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POWERLINK QUEENSLAND REVENUE PROPOSAL

APPENDIX 5.03

Powerlink Queensland
Transmission Annual Planning Report 2015

Delivering better value

Powerlink Queensland

TRANSMISSION ANNUAL PLANNING REPORT

2015

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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/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, the capability of the existing electricity supply system, 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 2015 TAPR outlines the key drivers impacting Powerlink's business. Excluding the positive effect of continued high levels of liquefied natural gas (LNG) development in the Surat Basin, forecasts for both energy and demand across the balance of Queensland over the outlook period remains relatively flat.

An amended planning standard for the transmission network also came into effect on 1 July 2014, allowing 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 changes discussed above have in combination caused a significant reduction in demand driven investment over the outlook period, which has had the effect of reducing Powerlink's overall outlook of capital investment compared to previous years.

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 the end of technical or economic life, represents the majority of Powerlink's program of work over the outlook period. Considerable emphasis is being given to 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 was discussed in the 2014 TAPR and has gained momentum over the last year. Stakeholder engagement activities have been conducted in relation to the demand and energy forecast methodology, non-network solution provision and the quality and usefulness of information provided in the TAPR. Powerlink has also proactively surveyed the views and priorities of consumers and directly connected customers in relation to the transmission service that Powerlink provides.

Electricity energy and demand forecasts

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

- recent high levels of investment in LNG development in South West Queensland
- continued growth of solar Photovoltaic (PV) installations
- continued slower Queensland economic growth
- 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 forecast, Powerlink conducted a forum with industry experts to share and build on knowledge related to emerging technologies. As a result, several enhancements were made to the forecasting methodology in this TAPR including more explicit analysis of emerging technologies.

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.

Powerlink has developed its own econometric model for forecasting DNSP energy and demand which has been applied since the 2013 Annual Planning Report (APR)[1]. For the forecasts in the 2015 TAPR, several enhancements were made to the model with the new methodology discussed in Appendix B. Key economic inputs to this model include population growth, Gross State Product (GSP) and the price of electricity. DNSP customer forecasts are reconciled to meet the totals obtained from this model.

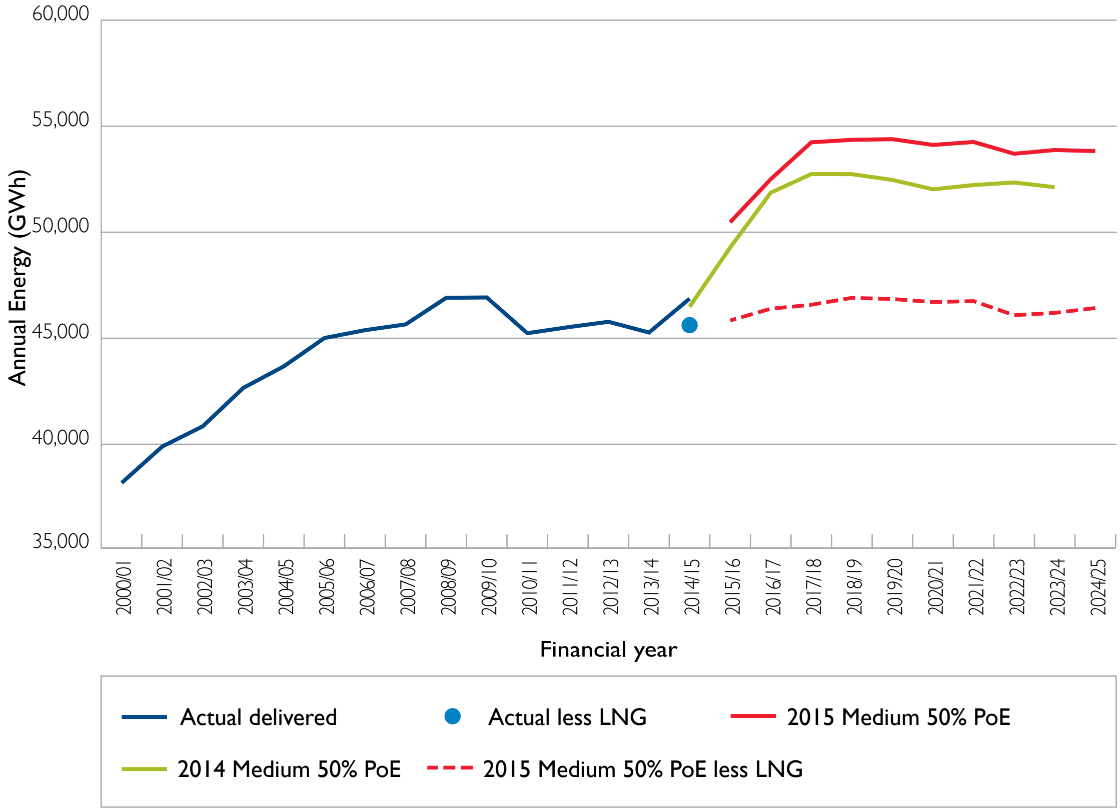
The 2014/15 summer in Queensland was hot and long lasting with record monthly demands in both October and March. Demand delivered from the transmission network exceeded the 2014 TAPR medium economic outlook 50% probability of exceedance (PoE) forecast by 355MW. This was the highest ever demand delivered from the transmission network. The maximum demand occurred on 5 March when scheduled generation reached 8,809MW, 82MW short of the highest ever scheduled generation recorded in January 2010. This above forecast demand was mainly driven by load located in South East Queensland.

Electricity energy forecast

Based on the medium economic outlook, Queensland's delivered energy consumption is forecast to increase at an average of 1.4% per annum over the next 10 years from 46,742GWh in 2013/14 to 53,700GWh in 2024/25. Without the LNG sector, energy over the forecast period grows at 0.1% per annum. Continued uptake of solar PV and energy efficiency initiatives are expected to keep this growth rate relatively flat.

A comparison of the 2014 TAPR and 2015 TAPR forecasts for energy delivered from the transmission network is displayed in Figure 1. Energy delivered from the transmission network for 2014/15 is on track to exceed the 2014 TAPR forecast by around 0.6%.

Figure 1 Comparison of energy forecasts for the medium economic outlook



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[1] This Transmission Annual Planning Report was formerly called the Annual Planning Report.

Electricity demand forecast

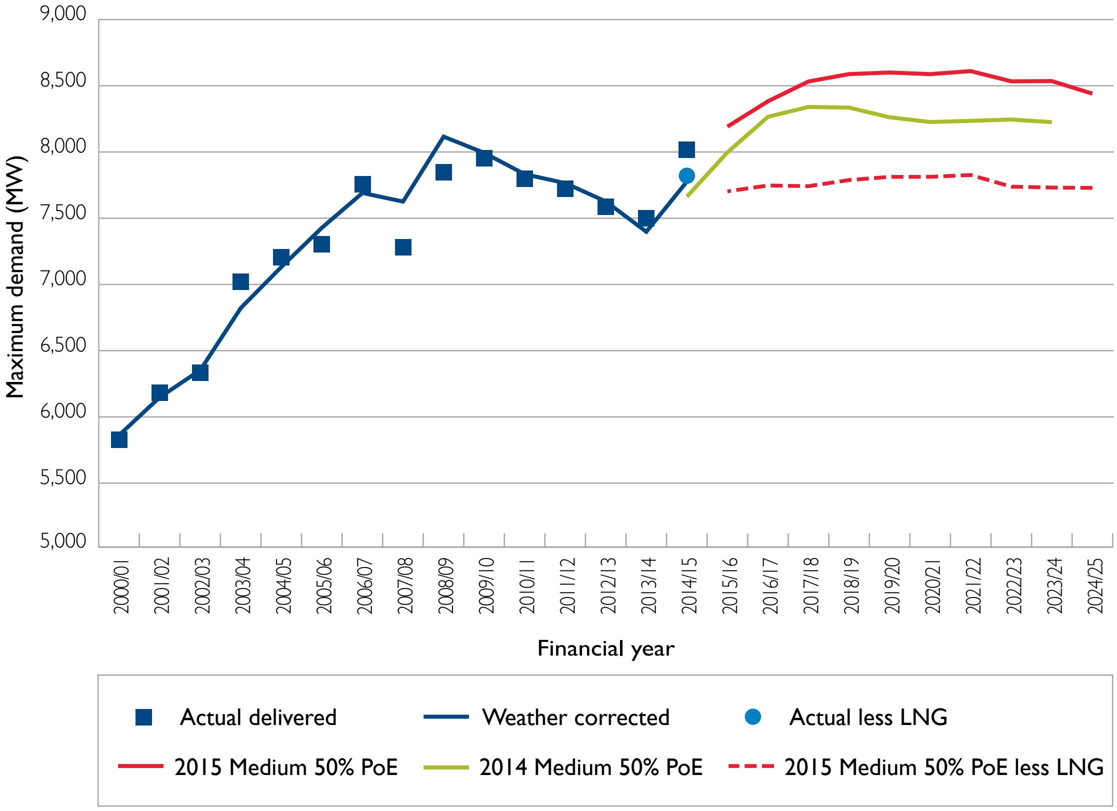
Based on the medium economic outlook, Queensland's transmission delivered summer maximum demand is forecast to increase at an average rate of 0.9% per annum over the next 10 years, from 7,777MW (weather corrected) in 2014/15 to 8,491MW in 2024/25. Without the LNG sector, maximum delivered summer demand is forecast to grow over the period at a rate of 0.2% per annum.

The transmission delivered maximum demand for summer 2014/15 of 8,019MW is 521MW higher than that recorded in summer 2013/14, which is 279MW higher on a weather corrected basis. Similarly, the projected transmission delivered energy consumption for 2014/15 of 46,742GWh is above that recorded in 2013/14 of 45,145GWh. This increase in demand and energy consumption is attributable to:

- the ramping up of the new LNG industry
- a hot and long lasting summer in Queensland.

A comparison of recent and current summer maximum demand forecasts for the medium economic outlook, based on a 50% PoE is displayed in Figure 2. As with the energy forecasts, the latest demand forecast has been adjusted to take account of actual consumption and demands over the 2014/15 period and updated to reflect the latest economic projections for the State.

Figure 2 Comparison of summer demand forecasts for the medium economic outlook



Powerlink's amended planning standard

On 1 July 2014, the Queensland Government amended Powerlink's Transmission Authority to formalise a change in the way the transmission network is to be planned and developed.

The amended 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 during the contingency event.

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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 amended 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 has established policy frameworks and methodologies to support the implementation of this standard, which are being applied in various parts of the Powerlink network where emerging limitations are being monitored.

Future network development

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

There are several proposals for large mining, metal processing and other industrial loads that have not yet 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 constructed in the 1960s and early 1970s where condition assessment has identified emerging risks requiring action within the outlook period.

Powerlink is mindful of this change in investment outlook and in response has expanded discussion on the required reinvestment needs within the outlook period. Considerable emphasis has been given to an integrated approach to the analysis of future reinvestment needs and options. With the relatively flat demand forecast outlook, 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.

The integrated planning approach has revealed a number of opportunities for reconfiguration of Powerlink's network within the outlook period. Powerlink has also sought to include additional information in the TAPR relating to long-term network reconfiguration strategies that in future years are likely to require further stakeholder engagement and consultation.

Committed and commissioned projects

During 2014/15, the majority of committed projects provided for reinvestment in transmission lines and substations across Powerlink's network, including the initial stages of a program of transmission line structural upgrade and refit works that is anticipated to expand in scale within the outlook period.

In terms of network augmentation, Powerlink completed projects to reinforce supply into the South West and north west Surat Basin zones in response to the additional demand in the region. This involved the establishment of:

- transmission lines between Western Downs, Columboola (near Miles) and Wandoan South
- substations at Wandoan South and Columboola.

Powerlink also has transmission augmentation projects in progress to manage localised voltage limitations in the Northern Bowen Basin and North zones, requiring the installation of 132kV capacitor banks in the Moranbah area and additional feeder bays at Pioneer Valley.

Grid section and zone performance

During 2014/15, the Powerlink transmission network supported the delivery of a summer maximum demand of 8,019MW, 521MW higher than that recorded in summer 2013/14.

Most grid sections showed greater levels of utilisation during the year. Increases in southerly transfers to New South Wales (NSW) is the predominant reason for the lower energy transfers across the South West grid section.

The transmission network in the Queensland region performed reliably during the 2014/15 year, including during the summer maximum demand. Queensland grid sections were largely unconstrained due in part to the absence of high impact events as well as prudent scheduling of planned transmission outages.

Stakeholder engagement and consultation

Queensland/New South Wales Interconnector (QNI) transmission line

In December 2014 following the publication of a Project Assessment Conclusions Report (PACR), Powerlink and TransGrid finalised a regulatory consultation relating to the upgrade of QNI in accordance with the requirements of the Regulatory Investment Test for Transmission (RIT-T).

The PACR concluded that the optimal timing and ranking of QNI upgrade options varied considerably across different market development scenarios, and that there was no upgrade option which was consistently and robustly ranked for the majority of the scenarios.

In light of uncertainties, Powerlink and TransGrid considered it prudent not to recommend a preferred upgrade option, and to continue to monitor market developments to determine if any material changes could warrant reassessment of an upgrade to QNI.

As part of the regulatory consultation process, Powerlink and TransGrid also provided information on the technical requirements for potential non-network options which may be capable of increasing the transfer capability of QNI. Although the formal consultation period for the QNI upgrade RIT-T has now closed, Powerlink and TransGrid encourage participants to express their interest if they are able to offer potential non-network solutions.

Customer and consumer engagement

Powerlink is currently developing a formal consumer engagement strategy to support the considerable work already being undertaken to engage with stakeholders and seek their input to Powerlink's business focus and objectives. The consumer engagement strategy is focused on building awareness, encouraging consumer input and responding to this input through relevant improvements to business planning and operational activities. A key aim is to ensure Powerlink's service better reflects consumer values, priorities and expectations.

In early 2015, Powerlink undertook additional targeted customer and consumer research to help gain a better understanding and respond to matters that are important to Powerlink's stakeholders as they relate to electricity transmission services. The results from this survey represented the views from a range of stakeholders including customers, consumer organisations, government/regulators and industry associations. A positive outcome from the survey was a general willingness by most participants for further engagement. All research and key findings will be incorporated into Powerlink's future customer and consumer engagement strategies.

More recently, Powerlink held its first customer and consumer panel meeting. This panel is anticipated to meet quarterly and provides a face to face forum for Powerlink's stakeholders to give input and feedback regarding Powerlink's decision making, processes and methodologies. It will also provide Powerlink with another avenue to keep stakeholders better informed about operational and strategic topics of relevance.

Non-network solution providers

Powerlink is continuing to develop its engagement process with non-network providers and where possible expand the use of non-network solutions to address future limitations within the transmission network. In 2014/15, Powerlink initiated consultation for the purposes of enhancing engagement with non-network providers and to further develop the processes for consideration of non-network solutions. Powerlink has responded to feedback by providing enhanced information on non-network alternatives within this TAPR, particularly as an alternative option to like for like replacement or to complement an overall network reconfiguration strategy, where technically feasible. Powerlink will also continue to request non-network solutions from market participants as part of the RIT-T process.

Response to feedback about Powerlink's TAPR

During early 2015, Powerlink engaged with a number of stakeholders to understand further opportunities to enhance the quality of information provided in the TAPR. These discussions indicated a number of common priorities and interest areas for stakeholders:

- Demand forecast – particularly the clear articulation of the building blocks that form part of the demand forecast methodology and the factors that may significantly influence the forecast in the future
- Non-network solutions – a focus on enhanced information for non-network solution providers, particularly any measures to elaborate on the duration, scale and potential value of a non-network solution
- Reliability standard – the need for stakeholders to gain a better understanding of Powerlink's approach to the application of the planning standard amended by the Queensland Government in July 2014.

Powerlink has given consideration to these matters and other feedback received and incorporated improvements in the development of the 2015 TAPR as listed in the table below.

Improvement actioned in 2015 TAPR	
Inclusion of a new table to illustrate Powerlink's planning process and terminology.	Section 1.6.2
Information provided on Powerlink's approach to the application of the amended planning standard.	Section 1.7
Provision of more detailed information on the demand and energy forecast, what has changed and why.	Section 2 – Demand and energy model to be published on website in conjunction with publication of the TAPR
Additional information provided on the requirements for potential non-network alternatives for reinvestment projects.	Section 4
Provision of more detailed information in relation to asset condition, reinvestment options and scopes of work.	Section 4
New section on zone performance providing information on historical zonal transmission delivered demand, intra-zonal constraints and management of high voltages.	Section 5.6
Strategic planning information on potential future asset reinvestments and potential network configuration within the five to 10-year outlook.	Section 6.3
Incorporation of explicit future impacts of emerging technologies into Powerlink's forecasting methodology. Details of this new approach and the forecasting process detailed in a new appendix.	New Appendix B – Forecasting methodology historical energy and demands
Focus on transmission delivered rather than native demand and energy.	All sections

Chapter 1

Introduction

Chapter 1

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 National Electricity Rules (NER) and publishes the findings of this review in its Transmission Annual Planning Report (TAPR).

This 2015 TAPR includes information on electricity energy and demand forecasts, the existing electricity supply system including committed generation and transmission network developments, and forecasts of network capability. Emerging limitations in the capability of the network and risks associated with the condition and performance of existing assets are identified and possible solutions to address these limitations are discussed. Interested parties are encouraged to provide input to facilitate identification of the most economical solution (including non-network solutions provided by others) that satisfies the required reliability standard to customers into the future.

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

1.2 Context of the Transmission Annual Planning Report

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

Information from this process is also provided to the Australian Energy Market Operator (AEMO) to assist in the preparation of their 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 20-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 promoting efficient outcomes. Similarly, information from the NTNDP is considered in this TAPR, and more generally in Powerlink's planning activities.

Interested parties may benefit from reviewing Powerlink's 2015 TAPR in conjunction with AEMO's 2015 NEFR, ESOO and NTNDP, which are anticipated to be published in June 2015, August 2015 and December 2015 respectively.

1.3 Purpose of the Transmission Annual Planning Report

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
- understand how the electricity supply system affects their needs
- consider 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 that 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 Jurisdictional Planning Body 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 that the network is able to be operated with sufficient capability and augmented, if necessary, to provide network services to customers in accordance with Powerlink's Transmission Authority and associated reliability standard
- ensuring that the risks associated with the condition and performance of existing assets are appropriately managed
- ensuring that 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, 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; solutions may include network upgrades or non-network options such as local generation and demand side management initiatives
- assessing whether or not a proposed transmission network augmentation has a material impact on networks owned by other TNSPs; 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 approach to planning of future network investment needs is in accordance with Powerlink's Asset Management Policy and Strategy. The principles and strategic objectives set out in these documents guides Powerlink's analysis of key investment drivers to form an integrated network investment plan over a 10-year outlook period.

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.

Factors that influence network development, such as energy and demand forecasts, generation development and risks related to the condition and performance of the existing asset base are analysed collectively in order to form an integrated view of future network investment needs.

With reinvestment in existing assets forming such a substantial part of Powerlink's future network investment plans, the assessment of emerging risks related to the condition and performance of 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[1]. In order to inform risk assessments, Powerlink undertakes a periodic review of network assets to assess a 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.

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 may be proposed to meet these legislative and NER obligations. Powerlink may also propose transmission investments that deliver a net market benefit when measured 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

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

- analysis and assessment of credible options, which include costs, market benefits and material inter-network 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. 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 and DNSPs. 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
- the assessment of future network capacity to meet the required planning criteria.

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 Section 5.2. 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 augmentations. 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 are appropriately managed. Powerlink routinely undertakes an assessment of the condition of assets and identifies potential emerging risks related to such factors as reliability, safety and obsolescence. Further information is provided in Section 4.2.

Therefore, planning of the network optimises the network topology as assets reach the end of their technical life so that the network is best configured to meet current and future capacity needs. Individual asset investment decisions are not determined in isolation. Powerlink's integrated planning process takes account of both future changes in demand 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 and the risks associated in allowing assets to remain in-service.

In response to these risks, a range of options are considered as asset reinvestments, including removing assets without replacement, non-network alternatives, line refits to extend technical life or replacing assets with assets of a different type, configuration or capacity. Each of these options is considered in the context of the future capacity needs accounting for forecast demand.

A summary of Powerlink's integrated planning approach that considers both asset condition and demand based limitations is presented in Table 1.1.

Table 1.1 **Overview of Powerlink's TAPR planning process**

Inputs	Integrated planning	Solution development	TAPR
Asset management policy and strategy Transmission Authority Generation, demand and energy forecasting Asset condition and performance monitoring New customer connection need Consultation and customer/consumer engagement	• Analysis of asset condition, performance and related risks • Analysis of network capability and limitations (including DNSP joint planning) • Compliance with system standards • Analysis of competition and market impacts • Analysis of operational impacts and constraints • Overall review of portfolio delivery and risks	• Integrated review of investment need and risks • Development of investment options (network reconfiguration, non-network solution, network solution) • Risk and cost benefit analysis of investment options • Project level delivery risk assessment • Market and regulatory consultation (e.g. RIT-T)	• Demand and energy forecast • Analysis of network capability and performance • Future network developments to address network limitations, condition and performance • Potential opportunities for non-network solutions • Committed and commissioned network projects • Strategic network development • Network technical data (e.g. connection point demand forecasts, fault levels) • Customer/consumer engagement

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, determination of technical requirements and completion of connection agreements. 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 $5 million, may be subject to the RIT-T.

1.6.4 Planning of interconnectors

Development and assessment of new or augmented interconnections between Queensland and New South Wales (NSW) or other States is the responsibility of the respective TNSPs. Information on potential upgrade activities is provided in Chapter 6.

1.7 Powerlink's planning standard

Amended planning standard

In recent years, significant focus has been placed on striking the right balance between reliability and cost of transmission services. In 2013, Powerlink sought to amend its Transmission Authority to allow for increased flexibility in response to these drivers, culminating in the Queensland Energy Regulator (QER) formally amending Powerlink's Transmission Authority and enabling the QER to vary Powerlink's N-1 criterion on a case-by-case basis. The Queensland Government subsequently made further amendments to Powerlink's Transmission Authority to formalise a change in the way the transmission network is to be planned and developed. This came into effect on 1 July 2014.

The amended 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.

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 amended 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 in 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 consistent 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. 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 amended planning standard. In this instance the amended planning standard is deferring investment and delivering savings to customers and consumers.

The amended planning standard will deliver further opportunities to defer investment if new mining, metal processing or other industrial loads (discussed in Table 2.1 of Chapter 2) develop. The amended planning standard may not only affect the timing of required investment but also in some cases afford the opportunity for incremental solutions that would not have otherwise met the original N-1 criterion.

Chapter 2 provides details of possible new 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 new large loads (Table 2.1) are within the resource rich areas of Queensland or at the associated coastal port facilities. 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.

1.8 Stakeholder engagement

Powerlink aims to share effective, timely and transparent information with our 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 we aim 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 implementing plans to proactively engage with stakeholders and seek their input to Powerlink's business processes and objectives. All engagement activities are undertaken in line with our Stakeholder Engagement Framework that sets out the principles, objectives and outcomes we are seeking to achieve in our interactions with stakeholders. The framework aims to achieve greater stakeholder trust and social licence to operate, better business decision making and improved 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, including social licence to operate and reputation measures.

Powerlink undertakes a comprehensive biennial survey, the most recent in 2014, to gain insights about stakeholder perceptions of Powerlink, its social licence to operate and reputation. The surveys provide an evidence base to support the Stakeholder Engagement Framework and inform engagement with individual stakeholders.

The 2014 survey highlighted that generally stakeholders remain positive about their relationship with Powerlink.

In early 2015, Powerlink undertook additional targeted customer and consumer research to help us better understand and respond to matters that are important to our stakeholders as they relate to electricity transmission services. The results from this survey represented the views from a range of stakeholders including customers, consumer organisations, government/regulators and industry associations. A positive outcome from the survey was a general willingness by most participants for further engagement. All research and key findings will be incorporated into our plans for engagement.

In late March we also held a Demand and Energy Forecasting Forum with a wide range of attendees from across the industry. The forum examined demand and energy forecasting on the Queensland transmission network with a particular focus on how advances in future technology are playing an ever increasing role in future demand and energy needs. The information provided as a result of this forum has supported the development of our TAPR forecast and is detailed further in Chapter 2 and Appendix B.

More recently, we held our first customer and consumer panel meeting. This panel is anticipated to meet quarterly and provides a face to face forum for our stakeholders to give input and feedback to Powerlink regarding our decision making, processes and methodologies. It will also provide us with another avenue to keep our stakeholders better informed about operational and strategic topics of relevance. More information on these 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. The current 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. Most recently Powerlink has entered into network support services as part of the solution to address emerging limitations in the Bowen Basin area. This is outlined in Section 4.2.

Powerlink is continuing to develop its non-network engagement process and where possible and economic expand the use of non-network solutions to address future limitations within the transmission network. In 2014/15, Powerlink initiated consultation for the purpose of enhancing engagement with non-network providers and to improve the processes for consideration of non-network solutions. Powerlink will also continue to request non-network solutions from market participants as part of the RIT-T process.

An example of this approach is Powerlink's recent collaboration with the Institute for Sustainable Futures[2] and other Network Service Providers regarding the Network Opportunity Mapping project. The project aims to provide enhanced information to market participants on network constraints and the opportunities for demand side solutions. The publicly available data provided via this project would extend on information typically provided in the TAPR and responds to feedback Powerlink has received from a number of stakeholders about the need to provide enhanced information on the potential value and timing of non-network solutions.

1.8.3 Response to feedback about Powerlink's TAPR

During early 2015, Powerlink engaged a number of stakeholders to understand further opportunities to enhance the quality and timeliness of information provided in the TAPR. These discussions indicated a number of common priorities and interest areas for stakeholders:

- demand forecast – particularly the clear articulation of the building blocks that form part of the demand forecast methodology and the factors that may significantly influence the forecast in the future
- non-network solutions – a focus on enhanced information for non-network solution providers, particularly any measures to elaborate on the duration, scale and potential value of a non-network solution (refer to Section 4.2)
- reliability standard – the need for stakeholders to gain a better understanding of Powerlink's approach to the application of the planning standard amended by the Queensland Government in July 2014.

Powerlink has given consideration to these matters and other feedback received and sought where possible to incorporate improvements in the development of the 2015 TAPR.

Since the 2014 TAPR, Powerlink has now also established the Non-Network Engagement Stakeholder Register (NNESR) to convey non-network solution providers the details of emerging network limitations. The NNESR is made up 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).

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[2] Information available at http://www.uts.edu.au/research-and-teaching/our-research/institute-sustainable-futures/news/network-opportunity-mapping

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.

The NNESR will be utilised as a two-way 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 below the RIT-T public consultation cost threshold
- with respect to network reinvestments which may have the potential to use non-network solutions.

Chapter 2

Energy and demand projections

Chapter 2

2.1 Overview

The 2014/15 summer in Queensland was hot and long lasting with record monthly demands in both October and March. Demand delivered from the transmission network exceeded the 2014 Transmission Annual Planning Report (TAPR) medium economic outlook 50% probability of exceedance (PoE) forecast by 355MW. This was the highest ever demand delivered from the transmission network. Energy delivered from the transmission network for 2014/15 is on track to exceed the 2014 TAPR forecast by around 0.6%. The maximum demand occurred on 5 March, when scheduled generation reached 8,809MW, 82MW short of the highest ever scheduled generation recorded in January 2010. This above forecast demand was mainly driven by load located in South East Queensland.

The liquefied natural gas (LNG) industry is now ramping up with observed demands close to those forecast in the 2014 TAPR. At the time of state maximum demand, 198MW was attributable to LNG. Since then this load has reached 250MW. By 2017/18, LNG demand is forecast to exceed 800MW. No new loads have committed to connect to the transmission network since the 2014 TAPR was released.

During the 2014/15 summer, Queensland had around 1,300MW of installed solar photovoltaic (PV) capacity and this has been increasing at the rate of around 20MW per month. An important impact of this new generation has been to delay the time of state peak, with state peak demand now occurring at around 5pm. As more solar PV is installed, future summer maximum demands are likely to occur in the early evening.

The forecasts presented in this TAPR indicate relatively flat growth for energy, summer maximum demand and winter maximum demand after growth due to the LNG industry is removed. While there has been significant investment in the resources sector, further developments in the short-term are unlikely due to low global coal and gas prices. Queensland on the whole is still experiencing slow economic growth. However, 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 is expected to increase by around one million people to 5.8 million over the 10-year forecast period.

Consumer response to high electricity prices continues to have a damping effect on electricity usage. Future developments in battery storage technology coupled with solar PV could see significant changes to future electricity usage patterns. In particular, battery storage technology has the potential to flatten electricity usage and thereby reduce the need to develop transmission services to cover short duration peaks.

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 hosted a forum in March 2015 to share and build on knowledge related to emerging technologies, which in turn has influenced the forecasting process. As a result, several enhancements were made to the forecasting methodology in this TAPR including more explicit analysis of emerging technologies. Details of Powerlink's new approach and the forecasting process can be found in Appendix B. Powerlink's demand and energy forecasting model is also being published in conjunction with the 2015 TAPR.

A new focus in this year's TAPR is to present demand and energy forecasts as delivered from the transmission network. This measure is more representative of the capacity required from the transmission network. Previous TAPRs have focused on native demand and energy and an explanation of the difference is given in Section 2.3.1.

Figure 2.1 presents a comparison of the delivered summer maximum demand forecast with that presented in the 2014 TAPR, based on a 50% PoE and medium economic outlook.

Figure 2.2 presents a comparison of the delivered energy forecast with that presented in the 2014 TAPR, based on the medium economic outlook.

Figure 2.1 Comparison of the medium economic outlook demand forecasts

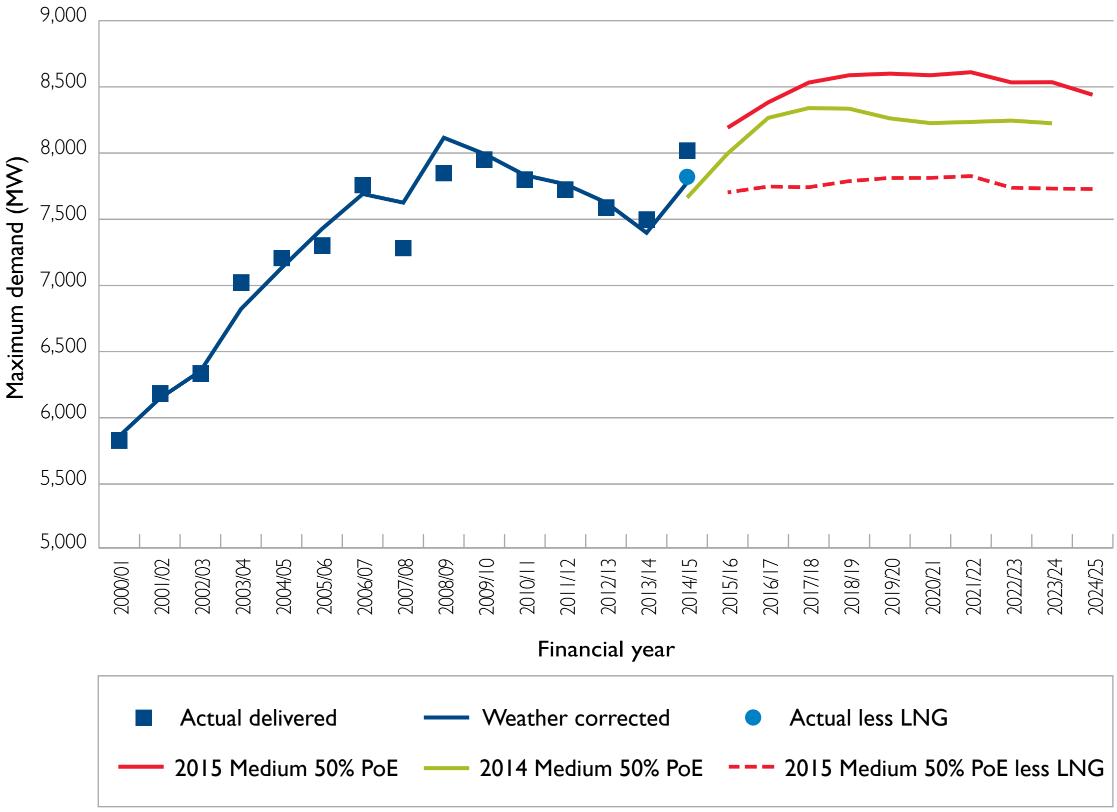
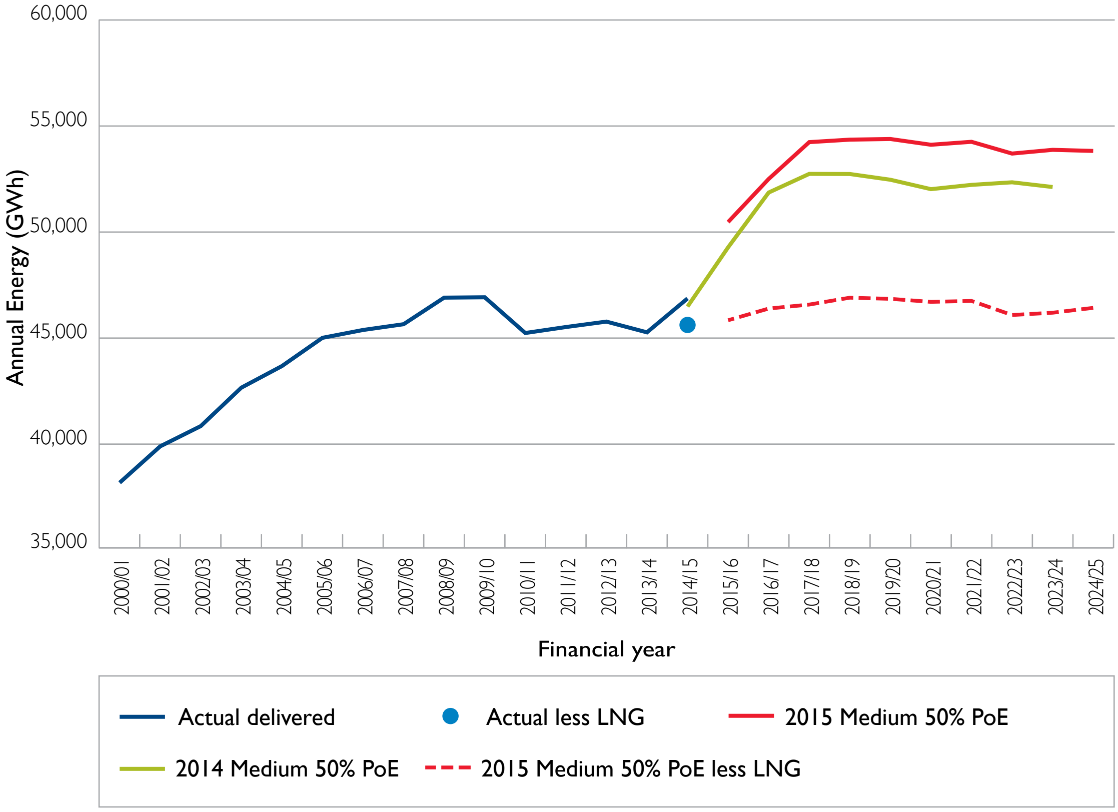


Figure 2.2 Comparison of the medium economic outlook energy forecasts



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 horizon 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 2.13 in Section 2.4, using diversity factors observed from historical trends.

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) and the wider industry to refine its forecasting process and input information. This engagement takes place through ongoing dialog and forums such as the TAPR release and the Demand and Energy Forecasting Forum undertaken in March.

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

Powerlink's forecasting methodology is described in Appendix B.

Transmission customer forecasts

New large loads

The medium economic outlook forecast includes the following loads that have connected since the last TAPR or have committed to connect in the outlook period:

- APLNG upstream LNG processing facilities west of Wandoan South Substation
- GLNG upstream LNG processing facilities west of Wandoan South Substation
- QGC upstream LNG processing facilities at Bellevue, near Columboola Substation.

The impact of these large customer loads is shown separately in Figure 2.1 as the difference between 2015 Medium 50% PoE demand forecast and 2015 Medium 50% PoE less LNG demand forecast.

Possible new large loads

There are several proposals for large mining and metal processing or 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 developments, totalling nearly 2,000MW could translate to the additional loads listed in Table 2.1 being supplied by the network.

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
Central West and North	Greater than forecast increase in coal mining and railway load (Bowen Basin area)	Up to 150MW
Central West and North	LNG upstream processing load (Bowen Basin area)	Up to 250MW
Central West	New coal mining load (Galilee Basin area)	Up to 1,000MW
Surat	Greater than forecast LNG upstream processing load (Surat Basin area)	Up to 400MW

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 2.3.1. For summer and winter maximum demand, growth rates are based on 50% PoE corrected values for 2014/15. Most of this growth is driven by the emerging LNG industry in South West Queensland.

Table 2.2 **Average annual growth rate over next 10 years**

	Economic growth outlooks		
	Low	Medium	High
Delivered energy	0.7%	1.4%	2.9%
Delivered summer maximum demand (50% PoE)	0.5%	0.9%	2.0%
Delivered winter maximum demand (50% PoE)	0.9%	1.4%	2.6%

Table 2.3 below shows the forecast average annual growth rates for the Queensland region with the impact of LNG removed.

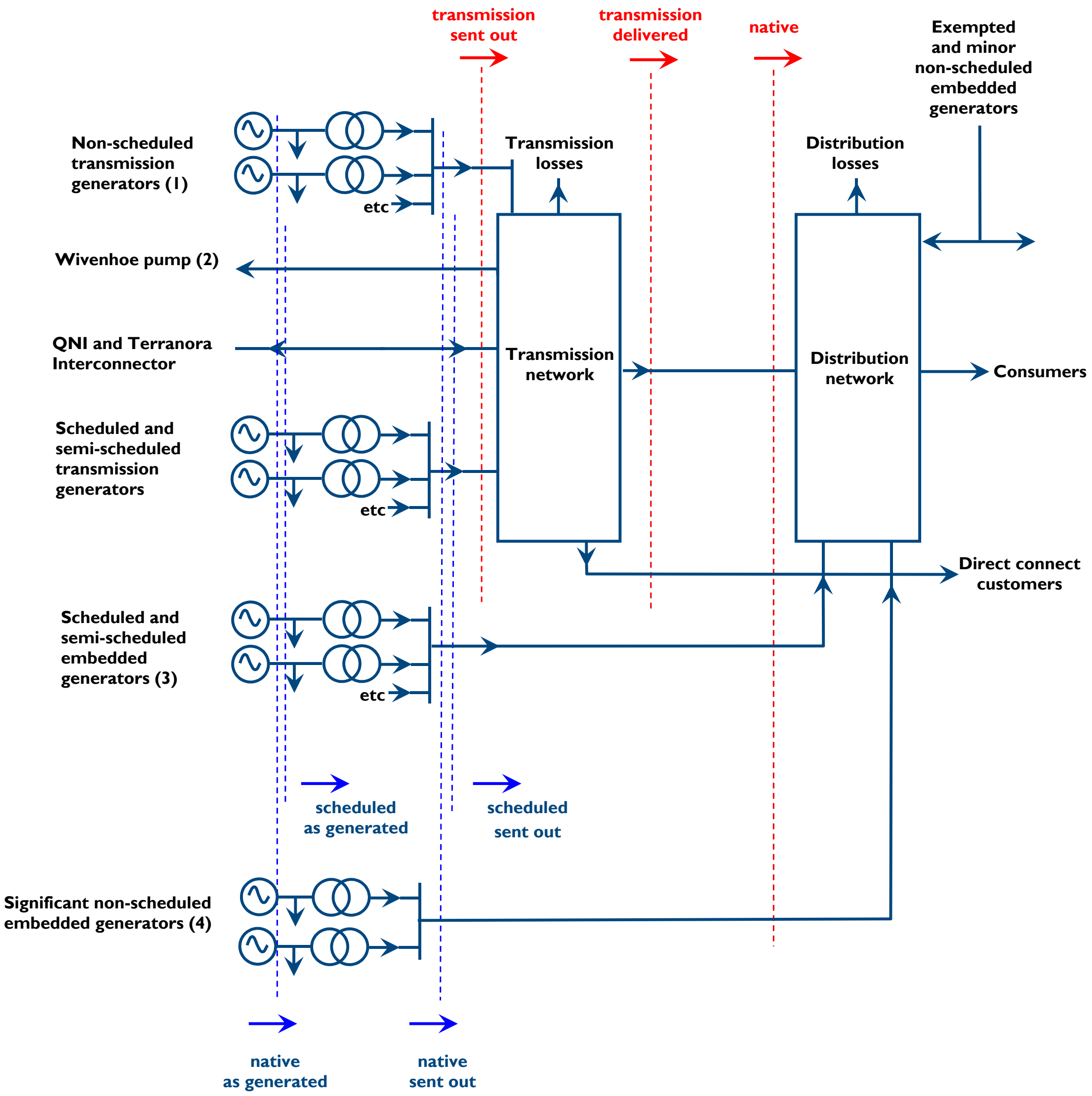
Table 2.3 **Average annual growth rate over next 10 years – without LNG**

	Economic growth outlooks		
	Low	Medium	High
Delivered energy	-0.3%	0.1%	1.5%
Delivered summer maximum demand (50% PoE)	-0.1%	0.2%	1.2%
Delivered winter maximum demand (50% PoE)	0.1%	0.4%	1.6%

2.3.1 Demand and energy terminology

The reported demand and energy on the network depends on where it is being measured. Different stakeholders have reasons to measure demand and energy at different points. Figure 2.3 below is presented to represent the common ways to measure demand and energy, with this terminology being used consistently throughout the TAPR.

Figure 2.3 Load forecast definitions



Notes:

(1) Includes Invicta, Callide A and Koombooloomba

(2) Depends on Wivenhoe generation

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

(4) Pioneer Mill, Racecourse Mill, Moranbah North, Moranbah, German Creek, Oaky Creek, Isis Central Sugar Mill, Daandine, Bromelton and Rocky Point

2.3.2 Energy forecast

Historical Queensland energies are presented in Table 2.4. 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 energies. Scheduled power station auxiliaries are the difference between scheduled as generated and scheduled sent out energies.

Table 2.4 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
2005/06	51,193	47,191	51,149	47,289	46,589	45,013	45,714	45,714
2006/07	51,193	47,526	51,445	47,905	46,966	45,382	46,320	46,320
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	47,640
2011/12	51,147	47,724	52,206	48,920	46,980	45,394	47,334	48,018
2012/13	50,711	47,368	52,045	48,702	47,259	45,651	47,090	48,197
2013/14	49,686	46,575	51,029	47,918	46,560	45,145	46,503	47,722
2014/15 (1)	51,813	48,404	53,393	49,986	48,324	46,742	48,565	49,996

Note:

(1) These projected end of financial year values are based on revenue and statistical metering data until March 2015.

The forecast transmission delivered energy forecasts are presented in Table 2.5 and displayed in Figure 2.4. Forecast native energy forecasts are presented in Table 2.6.

Table 2.5 Forecast annual transmission delivered energy (GWh)

Year	Low growth outlook	Medium growth outlook	High growth outlook
2015/16	49,046	50,471	51,830
2016/17	50,752	52,502	55,742
2017/18	51,956	54,114	57,338
2018/19	51,994	54,232	58,510
2019/20	51,606	54,262	59,431
2020/21	50,938	53,991	60,527
2021/22	50,721	54,130	61,327
2022/23	50,281	53,575	61,756
2023/24	50,252	53,751	62,184
2024/25	50,041	53,700	62,118

Figure 2.4 Historical and forecast transmission delivered energy

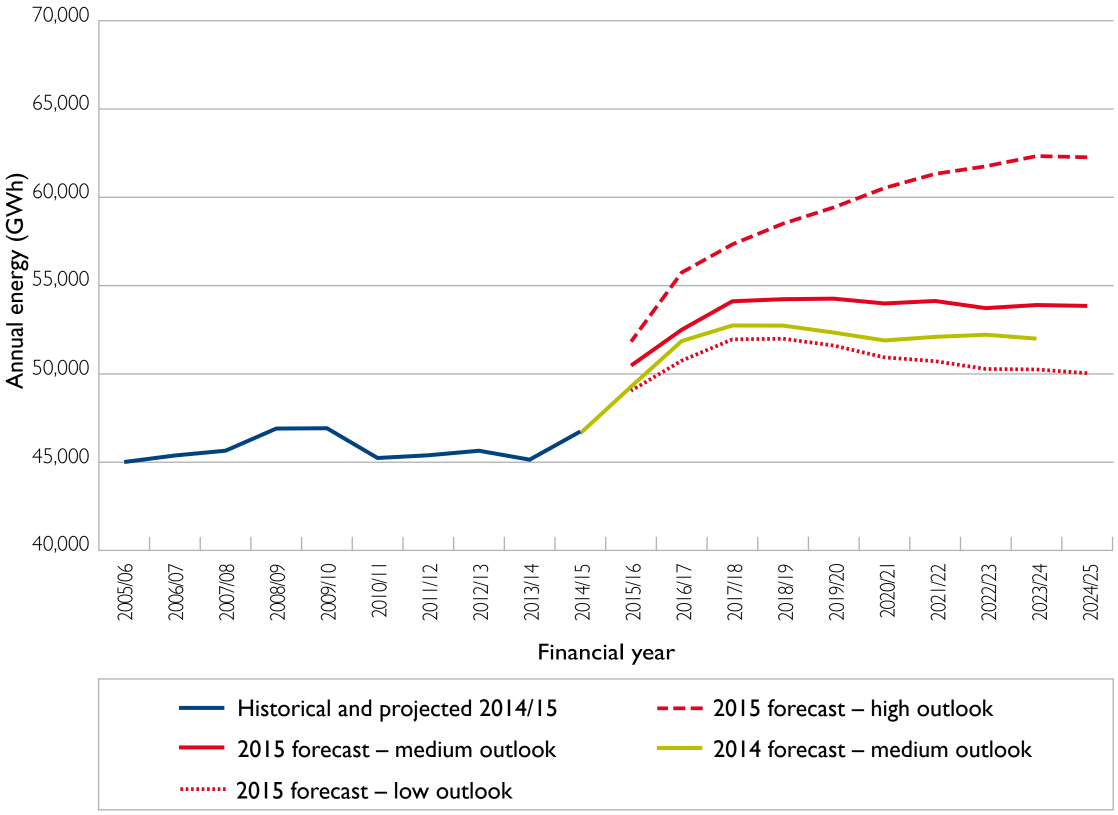


Table 2.6 Forecast annual native energy (GWh)

Year	Low growth outlook	Medium growth outlook	High growth outlook
2015/16	50,388	51,813	53,171
2016/17	52,092	53,842	57,082
2017/18	53,295	55,452	58,676
2018/19	53,331	55,568	59,846
2019/20	52,940	55,596	60,766
2020/21	52,271	55,323	61,859
2021/22	52,052	55,461	62,657
2022/23	51,610	54,904	63,085
2023/24	51,580	55,078	63,512
2024/25	51,367	55,025	63,443

2.3.3 Summer demand forecast

Historical Queensland summer demands are presented in Table 2.7.

Table 2.7 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
2005/06	8,295	7,740	8,316	7,777	7,654	7,301	7,481	7,481	7,588
2006/07	8,589	8,099	8,632	8,161	7,925	7,757	7,993	7,993	7,907
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

The transmission delivered summer maximum demand forecasts are presented in Table 2.8 and displayed in Figure 2.5. Forecast summer native demand is presented in Table 2.9.

Table 2.8 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
2015/16	7,711	8,113	8,659	7,789	8,192	8,740	7,928	8,331	8,881
2016/17	7,863	8,272	8,829	7,973	8,383	8,942	8,309	8,730	9,304
2017/18	7,960	8,374	8,939	8,117	8,533	9,099	8,453	8,879	9,460
2018/19	7,980	8,400	8,973	8,145	8,568	9,143	8,605	9,039	9,631
2019/20	7,943	8,365	8,940	8,153	8,580	9,161	8,715	9,155	9,754
2020/21	7,883	8,306	8,882	8,137	8,568	9,155	8,854	9,299	9,904
2021/22	7,862	8,287	8,866	8,155	8,590	9,183	8,947	9,397	10,009
2022/23	7,797	8,221	8,800	8,080	8,513	9,104	8,978	9,429	10,042
2023/24	7,771	8,198	8,781	8,077	8,515	9,113	9,037	9,493	10,114
2024/25	7,721	8,153	8,740	8,047	8,491	9,095	9,062	9,524	10,153

Figure 2.5 Historical and forecast transmission delivered summer demand

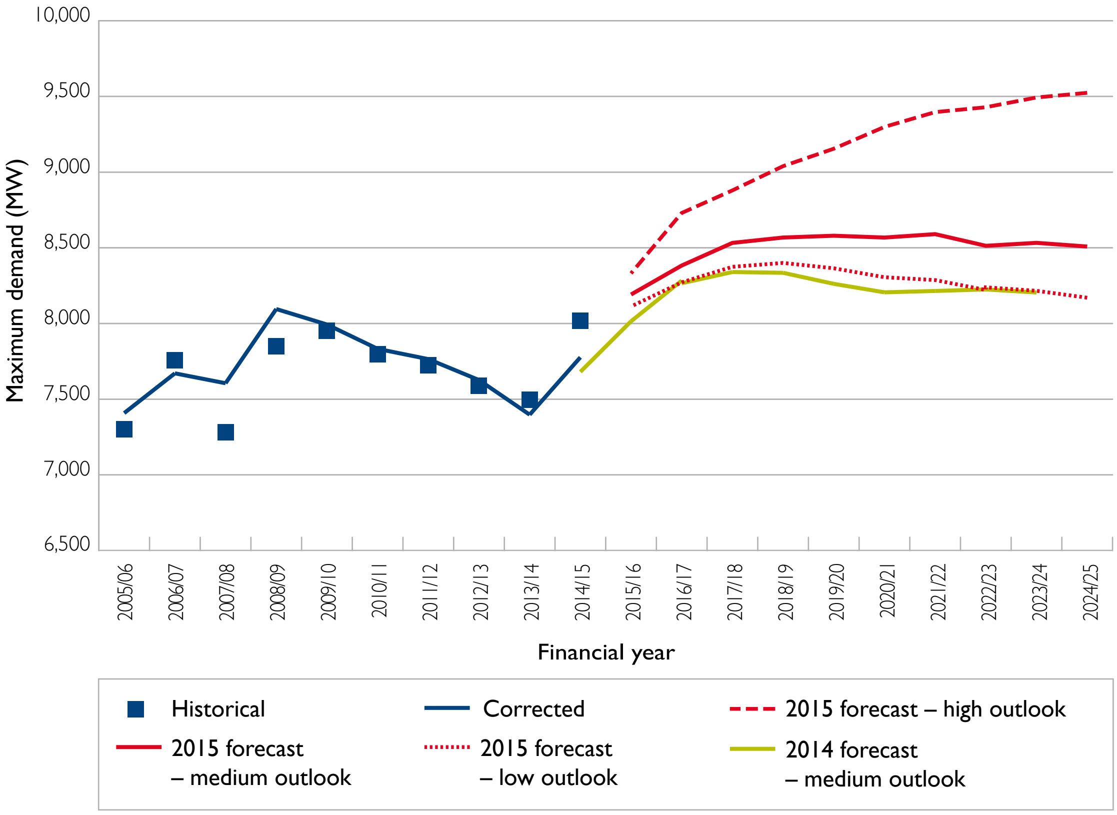


Table 2.9 Forecast summer native demand (MW)

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
2015/16	7,996	8,397	8,944	8,074	8,476	9,025	8,212	8,616	9,166
2016/17	8,147	8,557	9,114	8,258	8,668	9,227	8,594	9,015	9,588
2017/18	8,245	8,659	9,224	8,401	8,817	9,384	8,738	9,164	9,745
2018/19	8,265	8,685	9,258	8,430	8,853	9,428	8,890	9,324	9,916
2019/20	8,227	8,649	9,224	8,438	8,865	9,446	9,000	9,440	10,038
2020/21	8,167	8,591	9,167	8,422	8,853	9,439	9,139	9,584	10,189
2021/22	8,147	8,572	9,150	8,440	8,875	9,468	9,232	9,681	10,294
2022/23	8,082	8,506	9,085	8,364	8,798	9,389	9,263	9,714	10,327
2023/24	8,055	8,483	9,066	8,361	8,800	9,397	9,322	9,778	10,399
2024/25	8,006	8,437	9,025	8,332	8,776	9,380	9,347	9,809	10,438

2.3.4 Winter demand forecast

Historical Queensland winter demands are presented in Table 2.10. Notice that as winter normally peaks after sunset, solar PV has no impact on winter peak demand.

Table 2.10 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
2005	7,414	6,779	7,277	6,807	6,657	6,471	6,623	6,623	6,609
2006	7,674	7,160	7,747	7,249	7,119	6,803	6,933	6,933	6,978
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

The transmission delivered winter maximum demand forecasts are presented in Table 2.11 and displayed in Figure 2.6. Forecast winter native demand is presented in Table 2.12.

Table 2.11 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
2015	7,100	7,273	7,505	7,196	7,370	7,603	7,335	7,509	7,743
2016	7,347	7,523	7,760	7,494	7,671	7,908	7,852	8,034	8,278
2017	7,501	7,680	7,919	7,691	7,870	8,110	8,067	8,251	8,499
2018	7,603	7,783	8,026	7,831	8,012	8,256	8,262	8,449	8,700
2019	7,492	7,673	7,916	7,742	7,926	8,171	8,292	8,481	8,735
2020	7,413	7,594	7,837	7,707	7,891	8,139	8,381	8,572	8,829
2021	7,375	7,556	7,800	7,706	7,892	8,142	8,483	8,676	8,935
2022	7,293	7,474	7,717	7,608	7,793	8,041	8,501	8,694	8,953
2023	7,273	7,455	7,700	7,613	7,800	8,051	8,576	8,771	9,033
2024	7,202	7,385	7,632	7,556	7,745	7,999	8,574	8,771	9,036

Figure 2.6 Historical and forecast winter transmission delivered demand

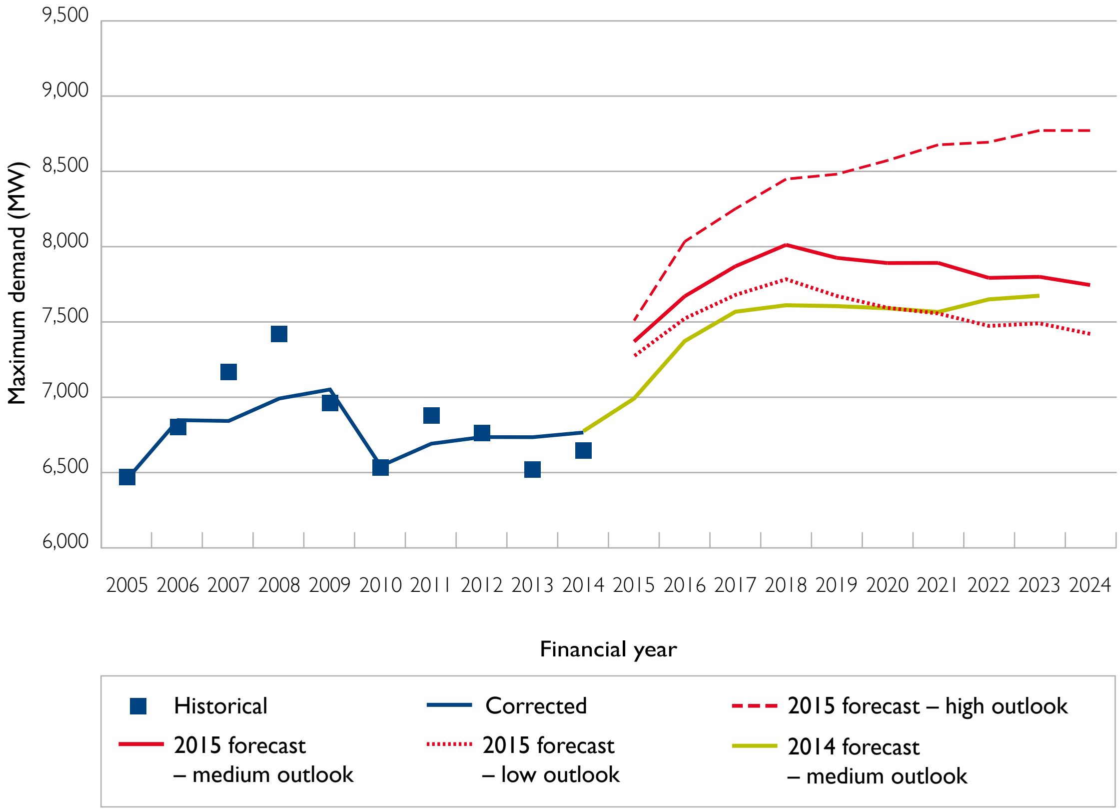


Table 2.12 Forecast winter native demand (MW)

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
2015	7,363	7,536	7,769	7,460	7,633	7,866	7,599	7,773	8,006
2016	7,610	7,786	8,023	7,758	7,934	8,172	8,116	8,297	8,542
2017	7,765	7,943	8,183	7,954	8,133	8,374	8,331	8,515	8,762
2018	7,866	8,047	8,290	8,094	8,276	8,519	8,525	8,712	8,963
2019	7,755	7,936	8,179	8,006	8,189	8,435	8,556	8,745	8,999
2020	7,677	7,858	8,101	7,970	8,155	8,402	8,645	8,836	9,092
2021	7,638	7,820	8,064	7,969	8,156	8,406	8,747	8,940	9,199
2022	7,556	7,737	7,980	7,871	8,056	8,305	8,764	8,957	9,216
2023	7,536	7,719	7,963	7,876	8,063	8,314	8,840	9,035	9,297
2024	7,465	7,649	7,895	7,820	8,009	8,263	8,837	9,034	9,300

2.4 Zone forecasts

The 11 geographical zones referred to throughout this TAPR are defined in Table 2.13 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 2.13 Zone definitions

Zone	Area covered
Far North	North of Tully, including Chalumbin
Ross	North of Proserpine and Collinsville, 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 zone
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 2.17 to 2.20.

Table 2.14 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 2.17 and 2.19 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. As load has only recently started to ramp up in the Surat zone, ratios for this zone cannot be reliably determined.

Table 2.14 Average ratios of zone maximum delivered demand to zone delivered demand at time of Queensland region maximum demand

Zone	Winter	Summer
Far North	1.10	1.16
Ross	1.64	1.42
North	1.12	1.16
Central West	1.12	1.11
Gladstone	1.03	1.06
Wide Bay	1.08	1.10
Surat		
Bulli	1.13	1.27
South West	1.07	1.33
Moreton	1.01	1.01
Gold Coast	1.01	1.02

Tables 2.15 and 2.16 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 2.15 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												
2005/06	1,745	2,393	2,571	3,363	9,707	1,468			2,092	18,425	3,249	45,013
2006/07	1,770	2,563	2,733	3,169	9,945	1,461			2,047	18,469	3,225	45,382
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	2,762	2,572	3,463	10,286	1,323		105	1,196	18,629	3,266	45,394
2012/13	1,722	2,782	2,642	3,414	10,507	1,267		103	1,746	18,233	3,235	45,651
2013/14	1,658	2,907	2,747	3,564	10,293	1,321	338	146	1,304	17,782	3,085	45,145
2014/15	1,698	3,025	2,846	3,402	10,638	1,263	704	622	1,215	18,159	3,163	46,742
Forecasts												
2015/16	1,587	2,826	3,189	3,444	10,841	1,244	3,686	1,354	1,326	17,684	3,290	50,471
2016/17	1,565	2,805	3,273	3,604	10,887	1,238	4,963	1,549	1,316	17,961	3,341	52,502
2017/18	1,542	2,738	3,307	3,898	10,845	1,200	6,156	1,763	1,262	18,046	3,357	54,114
2018/19	1,559	2,724	3,389	3,988	10,791	1,185	6,273	1,561	1,246	18,142	3,374	54,232
2019/20	1,546	2,716	3,465	3,950	10,785	1,174	6,211	1,704	1,235	18,156	3,320	54,262
2020/21	1,539	2,708	3,453	3,934	10,782	1,169	6,043	1,741	1,230	18,090	3,302	53,991
2021/22	1,541	2,711	3,457	3,939	10,782	1,170	6,098	1,783	1,231	18,115	3,303	54,130
2022/23	1,510	2,675	3,405	3,865	10,768	1,146	6,201	1,781	1,206	17,781	3,237	53,575
2023/24	1,515	2,680	3,413	3,877	10,770	1,150	6,359	1,691	1,210	17,844	3,242	53,751
2024/25	1,526	2,693	3,430	3,902	10,775	1,158	6,357	1,417	1,219	17,960	3,263	53,700

Table 2.16 Annual native energy (GWh) by zone

Year	Far North	Ross	North	Central West	Gladstone	Wide Bay	Surat	Bulli	South West	Moreton	Gold Coast	Total
Actuals												
2005/06	1,745	2,937	2,571	3,503	9,707	1,468			2,110	18,424	3,249	45,714
2006/07	1,770	3,141	2,761	3,375	9,945	1,459			2,110	18,534	3,225	46,320
2007/08	1,818	3,371	2,771	3,528	10,058	1,413		87	2,039	18,820	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	3,257	2,861	3,710	10,286	1,348		105	2,014	18,695	3,266	47,334
2012/13	1,722	3,169	2,974	3,767	10,507	1,292		103	1,988	18,333	3,235	47,090
2013/14	1,658	3,148	3,074	3,944	10,293	1,339	402	146	1,536	17,878	3,085	46,503
2014/15	1,698	3,234	3,399	3,837	10,638	1,280	963	622	1,460	18,265	3,163	48,565
Forecasts												
2015/16	1,587	3,070	3,744	3,629	10,841	1,261	3,721	1,354	1,532	17,784	3,290	51,813
2016/17	1,565	3,049	3,828	3,789	10,887	1,256	4,998	1,549	1,522	18,058	3,341	53,842
2017/18	1,542	2,982	3,863	4,083	10,845	1,218	6,191	1,763	1,468	18,140	3,357	55,452
2018/19	1,559	2,968	3,944	4,173	10,791	1,203	6,308	1,561	1,452	18,235	3,374	55,568
2019/20	1,546	2,960	4,020	4,136	10,785	1,191	6,246	1,704	1,441	18,247	3,320	55,596
2020/21	1,539	2,952	4,008	4,120	10,782	1,186	6,078	1,741	1,435	18,180	3,302	55,323
2021/22	1,541	2,955	4,012	4,124	10,782	1,188	6,133	1,783	1,437	18,203	3,303	55,461
2022/23	1,510	2,919	3,960	4,050	10,768	1,164	6,236	1,781	1,412	17,867	3,237	54,904
2023/24	1,515	2,924	3,969	4,062	10,770	1,168	6,394	1,691	1,416	17,927	3,242	55,078
2024/25	1,526	2,937	3,986	4,087	10,775	1,176	6,392	1,417	1,424	18,042	3,263	55,025

Tables 2.17 and 2.18 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 2.17 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												
2005	192	178	277	431	1,081	261			341	3,146	564	6,471
2006	207	243	325	409	1,157	228			361	3,279	594	6,803
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	226	312	426	1,201	215		20	346	3,207	594	6,761
2013	195	261	335	418	1,200	190	23	17	263	3,040	579	6,521
2014	226	360	344	463	1,200	204	16	51	257	2,975	551	6,647
Forecasts												
2015	224	262	384	465	1,221	193	312	151	285	3,322	551	7,370
2016	224	264	393	473	1,218	192	520	171	291	3,374	551	7,671
2017	222	264	412	497	1,215	190	631	193	289	3,398	559	7,870
2018	222	258	419	499	1,215	190	769	173	290	3,417	560	8,012
2019	220	258	426	497	1,209	188	679	188	288	3,419	554	7,926
2020	218	257	428	494	1,209	186	661	192	286	3,422	538	7,891
2021	217	257	429	490	1,209	185	665	196	290	3,419	535	7,892
2022	213	254	423	481	1,208	181	663	196	285	3,366	523	7,793
2023	211	254	422	478	1,208	180	693	187	284	3,364	519	7,800
2024	210	254	421	476	1,208	179	683	159	283	3,357	515	7,745

Table 2.18 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												
2005	192	257	277	431	1,081	261			415	3,145	564	6,623
2006	207	322	325	460	1,157	228			361	3,279	594	6,933
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	302	346	460	1,201	215		20	375	3,207	594	6,934
2013	195	304	362	499	1,200	195	89	17	290	3,039	579	6,769
2014	226	384	406	509	1,200	204	90	51	286	2,974	551	6,881
Forecasts												
2015	224	341	437	533	1,221	195	340	151	314	3,326	551	7,633
2016	224	343	446	541	1,218	195	548	171	319	3,378	551	7,934
2017	222	342	465	565	1,215	193	659	193	317	3,403	559	8,133
2018	222	337	472	567	1,215	193	797	173	319	3,421	560	8,276
2019	220	336	479	565	1,209	191	706	188	317	3,424	554	8,189
2020	218	336	481	562	1,209	189	689	192	315	3,426	538	8,155
2021	217	336	482	558	1,209	187	693	196	319	3,424	535	8,156
2022	213	332	476	549	1,207	183	691	196	314	3,372	523	8,056
2023	211	333	475	546	1,208	182	721	187	313	3,368	519	8,063
2024	210	333	474	544	1,208	181	711	159	312	3,362	515	8,009

Tables 2.19 and 2.20 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 2.19 State summer maximum transmission delivered demand (MW) by zone

Summer	Far North	Ross	North	Central West	Glad-stone	Wide Bay	Surat	Bulli	South West	Moreton	Gold Coast	Total
Actuals												
2005/06	296	331	359	472	1,125	231			357	3,510	620	7,301
2006/07	329	385	452	509	1,164	296			375	3,636	611	7,757
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	391	390	525	1,191	249		18	217	3,788	658	7,723
2012/13	277	320	366	536	1,213	232		14	241	3,755	634	7,588
2013/14	271	330	341	493	1,147	260	30	21	291	3,711	603	7,498
2014/15	278	398	382	466	1,254	263	130	81	227	3,848	692	8,019
Forecasts												
2015/16	280	335	397	517	1,232	242	371	145	271	3,779	623	8,192
2016/17	279	334	392	542	1,230	239	498	164	273	3,800	632	8,383
2017/18	278	326	416	538	1,226	237	632	187	273	3,795	625	8,533
2018/19	280	328	423	541	1,226	238	642	166	275	3,822	627	8,568
2019/20	279	326	429	540	1,226	236	636	181	275	3,829	623	8,580
2020/21	278	325	434	538	1,226	235	620	184	275	3,843	610	8,568
2021/22	278	325	435	537	1,226	234	625	189	280	3,853	608	8,590
2022/23	275	321	429	529	1,225	230	635	188	277	3,807	597	8,513
2023/24	275	320	429	528	1,225	229	653	179	278	3,805	594	8,515
2024/25	275	320	428	527	1,225	228	660	151	279	3,805	593	8,491

Table 2.20 State summer maximum native demand (MW) by zone

Summer	Far North	Ross	North	Central West	Gladstone	Wide Bay	Surat	Bulli	South West	Moreton	Gold Coast	Total
Actuals												
2005/06	296	407	359	519	1,125	231			414	3,510	620	7,481
2006/07	329	491	458	573	1,164	295			436	3,636	611	7,993
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	464	419	598	1,191	249		18	378	3,788	658	8,059
2012/13	277	434	405	568	1,213	241		14	328	3,799	634	7,913
2013/14	271	435	374	561	1,147	260	88	21	316	3,755	603	7,831
2014/15	278	416	462	548	1,254	263	189	81	254	3,889	692	8,326
Forecasts												
2015/16	280	413	458	563	1,232	244	430	145	294	3,794	623	8,476
2016/17	279	412	453	587	1,230	242	557	164	295	3,817	632	8,668
2017/18	278	403	477	584	1,226	240	691	187	295	3,811	625	8,817
2018/19	280	405	484	586	1,226	240	701	166	297	3,841	627	8,853
2019/20	279	404	490	586	1,226	238	694	181	297	3,847	623	8,865
2020/21	278	403	495	584	1,226	237	678	184	297	3,861	610	8,853
2021/22	278	403	496	583	1,226	236	684	189	302	3,870	608	8,875
2022/23	275	398	490	575	1,225	232	694	188	299	3,825	597	8,798
2023/24	275	398	490	574	1,225	231	712	179	300	3,822	594	8,800
2024/25	275	398	489	573	1,225	230	719	151	301	3,822	593	8,776

2.5 Daily and annual load profiles

The daily load profiles for the Queensland region on the days of 2014 winter and 2014/15 summer maximum transmission delivered demands are shown in Figure 2.7.

The annual cumulative load duration characteristic for the Queensland region transmission delivered demand is shown in Figure 2.8 for the 2013/14 financial year.

Figure 2.7 Winter 2014 and summer 2014/15 maximum transmission delivered demands

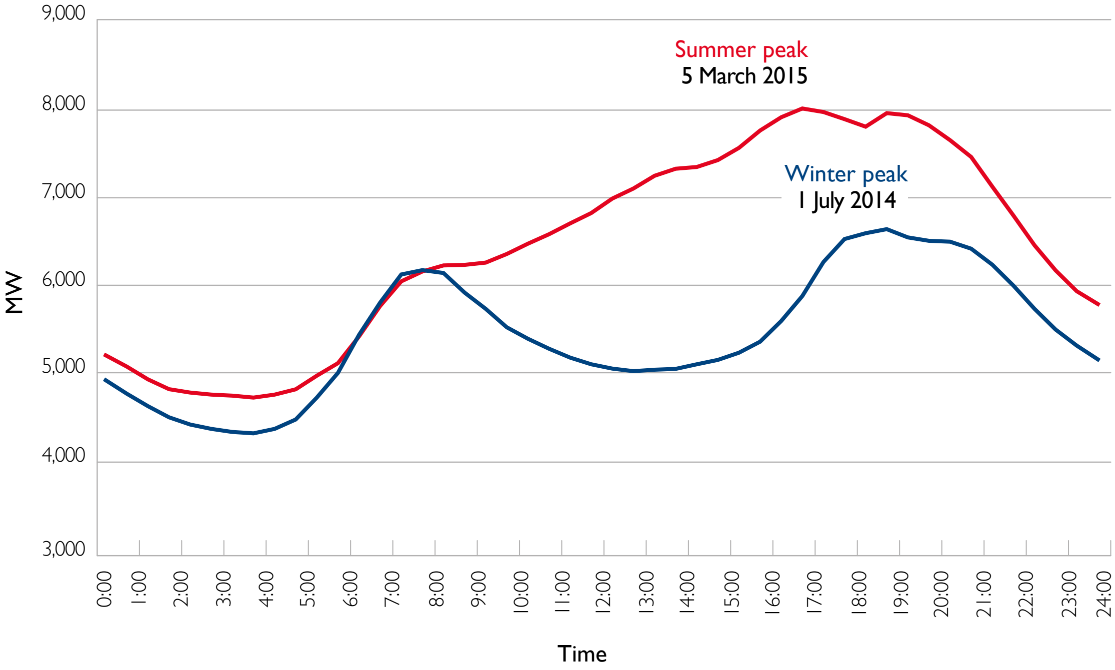
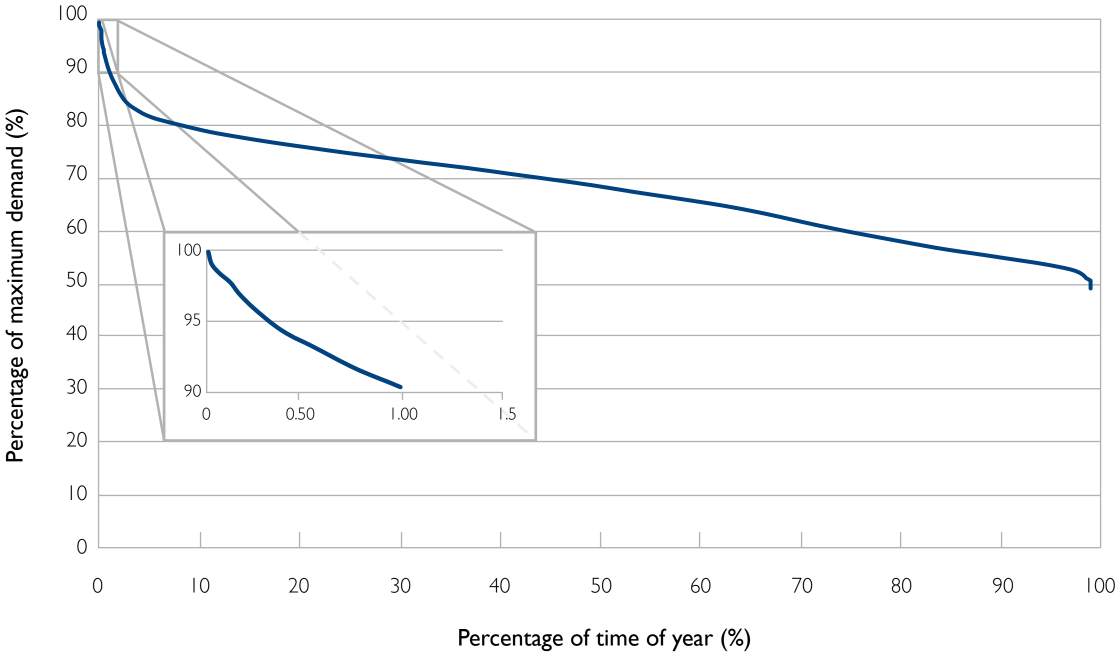


Figure 2.8 Normalised cumulative annual transmission delivered load duration 2013/14



Chapter 3

Committed and commissioned network developments

Chapter 3

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

Table 3.1 lists transmission network developments commissioned since Powerlink's 2014 Transmission Annual Planning Report (TAPR) was published.

Table 3.2 lists transmission network developments which are committed and under construction at June 2015.

Table 3.3 lists new transmission connection works for supplying loads which are committed and under construction at June 2015. These connection projects resulted from agreement reached with relevant connected customers, generators or Distribution Network Service Providers (DNSPs) as applicable.

Table 3.4 lists network reinvestments commissioned since Powerlink's 2014 TAPR was published.

Table 3.5 lists network reinvestments which are committed and under construction at June 2015.

Table 3.1 Commissioned transmission developments since June 2014

Project	Purpose	Zone location	Date commissioned
Columboola to Wandoan South 275kV line and Wandoan South 275kV Substation establishment, Columboola to Western Downs 275kV line and Columboola 275kV Substation	Increase supply capability to the Surat Basin north west area	Surat	September 2014
Western Downs to Halys 275kV line and Western Downs and Halys 275kV substations	Increase supply capability between Bulli and South West zones	Bulli and South West	September 2014

Table 3.2 Committed and under construction transmission developments at June 2015

Project	Purpose	Zone location	Proposed commissioning date
Moranbah area 132kV capacitor banks	Increase supply capability in the North zone	North	Progressively from winter 2013 to summer 2016/17
Pioneer Valley feeder bays	Increase voltage stability in Mackay	North	Summer 2015/16

Table 3.3 Committed and under construction connection works at June 2015

Project	Purpose	Zone location	Proposed commissioning date
Aurizon 132kV rail connection (Wotonga)	New connection to supply rail load in the Bowen Basin area (1)	North	Winter 2015
APLNG/GLNG Wandoan South connections	New connection for CSM/LNG compression (1)	Surat	Progressively from Winter 2015 to summer 2015/16

Note:

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

Table 3.4 Commissioned network reinvestments since June 2014

Project	Purpose	Zone location	Date commissioned
Collinsville to Proserpine 132kV partial line replacement	Maintain supply reliability to Proserpine Substation	North	October 2014
Gladstone Substation replacement	Maintain supply reliability in the Gladstone zone	Gladstone	July 2014

Table 3.5 Committed and under construction network reinvestments at June 2015

Project	Purpose	Zone location	Proposed commissioning date
Line refit works on 132kV transmission line between Woree and Kamerunga substations	Maintain supply reliability in the Far North zone	Far North	Winter 2015
Ross 300kV 100MVAr bus reactor	Maintain supply reliability in the Ross zone	Ross	Winter 2016
Garbutt to Alan Sherriff 132kV line replacement	Maintain supply reliability in the Ross zone	Ross	Winter 2017
Nebo 275/132kV transformer replacements	Maintain supply reliability in the North zone (1)	North	Progressively from summer 2013/14 to summer 2017/18
Collinsville Substation replacement	Maintain supply reliability in the North zone	North	Winter 2015
Proserpine Substation replacement	Maintain supply reliability in the North zone	North	Summer 2015/16
Moranbah 132/66kV transformer replacement	Maintain supply reliability in the North zone	North	Summer 2016/17
Mackay Substation replacement	Maintain supply reliability in the North zone	North	Summer 2017/18
Nebo primary plant replacement	Maintain supply reliability in the North zone	North	Summer 2019/20
Rockhampton Substation replacement	Maintain supply reliability in the Central West zone	Central West	Winter 2016
Blackwater Substation replacement	Maintain supply reliability in the Central West zone	Central West	Summer 2016/17
Moura Substation replacement	Maintain supply reliability in the Central West zone	Central West	Summer 2016/17
Callide A Substation replacement	Maintain supply reliability in the Central West zone	Central West	Summer 2017/18
Swanbank B Substation replacement	Maintain supply reliability in the Moreton zone	Moreton	Summer 2015/16
Line refit works on 110kV transmission line between Sumner Tee and Richlands substations	Maintain supply reliability in the Moreton zone	Moreton	Winter 2016

Note:

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

Figure 3.1 Existing Powerlink Queensland transmission network June 2015

Chapter 4

Future network development

Chapter 4

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 $5 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
- 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 horizon and their relationship to the Australian Energy Market Operator (AEMO) 2014 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.

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 and new customer supply requirements, existing network configuration and 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.

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[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.

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 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. 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.
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 load driven needs have diminished or can be deferred in order to achieve long-term economic benefits.
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 may include network support from existing and/or new generation or demand side management initiatives (either from individual providers or aggregators) which may reduce 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.

Powerlink's capital expenditure program of work for the outlook period is considerably less than that of previous years. As reinvestment will account for the majority of capital expenditure within the five-year outlook period, Powerlink considers it prudent to provide more detailed information than previously for these types of investments within this TAPR.

4.1.2 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. However, the amended planning standard, which came into effect 1 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 amended 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 in Chapter 3.

Assuming that the demand for electricity remains relatively flat as forecast in this TAPR, Powerlink does not anticipate undertaking any significant augmentation works within the outlook period other than those which could potentially be triggered from the commitment of mining or industrial block loads as discussed in Section 6.2.

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 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 end of life assets will form the majority of Powerlink's capital expenditure program of work moving forward.

Proposed network developments within the five-year outlook period are discussed below. 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 Ross, Chalumbin and Woree substations into the 132kV transmission network. This 132kV network supplies the Ergon Energy distribution network in the surrounding areas of Ingham, Cardwell, Tully, Innisfail, Turkinje and Cairns, and connection to the hydro power stations at Barron Gorge and Kareeya.

Network limitations

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. The extent of corrosion observed during Powerlink's condition assessment, and the inherent constraints of working within the Wet Tropics Management Authority area, requires that Powerlink consider options for line refit works in summer 2017/18 or replacement by summer 2022/23.

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 outlook period. Planning analysis confirms these assets are required to provide an ongoing reliable supply and power station connection within the zone and the related investment needs are outlined in Table 4.2.

Table 4.2 Possible reinvestment works in the Far North zone

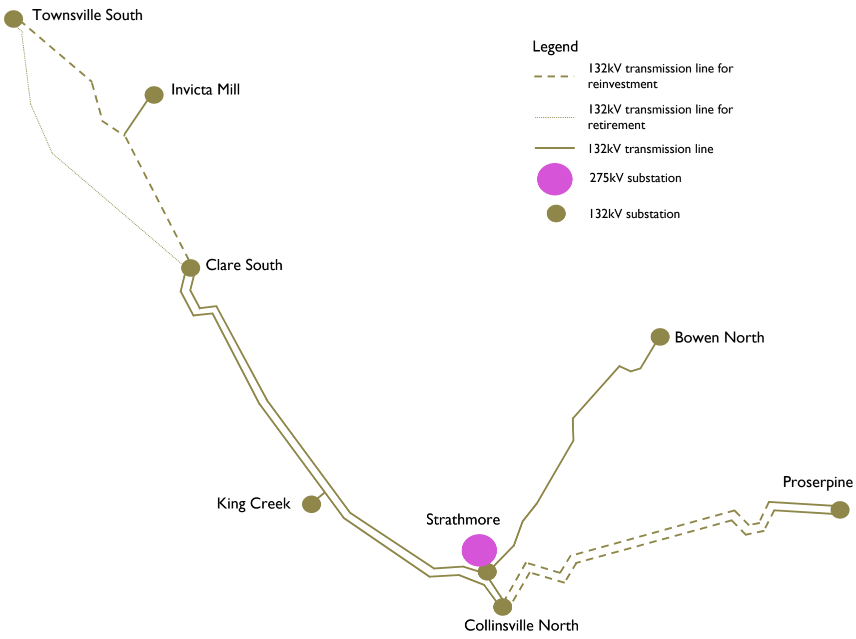
Potential project	High level scope	Purpose	Possible commissioning date	Alternatives	Indicative costs
Transmission lines					
Line refit works on the 132kV transmission line between Kareeya and Chalumbin substations	Line refit works on steel lattice structures	Maintain supply reliability to Kareeya	Summer 2017/18	New 132kV transmission line on new easement	$8m
Substations					
Turkinje secondary systems replacement	Full replacement of 132kV secondary systems	Maintain supply reliability to the Far North zone	Winter 2018	Staged replacement of 132kV secondary systems equipment	$5m
Kamerunga Substation replacement	Full replacement of 132kV substation	Maintain supply reliability to the Far North zone	Winter 2019	Staged replacement of 132kV primary plant and secondary systems Reconfiguration of network in the Kamerunga area	$27m

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 Figure 4.1).

Figure 4.1 Ross zone transmission network



Network limitations

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

Transmission lines

Townsville South to Clare South 132kV transmission lines

Two 132kV lines between Townsville South and Clare South substations were constructed in the 1960s on separate coastal and inland alignments. Planning studies have indicated the potential for a cost effective network reconfiguration involving the retirement of one of the two 132kV transmission lines from Townsville South to Clare South substations and the installation of a 132kV capacitor bank at Proserpine Substation. The capacitor bank is a possible solution to a voltage limitation at Proserpine Substation that occurs with the retirement of the transmission line beyond the outlook period (refer to Section 6.3.1).

A condition assessment has confirmed that the coastal circuit has experienced higher rates of structural corrosion with end of life expected to occur within the next five years. Although the inland circuit has experienced lower rates of structural corrosion, it is not economically feasible to retain this asset due to the design limitations and degraded condition of the existing foundations. As such, Powerlink is proposing to undertake line refit works on the coastal transmission line by around 2018/19 and to retire the inland transmission line at the end of its technical life.

Powerlink is also considering further network reconfiguration in the Ross zone that may occur beyond the outlook period, which is discussed in Section 6.3.1.

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 outlook period. Planning analysis confirms these assets are required to provide ongoing reliable supply and the related investment needs are outlined in Table 4.3.

Table 4.3 Possible reinvestment works in the Ross zone within five years

Potential project	High level scope	Purpose	Possible commissioning date	Alternatives	Indicative costs
Transmission lines					
Line refit works on one 132kV transmission line between Townsville South and Clare South substations	Line refit works on steel lattice structures	Maintain supply reliability in the Ross zone	Winter 2018	New 132kV transmission line	$29m
Substations					
Ingham South 132/66kV transformers replacement	Replacement of both 132/66kV transformers	Maintain supply reliability in the Ross zone	Winter 2018	Staged replacement of the two 132/66kV transformers	$11m
Garbutt 132/66kV transformers replacement	Replacement of both 132/66kV transformers	Maintain supply reliability in the Ross zone	Summer 2018/19	Staged replacement of the two 132/66kV transformers Reconfiguration to supply through a single transformer and non-network alternatives in the Townsville area (1)	$11m
Dan Gleeson Secondary Systems replacement	Full replacement of 132kV secondary systems	Maintain supply reliability to the Ross zone	Summer 2020/21	Staged replacement of 132kV secondary systems equipment	$7m

Note:

(1) Non-network solutions in the Ross zone to remain within Powerlink's amended planning standard may include up to 10MW and 500MWh in the Townsville area[2].

4.2.3 North zone

Existing network

Three 275kV circuits between Nebo (in the south) and Strathmore (in the north) substations form the 275kV transmission network supplying the Northern Region. Double circuit inland and coastal 132kV routes supply regional centres and infrastructure related to mines, coal haulage and ports associated with the Bowen Basin mines (refer to Figure 4.2).

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

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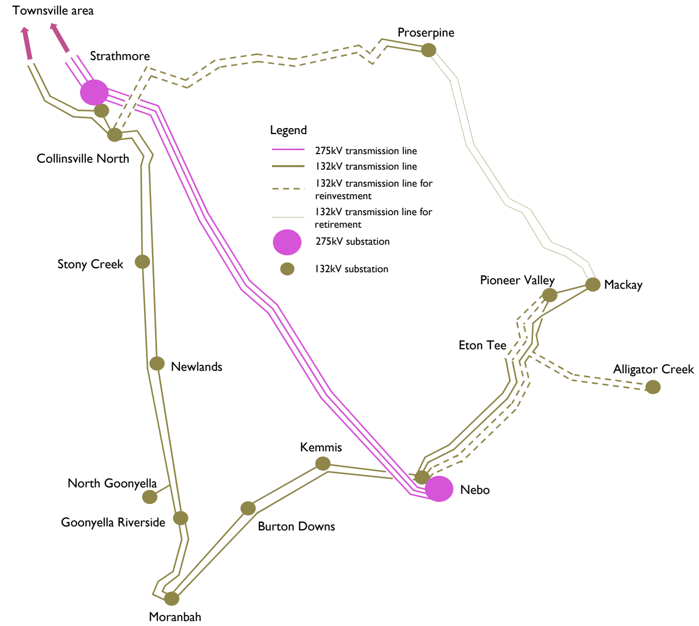
[2] The level of network support is dependent on the location and type of network support and is subject to change over time as the network and configuration changes, load forecasts are amended and operational and technical matters effect network performance. Interested parties are requested to contact Powerlink directly before considering any investment relating to the level of network support described.

Figure 4.2 North zone transmission network



Network limitations

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

However, demand in the Proserpine area has the potential to exceed the transmission capability depending on the Proserpine and Bowen Basin area loads. 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 12MW and 100MWh from summer 2018/19. The extent of load at risk is expected to remain within the 50MW and 600MWh limits established under Powerlink's amended planning standard (refer to Section 1.7.1) within the outlook period of the 2015 TAPR. Depending on the magnitude and location of additional load which may occur, a feasible network solution to the voltage limitation may involve the installation of a 132kV capacitor bank at Proserpine Substation at an approximate cost of $3 million (refer to Section 6.2.1).

Collinsville North to Proserpine 132kV transmission line

The 132kV transmission line was constructed in the late 1960s and supplies Proserpine Substation and the Whitsunday region. Following the retirement of the Proserpine to Mackay transmission line in 2017/18, it will be the only 132kV transmission line into the region. There is a committed project to replace the most critical coastal spans on the transmission line. A recent condition assessment identified levels of corrosion on the remaining inland structures requiring line refit works by summer 2017/18.

Eton Tee to Pioneer Valley 132kV transmission line

The 132kV transmission line was constructed in the late 1970s and runs parallel (approximately 20km inland) to the coast. Routine inspections have identified that the transmission lines corrosion is similar to other transmission lines in the area. Further detailed studies and condition assessments are required to evaluate potential options for line refit by summer 2019/20, continued operation and replacement by 2022/23 or the potential to reconfigure the network to retire this transmission line when required at the end of its technical life.

Eton Tee to Alligator Creek 132kV transmission line

The 132kV transmission line was constructed in the early 1980s and there is an ongoing need for this asset to supply critical port and coal haulage infrastructure associated with the Mackay ports. The line is in proximity to the coast and is exposed to highly corrosive, salt laden winds. The profile of corrosion observed along the feeder requires Powerlink to consider options for line refit of these lines in summer 2018/19 or replacement around 2020/21.

Eton Tee to Nebo 132kV transmission line

The 132kV transmission line traverses west over the Eton Range and was constructed in the late 1970s. Routine inspections have provided evidence that the condition of the asset located on the coastal side of the range has experienced accelerated corrosion when compared with the inland portion of the transmission line. Further analysis is required to evaluate the requirement for either a full or targeted line refit by summer 2020/21 or replacement around 2025/26.

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

Potential project	High level scope	Purpose	Possible commissioning date	Alternatives	Indicative costs
Line refit works on the 132kV transmission line between Collinsville North and Proserpine substations	Line refit works on all steel lattice structures	Maintain supply reliability to Proserpine	Summer 2017/18	New 132kV transmission line	$25m
Line refit works on the 132kV transmission line between Eton Tee and Pioneer Valley Substation	Staged line refit of steel lattice structures	Maintain supply reliability to Mackay Region	Summer 2019/20	New 132kV transmission line Reconfiguration of network and retirement of transmission line	$8m
Line refit works on the 132kV transmission line between Eton Tee and Alligator Creek Substation	Line refit works on steel lattice structures	Maintain supply reliability to Alligator Creek	Summer 2018/19	New 132kV transmission line	$12m
Line refit works on of the 132kV transmission line between Nebo Substation and Eton Tee	Staged line refit of steel lattice structures	Maintain supply reliability to Mackay Region	Summer 2020/21	New 132kV transmission line	$5m

Supply to Bowen Basin coal mining area

Forecast limitation

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 April 2012, Powerlink commenced 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 due to expected demand growth.

A Project Assessments Conclusions Report (PACR) published in July 2013 recommended a combination of network and non-network solutions to address the identified limitations.

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[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

Committed solutions

The committed projects to address the identified limitations include:

- installation of two 132kV capacitors at Dysart Substation and one 132kV capacitor at both the Moranbah and Newlands substations by summer 2013/14 (refer to Table 3.2)[4]
- network support services between 2014 and 2016[5].

There have been several proposals for new coal mining, liquefied natural gas (LNG) 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 500MW (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.

Mackay area voltage control

Forecast limitation

As assessed previously in the 2013 Annual Planning Report (APR) and 2014 TAPR, sufficient capacity is forecast to be available in this area until summer 2015/16, at which time, voltage limitations are forecast to occur during a critical contingency without action to augment supply.

Committed solution

This identified limitation is being addressed by a committed project to establish two new 132kV feeder bays at Pioneer Valley Substation and turn-in of the Nebo to Mackay 132kV circuit by summer 2015/16 (refer to Table 3.2).

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 drier 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. The 132kV injection point for Gladstone is the Calliope River Substation.

Network limitations

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

Transmission lines

Egans Hill to Rockhampton 132kV transmission line

Rockhampton is supplied via a 132kV transmission line from Boudercombe Substation. The portion 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 requiring action. Depending on easement constraints, this may require line refit works by summer 2018/19.

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[4] These capacitor banks address the voltage limitation identified for summer 2013/14.

[5] As identified in the Powerlink's 2014 TAPR, the scope of these committed services has been aligned to meet Powerlink's need.

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 regions. The condition assessment indicates moderate levels of structural corrosion and poor foundation integrity. Line refit works and foundation replacement, although technically feasible is unecomonic in relation to transmission line replacement. On this basis, Powerlink is proposing to replace this transmission line by summer 2019.

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 outlook period. Planning analysis indicates the possibility of reducing the number of transformers within the zone, particularly at Lilyvale. The analysis also confirms the balance of substation assets are required to provide ongoing reliable supply and the related investment needs are outlined in Table 4.5.

Powerlink is currently considering a potential network reconfiguration within the Central West and Gladstone zone that is beyond the outlook period, and discussed in Section 6.3.2.

Table 4.5 Possible replacement works in the Central West and Gladstone zones within five years

Potential project	High level scope	Purpose	Possible commissioning date	Alternatives	Indicative costs
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	Summer 2019/20	New 132kV transmission line	$6m
Line replacement of the 132kV transmission line between Callide A and Moura substations	New 132kV transmission line	Maintain supply reliability to Biloela and Moura in the Central West zone	Summer 2019/20	Foundation repair and line refit works	$59m
Substations					
Calvale and Callide B secondary systems replacement	Full replacement of 275kV secondary systems	Maintain supply reliability in the Central West zone	Summer 2017/18	In situ staged replacement of 275kV secondary systems equipment	$12m
Dysart Substation replacement	Staged replacement of the 132kV primary plant and secondary systems	Maintain supply reliability in the Central West zone	Summer 2019/20	Full replacement of 132kV substation	$19m
Dysart transformer replacement	Replacement of two 132/66kV transformers	Maintain supply reliability in the Central West zone	Summer 2019/20	Staged replacement of the two transformers	$9m
Bouldercombe primary plant replacement	Staged replacement of 275kV and 132kV primary plant	Maintain supply reliability in the Central West zone	Summer 2019/20	Full replacement of 275/132kV substation	$41m
Wurdong secondary systems replacement	Full replacement of 275kV secondary systems	Maintain supply reliability in the Gladstone zone	Summer 2019/20	In situ staged replacement of secondary systems equipment	$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	$12m
Lilyvale transformers replacement	Replacement of two of the three 132/66kV transformers (1)	Maintain supply reliability in the Central West zone	Summer 2020/21	Replacement of three 132/66kV transformers.	$13m

Note:

(1) Non-network solutions in the Central West and Gladstone zone:

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.

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 Central Queensland to Southern Queensland (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. Based on initial condition assessments many of these transmission lines are approaching end of life within five to 15 years. High level options to reconfigure this network beyond the outlook period are discussed in Section 6.3.3.

Network limitations

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 outlook period. Planning analysis confirms these substation assets are required to provide ongoing reliable supply and the related investment needs are outlined in Table 4.6.

Table 4.6 Possible reinvestment works in the Wide Bay zones within five years

Potential project	High level scope	Purpose	Possible commissioning date	Alternatives	Indicative costs
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	$26m

4.2.6 Surat zone

Existing network

The Surat Basin north west area is located north west of the Western Downs Substation. The area has significant development potential given the vast reserves of gas and coal. Electricity demand in the area is forecast to grow due to new developments of LNG upstream processing facilities by multiple proponents, together with the supporting infrastructure and services.

Network limitations

In the 2014 TAPR, Powerlink forecast voltage stability limitations may emerge in the Surat Basin north west area from winter 2017. Based on the medium economic forecast detailed in Chapter 2, this limitation is not forecast to occur within the five-year outlook period.

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

4.2.7 Moreton zone

Existing network

The Moreton zone includes a mix of 110kV and 275kV transmission network servicing a number of significant load centres in South East Queensland, 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 between the early 1960s and 1970s, with the 275kV network being developed and reinforced in response to load growth between the early 1970s and 2010. Multiple Powerlink 275/110kV injection points now interconnect with the Energex network to form two 110kV rings supplying the Brisbane CBD.

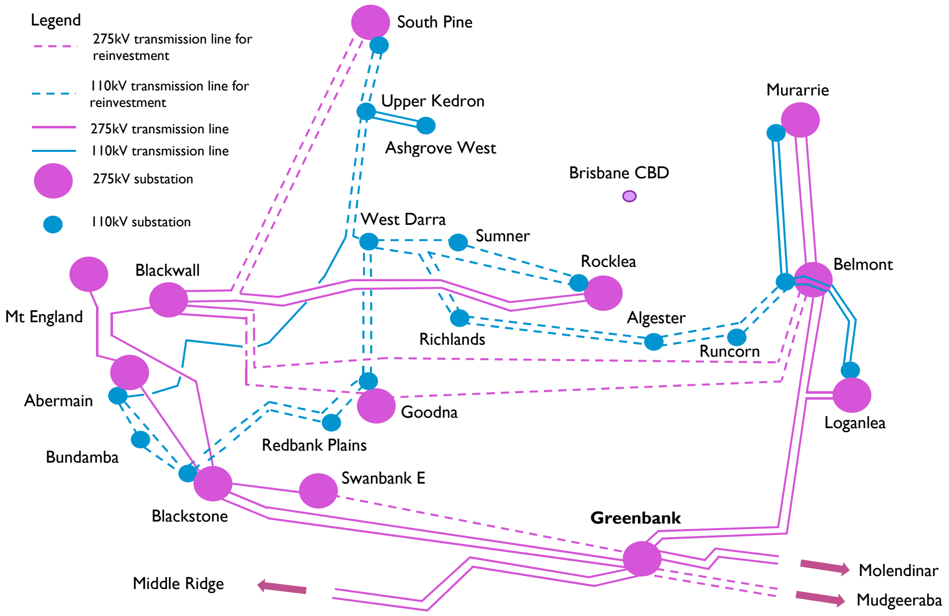
Network limitations

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. Most 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 life for most transmission line assets expected to occur between 2020 and 2025. Figure 4.3 illustrates the assets that are approaching end of life over this period.

Figure 4.3 Greater Brisbane transmission network



Planning studies have identified a number of 110kV and 275kV transmission line assets that could potentially be retired, and as such Powerlink has sought to exclude these assets from the proposed program of line refit works within the outlook period. Powerlink will continue to monitor demand forecast growth and undertake further joint planning with Energex to consider the strategic value of these assets. This ongoing review may yield a decision to retire these assets in the early 2020s and will be addressed in subsequent TAPRs.

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 outlook period. Planning analysis confirms these 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 Moreton zone within five years

Potential project	High level scope	Purpose	Possible commissioning date	Alternatives	Indicative costs
Transmission lines					
Line refit works on 110kV transmission lines between Belmont to Sumner Tee	Line refit works on steel lattice structures	Maintain supply reliability in CBD and Moreton zone	Winter 2016 to Winter 2017	Reconfiguration of network and retirement of transmission line (1) New 110kV transmission line/s	$19m
Line refit works on 110kV transmission lines between South Pine to West Darra	Line refit works on steel lattice structures	Maintain supply reliability in the CBD and Moreton zone	Summer 2016/17	Reconfiguration of network and retirement of transmission line (1) New 110kV transmission line/s	$13m
Line refit works on 110kV transmission lines between Rocklea to West Darra	Line refit works on steel lattice structures	Maintain supply reliability in CBD and Moreton zone	Winter 2017 to Summer 2017/18	New 110kV transmission line/s	$15m
Line refit works on 110kV transmission lines between Blackstone to Redbank Plains to West Darra	Line refit works on steel lattice structures	Maintain supply reliability in the Moreton zone	Summer 2018/19	Reconfiguration of network and retirement of transmission line (1) New 110kV transmission line/s	$20m
Line refit works on 110kV transmission lines between Blackstone to Abermain	Line refit works on steel lattice structures	Maintain supply reliability in the Moreton zone	Summer 2019/20	New 110kV transmission line/s	$17m
Line refit works on 275kV transmission lines between Karana Tee to Bergins Hill to Belmont	Line refit works on steel lattice structures	Maintain supply reliability in the Moreton zone	Winter 2020 to Summer 2020/21	New 275kV transmission line/s	$28m
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 2020/21	New 275kV transmission line/s	$16m

Table 4.7 Possible reinvestment works in the Moreton zone within five years *(continued)*

Potential project	High level scope	Purpose	Possible commissioning date	Alternatives	Indicative costs
Substations					
Belmont 275kV secondary system replacement	Full replacement of 275kV secondary systems	Maintain supply reliability in the CBD and Moreton zone	Winter 2019	Staged replacement of 275kV secondary systems equipment	$9m
Belmont 275/110kV transformer replacement	Replacement of two 275/110kV transformers with a single transformer (1)	Maintain supply reliability in the CBD and Moreton zone	Summer 2019/20	Replacement of two transformers	$11m
Palmwoods 275kV Substation primary and secondary replacement	Staged replacement of 275kV and 132kV primary plant and secondary systems panels	Maintain supply reliability in the Moreton zone	Summer 2019/20	Full replacement of 275/132kV substation	$25m
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	$30m
Redbank Plains primary plant replacement	Staged replacement of 110kV primary plant	Maintain supply reliability in the Moreton zone	Summer 2020/21	Full replacement of 110kV substation	$8m
Abermain secondary systems replacement	Full replacement of 110kV secondary systems	Maintain supply reliability in the Moreton zone	Summer 2020/21	Staged replacement of 110kV secondary systems equipment	$7m

Note:

(1) Non-network solutions in the Moreton zone:

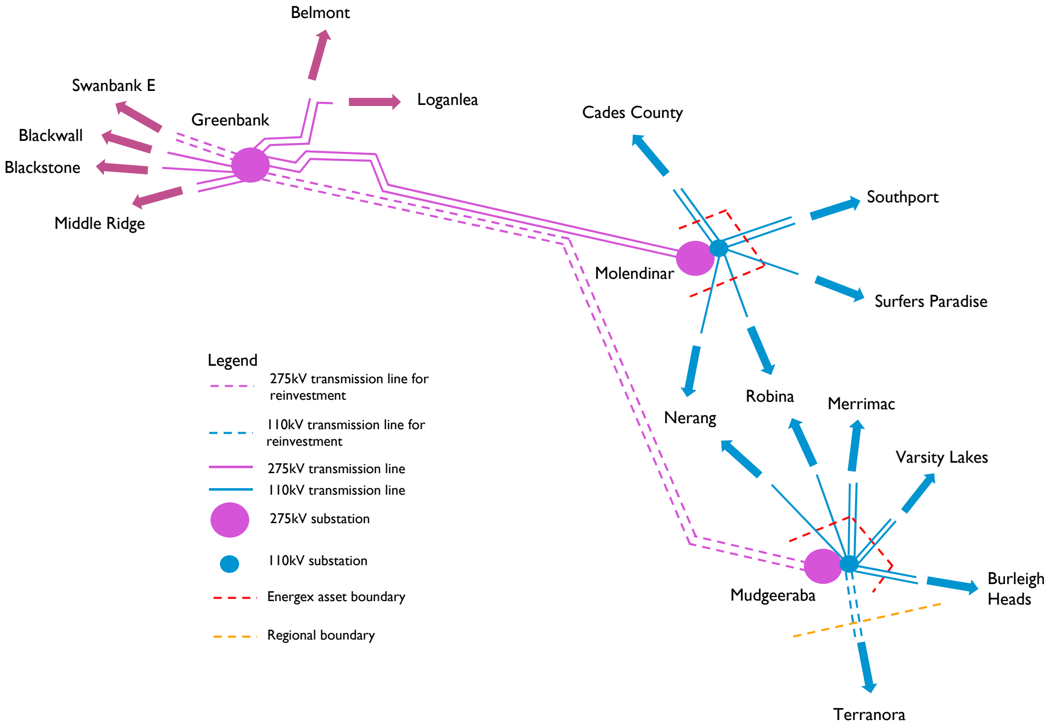
Due to the extent of available headroom, the retirement of identified 110kV transmission assets does not bring about a need for non-network solutions to avoid or defer load at risk or future network limitations, based on Powerlink's demand forecast outlook.

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 4.4) 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 4.4 Gold Coast transmission network



Network limitations

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 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 line refit of these lines in summer 2019/20 or the continued operation and replacement of the lines by around 2025. Network planning studies have confirmed the need to preserve 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. Essential Energy is currently undertaking works to upgrade and extend the life of their portion of the transmission line. Based on Powerlink's condition assessment, line refit or full replacement of the 13km transmission line section would be required by around 2020 or 2025 respectively.

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 outlook period.

The condition of two of 275/110kV transformers at Mudgeeraba Substation requires action within the outlook period. Planning studies have identified the potential to replace one of the two Mudgeeraba 275/110kV transformers and subsequently retire the other transformer in summer 2019/20. This 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 may require Powerlink undertake a RIT-T consultation.

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 4.8.

Table 4.8 **Possible replacement works in the Gold Coast zone within five years**

Potential project	High level scope	Purpose	Possible commissioning date	Alternatives	Indicative costs
Transmission lines					
Line refit works on the 275kV transmission lines between Greenbank and Mudgeeraba substations	Line refit works on steel lattice structures	Maintain supply reliability to the Gold Coast zone	Summer 2018/19	New 275kV transmission line/s	$53m
Line refit works on the 110kV transmission line between Mudgeeraba and Terranora substations	Line refit works on steel lattice structures	Maintain reliable interconnection to New South Wales	Summer 2020/21	New 110kV transmission line on new easement	$13m
Substations					
Mudgeeraba 110kV Substation primary plant and secondary system replacement	Staged replacement of 110kV primary and secondary systems equipment	Maintain supply reliability to the Gold Coast zone	Summer 2017/18	Full replacement of 110kV substation	$18m
Mudgeeraba 275/110kV transformer replacement	Replacement of a transformer (followed by retirement of the other transformer in summer 2019/2020) (1)	Maintain supply reliability to the Gold Coast zone	Summer 2017/18	Replacement of two transformers	$11m

Note:

(1) Non-network solutions in the Gold Coast zone:

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

Limitations discussed in Section 4.2 have been summarised in Table 4.9. This table provides an outlook (based on medium economic forecast demand, generation and committed network development assumptions contained in chapters 2, 3 and 5) for potential limitations in Powerlink's transmission network over a one, three and five-year timeframe. The table also identifies the manner in which potential limitations were analysed in the NTNDP.

Table 4.9 Summary of forecast network limitations

Anticipated limitation	Reason for limitation	Time limitation may be reached			Relationship to the 2014 NTNDP
		1-year outlook (2015/16)	3-year outlook (up to 2018/19)	5-year outlook (up to 2020/21)	
North zone					
Supply to Bowen Basin coal mining area	Due to potential mining growth by multiple proponents, thermal limitations expected to occur during a critical contingency	2013/14 to 2015/16 Committed project in progress (1)			Outside the scope of the 2014 NTNDP
Mackay area voltage control	Unacceptable voltage conditions during a critical contingency	2015/16 Committed project in progress (1)			Outside the scope of the 2014 NTNDP

Note:

(1) Refer to Table 3.2 – committed and under construction augmentations works.

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 has been particularly evident in the Queensland region.

Proposals for transmission investments 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 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

There are currently no anticipated consultations within the next 12 months.

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 amended 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. Table 4.10 provides a summary of network limitations identified by Powerlink in 2014 which fall into this category.

Table 4.10 Summary of forecast network limitations identified in the 2014 TAPR, now beyond the five-year outlook period

Anticipated limitation	Reason for limitation	Zone	2014 TAPR timing	Basis for timing change
Supply to Surat Basin north west area	Instability of the compression motor load during a critical contingency	Bulli and South West zones	Winter 2017	Reduction in forecast load growth

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 Windfarm	New windfarm near Atherton (1)	North	2017/18
Clare PV	New solarfarm near Clare	Central	Mid 2017
New coal mine/CSG 132kV connections	New industrial plant connections in the Bowen Basin area (1)	Central West	Progressively from summer 2018/19
Multiple new coal mine 132kV connections	New industrial plant connections in the Galilee Basin area (1)	Central West	Progressively from summer 2018/19
Multiple upstream gas compression facilities connections	Multiple new connections for coal seam methane (CSM) / LNG compression facilities in the Surat Basin north west area (1)	Surat	Progressively from summer 2018/19

Note:

(1) When Powerlink constructs a new line or substation as a non-regulated customer connection (e.g. generator, mine or CSM/LNG 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 2014 NTNDP was published by AEMO in December 2014. The focus of the NTNDP is to provide an independent, strategic view of the efficient development of the NEM transmission network over a 20-year planning horizon.

Modelling for the 2014 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 2014 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 2014 NTNDP did not identify any emerging reliability or potential economic dispatch limitations across the main transmission network linking NTNDP zones within the Queensland region. This outlook is consistent with the absence of forecast limitations identified across the main transmission network in this TAPR.

The NTNDP modelling did not identify a requirement for major investment in inter-regional augmentations. Powerlink and TransGrid also considered it prudent not to recommend a preferred upgrade option for Queensland/New South Wales Interconnector (QNI) transmission line, but to continue to monitor market developments to determine if and when any material changes could warrant reassessment of an upgrade to QNI.

Both the NTNDP and this TAPR recognise that asset reinvestment will be the focus within the five-year outlook period. 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. This may include reinvesting in assets to extend their technical life, removing some assets without replacement or replacing existing assets with assets of a different type, configuration or capacity.

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 2014 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 South East Queensland. AEMO and Powerlink will continue to monitor this situation.

Chapter 5

Network capability and performance

Chapter 5

5.1 Introduction

This chapter on network capability and performance provides:

- a table of existing and committed generation capacity over the next three years
- background on factors that influence network capability
- historical annual zonal energy transfer, constraint times and transfer duration curves at key sections of Powerlink Queensland's transmission network
- sample power flows at times of forecast Queensland maximum summer and winter demands under a range of interconnector flows and generation dispatch patterns
- a qualitative explanation of factors affecting power transfer capability at key sections of Powerlink Queensland's transmission network.

The capability of Powerlink's transmission network to meet forecast demand is dependent on a number of factors. In general terms, Queensland's transmission network is utilised more during summer than winter. During higher summer temperatures, reactive power requirements are greater and transmission plant has lower power carrying capability. Also, high summer maximum demands generally last for many hours, whereas winter maximum demands are lower and last for short evening periods (as shown in Figure 2.7).

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 2.14) and when embedded generation output is lower.

5.2 Existing and committed scheduled and transmission connected generation

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

There are no scheduled or semi-scheduled generation projects in Queensland that are currently classified as committed.

Due to the relatively flat outlook for load growth in the Queensland region, as outlined in Chapter 2, and more generally across the National Electricity Market (NEM), there have been a number of changes to the status of existing generating plant.

Stanwell Corporation withdrew two units at Tarong Power Station from service in October and December 2012 respectively. In February 2014, Stanwell Corporation announced its intention to withdraw Swanbank E Power Station for up to three years. Tarong Power Station unit 4 was returned to service in July 2014 and unit 2 is scheduled to return in mid 2015. Swanbank E Power Station was withdrawn in December 2014.

Table 5.1 summarises the available capacity of power stations connected to Powerlink's transmission network including the non-scheduled market generators at Yarwun, Invicta and Koombooloomba. This table also includes scheduled embedded generators at Barcaldine and Roma.

The information in this table has been provided to the Australian Energy Market Operator (AEMO) by the owners of the generators. Details of registration and generation capacities can be found on AEMO's website.

Table 5.1 **Available generation capacity**

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

Location	Available capacity MW generated (1)					
	Winter 2014	Summer 2014/15	Winter 2015	Summer 2015/16	Winter 2016	Summer 2016/17
Coal-fired						
Stanwell	1,460	1,460	1,460	1,460	1,460	1,460
Gladstone	1,680	1,680	1,680	1,680	1,680	1,680
Callide A (2)	–	–	–	–	–	–
Callide B	700	700	700	700	700	700
Callide Power Plant	900	900	900	900	900	900
Tarong North	443	443	443	443	443	443
Tarong (3)	1,050	1,400	1,400	1,400	1,400	1,400
Kogan Creek	744	730	744	730	744	730
Millmerran	852	760	852	760	852	760
Total coal-fired	**7,829**	**8,073**	**8,179**	**8,073**	**8,179**	**8,073**
Combustion turbine						
Townsville (Yabulu) (4)	243	234	243	234	243	233
Mt Stuart	419	379	419	379	419	379
Mackay (5)	34	34	34	34	–	–
Barcaldine (4)	37	34	37	34	37	34
Yarwun (6)	160	155	160	155	160	155
Roma (4)	68	54	68	54	68	54
Condamine	144	144	144	144	144	144
Braemar 1	504	465	504	465	504	465
Braemar 2	519	495	519	495	519	495
Darling Downs	633	580	633	580	633	580
Oakey (7)	340	282	340	282	340	282
Swanbank E (3)	–	–	–	–	–	–
Total combustion turbine	**3,101**	**2,856**	**3,101**	**2,856**	**3,067**	**2,821**
Hydro electric						
Barron Gorge	66	66	66	66	66	66
Kareeya (including Koombooloomba)	93	93	93	93	93	93
Wivenhoe (8)	500	500	500	500	500	500
Total hydro electric	659	659	659	659	659	659
Sugar mill						
Invicta	34	0	34	0	34	0
Total all stations	**11,623**	**11,588**	**11,973**	**11,588**	**11,939**	**11,553**

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 stepup 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) The demonstration phase of the Callide Oxyfuel Project reached completion in March 2015. The Connection Agreement with CS Energy for this unit expires December 2015. CS Energy has not indicated intentions to reapply.

(3) Stanwell Corporation has advised that Swanbank E will be withdrawn for up to 3 years and Tarong unit 2 is to be returned by mid-2015.

(4) Townsville 66kV component, Barcaldine and Roma power stations are embedded scheduled generators, which are accounted in the transmission delivered forecast.

(5) AEMO report an available scheduled generation of 0MW for the Mackay GT from winter 2017.

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

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

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

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 2015 to summer 2017/18 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 Queensland/New South Wales Interconnector (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 3.2, 3.3 and 3.5), 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 multi-term equations. These equations quantify the relationship between system operating conditions and transfer capability, and are implemented into NEMDE 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.

The trade-off for this maximisation of transfer capability is the complexity of analysis required to define network capability. The process of developing limit equations from a large number of network analysis cases involves regression techniques. The process also involves due diligence by AEMO before these equations are implemented as constraints in NEMDE.

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. It should be noted that 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.

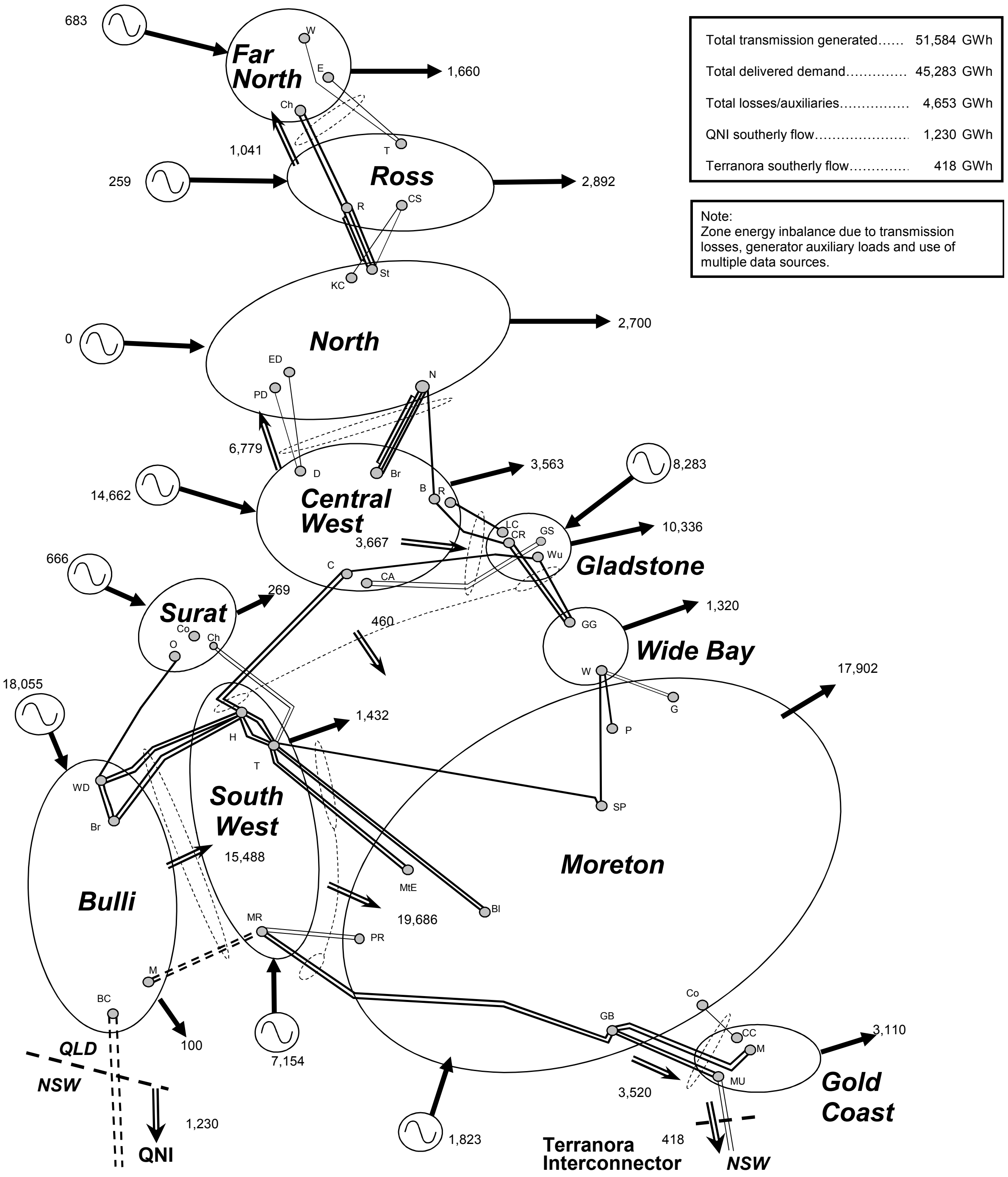
For each grid section, the time that the relevant constraint equations have bound is provided over the last 10 years. Years referenced in this chapter correspond to the period from April to March of the following year, capturing a full winter and summer period. Constraint times can be associated with 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.

Grid sections registering constraints over the last year are included in tables showing the proportion of the time that the relevant constraint equations have bound for two periods, namely from April to September 2014 (winter period) and from October 2014 to March 2015 (summer period).

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 2013 and 2014 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. These figures assist in the explanation of differences between 2013 and 2014 grid section transfer duration curves.

Figure 5.1 2013[1] zonal electrical energy transfers (GWh)



Total transmission generated……	51,584 GWh
Total delivered demand………….	45,283 GWh
Total losses/auxiliaries…………….	4,653 GWh
QNI southerly flow…………………	1,230 GWh
Terranora southerly flow………….	418 GWh

Note:
Zone energy inbalance due to transmission losses, generator auxiliary loads and use of multiple data sources.

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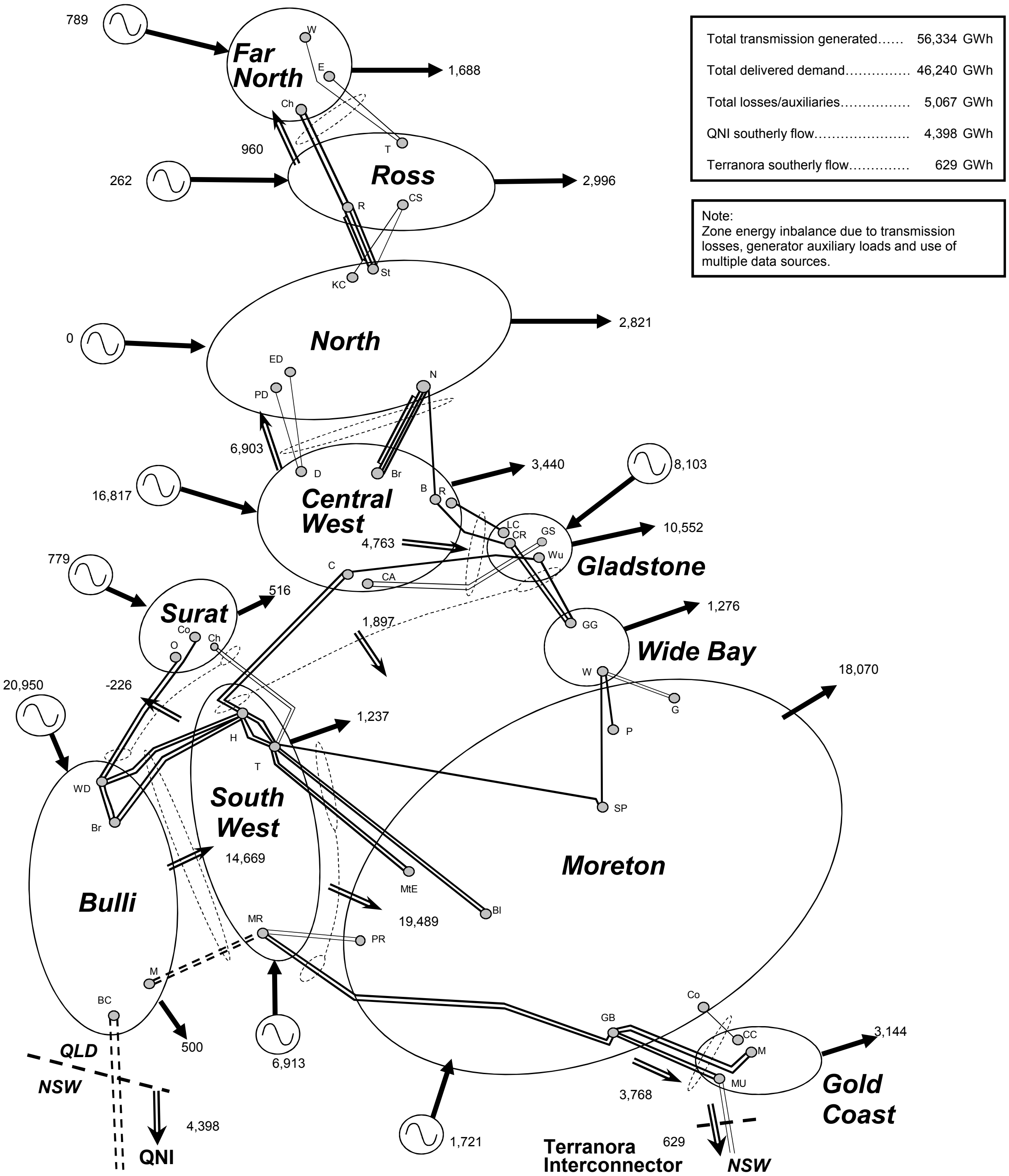
[1] Consistent with this chapter, time periods are from April 2013 to March 2014.

Figure 5.2 2014[2] zonal electrical energy transfers (GWh)



Total transmission generated……	56,334 GWh
Total delivered demand……………	46,240 GWh
Total losses/auxiliaries…………….	5,067 GWh
QNI southerly flow………………….	4,398 GWh
Terranora southerly flow………….	629 GWh

Note:
Zone energy inbalance due to transmission losses, generator auxiliary loads and use of multiple data sources.

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[2] Consistent with this chapter, time periods are from April 2014 to March 2015.

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.

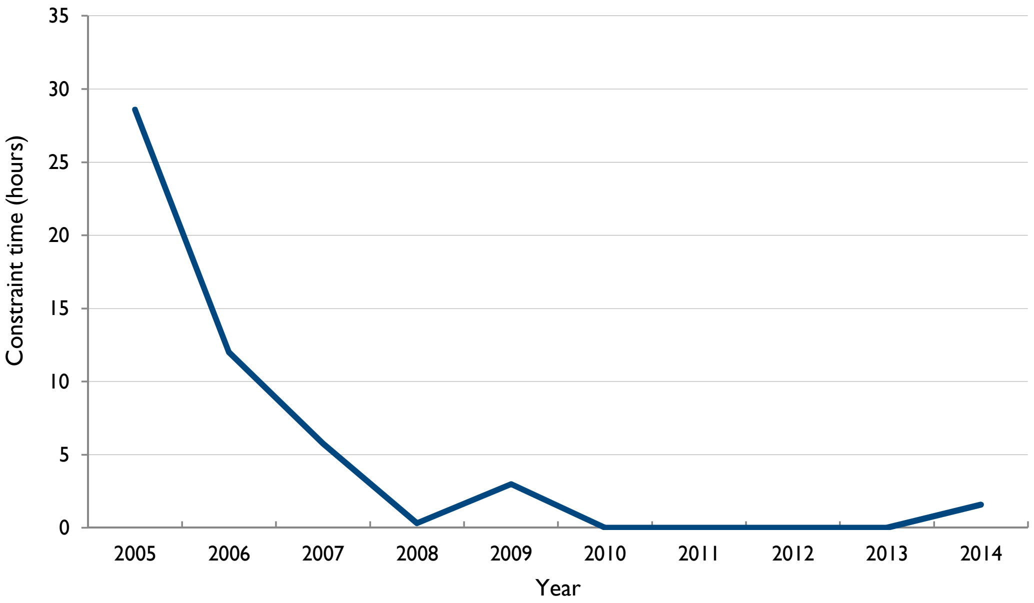
The limit equation in Table D.1 of Appendix D shows that the following variables have a significant effect on transfer capability:

- Far North zone to northern Queensland[3] 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 the reduction in power transfer due to increased local generation is greater than the reduction in grid section transfer capability.

Information pertaining to the historical duration of constrained operation for the FNQ grid section is summarised in Figure 5.3. Table 5.2 provides the proportion of the time the constraint equations have bound apportioned into two periods from April 2014 to March 2015.

Figure 5.3 Historical FNQ grid section constraint times



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

Table 5.2 FNQ grid section constraint times for April 2014 to March 2015

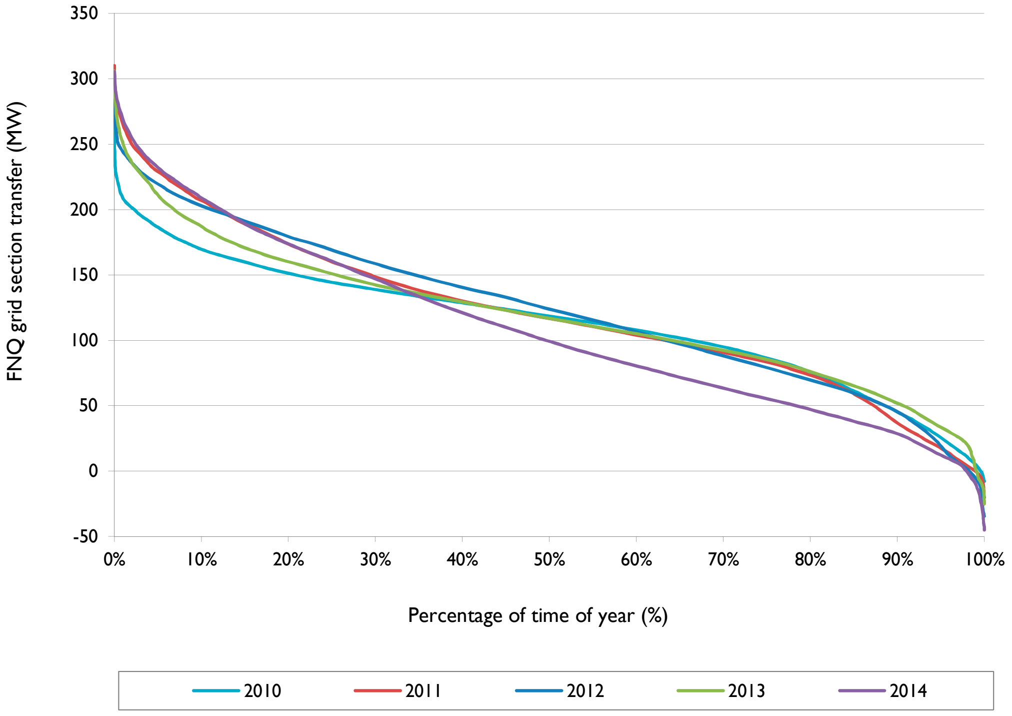
FNQ grid section	Time equations bound (hours)	Proportion of time constraint equations bound (%)
April 2014 to September 2014	0.00	0.00
October 2014 to March 2015	1.58	0.04

Constraint durations have reduced over time due to the commissioning of various transmission projects. The commissioning of the Woree static VAr compensator (SVC) in 2005/06 and the second Woree 275/132kV transformer in 2007/08 provided increased capacity to this grid section. There have been minimal constraints in this grid section since 2008.

On 16 January 2015, Ross to Chalumbin 275kV double circuit transmission line tripped as a result of a lightning strike. AEMO have added this double circuit into the vulnerable list. A double circuit transmission line in this category is eligible to be reclassified as a credible contingency event during a lightning storm if a cloud to ground lightning strike is detected within a specified distance of the vulnerable line. The 1.58 hours constraint times in Table 5.2 were due to this reclassification.

Figure 5.4 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. The peak output and annual capacity factor of the hydro generating power stations at Barron Gorge and Kareeya also impact the utilisation of this grid section. These vary depending on rainfall levels in the Far North zone. The capacity factor of the hydro generating power stations was approximately 15% greater in 2014 compared to 2013 (refer to figures 5.1 and 5.2).

Figure 5.4 Historical FNQ 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.

5.5.2 Central Queensland to North Queensland grid section

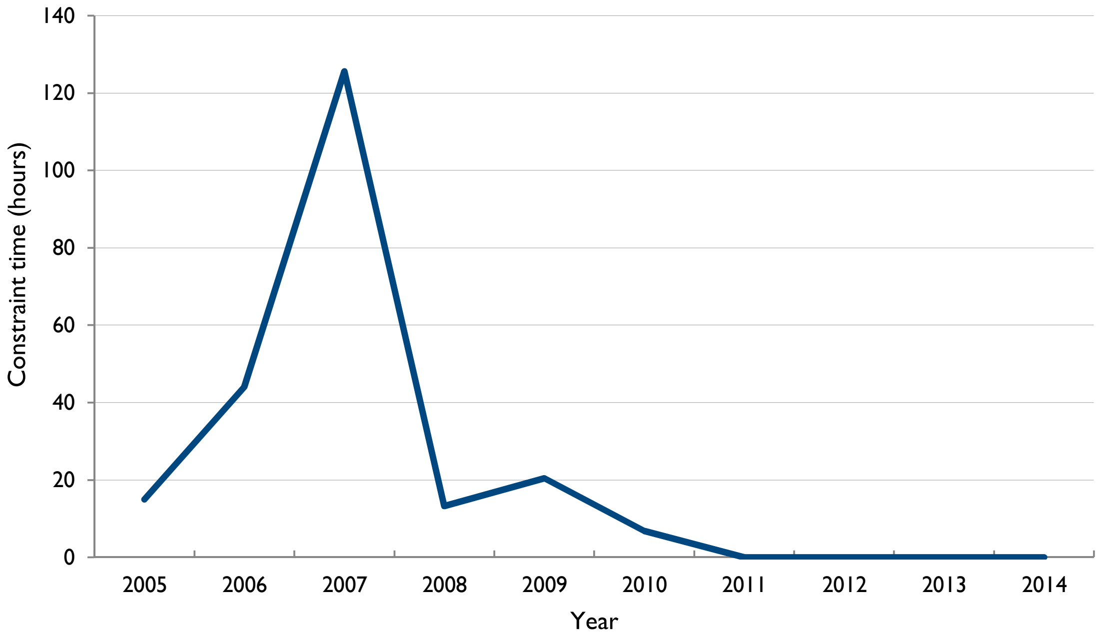
Maximum power transfer across the Central Queensland to North Queensland (CQ-NQ) grid section may be set by thermal ratings associated with an outage of a Stanwell to Broadsound 275kV circuit, under certain prevailing ambient conditions. Power transfers may also be constrained by voltage stability limitations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

Information pertaining to the historical duration of constrained operation for the CQ-NQ grid section is summarised in Figure 5.5.

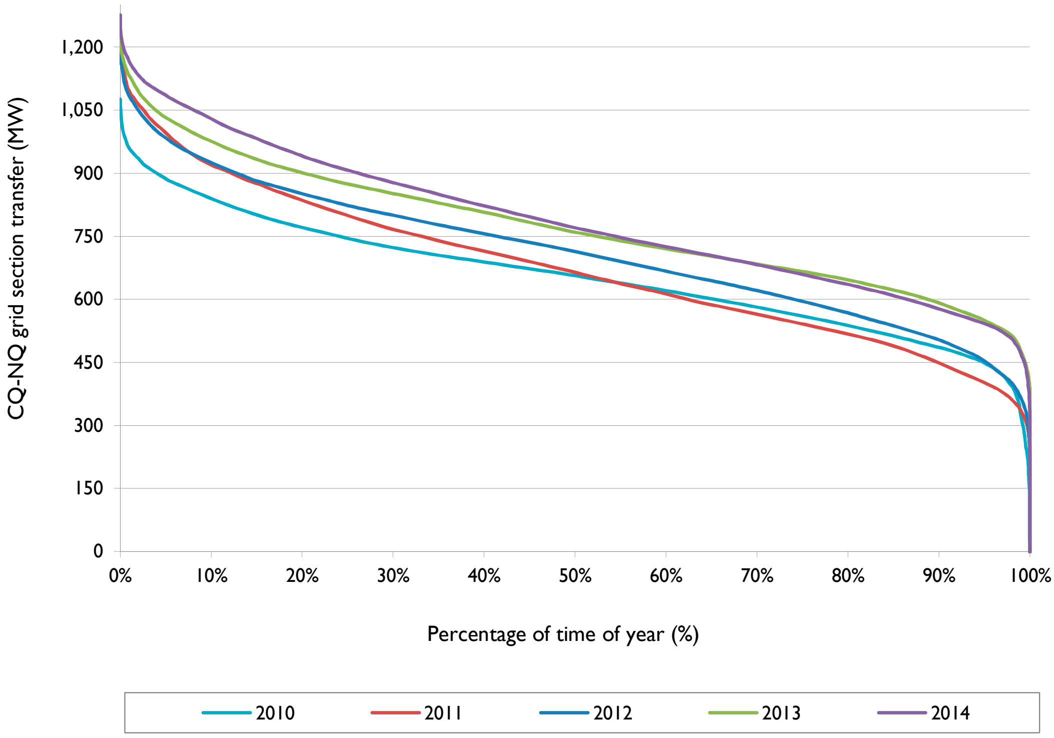
Figure 5.5 Historical CQ-NQ grid section constraint times



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 5.6 provides historical transfer duration curves showing small annual differences in grid section transfer demands and energy. The deregistration of the Collinsville Power Station in January 2013 has contributed to higher utilisation of the transmission network. Transmission delivered energy in North Queensland was higher in 2014 to 2013 contributing to higher utilisation (refer to figures 5.1 and 5.2).

Figure 5.6 Historical CQ-NQ 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.

The development of large loads in central or northern Queensland (additional to those included in the forecasts), without corresponding increases in central or northern Queensland generation, can significantly increase the levels of CQ-NQ transfers. This is discussed in Section 6.2.3.

5.5.3 Gladstone grid section

Maximum power transfer across the Gladstone grid section is set by the thermal rating of the 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.

Powerlink also implements network switching and support strategies when transfers reach the capability of this grid section. These strategies minimise the incidence of network constraints and extend to opening the 132kV lines at Gladstone South and/or Baralaba substations.

Information pertaining to the historical duration of constrained operation for the Gladstone grid section is summarised in Figure 5.7. Table 5.3 provides the proportion of the time the constraint equations have bound apportioned into two periods from April 2014 to March 2015.

Figure 5.7 Historical Gladstone grid section constraint times

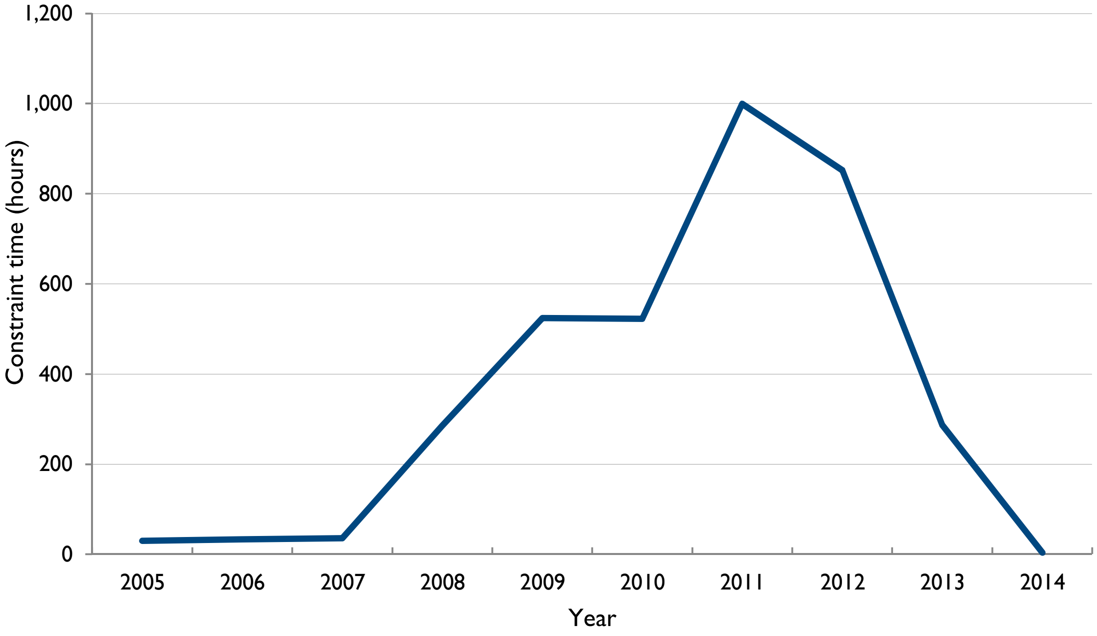


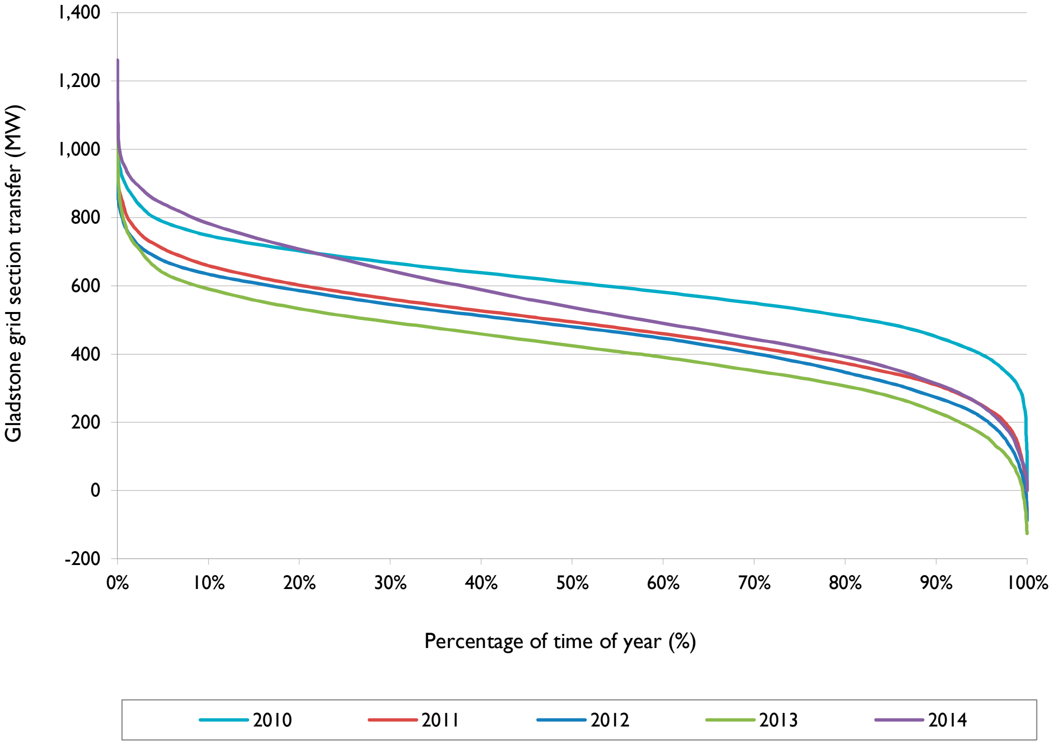
Table 5.3 Gladstone grid section constraint times for April 2014 to March 2015

Gladstone grid section	Time equations bound (hours)	Proportion of time constraint equations bound (%)
April to September 2014	3.33	0.08
October 2014 to March 2015	0.00	0.00

Powerlink commissioned a double circuit 275kV transmission line between Calvale and Stanwell substations in 2013/14. This transmission line provides additional capacity to the grid section accommodating a wider range of market dispatches. The 3.33 hours constraint times during April to September were due to a planned outage of the Calvale to Halys 275kV double circuit transmission line.

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 5.8 provides historical transfer duration curves showing a return to higher utilisation in 2014. This year's higher transfers are predominantly associated with a significant increase in Central West generation (refer to figures 5.1 and 5.2).

Figure 5.8 Historical Gladstone 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.

5.5.4 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.

Information pertaining to the historical duration of constrained operation for the CQ-SQ grid section is summarised in Figure 5.9. Table 5.4 provides the proportion of the time the constraint equations have bound apportioned into two periods from April 2014 to March 2015.

Figure 5.9 Historical CQ-SQ grid section constraint times

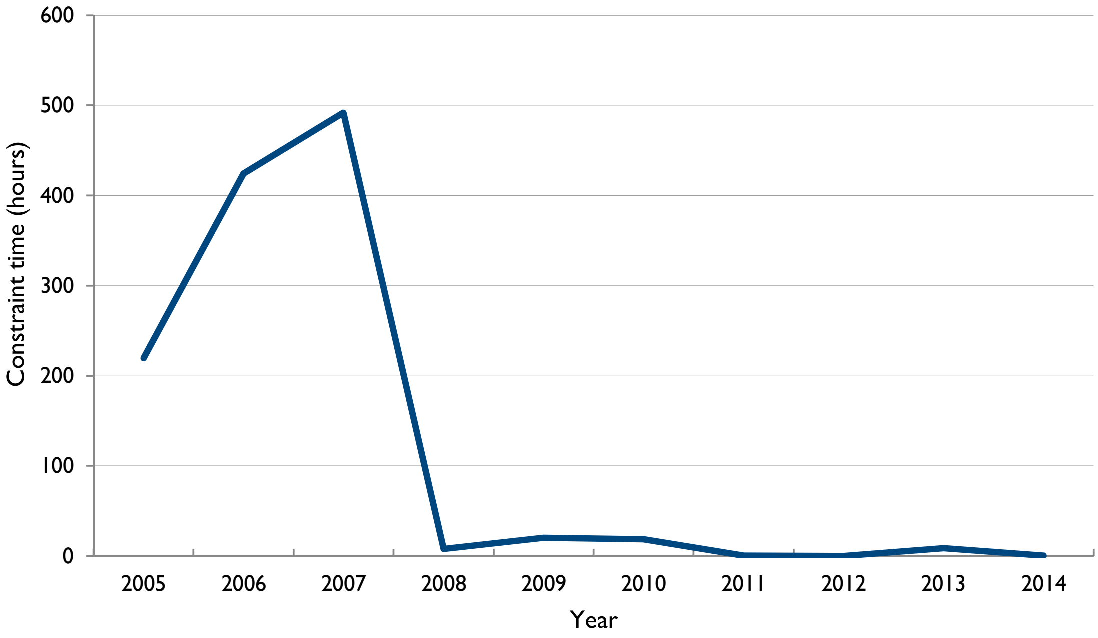
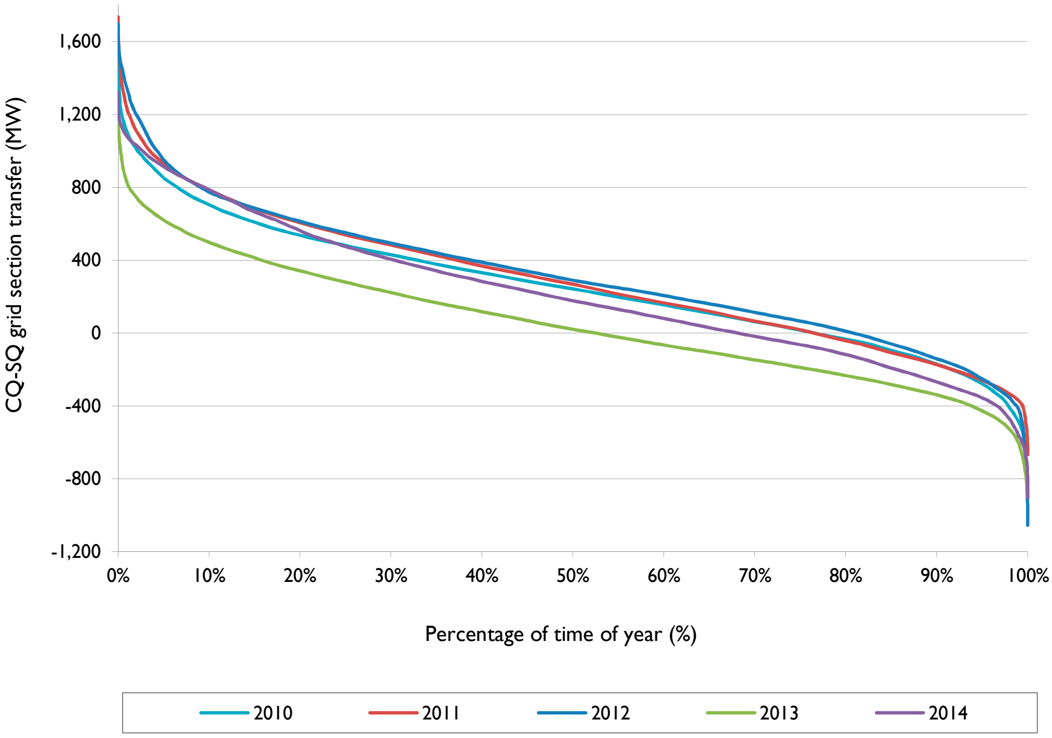


Table 5.4 CQ-SQ grid section constraint times for April 2014 to March 2015

CQ-SQ section	Time equations bound (hours)	Proportion of time constraint equations bound (%)
April 2014 to September 2014	0.33	0.01
October 2014 to March 2015	0.00	0.00

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 since the commissioning of significant levels of generation in the South West Queensland (SWQ) area between 2006 and 2010. Figure 5.10 provides historical transfer duration curves. Transfers in 2014 are higher to 2013 predominantly due to higher transfers to southern states and higher transmission delivered energy in South Queensland.

Figure 5.10 **Historical CQ-SQ grid section transfer duration curves**



The eastern single circuit transmission lines of CQ-SQ were constructed in the 1970s and 1980s. Based on condition assessment most of these single circuit lines will reach end of their technical life in the five to 10-year outlook period of the TAPR. This is discussed in Section 6.3.3.

5.5.5 Surat grid section

The Surat grid section was introduced in the 2014 TAPR with the imminent establishment of the Columboola to Western Downs 275kV transmission line, Columboola to Wandoan South 275kV transmission line and Wandoan South and Columboola 275kV substations. These network developments were completed in September 2014 (refer to Table 3.1) and significantly increased the supply capacity to the Surat Basin north west area.

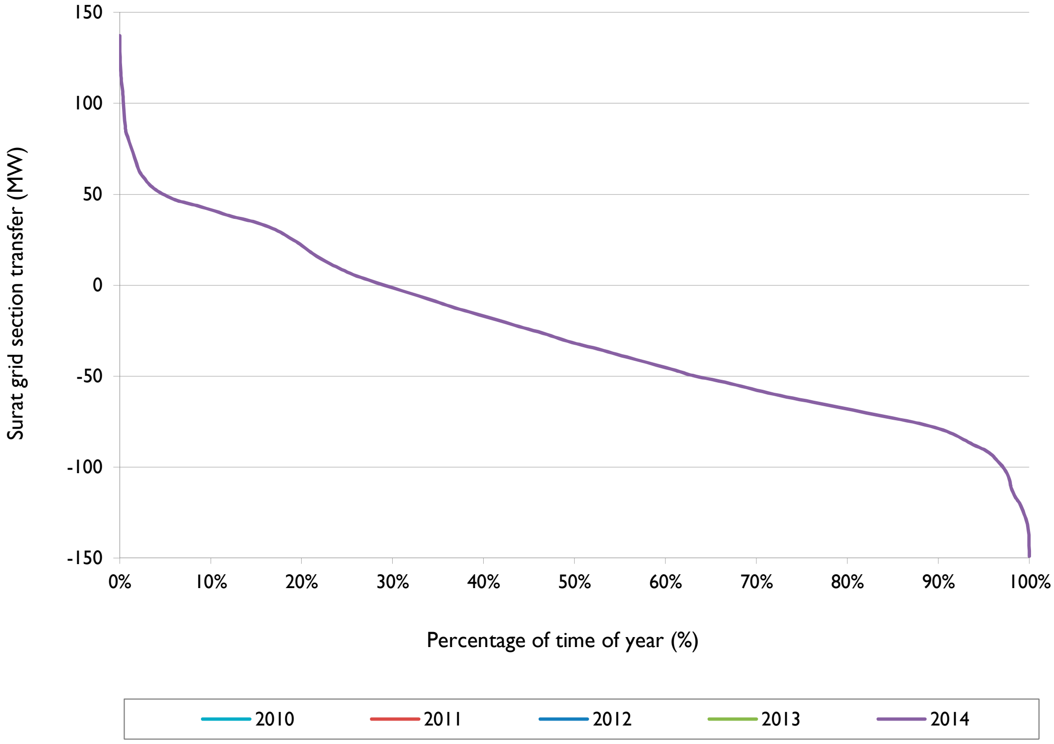
Following the commissioning of these projects, the maximum power transfer across the Surat grid section is expected to be set by voltage stability associated with an outage of a Western Downs to Orana 275kV circuit.

The voltage stability limit is set by insufficient reactive power reserves in the Surat zone following a contingency. More generating units online in these zones increase 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 5.11 provides the transfer duration curve for the first year recorded. Grid section transfers are reflective of a generation rich zone. Over the 2014 year, the zone has been a net exporter of energy.

Figure 5.11 Historical Surat grid section transfer duration curve



Based on the medium economic outlook in Chapter 2, the Surat grid section will become a net importer of electricity in line with the expected ramping of the liquefied natural gas (LNG) loads within the zone.

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

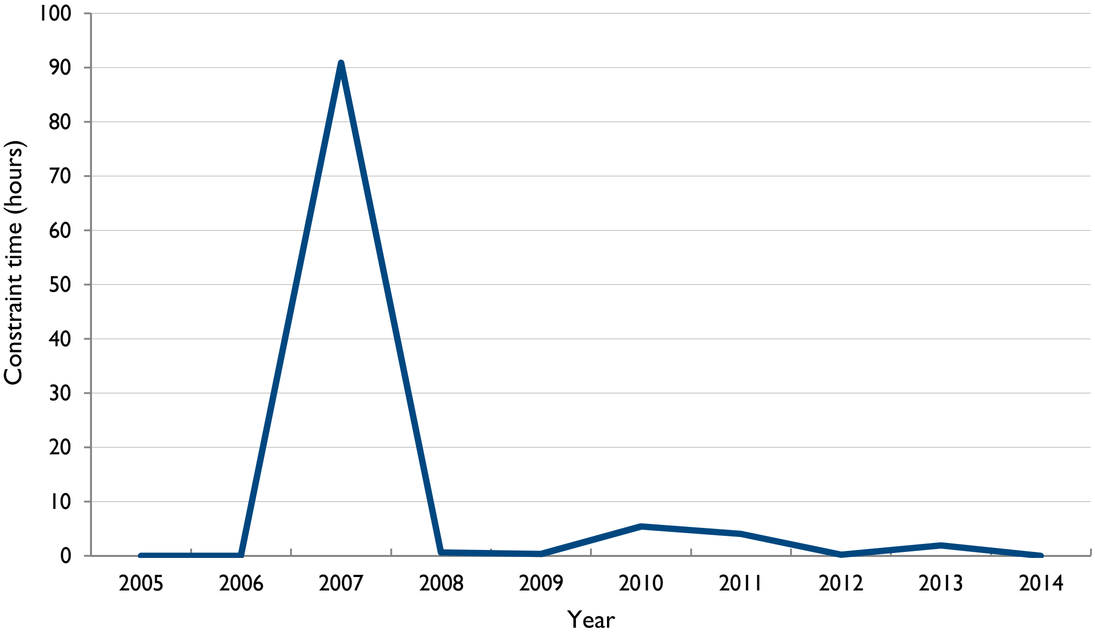
The development of large loads in Surat (additional to those included in the forecasts), without corresponding increases in generation, can significantly increase the levels of Surat grid section transfers. This is discussed in Section 6.2.4.

5.5.6 South West Queensland grid section

The South West Queensland (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.

Information pertaining to the historical duration of constrained operation for the SWQ grid section is summarised in Figure 5.12.

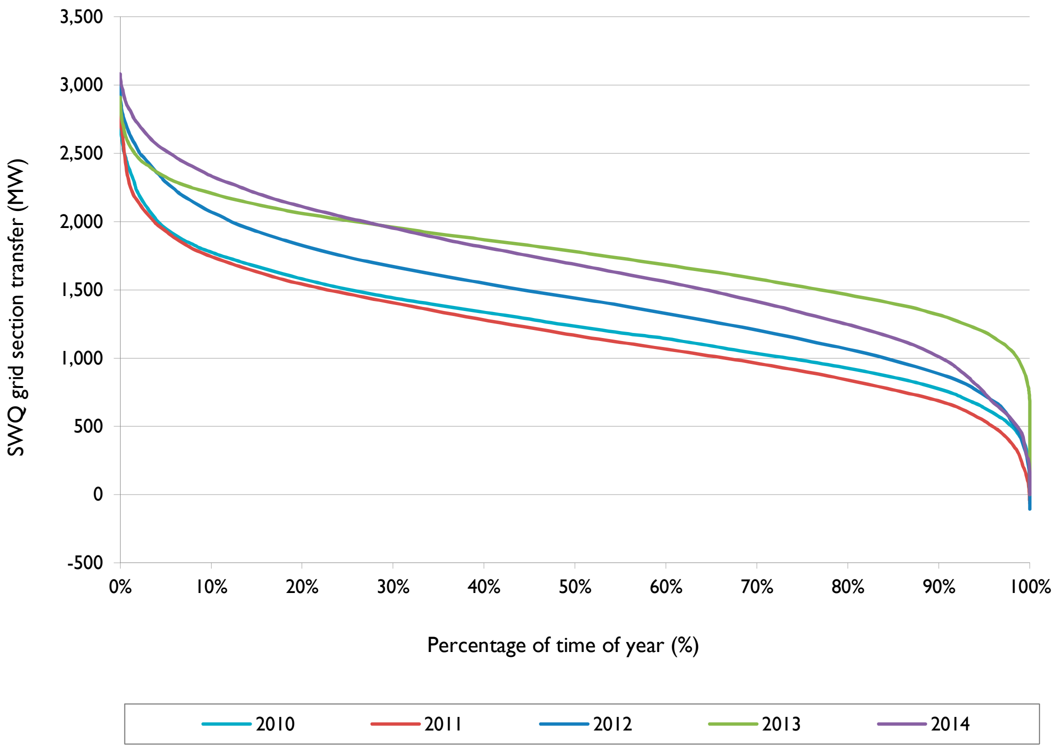
Figure 5.12 Historical SWQ grid section constraint times



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 5.13 provides historical transfer duration curves showing a small reduction in 2014 energy transfer to levels compared to 2013. Increases in generation in the Bulli area in 2014 from 2013 have only partially offset the large increase in southerly QNI transfer and local energy consumption (refer to figures 5.1 and 5.2).

Figure 5.13 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.

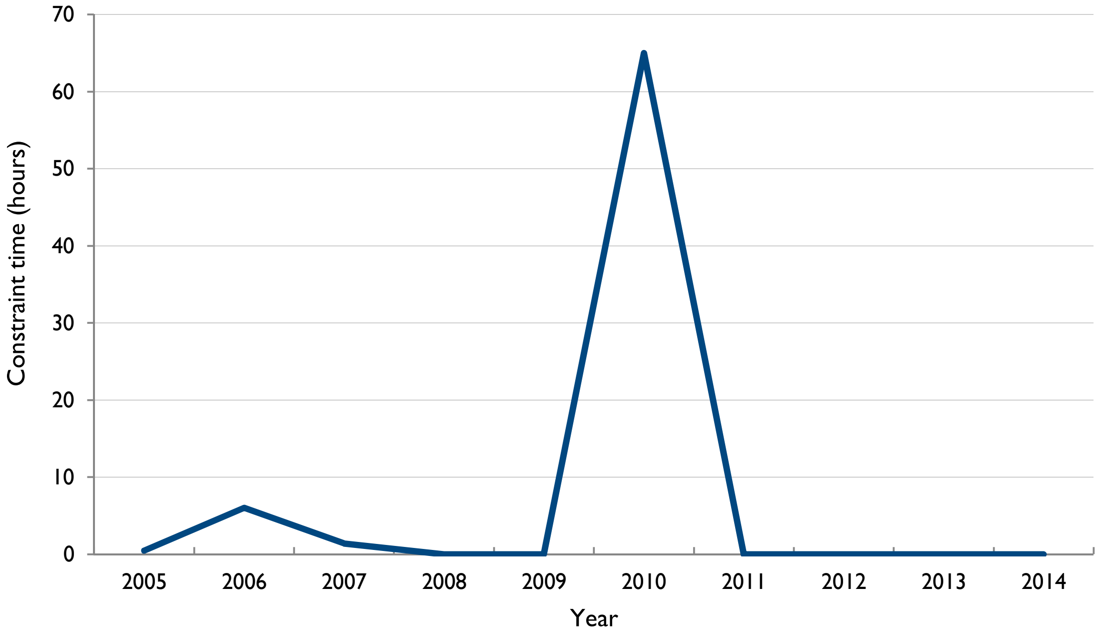
Limit equations in Table D.4 of Appendix D show that the following variables have a significant effect on transfer capability:

- 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 the reduction in power transfer due to increased generation east of this grid section is greater than the reduction in grid section transfer capability.

Information pertaining to the historical duration of constrained operation for the Tarong grid section is summarised in Figure 5.14.

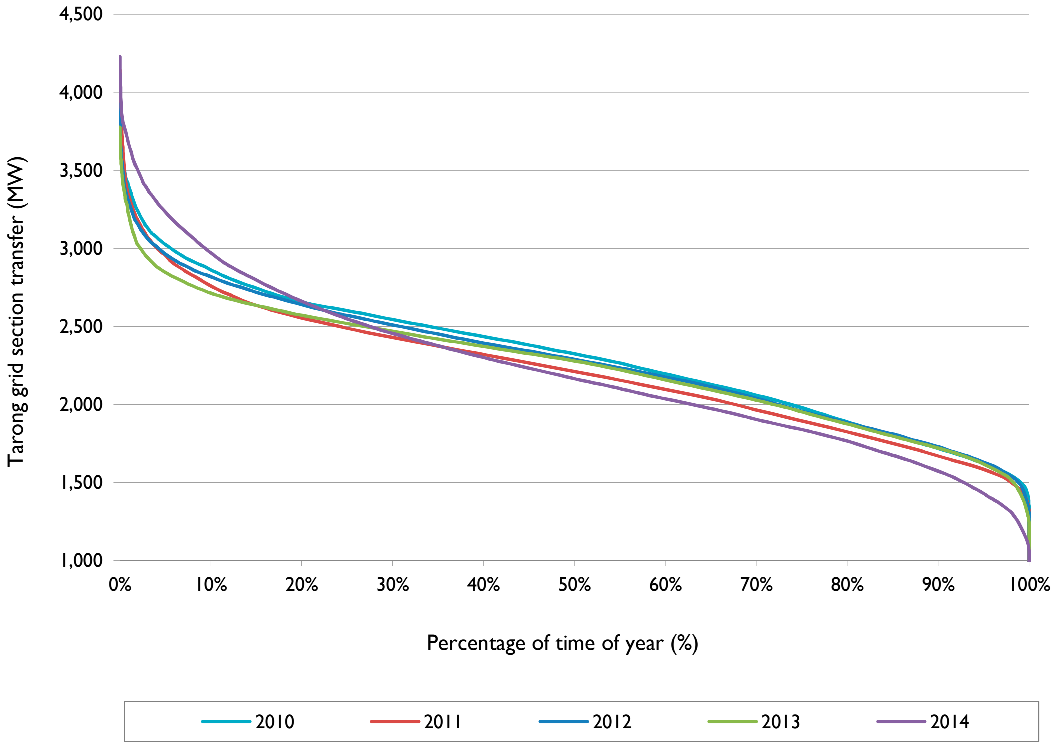
Figure 5.14 **Historical Tarong grid section constraint times**



Powerlink delivered increases to Tarong transfer capacity with projects including the Middle Ridge to Greenbank transmission reinforcement in 2007/08, Greenbank SVC and South Pine SVC in 2008/09. Constraint times have been minimal since 2007, 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 5.15 provides historical transfer duration curves showing small annual differences in grid section transfer demands. Increases in Terranora Interconnector transfers and SEQ transmission delivered energy in 2014 from 2013 levels have been largely met by transfers across the eastern part of CQ-SQ (refer to figures 5.1 and 5.2).

Figure 5.15 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.

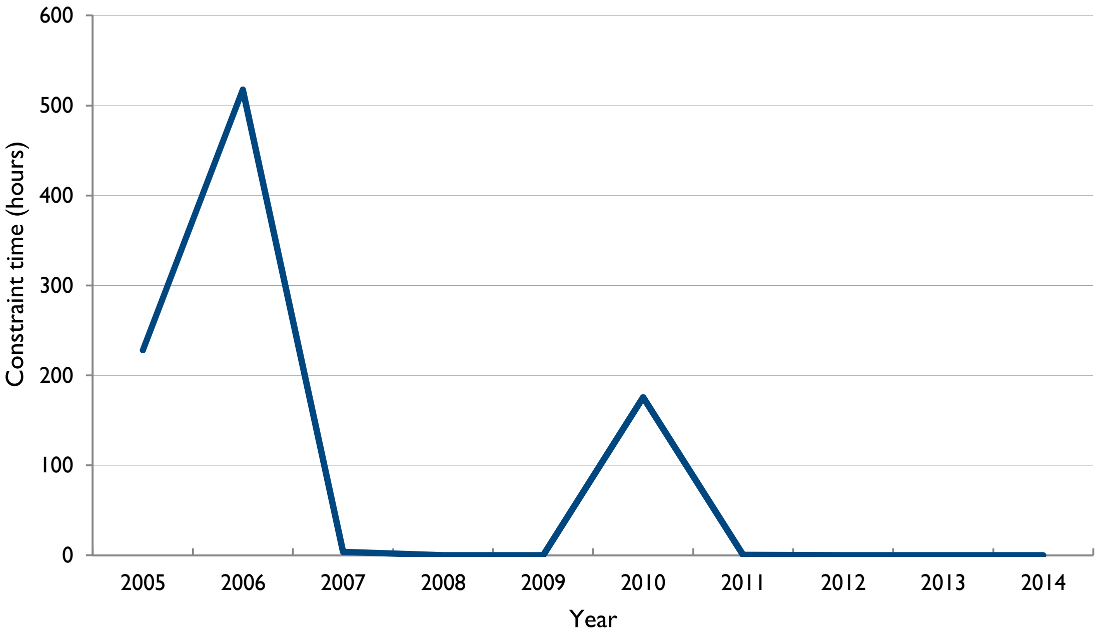
The limit equation in Table D.5 of Appendix D shows that the following variables have a significant effect on transfer capability:

- 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 reduction in power transfer due to reduced southerly flow on Terranora Interconnector is greater than the reduction in grid section transfer capability.

Information pertaining to the historical duration of constrained operation for the Gold Coast grid section is summarised in Figure 5.16.

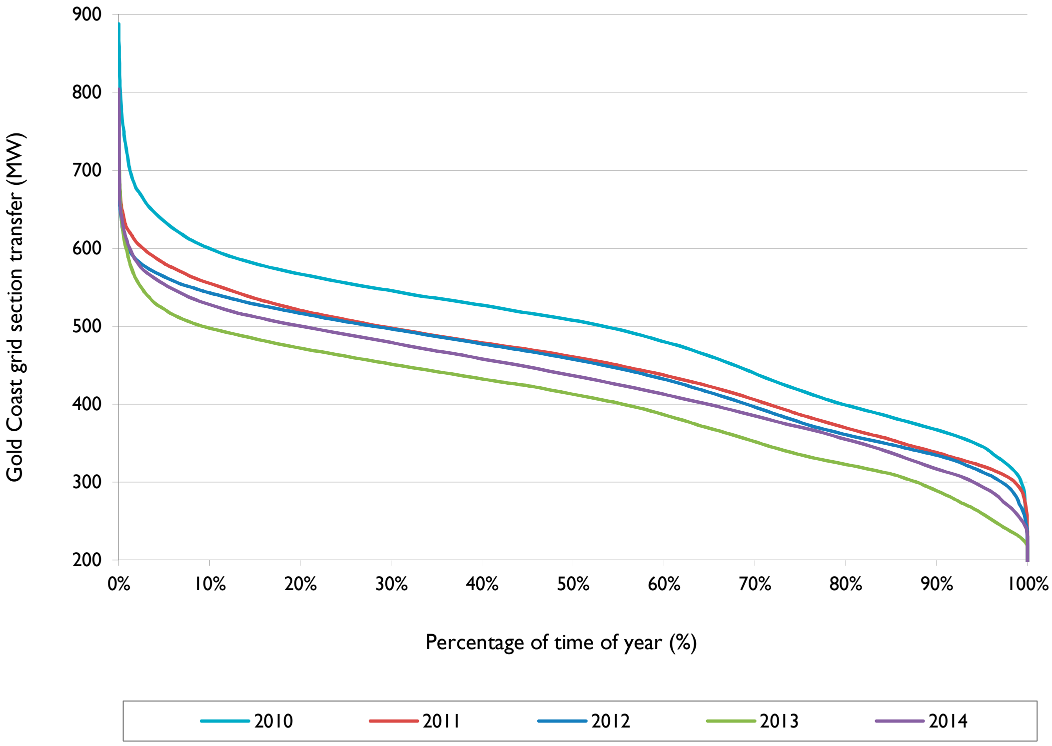
Figure 5.16 Historical Gold Coast grid section constraint times



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 5.17 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. Terranora Interconnector southerly transfer was higher in 2014 to 2013 (refer to figures 5.1 and 5.2).

Figure 5.17 Historical Gold Coast 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.

5.5.9 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 for the 2014 calendar year was published in April 2015 and can be found on AEMO's website.

In 2013, Powerlink, TransGrid and AEMO completed testing increasing the oscillatory limit to 1,200MW in the southerly direction, conditional on the availability of dynamic stability monitoring equipment.

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 in Queensland
- 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 November 2014, Powerlink and TransGrid published a Project Assessment Conclusions Report (PACR) 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.

5.6 Zone performance

This section presents, where applicable, a summary of:

- the capability of the transmission network to deliver 2014 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.

As described in Section 5.5, years referenced in this chapter correspond to the period from April to March of the following year, capturing a full winter and summer period.

Double circuit transmission lines that experience a lighting trip 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 fifth year from the last double circuit lightning trip.

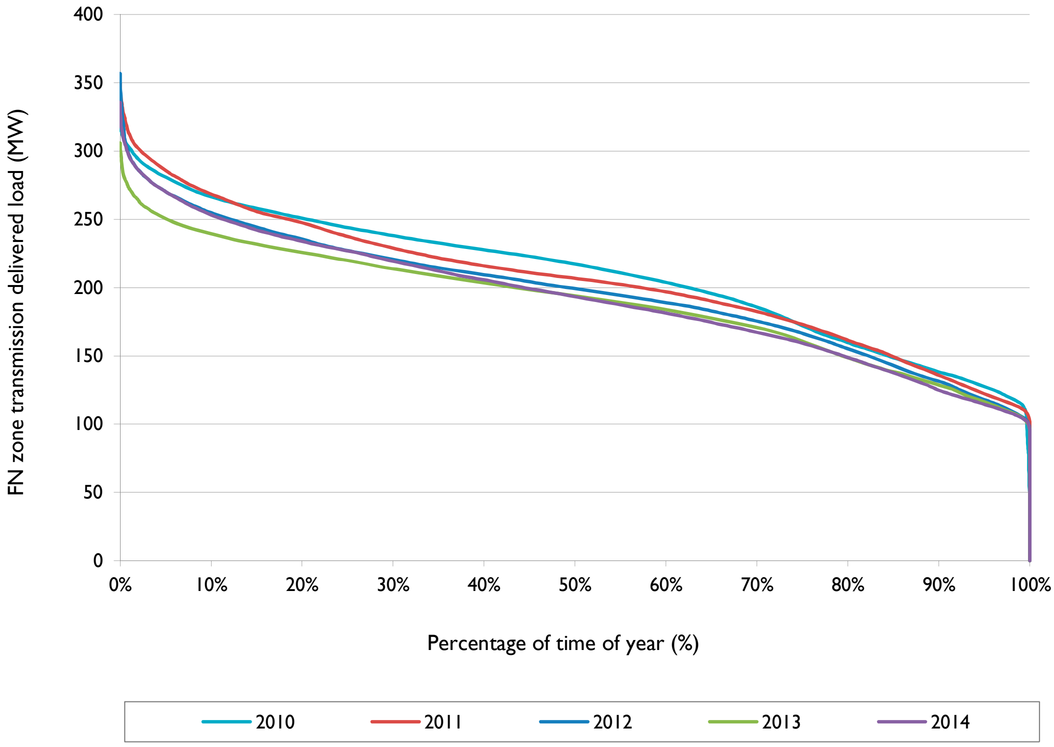
5.6.1 Far North zone

The Far North zone experienced no load loss for a single network element outage during 2014.

The Far North zone contains no scheduled/semi-scheduled embedded generators or significant non-scheduled embedded generators as defined in Figure 2.3.

Figure 5.18 provides historical transmission delivered load duration curves for the Far North zone. Energy delivered from the transmission network has increased by 1.7% between 2013 and 2014. The peak transmission delivered demand in the zone was 336MW which is below the highest peak demand over the last five years of 357MW set in 2012.

Figure 5.18 Historical Far 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 Far North zone in the vulnerable list:

- Chalumbin to Woree 275kV double circuit transmission line last tripped March 2013
- Chalumbin to Turkinje 132kV double circuit transmission line last tripped December 2014

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.

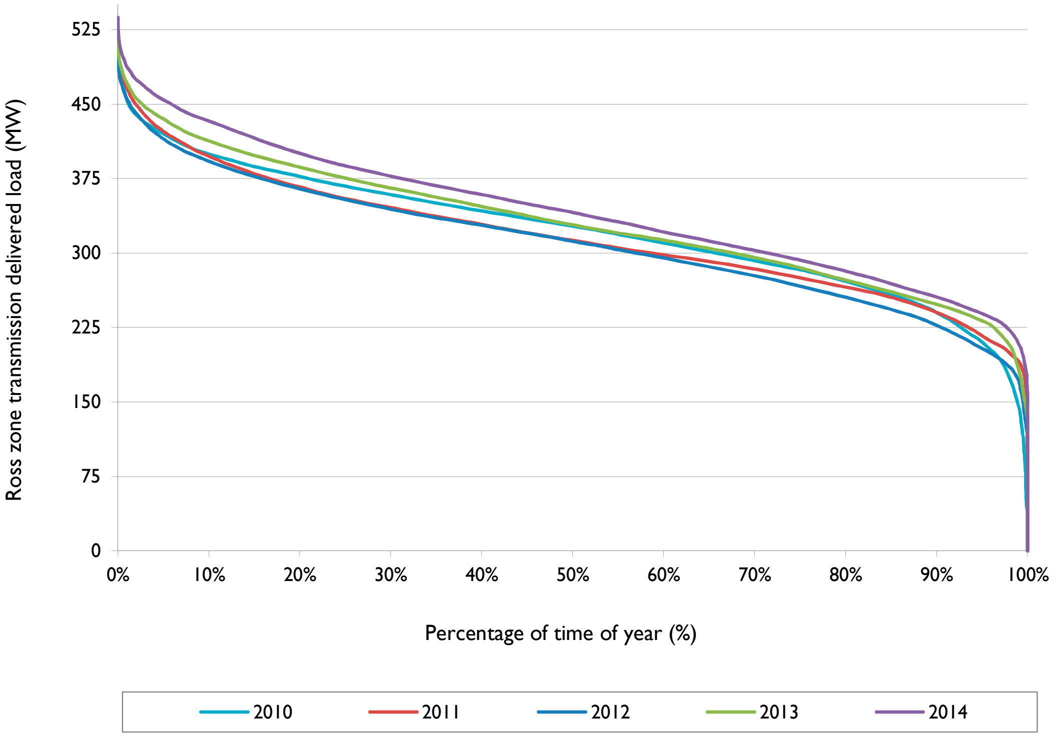
5.6.2 Ross zone

The Ross zone experienced no load loss for a single network element outage during 2014.

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 2.3. These embedded generators provided approximately 217GWh during 2014.

Figure 5.19 provides historical transmission delivered load duration curves for the Ross zone. Energy delivered from the transmission network has increased by 3.6% between 2013 and 2014. The peak transmission delivered demand in the zone was 537MW which is the highest peak demand over the last five years for the zone.

Figure 5.19 Historical Ross zone transmission delivered load duration curves



As a result of double circuit outages associated with lightning strikes, AEMO have, this year, included the Ross to Chalumbin 275kV double circuit transmission line in the vulnerable list. This double circuit tripped due to lightning in January 2015 (refer to Section 5.5.1).

High voltages associated with light load conditions are managed with existing reactive sources. Two tertiary connected reactors at Ross Substation will be replaced by a bus reactor by winter 2016 (refer to Table 3.5).

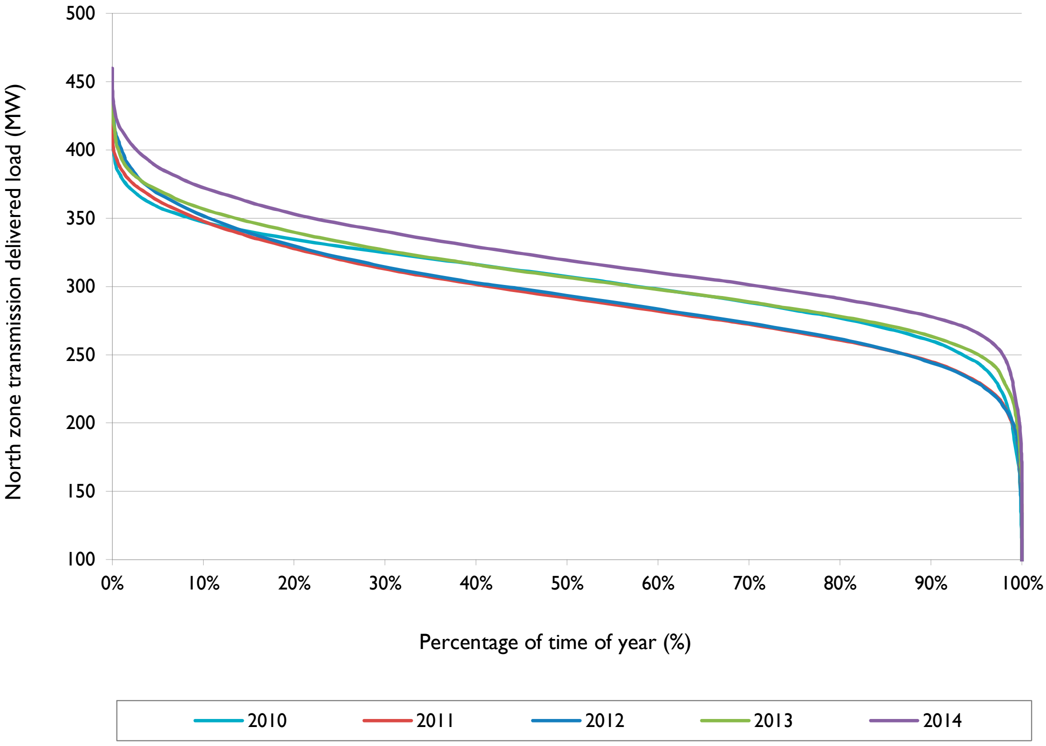
5.6.3 North zone

The North zone experienced no load loss for a single network element outage during 2014.

The North zone includes significant non-scheduled embedded generators Moranbah North, Moranbah and Racecourse Mill as defined in Figure 2.3. These embedded generators provided approximately 495GWh during 2014.

Figure 5.20 provides historical transmission delivered load duration curves for the North zone. Energy delivered from the transmission network has increased by 4.5% between 2013 and 2014. The peak transmission delivered demand in the zone was 560MW which is the highest peak demand over the last five years for the zone.

Figure 5.20 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 Mackay tee Proserpine 132kV double circuit transmission line last tripped March 2011
- Moranbah to Goonyella Riverside 132kV double circuit transmission line last tripped December 2014
- Kemmis to Moranbah tee Burton Downs 132kV and Nebo to Moranbah tee Coppabella 132kV double circuit transmission line last tripped February 2012.

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.

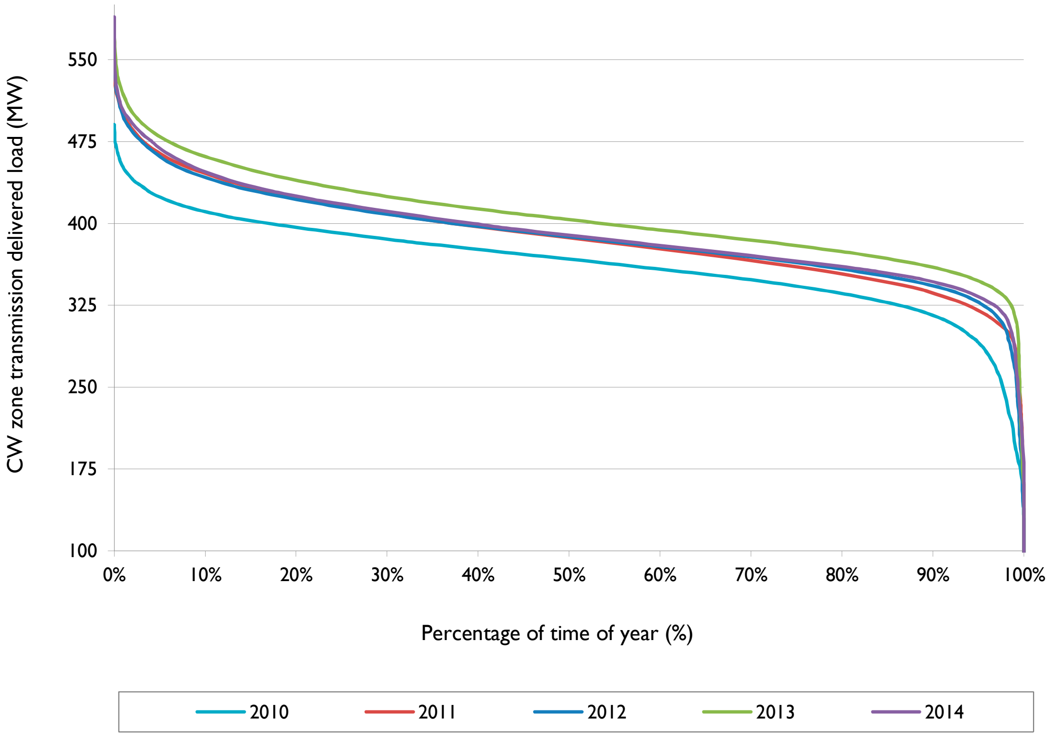
5.6.4 Central West zone

The Central West zone experienced no load loss for a single network element outage during 2014.

The Central West zone includes the scheduled embedded Barcaldine generator and significant non-scheduled embedded generators at German Creek and Oaky Creek as defined in Figure 2.3. These embedded generators provided approximately 423GWh during 2014.

Figure 5.21 provides historical transmission delivered load duration curves for the Central West zone. Energy delivered from the transmission network has reduced by 3.4% between 2013 and 2014. The peak transmission delivered demand in the zone was 589MW which is the highest peak demand for the zone.

Figure 5.21 Historical Central West zone transmission delivered load duration curves



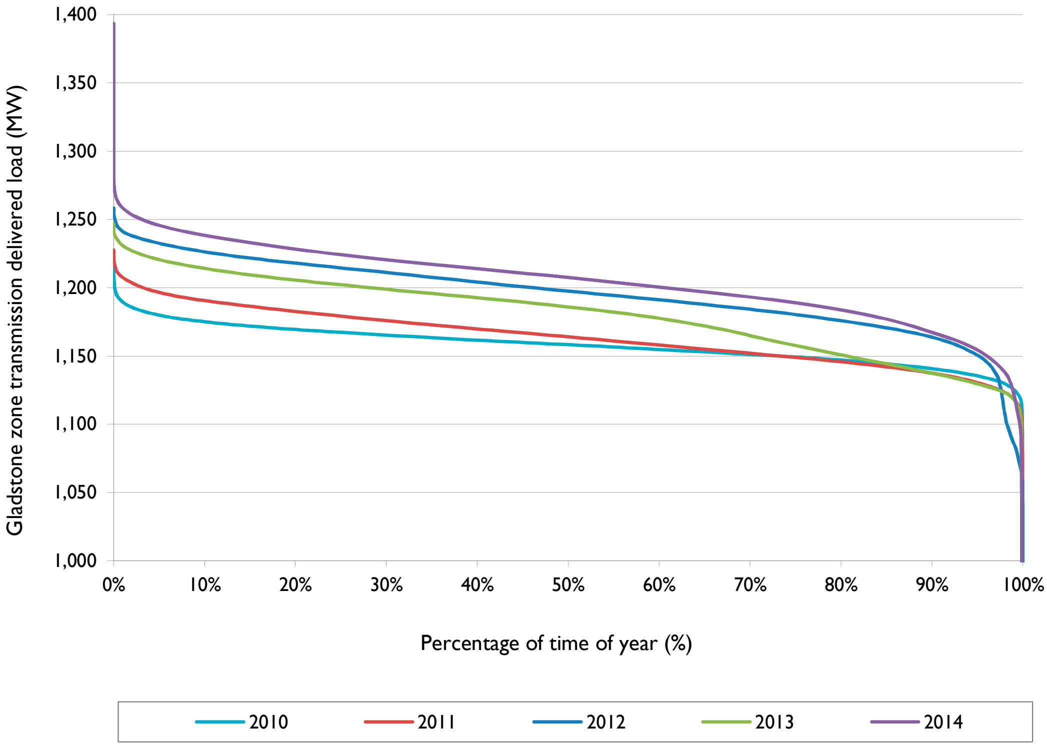
5.6.5 Gladstone zone

The Gladstone zone experienced no load loss for a single network element outage during 2014.

The Gladstone zone contains no scheduled/semi-scheduled embedded generators or significant non-scheduled embedded generators as defined in Figure 2.3.

Figure 5.22 provides historical transmission delivered load duration curves for the Gladstone zone. Energy delivered from the transmission network has increased by 2.1% between 2013 and 2014. The peak transmission delivered demand in the zone was 1,393MW which is the highest peak demand for the zone.

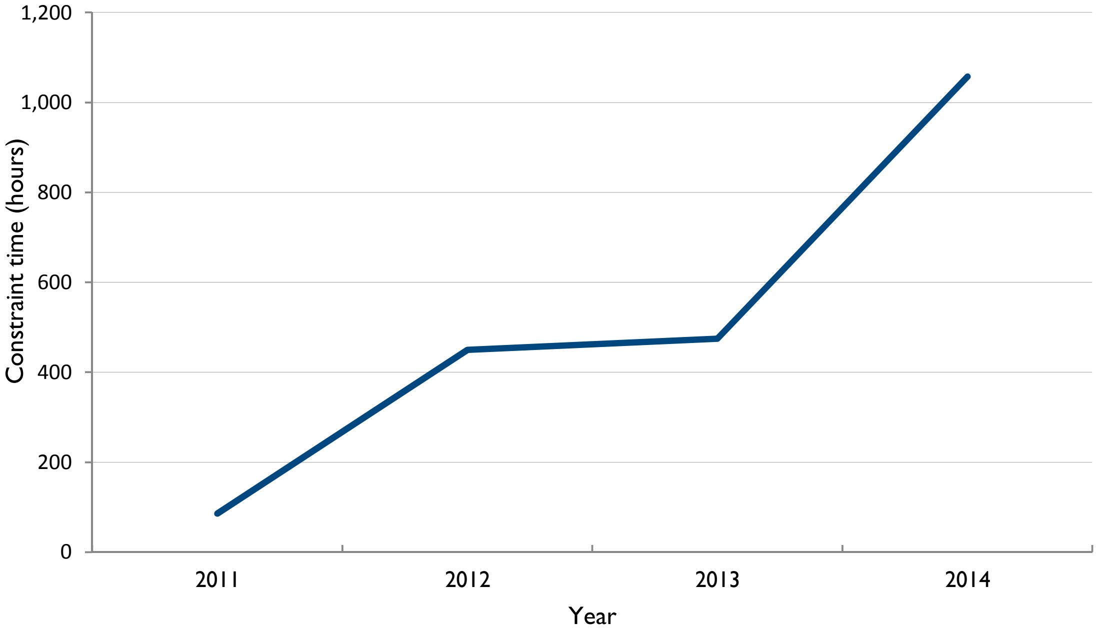
Figure 5.22 Historical Gladstone zone transmission delivered load duration curves



Constraints occur within the Gladstone zone under intact network conditions. The majority of these constraints are associated with maintaining flows within the continuous current rating of a 132kV feeder bushing within the Boyne Smelter Limited Substation. During the 2014 period, 1,057.58 hours were recorded against this constraint. 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.

Information pertaining to the historical duration of constrained operation due to this constraint is summarised in Figure 5.23. The trend is reflective of the operation of the two 132kV connected Gladstone Power Station units. During 2014, these units generated more energy than the prior three years.

Figure 5.23 **Historical Q>NIL_BI_FB constraint times**



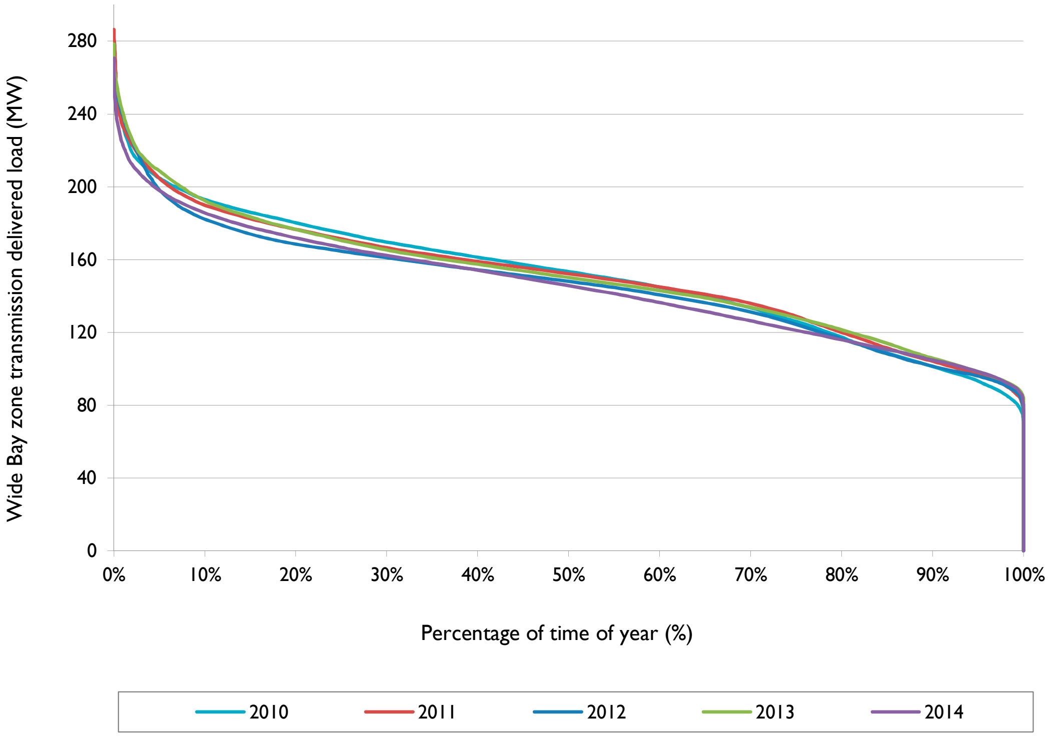
5.6.6 Wide Bay zone

The Wide Bay zone experienced no load loss for a single network element outage during 2014.

The Wide Bay zone includes the non-scheduled embedded Isis Central Sugar Mill as defined in Figure 2.3. This embedded generator provided approximately 17GWh during 2014.

Figure 5.24 provides historical transmission delivered load duration curves for the Wide Bay zone. Energy delivered from the transmission network has decreased by 3.3% between 2013 and 2014. The peak transmission delivered demand in the zone was 271MW which is below the highest peak demand over the last five years of 286MW set in 2011.

Figure 5.24 Historical Wide Bay zone transmission delivered load duration curves



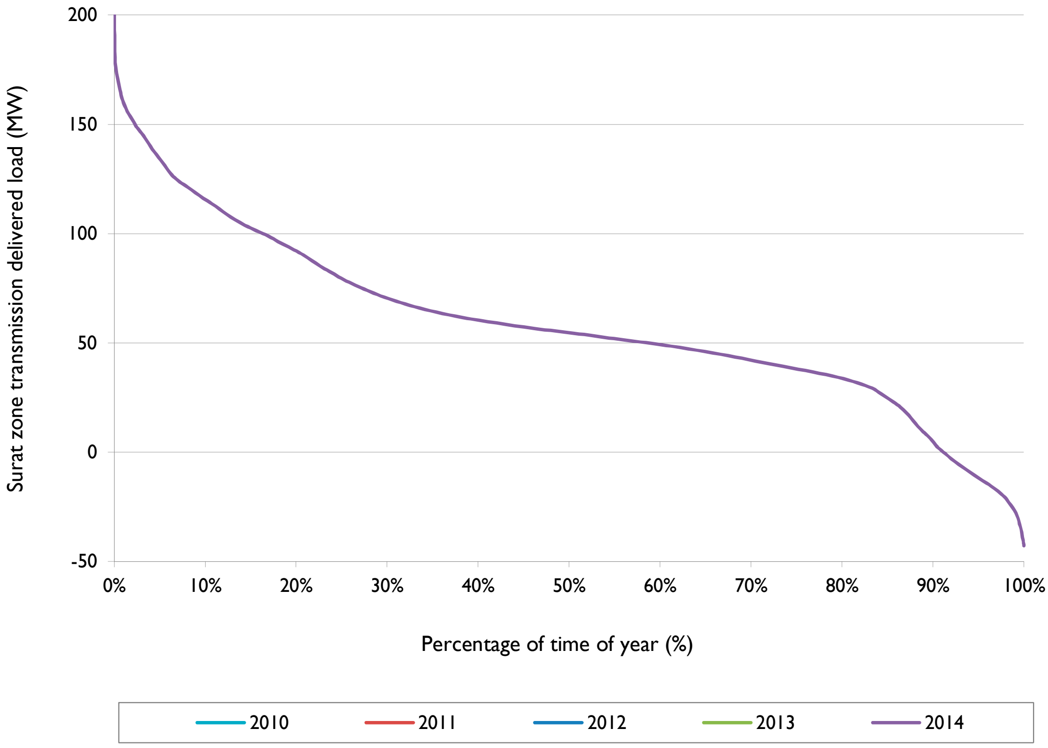
5.6.7 Surat zone

The Surat zone experienced no load loss for a single network element outage during 2014.

The Surat zone includes the scheduled embedded Roma generator as defined in Figure 2.3. This embedded generator provided approximately 212GWh during 2014.

The Surat zone was introduced in the 2014 TAPR, Figure 5.25 provides transmission delivered load duration curve for the 2014 year.

Figure 5.25 Historical Surat zone transmission delivered load duration curves

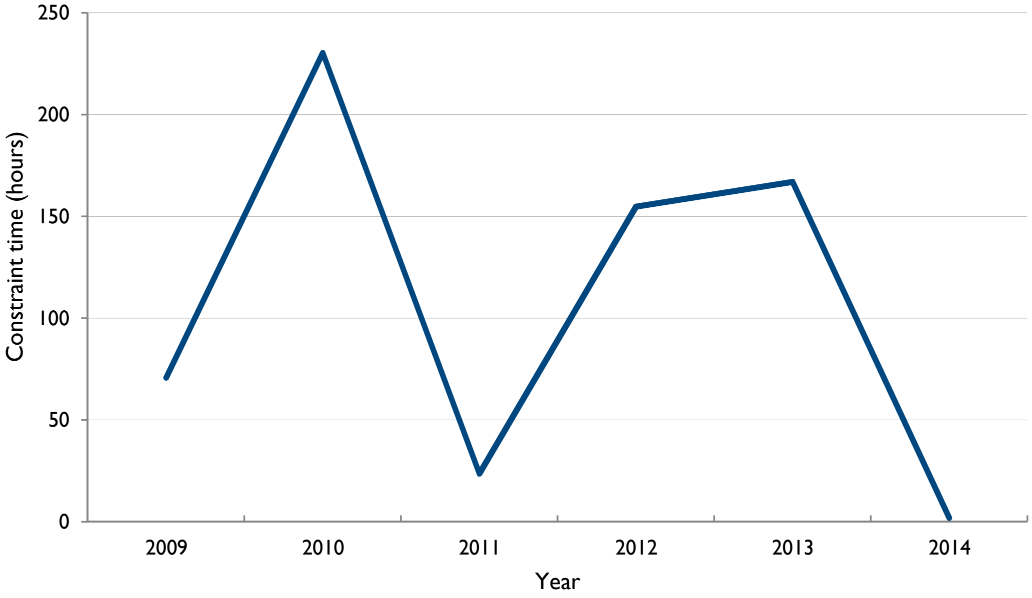


As a result of double circuit outages associated with lightning strikes, AEMO have included the Tarong to Chinchilla 132kV double circuit transmission line in the vulnerable list. This double circuit last tripped due to lightning in January 2014.

A runback scheme implemented in AEMO's NEMDE maximises the allowable generation from Roma and Condamine power stations whilst ensuring the transmission network is run within short-term ratings. The critical plant comprises Columboola to Chinchilla 132kV transmission lines and Tarong 275/132kV transformers. Constraints associated with this runback scheme applied for 1.92 hours in 2014. AEMO identify constraints associated with this runback scheme by constraint identifiers Q>NIL_TR_TX1_4, Q>NIL_CLBCN_CLBCN, Q>NIL_CLBCN7349 and Q>NIL_CLBCN_7350. These constraints were implemented in AEMO's market system from July 2009. Following the commissioning of Western Downs to Columboola 275kV double circuit transmission line flows on this 132kV network have significantly reduced and these constraints are not expected to be active.

Information pertaining to the historical duration of constrained operation due to these constraints is summarised in Figure 5.26.

Figure 5.26 Historical Q>NIL_TR_TXI_4, Q>NIL_CLBCN_CLBCN, Q>NIL_CLBCN7349 and Q>NIL_CLBCN_7350 constraint times



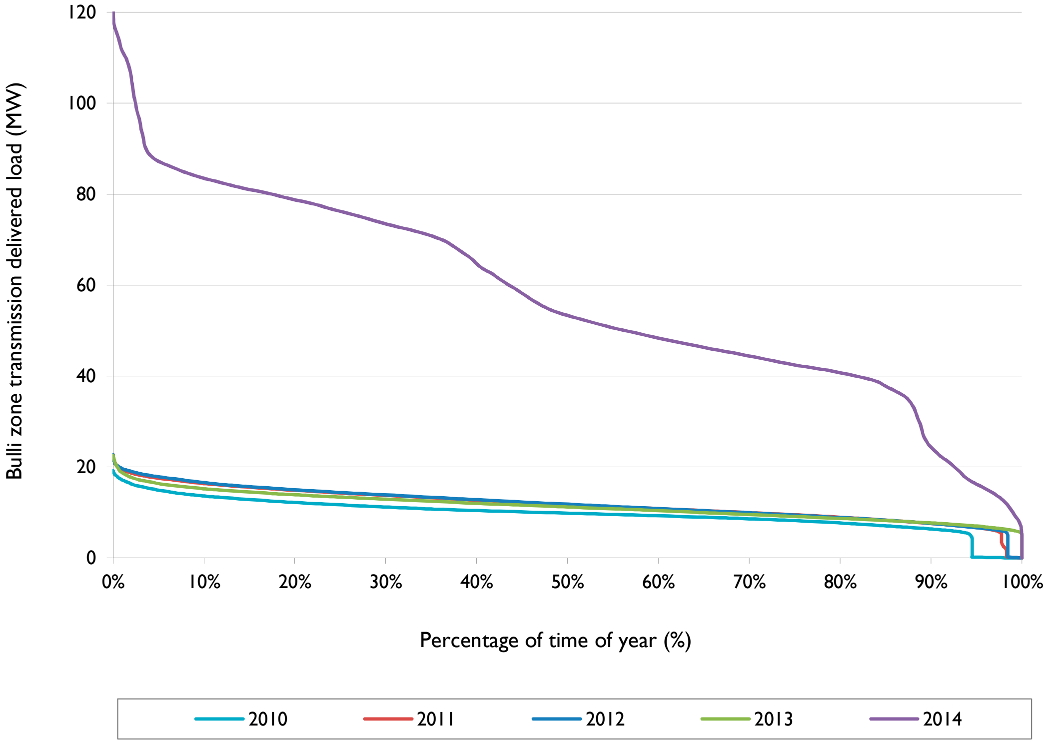
5.6.8 Bulli zone

The Bulli zone experienced no load loss for a single network element outage during 2014.

The Bulli zone contains no scheduled/semi-scheduled embedded generators or significant non-scheduled embedded generators as defined in Figure 2.3.

Figure 5.27 provides historical transmission delivered load duration curves for the Bulli zone. Energy delivered from the transmission network has increased by 401.8% between 2013 and 2014. The peak transmission delivered demand in the zone was 120MW. The significant increase is due to the connection of Kumbarilla Park a new substation in the zone.

Figure 5.27 Historical Bulli zone transmission delivered load duration curves



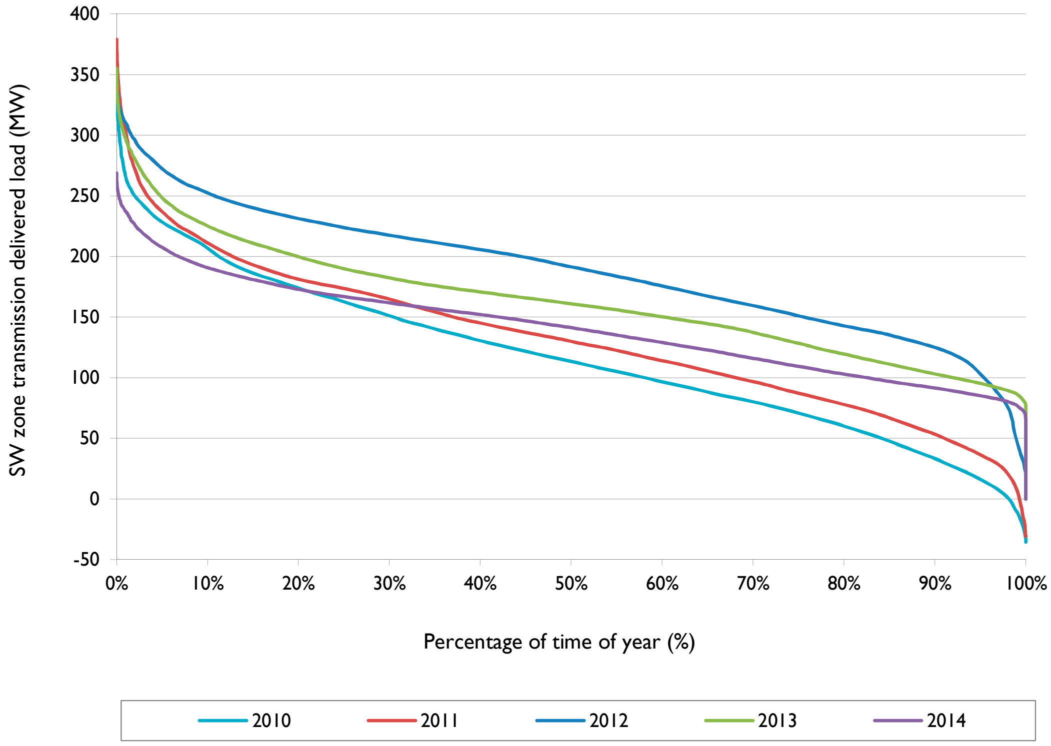
5.6.9 South West zone

The South West zone experienced no load loss for a single network element outage during 2014.

The South West zone includes the significant non-scheduled embedded Daandine generator as defined in Figure 2.3. This embedded generator provided approximately 242GWh during 2014.

Figure 5.28 provides historical transmission delivered load duration curves for the South West zone. Energy delivered from the transmission network has decreased by 13.3% between 2013 and 2014 due to the creation of the new Surat zone. The peak transmission delivered demand in the zone was 269MW.

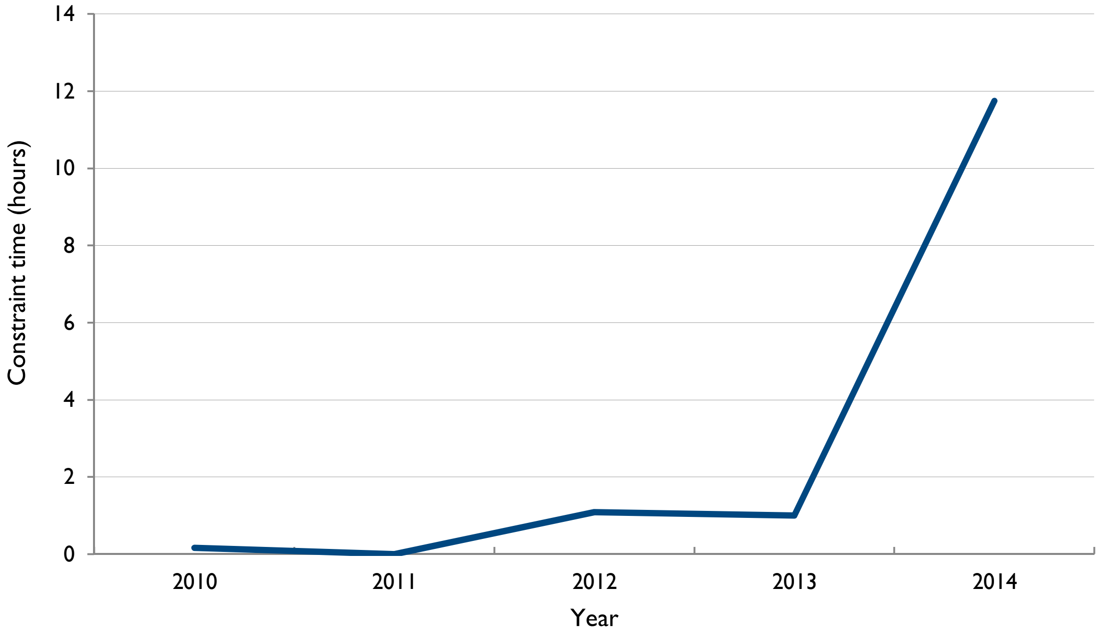
Figure 5.28 Historical South West zone transmission delivered load duration curves



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. During the 2014 period, 11.83 hours of constraints were recorded against this constraint. 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.

Information pertaining to the historical duration of constrained operation due to these constraints is summarised in Figure 5.29. The trend is reflective of the operation of the Oakey Power Station. During 2014, the Oakey Power Station generated more energy than the prior four years.

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



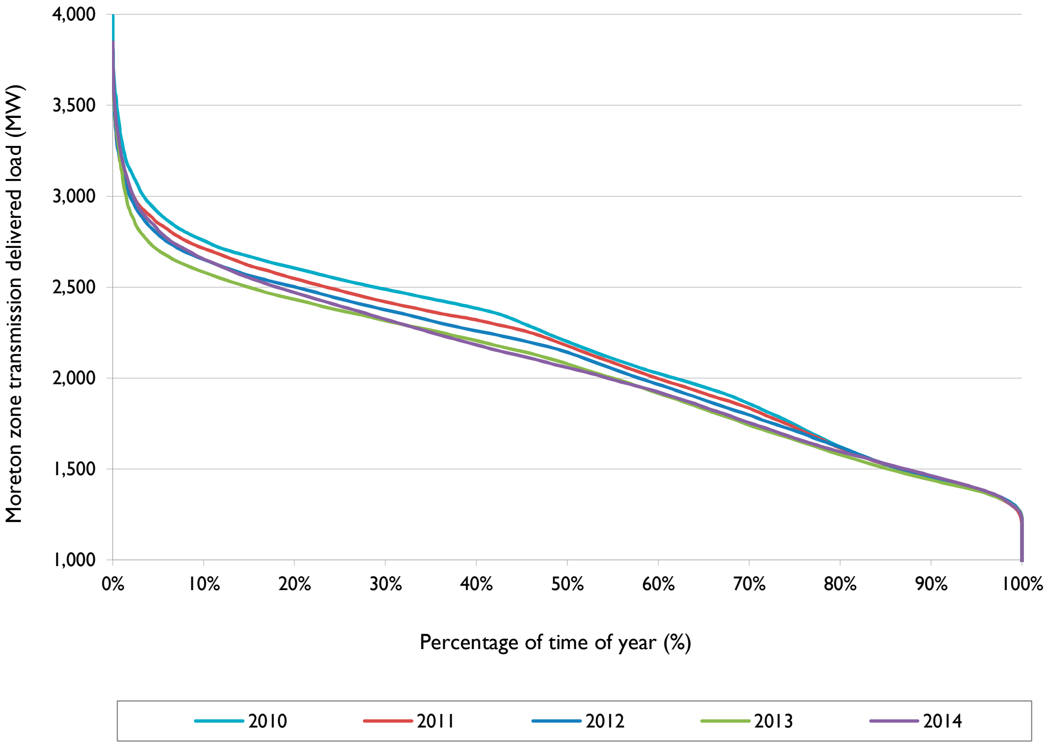
5.6.10 Moreton zone

The Moreton zone experienced no load loss for a single network element outage during 2014.

The Moreton zone includes the significant non-scheduled embedded generators Bromelton and Rocky Point as defined in Figure 2.3. These embedded generators provided approximately 103GWh during 2014.

Figure 5.30 provides historical transmission delivered load duration curves for the Moreton zone. Energy delivered from the transmission network has increased by 0.9% between 2013 and 2014. The peak transmission delivered demand in the zone was 3,710MW which is below the highest peak demand over the last five years of 3,992MW set in 2010.

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 South East Queensland. 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.

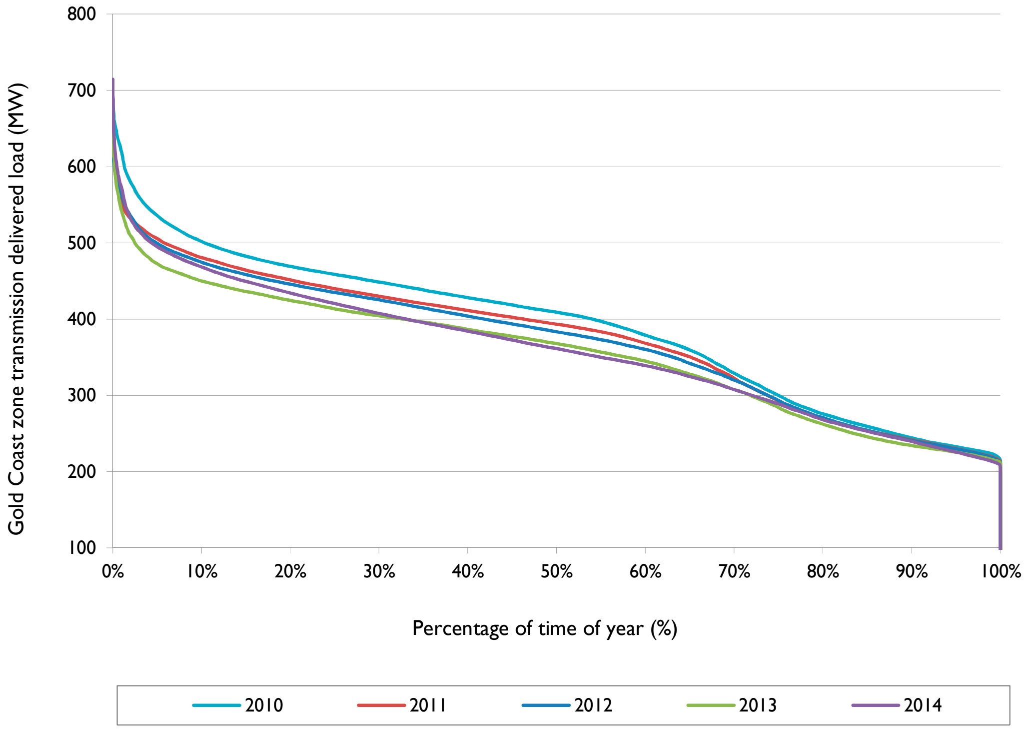
5.6.11 Gold Coast zone

The Gold Coast zone experienced no load loss for a single network element outage during 2014.

The Gold Coast zone contains no scheduled/semi-scheduled embedded generators or significant non-scheduled embedded generators as defined in Figure 2.3.

Figure 5.31 provides historical transmission delivered load duration curves for the Gold Coast zone. Energy delivered from the transmission network has increased by 1.1% between 2013 and 2014. The peak transmission delivered demand in the zone was 714MW which is the highest peak demand over the last five years for the zone.

Figure 5.31 Historical Gold Coast zone transmission delivered load duration curves



Chapter 6

Strategic planning

Chapter 6

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. The uncertain future 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 or retirement of large industrial and mining loads.

The 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. The 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 assets without replacement, extend technical life, initiate non-network alternatives, or replace assets with assets of a different type, configuration or capacity. The objective is not to automatically make 'like for like' replacements or to make individual asset investment decisions. Rather the objective is 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 of possible new large loads in Chapter 2 may have on the network. 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 horizon 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.

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 Surat Basin, Galilee Basin and Bowen 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 of new or withdrawn generation to maintain the supply demand balance for 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 (thermal and fault level ratings), voltage stability and/or transient stability. Options to address these limitations include network solutions, demand side management (DSM) and generation non-network solutions.

As the strategic outlook for non-network options is not able to be clearly determined, sections 6.2 and 6.3 focus on strategic network developments only. This should not be interpreted as predicting the outcome of the Regulatory Investment Test for Transmission (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.

Information on strategic network developments is limited to those required to address limitations that may emerge if the new large loads in Table 2.1 commit. Feasible network projects can range from incremental developments to large-scale projects capable of delivering significant increases in power transfer capability.

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, 6.2.2, 6.2.3 and 6.2.4. Consultation on the 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, and the committed network and non-network solutions described in sections 3.2 and 4.2.3, no additional capacity is forecast to be required as a result of network limitations within the five-year outlook period of this TAPR.

However, there have been several proposals for expansion or development of coal mines and upstream liquefied natural gas (LNG) processing load in the Bowen Basin and associated port expansions. The loads could be up to 500MW (refer to Table 2.1) and cause voltage and thermal limitations impacting network reliability on the transmission system upstream of their connection points. These loads have not reached the required development status to be included in the medium economic forecast for this TAPR.

These new loads within the Bowen Basin area would result in limitations on the 132kV transmission system. Thermal and voltage limitations may emerge during an outage of the Strathmore 275/132kV transformer, a 132kV circuit between Nebo and Moranbah substations, or the 132kV circuit between Lilyvale and Dysart substations (refer to Figure 4.2).

The impact of these loads on the Central Queensland to North Queensland (CQ-NQ) grid section and possible network solutions to address these is discussed in Section 6.2.3.

Possible network solutions

Feasible network solutions to address the limitations are dependent on the magnitude and location of load and may include one or more of the following options:

- 132kV capacitor bank at Proserpine Substation
- 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.

Further additional load, depending on location, may require the construction of additional transmission circuits into the Bowen Basin area. Feasible solutions may involve construction of 132kV transmission lines between the Nebo, Broadlea and Peak Downs areas. An additional 132kV transmission line may also be required between Moranbah and a future substation north of Moranbah.

6.2.2 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 1,000MW (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 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 transmission system. Possible network solutions to the resultant CQ-NQ limitations are discussed in Section 6.2.3.

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

Feasible network solutions to address the limitations are dependent on the magnitude and location of load and may include one or more of the following options:

- installation of capacitor bank/s at Lilyvale Substation
- third 275kV circuit between Broadsound and Lilyvale substations
- staged construction of a western 275kV transmission corridor as part of a broader development strategy.

6.2.3 Central Queensland to North Queensland grid section transfer limit

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

However, as discussed in sections 6.2.1 and 6.2.2 there have been proposals for large coal mine developments in the Galilee Basin and expansion or development of coal mines and upstream LNG processing load in the Bowen Basin and associated port expansions. The loads could be up to 1,500MW (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[1] or 275kV circuit supplying northern Queensland.

As generation costs are higher in northern Queensland due to reliance on liquid fuels, it may be economic due to positive net market benefits to augment the transmission network ahead of its reliability timing.

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 circuit.

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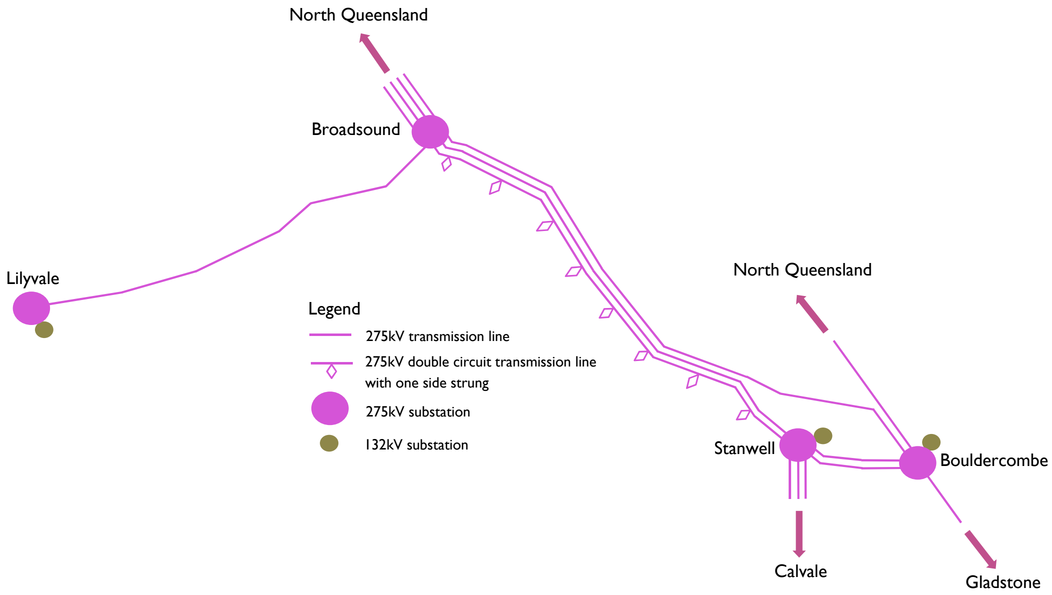
[1] Trip of the Townsville gas turbine can be a critical contingency if operating at high levels of power generation (refer to Appendix D).

Figure 6.1 Stanwell/Broadsound area transmission network



Following this augmentation, voltage and thermal limitations may emerge depending on new mining or industrial load developments. Feasible solutions to address the emerging limitations could vary depending on the size and location of load that commits and the size, location and type of generation, if new generation is required, to maintain an appropriate supply demand balance in the Queensland region.

Feasible network solutions to emerging voltage limitations may involve the installation of capacitor banks and/or a static VAr compensator (SVC) at existing northern Queensland substations. Depending on the location of the additional loads, capacitor banks may be required at Broadsound, Lilyvale and Nebo substations. If the voltage stability limitations require dynamic reactive compensation, then an SVC may be installed at Broadsound Substation.

For higher levels of load, feasible network solutions may include installation of series capacitors and/or the construction of new transmission lines.

Series capacitors on the Stanwell to Broadsound and Broadsound to Nebo circuits would reduce the effective series impedance of the circuits and increase the thermal[2], voltage and transient stability limits. A component of the series capacitors would be thyristor controlled. The Thyristor Controlled Series Capacitor (TCSC) mitigates the risk of subsynchronous resonance with nearby generator shaft systems.

The construction of new transmission lines between Stanwell and Broadsound substations and between Broadsound and Nebo substations would also increase the thermal, voltage stability and transient stability limits.

An alternative to augmenting the existing transmission corridor north of Stanwell is to establish a western 275kV corridor. This transmission line could ultimately connect Calvale and Lilyvale substations, via Blackwater Substation. The new corridor could be developed in stages and operated initially at 132kV. This western corridor has the following strategic benefits:

- diversifies CQ-NQ transmission infrastructure
- provides additional transmission capability directly to where future loads may connect
- defers or removes the need to augment the transmission capability between Broadsound and Lilyvale substations (refer to Section 6.2.2).

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[2] The thermal capacity could be increased by better sharing the available thermal capacity of the circuits that make up the grid section during contingency events.

The economic merits of establishing this western 275kV corridor should be assessed taking into account the asset management strategies for the existing transmission lines north of Calvale and Calliope River substations. The existing network north of Calvale and Calliope River substations contain several low capacity 132kV and 275kV transmission lines that are nearing the end of technical life. The cost of line refits to manage risks associated with allowing these lines to remain in-service and/or the cost of transmission augmentations required to meet reliability standards following the retirement of any assets approaching end of technical life should be taken into account in a holistic assessment.

6.2.4 Surat Basin north west area

Based on the medium economic forecast defined in Chapter 2, and the commissioned transmission developments and committed and under construction connection works described in Section 3.2, network limitations impacting reliability are not forecast to occur within the five-year outlook period of this TAPR.

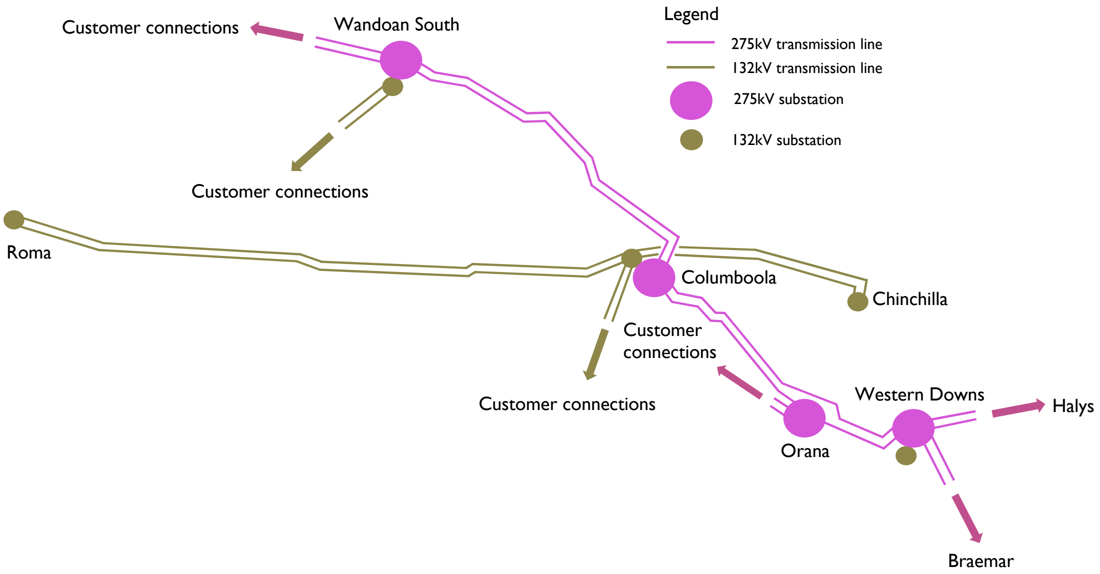
However, there have been several proposals for additional LNG upstream processing facilities and new coal mining load in the Surat Basin north west area. These loads have not reached the required development status to be included in the medium economic forecast for this TAPR. The loads could be up to 400MW (refer to Table 2.1) and cause voltage and thermal limitations impacting network reliability on the transmission system upstream of their connection points.

Depending on the location and size of additional load, voltage and thermal limitations may emerge in the Surat Basin north west area. The critical contingency is an outage of one of the 275kV circuits supplying the Surat Basin north west area between Western Downs and Orana/Columboola substations and between Columboola and Wandoan South substations.

Possible network solutions

Feasible network solutions to emerging voltage limitations may involve the installation of capacitor banks and/or an SVC within the Surat Basin north west area. For high levels of load, thermal limitations may emerge across one or both of the 275kV circuit sections from Western Downs to Wandoan South via Orana and Columboola substations (refer to Figure 6.2).

Figure 6.2 Surat Basin north west area transmission network



A feasible network solution to thermal limitations may involve the construction of a third 275kV circuit between Western Downs and Columboola substations and between Columboola and Wandoan South substations.

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 decisions will need to be made in the next five to 10-year period and where there may be opportunities for network reconfiguration. Information on reinvestment decisions within the current five-year outlook period of this TAPR is detailed in Section 4.2.

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

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

Powerlink will also continue to investigate opportunities for reconfiguration in other parts of the network as demand and generation scenarios evolve.

Reinvestment decisions in these areas plan 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 these associated risks. These 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 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 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, 6.3.2 and 6.3.3.

6.3.1 Ross zone

The network between Collinsville and Townsville has developed over many years. It comprises of a 132kV network and a 275kV network which operate in parallel. The 132kV lines are approaching end of technical life between 2019 and 2028, while the earliest end of technical life trigger for the 275kV lines is beyond the 10-year outlook period of this TAPR.

Powerlink is investigating options to ensure that the condition based risks associated with these 132kV lines are managed. Options include ongoing maintenance, asset retirement, line refit and rebuild. Based on the medium economic forecast in Chapter 2 there are a number of technically feasible options for the retirement of certain 132kV transmission line assets within this area.

The condition based risks for the single circuit 132kV lines between Townsville South and Clare South substations may need to be addressed within the five-year outlook period of the TAPR (refer to Section 4.2.2). One option will be to refit the single circuit 132kV line between Townsville South, Invicta Tee and Clare South substations and decommission the inland single circuit transmission line between Townsville South and Clare South substations with the associated installation of a capacitor bank at Proserpine Substation (refer to Figure 4.1).

Further condition based risks emerge on the double circuit 132kV line between Clare South and Collinsville North substations within the five to 10-year outlook period of this TAPR. Powerlink is investigating options to ensure that the associated condition based risks are managed appropriately. The current options being considered include refitting of these circuits or network reconfiguration.

Reinvestment in the double circuit transmission line may involve structural refit of the towers and tower painting. This line refit is likely to be required within the five to 10-year outlook period of this TAPR. However, reconfiguration options allow the majority of the double circuit transmission line to remain in-service to the end of technical life. Reconfiguration options therefore defer the reinvestment need compared to the line refit option which is performed approximately five years prior to the end of technical life.

A potential reconfiguration option consists of:

- a line refit of Collinsville North to King Creek substations
- decommission the circuit section between King Creek to Clare South substations
- install second 275/132kV transformer at Strathmore Substation[3]
- establish 275kV injection into Clare South Substation[4].

As discussed in Section 6.2.1 voltage and thermal limitations may emerge within the 132kV network supplying the Bowen Basin area if additional load commits within the area. Depending on the magnitude and location of this additional load a feasible network solution may involve the installation of a second 275/132kV transformer at Strathmore Substation. If the timing of this load driven limitation is prior to the reinvestment trigger, then the cost of the reconfiguration option is reduced relative to the refit option.

6.3.2 Central West and Gladstone zones

Section 4.2.4 identifies that within the five-year outlook period of the TAPR the condition based risks for the 132kV lines between Callide, Biloela and Moura substations will need to be addressed. These transmission lines will likely be rebuilt on newly acquired easements.

Within the five to 10-year period of this TAPR further condition based risks emerge on the double circuit 132kV line between Callide and Gladstone South substations. Powerlink is investigating options to ensure that the condition based risks are managed. The current options considered consist of refitting these circuits or decommissioning of this double circuit line with possible network reconfiguration.

Decommissioning the 132kV double circuit line between Callide and Gladstone South substations may impact reliability of supply to the Central West zone (particularly Biloela and Moura substations). With these circuits removed from service the critical contingency impacting reliability of supply to the Central West zone is an outage of the single 275/132kV transformer at Calvale Substation. A network option that addresses the impact on the supply reliability is the installation of a second 275/132kV transformer at Calvale Substation. The timing of this network investment will be assessed against the amended planning standard and subsequent demand forecasts.

The 132kV double circuit line operates in parallel with the 275kV Gladstone grid section. The removal of these circuits from service may therefore impact on the efficient delivery of market dispatch outcomes. Installation of a second Calvale 275/132kV transformer will not deliver more capacity across the Gladstone grid section. Recovering the lost capacity (or adding additional power transfer capacity) could be achieved by establishing new transmission assets between the Central West and Gladstone zones and/or investment within the Gladstone zone. Quantifying the impact that decommissioning these circuits will have on the relevant classes of market benefits will be performed as part of making the investment decision.

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[3] Required to deliver reliability of supply to the Proserpine and Bowen Basin areas with the loss of voltage support when the 132kV connection to Townsville South is removed.

[4] Required to deliver reliability of supply to Clare South Substation following the decommissioning of the double circuit transmission line between King Creek and Clare South substations.

6.3.3 Central Queensland to South Queensland grid section

Up to three single circuit 275kV transmission lines operate in parallel 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. Based on condition assessment most of these 275kV single circuit lines will reach end of technical life in the five to 10-year outlook period of the TAPR. The remainder of the circuits will be at end of technical life soon thereafter.

The 275kV lines at the northern end[5] of this coastal corridor are currently tracking to a higher rate of corrosion and it is expected that the risks associated with these lines will exceed acceptable levels by approximately 2022. 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 heavily polluted industrial area.

In response, Powerlink is investigating options to ensure that the condition based risks related to these lines remaining in-service are acceptable. These options include ongoing maintenance, line retirement, line refit and rebuild.

With the current demand forecast and the connection of additional generation in southern Queensland[6] the reliance on the CQ-SQ corridor to deliver efficient market outcomes and reliability of supply to south Queensland is forecast to remain low. As a result, it is likely that it will be economic and prudent for some level of reconfiguration of the CQ-SQ coastal corridor. Therefore, a number of technically feasible options for retirement of transmission line assets are being investigated as part of a CQ-SQ coastal corridor strategic plan.

One option being considered is a staged line refit of a sub-set of the existing single circuit transmission lines between Calliope River and South Pine substations. The timing of this reinvestment in the existing assets will be over the next five to 10-year period.

An alternative option is to allow the existing circuits to remain in-service until end of technical life. This would allow a staged rebuild of the coastal corridor as a new double circuit 275kV transmission line. This staged rebuild would occur over the next 10 to 20-year period.

The timing of investment is different for these two options. In addition, the maximum secure CQ-SQ power transfer capability of the two options is also different. Further updates of the electricity demand forecast and generation outlook will occur prior to quantifying the impact that the two potential options will have on the relevant classes of market benefits.

6.4 Supply demand balance

The outlook for the supply demand balance for the Queensland region was published in the AEMO 2014 Electricity Statement of Opportunities (ESOO). As part of the normal annual planning cycle, AEMO will publish a revised outlook in the 2015 ESOO in August 2015. 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).

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[5] In particular the 275kV single circuit transmission line between Calliope River and Wurdong substation

[6] Braemar 1, Braemar 2, Darling Downs, and Kogan power stations.

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 major 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 at the time.

The most recent assessment was carried out as part of the joint Powerlink and TransGrid regulatory consultation process commencing in late 2012. The formal consultation process was finalised in December 2014 following the publication of the QNI Upgrade Project Assessment Conclusions Report (PACR) and completion of the mandatory consultation period.

This economic assessment concluded that there were market benefits arising from an upgrade of the interconnector. The main source of market benefits was due to the displacement of relatively higher cost generating plant located in the Queensland region with lower cost generating sources from the southern states. However, the analysis found that the optimal timing and ranking of QNI upgrade options varied considerably across different market development scenarios, with a number of options having negative net market benefits across several of the scenarios. The assessment found that there was no upgrade option which was consistently and robustly ranked above the "do nothing" option for the majority of the scenarios.

In light of uncertainties, Powerlink and TransGrid considered it prudent not to recommend a preferred upgrade option, and to continue to monitor market developments to determine if any material changes could warrant reassessment of an upgrade to QNI.

As part of the most recent QNI upgrade regulatory consultation process, Powerlink and TransGrid also provided information on the technical requirements for potential non-network options which may be capable of increasing the transfer capability across the interconnector and hence deliver market benefits. Although the formal consultation period for the QNI upgrade RIT-T has now closed, Powerlink and TransGrid encourage participants to express their interest if they are able to offer potential non-network solutions[7]. 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).

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[7] Information on non-network solutions maybe found at QNI Upgrade consultation.

Appendices

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 peak demand

Connection point	Voltage (kV)	Zone	2015/16		2016/17		2017/18		2018/19		2019/20		2020/21		2021/22		2022/23		2023/24		2024/25(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	23	7	23	7	24	7	24	7	25	7	26	7	26	8	28	8	28	8	28	8
Aligator Creek (Louisa Creek)	132	N	41	8	40	8	40	8	39	8	39	8	39	8	39	8	40	8	39	8	39	8
Alligator Creek	33	N	32	11	32	10	32	10	32	11	33	11	33	11	33	11	34	11	34	11	34	11
Biloela	66	CW	31	2	31	2	31	2	31	2	32	2	32	2	32	2	32	2	32	2	32	2
Blackwater	132	CW	43	0	42	0	42	0	41	0	42	0	41	0	41	0	42	0	41	0	41	0
Blackwater	66	CW	99	25	99	25	97	25	97	25	98	25	97	25	97	25	99	25	98	25	97	25
Bowen North	66	R	22	5	22	5	23	6	23	5	24	6	24	6	24	6	25	6	24	6	24	6
Bulli Creek (Waggamba)	132	B	22	2	21	2	21	2	21	2	21	2	21	2	21	2	22	2	22	2	22	2
Cairns	22	FN	55	0	54	0	53	0	53	0	53	0	53	0	53	0	54	0	53	0	52	-2
Cairns City	132	FN	45	-4	45	-4	44	-4	44	-4	44	-4	43	-4	43	-4	44	-4	43	-4	43	-5
Calliope River	132	G	64	7	62	7	62	6	60	6	61	6	62	6	62	6	63	6	64	7	64	6
Cardwell	22	R	5	0	5	0	5	0	5	0	5	0	5	0	5	0	5	0	5	0	5	0
Chinchilla	132	SW	22	8	22	8	22	8	23	8	23	8	23	8	24	8	25	8	25	9	25	9
Clare South	66	R	74	23	73	22	72	22	71	21	71	21	71	21	71	21	72	22	71	21	70	21
Collinsville North	33	N	19	4	19	4	19	4	19	4	19	4	20	4	20	4	21	4	21	4	21	4
Columboola	132	SW	92	2	92	3	96	3	96	3	98	3	98	4	100	4	103	4	103	4	103	4
Dan Gleeson	66	R	108	23	107	23	102	20	103	20	105	21	105	21	106	21	110	22	109	22	109	22
Dysart	66	CW	42	9	62	11	61	11	61	11	61	11	61	11	61	11	62	11	61	11	61	10
Edmonton	22	FN	44	1	44	1	45	1	46	1	47	-1	48	-1	49	-1	51	-1	51	-1	52	-1
Egans Hill	66	CW	54	8	54	8	54	8	55	8	56	9	56	9	57	9	59	10	59	10	59	10
El Arish	22	FN	4	0	4	0	5	0	5	0	5	0	5	0	5	0	6	0	6	0	6	0

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

Connection point	Voltage (kV)	Zone	2015/16		2016/17		2017/18		2018/19		2019/20		2020/21		2021/22		2022/23		2023/24		2024/25(1)	
			MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Garbutt	66	R	110	23	110	23	104	21	105	21	107	21	107	22	109	22	112	23	112	23	112	23
Gin Gin	132	WB	100	0	99	-1	98	-1	98	-1	99	0	98	0	99	0	101	0	100	0	99	0
Gladstone South	66	G	123	23	124	23	127	24	129	25	132	25	134	26	136	26	141	27	142	27	143	27
Ingham	66	R	15	-1	15	-1	15	-1	15	-1	15	-1	15	-1	15	-1	15	-1	15	-1	15	-1
Innisfail	22	FN	24	-1	24	-1	23	-1	23	-1	23	-1	23	-1	23	-1	23	-1	23	-1	23	-1
Kamerunga	22	FN	58	-3	58	-3	58	-3	59	-3	61	-2	62	-2	63	-2	65	-2	65	-2	66	-2
Lilyvale (Barcaldine and Clermont)	132	CW	42	7	41	7	41	7	41	7	42	7	42	7	42	7	43	7	43	7	43	7
Lilyvale	66	CW	173	31	177	31	175	30	176	30	177	31	176	31	177	31	181	32	179	31	177	31
Mackay	33	N	93	16	91	16	90	16	90	15	91	16	91	16	91	16	94	16	93	16	92	16
Middle Ridge	110	SW	226	50	224	50	223	49	225	49	228	50	229	50	231	51	238	52	238	52	237	52
Middle Ridge (Postmans Ridge)	110	M	11	3	11	3	11	3	11	3	11	3	11	3	11	3	11	3	11	3	11	3
Moranbah (Broadlea)	132	N	35	6	35	6	35	6	35	6	35	6	39	7	39	7	40	7	39	7	39	7
Moranbah	66 and 11	N	133	29	131	27	158	35	158	35	157	35	156	34	156	34	156	34	156	34	156	34
Moura	66	CW	58	15	57	15	57	14	57	14	58	15	58	15	58	15	59	15	59	15	58	15
Nebo	11	N	4	1	4	1	4	1	4	1	4	1	4	1	4	1	4	1	4	1	4	1
Newlands	66	N	37	11	37	11	36	11	36	11	36	11	36	11	35	11	36	11	36	11	35	10
Oakey	110	SW	21	5	21	5	21	5	22	5	22	5	22	5	22	5	23	5	23	5	23	5
Pandoin	66	CW	40	6	41	6	41	6	41	6	42	6	42	7	43	7	44	7	44	7	44	7
Pioneer Valley	66	N	70	12	71	12	71	12	73	12	75	12	77	12	79	12	82	13	83	13	85	13

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

Connection point	Voltage (kV)	Zone	2015/16		2016/17		2017/18		2018/19		2019/20		2020/21		2021/22		2022/23		2023/24		2024/25(1)	
			MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Proserpine	66	N	54	14	53	14	53	14	53	14	53	14	53	14	54	14	55	14	55	14	54	14
Rockhampton	66	CW	90	13	90	13	90	13	91	14	93	14	94	15	95	15	98	16	98	16	98	16
Ross (Kidston, Milchester and Georgetown)	132	R	35	1	35	1	40	2	40	2	40	2	40	2	40	2	41	2	41	2	40	2
Stoney Creek	132	N	5	1	5	1	5	1	5	1	5	1	5	1	4	1	5	1	5	1	4	0
Tangkam	110	SW	31	14	32	14	32	14	32	14	32	14	32	14	33	14	34	15	34	15	34	14
Tarong	66	SW	39	12	38	11	38	11	38	11	39	12	39	12	44	14	45	14	44	14	44	14
Teebar Creek (Isis and Maryborough)	132	WB	171	20	169	20	167	19	167	19	169	20	168	19	169	20	173	21	172	20	170	20
Townsville East	66	R	47	10	46	10	44	9	45	9	45	9	46	9	46	9	48	10	47	10	47	10
Townsville South	66	R	100	21	99	21	95	19	95	19	97	19	98	20	99	20	102	21	102	21	102	21
Tully	22	R	15	1	15	1	15	1	15	1	15	1	15	1	15	1	15	1	15	1	15	1
Turkinje (Craiglie and Lakeland)	132	FN	21	4	20	4	20	3	20	3	20	3	20	3	20	3	20	4	20	3	20	3
Turkinje	66	FN	54	1	54	1	53	1	53	1	54	0	54	0	54	1	55	1	55	1	54	1
Woolooga (Kilkivan)	132	WB	22	-2	22	-2	21	-2	21	-2	21	-2	21	-2	21	-2	22	-2	21	-2	21	-2
Woree (Cairns North)	132	FN	37	-1	37	-1	37	-1	37	-1	38	-1	38	-1	38	-1	39	-1	39	-1	39	-1
Yarwun (Boat Creek)	132	G	47	17	46	17	45	17	52	18	52	18	52	17	51	17	52	18	52	18	51	17
Hail Creek and King Creek	Various	N	37	6	37	5	36	5	36	5	36	5	36	5	36	5	36	5	36	5	35	5

Note:

(1) Connection point loads for summer 2024/25 have been extrapolated.

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

Connection point	Voltage (kV)	Zone	2015		2016		2017		2018		2019		2020		2021		2022		2023		2024	
			MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Alan Sherriff	132	R	21	6	22	6	21	6	22	6	22	6	23	6	24	7	24	7	26	7	26	7
Alligator Creek (Louisa Creek)	132	N	41	9	41	9	38	9	39	9	39	9	39	9	39	9	39	9	40	9	39	9
Alligator Creek	33	N	31	6	31	6	29	6	30	6	30	6	30	6	30	6	30	6	31	6	30	6
Biloela	66	CW	32	1	30	1	28	1	29	1	29	1	30	1	30	1	30	1	31	1	30	1
Blackwater	132	CW	47	-1	47	-1	44	-1	45	-1	44	-1	45	-1	45	-1	44	-1	46	-1	44	-1
Blackwater	66	CW	98	17	101	19	96	18	98	18	97	18	99	18	99	18	98	18	101	19	99	18
Bowen North	66	R	29	5	33	6	32	6	34	7	34	7	38	8	37	8	37	8	38	8	37	8
Bulli Creek (Waggamba)	132	B	24	1	24	1	23	1	24	1	24	1	25	1	25	1	25	1	26	1	26	1
Cairns	22	FN	55	-4	55	-4	51	-5	52	-5	52	-5	53	-5	53	-5	52	-5	54	-4	52	-5
Cairns City	132	FN	42	-2	42	-1	39	-2	40	-2	40	-2	40	-2	40	-2	40	-2	41	-2	40	-2
Calliope River	132	G	60	-2	60	-2	56	-1	57	-1	57	-1	58	-1	59	-2	59	-2	61	-2	60	-2
Cardwell	22	R	4	0	5	0	4	0	4	0	4	0	5	0	5	0	5	0	5	0	5	0
Chinchilla	132	SW	18	4	18	4	17	3	18	3	18	3	18	4	18	4	18	4	19	4	19	4
Clare South	66	R	52	19	52	19	49	17	50	18	49	18	50	18	50	18	49	18	51	18	50	18
Collinsville	33	N	24	3	25	3	24	3	24	3	25	3	25	3	26	3	26	3	27	4	27	4
Columboola	132	SW	89	-6	91	-6	87	-6	94	-5	95	-5	98	-5	101	-5	102	-5	107	-5	106	-5
Dan Gleeson	66	R	105	30	107	31	102	29	99	28	100	28	103	29	105	29	106	30	111	31	110	31
Dysart	66	CW	43	5	44	5	60	6	61	6	61	6	62	6	62	6	62	6	64	6	63	6
Edmonton	22	FN	33	1	34	1	32	1	33	1	33	1	33	1	34	1	34	1	35	1	34	1
Egans Hill	66	CW	46	9	47	8	44	11	46	10	46	10	47	10	47	10	47	10	49	8	48	10
El Arish	22	FN	3	0	3	0	3	0	3	0	3	0	3	0	3	0	3	0	3	0	3	0
Garbutt	66	R	95	27	97	28	92	26	90	25	91	25	94	26	95	27	96	27	101	28	100	28

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

Connection point	Voltage (kV)	Zone	2015		2016		2017		2018		2019		2020		2021		2022		2023		2024	
			MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Gin Gin	132	WB	69	-4	70	-4	65	-4	67	-4	66	-4	67	-4	67	-3	67	-3	69	-3	68	-3
Gladstone South	66	G	66	8	68	8	66	8	68	8	69	8	71	9	72	9	72	9	76	9	75	9
Ingham	66	R	14	-1	14	-1	13	-1	13	-1	13	-1	14	-1	14	-1	13	-1	14	-1	14	-1
Innisfail	22	FN	26	0	26	0	24	-1	25	-1	25	-1	25	-1	25	-1	25	-1	26	-1	25	-1
Kamerunga	22	FN	47	-3	48	-3	45	1	46	1	46	1	47	1	47	-3	47	-3	49	-3	48	-3
Lilyvale Barcaldine and Clermont)	132	CW	38	6	39	6	36	5	37	6	37	5	38	6	38	6	38	6	39	6	39	6
Lilyvale	66	CW	203	28	205	28	199	27	205	28	204	27	208	28	208	28	207	28	214	29	209	28
Mackay	33	N	78	12	80	8	74	12	76	12	76	12	77	12	78	12	77	12	80	8	78	12
Middle Ridge	110	SW	226	28	229	28	215	27	221	27	221	27	226	28	227	28	227	28	236	29	232	29
Middle Ridge (Postmans Ridge)	110	M	14	1	14	1	13	1	13	1	13	1	13	1	13	1	13	1	13	1	13	1
Moranbah (Broadlea)	132	N	54	9	54	9	52	9	53	9	52	9	57	9	61	9	60	9	62	9	60	9
Moranbah	66 and 11	N	126	28	125	28	137	30	150	33	150	33	149	33	148	33	148	33	148	33	148	33
Moura	66	CW	61	11	62	11	58	10	60	11	60	11	62	11	62	11	62	11	64	12	63	11
Nebo	11	N	3	0	3	0	3	0	3	0	4	0	4	0	4	0	4	0	4	0	4	0
Newlands	66	N	41	9	41	9	38	8	39	8	38	8	39	9	39	8	39	8	40	9	39	8
Oakey	110	SW	22	4	23	4	21	4	22	4	21	4	22	4	22	4	21	4	22	4	22	4
Pandoin	66	CW	39	8	40	7	37	10	38	8	39	8	40	9	40	9	40	9	42	7	41	8
Pioneer Valley	66	N	59	8	61	9	59	8	62	8	63	9	66	9	67	9	68	9	73	10	73	10
Proserpine	66	N	39	5	39	5	37	5	38	5	38	5	39	5	39	5	39	5	40	5	39	5

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

Connection point	Voltage (kV)	Zone	2015		2016		2017		2018		2019		2020		2021		2022		2023		2024	
			MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Rockhampton	66	CW	82	17	84	14	79	20	81	18	82	18	84	18	84	19	84	18	88	15	86	17
Ross (Kidston, Milchester and Georgetown)	132	R	43	3	43	3	41	3	48	3	48	3	49	3	49	3	49	3	51	4	50	3
Stoney Creek	132	N	30	16	30	16	28	15	28	15	28	15	29	16	28	15	28	15	29	16	28	15
Tangkam	110	SW	47	15	49	15	46	14	47	15	48	15	49	15	49	15	49	15	51	16	51	15
Tarong	66	SW	38	9	38	9	36	9	37	9	37	9	37	9	42	10	42	10	43	10	43	10
Teebar Creek (Isis and Maryborough)	132	WB	199	18	201	18	188	19	192	17	191	19	195	17	195	17	194	19	201	18	196	17
Townsville East	66	R	43	12	44	13	42	12	41	12	41	12	43	12	43	12	44	12	46	13	46	13
Townsville South	66	R	95	27	98	28	93	26	90	25	91	26	95	27	96	27	97	27	102	29	101	29
Tully	22	R	11	0	11	0	10	0	10	0	10	0	11	0	11	0	10	0	11	0	10	0
Turkinje (Craiglie and Lakeland)	132	FN	19	2	20	2	18	2	19	2	19	2	19	2	19	2	19	2	20	2	19	2
Turkinje	66	FN	49	-2	50	-2	46	-3	47	-2	47	-2	48	-2	48	-2	48	-2	50	-2	48	-2
Woolooga (Kilkivan)	132	WB	31	-8	31	-8	29	-7	29	-8	29	-7	29	-8	29	-8	29	-7	30	-8	29	-8
Woree (Cairns North)	132	FN	32	-4	32	-4	30	-4	31	-4	31	-4	32	-4	32	-4	32	-4	33	-4	33	-4
Yarwun (Boat Creek)	132	G	49	14	49	14	46	13	54	14	53	14	54	14	54	14	54	14	55	14	54	14
Hail Creek and King Creek	110 and 132	N	38	5	39	5	36	5	37	5	36	5	37	5	37	5	36	5	38	5	37	5

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

Connection point	Voltage (kV)	Zone	2015/16		2016/17		2017/18		2018/19		2019/20		2020/21		2021/22		2022/23		2023/24		2024/25	
			MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Abermain	110	M	52	15	53	16	53	16	54	16	54	16	54	16	55	17	55	17	56	17	57	17
Abermain	33	M	87	29	89	30	91	31	92	31	94	33	95	33	96	33	97	34	99	35	100	35
Algester	33	M	65	16	66	16	67	11	67	17	66	17	67	11	67	11	67	11	68	11	68	11
Ashgrove West	110	M	153	30	163	32	168	30	170	31	171	30	175	30	177	31	180	32	184	34	186	35
Ashgrove West	33	M	65	17	66	17	66	17	66	17	66	17	66	17	66	17	67	17	67	18	67	12
Belmont	110	M	434	82	440	84	452	90	457	88	460	84	462	80	465	81	471	84	478	87	484	84
Blackstone (Raceview)	110	M	88	19	90	20	91	21	94	21	94	21	95	22	95	22	96	22	97	22	82	21
Bundamba	110	M	35	3	35	3	36	4	36	4	36	4	36	4	36	4	37	4	37	4	37	4
Goodna	33	M	106	21	112	24	116	26	119	28	121	24	124	26	114	23	117	24	119	25	121	26
Loganlea	110	M	388	89	393	85	401	89	403	90	404	90	412	93	417	90	421	91	426	93	429	100
Loganlea	33	M	91	20	92	20	93	21	92	20	92	20	93	21	93	21	93	21	94	21	94	21
Middle Ridge (Postmans Ridge and Gatton)	110	M	138	57	140	58	141	58	142	58	142	58	143	59	143	59	144	59	145	59	145	60
Molendinar	110	GC	474	68	490	67	500	70	494	69	492	68	497	65	499	65	504	67	509	68	512	70
Mudgeeraba	110	GC	340	51	346	49	350	51	350	51	348	51	351	51	352	52	353	52	356	53	357	53
Mudgeeraba	33	GC	20	6	20	6	21	6	20	6	20	6	21	6	21	6	21	6	21	6	21	6
Murarrie	110	M	341	77	349	81	356	83	359	79	362	81	367	82	371	83	377	91	385	94	391	97
Palmwoods	110 and 132	M	309	71	314	67	320	70	321	71	324	73	331	75	335	78	341	80	348	83	350	84
Redbank Plains	11	M	19	5	20	5	20	5	20	5	21	6	21	6	22	6	22	6	23	6	23	6
Richlands	33	M	93	18	111	20	112	20	112	20	111	20	112	20	113	21	113	21	114	21	114	21
Rocklea	110	M	146	33	134	29	133	23	134	23	134	23	144	30	145	31	146	31	148	32	148	32

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

Connection point	Voltage (kV)	Zone	2015/16		2016/17		2017/18		2018/19		2019/20		2020/21		2021/22		2022/23		2023/24		2024/25	
			MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Runcorn	33	M	63	24	64	18	67	20	68	15	67	15	68	15	68	15	68	16	69	16	69	16
South Pine	110	M	905	221	927	213	941	213	942	214	942	214	953	218	958	220	966	223	975	226	981	222
Sumner	110	M	36	4	36	4	42	7	48	4	47	4	48	4	48	4	48	4	48	4	49	4
Tennyson	33	M	168	42	170	42	172	43	172	43	171	43	173	43	173	44	174	44	176	44	177	45
Wecker Road	33	M	131	23	133	24	135	25	137	25	138	26	139	26	139	26	140	27	141	27	142	27
Woolooga (Gympie)	132	M	161	34	162	33	164	34	163	35	163	35	164	35	165	35	166	34	167	35	168	35

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

Connection point	Voltage (kV)	Zone	2015		2016		2017		2018		2019		2020		2021		2022		2023		2024	
			MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Abermain	110	M	36	12	37	12	37	12	37	12	38	12	38	13	39	13	39	13	40	13	40	13
Abermain	33	M	69	25	69	25	69	26	71	26	71	27	75	29	76	29	77	30	79	31	80	31
Algester	33	M	55	10	54	15	54	15	54	15	54	15	55	10	55	10	56	10	56	10	56	10
Ashgrove West	110	M	87	15	87	15	92	18	94	19	96	19	98	16	100	17	102	18	103	18	105	19
Ashgrove West	33	M	57	11	54	10	54	10	54	10	54	10	55	10	55	10	56	10	56	10	56	10
Belmont	110	M	291	55	287	55	286	55	292	57	298	59	304	56	304	54	307	55	311	57	315	58
Blackstone (Raceview)	110	M	67	17	67	17	67	17	68	17	71	18	72	18	73	18	73	18	74	18	75	19
Bundamba	110	M	29	4	29	3	29	3	29	3	29	4	30	4	30	4	30	4	30	4	31	4
Goodna	33	M	76	22	81	26	85	28	88	29	91	25	94	26	96	27	90	20	92	21	94	22
Loganlea	110	M	345	68	336	65	334	65	338	66	342	67	350	69	359	71	362	72	366	73	370	74
Loganlea	33	M	74	18	72	18	72	18	72	18	72	18	73	18	74	18	74	18	75	18	75	18
Middle Ridge (Postmans Ridge and Gatton)	110	M	85	27	88	28	88	28	89	29	90	29	91	29	92	30	93	30	93	30	94	30
Molendinar	110	GC	351	51	346	50	352	51	357	52	355	52	359	53	364	54	367	54	370	55	374	55
Mudgeeraba	110	GC	249	36	249	32	248	32	250	33	250	33	253	33	255	34	257	34	258	34	259	35
Mudgeeraba	33	GC	18	3	18	3	17	3	18	3	18	3	18	3	18	3	18	3	18	3	18	3
Murarrie	110	M	283	84	287	87	288	88	292	90	296	91	301	93	305	95	310	95	316	97	322	99
Palmwoods	110 and 132	M	272	40	271	40	271	41	275	42	278	43	285	40	292	42	297	44	303	46	309	48
Redbank Plains	11	M	14	3	14	3	15	3	15	3	15	3	16	3	16	3	17	3	17	3	18	3
Richlands	33	M	76	17	90	22	89	22	90	22	91	22	92	23	93	23	93	23	93	24	94	24
Rocklea	110	M	115	32	102	29	101	22	102	23	103	18	104	19	112	24	113	24	114	25	115	25

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

Connection point	Voltage (kV)	Zone	2015		2016		2017		2018		2019		2020		2021		2022		2023		2024	
			MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Runcorn	33	M	53	15	52	15	54	16	54	16	56	17	56	17	57	17	57	17	57	17	58	17
South Pine	110	M	710	156	716	164	724	161	731	163	736	164	745	161	755	163	762	165	767	166	774	168
Sumner	110	M	25	3	25	3	25	3	30	4	34	5	35	6	35	6	35	6	35	6	36	6
Tennyson	33	M	133	32	131	31	130	31	131	31	132	32	133	32	135	32	136	33	137	33	138	33
Wecker Road	33	M	99	22	97	22	97	22	99	23	101	23	103	24	104	25	105	25	106	25	106	25
Woolooga (Gympie)	132	M	157	31	155	35	154	35	155	35	156	35	157	30	159	31	160	31	161	31	162	31

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

Connection point (1)	2015/16		2016/17		2017/18		2018/19		2019/20		2020/21		2021/22		2022/23		2023/24		2024/25	
	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)	1,311	453	1,309	452	1,307	452	1,302	450	1,302	450	1,302	450	1,302	450	1,302	450	1,302	450	1,302	450
Transmission connected mining loads (3)	81	37	79	36	95	41	101	42	100	41	101	42	102	42	102	42	102	42	102	42
Transmission connected LNG loads (4)	543	178	707	232	878	289	866	285	876	288	862	283	872	286	884	290	893	294	869	286
Transmission connected rail supply substations (5)(6)	340	-331	344	-334	344	-334	344	-334	344	-334	344	-334	344	-334	344	-334	344	-334	344	-334

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 LNG 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) LNG 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, Moranbah South, Peak Downs and Mt McLaren
- Central West zone – Norwich Park, Gregory, Rocklands, Blackwater, Bluff, Wycarbah, Dingo, 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)	2015		2016		2017		2018		2019		2020		2021		2022		2023		2024	
	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)	1,312	455	1,308	453	1,307	453	1,303	452	1,298	450	1,298	450	1,298	450	1,298	450	1,298	450	1,298	450
Transmission connected mining loads (3)	81	37	81	36	102	43	100	41	101	41	101	41	101	41	101	41	101	41	101	41
Transmission connected LNG loads (4)	433	142	684	225	832	274	960	316	877	288	861	283	870	286	868	285	890	293	847	278
Transmission connected rail supply substations (5)(6)	340	-331	344	-334	344	-334	344	-334	344	-334	344	-334	344	-334	344	-334	344	-334	344	-334

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 LNG 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) LNG 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, Moranbah South, Peak Downs and Mt McLaren
- Central West zone – Norwich Park, Gregory, Rocklands, Blackwater, Bluff, Wycarbah, Dingo, 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 2015 Transmission Annual Planning Report (TAPR) 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

Customers other than Energex and Ergon Energy that connect directly to Powerlink's transmission network are assessed based on their forecast, recent history and 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 Energy 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 solar photovoltaic (PV), battery storage, electric vehicles, energy efficiency improvements, smart meters are factored into the forecast for Energex and Ergon Energy.

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

Econometric regressions

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

To prepare these forecasts, regression analysis is carried out using native demand and energy plus solar PV 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.

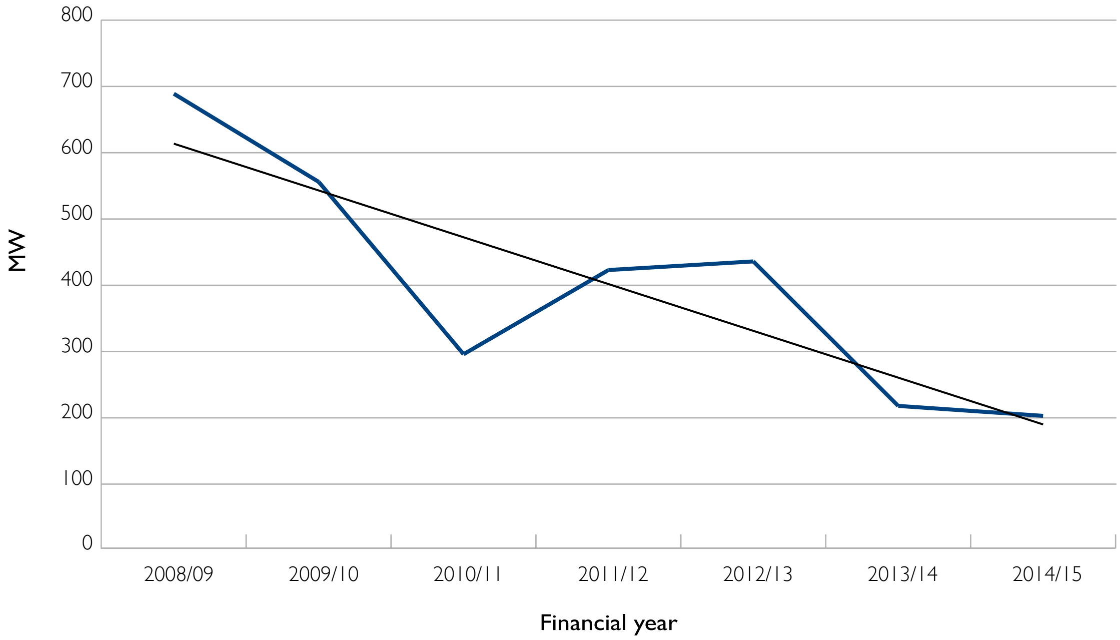
The first step in the regression analysis is to assemble historical native energy and maximum demand values as follows:

a) Energy. Determine DNSP native energy for each year going back to 2000/01. As this work is done in March, an estimation is prepared for the current financial year which will be updated with actuals 12 months later when preparing the next TAPR.

b) Winter maximum demand. The DNSP native demand at the time of winter state peak is collated back to winter 2000. These demands are then corrected to average weather conditions. Powerlink has enhanced its method for weather correction as described later in this appendix.

c) Summer maximum demand. The DNSP native demand at the time of summer state peak is collated back to summer 2000/01. These demands are then corrected to average weather conditions. DNSP native demand at the time of summer state evening peak (after 6pm) is also collated back to summer 2000/01. These demands are also corrected to average weather conditions. This evening series is now used as the basis for regressing as evidence supports Queensland moving to a summer evening peak network due to the increasing impact of solar PV. This move to an evening peak by 2017/18, is supported through an 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 corrected maximum demand



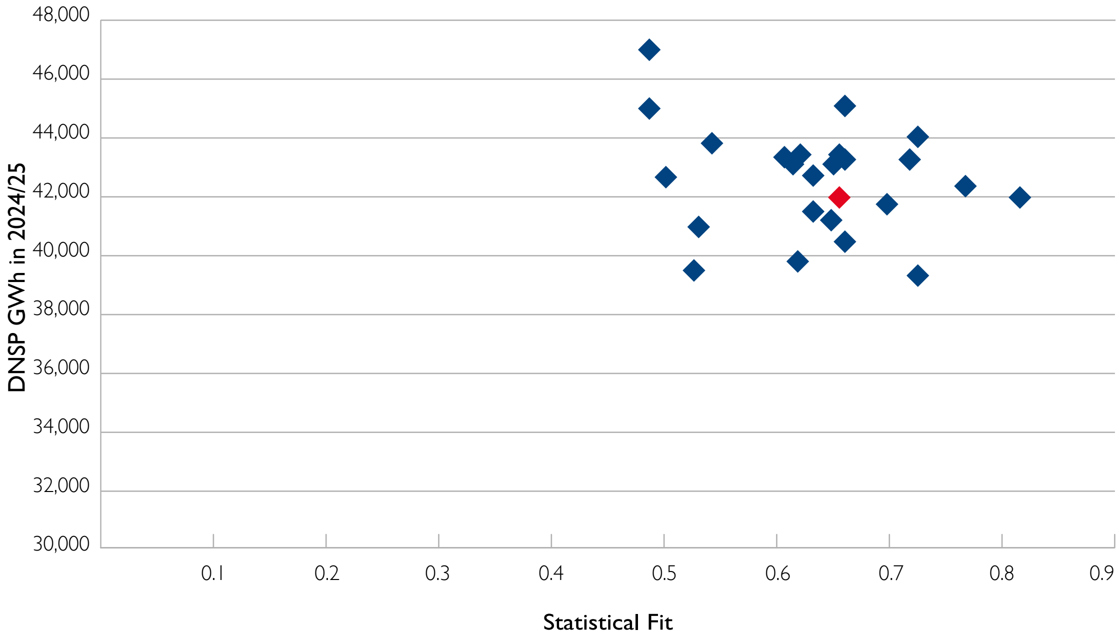
Before the energy data can be used in a regression, it is necessary to make appropriate adjustments to account for solar PV. This ensures that the full underlying DNSP load is being regressed. As forecast summer maximum demand is now based on an evening regression and winter maximum demand occurs in the evening, only an adjustment for energy is needed. This energy adjustment assumes that solar PV output averages 15% of capacity. The 15% 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 solar PV contributions based on forecast solar PV capacity.

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. This regression represents the relationship between input and output variables. A logarithmic relationship is used in keeping with statistical good practice.

Input variables are selected from three price variables (supplied by Australian Energy Market Operator (AEMO)) and 17 economic variables (supplied by AEMO and Deloitte Access Economics). This provides 51 combinations. For each of these 51 combinations the option of a one year delay to either or both input variables is also considered leading to a total of 204 regressions being assessed. Of these, the top 25 are selected and placed on a scatter plot as shown below 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 gross state product and total electricity price each with a one year delay. The regression selected reflects a central outcome at the end of the regression period and uses broad based input variables.

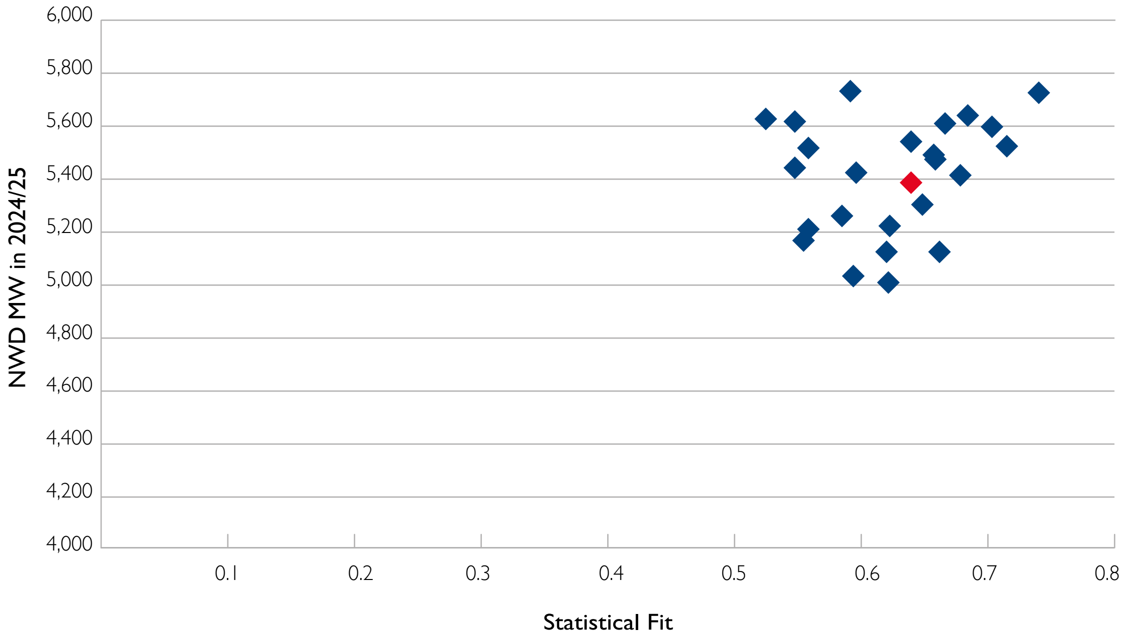
Economic forecast data supplied by AEMO has been provided for low, medium and high economic outlooks. The regression is carried out using medium data leading to the medium energy forecast. High and low energy forecasts are then determined by applying the appropriate forecast economic data to the model.

Summer and winter maximum demand regressions

Maximum demand forecasts are based on two regressions. The corrected 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 maximum demand and the NWD demand based on the previous September. For winter, this is the difference between the corrected 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.

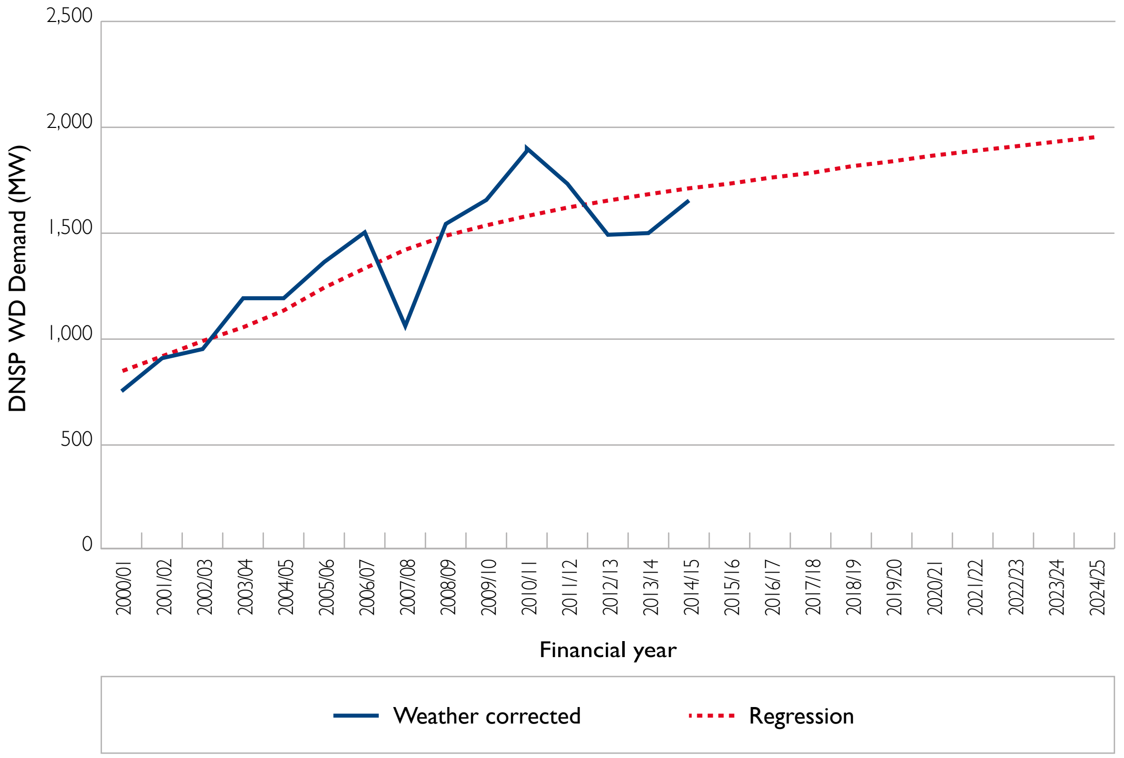
Figure B.3 Non-weather dependent demand regression results



The selected regression shown above in red uses Queensland gross state product and business electricity price each with a one year delay.

The 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. This variable is a measure of the air conditioning capacity in Queensland and demonstrates a good statistical fit as illustrated in Figure B.4 by the summer regression below. Historical and forecast air conditioning penetration rates are provided annually in the Queensland Household Energy Survey.

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% probability of exceedance (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. WD analysis described above is applied to historical demands temperature corrected to 50% PoE conditions. It therefore leads to the 50% PoE forecast. The analysis is repeated using historical demands corrected to 10% PoE and 90% PoE conditions to deliver the other forecasts.

New technologies

Developing an understanding of future impacts for new technologies is crucial to robust and meaningful demand and energy forecasts. In the past, Powerlink has incorporated the impact of solar PV into its forecasting process, while making no explicit allowance for other technologies. Recognising the importance that these technologies will play in shaping future demand and energy, Powerlink is committed to furthering its understanding of these drivers for change.

Driven by this commitment, Powerlink recently conducted a forum of industry experts to learn more about new technologies and the impacts that they may have on future electrical demand and energy. Based on the information shared for the 2015 TAPR, Powerlink adopted technology and other inputs as summarised in Table B.1. Other than assessing the impact of solar PV, this is a new approach for Powerlink.

Table B.1 **Impact of new technologies on Powerlink forecast**

	Solar PV	Battery Storage (1)	Energy Efficiency	Electric Vehicles	Tariff Reform / DSM
GWh (2)	3,154	0	1,686	0	0
MW (3)	200	185	315	0	100
Installed Capacity MW in 2024/25	3,700	370			
First Year of Impact	now	2017/18	now		2018/19

Notes:

(1) Take up of all technologies is assumed linear, except battery storage with growth more skewed to the later part the forecast period.

(2) This is the energy reduction In financial year 2024/25 compared to 2014/15.

(3) This is the maximum demand reduction in summer 2024/25 compared to summer 2014/15.

Powerlink recognises there is considerable uncertainty regarding the impact of new technology and other inputs on the demand and energy forecasts. Further, Powerlink recognises a range of other outcomes could have been adopted. Due to these uncertainties Powerlink has provided this additional information to provide transparency and allow other levels to be factored into the demand forecasts if desired.

Solar PV

The installed capacity of solar PV in Queensland as at the end of 2014 was 1,300MW. Installations are being added at a rate of 20MW[1] per month, predominately residential. While the residential installation rate is expected to decline as saturation effects begin, it is expected that commercial and industrial installations will make up the shortfall to maintain this rate over the 10-year forecast period. Therefore by the end of the 10-year forecast period, total Queensland capacity is expected to rise to 3,700MW.

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[1] Based on information from the Clean Energy website

Analysis has revealed that Queensland will move to a summer evening peak by 2017/18 and so further 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 15%[2] capacity.

Powerlink has recently become a member of the Australian PV Institute which supplies real time data for solar PV. This new information has significantly enhanced the ability to analyse a range of PV effects and in particular its impact on peak demand.

Battery storage

Battery storage technology has the potential to significantly change the electricity supply industry. 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 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 solar PV generation
- practical issues such as space, aesthetics and safety
- whether economies of scale favour a particular level of aggregation.

Consumer feedback[3] indicates that around 10% of solar PV owners are considering to purchase a battery storage system. Assuming that 10% of solar PV owners purchase battery storage and the battery storage systems contribute in aggregate 50% of the installed solar PV capacity at the time of system peak, then maximum demand will be cut by the equivalent of 5% of installed solar PV capacity, that is, 185MW. It is further assumed that battery storage itself will have little impact on energy as usage will just be 'moved in time'.

Energy efficiency

Energy efficiency improvements have been ongoing and include a range of initiatives associated with appliances and building standards. Therefore the regression inherently includes an energy efficiency forecast in line with past gains. The following two papers examine this area in further detail and support a case that future energy efficiency gains will be greater than those of the past.

- *Appliances: George Wilkenfeld and Associates. Review of Impact Modelling for E3 Work Program. March 2014.*
- *Buildings: Pitt and Sherry. Qualitative Assessment of Energy Savings from Building Efficiency Measures Final Report. March 2013.*

The proposed forecast takes into account findings summarised in these reports leading to a reduction (beyond trend) at the end of the 10-year forecast period of around 1,686GWh pa and 315MW reduction to summer peak demand.

Electric vehicles

Compared to world leading countries in electric vehicle uptake such as Norway and the Netherlands, the uptake of electric vehicles in Australia is low. Without significant government policy changes to actively encourage their purchase this is not expected to change in the short-term. Ultimately, lower battery costs and improved performance will drive up sales. In the meantime, Powerlink has not included a specific allowance in its demand and energy forecast for electric vehicles but will continue to monitor progress in this area. In the event that there is a significant update in electric vehicles it is expected that most owners will be incentivised to charge their cars at off peak times resulting in minimal increase in peak demand. Similarly it is estimated a 1% penetration of electric vehicles on the road would result in approximately 0.3% increase in total energy usage.

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

[3] 2014 Queensland Household Energy Survey

Tariff reform and demand side management

Network tariff reforms will influence consumer behaviour, shifting energy usage away from peak times. In addition to this maximum demand reduction, it is anticipated that network tariff reforms will also influence future use of battery storage technology, encouraging consumers to draw from the batteries during peak demand/high price times. The extent to which this occurs will depend on how quickly new tariffs are offered 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 per cent of trials internationally have resulted in peak reductions of 10 per cent or more."[4]

Some of this peak reduction will already be captured through the energy efficiency and battery storage factors above. An additional 100MW has been assumed within this forecast and represents a further 1.5% of the total maximum demand from the Energex and Ergon Energy networks. As tariff reform is likely to result in load shifting, the impact on energy is expected to be low.

Weather correction methodology

Peak 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. This results in two measures:

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

Temperature correction is applied to historical metered load supplied to connection points with Energex and Ergon Energy. 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 Energy supplied load in the vicinity of that weather station.
- Exclude mild days and holidays: To ensure that the fitted model accurately describes the relationship between temperature and peak demand on days when demand is high, days with mild weather, and the two-week period around Christmas (when many businesses are closed) are filtered out of the dataset.
- Calculate a regression model for each year: A regression model is calculated for each year, 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.
- Determine the 10% and 50% PoE thresholds using 20 years of weather data: The model calculated for each season is then applied to the daily weather data recorded since 1995. This effectively calculates what the peak demand would have been on each day if the relationship between peak 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 twenty years is recorded in a list, and the 10th and 50th percentile of the list is calculated to determine the 10% PoE and 50% 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 2014/15 summer was hotter than average. Therefore, the 50% PoE demand is 242MW lower than the observed peak demand. The 2014 winter was warmer (i.e. more mild) than average, resulting in an upwards adjustment to the observed winter peak demand.

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[4] Towards a National Approach to Electricity Network Tariff Reform (page 6) – ENA Position Paper December 2014

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 2015 to summer 2017/18. 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 2015 Queensland maximum demand 300MW northerly QNI flow
Figure C.4	Winter 2015 Queensland maximum demand 0MW QNI flow
Figure C.5	Winter 2015 Queensland maximum demand 700MW southerly QNI flow
Figure C.6	Winter 2016 Queensland maximum demand 300MW northerly QNI flow
Figure C.7	Winter 2016 Queensland maximum demand 0MW QNI flow
Figure C.8	Winter 2016 Queensland maximum demand 700MW southerly QNI flow
Figure C.9	Winter 2017 Queensland maximum demand 300MW northerly QNI flow
Figure C.10	Winter 2017 Queensland maximum demand 0MW QNI flow
Figure C.11	Winter 2017 Queensland maximum demand 700MW southerly QNI flow
Figure C.12	Summer 2015/16 Queensland maximum demand 200MW northerly QNI flow
Figure C.13	Summer 2015/16 Queensland maximum demand 0MW QNI flow
Figure C.14	Summer 2015/16 Queensland maximum demand 400MW southerly QNI flow
Figure C.15	Summer 2016/17 Queensland maximum demand 200MW northerly QNI flow
Figure C.16	Summer 2016/17 Queensland maximum demand 0MW QNI flow
Figure C.17	Summer 2016/17 Queensland maximum demand 400MW southerly QNI flow
Figure C.18	Summer 2017/18 Queensland maximum demand 200MW northerly QNI flow
Figure C.19	Summer 2017/18 Queensland maximum demand 0MW QNI flow
Figure C.20	Summer 2017/18 Queensland maximum demand 400MW southerly QNI flow

The power flows reported in this appendix assume the following open points in the Powerlink network:

- Callide A to Gladstone South 132kV circuit
- Baralaba end of Blackwater to Dingo to Baralaba 132kV multi-terminal transmission line
- Belmont to Loganlea 110kV 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 2.3

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[1] The transmission network diagrams shown in this appendix are high level representations only, used to indicate zones, grid sections and committed large capital projects.

Table C.1: Summary of figures C.3 to C.20 – possible 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 2015	Winter 2016	Winter 2017	Summer 2015/16	Summer 2016/17	Summer 2017/18	
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 132 kV (1 circuit)	183/183/183	183/183/183	181/181/181	240/240/240	239/239/239	238/238/201	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)	693/693/693	704/704/705	721/721/721	844/844/844	836/836/836	851/851/812	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)	755/719/634	768/713/626	701/609/617	609/594/598	606/591/611	585/603/614	Th
CQ-SQ Wurdong into Gin Gin 275kV (1 circuit) Calliope River into Gin Gin 275kV (2 circuits) Calvale into Halys 275kV (2 circuits)	1,485/1,590/1,845	1,423/1,575/1,830	1,535/1,791/1,792	1,631/1,576/1,576	1,616/1,561/1,616	1,553/1,609/1,647	Tr V
Surat Western Downs to Columboola 275kV (1 circuit) Western Downs to Orana 275kV (1 circuit) Tarong into Chinchilla 132kV (2 circuits)	314/314/314	525/525/525	639/639/639	373/373/319	503/503/359	640/640/499	V
SWQ Western Downs to Halys 275kV (2 circuits) Braemar (East) to Halys 275kV (2 circuits) Millmerran to Middle Ridge 330kV (2 circuits)	1,757/1,656/1,479	1,574/1,428/1,250	1,506/1,262/1,324	1,893/1,945/1,969	1,947/1,998/1,905	2,006/1,948/1,756	(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)	3,414/3,359/3,291	3,493/3,414/3,348	3,466/3,337/3,395	3,887/3,905/3,935	3,919/3,938/3,949	3,931/3,910/3,926	V

Table C.1: Summary of figures C.3 to C.20 – possible 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 2015	Winter 2016	Winter 2017	Summer 2015/16	Summer 2016/17	Summer 2017/18	
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)	666/666/728	666/666/729	675/675/737	737/737/768	747/747/778	739/739/771	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 2015	Winter 2016	Winter 2017	Summer 2015/16	Summer 2016/17	Summer 2017/18	Significant dependence on	Minor dependence on
Chalumbin 275/132kV (2x200MVA)	FN	48	48	48	50	50	50	Kareeya generation	
Woree 275/132kV (2x375MVA)	FN	127	127	127	168	169	169	Barron Gorge generation	Kareeya, Townsville and Mt Stuart generation
Ross 275/132kV (2x250 and 1x200MVA)	R	135	141	140	186	218	195	Mt Stuart, Townsville and Invicta generation	
Nebo 275/132kV (1x200MVA, 1x250MVA and 1x375MVA)	N	285	276	294	314	306	314	Mackay GT generation	
Strathmore 275/132kV (1x375MVA)	N	116	128	135	128	142	146	Invicta generation	Townsville and Mt Stuart generation
Bouldercombe 275/132kV (2x200MVA and 1x375MVA)	CW	159	161	158	180	181	182		
Calvale 275/132kV (1x250MVA)	CW	152	156	159	161	164	164	Callide, Yarwun and Gladstone generation and 132kV network configuration	
Lilyvale 275/132kV (2x375MVA)	CW	212	213	224	224	235	237	Barcaldine generation	CQ-NQ flow
Larcom Creek 275/132 kV (2x375MVA)	G	77	72	85	52	79	54	Yarwun generation	
Gin Gin 275/132kV (2x250MVA)	WB	148	140	131	152	151	151		CQ-SQ flow
Teebar Creek 275/132kV (2x375MVA)	WB	81	77	77	88	88	87		CQ-SQ flow
Woolooga 275/132kV (2x120 and 1x250MVA)	WB	218	218	216	215	215	216		CQ-SQ flow
Columboola 275/132kV (2x375MVA)	S	179	188	184	165	169	161	Roma and Condamine generation	SW Generation and 132kV network configuration
Middle Ridge 275/110kV (3 x 250MVA)	SW	295	310	301	290	297	291	Oakey GT 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 2015	Winter 2016	Winter 2017	Summer 2015/16	Summer 2016/17	Summer 2017/18	Significant dependence on	Minor dependence on
Tarong 275/132kV (2x90MVA)	SW	10	27	38	23	26	19	Roma and Condamine generation and 132kV network configuration	SW generation
Tarong 275/66kV (2x90MVA)	SW	41	41	41	34	34	34		
Abermain 275/110kV (1x375MVA)	M	149	152	152	180	178	179	110kV transfers to/from Blackstone and Goodna	Tarong flow
Belmont 275/110kV (2x250 and 2x375 MVA)	M	528	535	544	607	611	617	110kV transfers to/from Loganlea	110kV transfers to/from Rocklea and Swanbank E generation
Blackstone 275/110kV (1x250 and 1x240MVA)	M	163	167	168	202	202	203		
Goodna 275/110kV (1x375MVA)	M	147	150	153	170	170	170	110kV transfers to/from Blackstone and Abermain	
Loganlea 275/110kV (2x375MVA)	M	356	349	351	396	398	400	110kV transfers to/from Belmont	110kV transfers to/from Molendinar and Mudgeeraba and Swanbank E generation
Murarrie 275/110kV (2x375MVA)	M	331	334	335	373	381	380		
Palmwoods 275/132kV (2x375MVA)	M	286	290	294	291	291	291		CQ-SQ flow
Rocklea 275/110kV (2x375MVA)	M	348	356	357	405	409	408	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	577	599	601	644	650	647		
South Pine West 275/110kV (1x375, 1x250MVA)	M	262	266	265	305	307	305		CQ-SQ flow and Swanbank E generation
Molendinar 275/110kV (2x375MVA)	GC	410	408	416	441	443	443	110kV transfers to/from Loganlea and Mudgeeraba	Terranora Interconnector
Mudgeeraba 275/110kV (3x250MVA)	GC	358	357	360	372	375	373	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 downstream 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

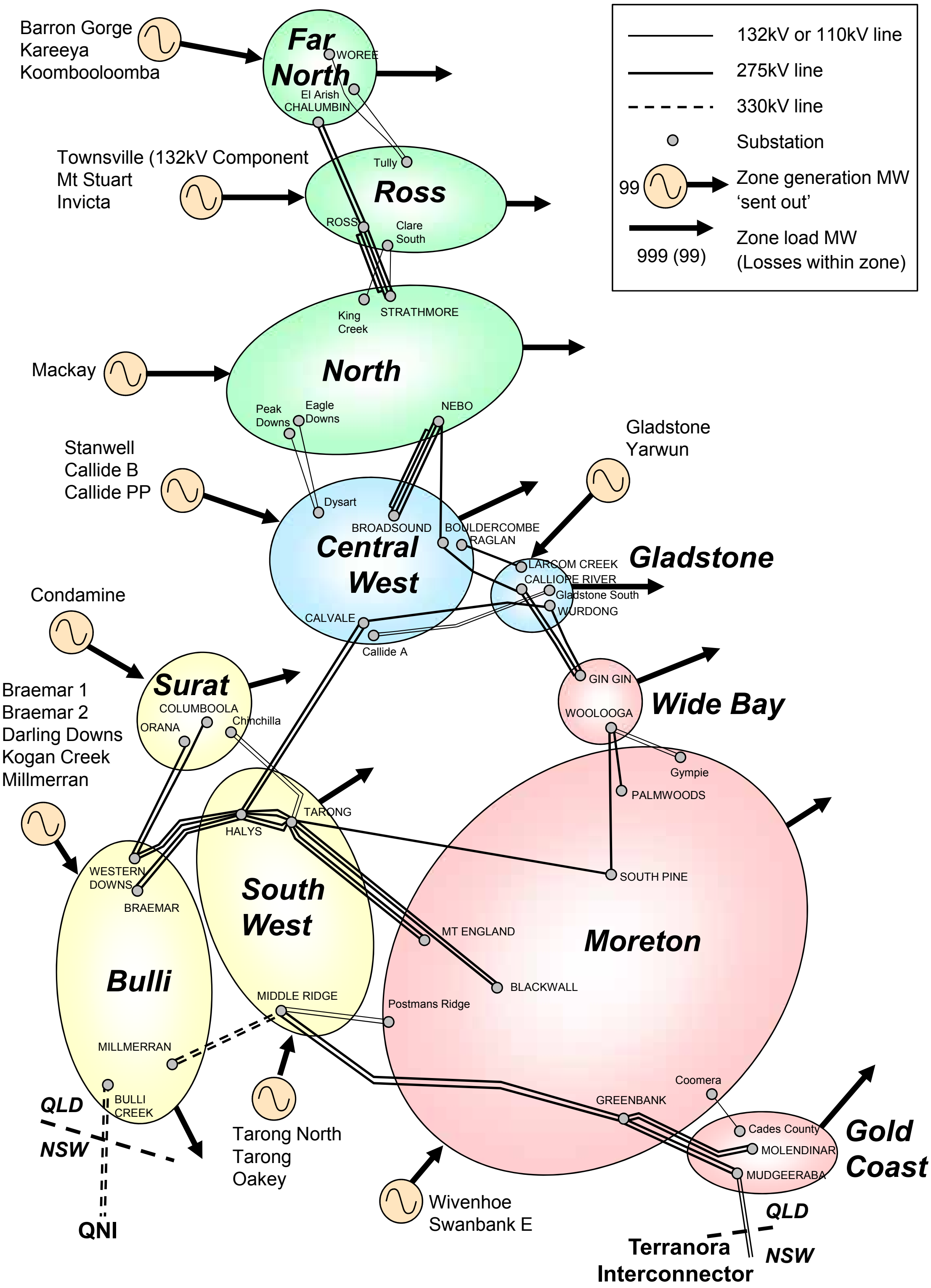


Figure C.2 Grid section legend for figures C.3 to C.20

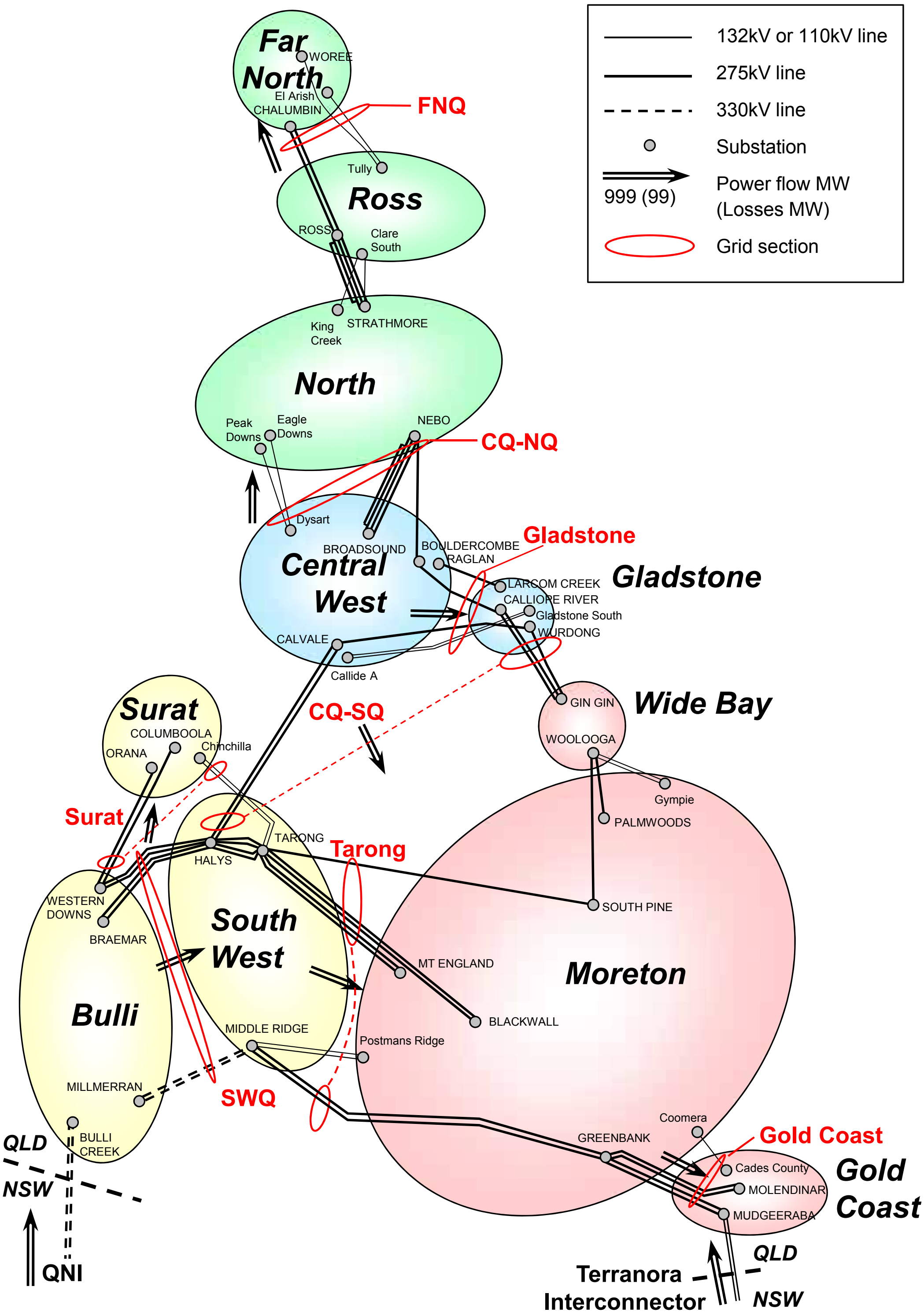
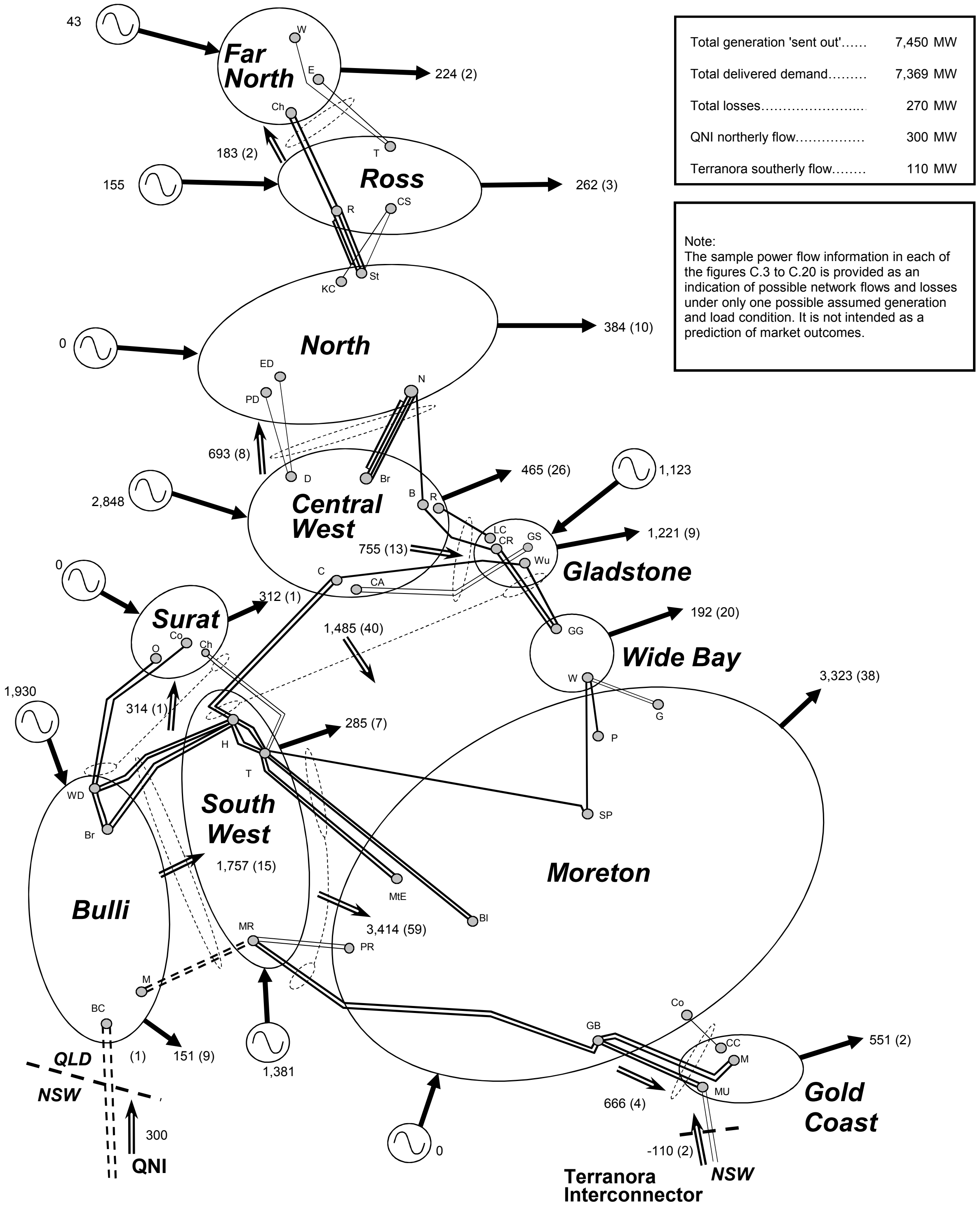


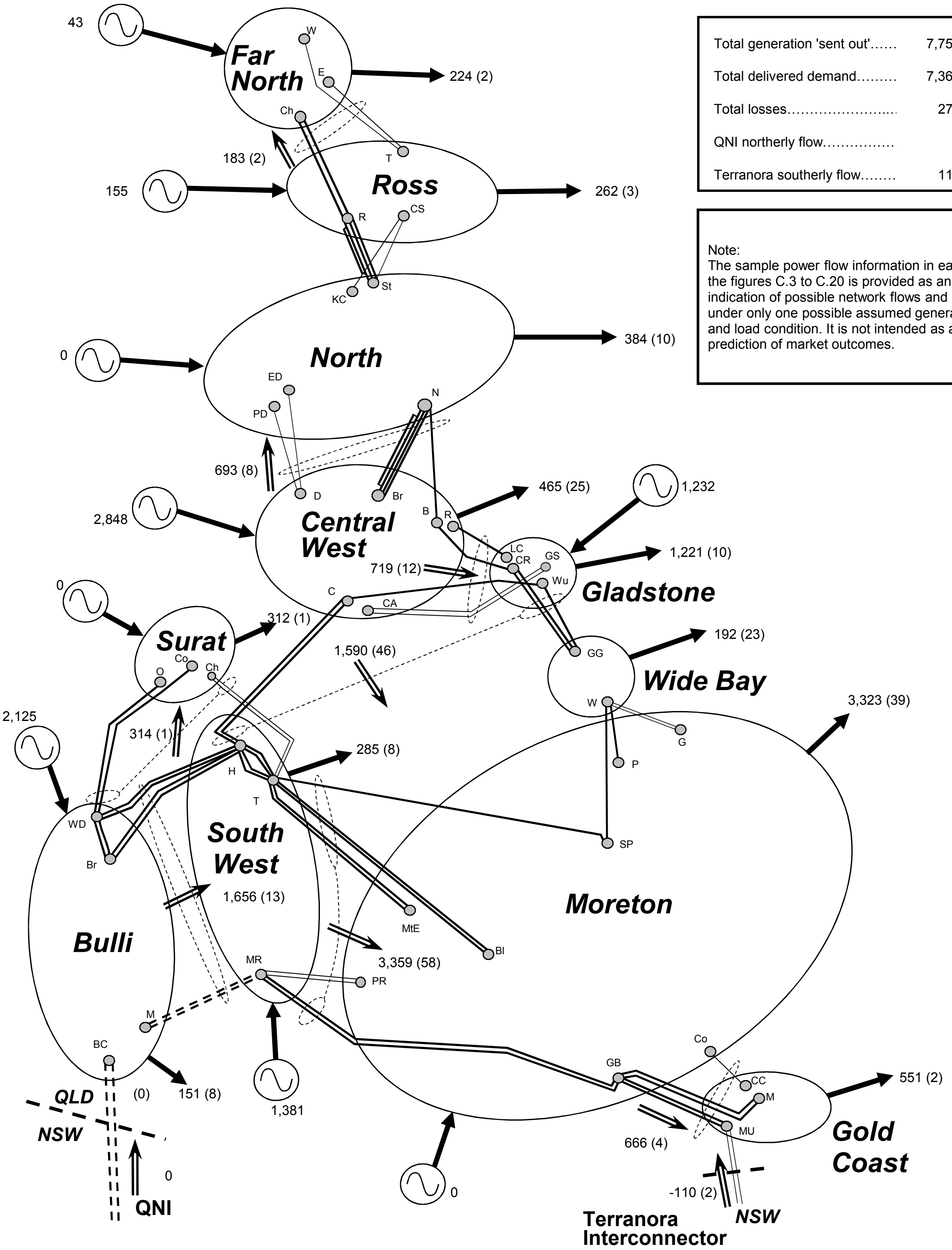
Figure C.3 Winter 2015 Queensland maximum demand 300MW northerly QNI flow



Total generation 'sent out'......	7,450 MW
Total delivered demand.........	7,369 MW
Total losses.........................	270 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.

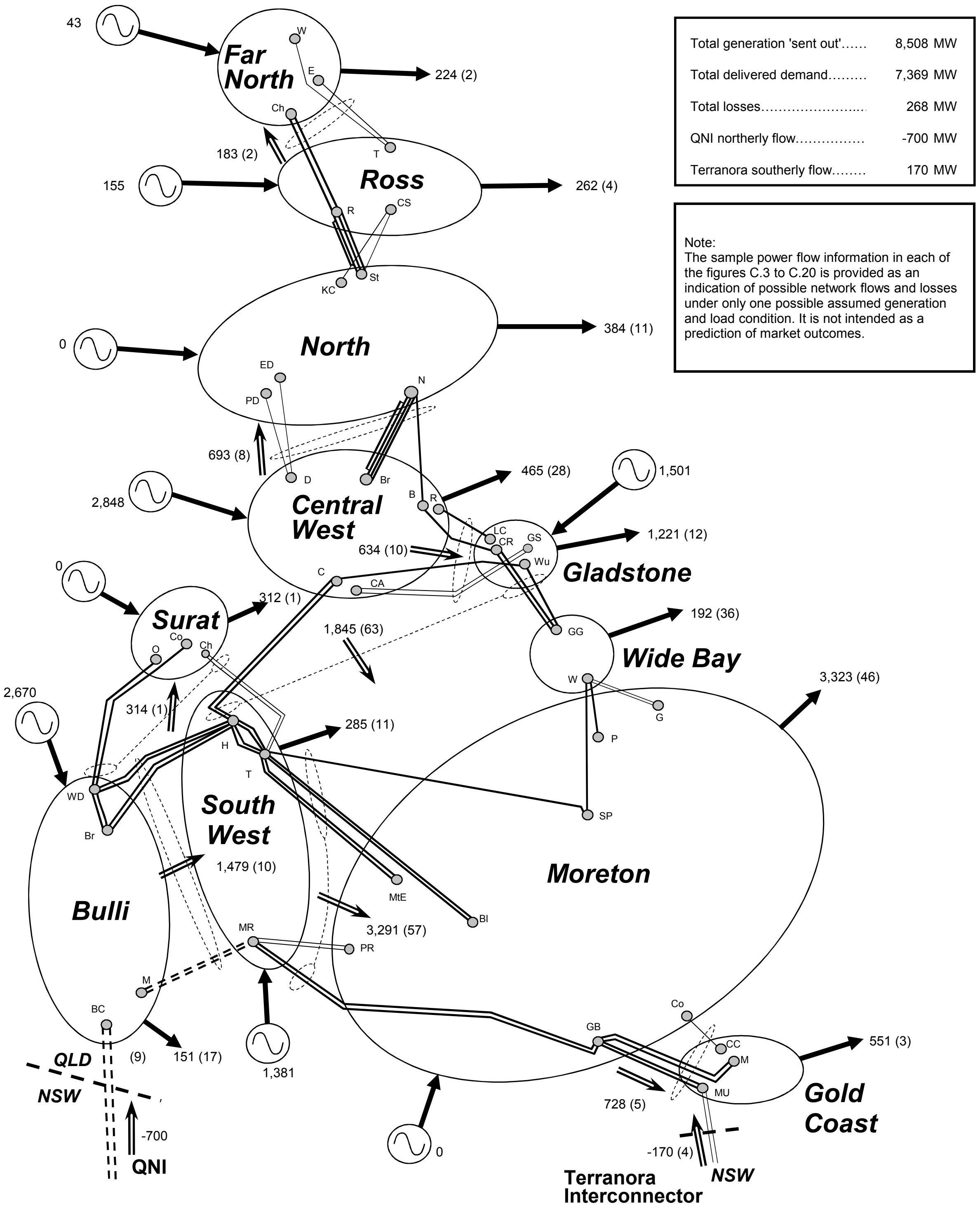
Figure C.4 Winter 2015 Queensland maximum demand 0MW QNI flow



Total generation 'sent out'……	7,754 MW
Total delivered demand………	7,369 MW
Total losses………………………	274 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.

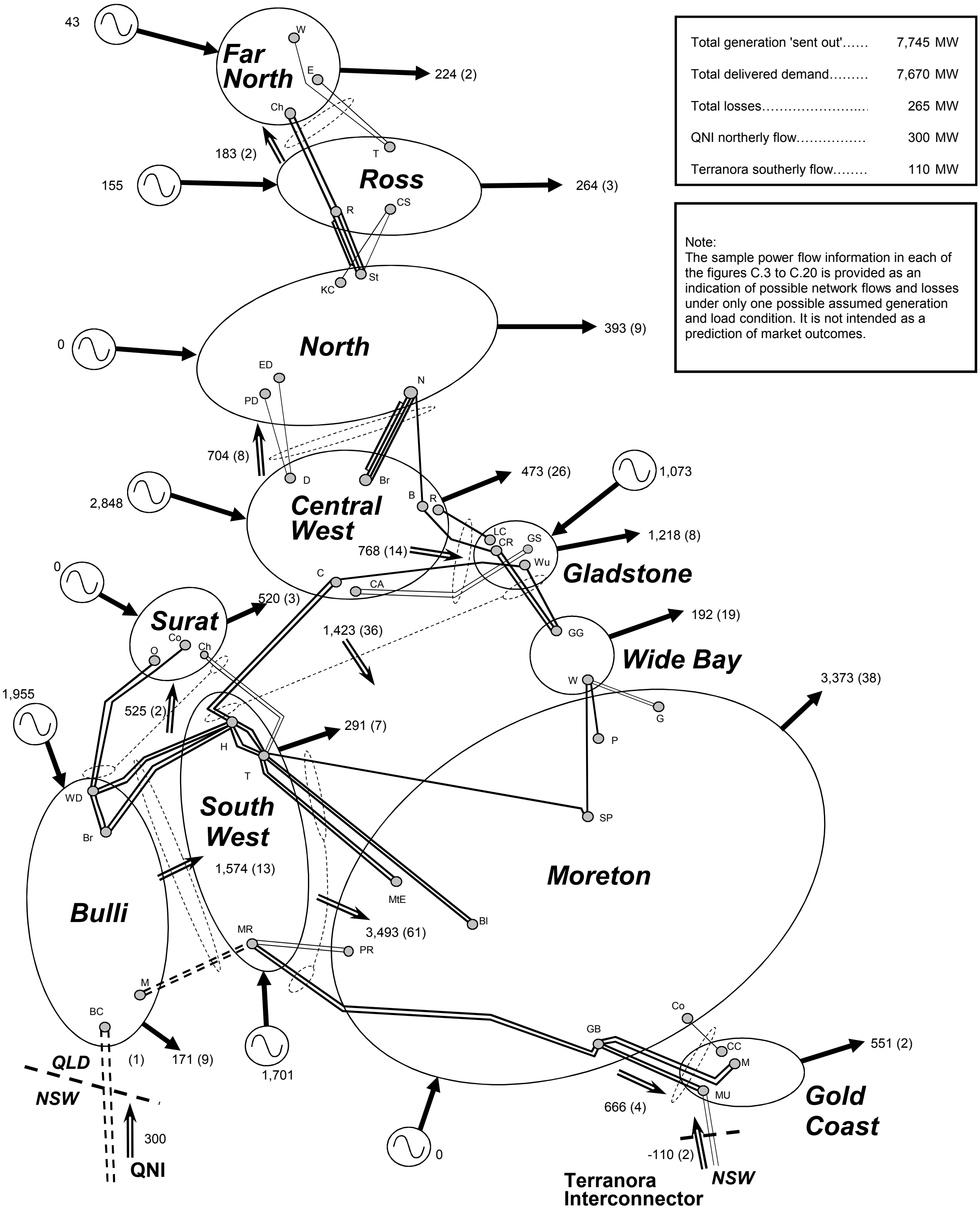
Figure C.5 Winter 2015 Queensland maximum demand 700MW southerly QNI flow



Total generation 'sent out'……	8,508 MW
Total delivered demand………	7,369 MW
Total losses…………………..	268 MW
QNI northerly flow…………….	-700 MW
Terranora southerly flow……..	170 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.

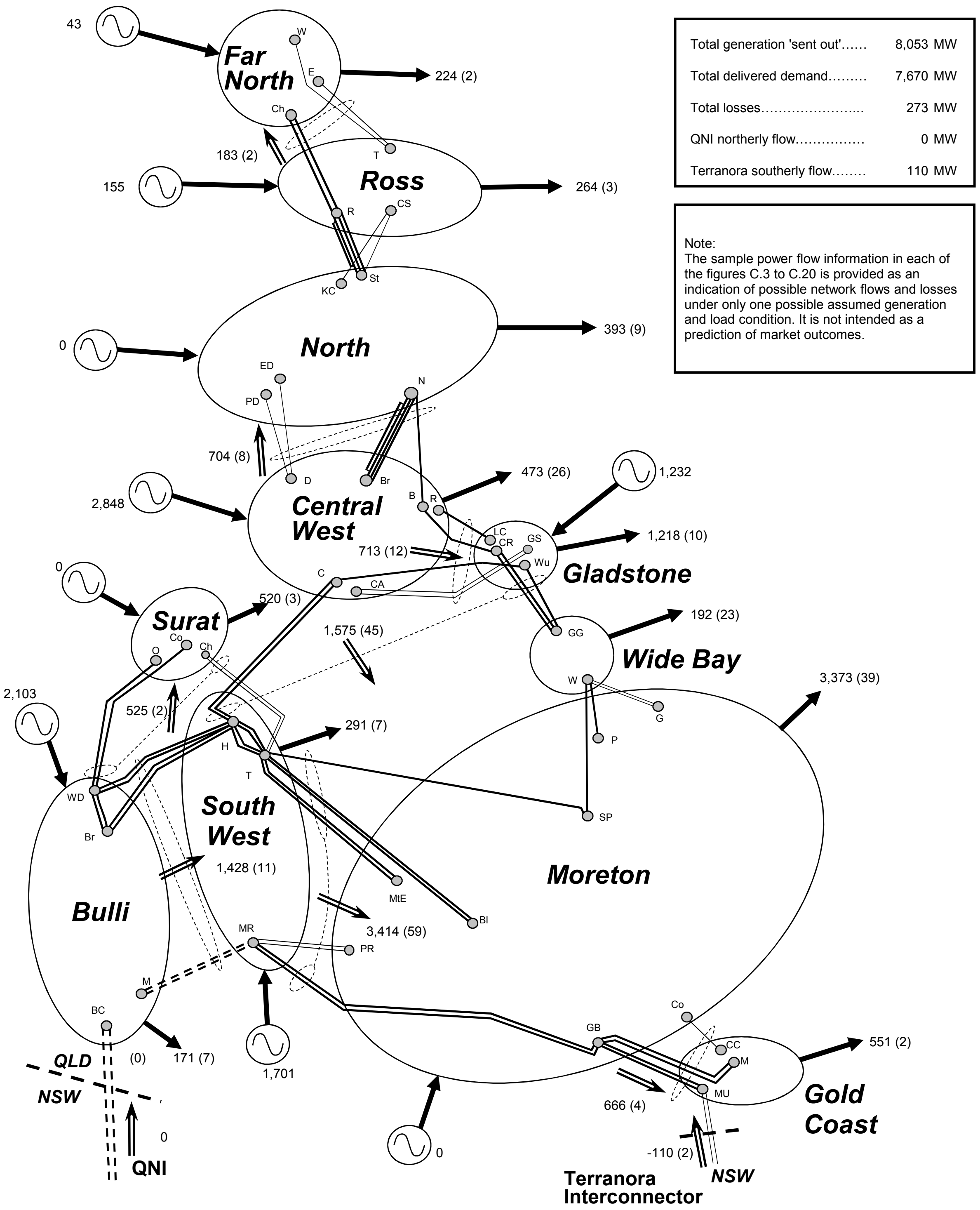
Figure C.6 Winter 2016 Queensland maximum demand 300MW northerly QNI flow



Total generation 'sent out'……	7,745 MW
Total delivered demand………	7,670 MW
Total losses……………………	265 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.

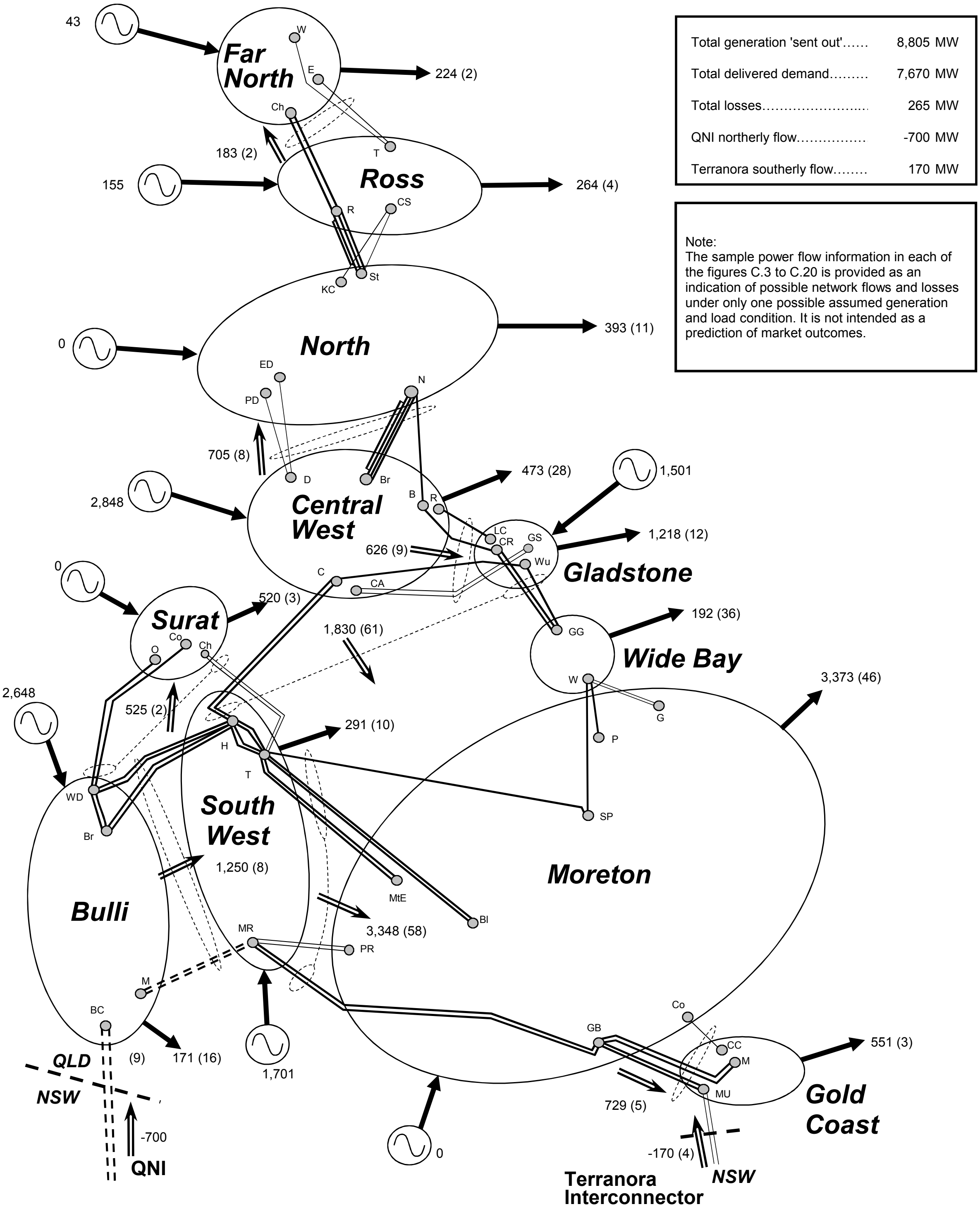
Figure C.7 Winter 2016 Queensland maximum demand 0MW QNI flow



Total generation 'sent out'......	8,053 MW
Total delivered demand.........	7,670 MW
Total losses.........................	273 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.

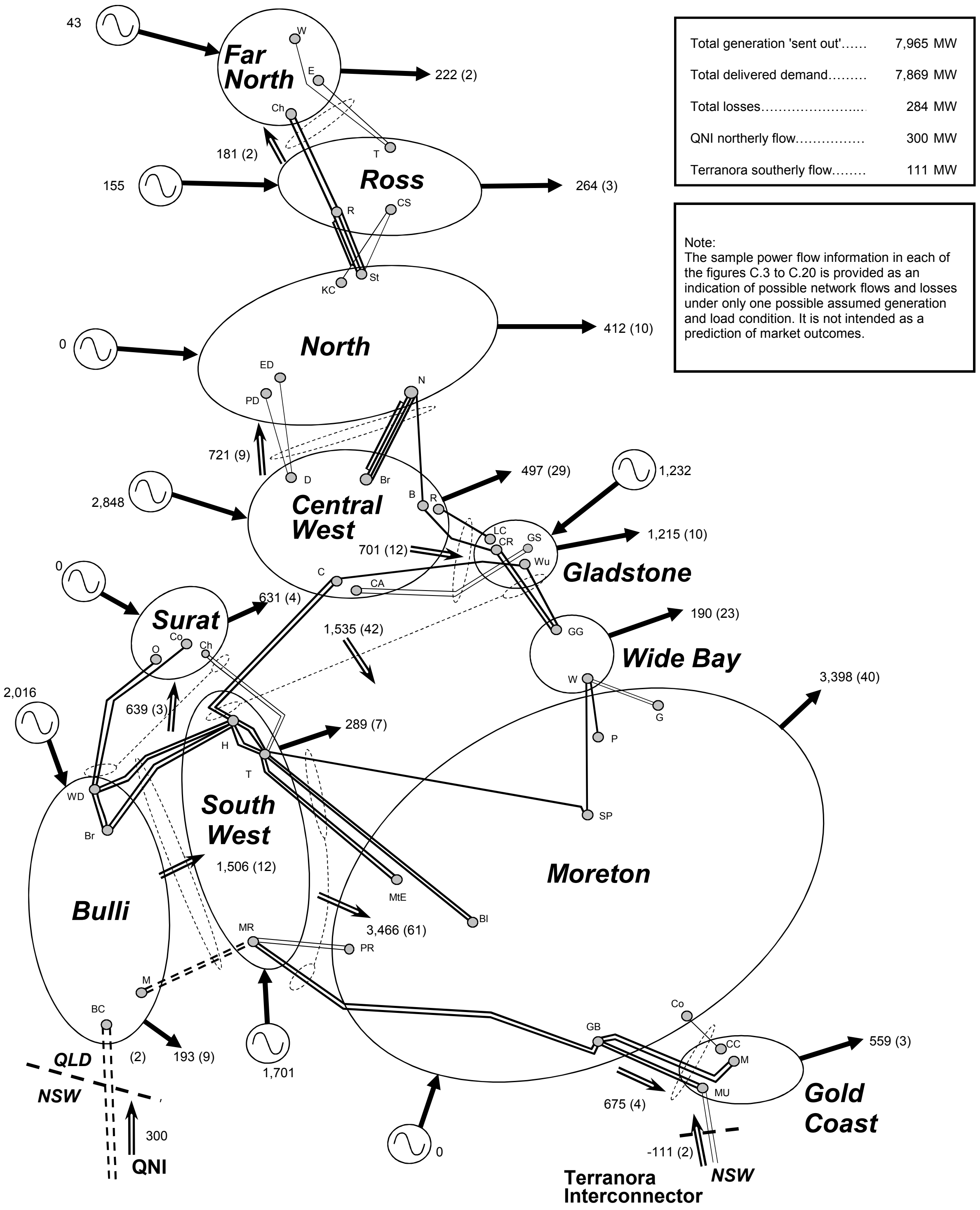
Figure C.8 Winter 2016 Queensland maximum demand 700MW southerly QNI flow



Total generation 'sent out'……	8,805 MW
Total delivered demand………	7,670 MW
Total losses………………………	265 MW
QNI northerly flow…………….	-700 MW
Terranora southerly flow……..	170 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.

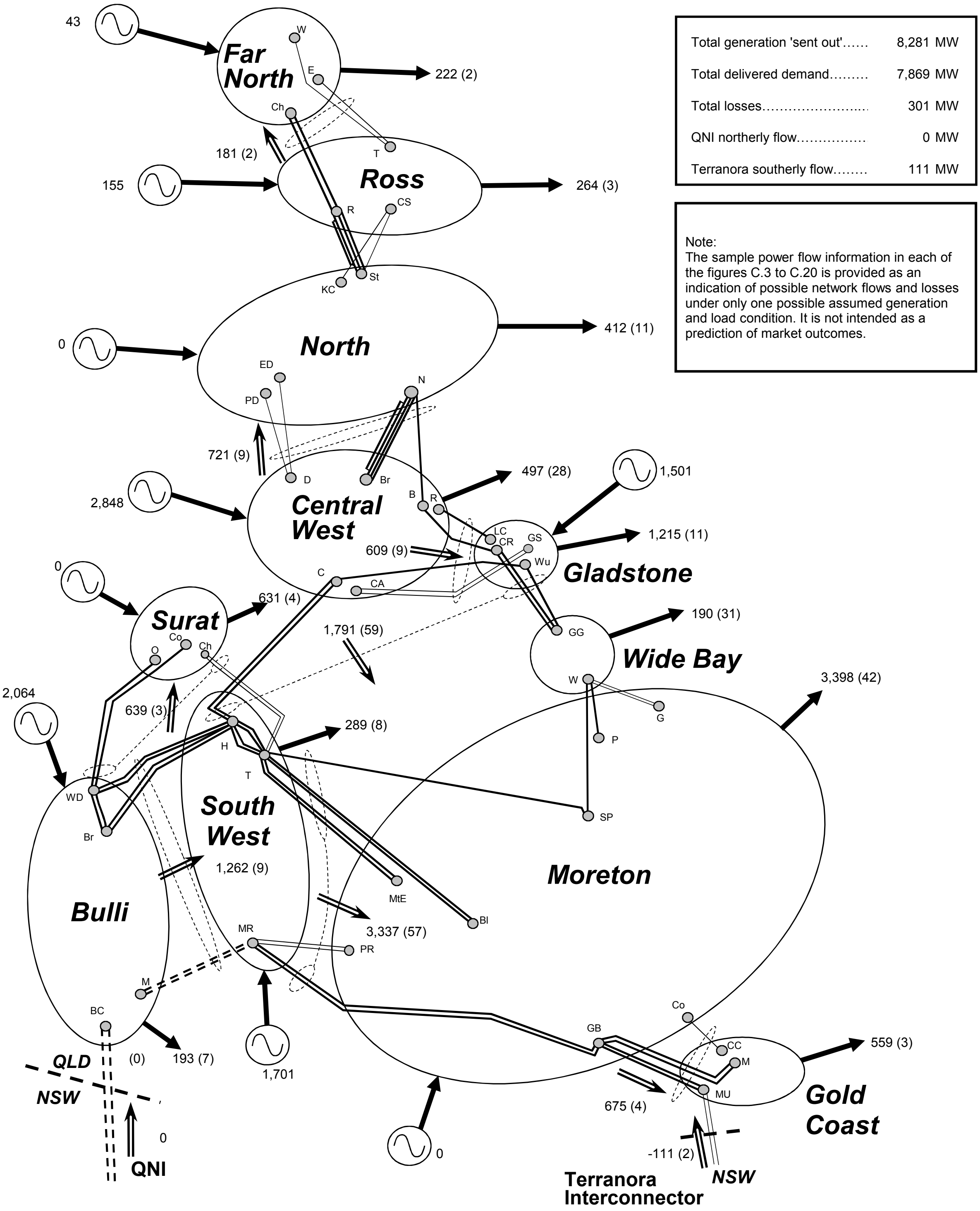
Figure C.9 Winter 2017 Queensland maximum demand 300MW northerly QNI flow



Total generation 'sent out'......	7,965 MW
Total delivered demand.........	7,869 MW
Total losses........................	284 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.

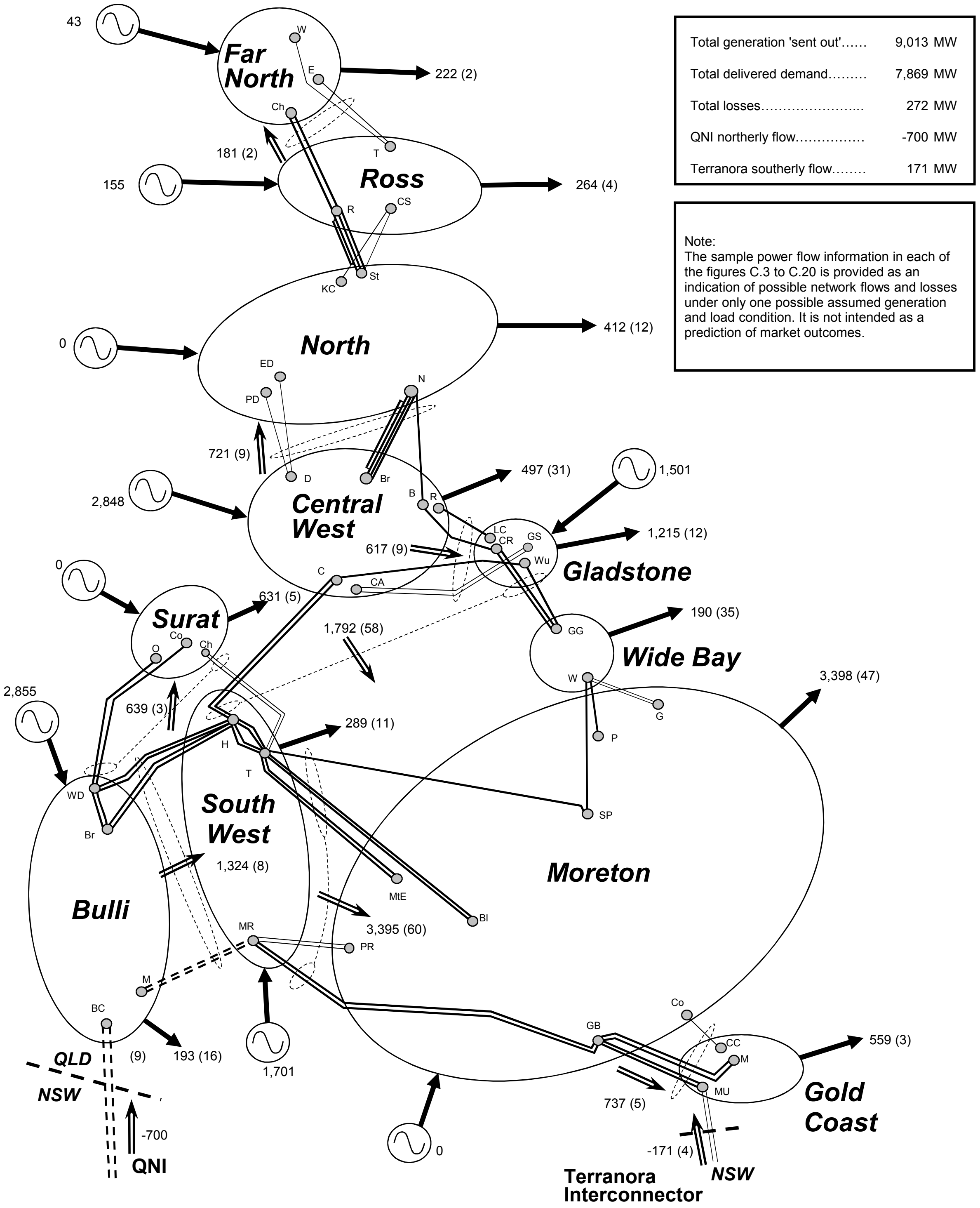
Figure C.10 Winter 2017 Queensland maximum demand 0MW QNI flow



Total generation 'sent out'……	8,281 MW
Total delivered demand………	7,869 MW
Total losses…………………….	301 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.

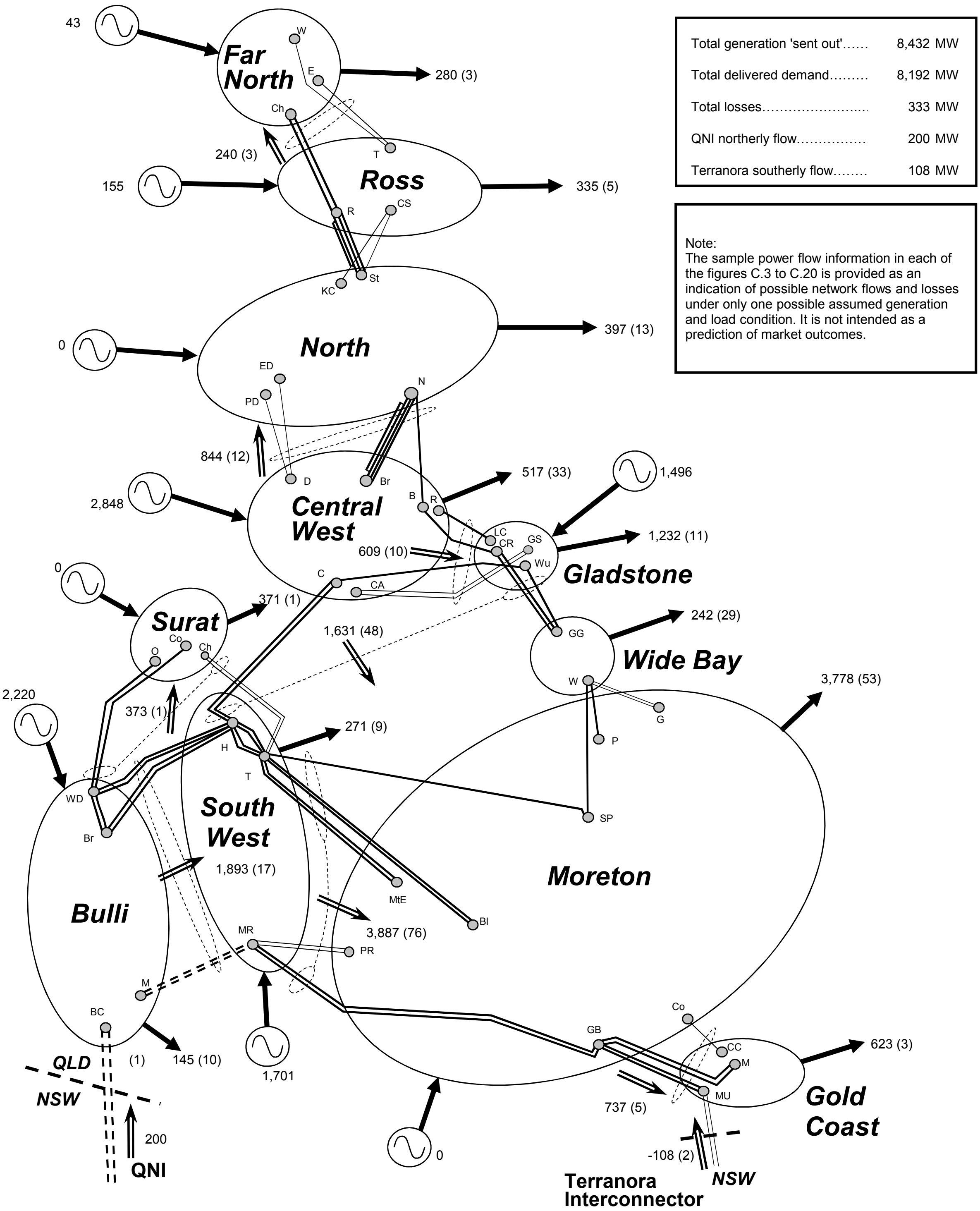
Figure C.11 Winter 2017 Queensland maximum demand 700MW southerly QNI flow



Total generation 'sent out'......	9,013 MW
Total delivered demand.........	7,869 MW
Total losses............................	272 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.

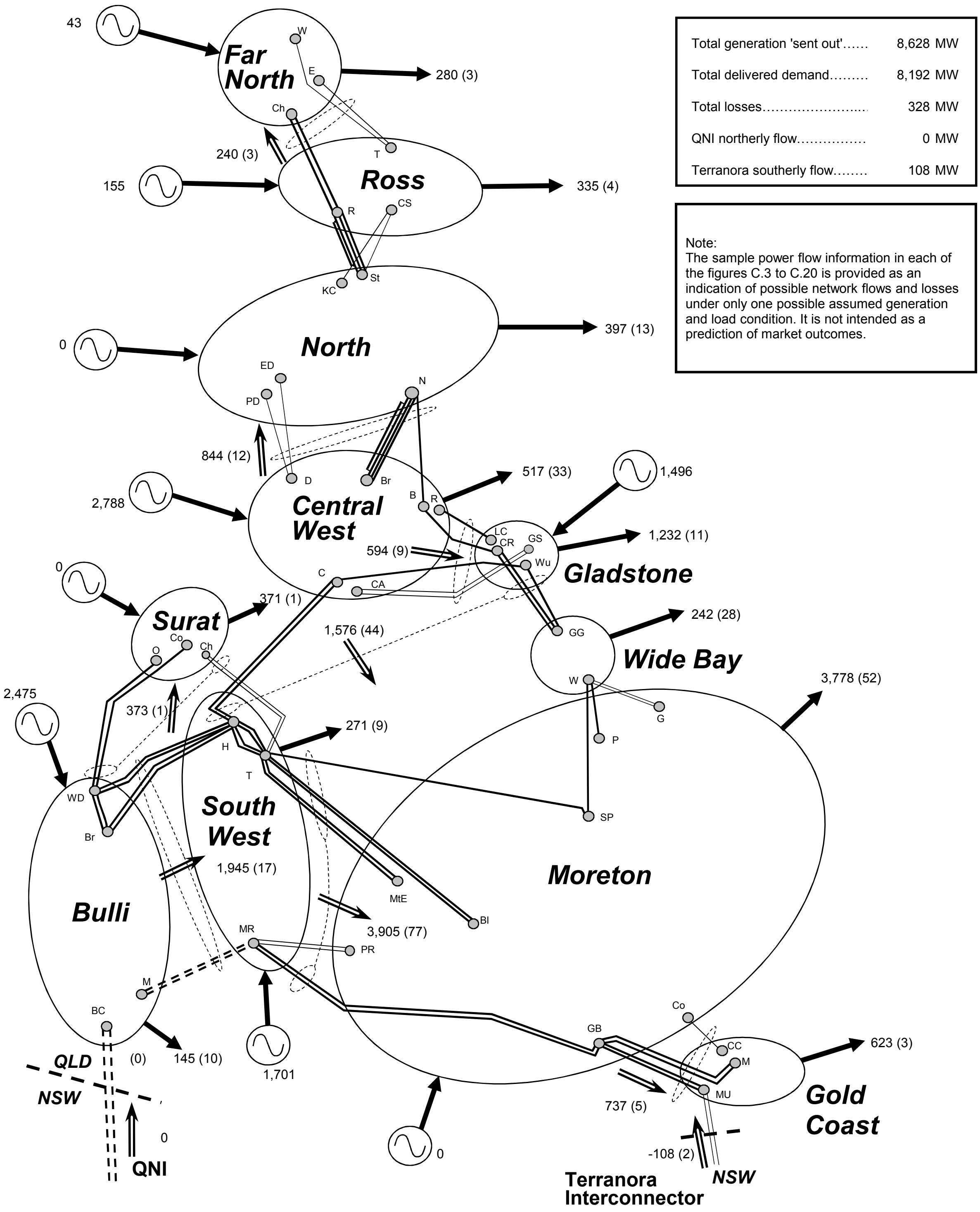
Figure C.12 Summer 2015/16 Queensland maximum demand 200MW northerly QNI flow



Total generation 'sent out'……	8,432 MW
Total delivered demand………	8,192 MW
Total losses……………………..	333 MW
QNI northerly flow…………….	200 MW
Terranora southerly flow……..	108 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.

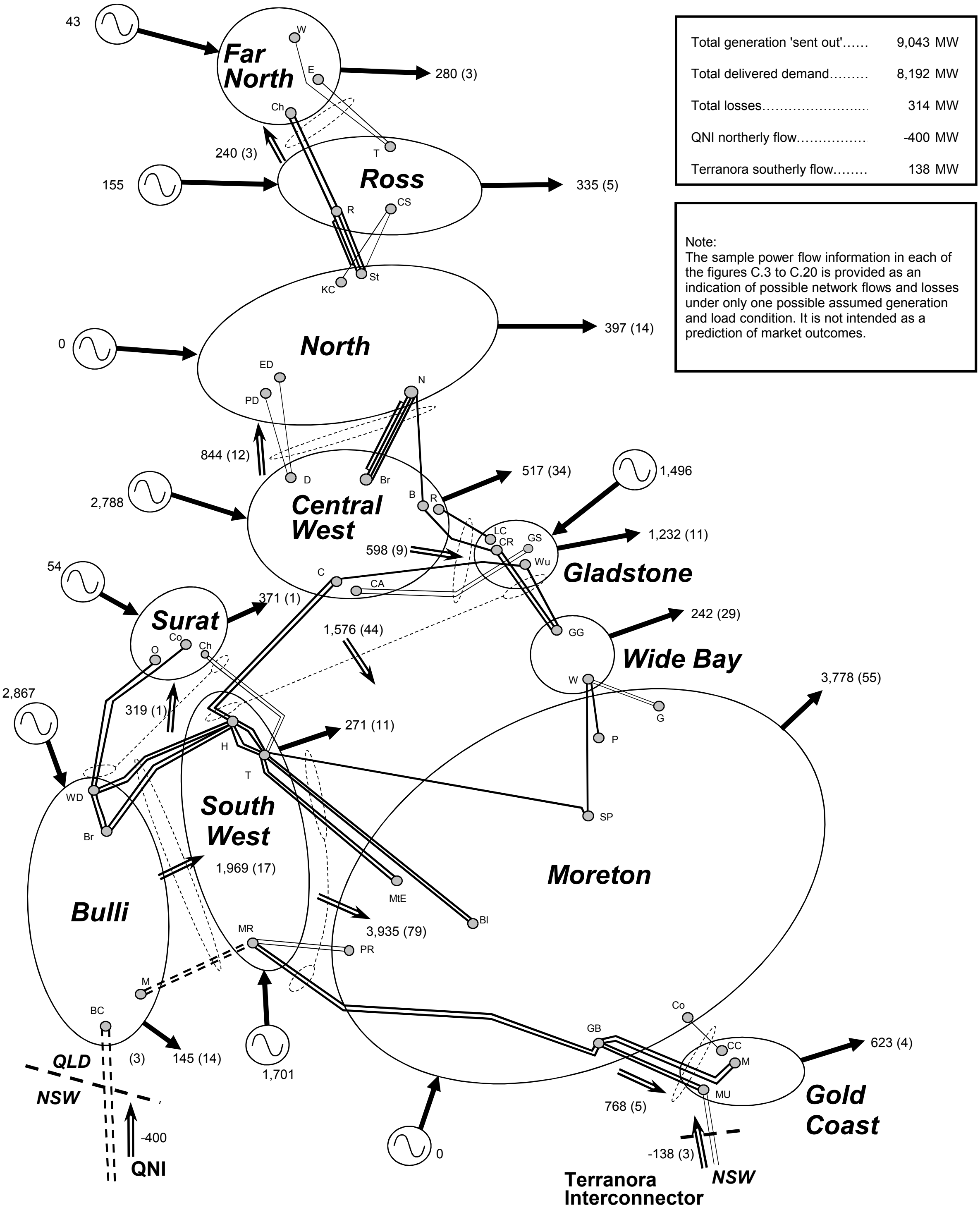
Figure C.13 Summer 2015/16 Queensland maximum demand 0MW QNI flow



Total generation 'sent out'……	8,628 MW
Total delivered demand………	8,192 MW
Total losses…………………….	328 MW
QNI northerly flow…………….	0 MW
Terranora southerly flow……..	108 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.

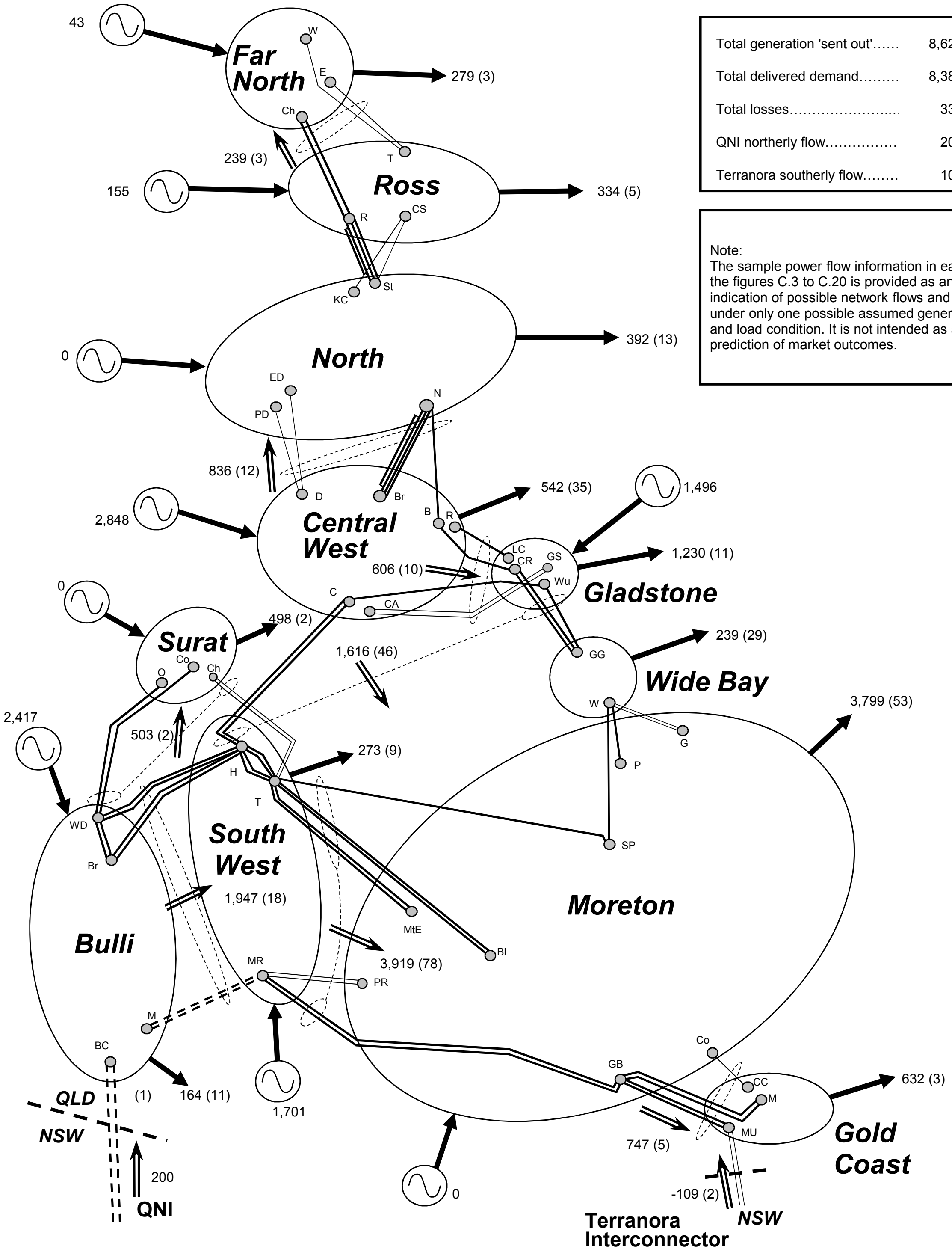
Figure C.14 Summer 2015/16 Queensland maximum demand 400MW southerly QNI flow



Total generation 'sent out'……	9,043 MW
Total delivered demand………	8,192 MW
Total losses……………………	314 MW
QNI northerly flow…………….	-400 MW
Terranora southerly flow……..	138 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.

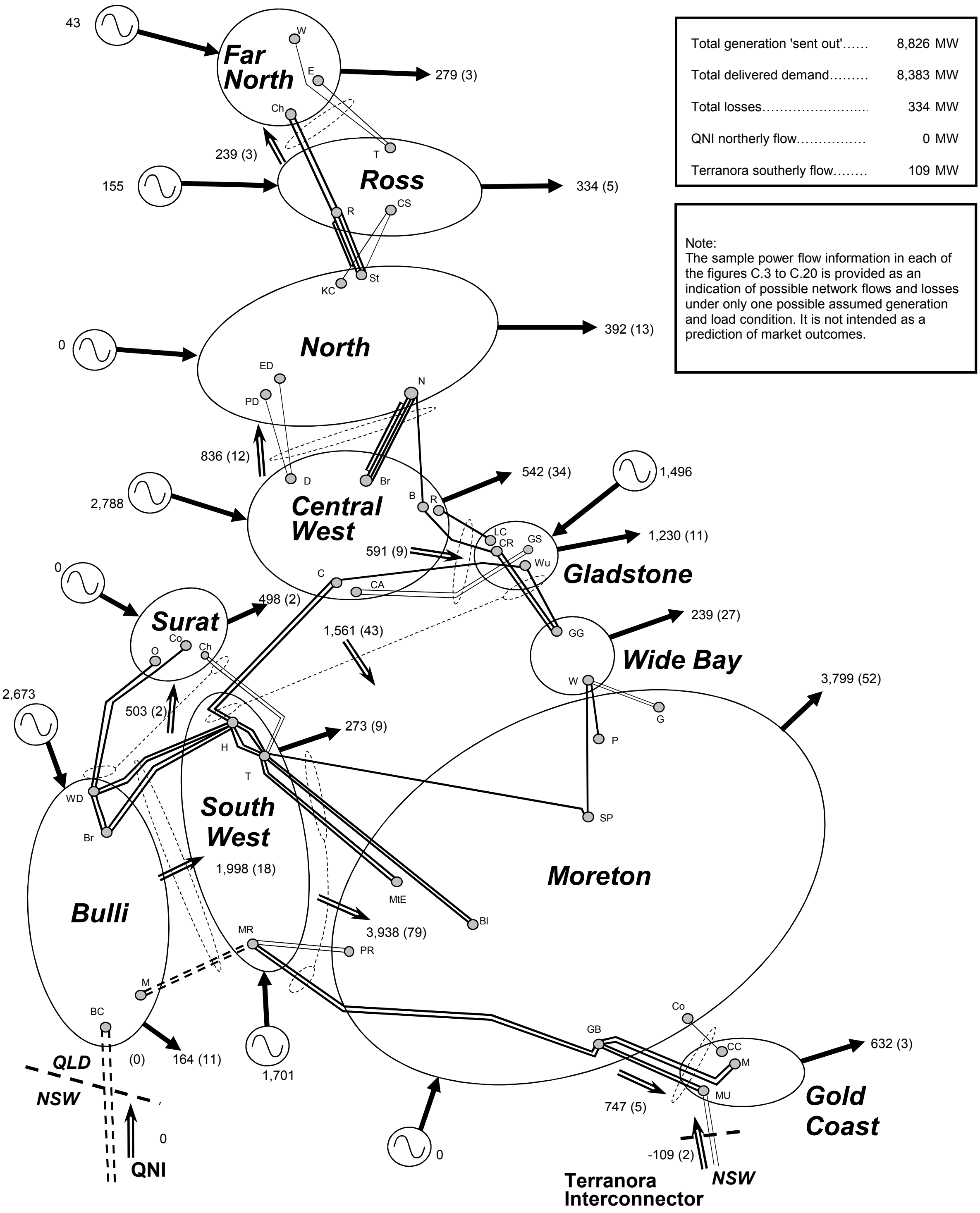
Figure C.15 Summer 2016/17 Queensland maximum demand 200MW northerly QNI flow



Total generation 'sent out'……	8,629 MW
Total delivered demand………	8,383 MW
Total losses……………………	337 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.

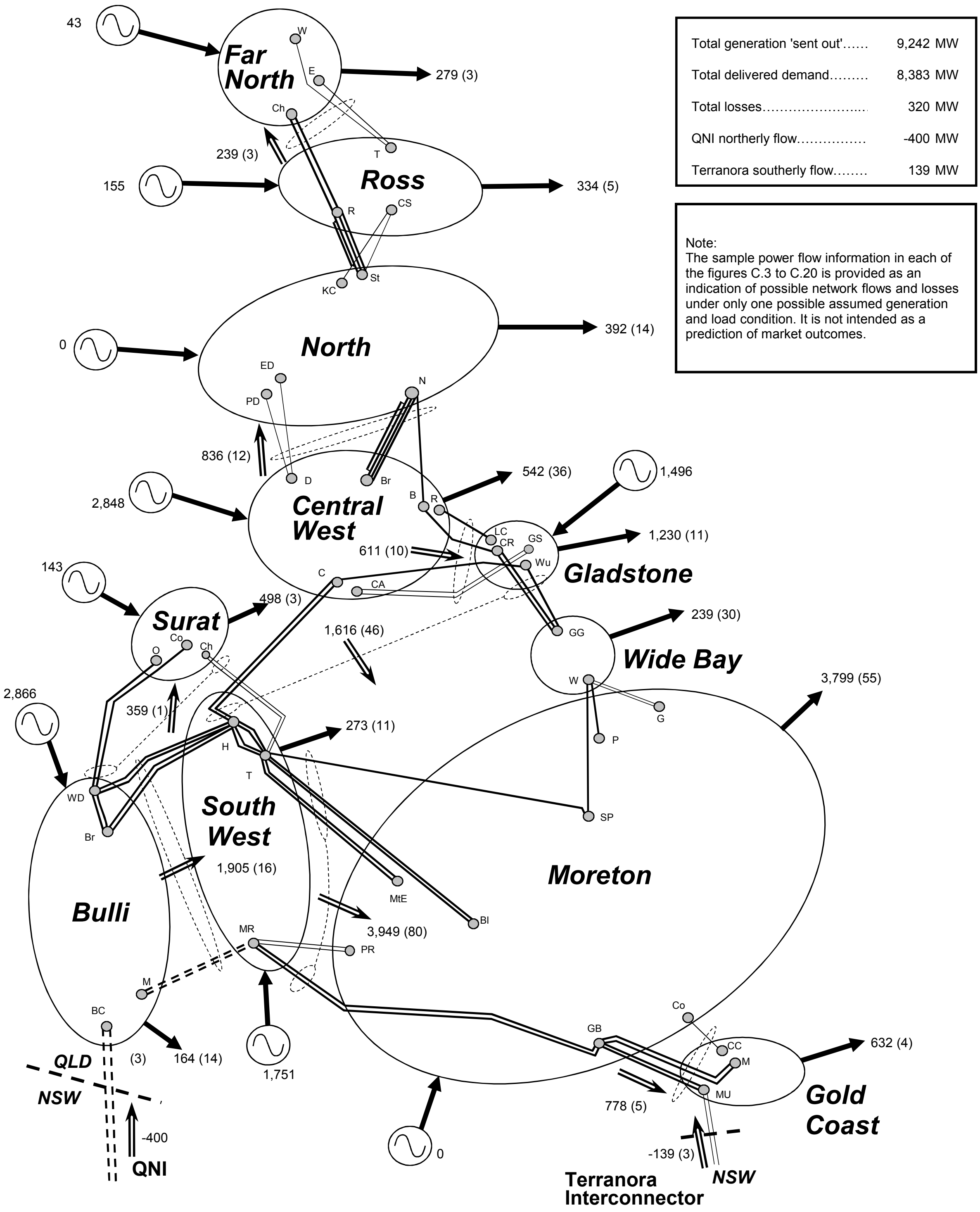
Figure C.16 Summer 2016/17 Queensland maximum demand 0MW QNI flow



Total generation 'sent out'……	8,826 MW
Total delivered demand………	8,383 MW
Total losses………………….…	334 MW
QNI northerly flow…………….	0 MW
Terranora southerly flow……..	109 MW

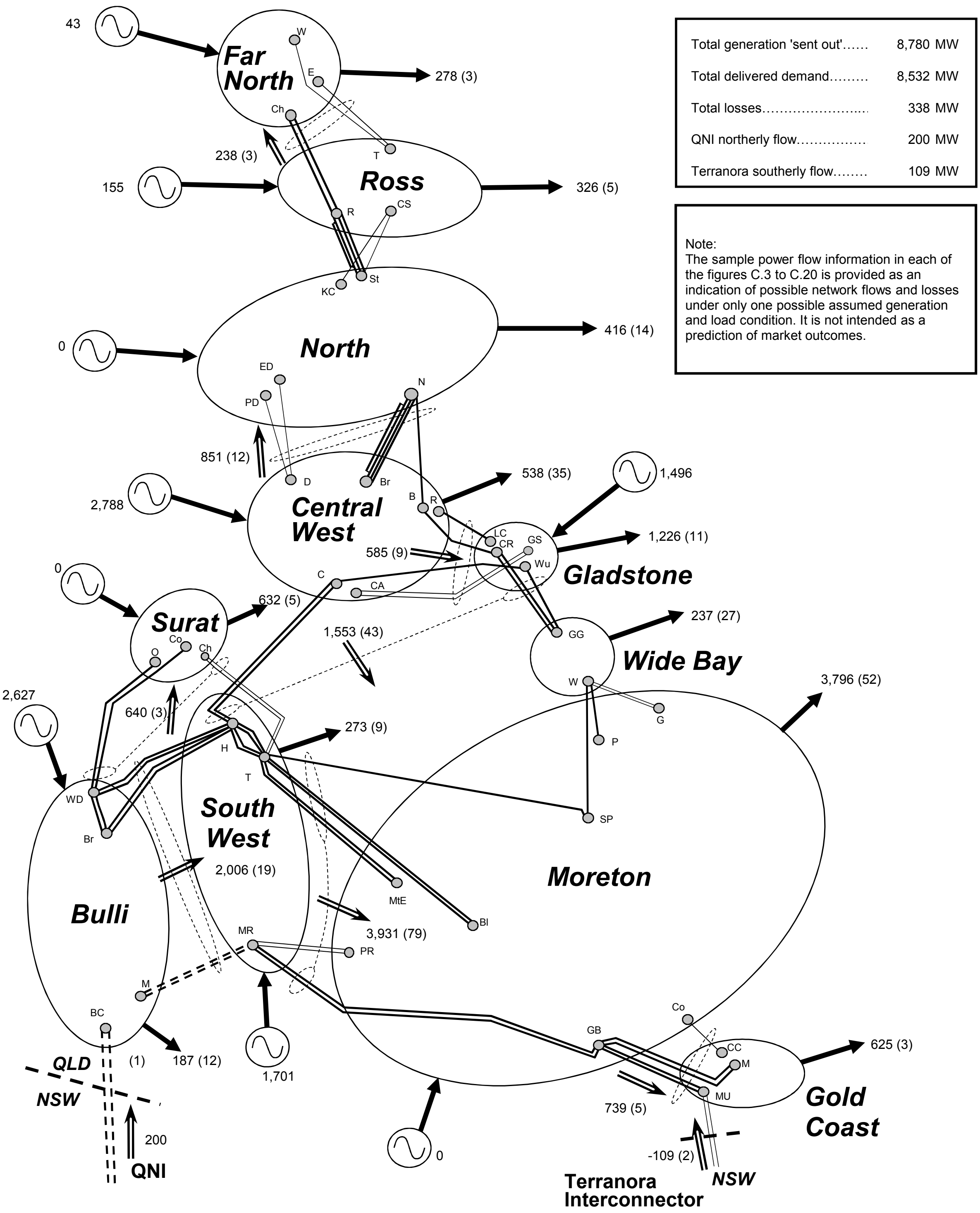
Note:
The sample power flow information in each of the figures C.3 to C.20 is provided as an indication of possible network flows and losses under only one possible assumed generation and load condition. It is not intended as a prediction of market outcomes.

Figure C.17 Summer 2016/17 Queensland maximum demand 400MW southerly QNI flow



Total generation 'sent out'......	9,242 MW
Total delivered demand.........	8,383 MW
Total losses..........................	320 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.

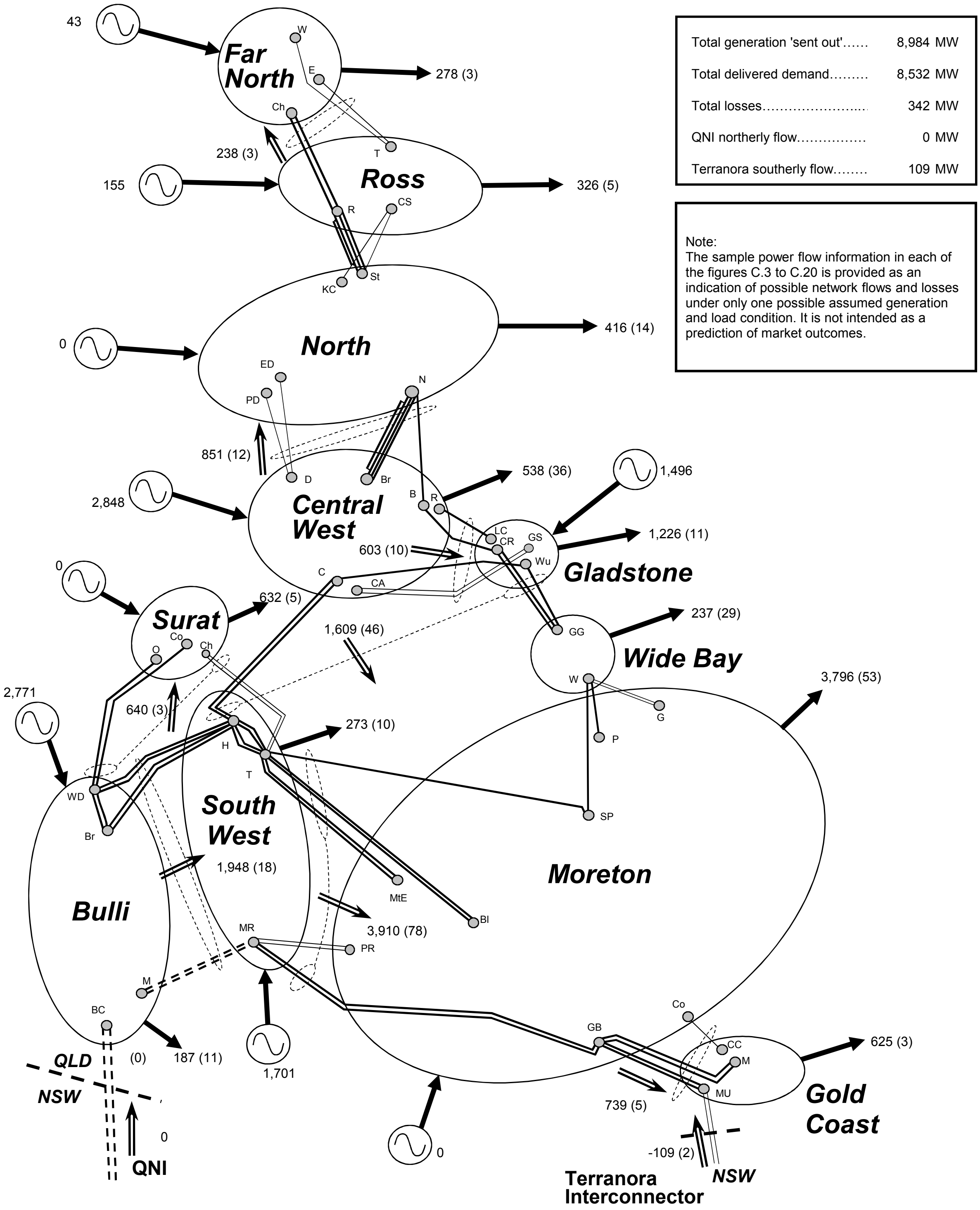


Total generation 'sent out'……	8,780 MW
Total delivered demand………	8,532 MW
Total losses…………………..	338 MW
QNI northerly flow…………….	200 MW
Terranora southerly flow……..	109 MW

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.18 Summer 2017/18 Queensland maximum demand 200MW northerly QNI flow

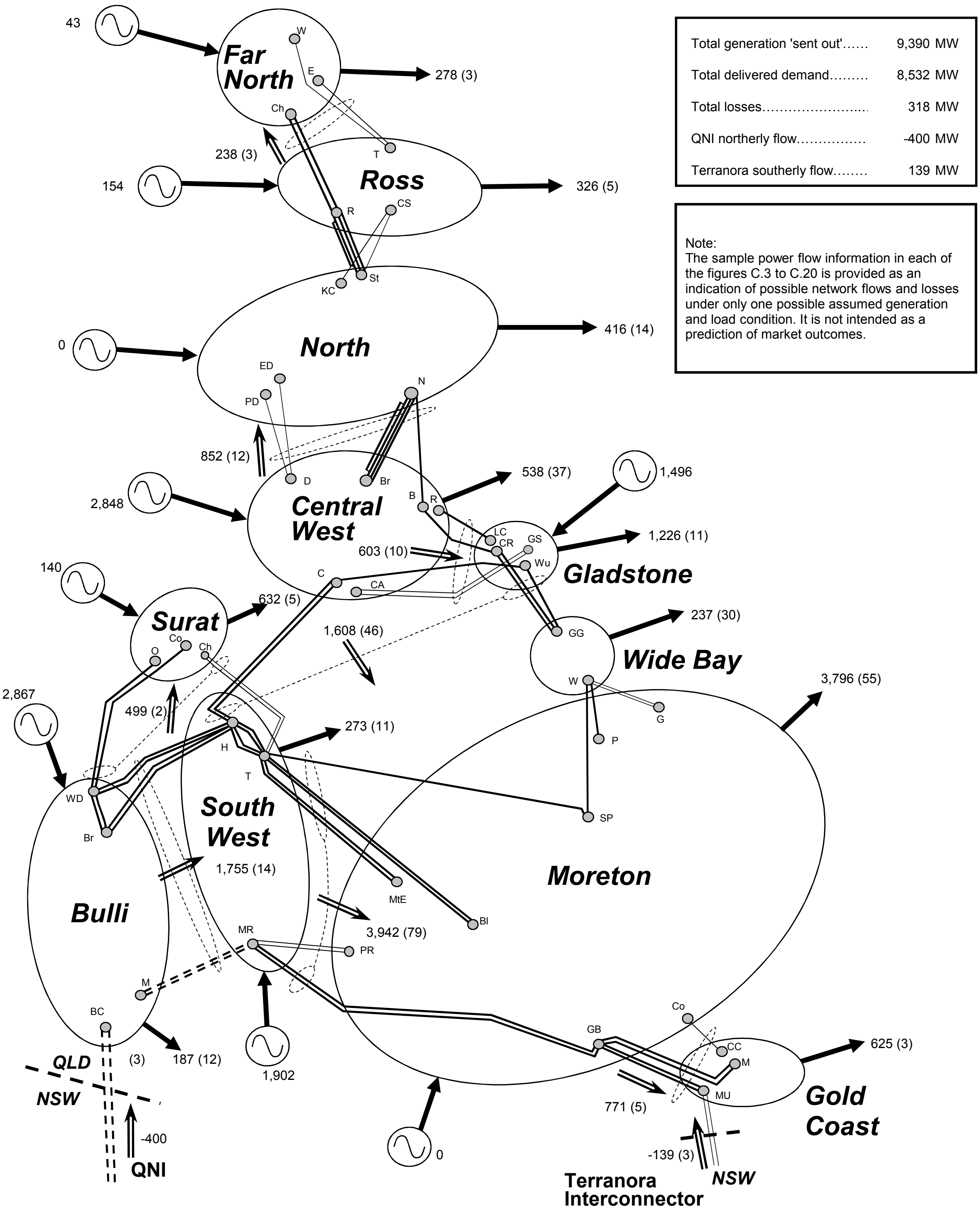
Figure C.19 Summer 2017/18 Queensland maximum demand 0MW QNI flow



Total generation 'sent out'……	8,984 MW
Total delivered demand………	8,532 MW
Total losses…………………..	342 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.20 Summer 2017/18 Queensland maximum demand 400MW southerly QNI flow



Total generation 'sent out'……	9,390 MW
Total delivered demand………	8,532 MW
Total losses………………………	318 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	1 x 84MVAr, 2 x 29.4MVAr
Ross 19.1kV	2 x 20.2MVAr

(4) The shunt capacitor bank locations, nominal sizes and quantities for the Strathmore area comprise the following:

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
Newlands 132kV	1 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**

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 40 capacitor banks of nominal size 50MVAr which may be available within this area.

(6) Reactive to active demand percentage $= \frac{\text{Zone reactive demand}}{\text{Zone active demand}} \times 100$

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 = $\frac{\text{Moreton zone active demand}}{\text{Gold Coast zone active demand}} \times 100$

(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 36 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 short circuit currents at Powerlink Queensland's substations. The tables also show indicative minimum short circuit currents.

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 2015/16, 2016/17 and 2017/18.

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[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 long-term solutions can be justified.

Indicative minimum short circuit currents

The connection of fluctuating load and reactive plant should consider the minimum short circuit current at the prospective point of connection to ensure that there is no adverse impact on power quality.

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 from a typical winter light load system condition and associated generation dispatch. The single network element that makes the greatest contribution to the symmetrical three phase short circuit fault current for each bus considered was also removed from service.

These minimum short circuit currents are indicative only. Fault currents can be lower for different generation dispatches and/or network elements out of service.

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[1] Swanbank E is out of service for Summer 15/16 consistent with Table 5.1. However, for the short circuit currents calculated for 2016/17 and 2017/18 Swanbank E is modelled in service. This was chosen on the basis that it is conservative for short circuit current assessment, Stanwell maintains a Connection and Access Agreement with Powerlink and Stanwell advises that a lead-time of six to nine months is required to restart Swanbank E.

Table E.1 Indicative short circuit currents – northern Queensland – 2015/16 to 2017/18

Substation	Voltage (kV)	Plant rating (lowest kA)	Indicative minimum 3 phase (kA)	Indicative maximum short circuit currents					
				2015/16		2016/17		2017/18	
				3 phase kA	L – G kA	3 phase kA	L – G kA	3 phase kA	L – G kA
Alan Sherriff	132	40.0	3.8	12.0	12.7	12.0	12.7	12.0	12.7
Alligator Creek	132	25.0	1.8	4.6	6.1	4.5	5.9	4.5	5.9
Bollingbroke	132	40.0	1.8	2.5	1.9	2.4	1.9	2.4	1.9
Bowen North	132	40.0	1.3	2.2	2.4	2.1	2.4	2.1	2.4
Burton Downs	132	19.3	3.9	5.1	4.9	5.1	4.9	5.1	4.9
Cairns (2T)	132	25.0	0.5	5.4	7.2	5.4	7.2	5.4	7.2
Cairns (3T)	132	25.0	0.5	5.4	7.2	5.4	7.2	5.4	7.2
Cairns (4T)	132	25.0	0.5	5.4	7.3	5.4	7.3	5.4	7.3
Cardwell	132	19.3	1.0	2.8	3.0	2.8	3.0	2.8	3.0
Chalumbin	275	31.5	1.3	3.7	4.0	3.7	4.0	3.7	4.0
Chalumbin	132	31.5	2.7	6.1	7.1	6.1	7.1	6.1	7.1
Clare South	132	40.0	2.9	7.2	7.6	7.1	7.5	7.1	7.5
Collinsville North	132	31.5	2.2	8.2	8.8	7.5	8.2	7.5	8.2
Coppabella	132	31.5	2.3	2.9	3.3	2.9	3.3	2.9	3.3
Dan Gleeson (Bus 1)	132	31.5	3.4	11.4	12.1	11.4	12.1	11.4	12.1
Dan Gleeson (Bus 2)	132	40.0	3.5	11.4	12.1	11.3	12.0	11.4	12.2
Edmonton	132	40.0	0.8	5.0	6.1	5.0	6.1	5.0	6.1
Eagle Downs	132	40.0	1.6	4.2	4.4	4.2	4.4	4.2	4.4
El Arish	132	40.0	1.0	3.1	3.7	3.1	3.7	3.1	3.7
Garbutt	132	40.0	1.7	10.2	10.5	10.2	10.5	10.2	10.5
Goonyella Riverside	132	40.0	3.3	5.3	5.1	5.3	5.0	5.3	5.0
Ingham South	132	31.5	1.0	2.8	2.8	2.8	2.8	2.8	2.8
Innisfail	132	40.0	1.2	2.7	3.3	2.7	3.3	2.7	3.3
Invicta	132	19.3	2.6	5.1	4.6	5.1	4.6	5.1	4.6
Kamerunga	132	15.3	0.6	4.3	5.1	4.3	5.1	4.3	5.1
Kareeya	132	40.0	2.9	5.3	6.0	5.3	6.0	5.3	6.0
Kemmis	132	31.5	3.6	5.8	6.4	5.8	6.4	5.8	6.4
King Creek	132	40.0	2.8	4.5	3.8	4.4	3.8	4.4	3.8
Mackay	132	10.9	1.7	6.6	7.5	4.7	5.4	5.6	6.6
Mackay Ports	132	40.0	1.6	3.6	4.2	3.5	4.1	3.5	4.1
Mindi	132	40.0	2.7	4.4	3.6	4.4	3.6	4.4	3.6

Table E.1 Indicative short circuit currents – northern Queensland – 2015/16 to 2017/18 *(continued)*

Substation	Voltage (kV)	Plant rating (lowest kA)	Indicative minimum 3 phase (kA)	Indicative maximum short circuit currents					
				2015/16		2016/17		2017/18	
				3 phase kA	L – G kA	3 phase kA	L – G kA	3 phase kA	L – G kA
Moranbah	132	10.9	4.2	6.7	8.3	6.6	8.1	6.6	8.1
Moranbah South	132	31.5	3.4	5.1	4.9	5.0	4.8	5.0	4.8
Mt McLaren	132	31.5	1.6	2.0	2.2	2.0	2.1	2.0	2.1
Nebo	275	31.5	3.7	9.4	9.9	9.4	9.9	9.4	9.9
Nebo	132	15.3	4.7	12.9	15.0	12.7	14.8	12.7	14.8
Newlands	132	25.0	1.3	3.4	3.8	3.3	3.8	3.3	3.8
North Goonyella	132	20.0	3.1	4.1	3.6	4.1	3.5	4.1	3.5
Oonooie	132	31.5	1.5	3.2	3.8	3.1	3.7	3.1	3.7
Peak Downs	132	31.5	1.7	3.9	3.7	3.9	3.7	3.9	3.7
Pioneer Valley	132	31.5	3.1	7.7	8.3	7.0	7.7	7.0	7.7
Proserpine	132	40.0	0.7	3.5	3.7	2.7	3.2	2.7	3.2
Ross	275	31.5	2.2	7.2	8.2	7.1	8.2	7.1	8.2
Ross	132	31.5	4.2	15.2	18.0	15.2	17.9	15.2	18.0
Stony Creek	132	40.0	1.3	3.5	3.5	3.4	3.4	3.4	3.4
Strathmore	275	31.5	2.7	7.8	8.4	7.8	8.3	7.8	8.3
Strathmore	132	40.0	2.3	8.9	10.1	8.2	9.5	8.2	9.5
Townsville East	132	40.0	1.4	11.7	11.7	11.6	11.7	11.6	11.7
Townsville South	132	20.0	4.0	15.1	18.8	15.1	18.8	15.1	18.8
Townsville PS Switchyard	132	31.5	2.4	9.8	10.5	9.8	10.5	9.8	10.5
Tully	132	31.5	1.9	3.7	3.9	3.7	3.9	3.7	3.9
Turkinje	132	20.0	1.2	2.6	3.0	2.6	3.0	2.6	3.0
Wandoo	132	31.5	2.7	4.5	3.1	4.5	3.1	4.5	3.1
Woree (1T)	275	40.0	0.9	2.6	3.0	2.6	3.0	2.6	3.0
Woree (2T)	275	40.0	0.9	2.6	3.0	2.6	3.0	2.6	3.0
Woree	132	40.0	2.5	5.6	7.7	5.6	7.7	5.6	7.7
Wotonga	132	40.0	3.3	5.5	5.5	5.5	6.7	5.5	6.6
Yabulu South	132	40.0	3.7	11.4	11.2	11.3	11.2	11.3	11.2

Table E.2 Indicative short circuit currents – central Queensland – 2015/16 to 2017/18

Substation	Voltage (kV)	Plant rating (lowest kA)	Indicative minimum 3 phase (kA)	Indicative maximum short circuit currents					
				2015/16		2016/17		2017/18	
				3 phase kA	L – G kA	3 phase kA	L – G kA	3 phase kA	L – G kA
Baralaba	132	15.3	2.2	4.7	4.0	4.7	4.0	4.7	4.0
Biloela	132	20.0	4.2	7.7	8.0	7.7	8.0	7.7	8.0
Blackwater	132	10.9	3.3	5.7	6.9	5.7	7.0	5.7	7.0
Bluff	132	40.0	2.0	2.7	3.5	2.7	3.5	2.7	3.5
Bouldercombe	275	31.5	9.1	19.7	19.5	19.7	19.5	19.7	19.5
Bouldercombe	132	21.8	8.3	14.5	16.8	14.5	16.8	14.5	16.8
Broadsound	275	31.5	4.5	11.3	8.6	11.3	8.6	11.3	8.6
Callemondah	132	31.5	7.2	24.2	26.6	24.2	26.6	24.2	26.6
Callide A (1)	132	11.0	2.6	10.8	11.7	10.8	11.7	10.8	11.7
Calliope River	275	40.0	8.4	21.0	23.9	21.0	24.0	21.0	24.0
Calliope River	132	40.0	16.3	27.1	32.3	27.1	32.4	27.1	32.4
Calvale	275	31.5	11.2	23.8	26.1	23.9	26.1	23.9	26.1
Calvale	132	31.5	2.5	10.8	11.7	10.8	11.8	10.8	11.8
Dingo	132	31.5	1.1	2.7	2.9	2.7	2.9	2.7	2.9
Duaringa	132	40.0	1.9	2.1	2.8	2.1	2.8	2.1	2.8
Dysart	132	10.9	2.1	4.4	5.2	4.4	5.2	4.4	5.2
Egans Hill	132	25.0	1.5	8.3	8.2	8.3	8.2	8.3	8.2
Gladstone PS	275	40.0	9.3	19.6	21.7	19.6	21.8	19.6	21.8
Gladstone PS	132	40.0	12.8	23.4	26.0	23.4	26.1	23.4	26.1
Gladstone South	132	40.0	10.4	18.8	19.3	18.8	19.3	18.8	19.3
Grantleigh	132	31.5	2.2	2.7	2.8	2.7	2.8	2.7	2.8
Gregory	132	31.5	5.0	8.8	10.1	8.8	10.2	8.8	10.2
Larcom Creek	275	40.0	3.4	15.5	15.5	15.5	15.5	15.5	15.5
Larcom Creek	132	40.0	4.1	12.4	13.8	12.5	13.8	12.5	13.8
Lilyvale	275	31.5	2.7	5.6	5.6	5.6	5.7	5.6	5.7
Lilyvale	132	25.0	5.1	9.2	10.9	9.2	11.0	9.2	11.0
Moura	132	12.3	1.6	4.0	4.3	4.0	4.3	4.0	4.3
Norwich Park	132	31.5	1.3	3.5	2.6	3.5	2.6	3.5	2.6
Pandoin	132	40.0	4.6	6.9	6.2	7.0	6.3	7.0	6.3
Raglan	275	40.0	4.5	11.9	10.4	11.9	10.4	11.9	10.4
Rockhampton	132	10.9	4.9	8.5	8.5	6.5	6.4	6.5	6.4
Rocklands	132	31.5	5.2	7.7	6.6	7.7	6.6	7.7	6.6

Table E.2 Indicative short circuit currents – central Queensland – 2015/16 to 2017/18 *(continued)*

Substation	Voltage (kV)	Plant rating (lowest kA)	Indicative minimum 3 phase (kA)	Indicative maximum short circuit currents					
				2015/16		2016/17		2017/18	
				3 phase kA	L – G kA	3 phase kA	L – G kA	3 phase kA	L – G kA
Stanwell Switchyard	275	31.5	9.8	22.4	24.1	22.4	24.1	22.4	24.1
Stanwell Switchyard	132	31.5	4.3	6.0	6.6	6.0	6.5	6.0	6.5
Wurdong	275	31.5	7.3	17.0	16.8	17.0	16.8	17.0	16.8
Wycarbah	132	40.0	3.4	4.6	5.6	4.5	5.5	4.5	5.5
Yarwun	132	40.0	4.8	13.0	15.0	13.0	15.0	13.0	15.0

Note:

(1) This location is operated with open points to keep short circuit currents below plant ratings.

Table E.3 Indicative short circuit currents – southern Queensland – 2015/16 to 2017/18

Substation	Voltage (kV)	Plant rating (lowest kA)	Indicative minimum 3 phase (kA)	Indicative maximum short circuit currents					
				2015/16		2016/17		2017/18	
				3 phase kA	L – G kA	3 phase kA	L – G kA	3 phase kA	L – G kA
Abermain	275	40.0	7.1	16.3	17.3	17.9	18.6	17.9	18.6
Abermain	110	31.5	11.6	20.4	24.3	21.3	25.2	21.3	25.2
Algester	110	40.0	12.9	20.5	20.6	21.5	21.2	21.5	21.2
Ashgrove West	110	26.3	12.6	18.4	19.5	19.0	19.9	19.0	19.9
Belmont	275	31.5	8.5	15.3	17.4	16.7	18.5	16.7	18.5
Belmont	110	37.4	17.5	27.8	35.1	29.7	37.0	29.7	37.0
Blackwall	275	37.0	9.8	20.0	22.3	22.0	23.9	22.0	23.9
Blackstone	275	40.0	9.2	18.2	20.9	20.9	23.2	20.9	23.2
Blackstone	110	40.0	15.1	23.9	27.7	25.2	28.9	25.2	28.9
Blythdale	132	40.0	2.4	–	–	4.1	5.2	4.1	5.2
Braemar	330	50.0	9.0	22.7	25.1	22.9	25.3	22.9	25.3
Braemar (East)	275	40.0	6.2	26.1	30.9	26.4	31.1	26.4	31.1
Braemar (West)	275	40.0	7.7	26.0	29.1	26.2	29.3	26.2	29.3
Bulli Creek	330	50.0	8.6	17.9	14.2	18.1	14.2	18.1	14.2
Bulli Creek	132	40.0	3.4	3.8	4.3	3.8	4.3	3.8	4.3
Bundamba	110	40.0	8.4	16.6	16.2	17.2	16.6	17.2	16.6
Chinchilla	132	25.0	4.6	7.9	7.8	7.9	7.8	7.9	7.8
Clifford Creek	132	40.0	3.7	5.5	5.1	5.5	5.1	5.5	5.1
Columboola	275	40.0	0.7	12.1	11.7	12.2	11.7	12.2	11.7
Columboola	132	25.0	6.3	15.3	17.2	15.4	17.2	15.4	17.2
Condabri North	132	40.0	6.5	12.6	11.7	12.7	11.7	12.7	11.7
Condabri Central	132	40.0	4.7	8.8	6.6	8.8	6.6	8.8	6.6
Condabri South	132	40.0	3.8	6.5	4.5	6.5	4.5	6.5	4.5
Dinoun South	132	40.0	4.6	6.2	6.6	6.2	6.6	6.2	6.6
Eurombah (1T)	275	40.0	3.0	4.2	4.6	4.2	4.6	4.2	4.6
Eurombah (2T)	275	40.0	3.0	4.2	4.6	4.2	4.6	4.2	4.6
Eurombah	132	40.0	4.0	6.5	8.0	6.5	8.0	6.5	8.0
Fairview	132	40.0	2.8	3.9	5.0	3.9	5.0	3.9	5.0
Fairview South	132	40.0	3.3	5.0	6.4	5.0	6.5	5.0	6.5
Gin Gin	275	14.5	6.2	10.9	10.0	10.9	10.0	10.9	10.0
Gin Gin	132	20.0	6.4	12.8	13.9	12.8	13.9	12.8	14.0
Goodna	275	40.0	2.6	14.9	15.2	16.0	15.9	16.0	15.9
Goodna	110	40.0	14.4	24.0	26.4	25.3	27.4	25.3	27.4

Table E.3 **Indicative short circuit currents – southern Queensland – 2015/16 to 2017/18** *(continued)*

Substation	Voltage (kV)	Plant rating (lowest kA)	Indicative minimum 3 phase (kA)	Indicative maximum short circuit currents					
				2015/16		2016/17		2017/18	
				3 phase kA	L – G kA	3 phase kA	L – G kA	3 phase kA	L – G kA
Greenbank	275	40.0	9.2	17.8	20.5	20.2	22.4	20.2	22.4
Halys	275	50.0	12.9	30.4	25.5	31.3	26.0	31.3	26.0
Kumbarilla Park (1T)	275	40.0	1.8	16.4	15.9	16.5	16.0	16.5	16.0
Kumbarilla Park (2T)	275	40.0	1.8	16.4	15.9	16.5	16.0	16.5	16.0
Kumbarilla Park	132	40.0	6.3	13.1	15.2	13.1	15.2	13.1	15.2
Loganlea	275	40.0	6.8	13.6	14.5	14.8	15.4	14.8	15.4
Loganlea	110	25.0	12.5	21.7	26.1	22.8	27.2	22.8	27.2
Middle Ridge (4T)	330	50.0	4.0	12.2	11.9	12.5	12.2	12.5	12.2
Middle Ridge (5T)	330	50.0	4.0	12.5	12.3	12.9	12.6	12.9	12.6
Middle Ridge	275	31.5	8.6	17.2	17.6	17.8	18.0	17.8	18.0
Middle Ridge	110	18.3	10.5	20.0	23.7	20.3	24.0	20.3	24.1
Millmerran Switchyard	330	40.0	8.8	18.0	19.4	18.2	19.6	18.2	19.6
Molendinar (1T)	275	40.0	2.3	7.8	7.8	8.2	8.1	8.2	8.1
Molendinar (2T)	275	40.0	2.3	7.8	7.8	8.2	8.1	8.2	8.1
Molendinar	110	40.0	12.3	19.0	24.2	20.0	25.2	20.0	25.2
Mt England	275	31.5	9.5	20.7	21.6	22.4	22.7	22.4	22.7
Mudgeeraba	275	31.5	4.9	8.9	9.1	9.4	9.5	9.4	9.5
Mudgeeraba	110	25.0	12.9	17.8	22.0	18.7	22.8	18.7	22.8
Murarrie (2T)	275	40.0	2.6	12.1	12.7	13.0	13.4	13.0	13.4
Murarrie (3T)	275	40.0	2.6	12.1	12.9	13.0	13.5	13.0	13.5
Murarrie	110	40.0	14.8	23.0	28.0	24.2	29.2	24.2	29.2
Oakey GT PS	110	31.5	5.4	10.8	12.0	10.8	12.0	10.8	12.0
Oakey	110	40.0	1.2	10.0	10.0	10.1	10.0	10.1	10.0
Orana	275	40.0	8.3	14.5	13.7	14.5	13.8	14.5	13.8
Palmwoods	275	31.5	3.6	8.3	8.7	8.4	8.8	8.4	8.9
Palmwoods	132	21.9	8.7	12.8	15.4	13.0	15.5	13.0	15.7
Palmwoods (7T)	110	40.0	2.8	7.2	7.5	7.2	7.5	7.2	7.5
Palmwoods (8T)	110	40.0	2.8	7.2	7.5	7.2	7.5	7.2	7.5
Redbank Plains	110	31.5	10.5	20.3	20.2	21.2	20.8	21.3	20.8
Richlands	110	40.0	12.3	21.1	22.1	22.0	22.7	22.0	22.7
Rocklea (1T)	275	31.5	2.5	12.4	11.8	13.1	12.3	13.1	12.3

Table E.3 Indicative short circuit currents – southern Queensland – 2015/16 to 2017/18 *(continued)*

Substation	Voltage (kV)	Plant rating (lowest kA)	Indicative minimum 3 phase (kA)	Indicative maximum short circuit currents					
				2015/16		2016/17		2017/18	
				3 phase kA	L – G kA	3 phase kA	L – G kA	3 phase kA	L – G kA
Rocklea (2T)	275	31.5	2.6	8.5	8.2	8.7	8.4	8.7	8.4
Rocklea	110	31.5	14.6	23.8	27.8	24.8	28.7	24.8	28.7
Runcorn	110	40.0	9.5	18.6	19.1	19.3	19.6	19.3	19.6
South Pine	275	31.5	8.9	17.4	20.2	18.5	21.1	18.5	21.1
South Pine (West)	110	40.0	11.3	19.7	22.9	20.3	23.5	20.3	23.5
South Pine (East)	110	40.0	13.0	20.8	26.9	21.4	27.5	21.4	27.5
Sumner	110	40.0	10.1	19.8	19.7	20.6	20.2	20.6	20.2
Swanbank E	275	40.0	8.4	17.9	20.5	20.6	22.7	20.6	22.7
Tangkam	110	31.5	4.2	12.7	12.0	12.8	12.0	12.8	12.0
Tarong (1)	275	31.5	13.7	31.6	33.6	32.8	34.5	32.8	34.5
Tarong (1T)	132	25.0	1.2	5.8	6.0	5.8	6.1	5.8	6.1
Tarong (4T)	132	25.0	1.2	5.8	6.0	5.8	6.1	5.8	6.1
Tarong	66	40.0	7.0	14.9	16.1	15.0	16.2	15.0	16.2
Teebar Creek	275	40.0	3.2	7.3	7.2	7.3	7.2	7.3	7.2
Teebar Creek	132	40.0	6.0	10.1	11.1	10.1	11.2	10.1	11.2
Tennyson	110	40.0	1.9	15.6	15.2	16.0	15.5	16.0	15.5
Upper Kedron	110	40.0	13.3	20.4	18.3	21.1	18.7	21.1	18.7
Wandoan South	275	40.0	3.2	7.0	7.7	7.0	7.7	7.0	7.7
Wandoan South	132	40.0	4.5	8.2	10.5	8.2	10.5	8.2	10.5
West Darra	110	40.0	15.0	23.6	23.1	24.8	23.8	24.8	23.8
Western Downs	275	40.0	11.6	23.9	24.1	24.1	24.3	24.1	24.3
Woolooga	275	31.5	5.5	9.5	10.7	9.6	10.8	9.6	10.8
Woolooga	132	20.0	7.7	12.9	15.4	13.0	15.5	13.0	15.5
Yuleba North	275	40.0	3.3	5.7	6.4	5.7	6.4	5.7	6.4
Yuleba North	132	40.0	4.4	7.3	8.9	7.3	8.9	7.3	8.9

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
APLNG	Australia Pacific Liquefied Natural Gas
APR	Annual Planning Report
BSL	Boyne Smelters Limited
CQ	Central Queensland
CSM	Coal Seam Methane
DNSP	Distribution Network Service Provider
ESOO	Electricity Statement of Opportunity
FNQ	Far North Queensland
GLNG	Gladstone Liquefied Natural Gas
GT	Gas Turbine
GWh	Gigawatt hour
JPB	Jurisdictional Planning Body
kA	Kiloampere
kV	Kilovolt
LNG	Liquefied natural gas
MVA	Megavolt Ampere
MVAr	Megavolt Ampere reactive
MW	Megawatt
MWh	Metawatt 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
PACR	Project Assessment Conclusions Report
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
RIT-T	Regulatory Investment Test for Transmission
SEQ	South East Queensland
SQ	South Queensland
SVC	Static VAr Compensator
SWQ	South West Queensland
TAPR	Transmission Annual Planning Report
TCSC	Thyristor Controlled Series Capacitor
TNSP	Transmission Network Service Provider
WD	Weather dependent

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