical fit and energy forecast at the end of the forecast period are assessed. The statistical fit combines several measures including R-squared, Durbin-Watson test for autocorrelation, mean absolute percentage error and mean bias percentage. All top 25 regressions shown in Figure B.2 qualify as statistically good regressions.

Figure B.2 Energy regression results



The selected regression shown above in red uses Queensland retail turnover with no delay and total electricity price with a one year delay. Within the population of statistically good regressions, the selected regression reflects a central outcome at the end of the regression period, uses broad based input variables and uses the same variables as used in the 2016 TAPR.

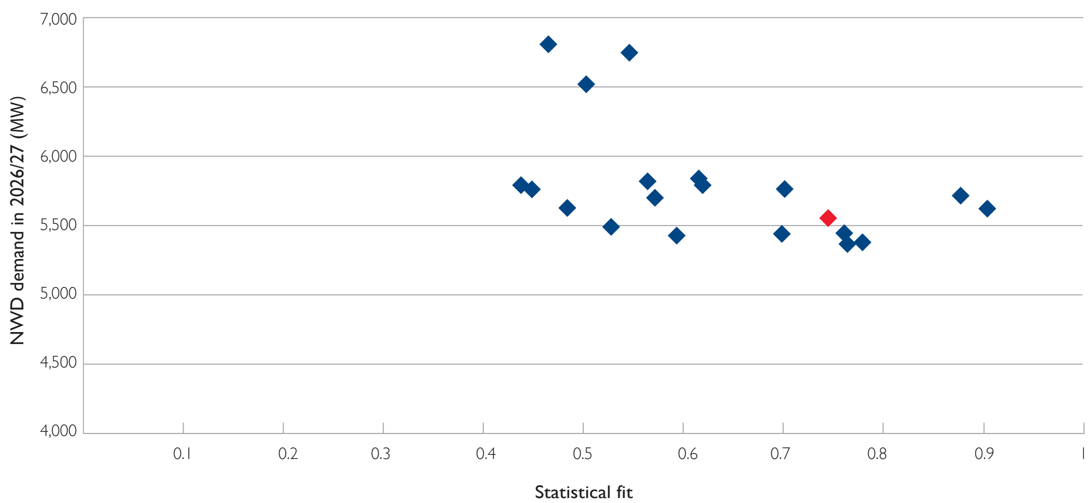
The regression is carried out using medium data leading to the medium economic forecast. High and low energy forecasts are then determined by applying the appropriate forecast economic data to the model.

Summer and winter maximum demand regressions

Maximum demand forecasts are based on two regressions. The temperature-normalised historical demands are split into two components: non-weather dependent (NWD) demand and weather dependent (WD) demand. NWD demand is determined as the median weekday maximum demand in the month of September. This reflects the low point in cooling and heating requirements for Queensland. The balance is the WD demand. For summer, this is the difference between the corrected summer maximum demand and the NWD demand based on the previous September. For winter, this is the difference between the corrected winter maximum demand and the NWD demand based on the following September.

The forecast NWD demand is therefore used for both the summer and winter maximum demand forecasts. The regression process used to determine the NWD demand is the same as used for energy with the results illustrated in Figure B.3.

Figure B.3 Non-weather dependent demand regression results

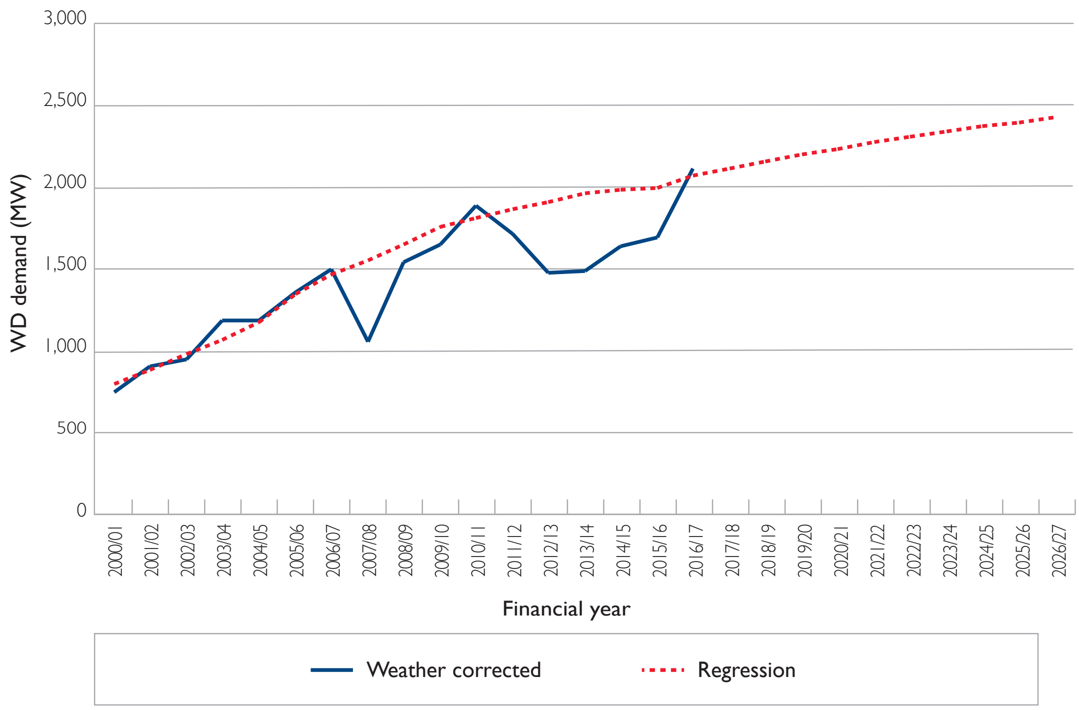


The selected regression shown above in red uses Queensland retail turnover and total electricity price, both with a one year delay. These are the same variables used in the 2016 TAPR.

The summer and winter WD demand is mainly a reflection of air conditioning usage. These regressions have been based on one input variable – population multiplied by Queensland air conditioning penetration. Historical and forecast air conditioning penetration rates are provided annually in the Queensland Household Energy Survey.

The 2016/17 summer WD demand (QHES) was a record peak and was substantially higher than the previous four summers. A number of troughs for the summer WD demand have been recorded, these include summer 2007/08 and the period from 2011/12 to 2015/16. Summer 2007/08 aligns with the initial shock of the Global Financial Crisis (GFC) and the period from 2011/12 to 2015/16 aligns with increases in electricity prices from about 2009. The QHES results indicate that households were more frugal in their electricity behaviours from 2011 to 2015 and that this behaviour has been tempered in 2016. The summer WD demand regression is illustrated in Figure B.4, with the years impacted by the GFC and increased prices removed from the regression.

Figure B.4 Weather dependent demand regression – summer



Similar to the energy analysis, low, medium and high economic outlook forecasts are produced for maximum demands by applying the appropriate economic forecasts as inputs. For maximum demand it is also necessary to provide three seasonal variation forecasts for each of these economic outlooks leading to nine forecasts in total. These seasonal variations are referred to as 10% PoE, 50% PoE and 90% PoE forecasts. They represent conditions that would expect to be exceeded once in 10 years, five times in 10 years and nine times in 10 years respectively. If the WD analysis described above is applied to historical demands, temperature corrected to 50% PoE conditions, it leads to the 50% PoE forecast. The analysis is repeated using historical demands corrected to 10% PoE and 90% PoE conditions to produce forecasts for each condition.

New technologies

Understanding the future impacts of new technologies is crucial to developing robust and meaningful demand and energy forecasts. Recognising the importance that these technologies will play in shaping future demand and energy, Powerlink is committed to furthering its understanding of these drivers. The new technologies discussed in this section are not incorporated within the energy regression and the summer and winter maximum demand regressions. To include these new technologies, post regression adjustments are made to the DNSP demand and energy forecasts.

Each year, Powerlink hosts a Demand and Energy forum to seek input from industry experts and stakeholders regarding new technologies and the impacts that they may have on future electrical demand and electrical energy consumption. A summary of the 2017 Demand and Energy Forum is available on Powerlink's website. Based on the input and discussion at this forum, Powerlink has adopted technology and other inputs as summarised in Table B.1.

Table B.1 New Technology Assumptions

	Rooftop PV	Distribution connected PV solar farms	Battery storage	Electric vehicles	Tariff reform / DSM	Customer momentum
Energy (GWh) (1)	2,498	1,894	0	-355	0	1,455
Maximum demand (MW) (2)	0	0	175	0	150	237
Installed capacity in 2026/27 (MW)	3,800	940				
Installed capacity in 2026/27 (MWh)			790			
First year of impact	now	now	now	now	2020/21	2019/20

Notes:

(1) This is the energy reduction in financial year 2026/27 compared to 2016/17.

(2) This is the maximum demand reduction in summer 2026/27 compared to summer 2016/17.

Powerlink recognises there is considerable uncertainty regarding the impact of new technology and other inputs on the demand and energy forecasts. Due to these uncertainties Powerlink has provided this additional information to provide transparency and allow readers to substitute alternative assumptions into the forecast if desired.

Rooftop solar PV

The installed capacity of rooftop solar PV in Queensland as at the end of 2016 was approximately 1,700MW. After a rapid uptake in the years 2011 to 2013, installations have now moderated to a rate of around 15MW[1] per month, predominately residential. This baseline level of growth is expected to continue.

As battery storage systems fall in price it is expected that an additional 300MW of rooftop solar PV will connect by 2026/27. In total, this will increase capacity of rooftop solar PV in Queensland to 3,800MW by 2026/27.

Analysis has revealed that Queensland will move to a summer evening peak by 2020/21 and so further rooftop solar PV which is predominantly installed facing north is expected to have little impact on maximum demand after this time. Energy impacts have been based on an average output of 13%[1] capacity.

Powerlink is a member of the Australian PV Institute which supplies real time data for rooftop solar PV. This information allows Powerlink to analyse a range of PV effects and in particular its impact on maximum demand.

Future impacts of rooftop solar PV will need to be monitored carefully. As older systems fail, they may be replaced with larger systems or not replaced at all. Furthermore, if enabling factors such as government incentives or rapid uptake of battery storage were to occur, then future rooftop solar PV installation levels could increase beyond this forecast.

Distribution connected solar PV farms

State and Federal Government initiatives are driving future renewable capacity in Queensland predominately in the form of solar PV farms. Solar PV farms connecting directly to the distribution network will reduce the amount of energy being delivered through the transmission network and accelerate the delay of the state peak from around 5:30pm to an evening peak. The 2016 TAPR did not separate rooftop solar PV and distribution connected solar PV farms. Current initiatives are expected to result in approximately 490MW of PV solar farms connecting to the distribution network by 2020.

[1] Based on information obtained from the Australian PV Institute

Future VRE initiatives by State and Federal Government to support Australia's commitment to the Paris Accord are expected to drive increases in distribution connected PV solar farms from 2023.

Battery storage

Battery storage technology has the potential to significantly change electricity consumption patterns. In particular, this technology could "flatten" electricity usage and thereby reduce the need to develop transmission services to cover short duration peaks. By coupling this technology with rooftop solar PV, consumers may have the option to go "off grid". A number of factors will drive the uptake of this technology, namely:

- affordability
- introduction of time of use tariffs
- continued uptake of rooftop solar PV generation
- practical issues such as space, aesthetics and safety
- whether economies of scale favour a particular level of aggregation.

The 2016 QHES indicates that around 8% of Queensland households are considering the purchase of a battery storage system. However the same survey indicates that most people underestimate the current price of installing a storage solution. For the 2017 TAPR, Powerlink developed a new methodology to estimate the uptake of battery storage and the impact on summer maximum demand. The methodology involves the following steps:

- Estimate the maximum population of residential battery storage systems, based on dwelling type, home ownership, and household income factors. This is estimated to be 400,000 households with batteries.
- Bell curved the uptake of battery storage systems based on the financial payback period, with a mean of five years and a standard deviation of 1.75 years.
- Calculate the pay-back period for a market leading battery storage system for each year in the 10-year outlook period. The installation price of future battery storage systems was estimated using CSIRO's battery cost path from their electricity network transformation roadmap interim program report.
- From the bell curve of battery uptake (based on the financial payback period) and the calculated yearly payback period of a battery system, calculate the uptake of battery storage systems. Multiply the yearly uptake by the predicted average size of a battery storage system (10kWh), to calculate a predicted yearly uptake in MWh.
- Calculate the yearly maximum demand reduction by taking into account the maximum discharge rate of the fleet of battery storage systems (a MW figure equivalent to 37% of the energy storage capacity) and the proportion of systems that are expected to be discharging at the time of summer maximum demand (assumed to be 60%).

Electric vehicles

The uptake of electric vehicles in Australia is quite low compared to world leading countries such as Norway and the Netherlands. Without government policy support for the adoption of electric vehicles, uptake is expected to be limited in the short-term. The expected reduction in battery costs will likely lift electric vehicle sales in the medium to long-term.

Powerlink has adopted the neutral uptake scenario from the Electric Vehicle Insights paper[2] prepared in August 2016 by Energeia for AEMO.

It is estimated that a 1% penetration of electric vehicles on the road would result in approximately 0.2% increase in total energy usage.

It is expected that most owners will charge their electric vehicles during off peak periods, resulting in minimal increase in maximum demand. Therefore, Powerlink has not included a specific adjustment for electric vehicles in its maximum demand forecast.

[2] Available on AEMO's website, at www.aemo.com.au

Tariff reform and demand side management

Network tariff reforms could influence consumer behaviour, shifting energy usage away from peak times. In addition to this maximum demand reduction, it is anticipated that network tariff reforms could also influence future use of battery storage technology, encouraging consumers to draw from batteries during maximum demand / high price times. The extent to which this occurs will depend on how quickly new tariffs are offered, the tariff structure and the adoption rate.

"In Australia and internationally there is evidence that customers will significantly reduce their demand in response to well-designed price signals that reward off-peak use and peak demand management. Sixty percent of trials internationally have resulted in peak reductions of 10 per cent or more."[3]

A big challenge to tariff reform is gaining consumer acceptance. Many consumers dislike complicated tariffs and any move to remove existing tariff cross subsidies could meet with resistance. Some of this peak reduction is already captured through the battery storage allowance described above. An additional 150MW has been assumed within this forecast and represents a further 2% reduction in the total maximum demand from the Energex and Ergon networks. As tariff reform is likely to result in load shifting, the impact on energy consumption is expected to be negligible.

Customer momentum factor

Over the last 10 years, many customers have been purchasing appliances with higher energy efficiency ratings and adopting more energy efficient behaviours in an effort to minimise financial impacts. The electricity price metric used in the regression model is forecast to increase by a further 16% over the next 10 years. The logic hardwired within the regression model suggests that customers will change their behaviour in response to moderating electricity prices.

To allow for this effect, a customer momentum factor has been developed and is explicitly incorporated within the energy and non-weather dependent demand regressions. The impact of price on electricity usage is determined for the last 10 years. Rather than simply accepting the regression model's prediction for the next 10 years, a weighting of two thirds has been applied. This results in a dampening effect, limiting the 'bounce-back' in energy and demand with the moderation of electricity prices.

It is expected that this factor will be reduced or removed in future years as additional information on customers' actual behaviour during moderating electricity prices is captured in the data series.

Weather correction methodology

Maximum demand is strongly related to the temperature. To account for the natural variation in the weather from year to year, temperature correction is carried out to normalise raw demand observations. Three conditions are calculated:

- 10% PoE demand, corresponding to a one in 10-year season (i.e. a particularly hot summer or cold winter)
- 50% PoE demand, which indicates what the demand would have been if it was an 'average' season
- 90% PoE demand, corresponding to a nine in 10-year season (particularly mild weather).

Within each year, separate temperature corrections are calculated for extended summer and extended winter seasons. Summer is taken as November to March. Winter is taken as May to August.

Temperature correction is applied to historical metered load supplied to connection points with Ergon and Energex. Powerlink's other direct-connect customers are largely insensitive to temperature.

Powerlink's temperature correction process is described below:

- Develop composite temperature

  The temperature from multiple weather stations is combined to produce a composite temperature for all of Queensland. The weighting of each weather station is based on the amount of Energex and Ergon-supplied load in the vicinity of that weather station.

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- Exclude mild days and holidays

  To ensure that the fitted model accurately describes the relationship between temperature and maximum demand on days when demand is high, days with mild weather, and the two-week period around Christmas (when many businesses are closed) are excluded from the dataset.

- Calculate a regression model for each season since 2000

  A regression model is calculated for each summer since 2000/01 and winter since 2000, expressing the daily maximum demand as a function of: daily maximum temperature, daily minimum temperature, daily 6pm temperature, and whether the day is a weekday.

- For each season, determine the 10% and 50% PoE thresholds using 22 years of weather data

  The regression model calculated for each season is then applied to the daily weather data recorded since 1995. This effectively calculates what the maximum demand would have been on each day if the relationship between maximum demand and temperature described by the model had existed at the time. A Monte-Carlo approach is used to incorporate the standard error from each season's regression model. The maximum demand calculated for each of the 22 years is recorded in a list, and the 10th, 50th and 90th percentile of the list is calculated to determine the 10% PoE, 50% PoE and 90% PoE thresholds.

- Final Scaling to Avoid Bias: To ensure that temperature correction process does not introduce any upward or downward bias, for each summer since 2000/01 and winter since 2000, the ratio of the calculated 50% PoE threshold to the actual maximum demand is calculated. The calculated PoE thresholds are divided by the average of these ratios.

Applying this methodology, the 2016/17 summer was hotter than average. Therefore, the 50% PoE demand is 90MW lower than the observed maximum demand on 12 February. The 2016 winter was slightly warmer than average, resulting in an upwards adjustment of 26MW to the observed winter maximum demand.

Appendix C – Estimated network power flows

This appendix illustrates 18 sample power flows for the Queensland region for each summer and winter over three years from winter 2017 to summer 2019/20. Each sample shows possible power flows at the time of winter or summer region 50% probability of exceedance (PoE) medium economic outlook demand forecast outlined in Chapter 2, with a range of import and export conditions on the Queensland/New South Wales Interconnector (QNI) transmission line.

The dispatch assumed is broadly based on historical observed dispatch of generators.

Sample conditions[1] include:

Figure C.3	Winter 2017 Queensland maximum demand 300MW northerly QNI flow
Figure C.4	Winter 2017 Queensland maximum demand 0MW QNI flow
Figure C.5	Winter 2017 Queensland maximum demand 700MW southerly QNI flow
Figure C.6	Winter 2018 Queensland maximum demand 300MW northerly QNI flow
Figure C.7	Winter 2018 Queensland maximum demand 0MW QNI flow
Figure C.8	Winter 2018 Queensland maximum demand 700MW southerly QNI flow
Figure C.9	Winter 2019 Queensland maximum demand 300MW northerly QNI flow
Figure C.10	Winter 2019 Queensland maximum demand 0MW QNI flow
Figure C.11	Winter 2019 Queensland maximum demand 700MW southerly QNI flow
Figure C.12	Summer 2017/18 Queensland maximum demand 200MW northerly QNI flow
Figure C.13	Summer 2017/18 Queensland maximum demand 0MW QNI flow
Figure C.14	Summer 2017/18 Queensland maximum demand 400MW southerly QNI flow
Figure C.15	Summer 2018/19 Queensland maximum demand 200MW northerly QNI flow
Figure C.16	Summer 2018/19 Queensland maximum demand 0MW QNI flow
Figure C.17	Summer 2018/19 Queensland maximum demand 400MW southerly QNI flow
Figure C.18	Summer 2019/20 Queensland maximum demand 200MW northerly QNI flow
Figure C.19	Summer 2019/20 Queensland maximum demand 0MW QNI flow
Figure C.20	Summer 2019/20 Queensland maximum demand 400MW southerly QNI flow

The power flows reported in this appendix assume the open points at the Gladstone South end of Callide A to Gladstone South 132kV double circuit. These open points can be closed depending on system conditions.

Table C.1 provides a summary of the grid section flows for these sample power flows and the limiting conditions capable of setting the maximum transfer.

Table C.2 lists the 275kV transformer nameplate capacity and the maximum loading of the sample power flows.

Figures C.1 and C.2 provide the generation, load and grid section legends for the subsequent figures C.3 to C.20. The reported generation and load is the transmission sent out and transmission delivered defined in Figure 2.4

1 The transmission network diagrams shown in this appendix are high level representations only, used to indicate zones and grid sections.

Table C.1: Summary of figures C.3 to C.20 – illustrative power flows and limiting conditions

Grid section (1)	Illustrative power flows (MW) at time of Queensland region maximum demand (2) (3)						Limit due to (4)
	Winter 2017	Winter 2018	Winter 2019	Summer 2017/18	Summer 2018/19	Summer 2019/20	
Figure	C.3 / C.4 / C.5	C.6 / C.7 / C.8	C.9 / C.10 / C.11	C.12 / C.13 / C.14	C.15 / C.16 / C.17	C.18 / C.19 / C.20	
FNQ Ross into Chalumbin 275kV (2 circuits) Tully into Woree 132kV (1 circuit) Tully into El Arish 132kV (1 circuit)	161/161/161	111/111/111	111/111/111	284/284/284	233/233/233	233/233/233	V
CQ-NQ Bouldercombe into Nebo 275kV (1 circuit) Broadsound into Nebo 275kV (3 circuits) Dysart to Peak Downs 132kV (1 circuit) Dysart to Eagle Downs 132kV (1 circuit)	532/532/532	498/498/498	501/501/501	726/726/726	677/677/677	675/675/675	Th V
Gladstone Bouldercombe into Calliope River 275kV (1 circuit) Raglan into Larcom Creek 275kV (1 circuit) Calvale into Wurdong 275kV (1 circuit) Callide A into Gladstone South 132kV (2 circuits)	718/608/598	701/772/619	703/765/590	527/529/532	501/533/537	533/534/539	Th
CQ-SQ Wurdong into Gin Gin 275kV (1 circuit) Calliope River into Gin Gin 275kV (2 circuits) Calvale into Halys 275kV (2 circuits)	1,717/2,025/2,067	1,332/1,636/2,069	1,347/1,650/2,071	1,767/1,767/1,767	1,718/1,832/1,832	1,832/1,832/1,832	Tr V
Surat Western Downs to Columboola 275kV (1 circuit) Western Downs to Orana 275kV (1 circuit) Tarong into Chinchilla 132kV (2 circuits)	480/480/480	508/510/508	516/516/516	477/475/412	493/493/491	496/494/496	V
SWQ Western Downs to Halys 275kV (2 circuits) Braemar (East) to Halys 275kV (2 circuits) Millmerran to Middle Ridge 330kV (2 circuits)	1,182/891/920	1,149/857/513	981/764/515	1,984/1,981/2,001	1,360/1,271/1,261	1,271/1,269/1,255	(5)
Tarong Tarong to South Pine 275kV (1 circuit) Tarong to Mt England 275kV (2 circuits) Tarong to Blackwall 275kV (2 circuits) Middle Ridge to Greenbank 275kV (2 circuits)	3,277/3,123/3,162	3,064/2,935/2,778	3,064/2,931/2,772	4,032/4,031/4,062	3,659/3,613/3,643	3,603/3,603/3,632	V

Table C.1: Summary of figures C.3 to C.20 – illustrative power flows and limiting conditions *(continued)*

Grid section (1)	Illustrative power flows (MW) at time of Queensland region maximum demand (2) (3)						Limit due to (4)
	Winter 2017	Winter 2018	Winter 2019	Summer 2017/18	Summer 2018/19	Summer 2019/20	
Figure	C.3 / C.4 / C.5	C.6 / C.7 / C.8	C.9 / C.10 / C.11	C.12 / C.13 / C.14	C.15 / C.16 / C.17	C.18 / C.19 / C.20	
Gold Coast Greenbank into Mudgeeraba 275kV (2 circuits) Greenbank into Molendinar 275kV (2 circuits) Coomera into Cades County 110kV (1 circuit)	691/691/754	687/687/749	684/684/747	793/793/824	783/783/814	780/780/812	V

Notes:

(1) The grid sections defined are as illustrated in Figure C.2. X into Y – the MW flow between X and Y measured at the Y end; X to Y – the MW flow between X and Y measured at the X end.

(2) Grid power flows are derived from the assumed generation dispatch cases shown in figures C.3 to C.20. The flows estimated for system normal operation are based on the existing network configurations and committed projects. Power flow across each grid section can be higher at times of local zone peak.

(3) All grid section power flows shown are within network capability.

(4) Tr = Transient stability limit, V = Voltage stability limit and Th = Thermal plant rating.

(5) As stated in Section 5.5.6, SWQ grid section is not expected to impose limitations to power transfer under intact system conditions with the existing levels of generating capacity.

Table C.2: Capacity and sample loadings of Powerlink owned 275kV transformers

275kV substation (1)(2)(3)(4) (Number of transformers x MVA nameplate rating)	Zone (5)	Possible MVA loading at Queensland region peak (6)(7)(8)						Dependence other than local load	
		Winter 2017	Winter 2018	Winter 2019	Summer 2017/18	Summer 2018/19	Summer 2019/20	Significant dependence on	Minor dependence on
Chalumbin 275/132kV (2x200MVA)	FN	17	20	20	34	33	34	Kareeya generation	
Woree 275/132kV (2x375MVA)	FN	117	125	127	206	218	214	Barron Gorge generation	Kareeya and Ross zone generation
Ross 275/132kV (3x250MVA)	R	133	130	124	218	210	214	Ross zone generation	Hamilton Solar Farm, Whitsunday Solar Farm and Collinsville Solar Farm
Nebo 275/132kV (1x200MVA, 1x250MVA and 1x375MVA)	N	275	275	276	293	289	286	Mackay GT generation	Hamilton Solar Farm, Whitsunday Solar Farm and Collinsville Solar Farm
Strathmore 275/132kV (1x375MVA)	N	120	119	121	160	156	156	Invicta and Clare South SF, Hamilton SF, Whitsundays SF, Collinsville SF generation	Ross zone generation
Bouldercombe 275/132kV (1x200MVA and 1x375MVA)	CW	135	132	132	161	159	159		
Calvale 275/132kV (1x250MVA)	CW	131	133	142	149	158	135	Callide, Yarwun and Gladstone generation and 132kV network configuration	
Lilyvale 275/132kV (2x375MVA)	CW	171	171	164	210	200	221	Barcaldine generation	CQ-NQ flow
Larcom Creek 275/132kV (2x375MVA)	G	73	70	76	74	61	73	Yarwun generation	
Gin Gin 275/132kV (2x250MVA)	WB	150	147	158	150	158	157		CQ-SQ flow
Teebar Creek 275/132kV (2x375MVA)	WB	74	77	77	69	76	70	Teebar Solar Farm	CQ-SQ flow
Woolooga 275/132kV (2x250MVA)	WB	239	237	237	227	228	228		CQ-SQ flow
Columboola 275/132kV (2x375MVA)	S	168	165	153	176	162	150	Surat zone generation	SW generation and 132kV network configuration
Middle Ridge 275/110kV (3x250MVA)	SW	280	273	268	283	280	279	Oakey generation	

Table C.2: Capacity and sample loadings of Powerlink owned 275kV transformers *(continued)*

275kV substation (1)(2)(3)(4) (Number of transformers x MVA nameplate rating)	Zone (5)	Possible MVA loading at Queensland region peak (6)(7)(8)						Dependence other than local load	
		Winter 2017	Winter 2018	Winter 2019	Summer 2017/18	Summer 2018/19	Summer 2019/20	Significant dependence on	Minor dependence on
Tarong 275/132kV (2x90MVA)	SW	32	40	39	21	19	16	Surat zone generation	SW generation and 132kV network configuration
Tarong 275/66kV (2x90MVA)	SW	40	39	39	39	38	38		
Abermain 275/110kV (1x375MVA)	M	147	152	153	186	187	188	110kV transfers to/from Blackstone and Goodna	Tarong flow
Belmont 275/110kV (2x250MVAand 2x375MVA)	M	458	441	457	526	533	532	110kV transfers to/from Loganlea	110kV transfers to/from Rocklea and Swanbank E generation
Blackstone 275/110kV (1x250MVA and 1x240MVA)	M	159	176	179	209	222	221		
Goodna 275/110kV (1x375MVA)	M	140	135	139	178	173	174	110kV transfers to/from Blackstone and Abermain	
Loganlea 275/110kV (2x375MVA)	M	370	371	375	445	451	449	110kV transfers to/from Belmont	110kV transfers to/from Molendinar and Mudgeeraba and Swanbank E generation
Murarrie 275/110kV (2x375MVA)	M	348	341	344	426	427	426		
Palmwoods 275/132kV (2x375MVA)	M	320	321	317	335	331	335		CQ-SQ flow
Rocklea 275/110kV (2x375MVA)	M	335	320	324	421	411	413	110kV transfers to/from South Pine and Belmont	110kV transfers to/from Blackstone and Swanbank E generation
South Pine East 275/110kV (3x375 MVA)	M	587	593	593	689	677	670		
South Pine West 275/110kV (1x375MVA and 1x250MVA)	M	262	251	253	324	316	316		CQ-SQ flow and Swanbank E generation
Molendinar 275/110kV (2x375MVA)	GC	419	420	455	477	513	510	110kV transfers to/from Loganlea and Mudgeeraba	Terranora Interconnector
Mudgeeraba 275/110kV (3x250MVA)	GC	369	369	323	406	353	352	110kV transfers to/from Molendinar and Terranora Interconnector	110kV transfers to/from Loganlea

Table C.2: Capacity and sample loadings of Powerlink owned 275kV transformers *(continued)*

Notes:

(1) Not included are 275/132kV tie transformers within the Calliope River Substation. Loading on these transformers varies considerably with local generation.

(2) Not included are 330/275kV transformers located at Braemar and Middle Ridge substations. Loading on these transformers is dependent on QNI transfer and south west Queensland generation.

(3) To protect the confidentiality of specific customer loads, transformers supplying a single customer are not included.

(4) Nameplate based on present ratings. Cyclic overload capacities above nameplate ratings are assigned to transformers based on ambient temperature, load cycle patterns and transformer design.

(5) Zone abbreviations are defined in Appendix A.

(6) Substation loadings are derived from the assumed generation dispatch cases shown within figures C.3 to C.20. The loadings are estimated for system normal operation and are based on the existing network configuration and committed projects. MVA loadings for transformers depend on power factor and may be different under other generation patterns, outage conditions, local or zone maximum demand times or different availability of local and dowstream capacitor banks.

(7) Substation loadings are the maximum of each of the northerly/zero/southerly QNI scenarios for each year/season shown within the assumed generation dispatch cases in figures C.3 to C.20.

(8) Under outage conditions the MVA transformer loadings at substations may be lower due to the interconnected nature of the sub-transmission network or operational switching strategies.

Figure C.1 Generation and load legend for figures C.3 to C.20

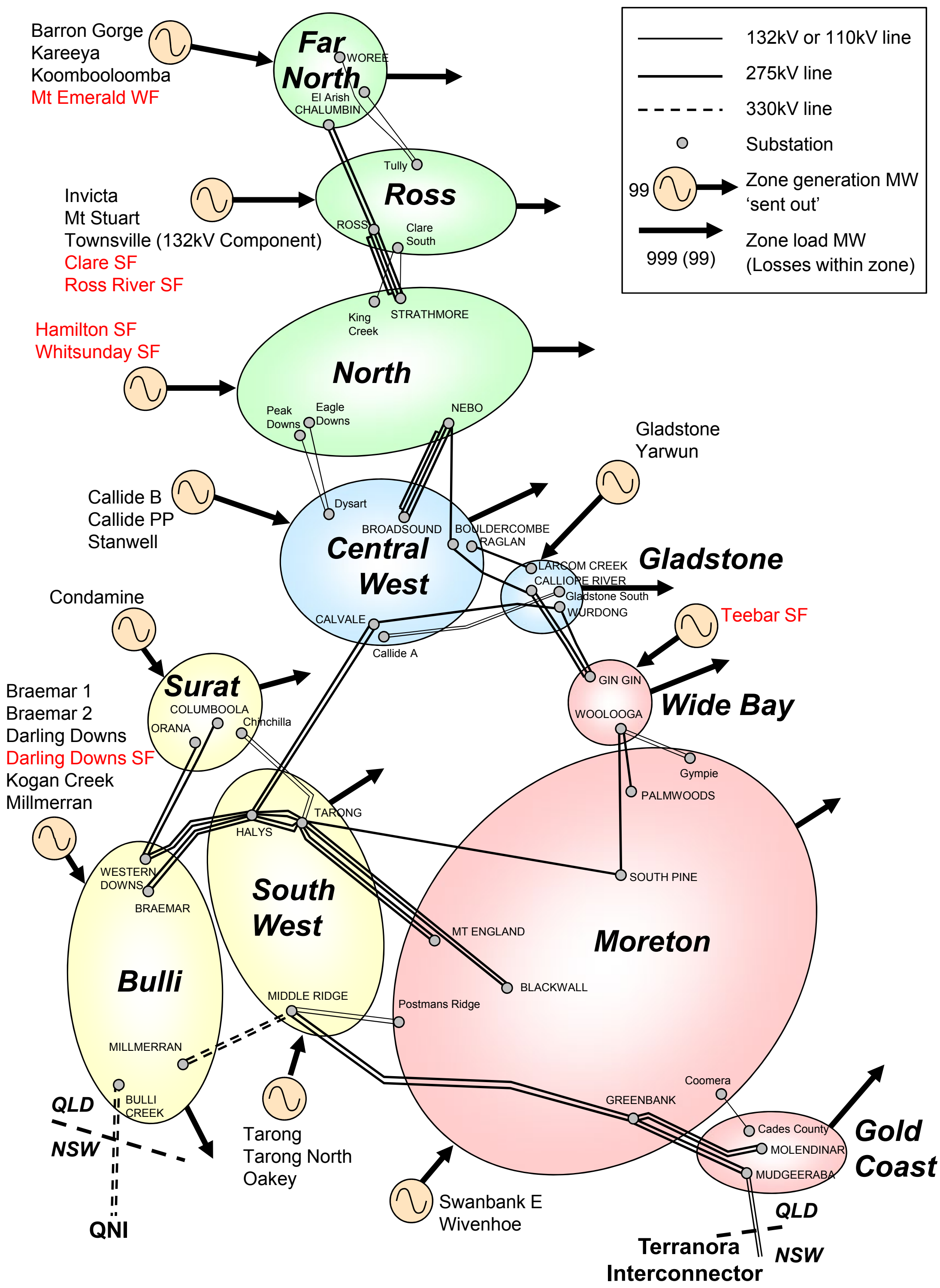


Figure C.2 Grid section legend for figures C.3 to C.20

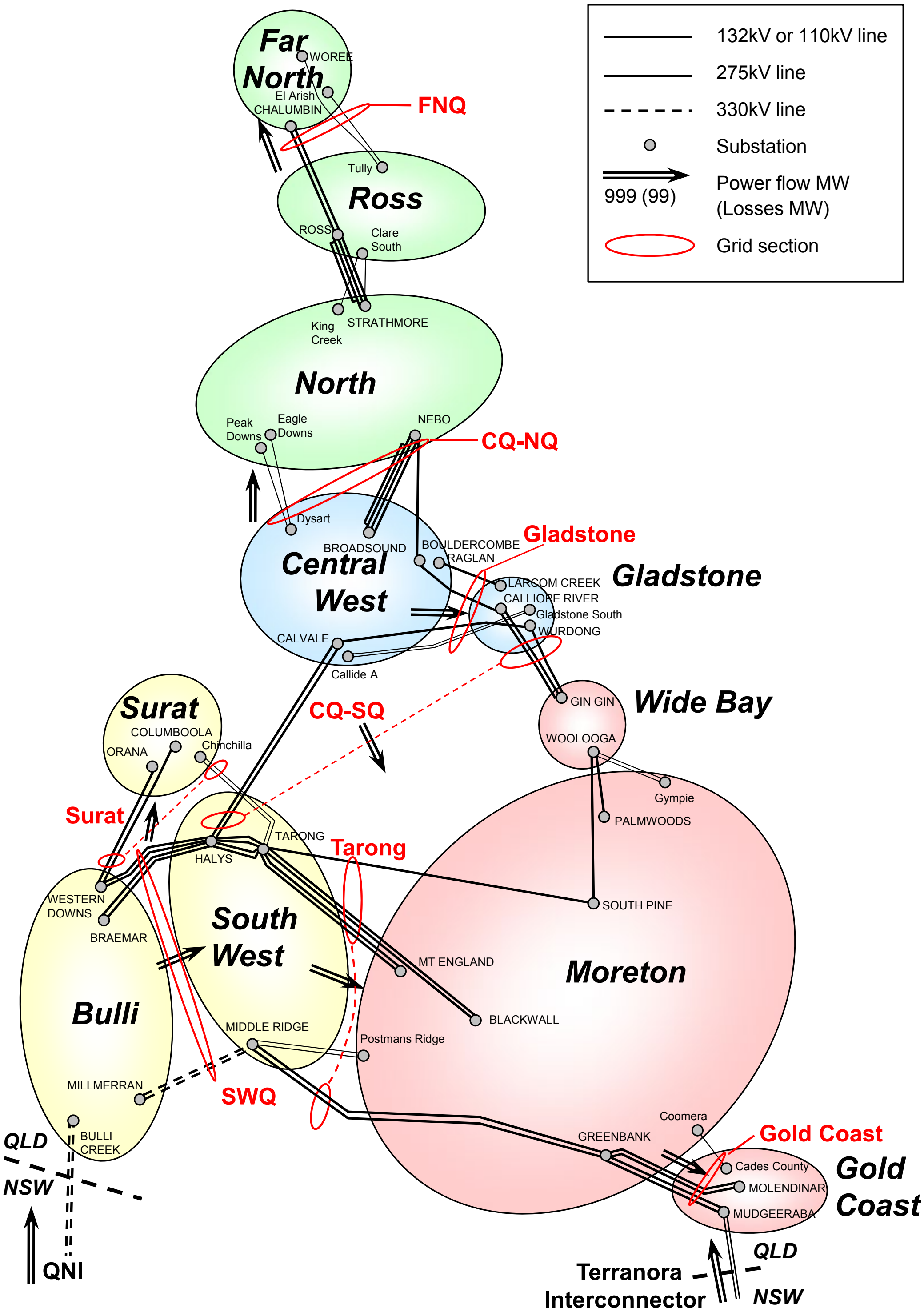
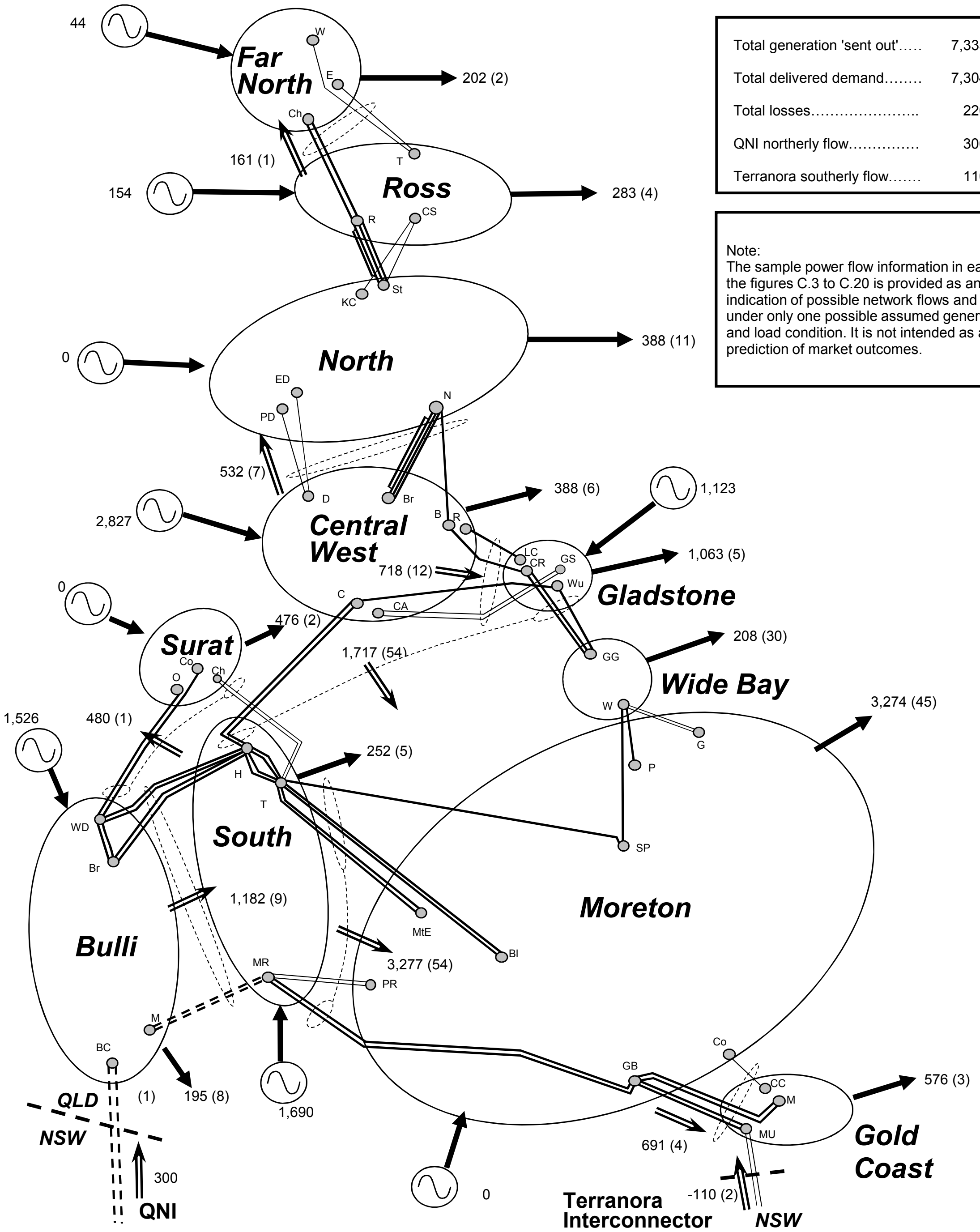


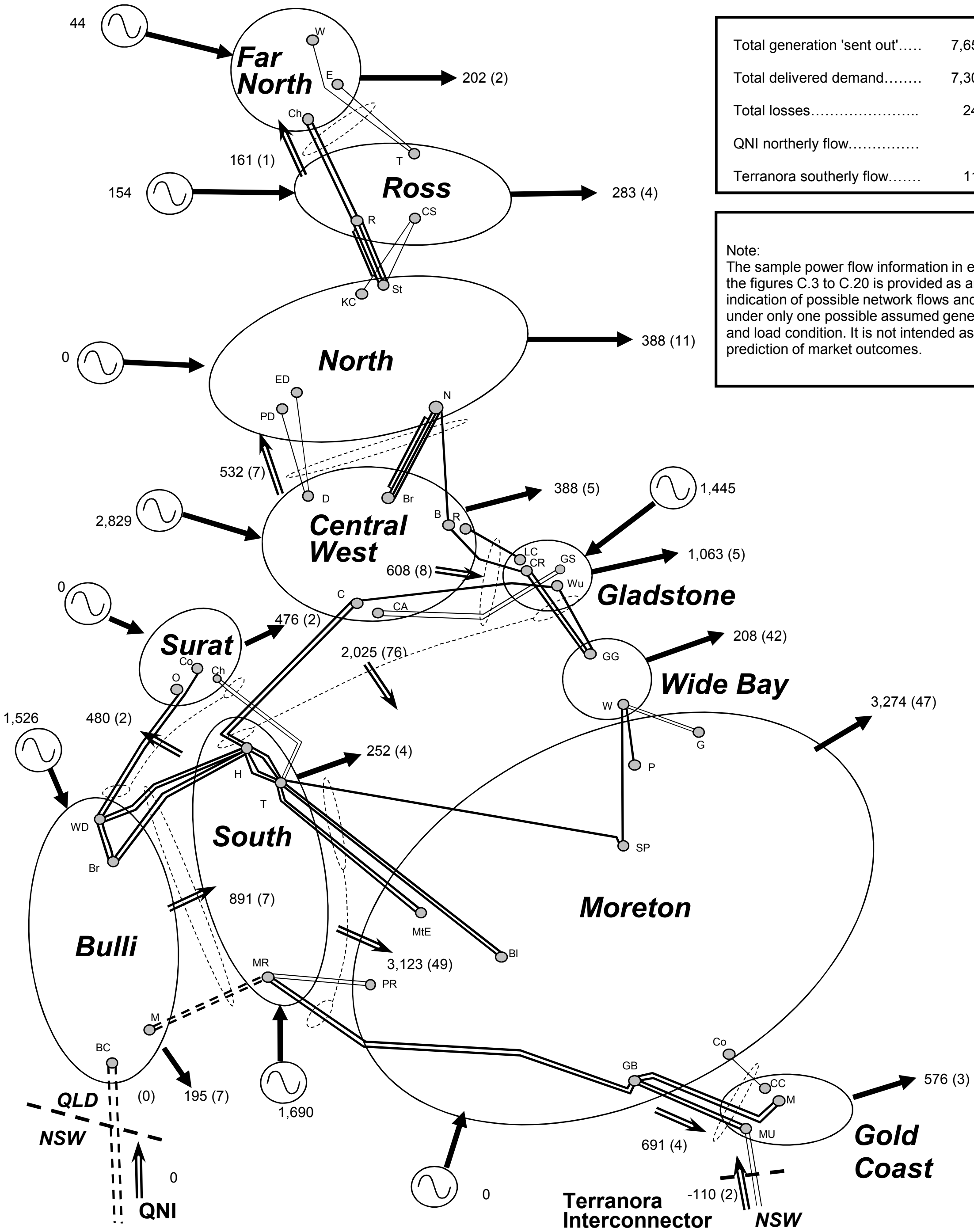
Figure C.3 Winter 2017 Queensland maximum demand 300MW northerly QNI flow



Total generation 'sent out'.....	7,335 MW
Total delivered demand........	7,304 MW
Total losses......................	220 MW
QNI northerly flow..............	300 MW
Terranora southerly flow.......	110 MW

Note:
The sample power flow information in each of the figures C.3 to C.20 is provided as an indication of possible network flows and losses under only one possible assumed generation and load condition. It is not intended as a prediction of market outcomes.

Figure C.4 Winter 2017 Queensland maximum demand 0MW QNI flow



Total generation 'sent out'…..	7,659 MW
Total delivered demand……..	7,304 MW
Total losses…………………..	244 MW
QNI northerly flow……………	0 MW
Terranora southerly flow…….	110 MW

Note:
The sample power flow information in each of the figures C.3 to C.20 is provided as an indication of possible network flows and losses under only one possible assumed generation and load condition. It is not intended as a prediction of market outcomes.

Figure C.5 Winter 2017 Queensland maximum demand 700MW southerly QNI flow

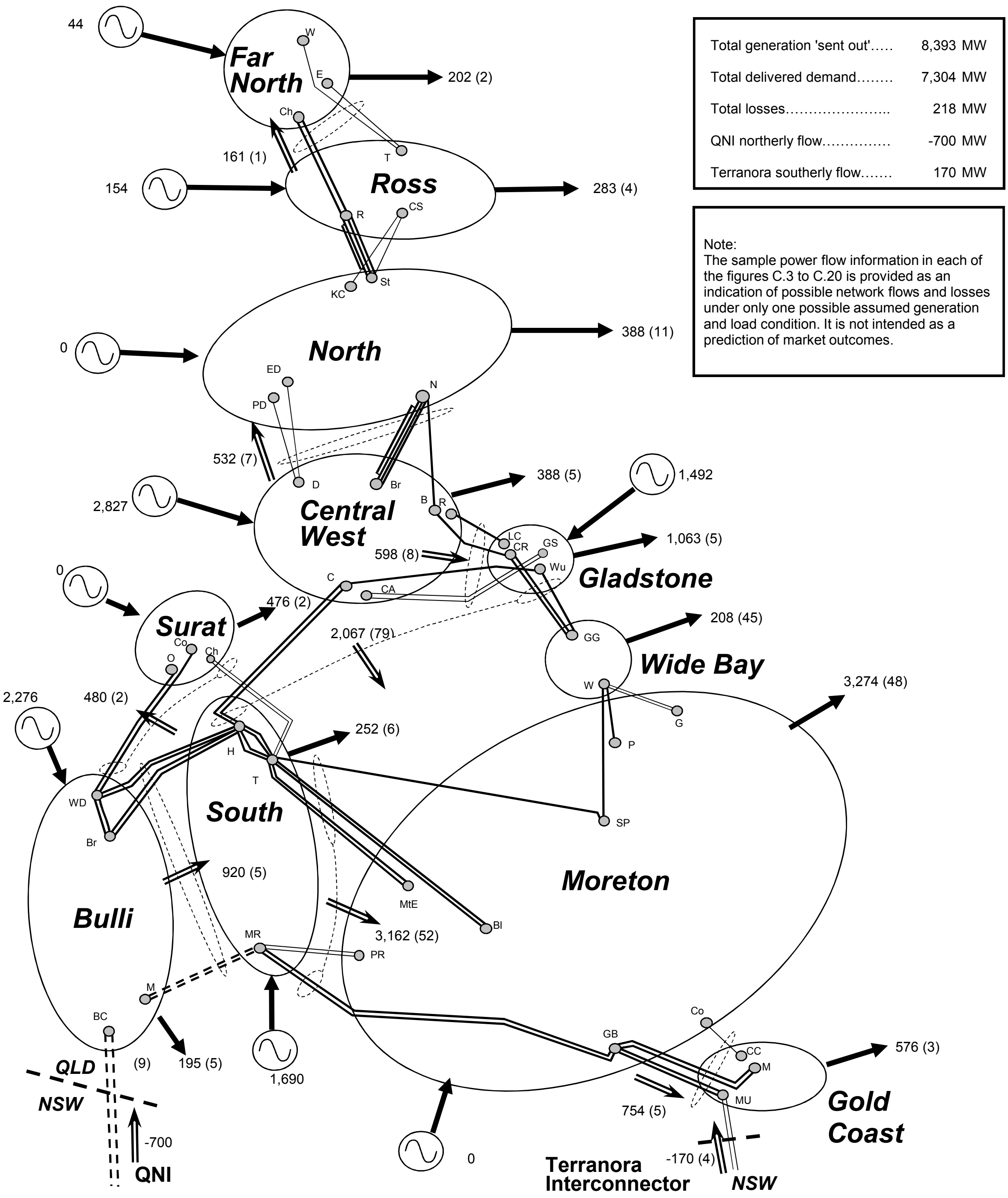
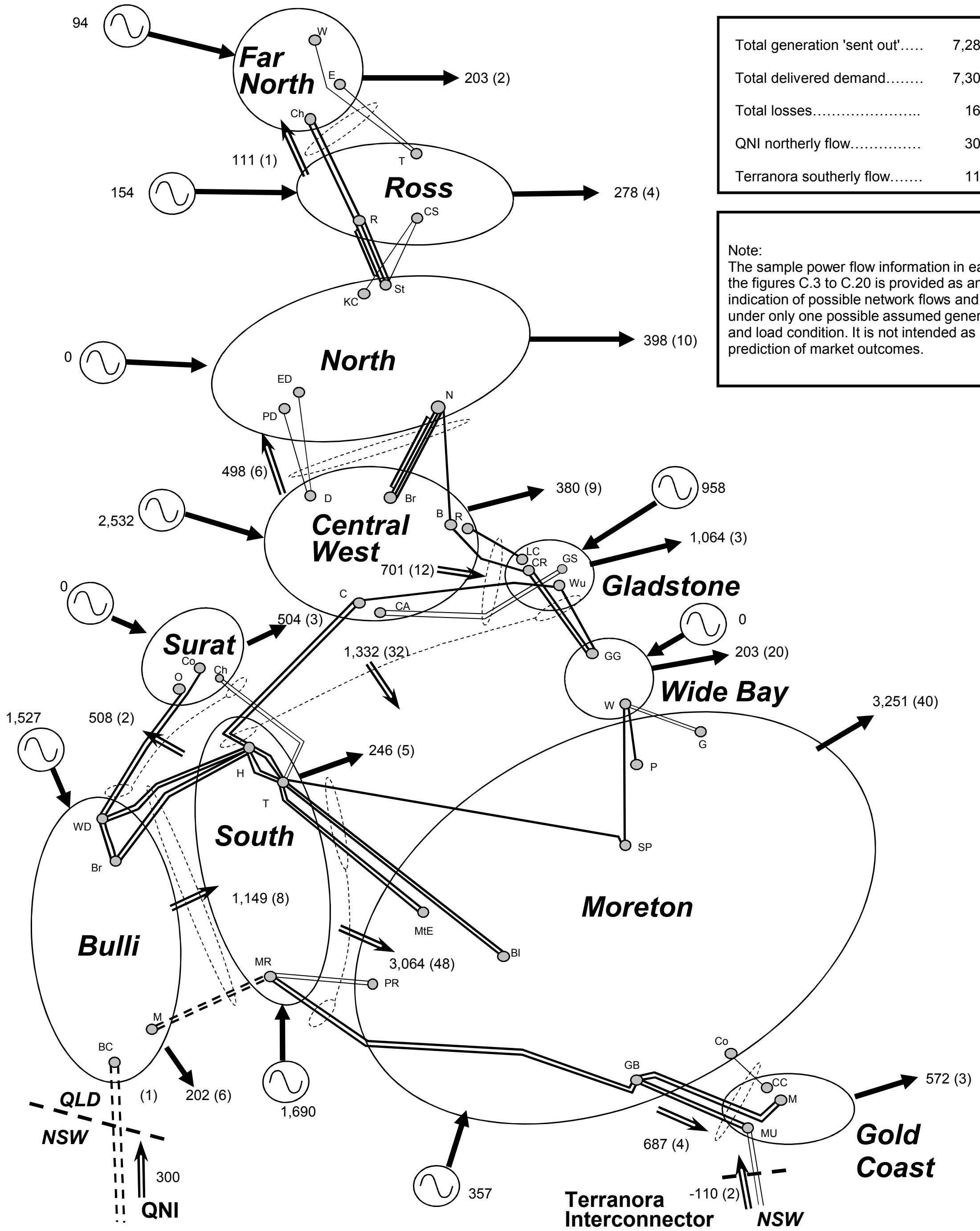


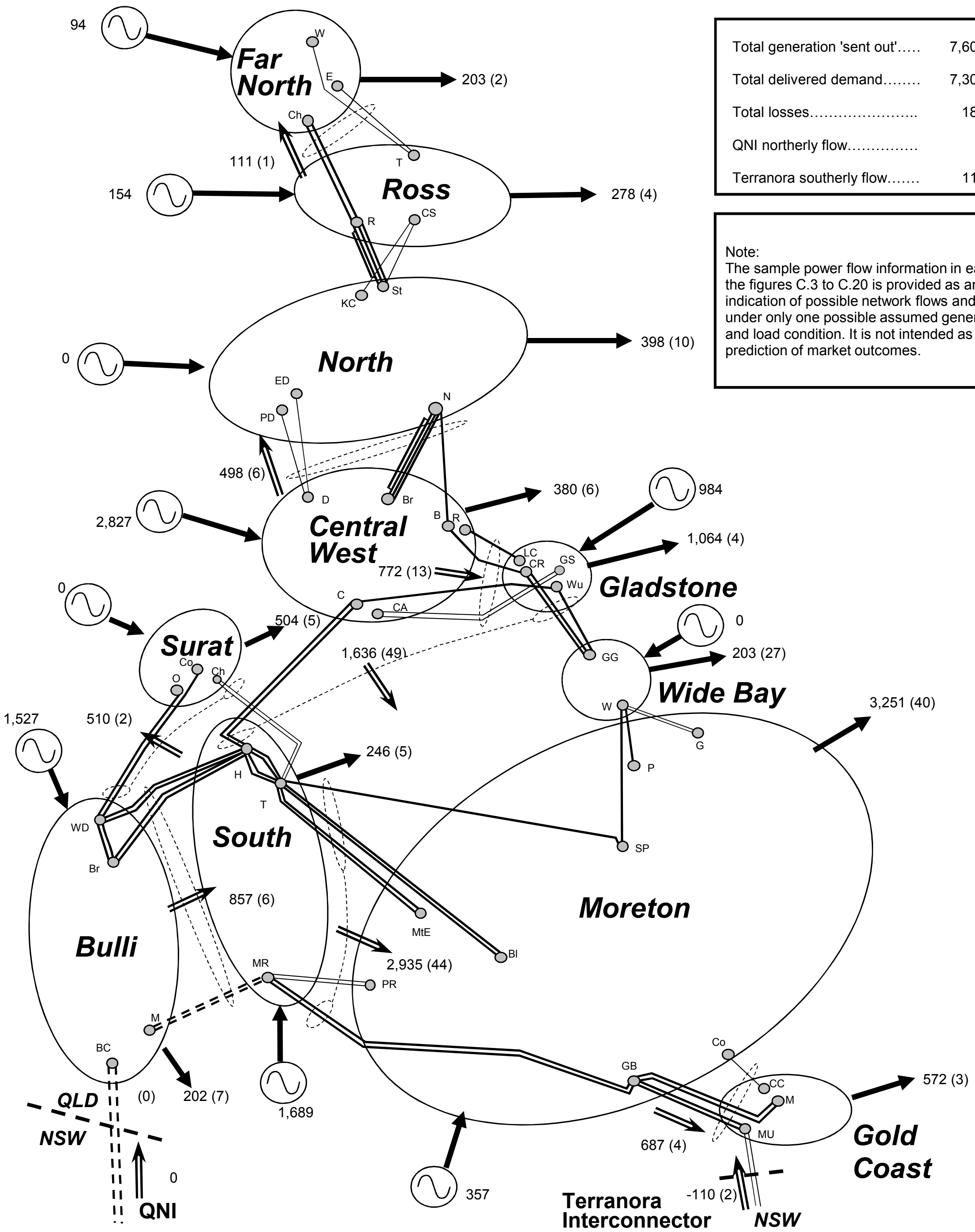
Figure C.6 Winter 2018 Queensland maximum demand 300MW northerly QNI flow



Total generation 'sent out'.....	7,281 MW
Total delivered demand........	7,302 MW
Total losses.......................	169 MW
QNI northerly flow..............	300 MW
Terranora southerly flow.......	110 MW

Note:
The sample power flow information in each of the figures C.3 to C.20 is provided as an indication of possible network flows and losses under only one possible assumed generation and load condition. It is not intended as a prediction of market outcomes.

Figure C.7 Winter 2018 Queensland maximum demand 0MW QNI flow



Total generation 'sent out'.....	7,601 MW
Total delivered demand........	7,302 MW
Total losses......................	189 MW
QNI northerly flow..............	0 MW
Terranora southerly flow.......	110 MW

Note:
The sample power flow information in each of the figures C.3 to C.20 is provided as an indication of possible network flows and losses under only one possible assumed generation and load condition. It is not intended as a prediction of market outcomes.

Figure C.8 Winter 2018 Queensland maximum demand 700MW southerly QNI flow

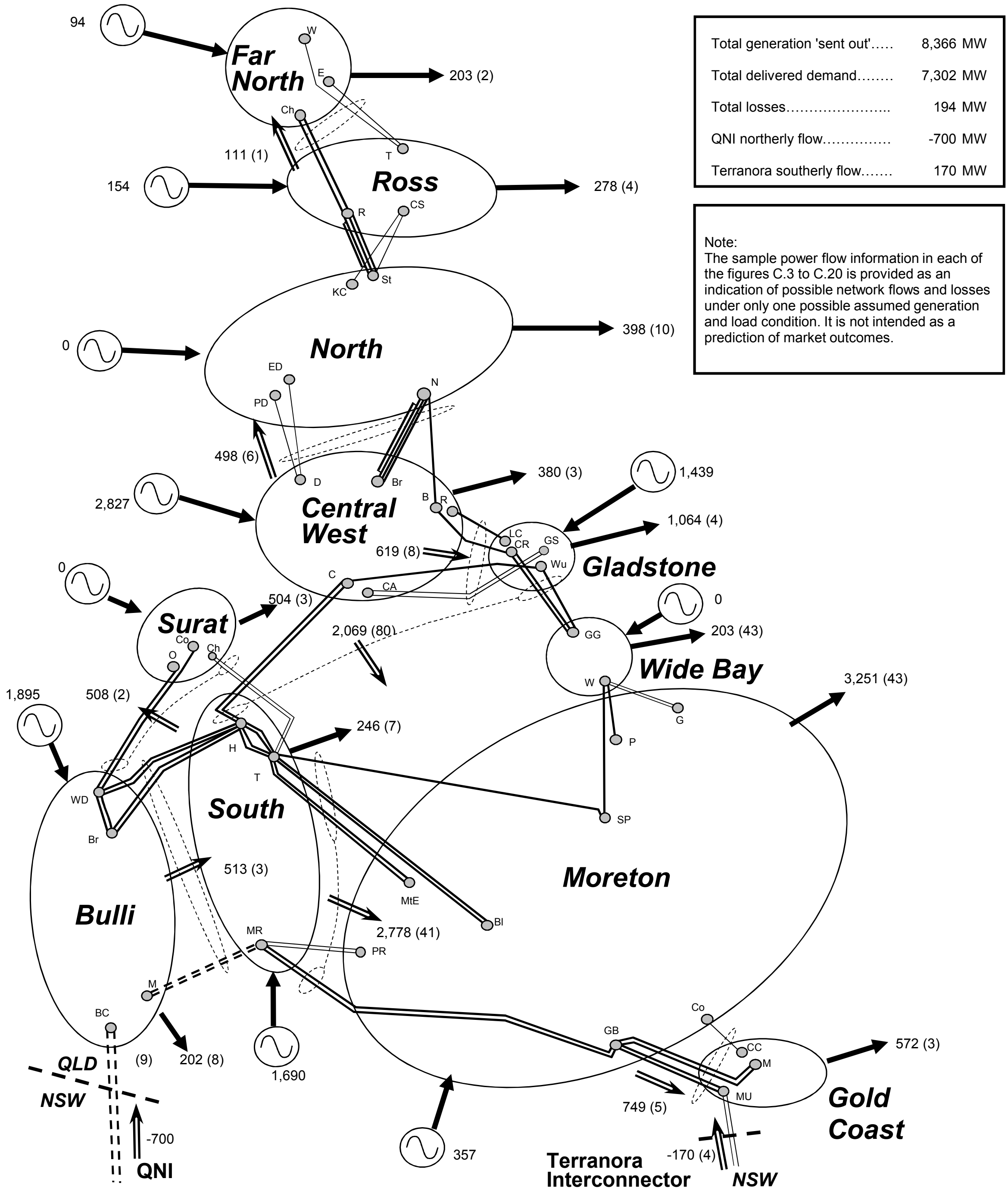
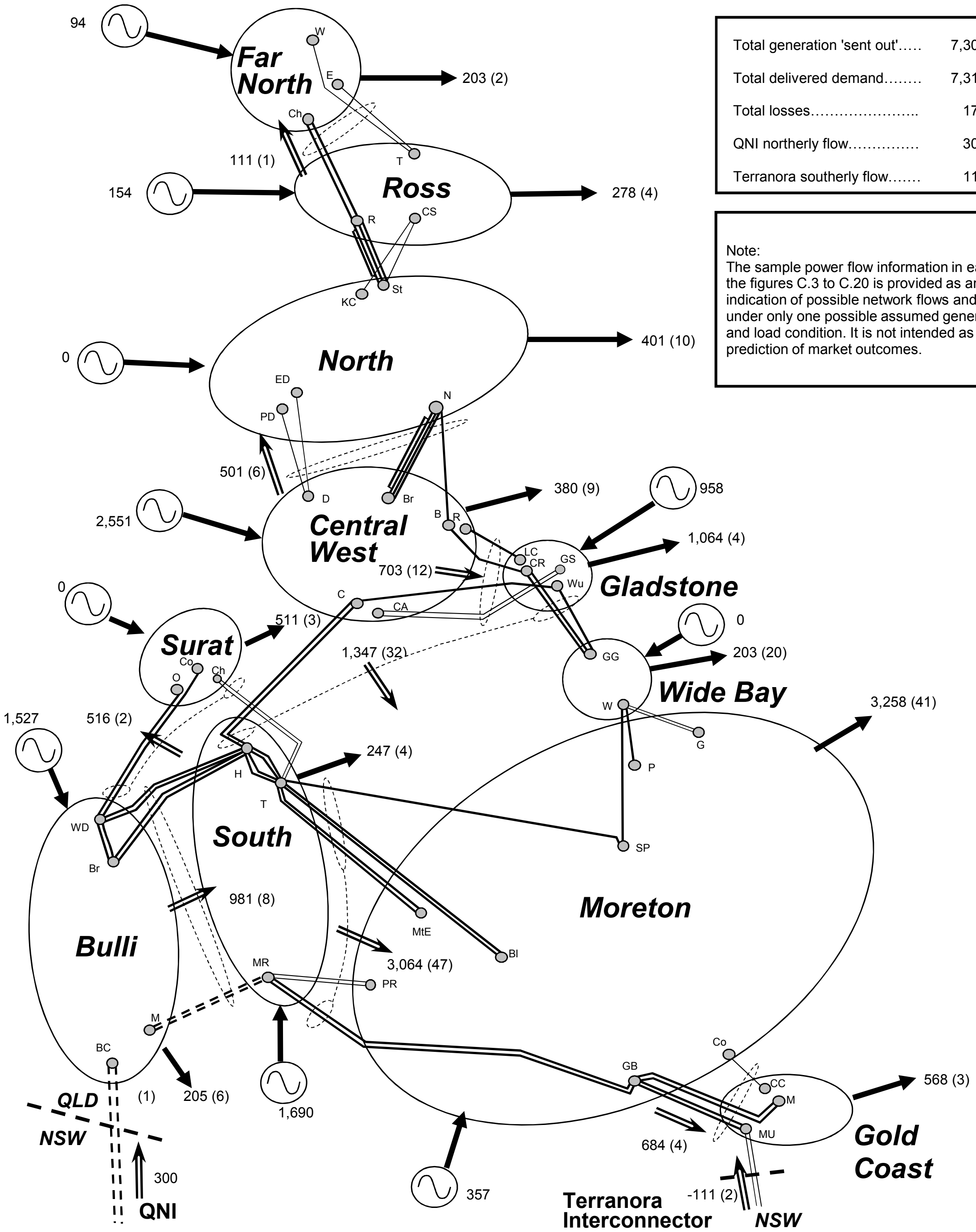


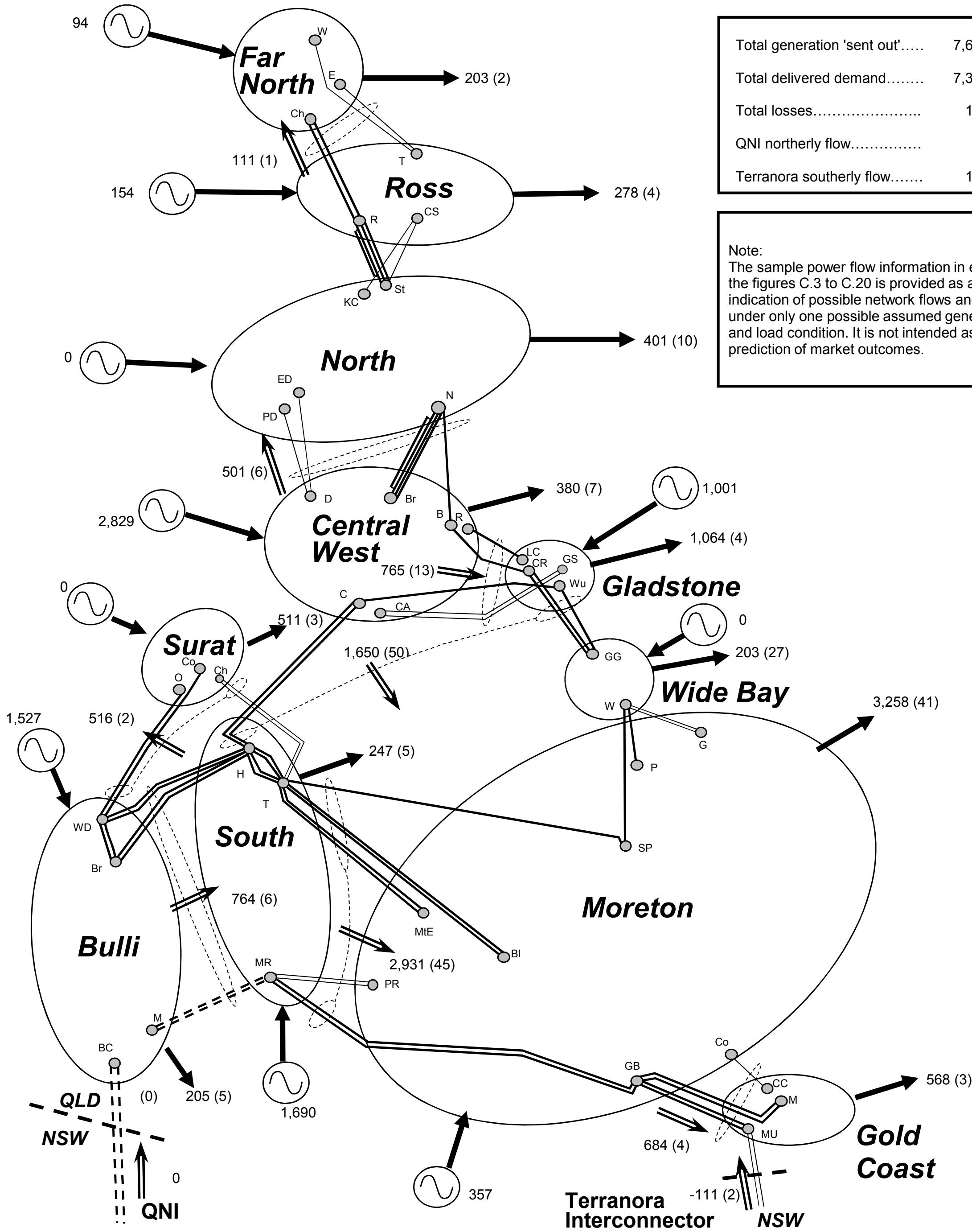
Figure C.9 Winter 2019 Queensland maximum demand 300MW northerly QNI flow



Total generation 'sent out'…..	7,301 MW
Total delivered demand……..	7,317 MW
Total losses…………………..	173 MW
QNI northerly flow…………..	300 MW
Terranora southerly flow…….	111 MW

Note:
The sample power flow information in each of the figures C.3 to C.20 is provided as an indication of possible network flows and losses under only one possible assumed generation and load condition. It is not intended as a prediction of market outcomes.

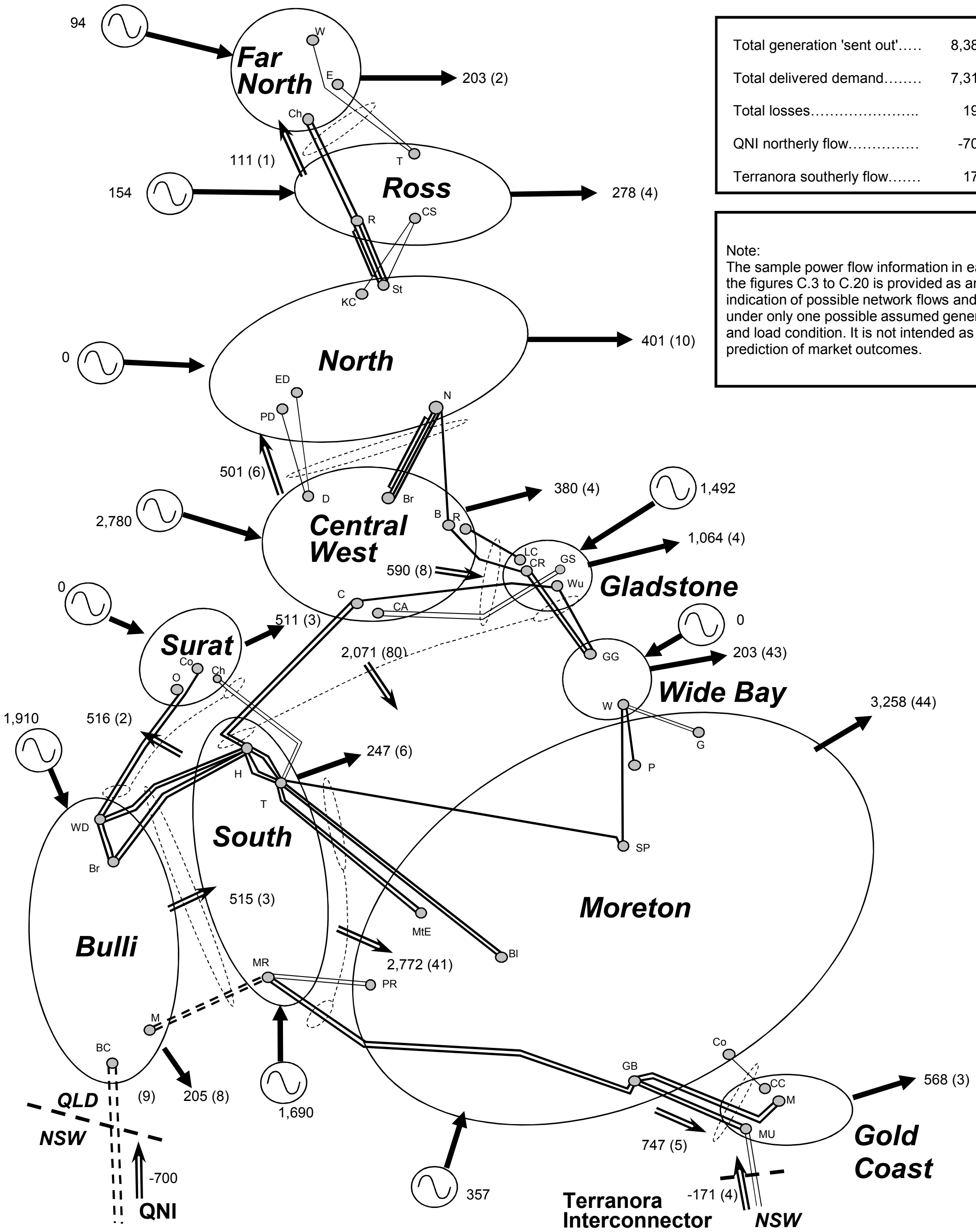
Figure C.10 Winter 2019 Queensland maximum demand 0MW QNI flow



Total generation 'sent out'…..	7,622 MW
Total delivered demand……..	7,317 MW
Total losses…………………..	194 MW
QNI northerly flow…………..	0 MW
Terranora southerly flow…….	111 MW

Note:
The sample power flow information in each of the figures C.3 to C.20 is provided as an indication of possible network flows and losses under only one possible assumed generation and load condition. It is not intended as a prediction of market outcomes.

Figure C.11 Winter 2019 Queensland maximum demand 700MW southerly QNI flow



Total generation 'sent out'…..	8,387 MW
Total delivered demand……..	7,317 MW
Total losses…………………..	199 MW
QNI northerly flow……………	-700 MW
Terranora southerly flow…….	171 MW

Note:
The sample power flow information in each of the figures C.3 to C.20 is provided as an indication of possible network flows and losses under only one possible assumed generation and load condition. It is not intended as a prediction of market outcomes.

Figure C.12 Summer 2017/18 Queensland maximum demand 200MW northerly QNI flow

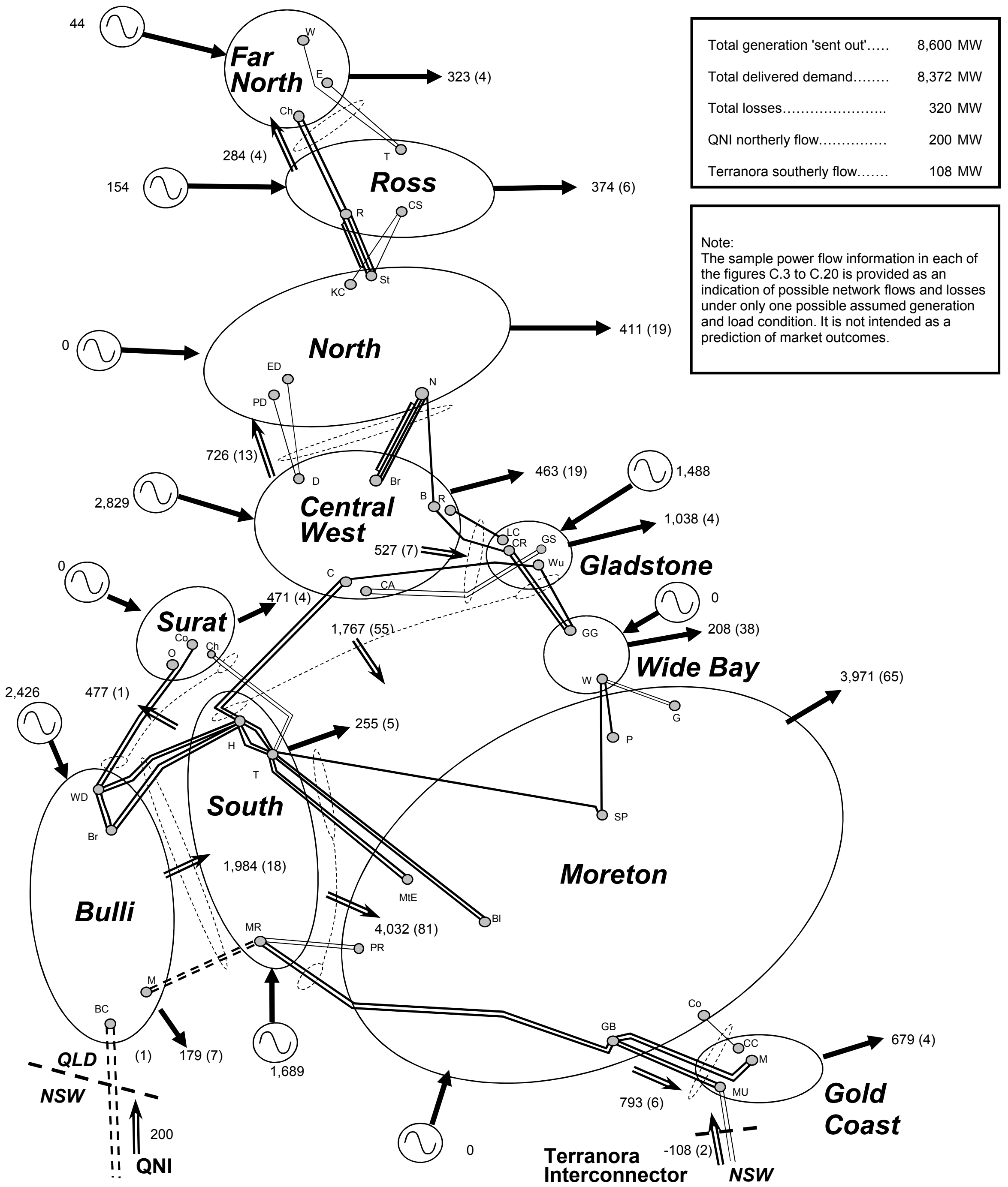


Figure C.13 Summer 2017/18 Queensland maximum demand 0MW QNI flow

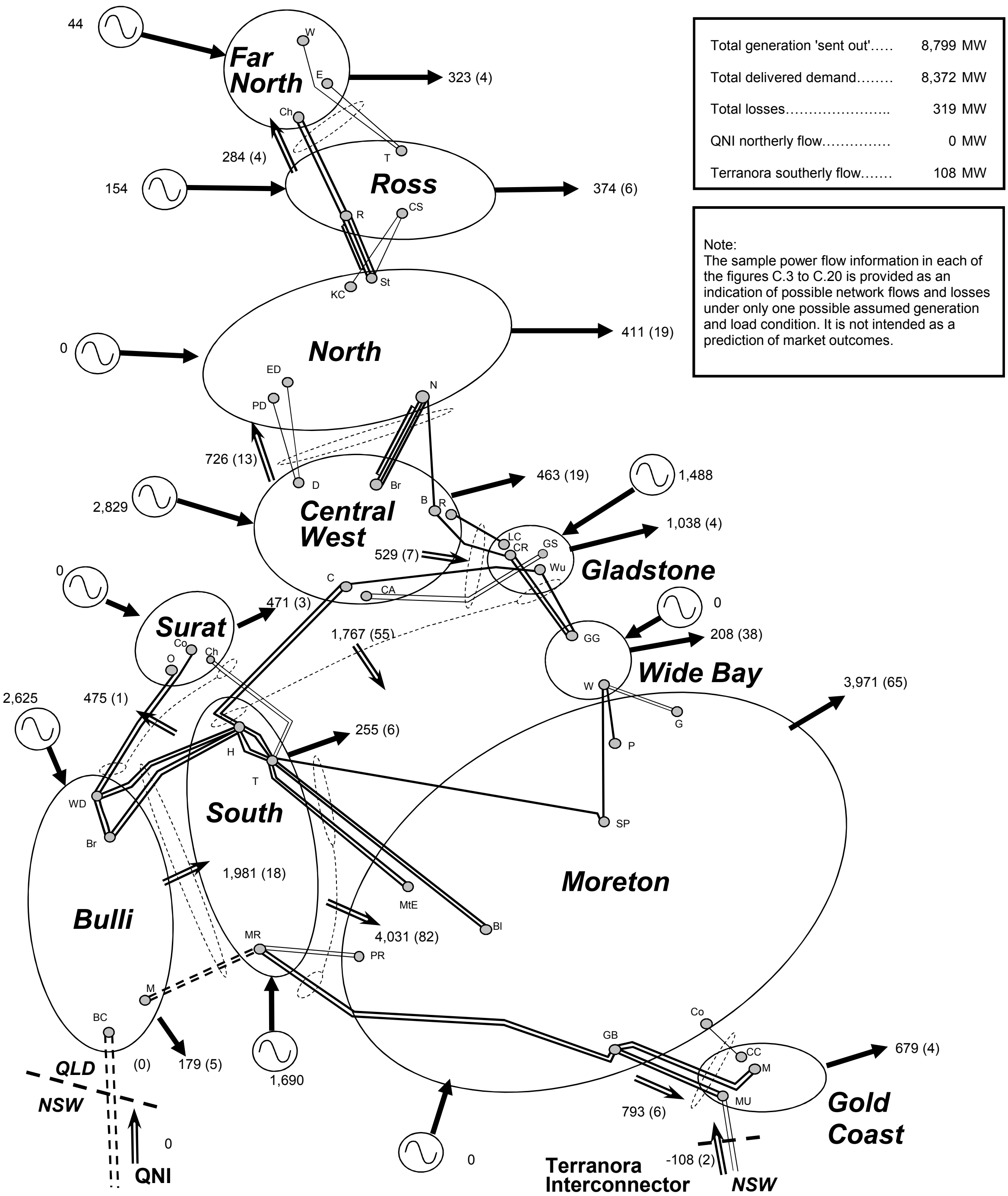


Figure C.14 Summer 2017/18 Queensland maximum demand 400MW southerly QNI flow

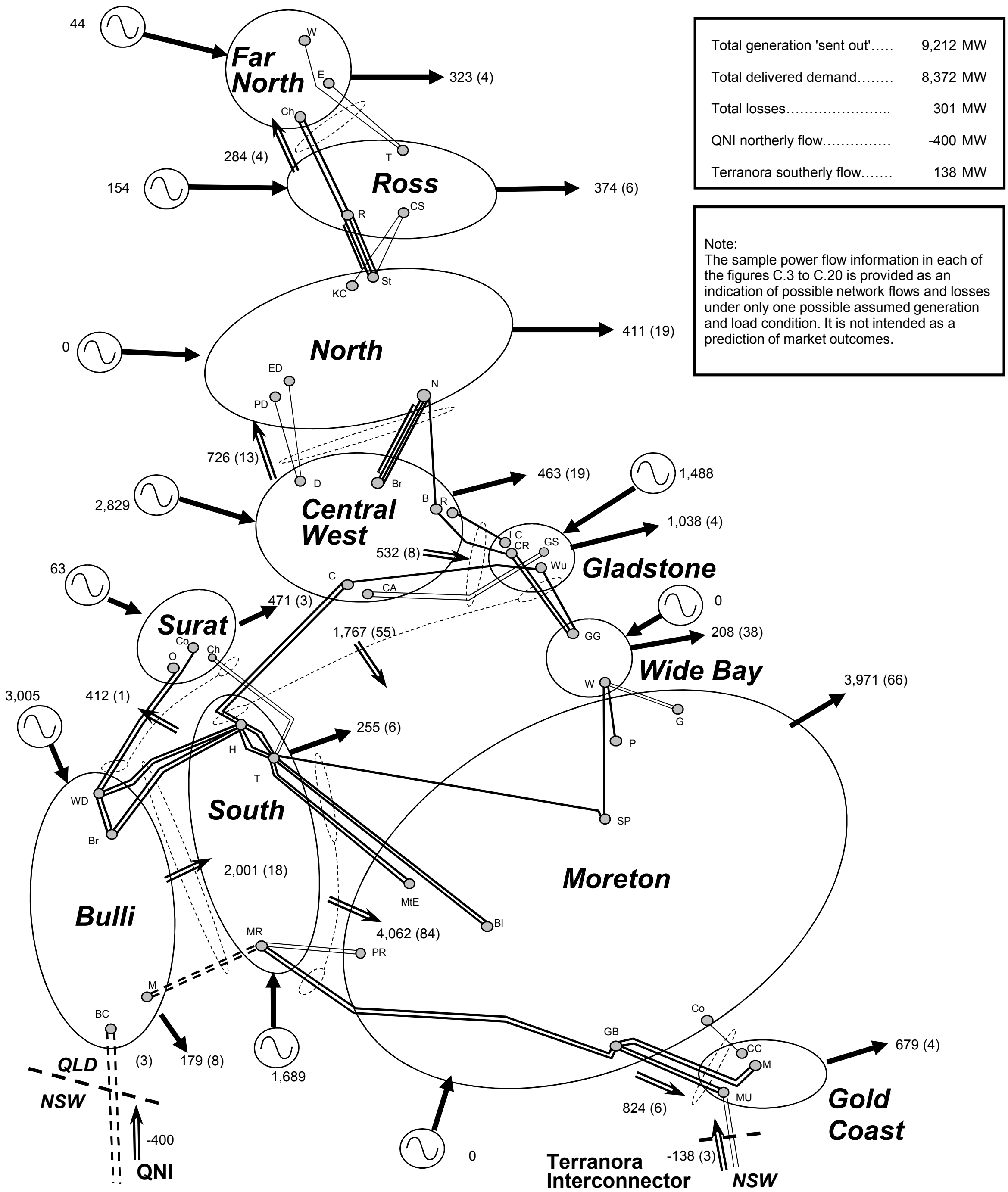


Figure C.15 Summer 2018/19 Queensland maximum demand 200MW northerly QNI flow

Total generation 'sent out'…..	8,533 MW
Total delivered demand……..	8,339 MW
Total losses…………………..	284 MW
QNI northerly flow…………..	200 MW
Terranora southerly flow…….	109 MW

Note:
The sample power flow information in each of the figures C.3 to C.20 is provided as an indication of possible network flows and losses under only one possible assumed generation and load condition. It is not intended as a prediction of market outcomes.

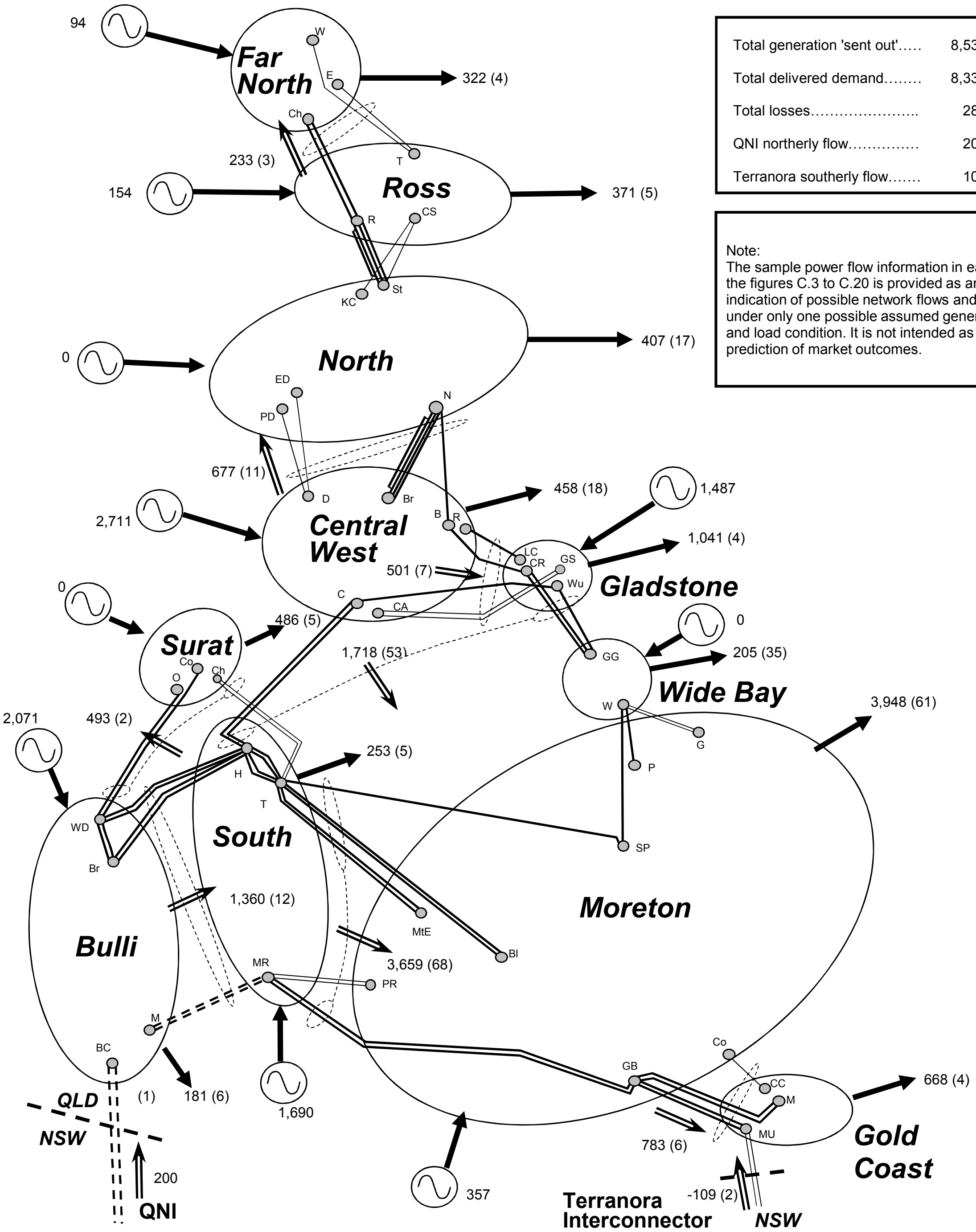
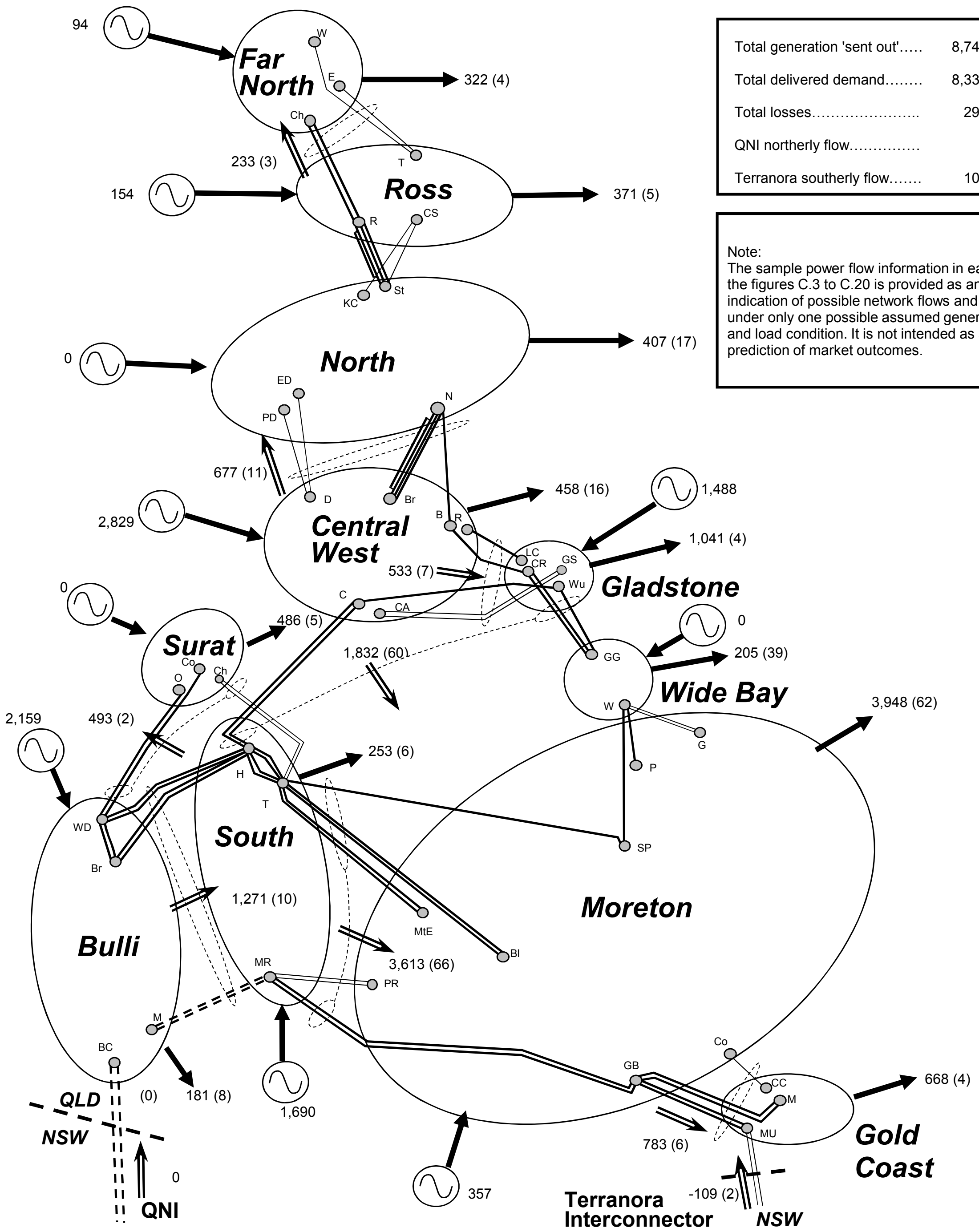


Figure C.16 Summer 2018/19 Queensland maximum demand 0MW QNI flow



Total generation 'sent out'.....	8,741 MW
Total delivered demand........	8,339 MW
Total losses.......................	292 MW
QNI northerly flow..............	0 MW
Terranora southerly flow.......	109 MW

Note:
The sample power flow information in each of the figures C.3 to C.20 is provided as an indication of possible network flows and losses under only one possible assumed generation and load condition. It is not intended as a prediction of market outcomes.

Figure C.17 Summer 2018/19 Queensland maximum demand 400MW southerly QNI flow

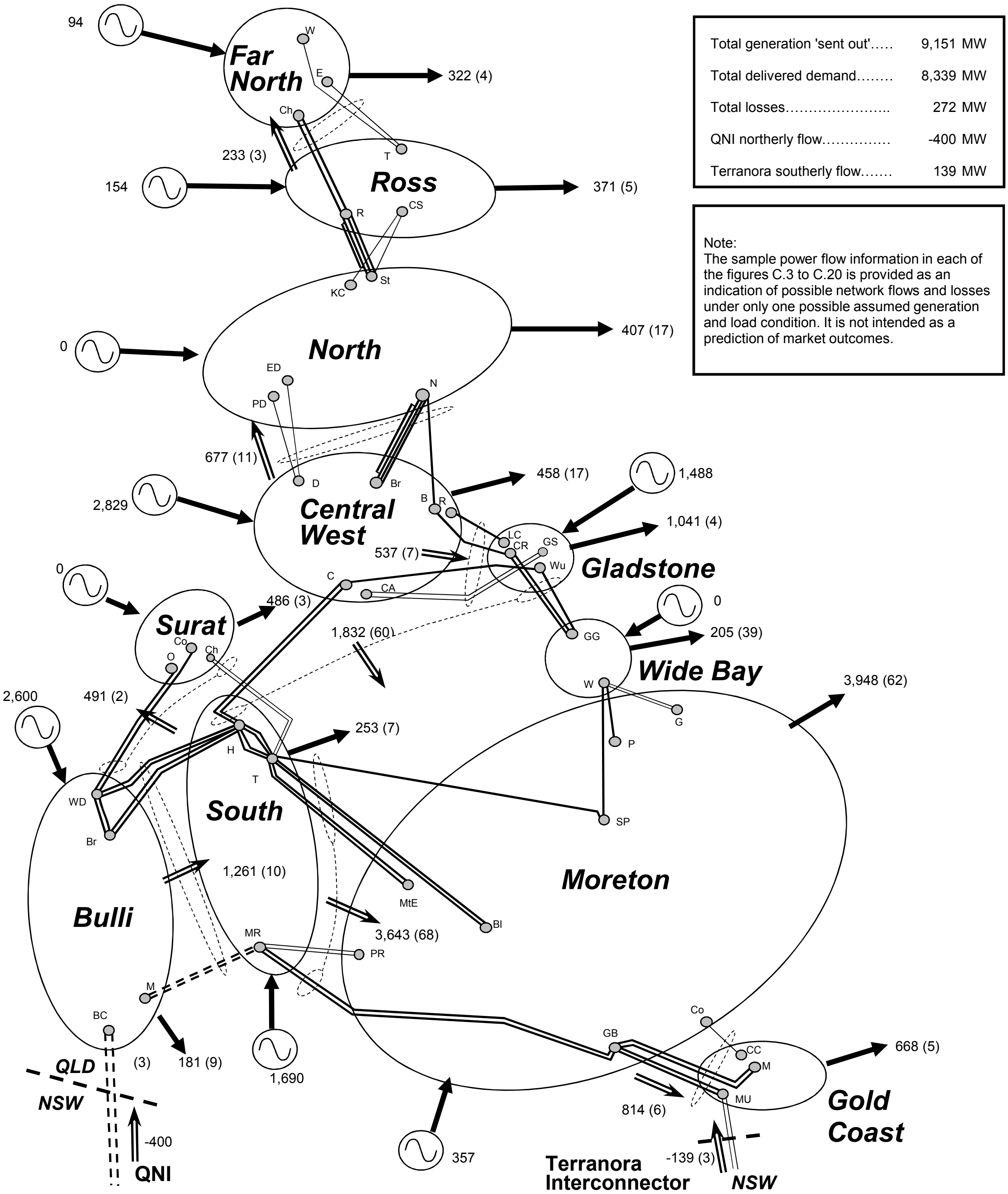


Figure C.18 Summer 2019/20 Queensland maximum demand 200MW northerly QNI flow

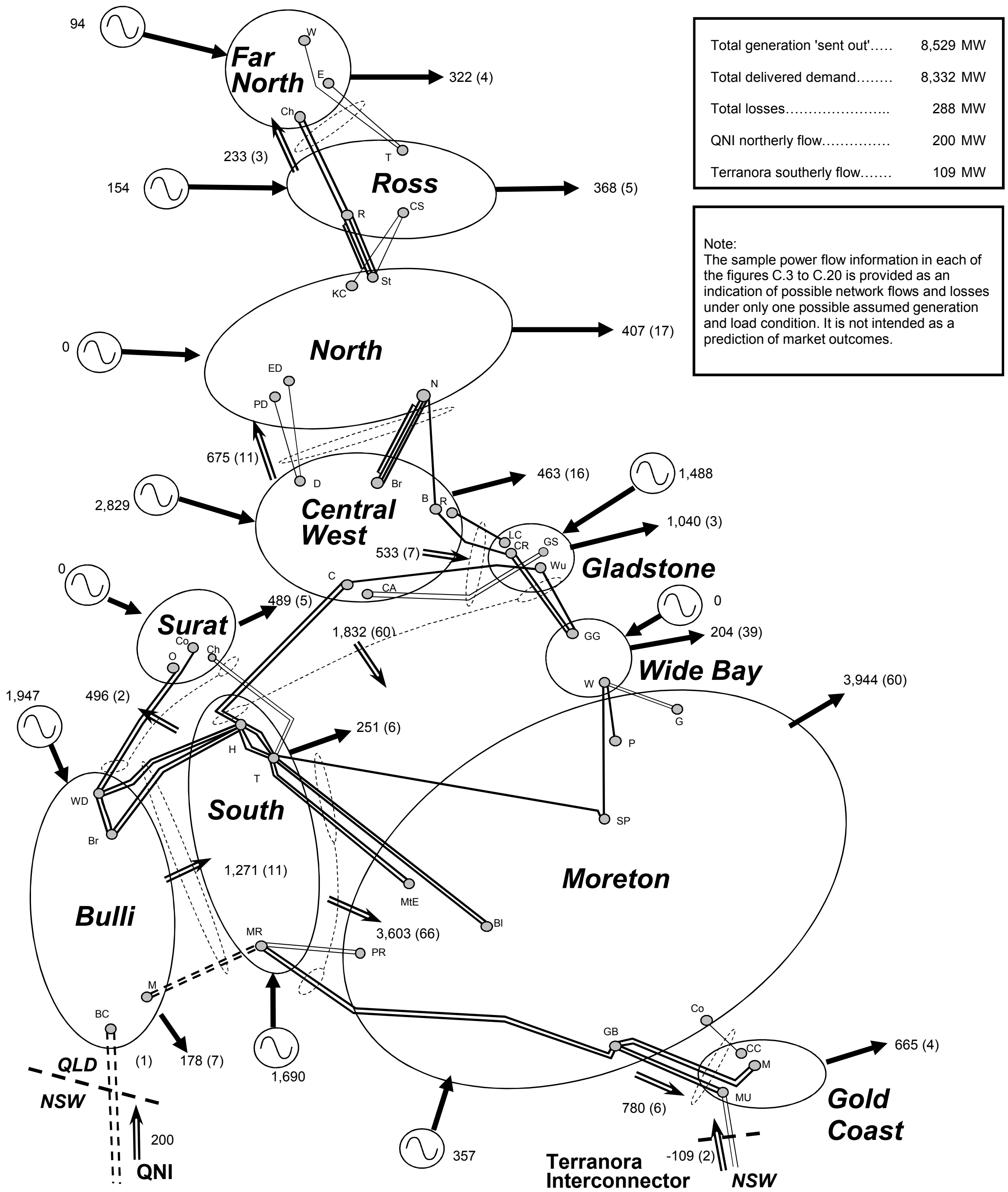


Figure C.19 Summer 2019/20 Queensland maximum demand 0MW QNI flow

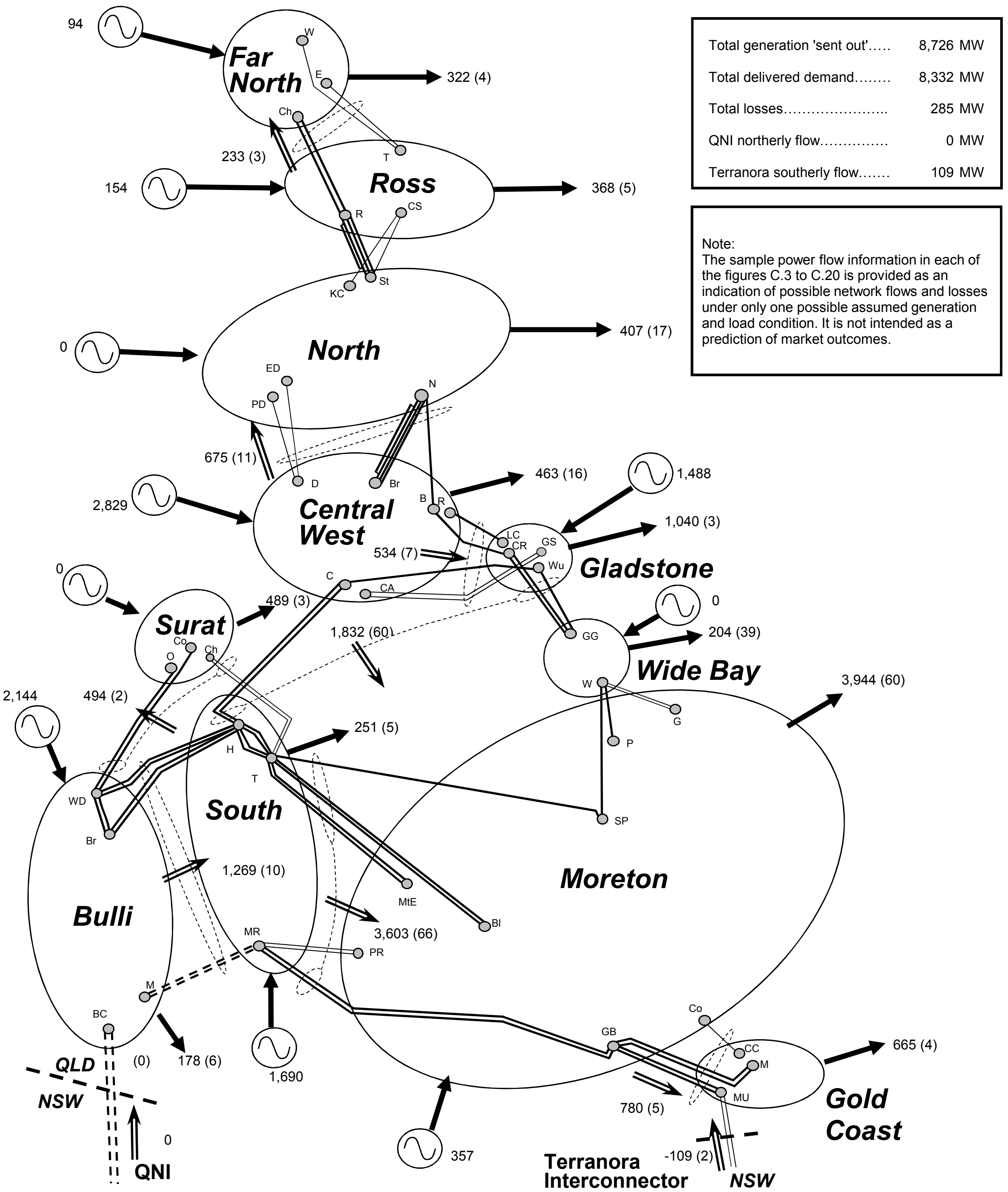
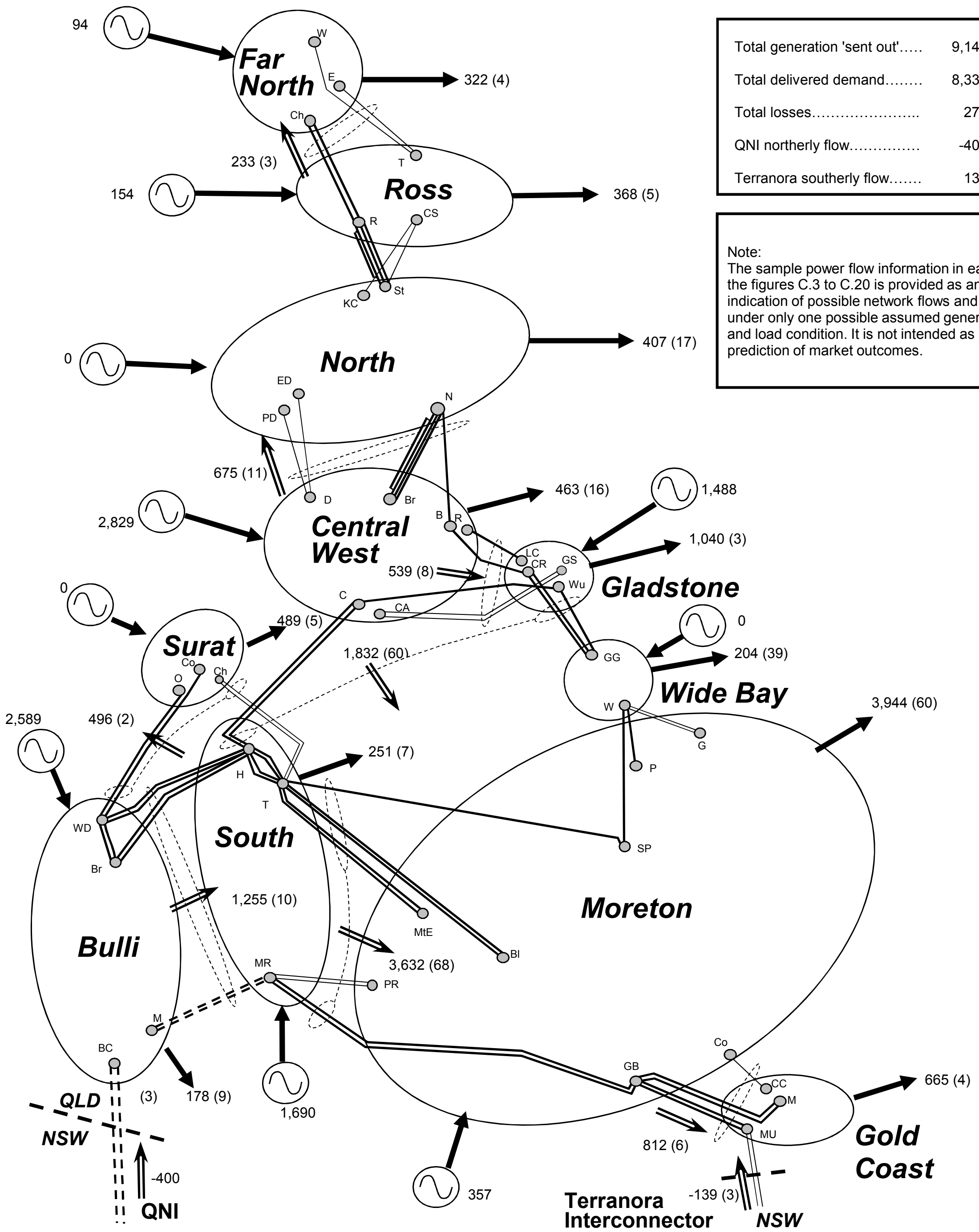


Figure C.20 Summer 2019/20 Queensland maximum demand 400MW southerly QNI flow



Total generation 'sent out'.....	9,142 MW
Total delivered demand........	8,332 MW
Total losses.......................	271 MW
QNI northerly flow..............	-400 MW
Terranora southerly flow.......	139 MW

Note:
The sample power flow information in each of the figures C.3 to C.20 is provided as an indication of possible network flows and losses under only one possible assumed generation and load condition. It is not intended as a prediction of market outcomes.

Appendix D – Limit equations

This appendix lists the Queensland intra-regional limit equations, derived by Powerlink, valid at the time of publication. The Australian Energy Market Operator (AEMO) defines other limit equations for the Queensland Region in its market dispatch systems.

It should be noted that these equations are continually under review to take into account changing market and network conditions.

Please contact Powerlink to confirm the latest form of the relevant limit equation if required.

Table D.1 Far North Queensland (FNQ) grid section voltage stability equation

Measured variable	Coefficient
Constant term (intercept)	-19.00
FNQ demand percentage (1) (2)	17.00
Total MW generation at Barron Gorge, Kareeya and Koombooloomba	-0.46
Total MW generation at Mt Stuart and Townsville	0.13
AEMO Constraint ID	**Q^NIL_FNQ**

Notes:

(1) FNQ demand percentage = $\frac{\text{Far North zone demand}}{\text{North Queensland area demand}} \times 100$

Far North zone demand (MW) = FNQ grid section transfer + (Barron Gorge + Kareeya + Koombooloomba) generation

North Queensland area demand (MW) = CQ-NQ grid section transfer + (Barron Gorge + Kareeya + Koombooloomba + Townsville + Mt Stuart + Invicta + Mackay) generation

(2) The FNQ demand percentage is bound between 22 and 31.

Table D.2 Central to North Queensland grid section voltage stability equations

Measured variable	Coefficient	
	Equation 1	Equation 2
	Feeder contingency	Townsville contingency (1)
Constant term (intercept)	1,500	1,650
Total MW generation at Barron Gorge, Kareeya and Koombooloomba	0.321	–
Total MW generation at Townsville	0.172	-1.000
Total MW generation at Mt Stuart	-0.092	-0.136
Number of Mt Stuart units on line [0 to 3]	22.447	14.513
Total MW generation at Mackay	-0.700	-0.478
Total nominal MVAr shunt capacitors on line within nominated Ross area locations (2)	0.453	0.440
Total nominal MVAr shunt reactors on line within nominated Ross area locations (3)	-0.453	-0.440
Total nominal MVAr shunt capacitors on line within nominated Strathmore area locations (4)	0.388	0.431
Total nominal MVAr shunt reactors on line within nominated Strathmore area locations (5)	-0.388	-0.431
Total nominal MVAr shunt capacitors on line within nominated Nebo area locations (6)	0.296	0.470
Total nominal MVAr shunt reactors on line within nominated Nebo area locations (7)	-0.296	-0.470
Total nominal MVAr shunt capacitors available to the Nebo Q optimiser (8)	0.296	0.470
Total nominal MVAr shunt capacitors on line not available to the Nebo Q optimiser (8)	0.296	0.470
AEMO Constraint ID	Q^NIL_CN_FDR	Q^NIL_CN_GT

Notes:

(1) This limit is applicable only if Townsville Power Station is generating.

(2) The shunt capacitor bank locations, nominal sizes and quantities for the Ross area comprise the following:

Ross 132kV	1 x 50MVAr
Townsville South 132kV	2 x 50MVAr
Dan Gleeson 66kV	2 x 24MVAr
Garbutt 66kV	2 x 15MVAr

(3) The shunt reactor bank locations, nominal sizes and quantities for the Ross area comprise the following:

Ross 275kV	2 x 84MVAr, 2 x 29.4MVAr

(4) The shunt capacitor bank locations, nominal sizes and quantities for the Strathmore area comprise the following:

Newlands 132kV	1 x 25MVAr
Clare South 132kV	1 x 20MVAr
Collinsville North 132kV	1 x 20MVAr

(5) The shunt reactor bank locations, nominal sizes and quantities for the Strathmore area comprise the following:

Strathmore 275kV	1 x 84MVAr

(6) The shunt capacitor bank locations, nominal sizes and quantities for the Nebo area comprise the following:

Pioneer Valley 132kV	1 x 30MVAr
Kemmis 132kV	1 x 30MVAr
Dysart 132kV	2 x 25MVAr
Alligator Creek 132kV	1 x 20MVAr
Mackay 33kV	2 x 15MVAr

(7) The shunt reactor bank locations, nominal sizes and quantities for the Nebo area comprise the following:

Nebo 275kV	1 x 84MVAr, 1 x 30MVAr, 1 x 20.2MVAr

(8) The shunt capacitor banks nominal sizes and quantities for which may be available to the Nebo Q optimiser comprise the following:

Nebo 275kV	2 x 120MVAr

Table D.3 Central to South Queensland grid section voltage stability equations

Measured variable	Coefficient
Constant term (intercept)	1,015
Total MW generation at Gladstone 275kV and 132kV	0.1407
Number of Gladstone 275kV units on line [2 to 4]	57.5992
Number of Gladstone 132kV units on line [1 to 2]	89.2898
Total MW generation at Callide B and Callide C	0.0901
Number of Callide B units on line [0 to 2]	29.8537
Number of Callide C units on line [0 to 2]	63.4098
Total MW generation in southern Queensland (1)	-0.0650
Number of 90MVAr capacitor banks available at Boyne Island [0 to 2]	51.1534
Number of 50MVAr capacitor banks available at Boyne Island [0 to 1]	25.5767
Number of 120MVAr capacitor banks available at Wurdong [0 to 3]	52.2609
Number of 120MVAr capacitor banks available at Gin Gin [0 to 1]	63.5367
Number of 50MVAr capacitor banks available at Gin Gin [0 to 1]	31.5525
Number of 120MVAr capacitor banks available at Woolooga [0 to 1]	47.7050
Number of 50MVAr capacitor banks available at Woolooga [0 to 2]	22.9875
Number of 120MVAr capacitor banks available at Palmwoods [0 to 1]	30.7759
Number of 50MVAr capacitor banks available at Palmwoods [0 to 4]	14.2253
Number of 120MVAr capacitor banks available at South Pine [0 to 4]	9.0315
Number of 50MVAr capacitor banks available at South Pine [0 to 4]	3.2522
Equation lower limit	**1,550**
Equation upper limit	**2,100 (2)**
AEMO Constraint ID	**Q^^NIL_CS, Q::NIL_CS**

Notes:

(1) Southern Queensland generation term refers to summated active power generation at Swanbank E, Wivenhoe, Tarong, Tarong North, Condamine, Roma, Kogan Creek, Braemar 1, Braemar 2, Darling Downs, Oakey, Millmerran and Terranora Interconnector and QNI transfers (positive transfer denotes northerly flow).

(2) The upper limit is due to a transient stability limitation between central and southern Queensland areas.

Table D.4 Tarong grid section voltage stability equations

Measured variable	Coefficient	
	Equation 1	Equation 2
	Calvale-Halys contingency	Tarong-Blackwall contingency
Constant term (intercept) (1)	740	1,124
Total MW generation at Callide B and Callide C	0.0346	0.0797
Total MW generation at Gladstone 275kV and 132kV	0.0134	–
Total MW generation at Tarong, Tarong North, Roma, Condamine, Kogan Creek, Braemar 1, Braemar 2, Darling Downs, Oakey, Millmerran and QNI transfer (2)	0.8625	0.7945
Surat/Braemar demand	-0.8625	-0.7945
Total MW generation at Wivenhoe and Swanbank E	-0.0517	-0.0687
Active power transfer (MW) across Terranora Interconnector (2)	-0.0808	-0.1287
Number of 200MVAr capacitor banks available (3)	7.6683	16.7396
Number of 120MVAr capacitor banks available (4)	4.6010	10.0438
Number of 50MVAr capacitor banks available (5)	1.9171	4.1849
Reactive to active demand percentage (6) (7)	-2.9964	-5.7927
Equation lower limit	**3,200**	**3,200**
AEMO Constraint ID	**Q^^NIL_TR_CLHA**	**Q^^NIL_TR_TRBK**

Notes:

(1) Equations 1 and 2 are offset by -100MW and -150MW respectively when the Middle Ridge to Abermain 110kV loop is run closed.

(2) Positive transfer denotes northerly flow.

(3) There are currently 4 capacitor banks of nominal size 200MVAr which may be available within this area.

(4) There are currently 18 capacitor banks of nominal size 120MVAr which may be available within this area.

(5) There are currently 38 capacitor banks of nominal size 50MVAr which may be available within this area.

(6) Reactive to active demand percentage $= \dfrac{\text{Zone reactive demand}}{\text{Zone active demand}} \times 100$

Zone reactive demand (MVAr) = Reactive power transfers into the 110kV measured at the 132/110kV transformers at Palmwoods and 275/110kV transformers inclusive of south of South Pine and east of Abermain + reactive power generation from 50MVAr shunt capacitor banks within this zone + reactive power transfer across Terranora Interconnector.

Zone active demand (MW) = Active power transfers into the 110kV measured at the 132/110kV transformers at Palmwoods and the 275/110kV transformers inclusive of south of South Pine and east of Abermain + active power transfer on Terranora Interconnector.

(7) The reactive to active demand percentage is bounded between 10 and 35.

Table D.5 Gold Coast grid section voltage stability equation

Measured variable	Coefficient
Constant term (intercept)	1,351
Moreton to Gold Coast demand ratio (1) (2)	-137.50
Number of Wivenhoe units on line [0 to 2]	17.7695
Number of Swanbank E units on line [0 to 1]	-20.0000
Active power transfer (MW) across Terranora Interconnector (3)	-0.9029
Reactive power transfer (MVAr) across Terranora Interconnector (3)	0.1126
Number of 200MVAr capacitor banks available (4)	14.3339
Number of 120MVAr capacitor banks available (5)	10.3989
Number of 50MVAr capacitor banks available (6)	4.9412
AEMO Constraint ID	**Q^NIL_GC**

Notes:

(1) Moreton to Gold Coast demand ratio $= \dfrac{\text{Moreton zone active demand}}{\text{Gold Coast zone active demand}} \times 100$

(2) The Moreton to Gold Coast demand ratio is bounded between 4.7 and 6.0.

(3) Positive transfer denotes northerly flow.

(4) There are currently 4 capacitor banks of nominal size 200MVAr which may be available within this area.

(5) There are currently 16 capacitor banks of nominal size 120MVAr which may be available within this area.

(6) There are currently 34 capacitor banks of nominal size 50MVAr which may be available within this area.

Appendix E – Indicative short circuit currents

Tables E.1 to E.3 show indicative maximum and minimum short circuit currents at Powerlink Queensland's substations.

Indicative maximum short circuit currents

Tables E.1 to E.3 show indicative maximum symmetrical three phase and single phase to ground short circuit currents in Powerlink's transmission network for summer 2017/18, 2018/19 and 2019/20.

These results include the short circuit contribution of some of the more significant embedded non-scheduled generators, however smaller embedded non-scheduled generators may have been excluded. As a result, short circuit currents may be higher than shown at some locations. Therefore, this information should be considered as an indicative guide to short circuit currents at each location and interested parties should consult Powerlink and/or the relevant Distribution Network Service Provider (DNSP) for more detailed information.

The maximum short circuit currents were calculated:

- using a system model, in which generators were represented as a voltage source of 110% of nominal voltage behind sub-transient reactance
- with all model shunt elements removed.

The short circuit currents shown in tables E.1 to E.3 are based on generation shown in Table 5.1 (together with any of the more significant embedded non-scheduled generators) and on the committed network development as at the end of each calendar year. The tables also show the rating of the lowest rated Powerlink owned plant at each location. No assessment has been made of the short circuit currents within networks owned by DNSPs or directly connected customers, nor has an assessment been made of the ability of their plant to withstand and/or interrupt the short circuit current.

The maximum short circuit currents presented in this appendix are based on all generating units online and an 'intact' network, that is, all network elements are assumed to be in-service. This assumption can result in short circuit currents appearing to be above plant rating at some locations. Where this is found, detailed assessments are made to determine if the contribution to the total short circuit current that flows through the plant exceeds its rating. If so, the network may be split to create 'normally-open' point as an operational measure to ensure that short circuit currents remain within the plant rating, until longer term solutions can be justified.

Indicative minimum short circuit currents

The connection of fluctuating load and power electronic connected systems (such as solar PV and static VAr compensators) should consider the minimum short circuit current at the prospective point of connection to ensure that there is no adverse impact on power quality and stability.

Tables E.1 to E.3 show indicative minimum symmetrical three phase short circuit currents at Powerlink's substations. These indicative minimum short circuit currents were calculated by analysing half hourly system normal snapshots over the period 1 April 2016 and 31 March 2017. The minimum of sub-transient, transient and synchronous short circuit currents over the year were compiled for each substation, with the individual outage of each significant network element.

Minimum system normal short circuit currents are also included, based on the same methodology, instead with all network elements in-service. These short circuit currents could be used to calculate connection capacity for proponents who would be willing to reduce capacity for specific network outages.

These minimum short circuit currents are indicative only, and are based on history. Short circuit currents can be lower for different generation dispatches and/or network elements out of service.

Table E.1 Indicative short circuit currents – northern Queensland – 2017/18 to 2019/20

Substation	Voltage (kV)	Plant Rating (lowest kA)	Indicative minimum system normal fault level (kA)	Indicative minimum post-contingent fault level (kA)	Indicative maximum short circuit currents 2017/18 3 phase (kA)	2017/18 L – G (kA)	2018/19 3 phase (kA)	2018/19 L – G (kA)	2019/20 3 phase (kA)	2019/20 L – G (kA)
Alan Sherriff	132	40.0	4.2	3.8	12.2	12.8	12.7	13.2	12.7	13.2
Alligator Creek	132	25.0	3.1	1.8	4.5	5.9	4.5	5.9	4.5	5.9
Bollingbroke	132	40.0	2.0	1.9	2.4	1.9	2.4	1.9	2.4	1.9
Bowen North	132	40.0	2.0	0.5	2.2	2.4	2.2	2.5	2.2	2.5
Cairns (2T)	132	25.0	2.7	0.7	5.5	7.3	5.9	7.8	5.9	7.8
Cairns (3T)	132	25.0	2.7	0.7	5.5	7.3	5.9	7.8	5.9	7.8
Cairns (4T)	132	25.0	2.7	0.7	5.5	7.4	5.9	7.9	5.9	7.9
Cardwell	132	19.3	1.9	1.0	3.0	3.2	3.0	3.3	3.0	3.3
Chalumbin	275	31.5	1.6	1.2	3.8	4.0	4.2	4.4	4.2	4.4
Chalumbin	132	31.5	2.9	2.3	6.2	7.1	6.5	7.5	6.5	7.5
Clare South	132	40.0	3.4	2.8	7.7	7.9	7.9	8.0	7.9	8.0
Collinsville North	132	31.5	4.5	2.3	7.6	8.6	8.3	9.1	8.3	9.1
Coppabella	132	31.5	2.2	1.4	2.9	3.3	2.9	3.3	2.9	3.3
Dan Gleeson (1T)	132	31.5	4.1	3.6	11.6	12.2	12.1	12.6	12.1	12.6
Dan Gleeson (2T)	132	40.0	4.1	3.6	11.6	12.2	12.0	12.5	12.0	12.5
Edmonton	132	40.0	2.6	0.8	5.0	6.2	5.3	6.5	5.3	6.5
Eagle Downs	132	40.0	2.9	1.5	4.2	4.2	4.2	4.2	4.2	4.2
El Arish	132	40.0	2.0	1.0	3.1	3.9	3.2	4.0	3.2	4.0
Garbutt	132	40.0	3.9	1.9	10.2	10.3	10.5	10.4	10.5	10.4
Goonyella Riverside	132	40.0	3.4	2.9	5.3	5.0	5.4	5.1	5.4	5.1
Ingham South	132	31.5	1.9	1.0	3.2	3.1	3.2	3.1	3.2	3.1
Innisfail	132	40.0	1.9	1.2	2.8	3.4	2.9	3.5	2.9	3.5
Invicta	132	19.3	2.6	1.7	5.2	4.7	5.3	4.7	5.3	4.7
Kamerunga	132	15.3	2.3	0.6	4.3	5.2	4.5	5.4	4.5	5.4
Kareeya	132	40.0	2.6	2.1	5.4	6.0	5.6	6.3	5.6	6.3
Kemmis	132	31.5	3.9	1.6	5.8	6.4	5.8	6.4	5.8	6.4
King Creek	132	40.0	2.9	1.4	4.5	3.8	4.6	3.9	4.6	3.9
Mackay (2T)	132	10.9	3.4	2.9	4.7	5.4	4.7	5.4	4.7	5.4
Mackay (1T & 3T)	132	10.9	3.4	2.9	4.8	5.4	4.8	5.4	4.8	5.4
Mackay Ports	132	40.0	2.6	1.6	3.5	4.1	3.5	4.1	3.5	4.1
Mindi	132	40.0	3.3	3.1	4.4	3.6	4.4	3.6	4.4	3.6
Moranbah	132	10.9	3.8	3.1	6.6	8.0	6.7	8.1	6.7	8.1

Table E.1 Indicative short circuit currents – northern Queensland – 2017/18 to 2019/20 *(continued)*

Substation	Voltage (kV)	Plant Rating (lowest kA)	Indicative minimum system normal fault level (kA)	Indicative minimum post-contingent fault level (kA)	Indicative maximum short circuit currents					
					2017/18		2018/19		2019/20	
					3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)
Moranbah South	132	31.5	3.2	2.6	5.0	4.8	5.0	4.8	5.0	4.8
Mt McLaren	132	31.5	1.5	1.4	2.0	2.1	2.0	2.1	2.0	2.1
Nebo	275	31.5	4.1	3.6	9.4	9.9	9.4	9.9	9.4	9.9
Nebo	132	15.3	6.9	6.1	12.8	14.8	12.8	14.8	12.8	14.8
Newlands	132	25.0	2.4	1.3	3.3	3.8	3.4	3.8	3.4	3.8
North Goonyella	132	20.0	2.8	1.0	4.1	3.5	4.1	3.6	4.1	3.6
Oonooie	132	31.5	2.3	1.5	3.1	3.7	3.1	3.7	3.1	3.7
Peak Downs	132	31.5	2.7	1.6	3.9	3.5	3.9	3.5	3.9	3.5
Pioneer Valley	132	31.5	4.1	3.5	7.0	7.8	7.0	7.8	7.0	7.8
Proserpine	132	40.0	2.3	1.5	2.6	3.2	2.7	3.3	2.7	3.3
Ross	275	31.5	2.6	2.3	7.2	8.3	7.7	8.6	7.7	8.6
Ross	132	31.5	4.7	4.2	15.6	18.0	16.7	19.0	16.7	19.0
Springlands	132	40.0	–	–	–	–	9.2	10.2	9.2	10.2
Stony Creek	132	40.0	2.5	1.2	3.4	3.4	3.5	3.5	3.5	3.5
Strathmore	275	31.5	3.2	2.8	7.9	8.4	8.2	8.7	8.2	8.7
Strathmore	132	40.0	4.8	2.2	8.4	9.7	9.2	10.5	9.2	10.5
Townsville East	132	40.0	4.0	1.5	11.8	11.8	12.2	12.0	12.2	12.0
Townsville South	132	21.9	4.3	3.9	15.5	19.0	16.1	19.7	16.1	19.7
Townsville PS	132	31.5	3.6	2.5	10.0	10.7	10.3	10.9	10.3	10.9
Tully	132	31.5	2.3	1.9	3.9	4.1	4.0	4.2	4.0	4.2
Turkinje	132	20.0	1.6	1.1	2.6	3.0	2.7	3.0	2.7	3.0
Walkamin	275	40.0	–	–	–	–	3.2	3.7	3.2	3.7
Wandoo	132	31.5	3.2	3.1	4.4	3.3	4.4	3.3	4.4	3.3
Woree (1T)	275	40.0	1.3	0.9	2.6	3.1	2.8	3.2	2.8	3.2
Woree (2T)	275	40.0	1.3	0.9	2.6	3.0	2.9	3.4	2.9	3.4
Woree	132	40.0	2.8	2.3	5.7	7.8	6.1	8.4	6.1	8.4
Wotonga	132	40.0	3.5	1.6	5.5	6.5	5.5	6.5	5.5	6.5
Yabulu South	132	40.0	4.1	3.7	11.7	11.4	12.1	11.7	12.1	11.7

Table E.2 Indicative short circuit currents – central Queensland – 2017/18 to 2019/20

Substation	Voltage (kV)	Plant Rating (lowest kA)	Indicative minimum system normal fault level (kA)	Indicative minimum post-contingent fault level (kA)	Indicative maximum short circuit currents					
					2017/18		2018/19		2019/20	
					3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)
Blackwater	132	10.9	3.9	3.0	5.7	6.9	5.2	6.5	5.2	6.5
Bluff	132	40.0	2.5	2.1	3.4	4.2	3.3	4.1	3.3	4.1
Bouldercombe	275	31.5	6.9	6.3	19.7	19.2	19.8	19.5	19.8	19.5
Bouldercombe	132	21.8	9.2	7.1	11.5	13.5	14.5	16.9	14.5	16.9
Broadsound	275	31.5	5.0	4.3	11.3	8.8	11.2	8.6	11.2	8.6
Callemondah	132	31.5	11.0	5.6	24.1	26.4	22.4	24.9	22.4	24.9
Callide A	132	11.0	5.2	1.0	10.2	10.5	–	–	–	–
Calliope River	275	40.0	7.5	6.8	21.0	23.8	20.8	23.7	20.8	23.7
Calliope River	132	40.0	11.7	10.4	27.0	31.9	25.1	30.2	25.1	30.2
Calvale	275	31.5	7.4	6.5	23.7	26.0	23.3	25.8	23.3	25.8
Calvale (1T)	132	31.5	5.3	1.0	10.2	10.6	8.7	9.6	8.7	9.6
Calvale (2T)	132	31.5	–	–	–	–	8.4	9.2	8.4	9.2
Dingo	132	31.5	2.1	1.1	2.7	2.9	2.7	2.9	2.7	2.9
Duaringa	132	40.0	1.7	1.1	2.1	2.8	1.3	1.8	1.3	1.8
Dysart	132	10.9	3.1	1.8	4.4	5.1	4.4	5.1	4.4	5.1
Egans Hill	132	25.0	6.0	1.6	7.3	7.4	8.3	8.2	8.3	8.2
Gladstone PS	275	40.0	7.2	6.6	19.5	21.7	19.4	21.6	19.4	21.6
Gladstone PS	132	40.0	10.7	9.6	23.4	26.3	22.0	25.2	22.0	25.2
Gladstone South	132	40.0	9.1	7.4	18.7	19.1	16.4	17.3	16.4	17.3
Grantleigh	132	31.5	2.2	2.1	2.6	2.7	2.7	2.8	2.7	2.8
Gregory	132	31.5	5.7	4.7	8.8	10.1	8.5	9.9	8.5	9.9
Larcom Creek	275	40.0	6.5	3.0	15.5	15.3	15.4	15.3	15.4	15.3
Larcom Creek	132	40.0	6.9	3.8	12.3	13.8	12.3	13.8	12.3	13.8
Lilyvale	275	31.5	3.3	2.5	5.6	5.6	5.5	5.6	5.5	5.6
Lilyvale	132	25.0	5.9	4.8	9.2	10.9	8.9	10.6	8.9	10.6
Moura	132	12.3	2.8	1.1	4.0	4.3	3.9	4.2	3.9	4.2
Norwich Park	132	31.5	2.7	1.2	3.5	2.6	3.5	2.6	3.5	2.6
Pandoin	132	40.0	5.3	1.3	6.2	5.8	7.0	6.3	7.0	6.3
Raglan	275	40.0	5.8	3.7	11.9	10.4	11.9	10.4	11.9	10.4
Rockhampton (1T)	132	10.9	4.9	1.8	5.8	5.9	6.5	6.4	6.5	6.4
Rockhampton (5T)	132	10.9	4.7	1.8	5.6	5.8	6.3	6.2	6.3	6.2
Rocklands	132	31.5	5.6	4.8	6.8	6.1	7.7	6.6	7.7	6.6

Table E.2 Indicative short circuit currents – central Queensland – 2017/18 to 2019/20 *(continued)*

Substation	Voltage (kV)	Plant Rating (lowest kA)	Indicative minimum system normal fault level (kA)	Indicative minimum post-contingent fault level (kA)	Indicative maximum short circuit currents 2017/18		2018/19		2019/20	
					3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)
Stanwell	275	31.5	7.1	6.5	22.4	24.0	22.4	24.1	22.4	24.1
Stanwell	132	31.5	4.6	4.0	5.4	6.0	6.0	6.5	6.0	6.5
Wurdong	275	31.5	7.1	5.7	17.0	16.8	16.8	16.7	16.8	16.7
Wycarbah	132	40.0	3.7	3.3	4.2	5.1	4.5	5.4	4.5	5.4
Yarwun	132	40.0	6.8	4.2	12.9	14.9	12.9	14.9	12.9	14.9

Table E.3 Indicative short circuit currents – southern Queensland – 2017/18 to 2019/20

Substation	Voltage (kV)	Plant Rating (lowest kA)	Indicative minimum system normal fault level (kA)	Indicative minimum post-contingent fault level (kA)	Indicative maximum short circuit currents 2017/18 3 phase (kA)	2017/18 L – G (kA)	2018/19 3 phase (kA)	2018/19 L – G (kA)	2019/20 3 phase (kA)	2019/20 L – G (kA)
Abermain	275	40.0	6.7	5.7	18.0	18.6	18.0	18.6	18.0	18.6
Abermain	110	31.5	12.2	10.0	21.3	25.2	21.4	25.2	21.4	25.2
Algester	110	40.0	12.4	11.1	21.5	21.2	21.5	21.2	21.5	21.2
Ashgrove West	110	26.3	11.5	9.1	19.0	20.0	19.1	20.0	19.1	20.0
Belmont	275	31.5	6.6	6.2	16.7	18.5	16.8	18.6	16.8	18.6
Belmont	110	37.4	14.7	14.0	29.7	37.0	29.7	37.0	29.7	37.0
Blackstone	275	40.0	7.0	6.5	20.9	23.2	21.0	23.2	21.0	23.2
Blackstone	110	40.0	13.4	12.5	25.2	28.9	25.3	29.0	25.3	29.0
Blackwall	275	37.0	7.2	6.7	22.0	23.9	22.1	24.0	22.1	24.0
Blythdale	132	40.0	3.3	2.4	4.2	5.2	4.2	5.2	4.2	5.2
Braemar	330	50.0	5.9	5.5	23.0	25.1	23.4	25.3	23.4	25.3
Braemar (East)	275	40.0	7.5	4.8	26.4	30.8	26.7	31.0	26.7	31.0
Braemar (West)	275	40.0	7.2	4.8	26.3	29.3	27.1	29.7	27.1	29.7
Bulli Creek	330	50.0	6.2	5.8	18.1	14.3	18.2	14.3	18.2	14.3
Bulli Creek	132	40.0	3.1	3.0	3.8	4.3	3.8	4.3	3.8	4.3
Bundamba	110	40.0	10.6	7.6	17.2	16.6	17.2	16.6	17.2	16.6
Chinchilla	132	25.0	5.3	4.2	7.9	7.8	8.0	7.8	8.0	7.8
Clifford Creek	132	40.0	4.3	3.5	5.7	5.2	5.7	5.2	5.7	5.2
Columboola	275	40.0	5.3	4.4	12.2	11.6	12.4	11.7	12.4	11.7
Columboola	132	25.0	7.7	6.0	16.1	18.2	16.1	18.2	16.1	18.2
Condabri North	132	40.0	6.9	5.6	13.1	12.1	13.1	12.1	13.1	12.1
Condabri Central	132	40.0	5.5	4.6	8.9	6.6	8.9	6.6	8.9	6.6
Condabri South	132	40.0	4.5	3.7	6.5	4.4	6.5	4.4	6.5	4.4
Dinoun South	132	40.0	4.7	3.8	6.5	6.8	6.5	6.8	6.5	6.8
Eurombah (1T)	275	40.0	2.9	1.2	4.3	4.5	4.3	4.5	4.3	4.5
Eurombah (2T)	275	40.0	2.9	1.2	4.3	4.5	4.3	4.5	4.3	4.5
Eurombah	132	40.0	4.9	3.6	6.8	8.4	6.9	8.4	6.9	8.4
Fairview	132	40.0	3.2	2.6	4.0	5.1	4.0	5.1	4.0	5.1
Fairview South	132	40.0	4.0	3.1	5.2	6.6	5.2	6.6	5.2	6.6
Gin Gin	275	14.5	6.1	5.6	10.9	10.1	11.0	10.1	11.0	10.1
Gin Gin	132	20.0	8.2	6.2	12.8	13.9	12.9	13.9	12.9	13.9
Goodna	275	40.0	6.5	5.2	16.0	16.0	16.1	16.0	16.1	16.0

Table E.3 Indicative short circuit currents – southern Queensland – 2017/18 to 2019/20 *(continued)*

Substation	Voltage (kV)	Plant Rating (lowest kA)	Indicative minimum system normal fault level (kA)	Indicative minimum post-contingent fault level (kA)	Indicative maximum short circuit currents 2017/18 3 phase (kA)	2017/18 L – G (kA)	2018/19 3 phase (kA)	2018/19 L – G (kA)	2019/20 3 phase (kA)	2019/20 L – G (kA)
Goodna	110	40.0	13.5	12.1	25.3	27.4	25.3	27.5	25.3	27.5
Greenbank	275	40.0	6.9	6.5	20.2	22.4	20.3	22.4	20.3	22.4
Halys	275	50.0	8.0	7.2	31.3	26.0	31.7	26.1	31.7	26.1
Kumbarilla Park (1T)	275	40.0	6.3	1.7	16.5	15.9	16.6	16.0	16.6	16.0
Kumbarilla Park (2T)	275	40.0	6.3	1.7	16.5	15.9	16.6	16.0	16.6	16.0
Kumbarilla Park	132	40.0	8.6	5.7	13.2	15.2	13.2	15.2	13.2	15.2
Loganlea	275	40.0	6.3	5.6	14.8	15.4	14.8	15.4	14.8	15.4
Loganlea	110	31.5	13.1	12.1	22.8	27.4	22.8	27.4	22.8	27.4
Middle Ridge (4T)	330	50.0	5.3	3.2	12.5	12.2	12.6	12.2	12.6	12.2
Middle Ridge (5T)	330	50.0	5.3	3.2	12.9	12.6	12.9	12.6	12.9	12.6
Middle Ridge	275	31.5	6.7	6.3	17.9	18.1	17.9	18.1	17.9	18.1
Middle Ridge	110	18.3	10.7	9.1	20.3	24.1	20.4	24.3	20.4	24.3
Millmerran	330	40.0	5.9	5.4	18.3	19.6	18.3	19.7	18.3	19.7
Molendinar (1T)	275	40.0	4.8	2.1	8.2	8.1	8.2	8.1	8.2	8.1
Molendinar (2T)	275	40.0	4.7	2.1	8.2	8.1	8.2	8.1	8.2	8.1
Molendinar	110	40.0	11.6	10.2	20.0	25.3	19.2	24.4	19.2	24.4
Mt England	275	31.5	7.1	6.6	22.4	22.7	22.5	22.8	22.5	22.8
Mudgeeraba	275	31.5	5.1	4.2	9.4	9.4	9.2	8.6	9.2	8.6
Mudgeeraba	110	25.0	10.9	10.0	18.7	22.8	17.3	21.0	17.3	21.0
Murarrie (2T)	275	40.0	6.0	2.5	13.0	13.5	13.0	13.5	13.0	13.5
Murarrie (3T)	275	40.0	6.0	2.5	13.0	13.5	13.0	13.5	13.0	13.5
Murarrie	110	40.0	13.5	12.8	24.2	29.2	24.3	29.2	24.3	29.2
Oakey GT PS	110	31.5	5.1	1.2	10.8	12.0	10.9	12.1	10.9	12.1
Oakey	110	40.0	4.9	1.3	10.1	10.0	10.2	10.1	10.2	10.1
Orana	275	40.0	5.8	3.4	14.6	13.6	14.9	13.7	14.9	13.7
Palmwoods	275	31.5	5.2	3.4	8.4	8.8	8.5	8.8	8.5	8.8
Palmwoods	132	21.9	9.1	6.9	13.0	15.5	13.0	15.6	13.0	15.6
Palmwoods (7T)	110	40.0	5.8	2.7	7.2	7.5	7.2	7.5	7.2	7.5
Palmwoods (8T)	110	40.0	5.8	2.7	7.2	7.5	7.2	7.5	7.2	7.5
Redbank Plains	110	31.5	12.1	9.2	21.3	20.8	21.3	20.8	21.3	20.8
Richlands	110	40.0	12.5	10.8	22.0	22.7	22.0	22.7	22.0	22.7
Rocklea (1T)	275	31.5	6.0	2.4	13.1	12.3	13.1	12.3	13.1	12.3

Table E.3 Indicative short circuit currents – southern Queensland – 2017/18 to 2019/20 *(continued)*

Substation	Voltage (kV)	Plant Rating (lowest kA)	Indicative minimum system normal fault level (kA)	Indicative minimum post-contingent fault level (kA)	Indicative maximum short circuit currents					
					2017/18		2018/19		2019/20	
					3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)
Rocklea (2T)	275	31.5	5.1	2.4	8.7	8.4	8.7	8.4	8.7	8.4
Rocklea	110	31.5	13.5	12.2	24.8	28.7	24.9	28.7	24.9	28.7
Runcorn	110	40.0	11.6	8.2	19.3	19.6	19.4	19.6	19.4	19.6
South Pine	275	31.5	7.1	6.7	18.5	21.1	18.6	21.2	18.6	21.2
South Pine (East)	110	40.0	12.9	11.3	21.4	27.5	21.5	27.5	21.5	27.5
South Pine (West)	110	40.0	12.2	9.9	20.3	23.5	20.4	23.5	20.4	23.5
Sumner	110	40.0	12.0	8.9	20.6	20.2	20.6	20.3	20.6	20.3
Swanbank E	275	40.0	6.9	5.8	20.6	22.7	20.7	22.8	20.7	22.8
Tangkam	110	31.5	5.9	4.0	12.8	12.0	12.9	12.1	12.9	12.1
Tarong (1)	275	31.5	8.0	7.3	32.9	34.5	33.2	34.7	33.2	34.7
Tarong (1T)	132	25.0	4.7	1.1	5.8	6.0	5.8	6.0	5.8	6.0
Tarong (4T)	132	25.0	4.7	1.1	5.8	6.0	5.8	6.0	5.8	6.0
Tarong	66	40.0	11.9	7.2	15.0	16.2	15.0	16.2	15.0	16.2
Teebar Creek	275	40.0	4.9	3.3	7.3	7.2	7.4	7.3	7.4	7.3
Teebar Creek	132	40.0	7.7	6.1	10.1	11.2	10.4	11.4	10.4	11.4
Tennyson	110	40.0	10.4	1.7	16.2	16.4	16.2	16.4	16.2	16.4
Upper Kedron	110	40.0	12.3	10.9	21.1	18.7	21.2	18.7	21.2	18.7
Wandoan South	275	40.0	4.0	3.2	7.0	7.7	7.1	7.7	7.1	7.7
Wandoan South	132	40.0	5.4	4.0	8.6	11.0	8.6	11.0	8.6	11.0
West Darra	110	40.0	13.3	12.4	24.8	23.8	24.8	23.8	24.8	23.8
Western Downs	275	40.0	6.8	5.5	24.1	24.2	25.1	24.5	25.1	24.5
Woolooga	275	31.5	5.8	5.0	9.7	10.8	9.8	10.9	9.8	10.9
Woolooga	132	20.0	9.4	7.8	13.0	15.5	13.1	15.6	13.1	15.6
Yuleba North	275	40.0	3.5	2.9	5.7	6.3	5.8	6.4	5.8	6.4
Yuleba North	132	40.0	5.4	4.2	7.7	9.3	7.7	9.4	7.7	9.4

Note:

(1) The lowest rated plant at this location is required to withstand and/or interrupt a short circuit current which is less than the maximum short circuit current and below the plant rating.

Appendix F – Abbreviations

AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
APR	Annual Planning Report
CAA	Connection and Access Agreement
CQ	Central Queensland
CSG	Coal seam gas
CSM	Coal seam methane
DNSP	Distribution Network Service Provider
EII	Energy Infrastructure Investments
ESOO	Electricity Statement of Opportunity
FNQ	Far North Queensland
GT	Gas Turbine
GWh	Gigawatt hour
JPB	Jurisdictional Planning Body
kA	Kiloampere
kV	Kilovolt
MJ	Megajoules
MVA	Megavolt Ampere
MVAr	Megavolt Ampere reactive
MW	Megawatt
MWh	Megawatt hour
NEFR	National Electricity Forecasting Report
NEM	National Electricity Market
NEMDE	National Electricity Market Dispatch Engine
NER	National Electricity Rules
NNESR	Non-network Engagement Stakeholder Register
NSCAS	Network Support and Control Ancillary Services
NTNDP	National Transmission Network Development Plan
NSW	New South Wales
NQ	North Queensland
NWD	Non-weather dependent
PoE	Probability of exceedance
PS	Power Station
PV	Photovoltaic
QAL	Queensland Alumina Limited
QER	Queensland Energy Regulator
QGC	Queensland Gas Company
QNI	Queensland/New South Wales Interconnector transmission line
REZ	Renewable Energy Zone
RIT-T	Regulatory Investment Test for Transmission
RTA	Rio Tino Aluminium
SCR	Short Circuit Ratio
SEQ	South East Queensland
SQ	South Queensland
STATCOM	Static Synchronous Compensator
SVC	Static VAr Compensator
SWQ	South West Queensland
SynCon	Synchronous Condensor
TAPR	Transmission Annual Planning Report
TNSP	Transmission Network Service Provider
VRE	Variable renewable electricity
WD	Weather dependent

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