annual planning report 2003

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COMMONLY USED ABBREVIATIONS

ACCC	Australian Competition and Consumer Commission
APR	Annual Planning Report
CB	Circuit Breaker
CBD	Central Business District
CCGT	Combined Cycle Gas Turbine
CQ	Central Queensland
DNSP	Distribution Network Service Provider
DSM	Demand Side Management
GSP	Gross State Product
GT	Gas Turbine
GWh	Gigawatt hour, one million kilowatt hours
IRPC	Inter Regional Planning Committee
kA	kiloamperes, one thousand amperes
kV	kilovolts, one thousand volts
MNSP	Market Network Service Provider
MVAr	Megavar, megavolt amperes reactive, one thousand kilovolt amperes reactive
MW	Megawatt, one thousand kilowatts
NEC	National Electricity Code
NEM	National Electricity Market
NEMMCO	National Electricity Market Management Company
NEMDE	National Electricity Market Dispatch Engine
NIEIR	National Institute of Economic and Industrial Research
NPV	Net Present Value
NQ	North Queensland
OCGT	Open Cycle Gas Turbine
PoE	Probability of Exceedance
PSS	Power System Stabiliser
QNI	Queensland-New South Wales Interconnection
SCADA	Supervisory Control and Data Acquisition
SEQ	South East Queensland
SOO	Statement of Opportunities, published annually by NEMMCO
SVC	Static Var Compensator
SWQ	South West Queensland
TNSP	Transmission Network Service Provider

EXECUTIVE SUMMARY

Powerlink Queensland has been appointed by the Queensland government to undertake transmission network planning in the State, and is the owner and operator of the Queensland electricity transmission network.

Powerlink has prepared this Annual Planning Report to document the annual planning review it has carried out, as required by the National Electricity Code.

The Annual Planning Report provides information about the electricity transmission network to Code participants and interested parties. It includes information on electricity demand forecasts, the existing electricity supply system including committed generation and network developments, estimates of grid capability and potential network developments.

Electricity usage in Queensland has grown strongly during the past ten years, and this trend is expected to continue. Summer maximum demand delivered from the transmission grid is forecast to increase at an average annual rate of 3.6% p.a. from 6462MW in 2002/03 to 9172MW in 2012/13. However, this ten year average masks the accelerated summer demand growth in the immediate three year period, particularly in south east Queensland where the summer peak demand is forecast to grow on average by around 6% annually. This accelerated demand growth is attributable to the expected continued high penetration and usage of domestic air conditioners and population growth. Annual energy to be delivered by the Queensland transmission grid is forecast to increase at an average rate of 3.1% p.a. over the next ten years for the medium growth scenario. Areas contributing most to this growth include Moreton North, Moreton South and Gold Coast/Tweed Zones, all in south east Queensland, which are experiencing energy growth of 4.0%, 3.6% and 3.8% p.a. respectively.

This high level of load growth is likely to require substantial augmentation of the capability of the Queensland transmission network to ensure grid capacity keeps pace with demand, particularly in the south eastern part of the state.

The most significant projects completed since the 2002 Annual Planning Report include the Stanwell to Broadsound 275kV transmission line which has augmented transmission capacity to north Queensland, and conversion of one of the Chalumbin to Woree (near Cairns) 132kV transmission lines to 275kV operation. In addition, network support contracts continued with power stations in north Queensland to allow ongoing management of network limitations. Following consultations with participants and interested parties, Powerlink is also carrying out major augmentations of its system supplying southern Brisbane through construction of the Blackwall to Belmont 275kV transmission line, and within the Gold Coast through establishment of the Molendinar 275/110kV substation. Powerlink is also constructing a 275kV line between Broadsound and Lilyvale to augment transmission capacity to the mining area of inland central Queensland. Smaller augmentations such as the installation of capacitor banks and transformer upgrades are also underway to satisfy network reliability standards.

As noted in previous planning reports, the development of the network to meet forecast load depends on the location and capacity of new scheduled generation developments on future generation patterns in the National Electricity Market, and on the development of non-scheduled embedded generation. For several years, Queensland has been characterised by considerable electricity supply side uncertainty that has made planning the transmission grid very difficult. While the uncertainty associated with the competitive market remains, the generation outlook in Queensland has become less uncertain. The 853MW Millmerran

Power Station, the 355MW Swanbank E Power Station and the 450MW Tarong North Power Station have all been commissioned since the publication of the 2002 Annual Planning Report. Works are currently underway for conversion and upgrade of the Townsville (Yabulu) power station to gas operation by 2005, including construction of the associated gas pipeline from the Bowen Basin to Townsville.

These significant generation developments will alter flows on the Queensland transmission grid, as these generators compete in the wholesale electricity market to supply the forecast load in Queensland and the interconnected states of NSW, Victoria and South Australia.

Powerlink is closely monitoring flows on the Queensland-New South Wales interconnector, and is working with its NSW counterpart, TransGrid, to identify augmentation options that could be implemented to relieve potential future constraints should this be warranted. At the time of writing this report, testing of the proposed increased southward capacity of the interconnector (950MW, up from 750MW) is underway. This increase in capacity was made possible due to extensive testing and the revision of transfer limits following commissioning of the Millmerran and Tarong North power stations. Testing will continue with a view to increasing the maximum southward capacity above 950MW.

Within Queensland, Powerlink's transmission grid reached transfer limits at most 'grid sections' for less than 1% of the time during the six months from October 2002 to March 2003, the period of highest loads. However, the CQ-NQ Limit reached transfer limits for over 1% for the previous six month period (April 2002 to September 2002). This was strongly impacted by low local hydro generation. This transfer is managed by a network support arrangement between Powerlink and north Queensland generators. The reduced occurrence of limiting transfers in the more recent period is a combined result of the network support arrangements and the significant increase in the transfer limit (800MW to 985MW) resulting from the Stanwell to Broadsound transmission line commissioned in November 2002.

Powerlink's expectation is that other 'grid sections', such as that between Tarong and Brisbane, and the grid supplying the Gold Coast, will continue to be heavily loaded relative to their capacity after considering committed generation and transmission developments, and network support arrangements. The Tarong limit experienced negligible binding over the 2002/03 summer due to the recently commissioned south Queensland power stations and from recently completed reliability augmentation works near Brisbane and on the Gold Coast.

Not surprisingly, the predominant driver for augmentations to network capability will be the need to maintain reliability standards. Reliability has long been the predominant driver for grid augmentation in Queensland.

Emerging needs are identified in this report. The areas of need include supply to the Darling Downs area in south west Queensland, supply to Cairns in the far north Queensland area, supply to the Gold Coast/Tweed area, supply to Gladstone in the central Queensland area and supply to the Brisbane CBD and surrounding suburbs within the Moreton North and Moreton South zones. An Application Notice associated with addressing the Darling Downs limitations has been issued. Work has also started on addressing the Gladstone Area, Cairns and Far North Queensland limitations, with Powerlink having issued papers to inform market participants and interested parties about the emerging issues, and to seek possible solutions. Powerlink expects to initiate consultation processes for the remainder to determine appropriate solutions to these limitations within the next twelve months so that corrective action can be implemented in a timely manner.

This Annual Planning Report also contains details of seven proposed new small network assets. These projects include proposals to establish a new 132/22kV substation at Edmonton, add transformer capacity at Pioneer Valley, Nebo and Loganlea substations and install shunt capacitor banks at Rockhampton, Alligator Creek and at several locations in south east Queensland. Powerlink invites submissions on these proposed new small network augmentations by Monday 28th July, 2003.

1. INTRODUCTION

Powerlink Queensland is the entity designated by the Queensland government to be responsible for transmission network planning in the State, and owns and operates the Queensland electricity transmission network.

Powerlink has prepared this Annual Planning Report to document the annual planning review it has carried out. The Report also contains information that allows and encourages input by interested parties to facilitate identification of the most appropriate developments for ensuring that the capability of the transmission network can meet forecast needs in the face of the accelerated load growth in the State over the next three years. The annual planning review and this report are an important part of the process of planning the Queensland transmission network to meet the needs of code participants in the National Electricity Market and users of electricity in Queensland.

The Annual Planning Report includes information on electricity demand forecasts, the existing electricity supply system including committed generation and transmission network developments, and forecasts of grid capability.

Information is also provided about emerging limitations in the capability of the grid. Proposals, including both network and non-network solutions, to overcome some immediate limitations are discussed and evaluated.

1.1 Purpose of the Annual Planning Report

Under Clause 5.6.2A of the National Electricity Code (NEC), Powerlink Queensland is required to publish an Annual Planning Report setting out the results of its annual planning review conducted in accordance with Clause 5.6.2(a) and (b) of the NEC.

The purpose of the Report is to provide information about the Queensland electricity transmission network to Code Participants and interested parties.

It aims to provide information that assists interested parties to:

- identify locations that would benefit from significant electricity supply capacity or demand side management (DSM) initiatives;
- identify locations where major industrial loads could be connected;
- understand how the electricity supply system impacts on their needs;
- consider the transmission network's capability to transfer quantities of bulk electrical energy; and
- provide input into the future development of the transmission grid.

Readers should note that this document is not intended to be relied upon or used for other purposes, such as for the evaluation of participants' investment decisions.

Powerlink also recommends that interested parties review this document in conjunction with the Statement of Opportunities (SOO) published by NEMMCO. The SOO provides information relevant to the entire National Electricity Market, including the supply/demand balance in the Queensland region of the NEM. NEMMCO's 2003 SOO is expected to be published by 31 July 2003.

1.2 Role of Powerlink Queensland

As the owner and operator of the electricity transmission network in the state of Queensland, Powerlink Queensland is registered with NEMMCO as a Transmission Network Service Provider under the National Electricity Code. In this role, and in the context of this Annual Planning Report, Powerlink's transmission network planning and development responsibilities include the following:

1. Ensure that its network is operated with sufficient capacity, and augmented if necessary, to provide network services to customers.

2. Ensure that its network complies with technical and reliability standards contained in the National Electricity Code and jurisdictional obligations.

3. Conduct annual planning reviews with Transmission and Distribution Network Service Providers whose networks are connected to Powerlink's transmission grid (ie. – TransGrid, Energex, Ergon Energy and Country Energy).

4. Advise Code Participants and interested parties of emerging network limitations within the time required for corrective action.

5. Develop recommendations to address emerging network limitations through joint planning with Distributors and consultation with Code Participants and interested parties. Solutions may include network or non-network options. Options may be proposed by providers other than Powerlink, such as local generation, demand side management initiatives and alternatives involving other networks.

6. The role of proponent of regulated transmission augmentations in Queensland.

These responsibilities are described more fully in Powerlink's transmission licence and Chapter 5 of the National Electricity Code.

Powerlink has also been nominated by the Queensland Government as the entity having transmission system planning responsibility in the State, with respect to Clause 5.6.3(b) of the NEC. In this role, Powerlink represents the Queensland jurisdiction on the Inter-Regional Planning Committee (IRPC). Powerlink's role on the IRPC includes:

- providing information on the Queensland network to allow NEMMCO to carry out its obligations, such as publication of the Statement of Opportunities and carrying out the Annual Interconnector Review;
- bringing forward to the Committee, where necessary, proposed Queensland augmentations which have a material inter-network impact;
- participating in inter region system tests associated with new or augmented interconnections; and
- participating in the technical evaluation of proposals for network developments which have a material inter-network impact.

The role of the IRPC is described in Clause 5.6 of the NEC.

1.3 Overview of Planning Responsibilities

Planning the development of the Queensland regulated transmission grid comprises a number of different categories:

- the connection of a new participant, or alteration of an existing connection;
- the shared network within Queensland; and
- new interconnectors or augmentation to existing interconnectors between Powerlink's network and networks owned by other TNSPs.

1.3.1 Planning of Connections

Participants wishing to connect to the Queensland transmission network include new and existing generators, major loads and electricity distributors (DNSPs). Planning of new or augmented connections involves consultation between Powerlink and the connecting party, determination of technical requirements and completion of connection agreements.

1.3.2 Planning of the Shared Network Within Queensland

Powerlink is responsible for planning the transmission grid within Queensland. The National Electricity Code sets out the planning process and requires Powerlink to apply the Regulatory Test promulgated by the ACCC to new regulated network augmentation proposals. The planning process requires consultation with interested parties including customers, generators and DNSPs.

The significant inputs into the network planning process within Queensland are:

- the forecast of customer electricity demand (including demand side management) and its location;
- location, capacity and expected operation of generation;
- the assessment of future network capability;
- planning criteria for the network; and
- prediction of future loadings on the transmission network.

The ten-year forecasts of electrical demand and energy across Queensland are used together with forecast generation patterns to determine potential flows on transmission system elements. The location and capacity of existing and committed generation in Queensland is sourced from the NEMMCO Statement of Opportunities, unless modified based on advice from relevant participants. Information about existing and committed embedded generation and demand management within distribution systems is provided by the DNSPs.

Powerlink examines the capability of its existing network, and future capability following any changes resulting from committed augmentations. This involves consultation with the relevant DNSP where the performance of the transmission system may be impacted by the distribution system (for example, where the two systems operate in parallel).

Where potential flows on transmission system elements could exceed network capability, Powerlink is required to notify market participants of these emerging network limitations. If augmentation is considered necessary, joint planning investigations are carried out with the DNSPs or TNSPs if relevant in accordance with the provisions of

Clause 5.6.2 of the NEC. The objective of this joint planning is to identify the most cost-effective network solution.

In addition to the requirement for joint planning, Powerlink has other obligations that govern how it should address emerging network limitations.

The Electricity Act (Queensland) 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 Powerlink plan and develop its transmission grid in accordance with good electricity industry practice such that power quality and reliability standards in the NEC are met for intact and outage conditions, and the power transfer available through the power system will be adequate to supply the forecast peak demand during the most critical single network element outage, unless otherwise varied by agreement.

Powerlink also has legal obligations to evaluate and consider environmental impacts when developing its transmission network.

In addition, other obligations are contained in schedule S5.1 to Chapter 5 of the NEC. The Code 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 Code obligations. Powerlink may also propose network augmentations that are not required to satisfy performance standards, but which deliver a net economic benefit when measured in accordance with the ACCC Regulatory Test.

The requirements for initiating new regulated network developments are set down in the Clauses 5.6.2, 5.6.6A and 5.6.6 of the Code. These clauses apply to different types of proposed augmentations. While each of these clauses involves a slightly different process, particularly with respect to consultation with interested parties, the main steps in network planning can be summarised as follows:

- Disclosure of information regarding the need for augmentation. This examines the load growth, generation and network capability to determine the time when corrective action is justified – for example, when the technical standards can no longer be met in supplying the forecast load.
- Consultation on assumptions made and potential solutions, which may include transmission or distribution network augmentation, local generation or demand side management.
- Where a network development has a material inter-network impact, either the agreement of the entities responsible for those impacted networks must be obtained, or the development must be examined by the Inter Regional Planning Committee.
- Analysis of the feasible options to determine the one that satisfies the ACCC's regulatory test. In the case of an augmentation required to meet reliability and quality standards, this involves a cost effectiveness analysis to determine the option that minimises net present value of costs. In all other cases, the

regulatory test requires that the proposed development maximises the net market benefit as defined in the regulatory test.

- Consultation and publication of a recommended course of action to address the identified network limitation.

1.3.3 Planning Interconnectors

Development and assessment of new or augmented interconnections between Queensland and New South Wales (or other States) are the responsibility of the respective project proponents.

Powerlink will develop plans in association with connected networks to augment interconnection capacity where justified. Any plans to establish or augment interconnectors will be outlined in Powerlink's Annual Planning Report. The Code also provides a role to be carried out by the Inter Regional Planning Committee. This committee, convened by NEMMCO, includes a representative of the entity having transmission planning responsibility in each state jurisdiction. In summary, the inter-jurisdictional planning process involves the following main steps:

- NEMMCO publishes the annual Statement of Opportunities (SOO) which provides information on load and generation forecasts and committed network developments with an inter-regional impact.

- NEMMCO and the IRPC carry out an Annual Interconnector Review.

- This review provides information relevant to the technical and economic need for inter regional augmentations. This includes information on the significance of forecast losses and constraints on power transfers between regions. It also identifies options, both network and non-network, for reduction or removal of future constraints and for reduction of losses.

- The interconnector review forms part of NEMMCO's SOO. NEMMCO and the IRPC also publish a program for the periodic review of options for the removal or reduction of constraints and network losses.

2. DEMAND AND ENERGY FORECASTS

2.1 Background to Load Forecasts

2.1.1 Sources of Load Forecasts

In accordance with Clause 5.6.1 of the National Electricity Code, Powerlink has obtained summer and winter demand forecasts over a ten-year horizon from Distribution Network Service Providers (DNSPs) and directly-connected customers at each connection supply point in Powerlink's transmission network.

These individual connection supply point forecasts were aggregated into estimated demand forecasts for the total Queensland region and for ten geographical zones as defined in Table 2.10 in Section 2.5, using diversity factors observed from historical trends up to the end of March 2003.

Energy forecasts for each connection supply point were also obtained from the DNSP's and directly connected customers, and these have also been aggregated for the Queensland region and for each of the ten geographical zones in Queensland.

NEMMCO engaged the National Institute of Economic and Industrial Research (NIEIR) to provide an independent assessment of economic outlook for all the regions of the NEM in April 2003, including high and low growth scenarios. The forecasts in this Chapter are consistent with those economic growth scenarios provided by NIEIR and will accordingly be consistent with the Queensland forecasts in NEMMCO's 2003 Statement of Opportunities.

2.1.2 Basis of Load Forecasts

Economic Activity:
Three forecast scenarios of economic activity in all NEM states were provided by NIEIR to NEMMCO in April 2003. The three scenarios can be characterised as:

(i) Medium Growth Scenario (the base case), considered to be most probable
(ii) High Growth Scenario
(iii) Low Growth Scenario

The average economic growth for the High, Medium and Low Growth Scenarios developed by NIEIR, over the ten-year period 2003/04 to 2012/13 are:

	High	Medium	Low
Australian Gross Domestic Product (average growth p.a.)	3.9%	3.0%	2.2%
Queensland Gross State Product (average growth p.a.)	4.7%	3.6%	2.6%

For Queensland, these growth rates are equal to or slightly lower than last year's NIEIR ten-year outlook predictions, as outlined in the Powerlink 2002 Annual Planning Report. Consistent with this change, the revised energy growth rates in Queensland are now slightly lower than in the previous forecast. However, peak demand forecast growth rates have increased significantly especially in the next three years (Refer Section 2.4).

Weather Conditions:
Within each of these three economic scenarios, three forecasts were also prepared to incorporate sensitivity of maximum summer and winter demands to prevailing weather conditions, namely:

(i) a 10% probability of exceedance (PoE), corresponding to one year in ten hot summer or cold winter conditions;

(ii) a 50% PoE, corresponding to one year in two (average summer or average winter) conditions;

(iii) a 90% PoE corresponding to mild summer or mild winter conditions, which would be expected to be exceeded in nine years out of ten.

Cogeneration and Renewable Energy Source Generation:
The 2002 Annual Planning Report showed that the forecasts provided by NIEIR for new cogeneration and renewable energy source generation projects in Queensland were substantially reduced from earlier predictions. In particular, a delay in new projects to beyond 2005/06 was included due to the uncertain and less than favourable economic position of the sugar industry and delays in new gas pipeline projects.

By comparison, this year's forecasts by NIEIR to NEMMCO in April 2003 contain similar levels up to 2007/08 but even fewer new projects in the period 2008/09 and beyond, as shown in Table 2.1 below. It should be noted that in this NIEIR summary, Invicta Sugar Mill generation is included even though it is connected to the Powerlink transmission grid.

Table 2.1: Forecast of Cogeneration and Other Embedded Generation

NIEIR Forecasts of Queensland Total Cogeneration and Other Embedded (Renewable and Non-Renewable Energy Source) Annual Generation (GWh) (1) (2) (3)

Year	Cogeneration	Other Embedded Generation	Total
2002/03	2,491	201	2,692
2003/04	2,491	228	2,719
2004/05	2,491	270	2,761
2005/06	2,531	302	2,833
2006/07	2,580	373	2,953
2007/08	2,580	394	2,974
2008/09	2,634	444	3,078
2009/10	2,709	445	3,154
2010/11	2,721	445	3,166
2011/12	2,752	453	3,205
2012/13	2,796	486	3,284

Notes:
(1) These total generator outputs do not represent export to the distribution network as they do not account for the energy required for the plant's own use.
(2) Invicta Mill bagasse cogeneration output is included in this Table despite being connected to Powerlink's transmission grid. It was not included in Table 2.1 of the 2002 Annual Planning Report.
(3) This Table excludes the output of Barcaldine and Roma Power Stations as these are scheduled market generators.

As in previous reports, the energy delivered to the Wivenhoe pumps is excluded from both the demand and energy forecasts in this report.

Other Loads:

Interconnector Loads
Energy flows across the Queensland New South Wales Interconnection (QNI) and the DirectLink market network service are not included in the forecast loads in this Chapter, as they are not part of the Queensland customer load. These flows will increase or decrease dispatch of generation within Queensland to meet the load demands and are therefore considered in Chapter 4 of this report which examines network capability.

New Queensland Loads
As reported in the 2002 Annual Planning Report, additional load is anticipated at Goondiwindi, a centre which has been supplied from the NSW network. This 2003 forecast includes this load from summer 2003/04 onwards, slightly later than previously reported. This area is planned to be supplied by a new 132kV line from Bulli Creek substation on QNI in southern Queensland, to a new Waggamba (Goondiwindi) 132/66kV substation, while the existing 66kV network from NSW will be retained for stand-by supply.

New Large Loads – Committed
The forecasts in this Chapter include the committed new Comalco Alumina Refinery plant at Yarwun (near Gladstone), Hail Creek coal mine (west of Nebo), Morvale coal mine (near Coppabella), and Rolleston coal mine (south west of Blackwater), as well as minor load increases at existing aluminium and zinc smelter plants.

New Large Loads – Uncommitted
There have been several announced proposals for large metal processing or other industrial loads which are not yet considered to be committed and are therefore not included in the forecast.

These developments include:
- A new aluminium smelter west of Gladstone (Aldoga);
- Possible major expansions of an existing aluminium smelter (Gladstone) and an existing zinc smelter plant (Townsville);
- Proposed magnesium smelter at Stanwell;
- A large chemical products plant at Yarwun (west of Gladstone); and
- An aluminium extrusion plant and a pulp and paper mill (between Swanbank and Abermain).

Whilst the load forecast does not include the above uncommitted large loads, some consideration to the impacts of these potential developments is given in Chapter 4. These developments could translate to the following additional loading of the network.

Zone	Type of Plant	Possible Load
Gladstone	Aluminium & Chemical	0-1800MW
Central West	Magnesium	0-250MW (1)
Ross	Zinc	0-130MW
Moreton South	Aluminium extrusion, pulp and paper mill and other industries	0-100MW

Notes:
(1) This loading includes a component of steam that would reduce the capacity of Stanwell Power Station output to the transmission grid.

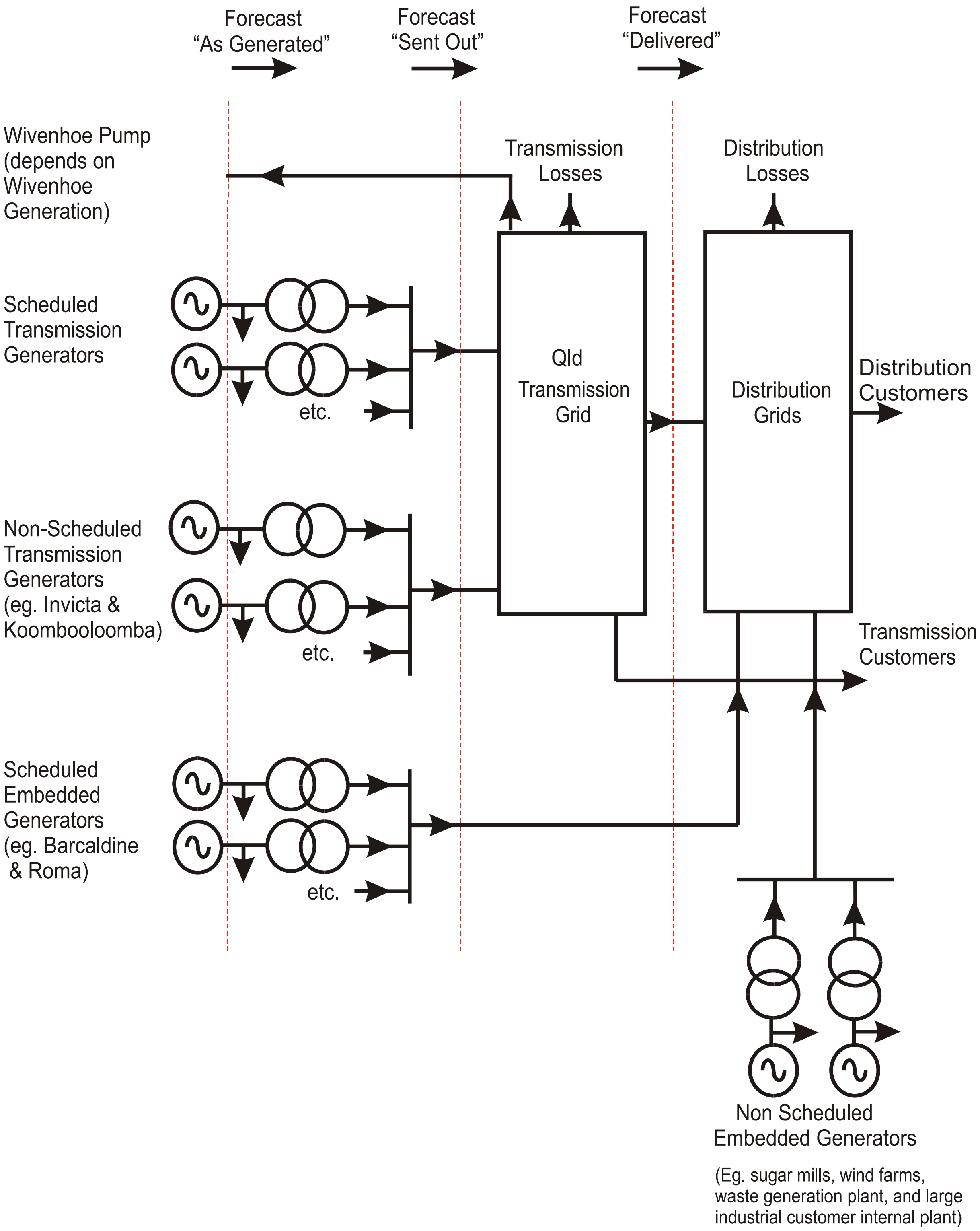
DNSP and NIEIR Forecast Reconciliation:
For previous issues of the Annual Planning Report, Powerlink contracted NIEIR to provide independent forecasts for Queensland enabling a reconciliation against the forecasts provided by DNSPs and customers. All the previous demand and energy forecasts were found to have very close overall agreement between these parties after allowance for weather corrections and allowance for embedded non-scheduled generation.

This year NEMMCO contracted NIEIR to provide economic outlook and embedded generation forecasts for all NEM States for inclusion in the 2003 Statement of Opportunities. This also enables an independent check with the new DNSP and customer forecasts in Queensland and these again were found to be consistent. As mentioned previously, the updated economic activity forecasts for Queensland recently provided by NIEIR to NEMMCO were almost unchanged from the growth rates which underpinned the previous forecast.

2.1.3 Load Forecast Definitions

The relationship between the classes of generation and the forecast quantities in this Report is shown in Figure 2.1.

Figure 2.1: Load Forecast Definitions



2.2 Recent Energy and Demands – Weather Correction

2.2.1 Recent Summers

The 1997/98 Queensland summer was hotter than average and initiated a substantial increase in the rate of air-conditioning installations[1]. Similarly, the extreme 2001/02 summer initiated an even more significant increase in air-conditioning installations during 2002, to levels greater than five times the pre-1998 annual installation rate. Despite the recent mild 2002/03 summer, installation of air-conditioning plant in 2003 to date has continued at more than twice the pre-1998 levels. Due to the recent popularity and relatively lower cost of domestic air-conditioners, continuing high levels of installation are now expected over the next two years until saturation effects are expected to reduce the rates to earlier levels. Whilst future usage of existing air-conditioners will depend on prevailing weather conditions, some 'drift' towards increasing general domestic utilisation in mild or average summers is expected.

The recent 2002/03 summer was in stark contrast to the sustained extreme dry and hot conditions across Queensland during 2001/02 summer. There was a return to more normal rainfall levels in south east Queensland and milder than average temperature conditions across Queensland. Despite this weather reversal, growth in actual summer demand and energy still occurred indicating substantial underlying electricity growth after allowing for weather correction. It should be noted though that the wet season arrived late in north Queensland in the recent 2002/03 summer.

A summary of recent summer electricity demands, seasonal energy delivered and prevailing weather conditions is shown in Table 2.2.

Table 2.2: Comparison of Recent Queensland Summer Delivered Load

Summer	Energy GWh	Demand MW	Prevailing Queensland Weather Conditions	Brisbane Temperature (1) Summer Ave	Peak Day	No days >27.2
1997/98	8,746	5,234	Very hot	25.4	27.0	8
1998/99	8,796	5,386	Average	24.2	26.4	3
1999/00	9,285	5,685	Mild	22.9	29.1	2
1900/01	9,678	5,891	Average, dry	24.1	28.0	3
2001/02	10,434	6,259	Sustained hot and dry Extreme central to north	25.1	25.7	12
2002/03	10,530	6,462 (2)	Mild, late wet season in north	23.9	26.5	0

Notes:

(1) Brisbane temperature measured at Brisbane Airport. Day temperatures refer to average of daily minimum and daily maximum to represent the driver for cooling load.

(2) A correction of 60MW is added to reflect an abnormal plant failure in a large industrial load.

[1] Based on estimates of air-conditioning sales outlined by NIEIR

2.2.2 *Recent Winters*

The winter of 2002 was again milder than average as was the case in winter 2001. However, during winter 2002 there was no significant coincidence of cold weather on working week days and the day of winter peak demand was actually on a warmer than average winter day in Brisbane. This explains why the winter peak in 2002 was lower than the previous year.

A summary of recent winter electricity demands, seasonal energy delivered and prevailing weather conditions is shown in Table 2.3.

Table 2.3: Comparison of Recent Queensland Winter Delivered Load

Winter	Energy GWh	Demand MW	Prevailing Queensland Weather Conditions	Brisbane Temperature (1) Winter Ave	Peak Day	No days <12.1
1998	8,633	5,042	Mild to warm	16.0	11.4	6
1999	9,116	5,309	Mild	15.6	13.8	4
2000	9,668	5,691	Cooler than average	14.7	9.0	6
2001	9,912	5,811	Mild	15.5	13.0	4
2002	10,177	5,743	Average	15.0	15.8	6

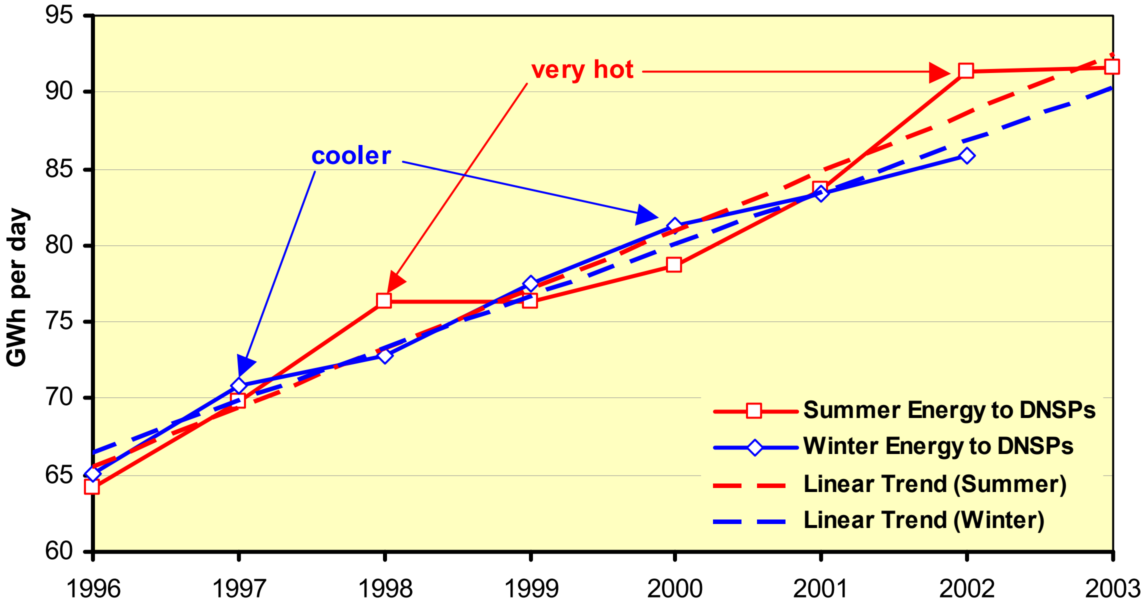
Notes:

(1) Brisbane temperature measured at Brisbane Airport. Day temperatures refer to average of daily minimum and daily maximum to represent the driver for heating load.

2.2.3 *Seasonal Growth Patterns*

The hot summers of 1997/98 and 2001/02 resulted in large increases in summer delivered energy. The relatively cooler than average winters of 1997 and 2000 also resulted in higher delivered energy. These effects can be seen in Figure 2.2 by comparison to the trend-line of summer and winter energy delivered to DNSPs over the last seven years. Figure 2.2 excludes the energy delivered to major industrial customers, connected directly to the transmission grid so that it is indicative of the underlying trend of electricity consumption in Queensland.

Figure 2.2: Recent Summer & Winter Energy Delivered to DNSPs in Qld (excluding energy to the major direct industrial customers)

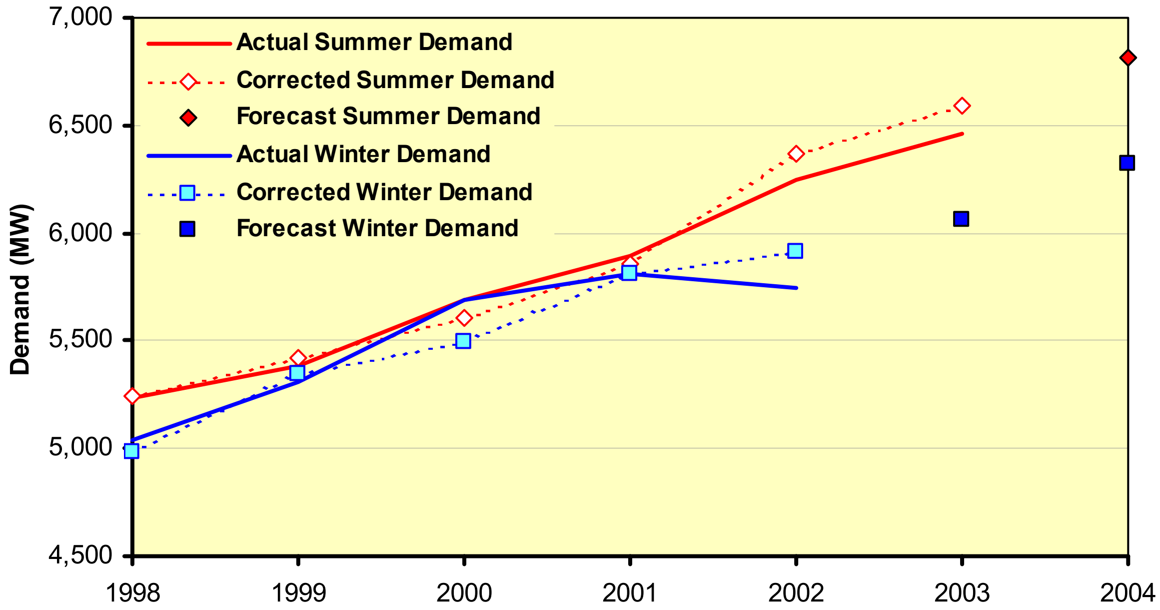


2.2.4 Temperature Correction of Demands

As demonstrated by Tables 2.2 and 2.3, actual recorded peak summer and winter demand values can be misleading unless the weather conditions are taken into account. A more accurate picture of year to year demand comparison can be obtained by applying a correction factor to actual demands to obtain a result as though the day was 'a standard peak demand day' as shown in Figure 2.3. Powerlink has based the standard peak demand day on the last twenty years of weather data.

Queensland is a large state where the degree of weather variance from average can be substantially different across the State on any given day. However, the major proportion of weather dependent Queensland load is located in south east Queensland. Accordingly, it has been found that correction of the south east Queensland load for Brisbane conditions on the peak Queensland demand day is sufficient for comparison purposes, particularly as the major industrial customers loads in central Queensland are largely independent of weather conditions.

Figure 2.3: Recent Summer and Winter Actual and Temperature Corrected Demands MW Compared to Initial Values of New Forecast



2.3 Comparison with the 2002 Annual Planning Report

Features of the new load forecasts compared to the previous report are:

- Substantially increased summer demand over the next three years driven by a recent increase in domestic air-conditioning installation and continuing high usage of air-conditioners, until an assumed saturation effect restores the forecast back to more typical levels around 2008;
- Increased temperature sensitivity of both summer and winter demands due to increased domestic air-conditioning usage;
- Energy growth is very similar to previous forecasts due to little change in forecast economic growth rates and the level of embedded generation;
- Reduced initial average weather winter demand forecast based on recent low demand levels, but with a caution that much higher demands could occur in severe cold snap periods through use of reverse cycle air-conditioning;
- Decreasing overall load factor in Queensland as high load factor major industrial consumers become a lower proportion of the total load;
- Whilst not included in the forecasts, substantial levels of potential but as yet uncommitted new large industrial loads have been announced;
- Particularly strong growth in summer demands in south east Queensland where the increase in domestic air-conditioning has been strongest;
- Continuing high growth levels in the Darling Downs, Brisbane, Logan City and Gold Coast areas, which are characterised by sustained relatively high population growth as well as growth in air-conditioning load.

2.4 Forecast Data

The information pertaining to the forecasts are shown in Tables and Figures as follows:

- Figure 2.1 shows the relationship between the classes of generation and the forecast quantities in this Report.
- Table 2.1 shows the NIEIR forecast of cogeneration and other embedded generation (both renewable and non-renewable energy source).
- Tables 2.2 and 2.3 show recent summer and winter demands, seasonal energy delivered and prevailing weather conditions for comparison purposes.
- Figure 2.2 shows recent growth in energy by seasons to illustrate the impact of the recent very hot and dry summer across Queensland in 2001/02, and the milder 2002/03 summer, and the recent mild winters.
- Figure 2.3 shows recent summer and winter demands and estimated temperature corrections to show consistency with initial values of the new forecast demands.
- Table 2.4 shows average growth rates of Queensland GSP, energy, summer and winter peak demands for the next ten years.
- Table 2.5 and Figure 2.4 show the historical and ten-year forecast of net **energy** supplied from the transmission grid together with embedded scheduled generators in the Queensland region for the Medium Growth scenario. Table 2.5 also shows forecasts for the Low and High Economic Growth scenarios.
- Table 2.6 and Figure 2.5 show the historical and ten-year Queensland region **summer demand** forecast (delivered from the grid and embedded scheduled generators) for each of the three economic scenarios and also for 10%, 50% and 90% PoE weather conditions. The actual peak delivered demand recorded in summer 2002/03 was 6402MW, but at that time a major breakdown in an industrial plant was reducing the expected demand by about 60MW. Accordingly 6462MW is an appropriate demand for comparison and forecasting purposes. Whilst the summer 2001/02 peak occurred on an unusual day where very hot weather was experienced simultaneously across all of central and northern Queensland, the 2002/03 peak was driven by the south east Queensland load under milder conditions compared to the previous summer.
- Table 2.7 and Figure 2.6 show the historical and ten-year Queensland region **winter demand** forecast (delivered from the grid and embedded scheduled generators) for each of the three economic scenarios and also for 10%, 50% and 90% PoE weather conditions.
- Table 2.8 shows the **Medium Growth** Scenario forecast of **average weather** winter and summer maximum coincident region electricity **demand** including estimates of Transmission Grid Losses, Power Station Sent Out and As Generated Demands.
- Table 2.9 shows the **Medium Growth** forecast of **one in ten year or 10% PoE** weather winter and summer maximum co-incident region electricity **demand** including estimates of Transmission Grid Losses, Power Station Sent Out and As Generated Demands.
- The forecast loading at Powerlink Queensland 275kV substations at the time of the coincident Queensland region maximum demand, under a range of possible generation dispatch patterns and up to summer 2005/06 is shown in Table A2 of Appendix A. These loadings can be higher at the time of local area maximum demand, and can also vary under different generation dispatch patterns.

It should also be noted that the forecasts have been derived from information and historical revenue metering data up to and including April 2003, and are based on assumptions and third party predictions which may or may not prove to be correct. The 'projected actual' forecast for the 2002/03 year accounts for actual energy delivery in the first ten months of the financial year, ie. up to end of April 2003 plus forecast energy to end June based on statistical 'as generated' data.

In summary the forecast average annual growth rates for the Queensland region over the next ten years under low, medium and high economic growth scenarios are shown in Table 2.4. These averages mask the accelerated summer demand growth over the first three years, which exceeds 6% p.a. in south east Queensland.

Table 2.4: Average Annual Growth Rate Over Next Ten Years

	Economic Growth Scenario		
	High	**Medium**	**Low**
Queensland Gross State Product	4.7%	3.6%	2.6%
Energy Delivered (1)	5.0%	3.1%	1.2%
Summer Peak Demand (50% PoE) (2)	5.8%	3.6%	1.6%
Winter Peak Demand (50% PoE) (2)	5.5%	3.1%	1.2%

Notes:

(1) This is energy delivered from the transmission grid and from embedded scheduled generators, and is reduced by the forecast growth in embedded non-scheduled generation. If there were to be no increase in embedded non-scheduled generation above current levels the average forecast growth rate in energy delivered would be 3.3% p.a. under the medium growth scenario.

(2) This is the half-hour average power delivered from the transmission grid and from embedded scheduled generators.

Table 2.5: Annual Energy – Actual and Forecast

Annual energy (GWh) sent out to and delivered from the transmission grid and from embedded scheduled generation (except to Wivenhoe Pumps), actual and forecasts for different economic growth scenarios

Year	Sent Out (1)			Transmission Losses			Delivered		
92/93		26,521			1,342			25,179	
93/94		27,664			1,411			26,253	
94/95		29,240			1,427			27,813	
95/96		30,255			1,497			28,758	
96/97		31,375			1,506			29,869	
97/98		35,675			1,662			34,013	
98/99		36,555			1,556			34,999	
99/00		38,439			1,486			36,953	
00/01		40,203			1,642			38,561	
01/02		42,291			1,994			40,297	
02/03 (2)		43,321			1,906			41,415	
Forecast	**Low**	**Medium**	**High**	**Low**	**Medium**	**High**	**Low**	**Medium**	**High**
03/04	44,620	45,225	45,987	2,040	2,080	2,132	42,581	43,144	43,855
04/05	44,548	46,940	48,613	2,037	2,199	2,315	42,511	44,741	46,298
05/06	43,690	48,402	51,090	1,980	2,300	2,490	41,710	46,102	48,600
06/07	44,205	49,599	53,478	1,952	2,311	2,580	42,253	47,288	50,898
07/08	45,502	51,440	56,446	2,038	2,440	2,796	43,463	48,999	53,650
08/09	46,442	52,899	59,427	2,110	2,558	3,049	44,332	50,340	56,378
09/10	47,483	54,457	62,983	2,191	2,687	3,362	45,292	51,770	59,621
10/11	48,213	56,058	65,909	2,248	2,821	3,629	45,965	53,237	62,280
11/12	49,256	57,792	69,672	2,331	2,970	3,984	46,925	54,822	65,688
12/13	49,178	59,318	71,722	2,325	3,103	4,182	46,854	56,215	67,539

Notes:

(1) This is the energy that is sent into the Grid from Queensland Scheduled generators, Invicta Mill, Koombooloomba hydro generator and imports to Queensland. The energy to Wivenhoe Pumps is not included in this Table, as it is assumed to be netted off any Wivenhoe generation.

(2) These projected end of financial year values are based on revenue metering data up to April 2003 and statistical metering up to mid June 2003.

Figure 2.4: History and Forecasts of Annual Energy Delivered

From Transmission Grid and from Embedded Scheduled Generators (GWh p.a.) - Medium Economic Growth Scenario

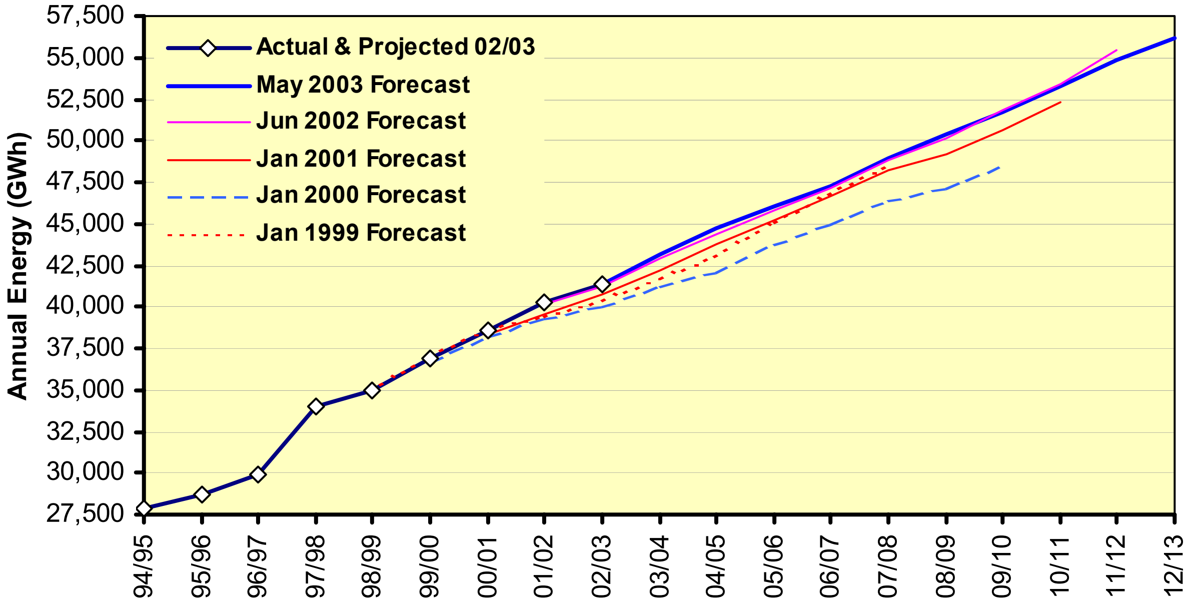


Table 2.6: Peak Summer Demand

Peak summer demand (MW) delivered from the transmission grid as well as from embedded scheduled generators.

Summer	Actual	High Growth Scenario H 10%	H 50%	H 90%	Medium Growth Scenario M 10%	M 50%	M 90%	Low Growth Scenario L 10%	L 50%	L 90%
93/94	**3,901**									
94/95	**4,073**									
95/96	**4,323**									
96/97	**4,576**									
97/98	**5,161**									
98/99	**5,386**									
99/00	**5,685**									
00/01	**5,891**									
01/02	**6,246**									
02/03	**6,462** (1)									
03/04		7,297	7,028	6,876	7,075	**6,814**	6,666	6,919	6,664	6,519
04/05		7,917	7,632	7,470	7,508	**7,238**	7,085	7,145	6,888	6,742
05/06		8,460	8,159	7,988	7,849	**7,570**	7,411	7,249	6,991	6,845
06/07		8,905	8,587	8,407	8,062	**7,774**	7,610	7,317	7,055	6,907
07/08		9,396	9,057	8,865	8,314	**8,015**	7,845	7,456	7,187	7,035
08/09		9,824	9,468	9,266	8,531	**8,222**	8,047	7,521	7,249	7,094
09/10		10,327	9,951	9,738	8,767	**8,448**	8,267	7,600	7,323	7,167
10/11		10,787	10,391	10,167	8,981	**8,651**	8,465	7,650	7,369	7,210
11/12		11,351	10,930	10,692	9,197	**8,856**	8,663	7,739	7,452	7,290
12/13		11,819	11,385	11,139	9,522	**9,172**	8,974	7,875	7,586	7,422

Notes:

(1) For comparison purposes 60MW of industrial plant failure reduced load has been added to the actual recorded demand.

Figure 2.5: Queensland Region Summer Peak Demand

History and Forecasts, Different Economic Growth and Weather Scenarios

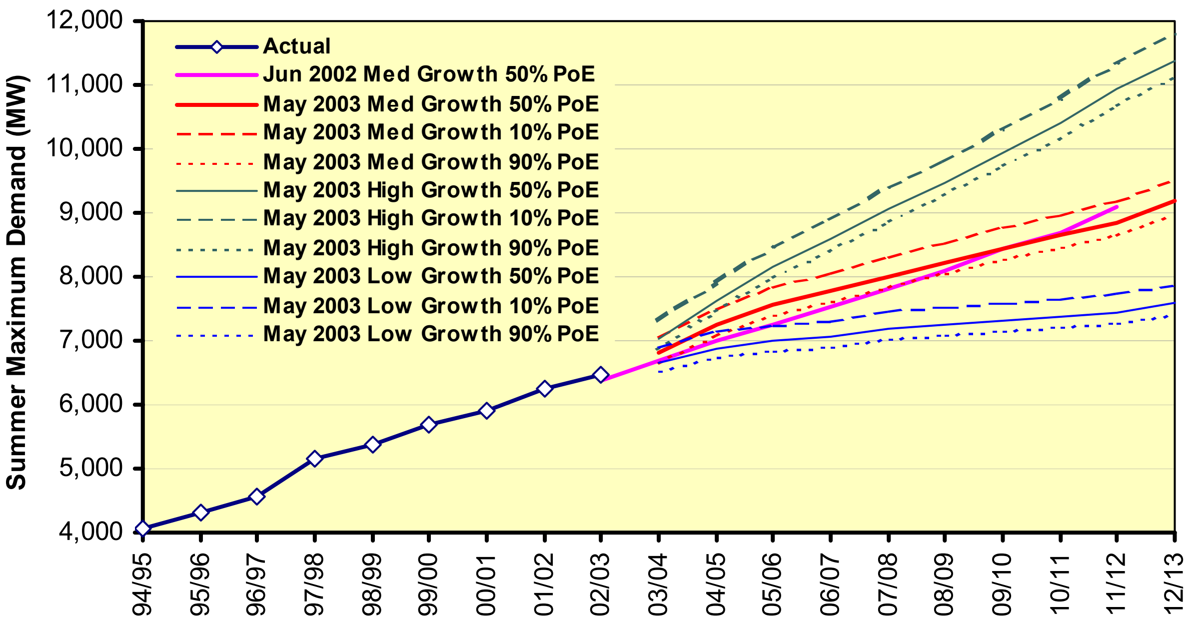


Table 2.7: Peak Winter Demand

Peak winter demand (MW) delivered from the transmission grid as well as from embedded scheduled generators.

Winter	Actual	High Growth Scenario			Medium Growth Scenario			Low Growth Scenario		
		H 10%	H 50%	H 90%	M 10%	M 50%	M 90%	L 10%	L 50%	L 90%
1993	**3,946**									
1994	**4,085**									
1995	**4,304**									
1996	**4,459**									
1997	**4,770**									
1998	**5,021**									
1999	**5,309**									
2000	**5,691**									
2001	**5,811**									
2002	**5,743**									
2003		6,183	6,059	5,934	6,183	**6,059**	5,934	6,183	6,059	5,934
2004		6,660	6,526	6,391	6,451	**6,320**	6,190	6,304	6,177	6,050
2005		7,127	6,984	6,842	6,748	**6,613**	6,478	6,415	6,287	6,159
2006		7,508	7,357	7,206	6,944	**6,805**	6,665	6,397	6,269	6,140
2007		7,883	7,723	7,563	7,106	**6,962**	6,818	6,423	6,293	6,162
2008		8,322	8,152	7,981	7,318	**7,168**	7,018	6,525	6,392	6,258
2009		8,692	8,513	8,333	7,485	**7,331**	7,175	6,550	6,415	6,279
2010		9,125	8,935	8,744	7,667	**7,508**	7,347	6,584	6,447	6,309
2011		9,526	9,326	9,123	7,833	**7,668**	7,502	6,594	6,455	6,315
2012		10,008	9,795	9,578	7,993	**7,822**	7,649	6,633	6,492	6,348

Figure 2.6: Queensland Region Winter Peak Demand

History and Forecasts, Different Economic Growth and Weather Scenarios

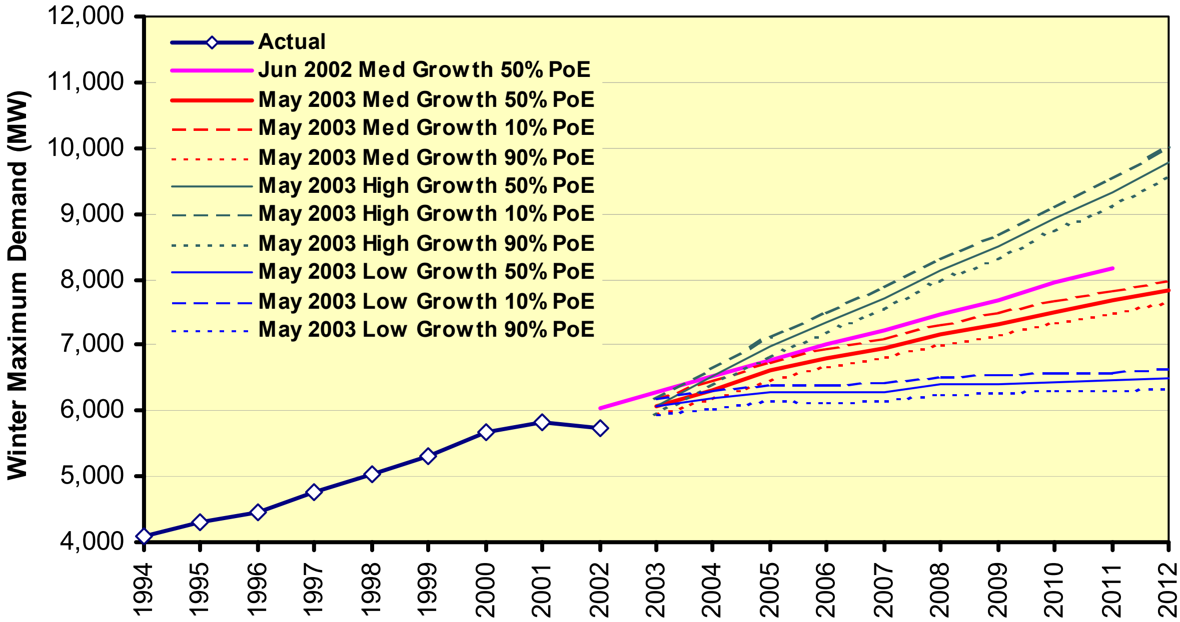


Table 2.8: Maximum Demand – 50% PoE Forecast

Queensland Region Maximum Demand Forecast (MW) Medium Growth, 50% Probability of Exceedance (average) Weather.

Year	Power Station as Generated MW (1)	Power Station Net Sent Out to Grid	Transmission Grid Losses	Delivered from Grid (2)
2003 W	6,768	6,362	303	6,059
2004 W	7,059	6,635	315	6,320
2005 W	7,383	6,940	327	6,613
2006 W	7,622	7,164	359	6,805
2007 W	7,802	7,334	372	6,962
2008 W	8,040	7,557	389	7,168
2009 W	8,227	7,733	403	7,331
2010 W	8,431	7,926	418	7,508
2011 W	8,617	8,100	431	7,668
2012 W	8,794	8,267	445	7,822
2003/04 S	7,663	7,203	389	6,814
2004/05 S	8,132	7,644	406	7,238
2005/06 S	8,540	8,028	458	7,570
2006/07 S	8,777	8,251	477	7,774
2007/08 S	9,058	8,515	500	8,015
2008/09 S	9,300	8,742	520	8,222
2009/10 S	9,564	8,990	542	8,448
2010/11 S	9,802	9,214	562	8,651
2011/12 S	10,041	9,439	583	8,856
2012/13 S	10,412	9,787	615	9,172

Notes:

(1) Station Auxiliaries and generator transformer losses are now estimated at 6.0% of Station ‘As Generated’ dispatch at times of peak loading, lower than previous years based on recent trends.

(2) ‘Delivered from Grid’ includes the demand taken directly from the transmission grid and power from embedded scheduled generators (currently Barcaldine and Roma Power Stations).

Table 2.9: Maximum Demand – 10% PoE Forecast

Queensland Region Maximum Demand Forecast (MW) Medium Growth, 10% Probability of Exceedance Weather.

Year	Power Station as Generated MW (1)	Power Station Net Sent Out to Grid	Transmission Grid Losses	Delivered from Grid (2)
2003 W	6,912	6,497	314	6,183
2004 W	7,210	6,777	326	6,451
2005 W	7,539	7,087	339	6,748
2006 W	7,784	7,317	372	6,944
2007 W	7,970	7,492	386	7,106
2008 W	8,214	7,721	403	7,318
2009 W	8,407	7,903	418	7,485
2010 W	8,618	8,101	433	7,667
2011 W	8,810	8,281	448	7,833
2012 W	8,994	8,454	462	7,993
2003/04 S	7,968	7,490	415	7,075
2004/05 S	8,448	7,941	433	7,508
2005/06 S	8,869	8,337	488	7,849
2006/07 S	9,117	8,570	508	8,062
2007/08 S	9,412	8,848	533	8,314
2008/09 S	9,666	9,086	555	8,531
2009/10 S	9,942	9,345	578	8,767
2010/11 S	10,193	9,582	600	8,981
2011/12 S	10,447	9,820	623	9,197
2012/13 S	10,828	10,178	657	9,522

Notes:

(1) Station Auxiliaries and generator transformer losses are now estimated at 6.0% of Station 'As Generated' dispatch at times of peak loading, lower than in previous years based on recent trends.

(2) 'Delivered from Grid' includes the demand taken directly from the transmission grid and power from embedded scheduled generators (currently Barcaldine and Roma Power Stations).

2.5 Zone Forecasts

The ten geographical zones referred to throughout this report are defined as follows (refer to Section 3.4 and the diagrams in Figures 3.1 and 3.2).

Table 2.10: Zone Definitions

Zone	Area Covered
Far North	North of Tully including Chalumbin
Ross	North of Proserpine and Collinsville, but excluding the Far North Zone.
North	North of Broadsound and Dysart but excluding the Far North and Ross Zones.
Central West	Collectively encompasses the area south of Nebo and Peak Downs and north of Gin Gin, but excluding that part defined as the Gladstone Zone.
Gladstone	Specifically covers the Powerlink transmission network connecting Gladstone Power Station, Callemondah (railway supply), Gladstone South, QAL supply, Wurdong and Boyne Smelter supply.
Wide Bay	Gin Gin and Woolooga 275kV substation loads excluding Gympie.
South West	Tarong and Middle Ridge load areas west of Postmans Ridge. From summer 2003/04 onwards, includes Goondiwindi (Waggamba) load.
Moreton North	South of Woolooga and east of Middle Ridge, but excluding the Moreton South and Gold Coast/Tweed Zones.
Moreton South	South of the Brisbane River, but includes the Energex Victoria Park and Mayne 110kV substation load areas, and excludes the Gold Coast/Tweed Zone.
Gold Coast/Tweed	Initially, south of Cades County to the Gold Coast and includes Tweed Shire of NSW. Energex's planned Coomera substation from summer 2004/05 onwards will cause a small net transfer of load to Moreton South, despite Cades County substation then shifting from Moreton South to the Gold Coast/Tweed Zone.

Each zone normally experiences its own zone peak demand, which is usually greater than that shown in Tables 2.13 and 2.14, as it does not coincide with the time of Queensland region coincident maximum demand.

Table 2.11 below shows the average ratio of forecast zone peak demand to zone demand at the time of forecast Queensland region peak demands. These values can be used to multiply demands in Tables 2.13 and 2.14 to estimate each zone's individual peak demand, not necessarily co-incident with the time of Queensland region peak demand. The ratios are based on historical trends as well as allowing for changing patterns whereby the recent sharp increase in air-conditioning load means that a greater level of coincident high demand is expected between zones.

Table 2.11: Average Ratio of Zone Peak Demand to Zone Demand at Time of Queensland Region Peak

Zone	Winter	Summer
Far North	1.100	1.025
Ross	1.060	1.023
North	1.163	1.060
Central West	1.040	1.100
Gladstone	1.010	1.010
Wide Bay	1.110	1.110
South West	1.040	1.090
Moreton North	1.009	1.012
Moreton South	1.040	1.013
Gold Coast / Tweed	1.000	1.050

Table 2.12 shows the forecast of energy supplied from the transmission grid and embedded scheduled generators for the Medium Growth Scenario for each of the ten zones in the Queensland region.

Table 2.13 shows the forecast of winter demand delivered from the transmission grid and embedded scheduled generators (coincident with the Queensland region winter peak) for each of the ten zones within Queensland. It is based on the Medium Growth scenario and average winter weather.

Table 2.14 shows the forecast of summer demand delivered from the transmission grid and embedded scheduled generators (coincident with the Queensland region summer peak) for each of the ten zones within Queensland. It is based on the Medium Growth scenario and average summer weather.

Particularly noteworthy in Table 2.14 is the data for summer peak loads in the relatively mild summer of 2002/03 compared to the very hot 2001/02 summer. However, the 2002/03 peak demands in South West, Moreton South and Gold Coast/Tweed zones were 9-13% higher reflecting population growth and increase in air-conditioning load.

Table 2.12: Annual Energy by Zone

Actual and Forecast Annual Energy (GWh) Delivered from the Transmission Grid including from Embedded Scheduled Generators - In each Zone - Medium Growth Scenario

Year	Far North	Ross	North	Central West	Gladstone	Wide Bay	South West	Moreton North	Moreton South	Gold Coast/ Tweed	Total
Actuals											
1997/98	1,364	1,967	1,844	2,638	7,925	1,051	1,482	5,530	7,684	2,529	**34,013**
1998/99	1,407	2,030	1,809	2,587	8,434	1,024	1,511	5,752	7,808	2,637	**34,999**
1999/2000	1,430	2,454	1,963	2,789	8,660	1,088	1,575	6,101	8,116	2,777	**36,952**
2000/01	1,457	2,962	2,055	2,876	8,697	1,187	1,659	6,421	8,333	2,913	**38,561**
2001/02	1,536	2,971	2,219	3,069	8,948	1,257	1,717	6,769	8,746	3,064	**40,296**
projected 2002/03	1,537	2,932	2,248	3,182	9,147	1,284	1,760	7,006	8,983	3,337	**41,415**
Forecasts											
2003/04	1,594	3,128	2,357	3,267	9,556	1,321	1,892	7,191	9,352	3,487	**43,144**
2004/05	1,629	3,260	2,422	3,472	10,051	1,351	1,935	7,368	9,673	3,580	**44,741**
2005/06	1,669	3,344	2,492	3,578	10,243	1,386	1,983	7,655	10,065	3,687	**46,102**
2006/07	1,710	3,399	2,525	3,638	10,267	1,422	2,034	8,038	10,408	3,848	**47,288**
2007/08	1,757	3,465	2,566	3,687	10,715	1,463	2,091	8,474	10,791	3,990	**48,999**
2008/09	1,799	3,522	2,607	3,723	10,856	1,497	2,138	8,812	11,189	4,197	**50,340**
2009/10	1,848	3,591	2,656	3,761	10,983	1,536	2,192	9,220	11,621	4,362	**51,770**
2010/11	1,898	3,663	2,707	3,800	11,098	1,576	2,248	9,655	12,060	4,534	**53,237**
2011/12	1,955	3,744	2,766	3,840	11,216	1,621	2,311	10,064	12,578	4,729	**54,822**
2012/13	1,987	3,815	2,808	3,951	11,541	1,651	2,353	10,352	12,856	4,840	**56,154**

Table 2.13: State Winter Peak Demand by Zone

Actual and Forecast Demand (MW) on the Transmission Grid and Embedded Scheduled Generators in each Zone at the time of Coincident State Winter Peak Demand - Average Weather Conditions

Year	Far North	Ross	North	Central West	Gladstone	Wide Bay	South West	Moreton North	Moreton South	Gold Coast/ Tweed	Total
Actuals											
1998	166	236	214	365	961	152	256	962	1,250	479	**5,042**
1999	173	238	229	377	994	165	278	1,022	1,315	517	**5,309**
2000	179	354	271	423	986	198	312	1,080	1,350	536	**5,691**
2001	184	378	255	442	1,019	189	301	1,110	1,365	567	**5,811**
2002	163	339	285	383	1,055	160	286	1,116	1,432	523	**5,743**
Forecasts											
2003	207	381	280	423	1,083	200	300	1,131	1,456	597	**6,059**
2004	214	405	295	440	1,124	210	325	1,182	1,505	619	**6,320**
2005	222	429	312	470	1,187	217	336	1,236	1,569	635	**6,613**
2006	232	442	327	490	1,206	228	341	1,272	1,616	650	**6,805**
2007	239	453	335	503	1,213	233	349	1,293	1,676	667	**6,962**
2008	247	463	342	511	1,276	241	353	1,325	1,726	684	**7,168**
2009	254	471	349	521	1,298	246	358	1,361	1,769	703	**7,331**
2010	263	486	359	535	1,315	253	366	1,402	1,804	724	**7,508**
2011	273	500	366	539	1,327	260	374	1,439	1,846	743	**7,668**
2012	283	515	374	543	1,334	264	382	1,476	1,888	763	**7,822**

Table 2.14: State Summer Peak Demand by Zone

Actual and Forecast Demand (MW) on the Transmission Grid and Embedded Scheduled Generators in each Zone at the time of Coincident State Summer Peak Demand - Average Weather Conditions

Year	Far North	Ross	North	Central West	Gladstone	Wide Bay	South West	Moreton North	Moreton South	Gold Coast/ Tweed	Total
Actuals											
1998/99	244	292	271	372	959	189	242	992	1,381	444	5,386
1999/00	234	412	240	346	1,003	197	265	1,055	1,433	499	5,685
2000/01	252	458	294	391	993	195	270	1,068	1,472	498	5,891
2001/02	278	504	355	436	1,040	222	258	1,183	1,461	509	6,246
2002/03	264	470	367 (1)	426	1,048	200	298	1,243	1,653	554	6,402
Forecasts											
2003/04	288	502	356	430	1,100	212	285	1,300	1,722	618	**6,814**
2004/05	297	530	373	461	1,169	219	295	1,393	1,844	657	**7,238**
2005/06	310	547	391	482	1,190	230	300	1,485	1,949	687	**7,570**
2006/07	319	561	400	496	1,198	235	306	1,519	2,027	712	**7,774**
2007/08	329	575	408	504	1,255	242	310	1,554	2,105	731	**8,015**
2008/09	339	585	417	514	1,277	247	314	1,601	2,171	757	**8,222**
2009/10	350	605	428	528	1,295	254	322	1,655	2,231	779	**8,448**
2010/11	362	624	438	532	1,308	262	329	1,714	2,280	803	**8,651**
2011/12	375	643	448	537	1,317	265	336	1,764	2,344	828	**8,856**
2012/13	383	657	461	561	1,365	274	340	1,824	2,450	855	**9,172**

Notes:

(1) For comparison purposes 60MW of industrial plant failure reduced load has been added to the actual recorded demand.

2.6 Daily and Annual Load Profiles

The daily load profile is shown in Figure 2.7 for the entire Queensland region, for the 2002 winter peak and 2002/03 summer peak. Figure 2.8 shows the cumulative annual load duration characteristic for the Queensland region for the entire 2001/02 financial year. The information in Figures 2.7 and 2.8 is historical, being derived from revenue metering ‘delivered’ demand and energy data.

Figure 2.7: Daily Load Profile

Queensland Region 2002/03 Summer Peak and 2002 Winter Peak

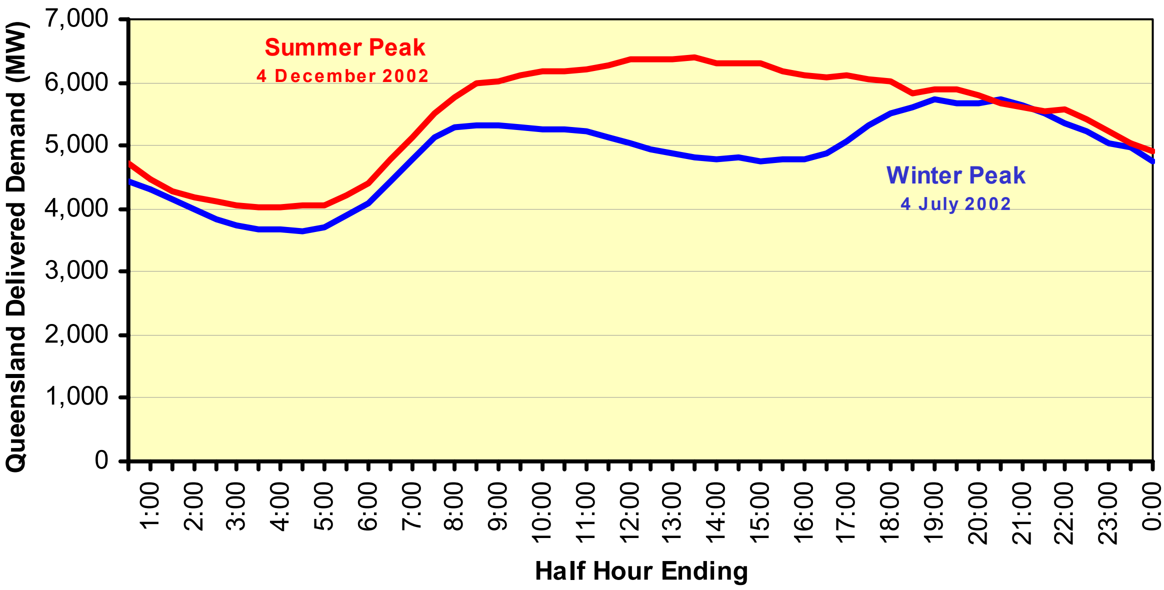
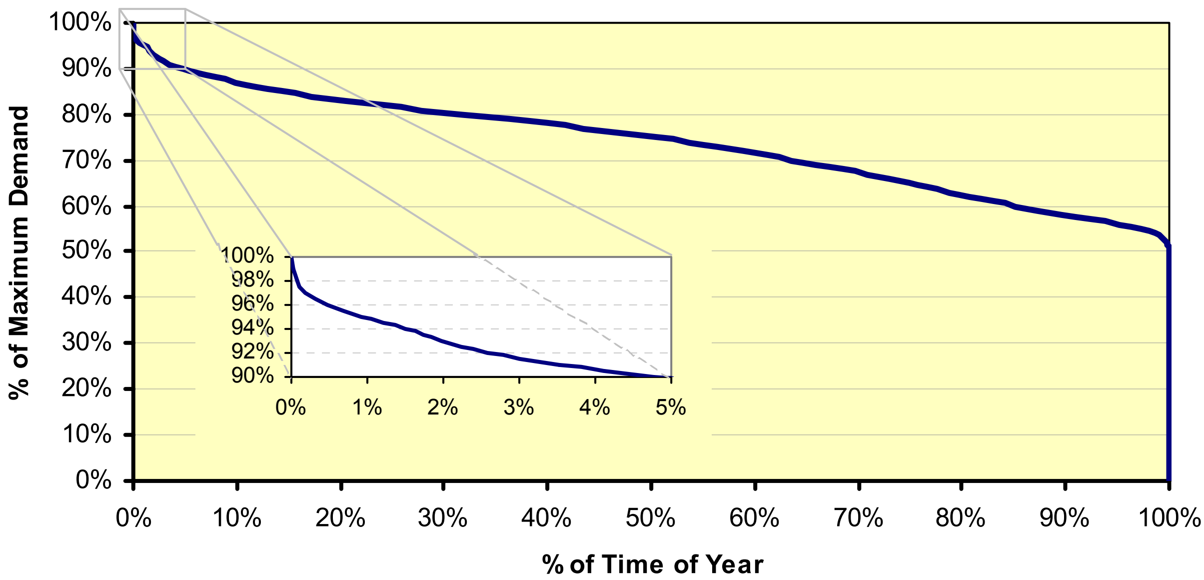


Figure 2.8: Cumulative Load Duration

Queensland Region - 2001/2002



3. EXISTING AND COMMITTED DEVELOPMENTS

3.1 Generation

The bulk of Queensland's electrical energy is generated by coal-fired power stations located in central and southern Queensland. Three relatively small hydro-electric power stations (with limited water storage) operate in Far North Queensland. The remaining capacity is mostly pumped storage hydro in southern Queensland and gas turbines at Swanbank, Townsville, Oakey and other locations.

Table 3.1 summarises the existing and committed power stations connected or to be connected to the Powerlink transmission network, including the non-scheduled market generators at Invicta and Koombooloomba, as well as the scheduled embedded generators at Barcaldine and Roma.

The following notes apply to Table 3.1:

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

(2) 'Other various locations' comprise gas turbines at Mackay (33MW Winter/30MW Summer), Gladstone (14/13MW) and Tarong (15/14MW) – note that Tarong and Gladstone GTs are non-scheduled.

(3) Conversion of the Townsville Power Station from liquid fuelled open cycle gas turbine (OCGT) to gas fuelled combined cycle gas turbine (CCGT) in early 2005 has been included. Note that the steam turbo-alternator will be connected to the Ergon distribution network.

Table 3.1: Generation Capacity

Connected to Queensland Transmission Network (Existing and Committed Plant only) including Embedded Market Scheduled Generators

Location	Capacity MW Generated (1) (2) (3)					
	Winter 2003	**Summer 2003/04**	**Winter 2004**	**Summer 2004/05**	**Winter 2005**	**Summer 2005/06**
Coal Fired						
Callide B	700	700	700	700	700	700
Tarong	1,400	1,400	1,400	1,400	1,400	1,400
Stanwell	1,400	1,400	1,400	1,400	1,400	1,400
Swanbank B	500	480	500	480	500	480
Callide A	0	0	0	0	120	120
Gladstone	1,680	1,680	1,680	1,680	1,680	1,680
Collinsville	185	185	185	185	185	185
Callide Power Plant	840	840	840	840	840	840
Millmerran	863	853	863	853	863	853
Tarong North	450	450	450	450	450	450
TOTAL – Coal Fired	8,018	7,988	8,018	7,988	8,138	8,108
Combustion Turbines						
Barcaldine	55	53	55	53	55	53
Mt Stuart (Townsville)	294	288	294	288	294	288
Townsville (Yabulu) (3)	160	160	160	160	223	223
Oakey	320	276	320	276	320	276
Swanbank D (37/32MW)	0	0	0	0	0	0
Swanbank E (CCGT)	385	355	385	355	385	355
Roma	68	62	67	61	66	60
Other (various locations) (2)	62	57	62	57	62	57
Hydro Electric						
Barron Gorge	60	60	60	60	60	60
Kareeya	72	72	72	72	72	72
Koombooloomba	7	7	7	7	7	7
Wivenhoe (pumped storage)	500	500	500	500	500	500
Sugar Mills						
Invicta	39	39	39	39	39	39
TOTAL – Other Than Coal (rounded)	2,022	1,929	2,021	1,928	2,083	1,990
TOTAL – ALL STATIONS (rounded)	**10,040**	**9,917**	**10,039**	**9,916**	**10,221**	**10,098**
Interconnections Queensland – New South Wales Import Capacity	500	500	500	500	500	500

[Source: NEMMCO and Powerlink]

3.2 Changes to Supply Capacity

3.2.1 Generation

Since Powerlink's 2002 Annual Planning Report was published, the Swanbank E Power Station (355MW), Millmerran Power Station (853MW), and Tarong North Power Station (450MW) have been placed in service.

Powerlink has been advised the conversion of the Townsville Power Station from liquid fuel to gas fuel, along with addition of a steam turbine, is committed for completion by early 2005. The steam turbo-alternator (83MW) will be connected to the distribution network, while the output of the existing transmission connected generator will reduce from 160MW to 140MW.

Powerlink has not been advised of any other commitments to new generating capacity since the 2002 Annual Planning Report.

The Swanbank A Power Station (408MW) was nominated as mothballed in the 2002 Annual Planning Report. The status has since been revised to unregistered and not connected to the network.

While Swanbank D is currently operational, its owner has advised that it plans to relocate or sell the plant and therefore its availability cannot be relied upon into the future. Accordingly the generator capacity has been nominated as zero for the purposes of Table 3.1.

The mothballed Callide A Power Station is planned to be returned to service in 2005.

3.2.2 Interconnection

Table 3.1 also includes combined import capability for the Queensland New South Wales Interconnection (QNI) and the market network service provider (DirectLink) between Mullumbimby and Terranora in New South Wales.

The combined QNI plus DirectLink maximum import capacity is limited by the transient stability, oscillatory stability and the thermal capability of the 330kV network in New South Wales.

In addition, the combined QNI plus DirectLink maximum import capacity can also be constrained by intra-regional constraints in northern New South Wales and south western Queensland.

Based on the above network limits, the combined import capability of QNI plus DirectLink is nominated as 500MW for the purposes of the generation capacity schedule shown in Table 3.1.

3.3 Supply Demand Balance

The outlook for the supply demand balance for the Queensland region was published in NEMMCO's 2002 Statement of Opportunities on 30 March 2002. A revised outlook is expected to be published by NEMMCO in the 2003 SOO (July 2003).

3.4 Transmission Network

The 1700km long Queensland transmission network comprises 275kV transmission from Cairns in the north to Mudgeeraba in the south, with 110kV and 132kV systems providing transmission in local zones, and providing limited backup to the 275kV grid. Also, 330kV lines forming part of the QNI run from Braemar to the New South Wales border near Texas.

Figures 3.1 and 3.2 show the single line diagram of the Queensland network.

Since a large proportion of the Queensland generating capacity is located in central Queensland, there are high power transfers from central to south Queensland and central to north Queensland. However, flows from central to south Queensland have decreased in recent times due to new generating plant in southern Queensland coming on line.

The implications of this, together with forecast load growth, are:

- new generation capacity in central Queensland may again increase power flows from central Queensland to both north Queensland and south Queensland which may result in transmission limits being reached;

- new generation in north Queensland may reduce occurrences of transmission limits being reached in the north; however, this alone may also increase flows from central to south Queensland which may result in transmission limits being reached in the south;

- additional new generation in south west Queensland may alleviate network constraints between central and south Queensland, however it may exacerbate constraints in the north. This will also tend to increase power flows into south east Queensland (Tarong transfer) but will have a compensating impact by increasing the Tarong transfer capability;

- additional new generation in south east Queensland may alleviate network constraints between central and south Queensland, however it may exacerbate constraints in the north. This will also tend to reduce total flows into south east Queensland and thus reduce utilisation of capacity across the Tarong 'grid section';

- new loads may be connected in central Queensland without significantly influencing transmission limits to the north or south; however network constraints may then arise within central Queensland;

- New loads in north Queensland may exacerbate constraints between central and north Queensland;

- New loads in south east Queensland may exacerbate constraints associated with the Tarong limit and the CQ-NQ limit.

3.4.1 Committed Transmission Projects

Table 3.2 lists transmission grid developments commissioned since Powerlink's 2002 Annual Planning Report was published in July 2002.

Table 3.3 lists transmission grid developments which are committed and under construction at June 2003.

Table 3.4 lists connection works that have been commissioned since Powerlink's 2002 Annual Planning Report was published in July 2002.

Table 3.5 lists new transmission connections or connection works for supplying load which are committed and under construction at June 2003. These connection projects resulted from agreement reached with relevant connected customers, generators or distribution network service providers as applicable.

3.4.2 Possible Connection Projects

Table 3.6 lists connection works which may be required over the next few years. New connections can be initiated by generators or customers, or result from joint planning with the relevant DNSP.

3.4.3 Possible Shared Grid Projects

Discussion of possible future development of the shared transmission grid is contained in Chapter 5.

Table 3.2: Commissioned Transmission Developments

Commissioned Since June 2002 (1)

Project	Purpose	Zone Location (2)	Date Commissioned
Major Developments			
Cairns reinforcement	Provide additional capacity to meet growing loads in the Cairns area	Far North	October 2002
Stanwell – Broadsound 275kV line reinforcement	Part of solution to provide market benefits relating to supply to NQ	Central West	November 2002
Network support Arrangements			
Contract with local generators to provide network support in North Queensland	Part of solution to provide market benefits relating to supply to NQ	North	Ongoing from January 2002
Minor Developments			
Blackwall 1st 120MVAr, 275kV capacitor bank	Provide capacity to meet increasing reactive demand	Moreton North	August 2002
2nd Swanbank 200MVA, 275/110kV transformer	Provide transformer capacity to meet load growth	Moreton South	November 2002
Strathmore 275/132kV transformer	Provide transformer capacity to meet load growth	North	November 2002
Blackwall 2nd 120MVAr, 275kV capacitor bank	Provide capacity to meet increasing reactive demand	Moreton North	November 2002
Lilyvale 2 x 40MVAr, 132kV capacitor banks	Provide capacity to meet increasing reactive demand	Central West	December 2002
Palmwoods 275/132kV transformer reinforcement	Provide transformer capacity to meet load growth	Moreton North	December 2002
Mudgeeraba 120MVAr, 275kV capacitor bank	Provide capacity to meet increasing reactive demand	Gold Coast – Tweed	December 2002
Abermain 50MVAr, 110kV capacitor bank	Provide capacity to meet increasing reactive demand	Moreton South	April 2003
Woolooga 275/132kV transformer reinforcement	Provide transformer capacity to meet load growth	Wide Bay	April 2003

Notes:

(1) Does not include new connections.

(2) Zone locations are defined in Section 2.5.

Table 3.3: Committed Transmission Developments

Committed and under construction at June 2003 (1)

Project	Purpose	Zone Location (2)	Planned Commissioning Date
Major Developments			
Belmont 275kV line reinforcement	Increase supply capacity to maintain reliability to growing loads in southern areas of Brisbane	Moreton South	November 2003
Molendinar 275kV substation establishment (and transmission line from Maudsland)	Increase supply capacity to maintain reliability to growing loads within Gold Coast and surrounding areas	Gold Coast – Tweed	November 2003
Lilyvale 275kV reinforcement	Increase supply capacity to maintain reliability to inland central Queensland mining area	Central West	October 2004
Minor Developments			
Tarong to Blackwall circuit switching at Mt England	Provide voltage support	Moreton North	July 2003
Mt England 120MVAr, 275kV capacitor bank	Provide capacity to meet increasing reactive demand	Moreton North	December 2003
Palmwoods 120MVAr, 275kV capacitor bank	Provide capacity to meet increasing reactive demand	Moreton North	April 2004
Wurdong 120MVAr, 275kV capacitor bank	Provide capacity to meet increasing reactive demand	Gladstone	August 2004
Ross and Chalumbin 275kV line switching	Provide improved switching arrangement	Far North	September 2004
Ross-Dan Gleeson 132kV Transmission line retension	Increase thermal rating to maintain reliability to the north Townsville area	Ross	October 2004

Notes:

(1) Does not include new connections.

(2) Zone locations are defined in Section 2.5.

Table 3.4: Commissioned Connection Works since June 2002

Project	Purpose	Location	Commissioning Date
South Pine modification for Beerwah	Increase connection point capacity to meet distribution network rearrangement	Moreton North	August 2002
Mackay 132/33kV Transformer Upgrade	Increase transformer capacity to meet load growth	Mackay and surrounding areas	November 2002
QAL West establishment	Increase transformer capacity to meet load growth	Gladstone	January 2003
Alan Sheriff 132/11kV substation	132kV connection point for new Ergon zone substation	Inner western areas of Townsville	February 2003
Kemmis 132/66kV substation	New connection point for mining and other developments	West of Nebo, North Zone	April 2003
Murarrie 110kV Switching Station	New connection point to Energex to augment capacity to Australia Trade Coast area	Brisbane Port and other areas south of Brisbane River	April 2003
Abermain 110/33kV Transformer Upgrade and 110kV Connections	Provide transformer and line connection capacity to meet load growth	North Ipswich and surrounding areas	June 2003
Proserpine 132/66kV substation Transformer Upgrade	Increase transformer capacity to meet load growth	Proserpine, Bowen and Whitsunday areas	June 2003

Table 3.5: Committed Connection Works at June 2003

Project	Purpose	Location	Planned Commissioning Date
Bulli Creek 330/132kV Transformer	Provide new 132kV connection point for Ergon supply to Goondiwindi (Waggamba)	South West	September 2003
Turkinje modification for Craiglie	Increased transformer capacity	Far North	September 2003
Molendinar 275/110kV substation (1)	New connection point to Energex to augment 110kV capacity to parts of the Gold Coast and surrounding areas	Gold Coast CBD	November 2003
West End connection reinforcement	Increase capacity to West End and CBD	Moreton South	November 2003
Blackwater 132kV supply to Rolleston	New connection point for mining and other developments	Central West	May 2004
Biloela substation refurbishment and switching upgrade	Provide improved switching arrangement	Central West	October 2004
Ingham 132/66kV substation reconstruction and transformer replacement	Replace end of life assets and increase transformer capacity to meet load growth	North	June 2005
Rocklea 110kV 2nd Connection for Archerfield	Increase capacity to Energex 33kV network to match load growth Archerfield and surrounding areas	Moreton South	Deferred to October 2005

Notes:

(1) Connection point created as a result of Molendinar project included in Table 3.3.

Table 3.6: Possible Connection Works

Project	Purpose	Location	Possible Commissioning Date
Ebbwvale 110/11kV substation	New connection point to Energex to increase 11kV and sub-transmission capacity for new loads	Industrial area near Ipswich	May 2004
Pioneer Valley 132/66kV substation 2nd Transformer	Provide reliable supply to growing load	Areas west of Mackay	October 2004
Edmonton 132/22kV substation	New connection point to Ergon to increase 22kV capacity to growing load south of Cairns	Areas between Cairns and Innisfail	October 2004
Blackwater 132/66kV substation 3rd Transformer	Increase 66kV capacity for reliable supply to growing load	Bowen Basin mining area	October 2005
Mudgeeraba 110kV Connections for Varsity Lakes	Provide supply to new Energex zone substation	Gold Coast areas near Bond University	October 2005
Runcorn 110/33kV substation 3rd Transformer	Increase 33kV capacity for reliable supply to growing load	South east areas of Brisbane	October 2005
Dan Gleeson 132/66kV substation 2nd Transformer	Increase 66kV capacity for reliable supply to growing load	South western areas of Townsville	October 2005
Algester 110/33kV substation	New connection point to Energex to increase 33kV capacity for load growth	Algester and surrounding areas	October 2005
New 110kV connection to Brisbane CBD and surrounding areas	New connection point to enable Energex to increase 110kV capacity to Brisbane CBD areas	Brisbane CBD and inner suburbs	October 2005
Sumner 110/11kV substation	New connection point to Energex to increase 11kV capacity for load growth and new loads	Supply to industrial areas near Sumner Park	April 2006
Larcom Creek 275/132kV substation (connection point created as a result of possible Larcom Creek establishment)	New connection point to Ergon to augment CQ transformer capacity	Gladstone and central Queensland	October 2006
Redbank 110/33kV substation	New connection point to Energex to increase 33kV capacity to rapidly developing areas	Redbank, Goodna and surrounding areas	April 2007
Townsville South to Townsville Port area 132kV and 132/66kV substation	Provide increased 66kV capacity to growing loads and potential new loads	Townsville CBD, Port and surrounding areas	October 2007

Figure 3.1: Existing 275/132/110kV Network June 2003 – North and Central Queensland

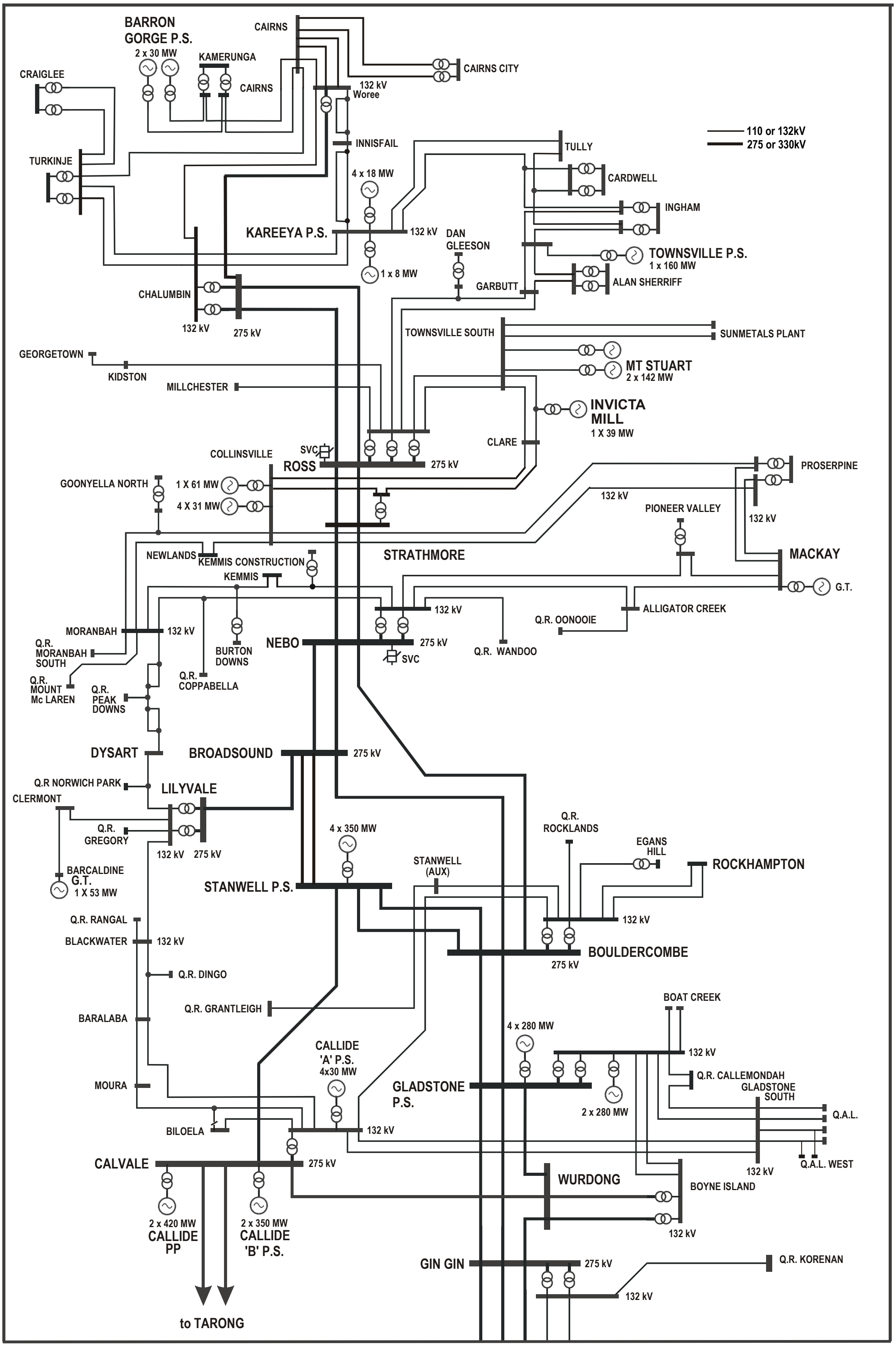
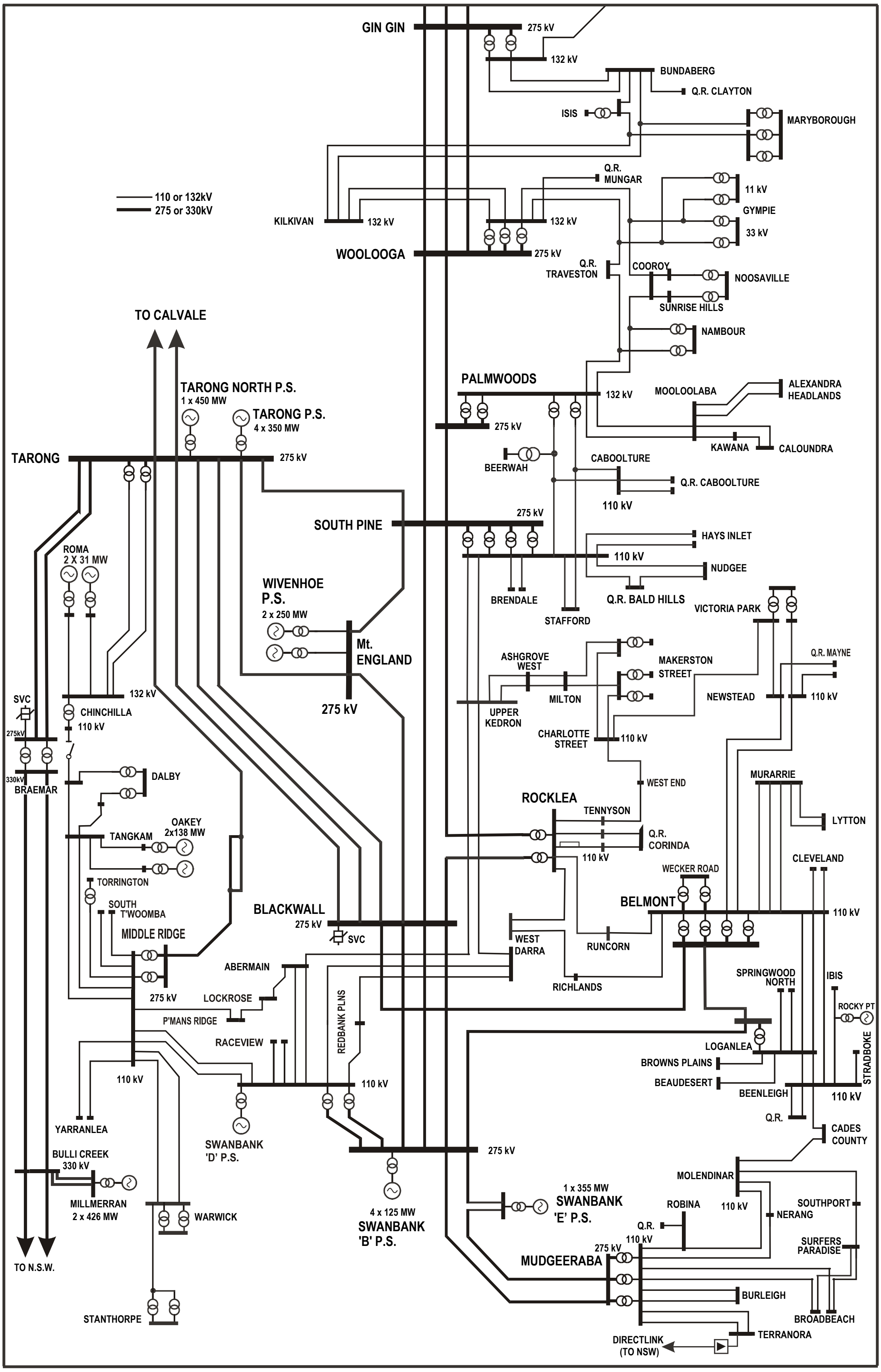


Figure 3.2: Existing 275/132/110kV Network June 2003 – South Queensland



4. NETWORK CAPABILITY

The National Electricity Code (Clause 5.6.2A(b)(3)) requires the Annual Planning Report to set out 'a forecast of constraints and inability to meet the network performance requirements set out in NEC Schedule 5.1 or relevant legislation or regulations of a participating jurisdiction over 1, 3 and 5 years.'

This chapter on network capability provides this and other related information. It contains:

- A background on the factors that influence network capability;
- Diagrams of possible grid power flows under a sample range of scenarios;
- Estimates of short circuit levels and transformer capacity;
- A qualitative explanation of factors impacting power transfer capability at key 'grid sections' on the Powerlink grid;
- Identification of emerging limitations with the potential to impact on supply reliability;
- A table summarising the outlook for grid constraints and network limitations over a five year horizon.

The capability of Powerlink's transmission grid to meet forecast demand is dependent on a number of factors that are subject to considerable uncertainty.

In general terms, the Queensland transmission grid is more highly loaded relative to its capacity during summer than during winter. The reactive power requirements are greater in summer than in winter and transmission plant has lower power carrying capacity in the higher summer temperatures. Also high summer peak demands generally last for many hours, whereas winter peak demands are for short evening periods, as shown in Figure 2.7.

The power flows across most of the Queensland grid are influenced by the location and pattern of power generation. Future generation dispatch patterns are uncertain under the electricity market and can also vary substantially due to the impact of planned or unplanned outages of generation plant. Power flows on transmission grid elements can also vary substantially with planned or unplanned outages of transmission lines and transformers. Power flow levels can also be higher at times of local area or zone peak demands, as distinct from those at the time of Queensland region peak demand. Power flows can also be higher when embedded generation levels are lower than forecast.

This chapter outlines some of these sensitivities using illustrative grid power flows over the next three years under a sample range of scenarios. Qualitative explanation is also provided on the factors which impact power transfer capability at key 'grid sections' on the Powerlink grid, and on the cause of emerging limitations which may impact supply reliability.

4.1 Sample Winter and Summer Grid Power Flows

Powerlink has selected 18 sample scenarios to illustrate possible grid power flows for the Queensland region summer and winter peaks over the period 2003 winter to 2005/06 summer.

This information is based on one possible sample generation dispatch and load condition for each case and is provided only as an indication of network power flows. These can vary for different load conditions and generator bidding behaviour. In providing this information, Powerlink has not attempted to predict market outcomes.

Illustrative grid power flows at forecast region average weather (50% PoE) winter and summer peak demand over the next three years are shown in Appendix A for the Medium Growth Scenario load forecast outlined in Chapter 2 of this report. These show possible grid power flows at the time of forecast winter or summer region peak demand, and with a range of import and export conditions on the Queensland – New South Wales interconnection (QNI) as indicated below.

Grid power flows in Appendix A are based on existing network configuration, committed projects and proposed new network assets (as proposed in Chapter 5) only, and assume the grid is in its 'normal' or 'intact' state, that is, all network elements in service. Power flows can be higher than those levels during network or generation contingencies and/or during times of local area or zone peak demands.

Appendix A also indicates where grid flows are expected to exceed the relevant limit for the system conditions analysed.

Sample conditions in Appendix A include:

- Figure A1: Generation & Load Legend for Figures A3 to A20
- Figure A2: Power Flow & Limits Legend for Figures A3 to A20
- Figure A3: Winter 2003 Qld Peak 300MW Import QNI Flow
- Figure A4: Winter 2003 Qld Peak Zero QNI Flow
- Figure A5: Winter 2003 Qld Peak 300MW Export QNI Flow
- Figure A6: Winter 2004 Qld Peak 300MW Import QNI Flow
- Figure A7: Winter 2004 Qld Peak Zero QNI Flow
- Figure A8 Winter 2004 Qld Peak 300MW Export QNI Flow
- Figure A9: Winter 2005 Qld Peak 300MW Import QNI Flow
- Figure A10: Winter 2005 Qld Peak Zero QNI Flow
- Figure A11: Winter 2005 Qld Peak 300MW Export QNI Flow
- Figure A12: Summer 2003/04 Qld Peak 300MW Import QNI Flow
- Figure A13: Summer 2003/04 Qld Peak Zero QNI Flow
- Figure A14: Summer 2003/04 Qld Peak 300MW Export QNI Flow
- Figure A15: Summer 2004/05 Qld Peak 300MW Import QNI Flow
- Figure A16: Summer 2004/05 Qld Peak Zero QNI Flow
- Figure A17: Summer 2004/05 Qld Peak 300MW Export QNI Flow
- Figure A18: Summer 2005/06 Qld Peak 300MW Import QNI Flow
- Figure A19: Summer 2005/06 Qld Peak Zero QNI Flow
- Figure A20: Summer 2005/06 Qld Peak 300MW Export QNI Flow

The power flows shown in Figures A3 to A20 are a sample of possible generation dispatch and grid power flows for the forecast region peak demand conditions nominated. The dispatch assumed is broadly based on the relative outputs of generators since the commencement of the National Electricity Market but is not intended to imply a prediction of future market behaviour. Dispatch patterns have been adjusted at generators in north Queensland where Powerlink Queensland has a network support contract and where the power flow would have otherwise exceeded the CQ-NQ 'grid section' limit.

The impact of DirectLink, between Mullumbimby and Terranora in NSW, is uncertain as the flows could vary in either direction in its role as a Market Network Service Provider. For the purposes of the sample power flows in Figures A3 to A20, the power flow on this link is assumed to be zero. In the simplified system representation in Appendix A, actual flows on DirectLink would have a similar impact to varying the generation level in the combined Moreton South and Gold Coast/Tweed zones.

4.2 Network Power Transfer Capability

4.2.1 Location of Network 'Grid Sections' and 'Observation Points'

Powerlink has identified a number of 'grid sections' which allow grid capability and emerging limits of the whole grid to be assessed in a simplified manner. Limit equations have been derived for each of these 'grid sections'. These limit equations quantify the maximum secure power transfer across these 'grid sections'. NEMMCO has incorporated these limit equations as part of the constraint analyses within its market dispatch process (NEMDE).

In Powerlink's Annual Planning Report 2002, 'observation points' in addition to the 'grid sections' were discussed. The power flow across these 'observation points' is still shown in Figures A3 to A20. However, discussion on network capability or transfer limits is restricted to the 'grid sections' where the limit equations are defined.

Figure A2 in Appendix A shows the location of power transfer limits (where limit equations apply) and 'observation points' on the Queensland grid, some of which may be exceeded under some circumstances in the next three years. Potential limitations are summarised in Table 4.6.

The maximum power transfer across these 'grid sections' may be limited by transient/dynamic stability, voltage stability, thermal plant ratings or protection relay load limits.

4.2.2 Determining Grid Transfer Capacities

The transfer capacity across each 'grid section' varies with different system operating conditions. Transmission limits in the NEM are not generally amenable to definition by a single number. Instead, Transmission Network Service Providers define the capacity of their network in terms of multi-term equations. These equations quantify the relationships between the system operating conditions and the network transfer limit, and are implemented into NEMMCO's market systems for the optimal dispatch of generation. This is very relevant in Queensland as the grid transfer capacity is highly dependent on which generators are in service, and their dispatch level.

This 'limit equation' approach aims to maximise the transmission capacity available to electricity market participants at any point in time depending on the prevailing system conditions.

The trade-off for this maximisation of grid transfer capacity is the complexity of analysis required to define grid capacity. The process of developing transfer limit equations from multiple network analysis cases (using regression techniques) is very complicated and time consuming. It also involves a due diligence process by NEMMCO before these equations are implemented in the market dispatch processes.

The present limit equations applying to the Queensland transmission network 'grid sections' are provided in Appendix B. Readers should note that the limit equations will change over time with load, generation and network development.

Such detailed and extensive analysis has not been carried out for future network and generation developments for this Report. Instead, Figures A3 to A20 show if the flow on any 'grid section' is expected to exceed the limit for that particular condition and generation dispatch. Section 4.3 gives a qualitative description of the main system conditions that impact on the capacity of each of the 'grid sections'.

4.2.3 Grid Capacity Ranges

Grid capacity may vary depending on system conditions at the time. The grid capacity is the maximum power transfer for which the system will remain stable for any credible contingency event.

Table A1 in Appendix A shows the power flows at each of these 'grid sections' for intact operation (that is, with all network elements in service) at the time of peak demand in the Queensland region, corresponding to the sample generation dispatch shown in Figures A3 to A20. It also shows where grid flows are expected to exceed the relevant secure limit, and the mode of insecurity that determines the limit.

Forecast average weather (50% PoE) coincident region peak demands, as outlined in Chapter 2, were used to determine the grid flows shown in Figures A3 to A20. Grid power flows can be higher than shown in Table A1 at times of local area or zone peak demands, extreme weather conditions, lower embedded non-scheduled generation output or for different scheduled generation dispatch patterns.

The factors that influence the transfer capability, and the impact of committed developments are discussed in Section 4.3.

4.3 Transmission Limits

This section is a qualitative summary of the main system conditions that impact transfer capability across key 'grid sections' in the Queensland transmission network.

Powerlink has also provided a qualitative outlook for the likelihood that these 'grid sections' will translate into restrictions on generator dispatch (ie. binding limits). This outlook is provided to assist readers to understand the information provided in Appendix A, and is in no way meant to imply that this outlook holds true for system conditions other than those in the sample power flows. Grid power flows and capability limits are highly sensitive to actual demand and generator dispatch patterns, and embedded non-scheduled generation output, and Powerlink makes no prediction of market outcomes in the information provided.

Note that power flows across the ‘grid sections’ and ‘observation points’ can be higher than as shown in Figures A3 to A20 at times of local area or zone peak demands. However, the transmission capability may also be higher under such conditions depending on how generation or interconnector flow varies to meet the higher local load levels.

For each of the ‘grid sections’ discussed below, the proportion of time that the limit equation has actually bound in the NEMMCO dispatch process (NEMDE) is provided for two periods, namely from April to September 2002 (winter) and from October 2002 to March 2003 (summer).

This information on binding limits includes all dispatch intervals in the relevant period. No attempt has been made to distinguish between dispatch intervals when planned or forced outages may have affected network capability, or intervals when network flows may have been affected by network support contracts that Powerlink has in place with some generators.

This binding constraint information is provided for the information of readers and is not intended to imply that the historical information represents a prediction of constraints in the future.

4.3.1 Far North 'Grid Section'

The maximum power transfer across the Far North ‘grid section’ is limited by the occurrence of unstable voltage levels following transmission contingencies. The critical contingency is an outage of a Ross to Chalumbin 275kV transmission circuit or the 275kV transmission circuit into Woree (Cairns area).

The present limit equation, for each of these critical contingencies, is shown in Table B1 of Appendix B. The equations show that the following variables have the most significant effect on the limit:

- MW generation within the Far North zone;
- Generators on-line within the Far North zone; and
- Capacitor banks on-line within the Far North zone.

For these contingencies, the operation of local hydro generators (including operation as synchronous condensers) provides voltage support (reactive power) and increases the secure power transfer capability. However, the Far North Limit is also sensitive to the MW output from these hydro units. Local hydro MW output reduces the grid transfer limit, but more load can be securely supported in the Far North zone because the reduction in the grid transfer limit is more than offset by the increase in MW output by the local generators.

Loadings in the Far North zone can vary due to dispatch levels of embedded generation at sugar mills and wind farms.

Information pertaining to duration of constrained operation over the period April 2002 to March 2003, for the Far North limit is summarised in the following table:

Table 4.1: Far North Limit Constraint for April 2002 – March 2003

Far North Limit	Proportion of Time Constraint Equation Bound (%)	Equation Bound Hours
April to September 2002	0.1%	6 hours
October 2002 to March 2003	0.4%	18 hours (1)

Note:
(1) Powerlink advises that power transfers across this 'grid section' were higher than average over the last summer period due to low hydro MW output.

Completion of the 132kV circuits between Chalumbin and Woree substations in 2001 (one circuit energised at 275kV in 2002) increased the maximum secure power transfer across the Far North 'grid section'. This augmentation, together with the capacitive compensation commissioned at Chalumbin in the same year, and the subsequent revision of the limit equations, makes it unlikely that power flows across this 'grid section' will encroach on the limit for the period to 2005. This assessment of the outlook is based on the assumed sample generation scenarios, and for average levels of embedded non-scheduled generators in the area.

Key factors which could alter this outlook over the period to 2005 include non-availability or low MW output of the hydro generators or higher than forecast loads in the Far North zone. Powerlink and NEMMCO have implemented operational arrangements to avoid any pre-contingent load shedding should binding limit conditions eventuate. Powerlink has also initiated a consultation process to identify options to address limitations which could occur under low generation or high load conditions from summer 2005/06 onwards. This is discussed further in Chapter 5.

4.3.2 CQ-NQ 'Grid Section'

The following discussion covers both the Ross and CQ-NQ 'observation points' previously documented in the Powerlink Queensland Annual Planning Report 2002. The transfer capability at both these 'observation points' is collectively represented as the CQ-NQ limit equation in NEMMCO's dispatch process.

The maximum power transfer across the CQ-NQ 'grid section' is limited by the occurrence of dynamic instability or unstable voltage levels following transmission contingencies.

The maximum secure power transfer across this 'grid section' was significantly increased following the commissioning of a new 275kV transmission line from Stanwell to Broadsound, in November 2002. The north Queensland system was further augmented in November 2002 with the commissioning of a 275/132kV transformer at the Strathmore 275kV switching station (approximately midway between Nebo and Ross).

These augmentations increased the maximum secure transfer across this 'grid section' from 800MW (as documented last year) to between 925MW and 985MW. These significantly higher flows are limited by dynamic stability following an outage of a 275kV transmission circuit between Nebo and Strathmore or between Strathmore and Ross substations.

However, this increased grid transfer capacity is already fully utilised, with limits being reached particularly at times of summer peak loads in north Queensland. This limitation is currently managed by network support contracts which Powerlink has with local generators. Further corrective action may be required in the future.

Information pertaining to duration of constrained operation over the period April 2002 to March 2003, for the CQ-NQ Limit is summarised in the following table. This constraint information is over a period during which the change of the CQ-NQ limit occurred.

Table 4.2: CQ-NQ Limit Constraint for April 2002-March 2003

CQ-NQ Limit (1)	Proportion of Time Constraint Equation Bound (%)	Equation Bound Hours
April to September 2002	3.4%	148 hours (2)
October 2002 to March 2003	0.1%	5 hours

Note:
(1) Powerlink has entered into network support agreements with some generators in northern Queensland. The figures reported above include all periods of constraint, including those managed by network support agreements. NEMMCO does not consider that periods of congestion that are managed through a network support agreement contribute to the total number of hours of a binding intra-regional constraint.
(2) The higher amount of binding operation was due to the transfer limit being only 800MW prior to the November 2002 network augmentations.

The transfer limit is currently described by a single equation. This limit equation for the CQ-NQ 'grid section' is shown in Table B2 of Appendix B. The equation defines the dynamic stability limit and shows that as the number of hydro generators operating as synchronous condensers in the Far North zone increases the CQ-NQ limit reduces. Therefore, depending on generation dispatch, the CQ-NQ limit may vary between 925MW and 985MW.

In February 2003, the Nebo Static Var Compensator (SVC) sustained significant fire damage. The SVC is planned to be returned to service prior to the 2003/04 summer. For the duration of this outage, the CQ-NQ transfers are to be limited to a maximum of 930MW due mainly to voltage stability.

Power flows across this 'grid section' can be higher than shown in Figures A3 to A20 at times of local area or north Queensland peak demands. Flows can also be higher if output from embedded generators in north Queensland is lower than forecast.

The outlook for the CQ-NQ Limit is that it is likely that the power flow across this 'grid section' may encroach on the limit from time to time. Powerlink has a network support contract with local generators to manage the CQ-NQ limit in these circumstances.

The reliance on network support is expected to increase steadily as load in north Queensland continues to grow. This trend could be modified with the conversion of the existing OCGT Townsville (Yabulu) power station to gas fired CCGT operation. The reliance on network support may be reduced if the Townsville power station operates regularly due to market dispatch over periods of northern Queensland summer peaks.

Other key factors which could influence the reliance on network support include non-availability or low MW output of the hydro generators in the Far North zone. Without this hydro generation, the CQ-NQ 'grid section' is likely to be constrained over sustained summer load periods. Availability and dispatch of Collinsville generation contributes to the resultant flows across this 'grid section'.

Development of large industrial loads in north Queensland not included in the load forecast, or lower levels of embedded generation than forecast, will result in increased power transfers across the CQ-NQ 'grid section', and lead to greater reliance on network support or other forms of capability augmentation.

Powerlink may initiate a consultation process to identify options to address the CQ-NQ transfer limitations. This is discussed further in Chapter 5.

4.3.3 CQ-SQ 'Grid Section'

The maximum power transfer across this 'grid section' is limited by the occurrence of unstable voltage levels. The critical contingency is an outage of a Calvale to Tarong 275kV transmission circuit. The limit results from an exhaustion of reactive power reserves in the Central West and Gladstone zones. As a result, the number of generating units on-line in these zones impacts on the limit. More generating units on-line increases the reactive power support, and therefore increases the limit.

The present voltage stability limit equations for the CQ-SQ Limit are shown in Table B3 of Appendix B. The equations show that the following variables have the most significant effect on the limit:

- Number of generating units on line in Central West and Gladstone zones; and
- MW Generation at the Gladstone Power Station.

At transfers above about 2000MW, the CQ-SQ capability is limited by transient instability.

Information pertaining to duration of constrained operation over the period from April 2002 to March 2003, for the CQ-SQ Limit is summarised in the following table:

Table 4.3: CQ-SQ Limit Constraint for April 2002-March 2003

CQ-SQ Limit	Proportion of Time Constraint Equation Bound (%)	Equation Bound Hours
April to September 2002	0.9%	38 hours
October 2002 to March 2003	0.4%	16 hours (1)

Note:

(1) Less binding occurred during this period due to the commissioning of generating plant in southern Queensland. No binding occurred for the three months from January to March 2003.

Power flows across this 'grid section' can be higher than shown in Figures A3 to A20. The outlook for the CQ-SQ limit is that power flows are unlikely to encroach on this limit over the period to 2006 based on the generation patterns in the sample power flows. This outlook can be attributed to the recent commissioning of generating plant in southern Queensland (Swanbank E, Tarong North and Millmerran).

Factors which could change this outlook include extreme weather and demand patterns and/or generation patterns that result in higher power flows across the CQ-SQ 'grid section'. The latter is the most variable and has the largest potential for producing transfers that encroach on the limit.

On the other hand, should any of the possible large metal processing load developments currently under investigation in central or north Queensland proceed within the review period, CQ-SQ flows are likely to reduce significantly.

4.3.4 Tarong 'Grid Section'

The following discussion covers the Tarong, Woolooga and Blackwall 'observation points' previously documented in the Powerlink Queensland Annual Planning Report 2002. For convenience and ease of comparison the transfer capability at each of these 'observation points' are collectively represented as Tarong limit equations in NEMMCO's dispatch process.

The maximum power transfer across this 'grid section' is limited by the occurrence of unstable voltage levels. The critical contingency is the loss of a 275kV transmission circuit either between central and southern Queensland or between Tarong and the greater Brisbane load centre. Currently one of three contingencies can limit the maximum secure power transfer across this 'grid section'. These critical contingencies are:

- Calvale to Tarong 275kV transmission circuit;
- Woolooga to Palmwoods 275kV transmission circuit; and
- Blackwall to Belmont 275kV transmission circuit.

The limit results from an exhaustion of reactive power reserves in southern Queensland.

The present limit equations for the Tarong Limit are shown in Table B4 of Appendix B. The equations show that the following variables have the most significant effect on the limit:

- Transfer on QNI;
- MW generation within the South West zone;
- Number of generators on-line in the Moreton North and South zones; and
- MW generation within the Moreton North and South zones.

There is an inter-dependence between the CQ-SQ transfer and the Tarong Limit. High flows between central and southern Queensland reduce the Tarong limit. This reduction is due to the high reactive losses between central and southern Queensland eroding the reactive power reserves in southern Queensland. Therefore, reducing the CQ-SQ transfer by increasing generation west of the 'grid section' increases the Tarong limit. Increasing the generation east of the 'grid section' reduces the transfer limit, but increases the overall amount of secure supportable southern Queensland load. This is because the reduction in the power transfer limit is more than offset by the increase in MW output of the generators east of the 'grid section'.

Information pertaining to duration of constrained operation over the period April 2002 to March 2003, for the Tarong Limit is summarised in the following table:

Table 4.4: Tarong Limit Constraint for April 2002-March 2003

Tarong Limit (1)	Proportion of Time Constraint Equation Bound (%)	Equation Bound Hours
April to September 2002	0.1%	3 hours
October 2002 to March 2003	Less than 0.1%	2 hours

Note:

(1) The form of the Tarong intra-regional constraint is the subject of a consultation by NEMMCO. There is a view that the current formulation of the constraint tends to bind more frequently than is necessary.

The advent of the Swanbank E, Millmerran and Tarong North generators has increased the amount of secure supportable load in southern Queensland for these critical contingencies. In addition, several completed, committed and proposed projects, aimed at addressing reliability limitations within the greater Brisbane area, contribute to increasing this limit (refer Chapters 3 and 5).

It should be noted that the 2 hours of binding in the October 2002 to March 2003 period occurred prior to the December 2002 revision of the Tarong limit which took account of all the relevant developments. The limit has not bound since.

With all committed developments the outlook for the Tarong Limit is that, over the period to 2006, the power flows across this 'grid section' are rarely expected to encroach on the limits because:

- New generation that has come on line in south west Queensland will tend to increase the transfer limit;
- The committed transmission projects will increase the transfer limit; and
- Powerlink will continue to investigate network support arrangements that will economically manage this limit.

This outlook is supported by the sample generation scenarios examined in Appendix A where power flows across this 'grid section' are seen not to encroach on the Tarong transfer capability over the period to 2006.

Power flows across this 'grid section' can be higher than shown in Figures A3 to A20 at times of local area or zone peak demands and during worse than average weather conditions. Flows can also be higher during planned or unplanned outages of generating plant in the Moreton North and South zones. Combination of these conditions may result in flows encroaching the Tarong limit. Powerlink and NEMMCO have implemented operational arrangements to minimise the occurrence of binding limits during these unusual conditions.

Beyond 2006, the accelerated load growth in the Logan area and other parts of south east Queensland may lead to binding limits on the Tarong 'grid section'.

4.3.5 Gold Coast 'Grid Section'

The maximum power transfer across this ‘grid section’ is limited by the occurrence of unstable voltage levels during winter and potential 110kV overloads and unstable voltage levels during summer. The critical contingency is an outage of a 275kV transmission line between Swanbank and Mudgeeraba.

Several completed, committed and proposed projects within southern Queensland, aimed at addressing reliability limitations, contribute or will contribute to increasing the Gold Coast limit. These projects include the installation of load compensation shunt capacitors at a number of locations in the Energex distribution network, installation of a 275kV 120MVAr capacitor bank at Mudgeeraba and a 110kV 50MVAr capacitor bank at Molendinar.

The present equation for the Gold Coast Limit is shown in Table B5 of Appendix B. The equation shows that the following variables have the most significant effect on the limit:

- Number of generating units on-line in the Moreton North and South zones;
- Reactive power reserve at the Blackwall static var compensator;
- MW loading of DirectLink; and
- Reactive power flow into the Gold Coast-Tweed zone.

In general, the voltage stability limit is sensitive to the power factor of the load. As a result, the winter limits are higher than the corresponding limits during summer. The voltage limits are also higher if the Swanbank source voltage is stronger (ie. the more Swanbank B or E units on line, the higher the reactive capability). This limit also reduces for Queensland import on DirectLink (however, this increases the overall amount of secure supportable load because the reduction in the power transfer limit is more than offset by the increase in DirectLink MW import).

Information pertaining to duration of constrained operation over the period April 2002 to March 2003, for the Gold Coast Limit is summarised in the following table:

Table 4.5: Gold Coast Limit Constraint for April 2002-March 2003

Gold Coast Limit (1)	Proportion of Time Constraint Equation Bound (%)	Equation Bound Hours
April to September 2002	0.7%	29 hours
October 2002 to March 2003	0.2%	11 hours

Note:
(1) The transfer across this ‘grid section’ is managed through an agreement whereby southerly flows on the DirectLink market network service are runback during binding conditions. NEMMCO does not consider that periods of congestion that are managed through this arrangement contribute to the total number of hours of a binding intra-regional constraint.

The duration of binding events outlined in Table 4.5 includes periods when Queensland export on DirectLink has loaded the Gold Coast transfer up to its secure limit.

For the winter system conditions considered, the flow across this ‘grid section’ is unlikely to encroach on the limit. However, the situation may be different during summer. Critical to the summer outlook for this ‘grid section’ is the completion of the uprating of the 110kV network between Beenleigh and Cades County. This work is planned to be completed by Energex prior to summer 2003/04. This 110kV upgrade is necessary to prevent thermal ratings on the 110kV system being exceeded following the critical 275kV contingency into the Gold Coast zone. The 50MVAr 110kV shunt capacitor bank proposed for Molendinar by October 2004, as a small network asset to address reactive shortfall in south east Queensland will also assist in maintaining this limit with growing MVAr loads on the Gold Coast. Further details are discussed in Chapter 5.

With these augmentations, the outlook for the Gold Coast 'grid section' is that the flows in Figures A15 to A17 (summer 2004/05) do not exceed the voltage stability limit. However, by the following 2005/06 coincident state summer peak, the flows may exceed the voltage stability limit (Figures A18 to A20).

Power flows across this 'grid section' can also be higher than shown in Figures A3 to A20 at times of local Gold Coast area peak demands (typically up to 5% higher). With such local peak demands the flows across this 'grid section' may exceed the voltage stability limit from summer 2004/05 depending on the generation in the Moreton zones. However, these limitations can be managed by operational measures over the 2004/05 summer. In addition, the 275kV circuits are forecast to reach emergency thermal rating under contingency conditions towards the end of the 5 year outlook for network limitations in this report. Powerlink expects to initiate a consultation process to identify options to address these limitations shortly. This also is discussed further in Chapter 5.

4.3.6 Braemar 'Grid Section'

The maximum power transfer across this 'grid section' is limited by a combination of the thermal rating of the Braemar 330/275kV transformers and the protection characteristics of the circuits between the Bulli Creek and Tarong substations. The critical contingency may be an outage of either one of the Braemar transformers, a 275kV circuit between Tarong and Braemar or a 330kV circuit between Braemar and Bulli Creek.

Power flow across this 'grid section' can occur in a northerly or southerly direction. With the commissioning of the Millmerran Power Station in 2002/03, power flows south on the 275kV grid between Tarong and Braemar are expected to decrease. Therefore, it is considered that southward flows from Tarong to Braemar will be well within the capability of this 'grid section'.

However, with Millmerran generation, northward flows may increase on this 'grid section'. At times of northward flow on QNI these flows may reach the 'grid section' capacity.

The capacity of this 'grid section' is currently limited to 1025MW in NEMMCO's dispatch process. The present equation for the Braemar Limit is shown in Table B6 of Appendix B. The current constraint implementation acts on the output of Millmerran. As a result, if this limit binds the Millmerran generation is reduced and the QNI transfer capability is unaffected.

Powerlink is considering possible options to increase this limit. In addition, this limitation is likely to be impacted by the proposed new large network asset to address emerging reliability limitations in supply to the Darling Downs area (discussed in Chapter 5). The recommended solution is to construct a 330kV double circuit transmission line between Millmerran and Middle Ridge. The Application Notice issued by Powerlink in March 2003 noted that the proposed reliability augmentation would have consequential market benefits associated with alleviating potential congestion on the Braemar 'grid section' during northward flows on QNI.

4.3.7 Other 'Observation Points'

Gladstone Transfer

The maximum power transfer across this 'grid section' is limited by the thermal rating of the 275kV lines between the Central West and Gladstone zones, usually the circuit from Calvale to Wurdong, and potentially the thermal rating of the Calvale 275/132kV transformer. The highest loadings on the Calvale to Wurdong 275kV circuit generally occur following a contingency of the Calvale to Stanwell circuit.

Flows through the Calvale 275/132kV transformer are currently managed via a network switching strategy to ensure they do not exceed the transformer thermal rating. This strategy has been assumed to be in place for all of the 18 sample power flows shown in Figures A3 to A20 of Appendix A.

For the sample power flows shown in Figures A3 to A20 the highest flows, relative to the thermal rating of the Calvale to Wurdong circuit, occur in winter 2003 and summer 2003/04. In winter 2003 the margin to the emergency thermal rating may be small. During summer 2003/04 the power flows may exceed the emergency thermal rating. From the sample power flows, the flow on the Calvale-Wurdong circuit may reduce in subsequent years as more Gladstone generation is scheduled and the CQ-SQ transfer again begins to increase.

However, the power flow on these critical elements can vary considerably. Different generation schedules (particularly at Gladstone, Callide and Stanwell), than assumed for Figures A3 to A20, can change the outlook for this 'observation point'. In recognition of this Powerlink and NEMMCO are investigating operational strategies to manage this potential limitation.

By about 2006, assuming only underlying load growth as forecast in Chapter 2, management of this limitation is expected to become very difficult. Key factors that could alter this outlook, and cause this 'observation point' to be further stressed, include significant extra load in the Gladstone zone or reduced generation at the Gladstone Power Station. Powerlink has initiated a consultation process related to these limitations. This is discussed further in Chapter 5.

4.3.8 QNI Limits

The Queensland – New South Wales Interconnection (QNI) was constructed of assets with plant ratings of at least 1000MW. However the actual transfer capability will vary from time to time depending on system conditions.

At the time of publication of this Annual Planning Report, QNI has a maximum southward capacity of 750MW (Queensland export), and a maximum northward capacity of QNI and DirectLink combined of 700MW (New South Wales export). Transfer capacity is limited by a range of criteria, viz:

Southward: (QNI)

- Transient stability based on faults in Queensland;
- Transient stability based on loss of largest load in Queensland;
- Transient stability based on faults in the Hunter Valley;
- Thermal rating limits of 132kV network in New South Wales;
- Oscillatory stability upper limit of 750 MW.

Northward: (combined QNI and DirectLink)

- Transient stability based on loss of the largest generator in Queensland;
- Transient stability based on faults in the Hunter Valley;
- Transient stability based on faults on a Tarong to Braemar circuit;
- Thermal rating limits of 330kV network in New South Wales;
- Oscillatory stability upper limit of 700 MW.

The 132kV network within NSW which has been imposing thermal limits at times in the southward direction is in the process of being upgraded and is expected to be less of an issue in the limit equations from summer 2003/04 onwards.

With the commissioning of the Millmerran Power Station higher southerly secure power transfers on QNI are possible. To realise these higher limits further testing is required to confirm a corresponding increased oscillatory stability performance. At the time of publication of this report these tests were in progress with the release of a provisional southward QNI capacity of 950MW, subject to the availability of performance monitoring equipment. The aim of this testing is to release a maximum southward capacity of 1080MW (limited by transient stability). The maximum northward capacity of QNI (including northerly transfer on DirectLink) is expected to be limited to between 400MW and 700MW (limited by either transient/oscillatory stability, northern NSW voltage stability or NSW thermal criteria).

The IRPC 'Annual Interconnector Review', to be published as part of NEMMCO's SOO, may forecast material constraints on QNI. In response to this Powerlink and TransGrid may need to consider means of increasing the QNI transfer capability.

4.4 Transformer Loading at 275kV Substations

Table A2 of Appendix A shows the range of loads on 275/110kV and 275/132kV substations in the period 2003 to 2006 (with all transformers in service) covering committed projects, and corresponding to the sample system conditions in Figures A3 to A20. These transformer loadings depend on load power factor and may be higher than those shown in Table A2 at the time of local zone peaks during unavailability of local or down stream capacitor banks and lower than forecast levels of embedded generation.

4.5 Short Circuit Levels

Tables C1 to C3 in Appendix C show estimates of the three phase and single phase to earth short circuit levels in the Powerlink transmission network in the period 2003 to 2006. They also show the short circuit interruption capacity of the lowest rated circuit breaker(s) at each location.

The information in Tables C1 to C3 of Appendix C should be taken only as an approximate guide to conditions at each location:

- The short circuit level calculations were determined using a simple system model, in which generators are represented as a voltage source of 110% of nominal voltage behind sub-transient reactance.
- System loads and all shunt admittances are not represented.
- The impacts of some of the more significant embedded non-scheduled generators are included as noted in the Tables.

The short circuit levels shown in Tables C1 to C3 have been determined on the basis of the generation capacity shown in Table 3.1 (together with any noted embedded non-scheduled generators) and on the network development as at the end of each calendar year. These network models are based on the existing network configuration, committed projects and proposed new network assets (as proposed in Chapter 5).

The fault levels determined assume the grid is in its 'normal' or 'intact' state, that is, all network elements in service. Exceptions to this include potential open points at Belmont 110kV, Swanbank 110kV and Gladstone South 132kV substations. These open points may be necessary to keep the maximum short circuit level below the critical circuit breaker ratings. These open points have been taken into account in the estimates in Tables C1 to C3.

At some locations where the short circuit level appears to be above the switchgear rating in Tables C1 to C3 of Appendix C, the critical switchgear is required to interrupt only a portion of the total fault current, and that portion is less than the switchgear rating over the three year outlook period.

No account has been taken of short circuit interruption capability of switchgear in the distribution systems.

Interested parties needing to consider the effects of their proposals on system short circuit levels should consult Powerlink and/or the relevant Distribution Network Service Provider for detailed information.

4.6 Emerging 'Reliability' Limitations

Tables C1 to C3 in Appendix C show estimates of the three phase and single phase to earth short circuit levels in the Powerlink transmission network in the period 2003 to 2006. They also show the short circuit interruption capacity of the lowest rated circuit breaker(s) at each location.

The information in Tables C1 to C3 of Appendix C should be taken only as an approximate guide to conditions at each location:

- The short circuit level calculations were determined using a simple system model, in which generators are represented as a voltage source of 110% of nominal voltage behind sub-transient reactance.
- System loads and all shunt admittances are not represented.
- The impacts of some of the more significant embedded non-scheduled generators are included as noted in the Tables.

The short circuit levels shown in Tables C1 to C3 have been determined on the basis of the generation capacity shown in Table 3.1 (together with any noted embedded non-scheduled generators) and on the network development as at the end of each calendar year. These network models are based on the existing network configuration, committed projects and proposed new network assets (as proposed in Chapter 5).

The fault levels determined assume the grid is in its 'normal' or 'intact' state, that is, all network elements in service. Exceptions to this include potential open points at Belmont 110kV and Gladstone South 132kV substations. These open points may be necessary to keep the maximum short circuit level below the critical circuit breaker ratings. These open points have been taken into account in the estimates in Tables C1 to C3.

At some locations where the short circuit level appears to be above the switchgear rating in Tables C1 to C3 of Appendix C, the critical switchgear is required to interrupt only a portion of the total fault current, and that portion is less than the switchgear rating over the three year outlook period.

No account has been taken of short circuit interruption capability of switchgear in the distribution systems.

Interested parties needing to consider the effects of their proposals on system short circuit levels should consult Powerlink and/or the relevant Distribution Network Service Provider for detailed information.

4.6.1 Addressing Emerging 'Reliability' Limitations

It is a condition of Powerlink's transmission authority that it meet licence and Code requirements relating to technical performance standards during intact and contingency conditions. The transmission authority also requires Powerlink to plan and develop the network such that peak demand can be supplied during a single network element outage. The limitations described below can therefore be viewed as 'triggers' for action. If no other solutions arise, Powerlink must implement a solution to ensure that a reliable power supply to customers can be maintained.

In accordance with Code requirements, Powerlink will consult with market participants and interested parties on feasible solutions. Solutions may include local generation, provision of network support by existing generation, demand side solutions and network augmentations.

The information below provides advance notice of anticipated consultation processes, and extends the time available to interested parties to develop solutions. Further information will be provided during the relevant consultation process, if or when this is required (see Chapter 5 for current and anticipated consultation processes).

Solution providers should be aware that there is some uncertainty surrounding the timing that corrective action will be required to address some of the following emerging limitations. Timing is dependent on load growth and developments in the wholesale electricity market.

4.6.2 Emerging Reliability Limitations in the Queensland Grid

Far North Zone: Voltage Control/Transformer Capacity

It has been determined that by 2005, depending on generation and load assumptions, an outage of one of the 275kV circuits between Chalumbin and Woree or Ross and Chalumbin, will result in severe voltage problems and the risk of voltage collapse at times of high demand. An information paper regarding this limitation has been issued (refer Chapter 5) and is available on Powerlink's website.

Solutions to the voltage control limitation could include one or a combination of demand side initiatives, local generation and/or network augmentation. An indicative network augmentation would be the installation of dynamic reactive support at an expected cost of $10-$16M.

It is also anticipated that the 275/132kV transformer capacity in the Far North Zone could be exceeded from about 2006 onwards, depending on load growth, the impact of demand side initiatives and the operation of existing and/or new hydro and embedded generation such as Windy Hill. This timing could also be affected by the solution to the voltage control problem referred to above.

Solutions to the transformer capacity limitation could include one or a combination of demand side initiatives, local generation and/or a network augmentation. An indicative network augmentation would be the installation of additional transformer capacity at an expected cost of $8-12M.

Far North Zone: Supply to Edmonton area

Ergon Energy advised in 2002 that action was urgently required to address high load growth in coastal areas to the south of Cairns. Continued high demand growth is anticipated to cause the capacity of the low voltage (22kV) system to be exceeded by late 2004. A proposed small network asset has been recommended (refer Chapter 5) to address this limitation.

Ross Zone: Supply to Northern and Western Townsville Areas

Load in the Townsville area has grown rapidly in recent years. Average demand growth is expected to be about 4% p.a. for the next several years, but may be much higher in specific areas due to new commercial, industrial and residential developments.

Northern and western areas of Townsville are presently supplied from the Dan Gleeson and Garbutt 132/66kV substations. Primary supply to these substations occurs via 132kV connections from Ross substation. Generation in the Townsville area can alter the flows on these circuits, but does not change their essential role in transferring power within the Townsville area. Studies indicate that these circuits may become overloaded during Townsville 132kV network contingencies from late 2004 onwards.

A committed project to retension conductors between Ross and Dan Gleeson at a cost of less than $1M (refer Chapter 3) will address these limitations for the outlook period for network limitations in this report.

Ross Zone: Supply to Townsville CBD and Port Areas

The Townsville CBD and nearby areas continue to develop with steady increases in electricity demand. Potential industrial development is now also earmarked for the Townsville port area particularly on the southern side of the river.

Studies indicate that the existing Ergon 66kV network with feasible upgrades could reach thermal capacity limits by about 2007/08, or earlier if new industrial loads emerge.

Initial joint planning studies indicate that a feasible network solution would be to develop 132kV network from Townsville South to the port area at an approximate cost of $10-25M. Non-network solutions may include local generation and/or a demand side response.

Ross Zone: Supply to the Townsville South Area

The Townsville South area includes the Sun Metals Zinc Smelter load and is supplied via a double circuit 132kV line from Ross 275/132kV substation and two longer single circuit 132kV lines from Collinsville via Clare.

With increasing loads at the zinc smelter, in the Townsville area distribution network and at Clare, together with potential new loads in the Townsville port area, the thermal capacity of the Ross to Townsville South 132kV circuits is being approached under contingency conditions. The loading on these circuits is dependent on generation at Mt Stuart Power Station.

Network limitations may arise from summer 2005/06 onwards. Indicative network solutions include a new 275kV or 132kV transmission line between Ross and Townsville South, at an indicative cost of $10-$25M. Non-network solutions may include demand side management or local generation in the southern Townsville area.

North Zone: Nebo Transformer Limitations

Nebo substation is a major bulk supply point in north Queensland. Due to load growth in the Mackay and central Queensland areas, including increases in mining load, the existing Nebo 275/132kV transformers are expected to reach capacity limitations by late 2004. A proposed small network asset has been recommended (refer Chapter 5) to address this limitation.

North Zone: CQ-NQ and Nebo-Ross Limitations

Flows from central to north Queensland are limited by dynamic and voltage stability. The critical contingencies are loss of a Nebo-Strathmore or Strathmore-Ross 275kV circuit. This limit would be exceeded at the present time for cases of high northern Queensland load coincident with low local generation (FNQ hydro and Collinsville). This limit is currently managed to its capacity by network support contracts with Collinsville and OCGT power stations in the Townsville area.

The increasing gap between the growing north Queensland load and the limited network capability, could place reliability of supply to this area at risk by as early as 2006. Non-network solutions could include network support contracted from additional local generators, and/or a demand side response. Network solutions could include major augmentations costing $100-$150M. This is also referred to in Chapter 5. There may be sufficient market benefits to justify advancement of corrective action.

North Zone: Supply to Pioneer Valley Substation

Pioneer Valley 132/66kV substation, which supplies areas to the west of Mackay, comprises only a single transformer. Alternative but limited supply is available to this area via Ergon's 33kV distribution network from Mackay and Alligator Creek 132/33kV substations and a small capacity 33/66kV step-up transformer substation.

Due to continuing relatively high load growth in the Mackay region, and in particular the western Mackay areas, the alternative supply capacity to cover outage of the single Pioneer Valley transformer, is becoming increasingly limited and is considered to be inadequate by summer 2004/05.

A proposed small network asset (installation of a second Pioneer Valley transformer – refer Chapter 5) has been recommended to address this limitation.

North Zone: Supply to Mackay-Proserpine Area

Load in the Alligator Creek-Mackay-Pioneer Valley-Proserpine area continues to grow at relatively high rates. A point will soon be reached where the existing 132kV network from Nebo and Strathmore 275/132kV substations will not be able to maintain a reliable power supply during a 132kV network contingency.

During an outage of a 132kV circuit between Nebo and Alligator Creek or Nebo and Pioneer Valley, unacceptably low voltages are expected to occur by summer 2004/05 at periods of high demand. A proposed new small network asset (capacitor bank at Alligator Creek – refer Chapter 5) has been recommended to address this limitation.

Further limitations in supply to this greater Mackay-Proserpine area are expected to arise in subsequent years. During a 132kV outage of the above circuits, thermal ratings of the remaining circuits in service could be reached. The timing range for this limitation is dependent on load growth and other network developments, but is anticipated to arise between 2006 and 2008.

Potential network solutions include substation upgrades to alter 'sharing' of load flows on the 132kV network or the construction of a new line to the area costing $15-$25M. Non-network solutions such as local generation and demand side management may also be feasible alternatives.

Central West Zone: Supply to the Rockhampton Area

Load growth in the Rockhampton area is forecast to grow at an average of 2.7% over the next five years. This area is supplied by two double circuit 132kV lines from Bouldercombe 275/132kV substation arranged to supply Rockhampton 132/66kV, Egans Hill 132/66kV and Rocklands 132kV railway supply substations. Under single credible contingency conditions, 132kV feeder overloads can occur from summer 2004/05 onwards.

Loadings can be reduced in the short-term by reducing reactive power flows. A proposed new small network asset (capacitor bank at Rockhampton – refer Chapter 5), has been recommended to address this limitation. By 2007 or 2008, further corrective action to address network loadings may be required.

Central Zone: Supply to the Gladstone Area

The Gladstone area is one of the most heavily loaded areas of the Queensland region. The Boyne Island aluminium smelter dominates this load, but there is also significant demand at the Queensland Alumina plant and at the Boat Creek bulk supply point. There have also been announcements about significant new metal processing plants which could come into production in the next few years.

At the present time, there is a transmission limitation between the Callide and Gladstone areas and operational measures are being employed to manage the loading of the Calvale 275/132kV tie transformer. These measures include opening of the Callide to Gladstone South 132kV circuits. This limitation could soon result in a thermal overload condition on either the Calvale-Wurdong 275kV transmission line, or the Calvale transformer. The Calvale-Wurdong 275kV line overload trigger has already occurred infrequently, but has been managed through the application of dispatch constraints by NEMMCO. By about 2006, assuming underlying load growth as forecast in Chapter 2, Powerlink considers that more significant corrective action will be required to address this line overload. Major new industrial loads in the Gladstone area could bring forward these network limitations.

Potential non-network solutions could include new generation capacity in the Gladstone area and/or demand side load reduction. Feasible network solutions include construction of a major transmission line into the Gladstone area which would cost in the range $30-90 million. A consultation process has been initiated to identify solutions to this emerging network limitation (refer Chapter 5).

South West Zone: Supply to South West Qld (Darling Downs Area)

Limitations are expected to arise from late 2004 in the transmission system supplying the Darling Downs area of south west Queensland. Studies show that voltage limitations and thermal overloads will occur during an outage of the 275kV single circuit line between Tarong and Middle Ridge substations.

Corrective action is required to prevent voltage collapse and allow reliable operation of the system. Powerlink has issued an Application Notice (refer Chapter 5) that recommends a solution to address this emerging limitation. A final report will be issued around the same time as the publication of this report and will be available on Powerlink's website.

Moreton North & South Zones: Supply to Brisbane CBD and Inner Suburbs

The Brisbane CBD and inner suburbs are supplied by five 110kV circuits comprising a double-circuit 110kV line from Belmont to Newstead, a double-circuit 110kV line with cable sections from Upper Kedron to Ashgrove West and a 110kV overhead/underground cable single circuit from Rocklea/Tennyson to West End.

By 2005/06, various thermal capacity limits on this 110kV network and in parts of the distribution network are expected to be reached under normal or single contingency conditions.

Major expenditure, potentially $50-$150M, would be necessary for network solutions to address these limitations. A consultation paper will be issued around the same time as this report to identify potential non-network solutions.

Moreton North & South Zones: SEQ Voltage Control

Growing load in south east Queensland (SEQ) results in higher reactive power requirements and greater reactive losses in the system due to increased transmission line and transformer loading.

The net effect is an annual increase in reactive demand above that already being supplied through existing reactive devices and ancillary service arrangements. Potential solutions include demand side management or a program of shunt capacitor installation in SEQ to keep pace with this growing reactive demand. A proposed small network asset, consisting of new capacitor banks, to keep pace with reactive demand has been recommended (refer Chapter 5) but this is expected to be an ongoing requirement as SEQ electricity demand continues to grow rapidly.

Network solutions include reactive support at various locations. Indicative costs of such a network solution are in the range $2-$5M.

Moreton North & South Zones: 275/110kV Transformer Capacity

Load in the Moreton North and Moreton South Zones is forecast to grow at around 4.5% p.a. over the next five years. This load is supplied from the 110kV network, which receives supply via the 275kV system. The 275/110kV transformer capacity must at least keep pace with load growth or unacceptable overloads can occur following transformer outages.

The emergence of transformer capacity limitations is monitored closely by considering the impact of future load growth, and the loading of existing and committed future transformers.

Based on forecast load growth, 275/110kV transformer capacity limitations will occur at a number of existing locations within the Moreton North and Moreton South zones over a 5 year outlook period. The most immediate limitation is the loading on the Belmont transformers, where the overload during single contingency conditions becomes unacceptable by 2004/05 summer. A proposed small network asset has been recommended (refer Chapter 5) to address this limitation. Further corrective action will be required in subsequent years.

Network solutions include transformer augmentation at existing 275/110kV substations, or establishing new 275/110kV injection points where necessary to also prevent overloading of the 110kV network. Indicative costs of such a network solution are in the range of $6-25M.

Non-network alternatives to transformer augmentation include new local generation connected at suitable 110kV or lower voltage locations, and/or demand side initiatives to maintain loadings within the capacity of existing transformers.

Moreton South Zone: Supply to Richlands-Algester-Runcorn Areas

Southern suburbs of Brisbane in the Richlands, Algester and Runcorn areas are undergoing rapid development and by 2005/06 thermal capacity limitations are expected to arise in the Energex 33kV network, 110/33kV transformer capacity and 110kV lines supplying this area from Rocklea and Belmont 275/110kV substations.

Energex and Powerlink have commenced detailed joint planning studies relating to this emerging network limitation. Potential network solutions may cost $10-$25M. Non-network solutions could include demand side management or local generation.

Moreton South Zone: Supply to Sumner Area

The industrial areas of Sumner are supplied from the Energex 11kV distribution network fed by a 33kV network from Powerlink's Richlands 110/33kV substation.

Expected continuing development of this industrial area is anticipated to result in overloads of the Energex 11kV and 33kV network, and limitations in the capacity of the Richlands substation capacity by about 2006.

Indicative network solutions include the establishment of a new 110/11kV zone substation on a site centrally located in the industrial area which is traversed by the existing Rocklea to West Darra/Runcorn 110kV double circuit line, at an indictive cost of $5-$10M.

Non-network options could include demand side management initiatives or cogeneration developments by customers within this localised industrial area.

Moreton South Zone: Supply to Murarrie and Trade Coast Areas

Belmont 275/110kV substation supplies part of the Brisbane CBD, Murarrie and Trade Coast (Brisbane Port), Redlands Shire, coastal areas and part of the Richlands-Algester-Runcorn area.

Thermal capacity limitations in the 110kV network supplying Murarrie are expected by 2006 to 2008 under single contingency conditions.

Potential network solutions to these limitations may depend on corrective action to address the emerging limitations in supply to the Brisbane CBD. Indicative cost for network solutions are in the range $10-$25M. Non-network solutions could include demand side management initiatives or local generation that would reduce the requirement to transfer power into the Belmont and Murrarie and Trade Coast areas.

Moreton South Zone: Load Growth South East Queensland (Logan)

Power in the Moreton South zone is supplied from local generation (or equivalent) and transmission connections from adjacent zones. The majority of power used in the Moreton South area and other south east Queensland zones is transferred via five 275kV circuits between Tarong and south east Queensland.

Very high load growth in south east Queensland (including Logan and southern Brisbane) is expected to result in reliability of supply limitations to south east Queensland within the 5 year outlook for network limitations in this Chapter. Supply capability limitations are expected to arise due to a combination of full utilisation of existing local generation sources and the inability to transfer additional power into south east Queensland on the existing transmission network.

Feasible solutions will be required to meet the anticipated increase in SEQ demand of approximately 200MW per year over the next five years. Powerlink is not aware of any major generation proposals being discussed which could address this limitation. An indicative network solution is an additional transmission connection to the Moreton South zone from Middle Ridge substation at a cost of approximately $60M.

Gold Coast/Tweed Zone: Supply to South Coast

The South Coast (Gold Coast) area is one of the fastest-growing areas in the State, in terms of population, commercial development and load growth. Summer electricity demand growth is expected to average about 5.0% p.a. for the next five years.

The South Coast load is or will be supplied or supported by:

- two 275kV transmission lines which run from Swanbank to Mudgeeraba;
- a 275kV tee connection to Molendinar to be operational by late 2003;
- a 110kV network which runs from Belmont to Mudgeeraba;
- DirectLink, via the Terranora to Mudgeeraba 110kV double circuit line.

Due to the high load growth, reinforcement of supply to the Gold Coast will be required. Emerging reliability limitations will arise due to emergency thermal limits of the 110kV network, voltage stability limits associated with a 275kV network outage, and (in the longer-term) emergency thermal limits of the 275kV transmission lines supplying the Gold Coast area. Anticipated limitations in the coming summer will be addressed by committed projects being undertaken by Powerlink and Energex. However, other limitations will arise from late 2004 onwards. These limitations can be managed by operational measures over the 2004/05 summer but corrective action is anticipated to be required prior to the 2005/06 summer.

Powerlink expects to undertake consultation and detailed studies relating to this emerging limit (refer to Chapter 5). Joint planning studies will be undertaken with TransGrid to ensure that the capabilities and limitations of the NSW network are also considered. Potential network solutions could include major augmentations costing $40-$70M.

4.7 Summary of Forecast Network Limitations

Limitations discussed in Section 4.6 have been summarised in Table 4.6. This table provides an outlook (based on load, generation and committed network development assumptions contained in Chapters 2, 3 and 4) for potential limitations in Powerlink's transmission network over a one, three and five year timeframe.

Table 4.6: Summary of Forecast Network Limitations

Refer Chapter 5 (Network Development) for information on corrective action to address future limitations

Anticipated Limitation	Reason for constraint or limitation	Time Limitation May Be Reached		
		1 Yr Outlook	3 Yr Outlook	5 Yr Outlook
FAR NORTH AND ROSS ZONES				
Far North voltage control/transformer capacity	275kV outage in Far North Queensland will result in unacceptable voltage conditions. This condition is exacerbated when output from Barron is low. Continued load growth expected to result in 275/132kV transformer capacity being exceeded.		2005 (1)	2006-2008
Supply to Edmonton	Future limitations in the 22kV distribution capability in meeting continued load growth in the areas south of Cairns.		2004 (1) (2)	
Supply to northern and western Townsville	Future 132kV network thermal capacity limitations in meeting load growth in northern and western Townsville.		2004 Corrective action in progress (3)	
Supply to Townsville CBD and port area	Future 66kV network thermal capacity limitations in meeting growing potential new loads in CBD and surrounding areas.			2007-2008
Supply to Townsville South area	Future limitations in the thermal capacity of the Ross to Townsville South 132kV line to meet load growth in the zinc smelter, Clare, southern Townsville and/or Townsville port areas.		2005-2008	2005-2008
NORTH ZONE				
Nebo Transformer Limitations	Due to load growth, Nebo 275/132kV transformers expected to reach thermal capacity limitations in the event of a single transformer outage.		2004 (1)	
CQ-NQ and Nebo Ross Limitations	Voltage and dynamic instability may result for 275kV line outages during periods of high northern Qld load coincident with low local generation.	Corrective action in progress (3) (4)	2006-2007	2006-2007
Supply to Pioneer Valley substation	Due to load growth, limitations arise in alternative supply, via distribution networks, to the single Pioneer Valley transformer.		2004 (1)	
Supply to Mackay & Proserpine area	Voltage and thermal limitations likely to arise in two stages during local 132kV outages.		2004 (1)	2006-2008

Anticipated Limitation	Reason for constraint or limitation	Time Limitation May Be Reached		
		1 Yr Outlook	3 Yr Outlook	5 Yr Outlook
CENTRAL AND CENTRAL WEST ZONE				
Supply to Lilyvale (central Queensland mining area)	Load growth is expected to result in loadshedding during outage of the exiting 275kV single circuit line supplying Lilyvale		2004 Corrective action in progress (3)	
Supply to Rockhampton area	Thermal overloading of 66kV and 132kV networks likely to arise in two stages during single contingency conditions.		2005 (1)	2007-2008
Supply to Gladstone area	Potential for overload condition on Calvale-Wurdong 275kV line and/or Calvale 275/132kV tie transformer.		2004-2006 (1) (5)	2004-2006 (1) (5)
WIDE BAY AND SOUTH WEST ZONES				
Supply to SW Queensland	Load growth expected to cause voltage control and thermal limitations during 275kV Tarong-Middle Ridge contingency.		2004 (1)	
Grid transfer limit: Braemar-Tarong	Some NEM generation dispatch scenarios may give rise to binding transfer limits for northerly flows		2005-2008	2005-2008
MORETON NORTH AND SOUTH ZONES				
South East Qld Voltage Control	Increasing reactive demand due to load growth likely to require program of corrective action to satisfy voltage control standards.	2003 Corrective action in progress (3)	2004-2008 (1)	2004-2008
Supply to Brisbane South (Belmont substation)	Load growth is expected to result in loadshedding during 275kV Swanbank/Blackwall-Belmont contingency	2003 Corrective action in progress (3)		
Supply to Brisbane CBD	Increasing loads in Brisbane CBD and inner suburbs leading to thermal capacity limits in the distribution and 110kV networks.		2005-2006	
275/110kV transformer capability	Due to load growth, future 275/110kV transformer capacity limitations are anticipated at multiple locations.		2004-2008 (1)	2004-2008
Supply to Richlands-Runcorn-Algester area	Distribution and 110kV network thermal capacity limitations in meeting rapid load growth in southern Brisbane suburbs.		2005-2006	
Supply to Sumner area	Distribution network capacity and Richlands 110/33kV transformer capacity limitations in meeting growth in an industrial development area.			2006-2008

Anticipated Limitation	Reason for constraint or limitation	Time Limitation May Be Reached		
		1 Yr Outlook	3 Yr Outlook	5 Yr Outlook
Supply to Murarrie-Trade Coast areas	Thermal capacity limitations of 110kV network to Murarrie in meeting growing and potential new Trade Coast area loads.		2006-2008	2006-2008
Load Growth SE Qld (Logan)	High load growth expected to result in limitations in supply to entire south east area		2006-2009	2006-2009
GOLD COAST/TWEED ZONE				
110kV supply within South Coast area	Load growth is expected to cause overloads of 110kV Gold Coast system and 275kV transformers at Mudgeeraba	2003 Corrective action in progress (3)		
275kV Supply to South Coast	Expected power flows likely to exceed Gold Coast voltage stability limits. Thermal limits also may also arise in Energex system.		2005-2007	2005-2007

Notes:
(1) Refer to Network Development Chapter 5
(2) Refer to Table 3.6
(3) Refer Tables 3.3 and 3.5 – Committed Augmentations
(4) Network support arrangements in place
(5) Earlier timeframe if major new industrial loads proceed

5. NETWORK DEVELOPMENT

5.1 Introduction

Queensland is expected to experience continuing growth in demand for electricity, with particularly high growth forecast for the south east area of the state over the next 3 years.

Network development to meet forecast load depends 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 where a significant amount of new large generation capacity has entered the market over the past few years. However, following the recent commissioning of major new generators, a new pattern of generation and power flows is becoming more evident.

The previous chapter outlined potential transfer limitations and emerging 'reliability limitations'. The possible timing and severity of limitations is dependent on load growth and market developments.

This chapter focuses on those limitations identified in the previous chapter for which Powerlink intends to implement corrective action or initiate consultation with market participants and interested parties in the near future. It should be noted that the information provided in this section regarding Powerlink's network development plans may change, and should therefore be confirmed with Powerlink before any action is taken based on this information.

5.2 Processes for Possible Network Developments

Chapter 4 of this report identified anticipated network limitations and constraints that may arise in the Queensland transmission network over the next five years. Where action is considered to be necessary, Powerlink will:

- Notify Code participants of anticipated limitations within the timeframe required for corrective action.
- Seek information from market participants and interested parties on feasible non-network solutions to address anticipated constraints.
  - Powerlink's general approach is to seek input on potential solutions to network limitations which may result in small network assets via the Annual Planning Report. Those that cannot be identified for inclusion in the APR will be the subject of separate consultation with market participants and interested parties.
  - For emerging network limitations which may result in large network assets, Powerlink's approach is to issue detailed information papers outlining the limitations to assist in identifying feasible non-network solutions.
- Consult with Code Participants and interested parties on all feasible alternatives (network and non-network) and recommended solutions.
- Carry out detailed analysis to determine feasible network solutions that Powerlink may propose to address identified network constraints.

- In the event a regulated solution (network or network support) is found to satisfy the ACCC Regulatory Test, Powerlink will implement the recommended solution.

Alternatively, Powerlink may undertake network augmentations under the ‘funded augmentation’ provisions of the Code.

5.3 Proposed New Large Network Assets

Proposals for new large network assets[1] are required to be progressed under the provisions of Clause 5.6.6 of the NEC.

Powerlink is required to carry out separate consultation processes for each proposed new large network asset. Summary information is provided in this Annual Planning Report. Interested parties are referred to consultation documents published on Powerlink’s website for further information.

Information on other network limitations that could result in a recommendation to implement a new large network asset, but where consultation on alternative solutions is still underway, is provided in Section 5.4.

5.3.1 Proposed New Large Network Asset - Darling Downs

Emerging limitations have been identified in the electricity transmission network supplying the Darling Downs Area in south west Queensland. Technical studies have identified that, from late 2004, an outage of the single circuit 275kV line between Tarong and Middle Ridge substation in Toowoomba will cause loss of supply to customers. Under this contingency condition, the voltage level of the entire area would become unacceptably low and the thermal ratings of the 110kV line between Abermain and Lockrose will be exceeded. Action is required to overcome these limitations before late 2004 to allow Powerlink to meet its obligations under the Electricity Act, the National Electricity Code, connection agreements and its Transmission Authority.

Powerlink carried out consultation to identify and determine feasible options to address the emerging network limitations. Analysis of options was carried out in accordance with the ACCC Regulatory Test.

The recommended solution is the construction of a 330kV double circuit transmission line between Millmerran and Middle Ridge, with associated substation works. The proposed asset, estimated to cost $71.3M, is required to be commissioned by the summer of 2004/05.

An Application Notice for this proposed new large network asset was issued on 31 March 2003. This document can be accessed on the Powerlink website at www.powerlink.com.au. This proposed augmentation is being progressed under the relevant Code provisions. A final report is anticipated to be released around the same time as this Annual Planning Report and will be available for access on the Powerlink website.

[1] Augmentations with greater than $10M capitalisation value

5.3.2 Committed New Large Network Asset - Inland Central Queensland

Interested parties are advised that Powerlink recently finalised regulatory processes associated with a proposed new large network asset to address emerging network limitations in the inland central Queensland area. The recommended solution was the construction of a 275kV single circuit transmission line between Broadsound and Lilyvale, and associated substation works at a cost of $23.1M. This project is now committed, and implementation is underway to achieve commissioning by October 2004.

5.4 Consultation – New Large Network Assets

5.4.1 Consultation Underway

Network limitations have been identified that could give rise to a requirement for a proposed new large network asset. This section provides a summary of the status of corrective action to address identified network limitations in the Gladstone and Cairns/Far North Queensland areas. At this stage, Powerlink is consulting market participants regarding potential solutions or is in the process of evaluating potential solutions. No recommendation for a new large network asset has been made in either case.

Emerging Network Limitations - Gladstone Area

An information paper outlining the system limitations anticipated in the Gladstone area was issued on 28th November, 2002 (refer Powerlink website at www.powerlink.com.au). No submissions regarding potential non-network solutions were received in response to this information paper.

Delays to the process have occurred due to ongoing discussions with potential industrial loads in the Gladstone area regarding their requirements and the revision of forecast demand by existing Gladstone area customers. Powerlink is presently evaluating transmission options in accordance with the ACCC Regulatory Test. Publication of an Application Notice is anticipated prior to September 2003.

Emerging Network Limitations - Cairns and Far North Queensland

An information paper outlining the system limitations anticipated in Cairns and Far North Queensland was issued on 30th May 2003. Voltage control limitations are expected to arise under some contingency conditions. The information paper, published on the Powerlink website at www.powerlink.com.au, also requested information on feasible non-network solutions for inclusion in subsequent analysis. Alternatives may include new local generation, a network support arrangement and/or demand side alternatives.

Interested parties are invited to review this document and provide Powerlink with any relevant information by the closing date for submissions of 4th July 2003.

5.4.2 Anticipated Consultation Processes

Other consultation processes are likely to be initiated prior to the publication of the 2004 Annual Planning Report:

Table 5.1: Consultation Likely Within 12 Months

Location	Major Emerging Limitation
Gold Coast/Tweed area	Load growth is anticipated to result in voltage stability and potential thermal limitations during an outage of one of the 275kV circuits between Swanbank and Mudgeeraba.
Brisbane CBD	Load growth in Brisbane central business district and inner suburbs is anticipated to result in network capacity limits being reached.
Belmont/Murarrie/Trade Coast	Thermal capacity limitations of 110kV network to Murarrie in meeting growing and potential new Trade Coast area loads.
Townsville area	Load growth may result in thermal overload issues in the Townsville 132kV and 66kV networks.
Central – North Queensland transfer	Increasing demand in north Queensland may result in increasing network support costs due to limited network transfer capability between central and north Queensland. Reliability of supply limitations may also be reached.
Ipswich/West Brisbane	Industrial growth in Sumner/Wacol area is anticipated to result in distribution network limits being reached.
Southern Brisbane	High growth in southern Brisbane suburbs is anticipated to result in thermal overload issues in distribution network supplied from Runcorn substation and the 110kV network to this area.
Interconnection upgrade between Queensland and New South Wales	To the extent that the Annual Interconnector Review (to be published as part of NEMMCO's 2003 SOO), forecasts material constraints on QNI, there may be a need to consider means of increasing the transfer capability.

Emerging limitations other than those listed will be monitored, and Powerlink will initiate action, including consultation with interested parties, should this be required.

5.5 Outline of Proposed New Small Network Assets

This section outlines proposed network augmentations which are required to be progressed under the provisions of Clause 5.6.6A of the NEC (new small network assets[2]). At the time of publication of this report, Powerlink has developed plans for the following proposed new small network augmentations listed in Table 5.2 to the point where they can be consulted on through this document.

[2] Augmentations with capitalisation value between $1M-$10M

Table 5.2: Proposed New Small Network Assets

Proposed New Small Network Asset	Date to be Operational	Capital Cost
Pioneer Valley 132/66kV transformer augmentation	October 2004	$3.5M
Edmonton 132/22kV switching station	October 2004	$8.5M
Loganlea 2nd 275/110kV transformer augmentation	October 2004	$5.7M
Rockhampton 40MVAr 132kV capacitor bank	October 2005	$1.0M
SEQ capacitor banks		$4.2M
- Molendinar 50MVAr 110kV capacitor bank	October 2004	
- Ashgrove West 50MVAr 110kV capacitor bank	October 2005	
- Murarrie 2 x 50MVAr 110kV capacitor banks	October 2005	
Nebo 275/132kV transformer augmentation	October 2004	$7.7M
Alligator Creek 30MVAr 132kV capacitor bank	October 2005	$1.1M

Further details on each of these proposed new small network assets, including purpose, possible alternatives and the reasons that Powerlink is recommending these augmentations proceed, are in Appendix D.

Code Participants and interested parties are invited to make submissions regarding these proposed augmentations and any non-network options they consider to be an alternative. The closing date for submissions is Monday 28th July. Submissions should be addressed to:

Manager Network Assessments
Powerlink Queensland
PO Box 1193 Virginia QLD 4014
enquiries@powerlink.com.au

If there are any material changes required following consideration of submissions, Powerlink will publish its conclusions and a revised recommendation. If no changes are required, Powerlink will proceed to implement these proposed new small network assets in the required timeframes.

Other proposed new small network assets will be subject to separate assessment and consultation as per Clause 5.6.6A of the Code, if commitment is required prior to the publication of the 2004 Annual Planning Report.

APPENDIX A: ESTIMATED NETWORK POWER FLOWS

Table A1: Summary of Figures A3 to A20 - Possible Grid Power Flows and Limit Stability States

Grid Section (1)		Illustrative Grid Power Flows (MW) and Limit Stability at Queensland Region Peak Load Time (2)(3)						Limit Due To (4)
		2003 WINTER Fig A3 / A4 / A5	2004 WINTER Fig A6 / A7 / A8	2005 WINTER Fig A9 / A10 / A11	2003/04 SUMMER Fig A12 / A13 / A14	2004/05 SUMMER Fig A15 / A16 / A17	2005/06 SUMMER Fig A18 / A19 / A20	
'Far North' Transfer								
Ross into Chalumbin 275kV (2 circuits)	Flow	154 / 154 / 154	161 / 161 / 161	169 / 169 / 169	220 / 220 / 220	229 / 229 / 229	243 / 243 / 243	V
Tully into Kareeya 132kV (2 circuits)	Stability	S / S / S	S / S / S	S / S / S	S / S / S	S / S / S	S / S / S	
'CQ-NQ' Transfer								
Broadsound into Nebo 275kV (2 circuits)	Flow	775 / 775 / 775	825 / 825 / 825	881 / 881 / 876	949 / 949 / 949	930 / 930 / 930	921 / 921 / 907	Dy
Bouldercombe into Nebo 275kV (1 circuit)	Stability	S / S / S	S / S / S	S / S / S	S / S / S	S / S / S	S / S / S	
Dysart to Peak Downs 132kV (2 parallel circuits)								
'Gladstone' Transfer								
Bouldercombe into Gladstone 275kV (2 circuits)	Flow	858 / 975 / 1047	986 / 1051 / 920	1035/ 950 / 843	923 / 796 / 665	804 / 671 / 592	779 / 643 / 639	Th
Calvale into Wurdong 275kV (1 circuit)	Stability	S / S / S	S / S / S	S / S / S	U / S / S	S / S / S	S / S / S	
Callide A into Gladstone South 132kV (2 circuits)								
'CQ-SQ' Transfer								
Wurdong into Gin Gin 275kV (1 circuit)	Flow	412 / 690 / 948	536 / 814 / 1105	677 / 963 / 1260	891 / 1175 / 1469	1167 / 1460 / 1617	1437 / 1733 / 1748	Tr, V
Gladstone into Gin Gin 275kV (2 circuits)	Stability	S / S / S	S / S / S	S / S / S	S / S / S	S / S / S	S / S / S	
Calvale into Tarong 275kV (2 circuits)								
'Tarong' Transfer								
Tarong to South Pine, Mt England	Flow	2593 / 2458 / 2302	2630 / 2491 / 2334	2714 / 2563 / 2406	2817 / 2665 / 2505	2949 / 2790 / 2570	3059 / 2901 / 2621	V
and Blackwall 275kV (5 circuits)	Stability	S / S / S	S / S / S	S / S / S	S / S / S	S / S / S	S / S / S	
Middle Ridge to Swanbank and Postmans Ridge 110kV (3 circuits)								
'Gold Coast' Transfer (5)								
Swanbank into Mudgeeraba 275kV (2 circuits)	Flow	604 / 604 / 604	625 / 625 / 625	642 / 642 / 642	625 / 625 / 625	664 / 664/ 664	694 / 694 / 694	V, Th
Cades County into Molendinar 110kV (1 circuit)	Stability	S / S / S	S / S / S	S / S / S	S / S / S	S / S / S	U / U / U	
'Braemar' Transfer								
Braemar 330kV to Braemar 275kV	Flow	1073 / 779 / 482	1055 / 761 / 463	467 / 280 / 92	1058 / 764 / 466	468 / 281 / 94	461 / 275 / 89	Th, PSE
(2 transformers)	Stability	U / S / S	U / S / S	S / S / S	U / S / S	S / S / S	S / S / S	

Notes:

(1) 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 A3 to A20. The flows are estimated for system intact (ie. all network circuits in service), and are based on existing network configurations and committed projects. Power flows within each 'grid section' can be higher at times of local zone peak loading.
(3) S = Stable condition, U = Unstable condition.
(4) V = Voltage stability limit, Th= Thermal limit, Tr = Transient stability limit, Dy = Dynamic stability limit and PSE = Power Swing Encroachment.
(5) The Gold Coast 'grid section' is defined for the winter 2003 network configuration.
Following the commissioning of the Molendinar 275kV Substation (and transmission line from Maudsland) in November 2003, the 'grid section' will be defined as:
- Swanbank into Mudgeeraba 275kV (2 circuits);
- Maudsland 'tee' into Molendinar 275kV (2 parallel circuits);
- Cades County into Molendinar 110kV (1 circuit).

Energex's planned Coomera substation is to be established by summer 2004/05, at which time the 'grid section' will be defined as:
- Swanbank into Mudgeeraba 275kV (2 circuits);
- Maudsland 'tee' into Molendinar 275kV (2 parallel circuits);
- Coomera into Cades County 110kV (1 circuit).

Table A2: Transformer Capacity and Estimates of Loading of 275kV Substations

275kV Substation (1) (2) **Transformers No. x MVA Nameplate Rating** (3)	**Possible MVA at Queensland Region Peak** (4)(5) **Winter 2003**	**Winter 2004**	**Winter 2005**	**Summer 2003/04**	**Summer 2004/05**	**Summer 2005/06**	**Dependence other than Local Load** **Significant dependence on:**	**Minor dependence on:**	**Other Comments**
Woree 275/132 (1x375)	96	87	95	114	123	128	Barron Gorge generation	Kareeya generation	
Chalumbin 275/132 (2x200)	100	91	93	114	109	106	Barron Gorge and Kareeya generation		
Ross 275/132 (3x250)	246	264	278	299	274	222	Mt Stuart, Townsville & Invicta generation	Collinsville generation	
Strathmore 275/132 (1x375)	71	80	85	59	58	96	Collinsville & Invicta generation	Townsville generation	
Nebo 275/132 (2x220)	236	251	264	289	294	314	Mackay GT generation	Collinsville & Barcaldine generation	Summer 2005/06 (3rd 250MVA)
Bouldercombe 275/132 (2x200)	130	135	141	153	161	169			
Lilyvale 275/132 (2x200)	170	183	215	182	217	220	Barcaldine generation	CQ-NQ flow	Summer 2004/05 change to 2 x 375MVA
Gin Gin 275/132 (2x120)	136	146	155	162	174	186	132kV transfers to/from Woolooga	CQ-SQ flow	
Woolooga 275/132 (2x120) and (1 x 200)	214	227	239	245	262	259	132kV transfers to/from Gin Gin	CQ-SQ flow	
Palmwoods 275/132 (2x300)	271	283	294	265	308	317	132/110kV transfers to/from South Pine & Woolooga	CQ-SQ flow	
South Pine 275/110 (1x375) (1x250) and (2x200)	649	653	669	782	834	884	110kV transfers to/from Palmwoods & Rocklea	CQ-SQ flow & Swanbank generation	
Rocklea 275/110 (2x375)	440	419	431	533	560	588	110kV transfers to/from South Pine, Belmont, Swanbank & Swanbank generation		
Belmont 275/110 (2x250) (2x200)	616	594	629	784	746	775	110kV transfers to/from Loganlea	110kV transfers to/from Molendinar & Mudgeeraba	

275kV Substation (1) (2) Transformers No. x MVA Nameplate Rating (3)	Possible MVA at Queensland Region Peak (4)(5) Winter 2003	Winter 2004	Winter 2005	Summer 2003/04	Summer 2004/05	Summer 2005/06	Dependence other than Local Load Significant dependence on:	Minor dependence on:	Other Comments
Loganlea 275/110 (1x375)	324	393	415	335	486	516	110kV transfers to/from Belmont	110kV transfers to/from Molendinar & Mudgeeraba	Winter 2004 (2nd 375MVA)
Molendinar 275/110	–	210	206	243	211	220	110kV transfers to/from Loganlea & Mudgeeraba	110kV transfers to/from Belmont & DirectLink MNSP	Summer 2003/04 (1st 375MVA)
Mudgeeraba 275/110 (3x250)	569	413	425	425	437	463	Molendinar 275/110kV establishment & DirectLink MNSP	110kV transfers to/from Loganlea	
Tarong 275/132 (2x90)	59	59	60	53	54	55	Roma generation		
Tarong 275/66 (2x90)	36	37	39	27	28	29			
Middle Ridge 275/110 (2x200)	300	309	442	308	443	454	Oakey GT generation		Summer 2004/05 (3rd 250MVA)
Calvale 275/132 (1x250)	177	179	180	170	169	75	Central Queensland Generation		
Swanbank 275/110 (2x250)	253	253	210	271	242	264	110kV transfers to/from South Pine & Rocklea	Swanbank generation	

Notes:

(1) Not included are the 275/132kV tie transformers within the Power Station switchyard at Gladstone. Loading on these transformers vary considerably with local generation.

(2) Also not included are 330/275kV transformers located at Braemar substation. Loading on these transformers are dependent on QNI transfer and Millmerran power station output.

(3) 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.

(4) Substation loadings are derived from the assumed generation dispatch cases shown within Figures A3 to A20. The loadings are estimated for system normal (i.e. all network elements in service), and are based on existing network configurations and committed projects. MVA loadings for transformers depend on power factor, and may be different under coincident region peak demands conditions, other generation patterns, outage conditions, local peak demand times or different availability of local and down stream capacitor banks.

(5) Substation loadings are the maximum of each of the import/zero/export QNI scenarios for each year/season shown within the assumed generation dispatch cases in Figures A3 to A20.

Figure A1: Generation and Load Legend for Figures A3 to A20

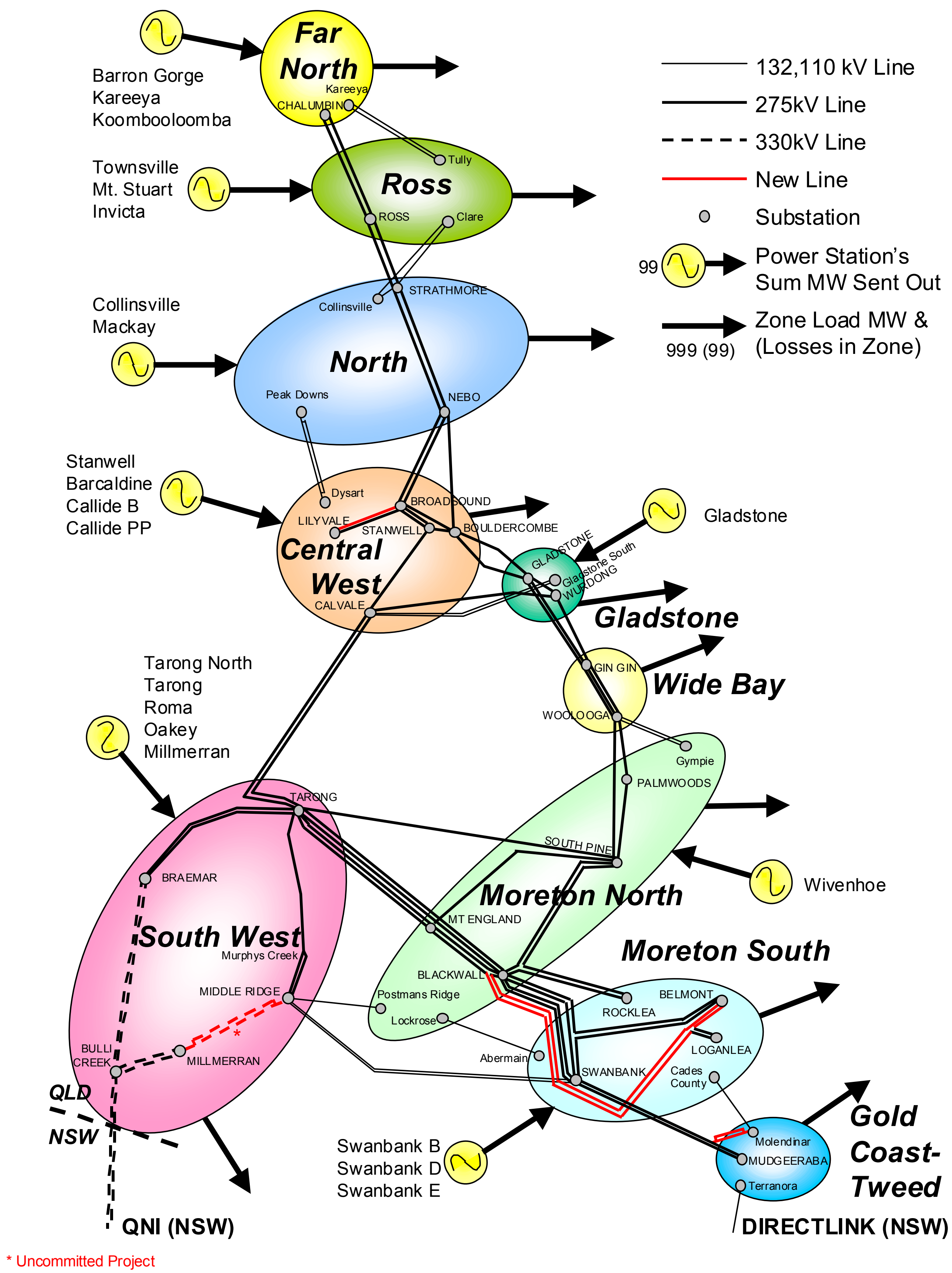


Figure A2: Power Flow and Limits Legend for Figures A3 to A20

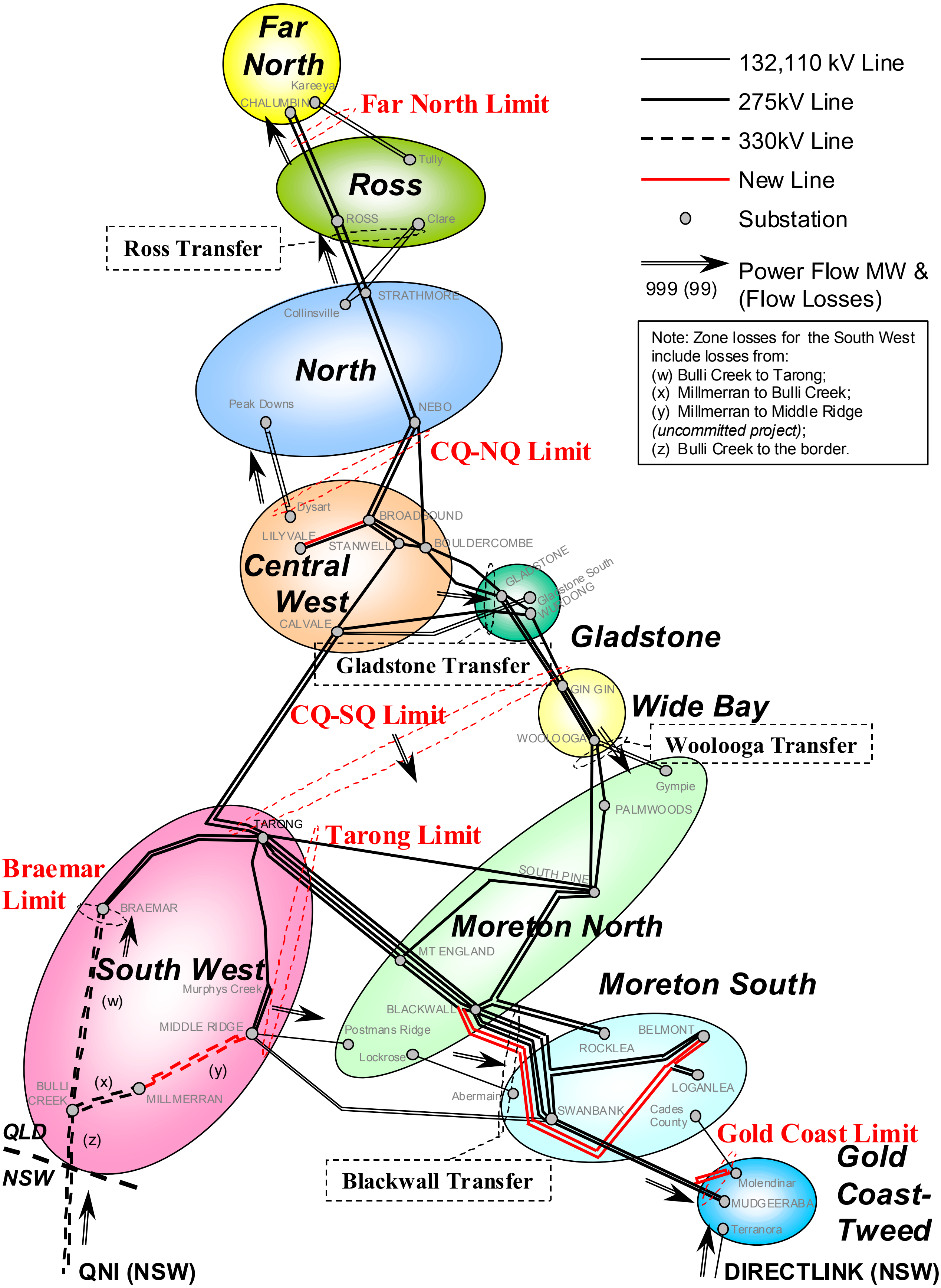
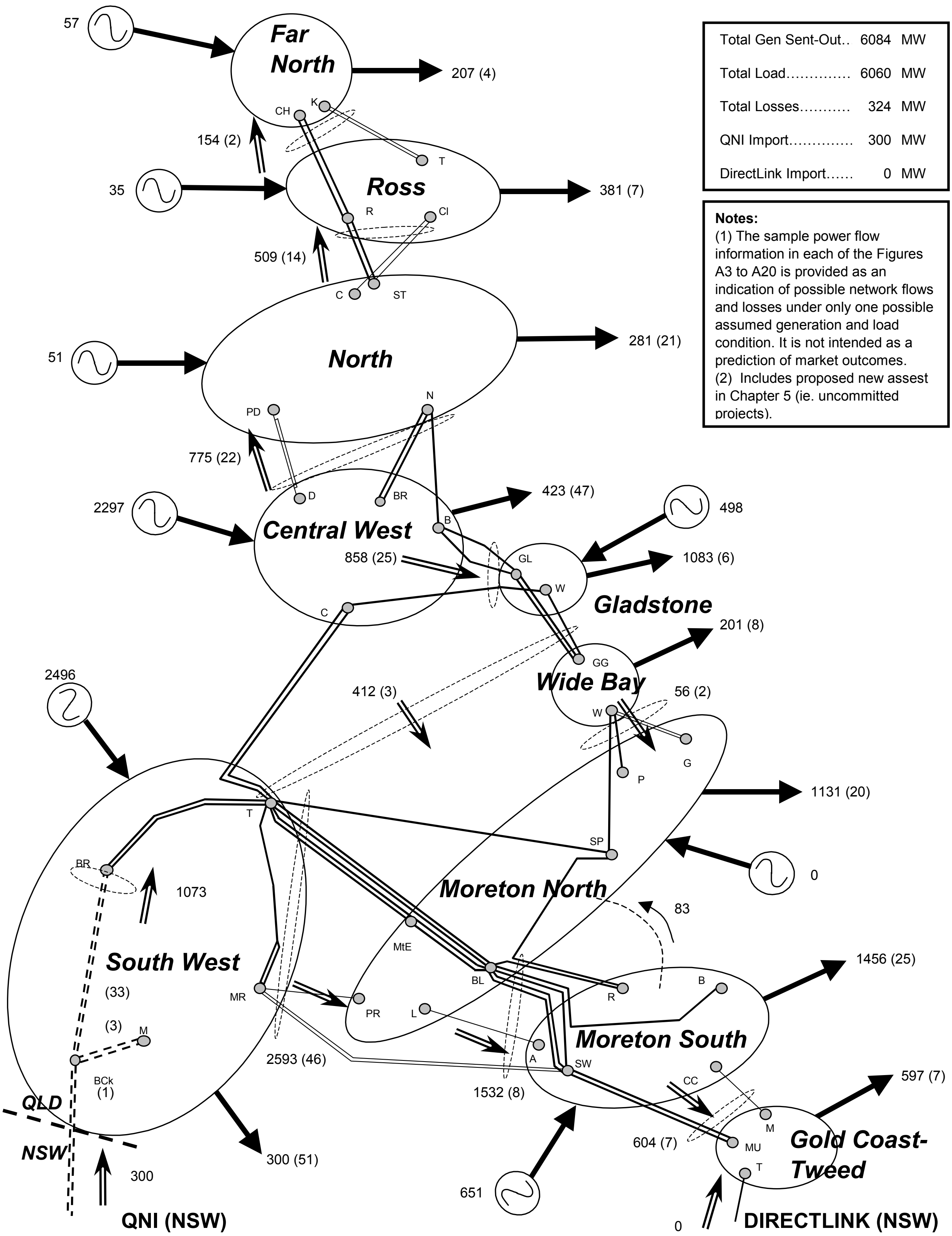


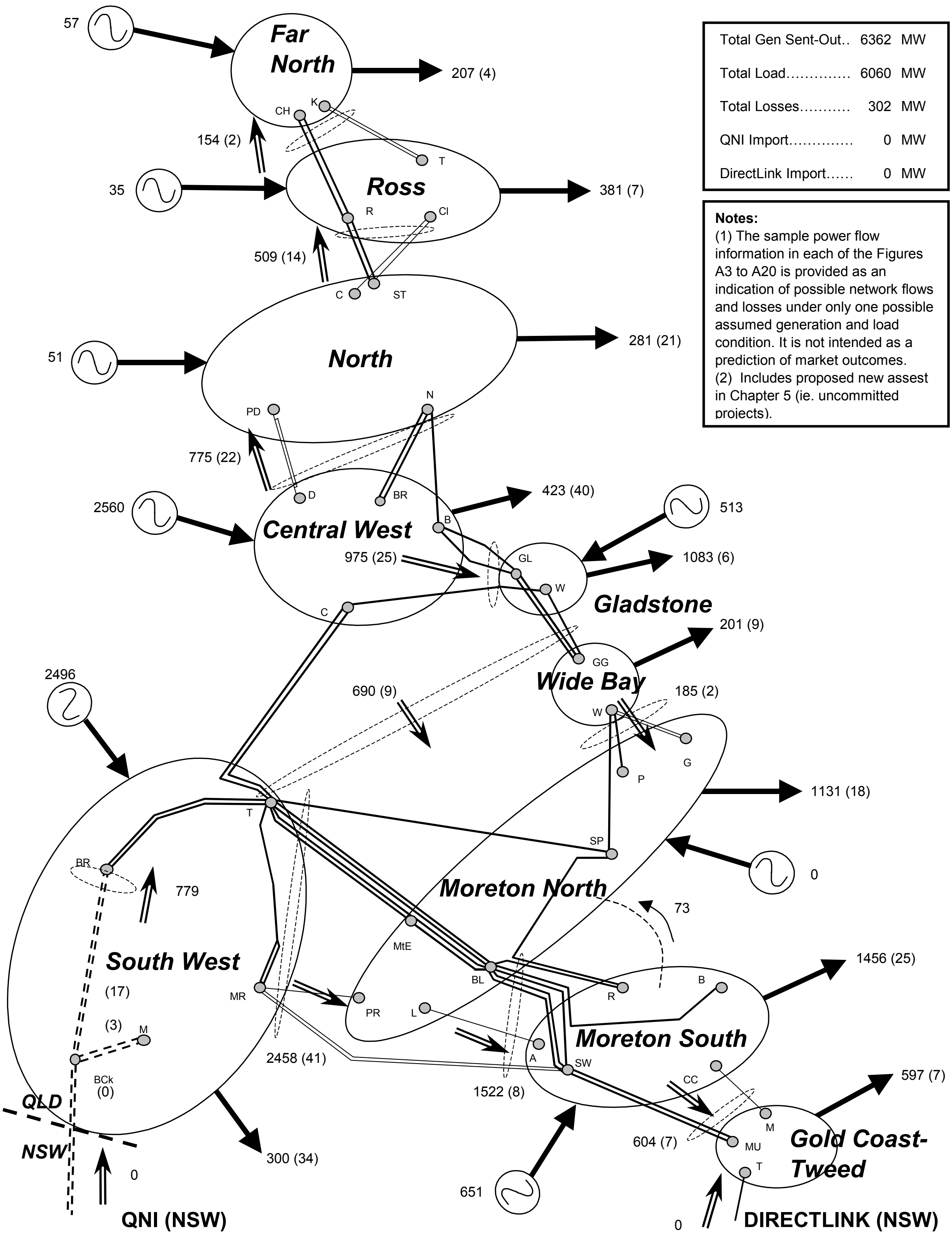
Figure A3: Winter 2003 Qld Peak 300MW Import QNI Flow



Total Gen Sent-Out..	6084 MW
Total Load.............	6060 MW
Total Losses...........	324 MW
QNI Import.............	300 MW
DirectLink Import......	0 MW

Notes:
(1) The sample power flow information in each of the Figures A3 to A20 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.
(2) Includes proposed new assest in Chapter 5 (ie. uncommitted projects).

Figure A4: Winter 2003 Qld Peak Zero QNI Flow



Total Gen Sent-Out..	6362	MW
Total Load.............	6060	MW
Total Losses...........	302	MW
QNI Import.............	0	MW
DirectLink Import......	0	MW

Notes:
(1) The sample power flow information in each of the Figures A3 to A20 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.
(2) Includes proposed new assest in Chapter 5 (ie. uncommitted projects).

Figure A5: Winter 2003 Qld Peak 300MW Export QNI Flow

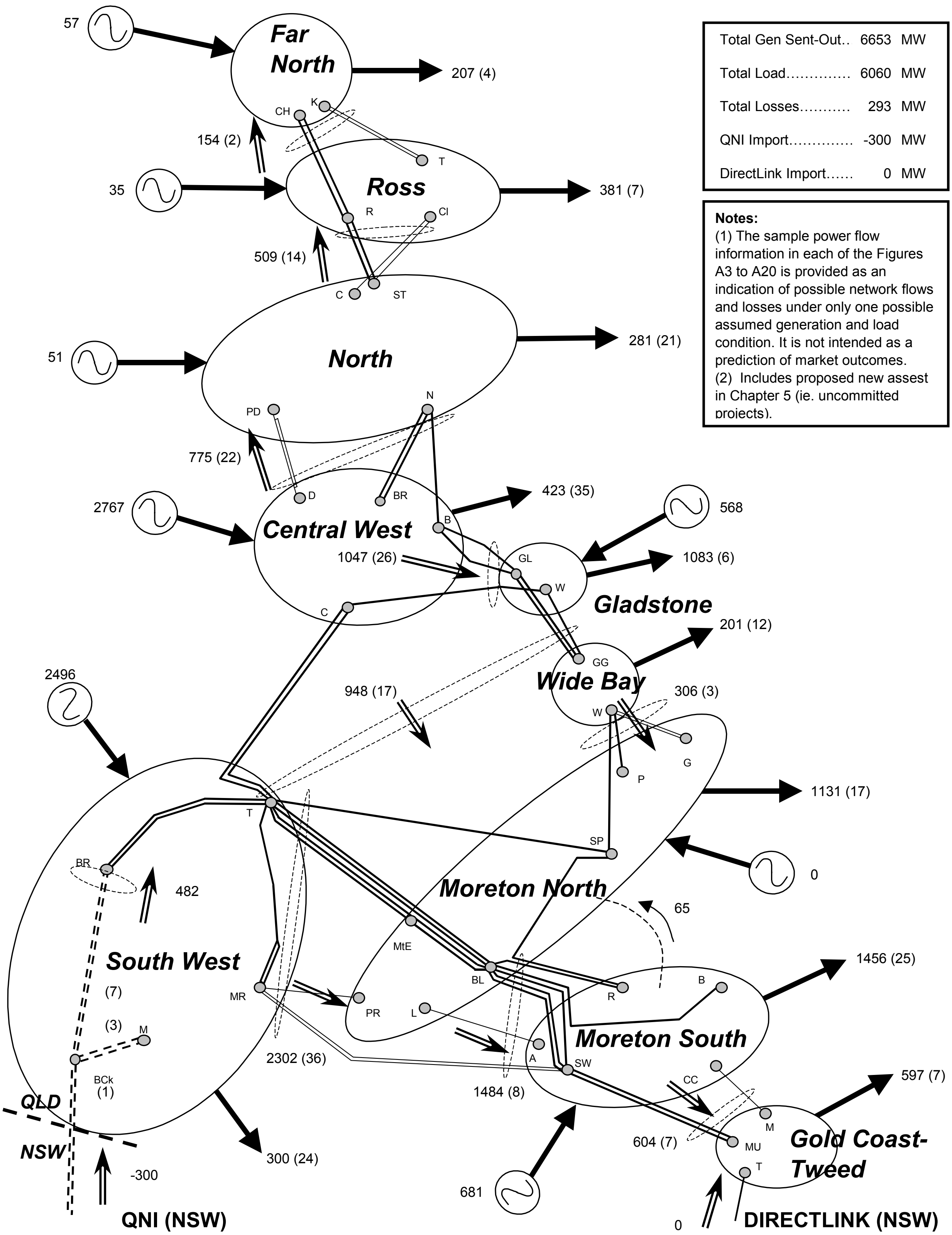
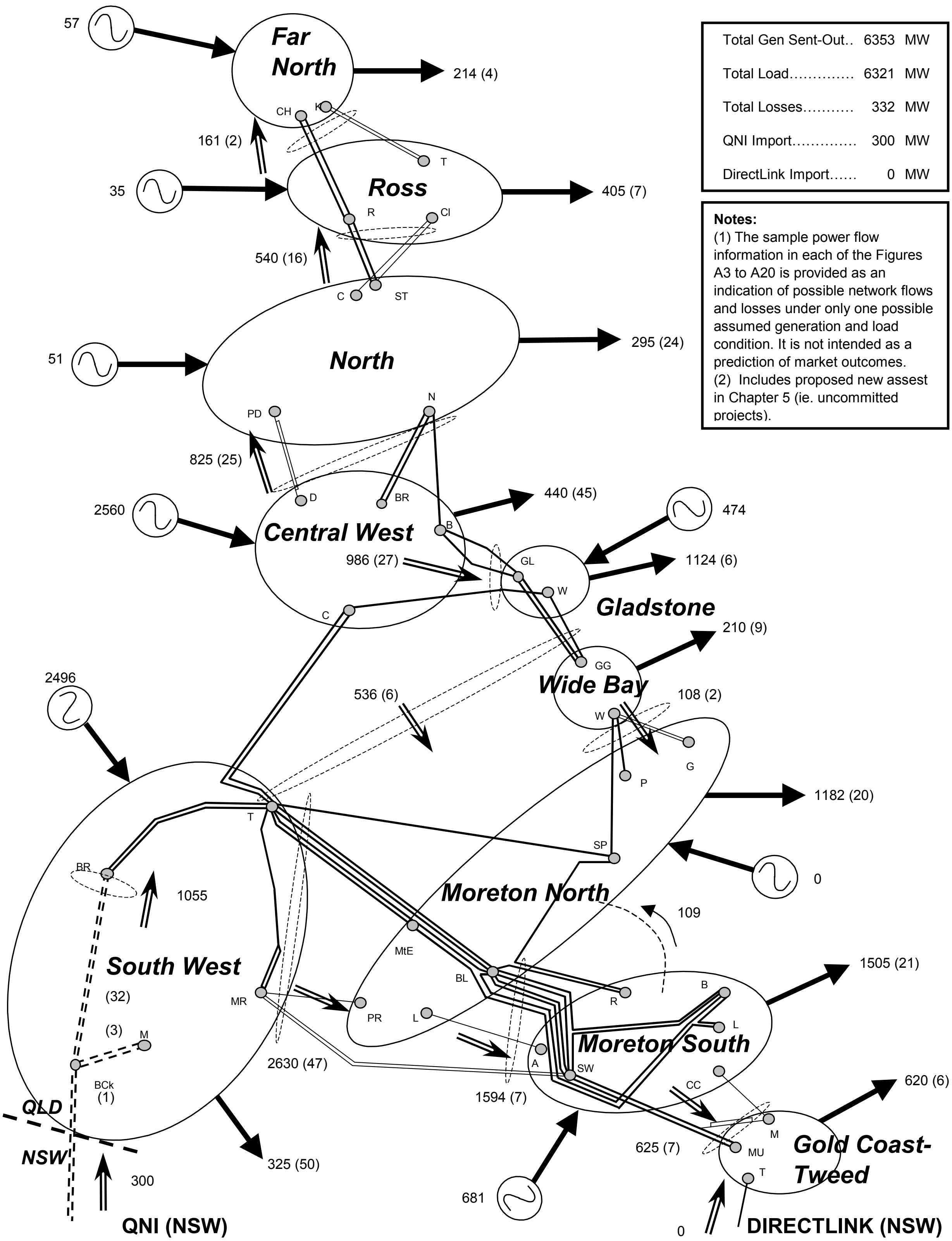


Figure A6: Winter 2004 Qld Peak 300MW Import QNI Flow



Total Gen Sent-Out..	6353	MW
Total Load.............	6321	MW
Total Losses...........	332	MW
QNI Import.............	300	MW
DirectLink Import......	0	MW

Notes:
(1) The sample power flow information in each of the Figures A3 to A20 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.
(2) Includes proposed new assest in Chapter 5 (ie. uncommitted projects).

Figure A7: Winter 2004 Qld Peak Zero QNI Flow

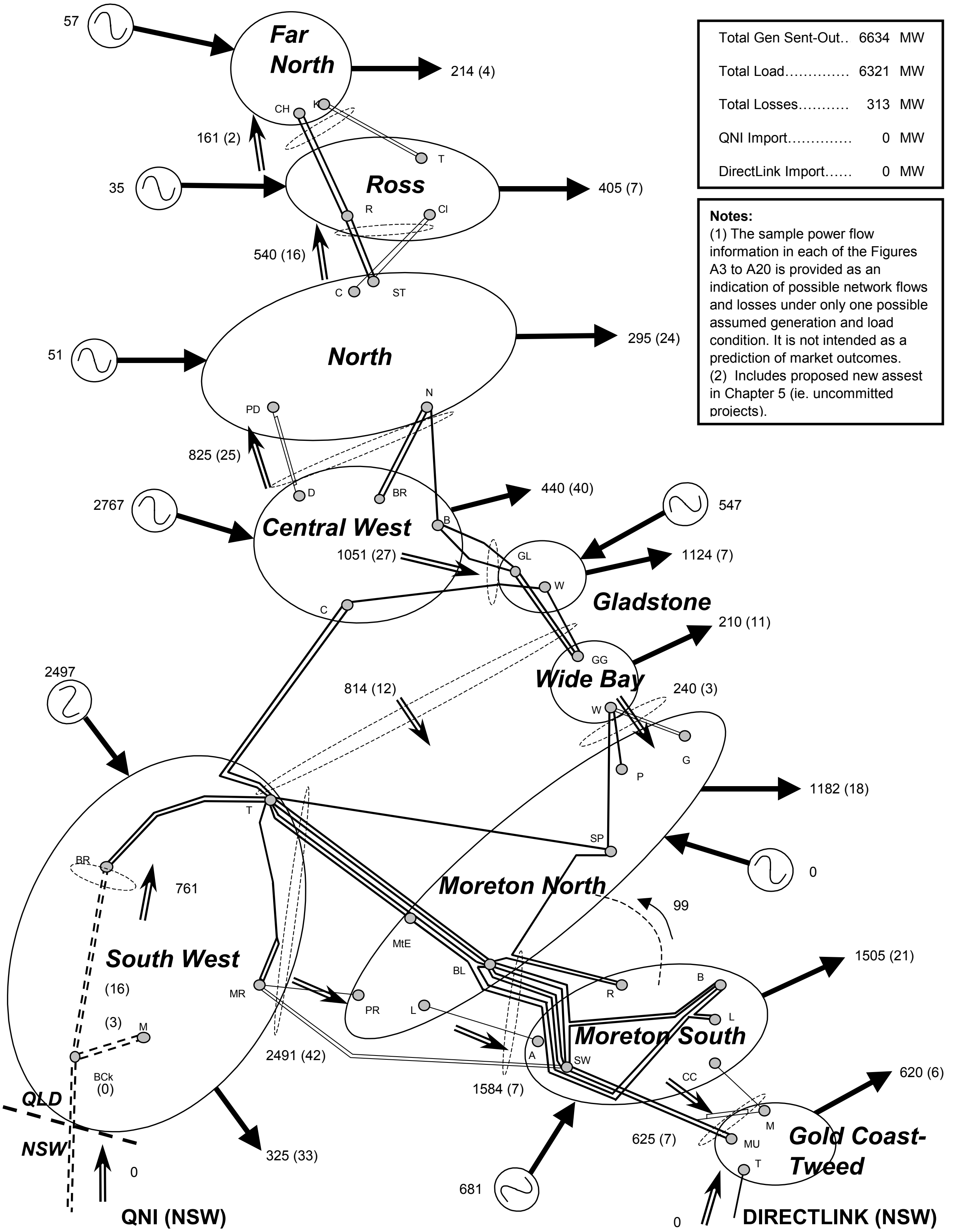
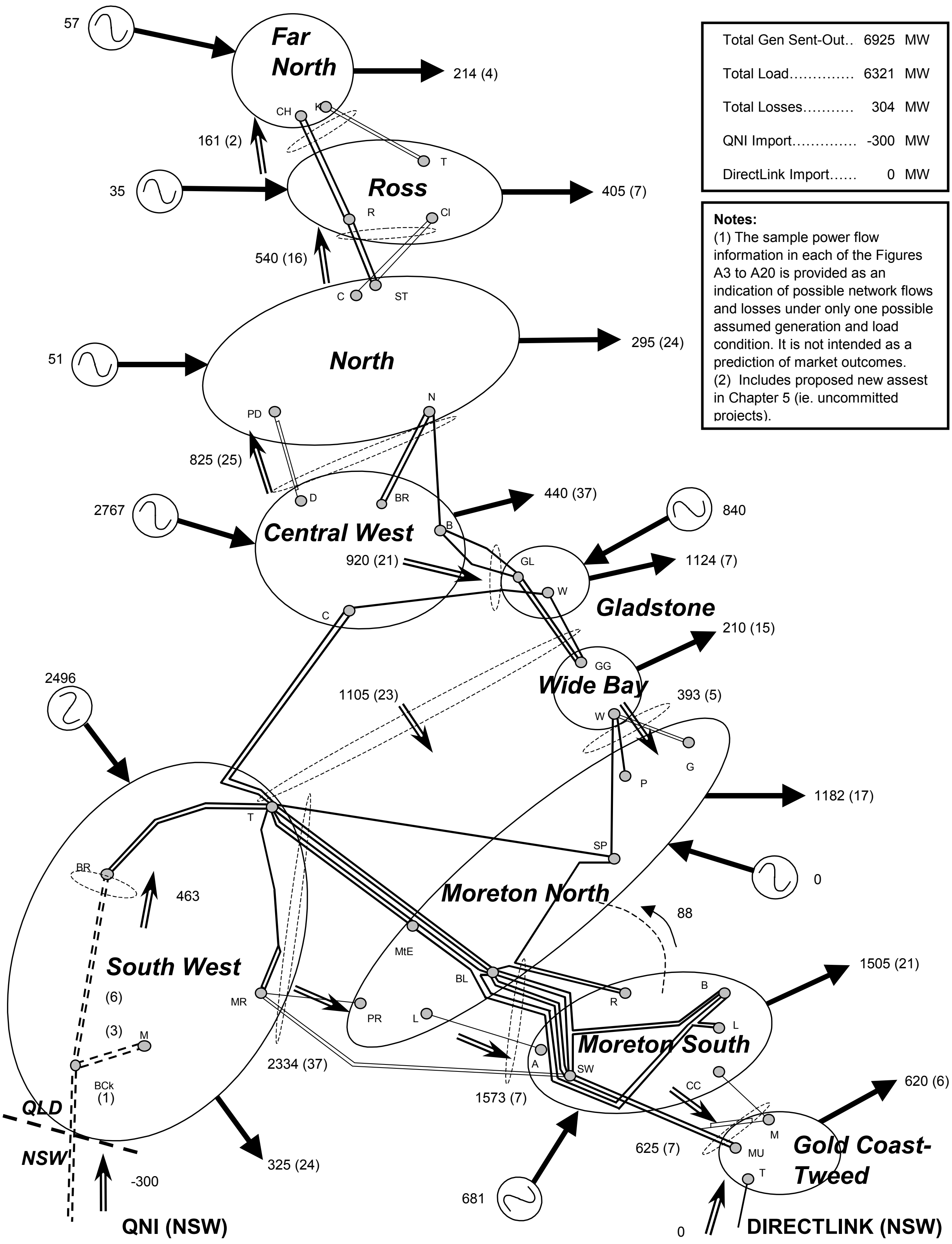


Figure A8: Winter 2004 Qld Peak 300MW Export QNI Flow



Total Gen Sent-Out..	6925 MW
Total Load………….	6321 MW
Total Losses……….	304 MW
QNI Import………….	-300 MW
DirectLink Import……	0 MW

Notes:
(1) The sample power flow information in each of the Figures A3 to A20 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.
(2) Includes proposed new assest in Chapter 5 (ie. uncommitted projects).

Figure A9: Winter 2005 Qld Peak 300MW Import QNI Flow

Total Gen Sent-Out..	6650 MW
Total Load………….	6613 MW
Total Losses……….	337 MW
QNI Import………….	300 MW
DirectLink Import……	0 MW

Notes:
(1) The sample power flow information in each of the Figures A3 to A20 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.
(2) Includes proposed new assest in Chapter 5 (ie. uncommitted projects).

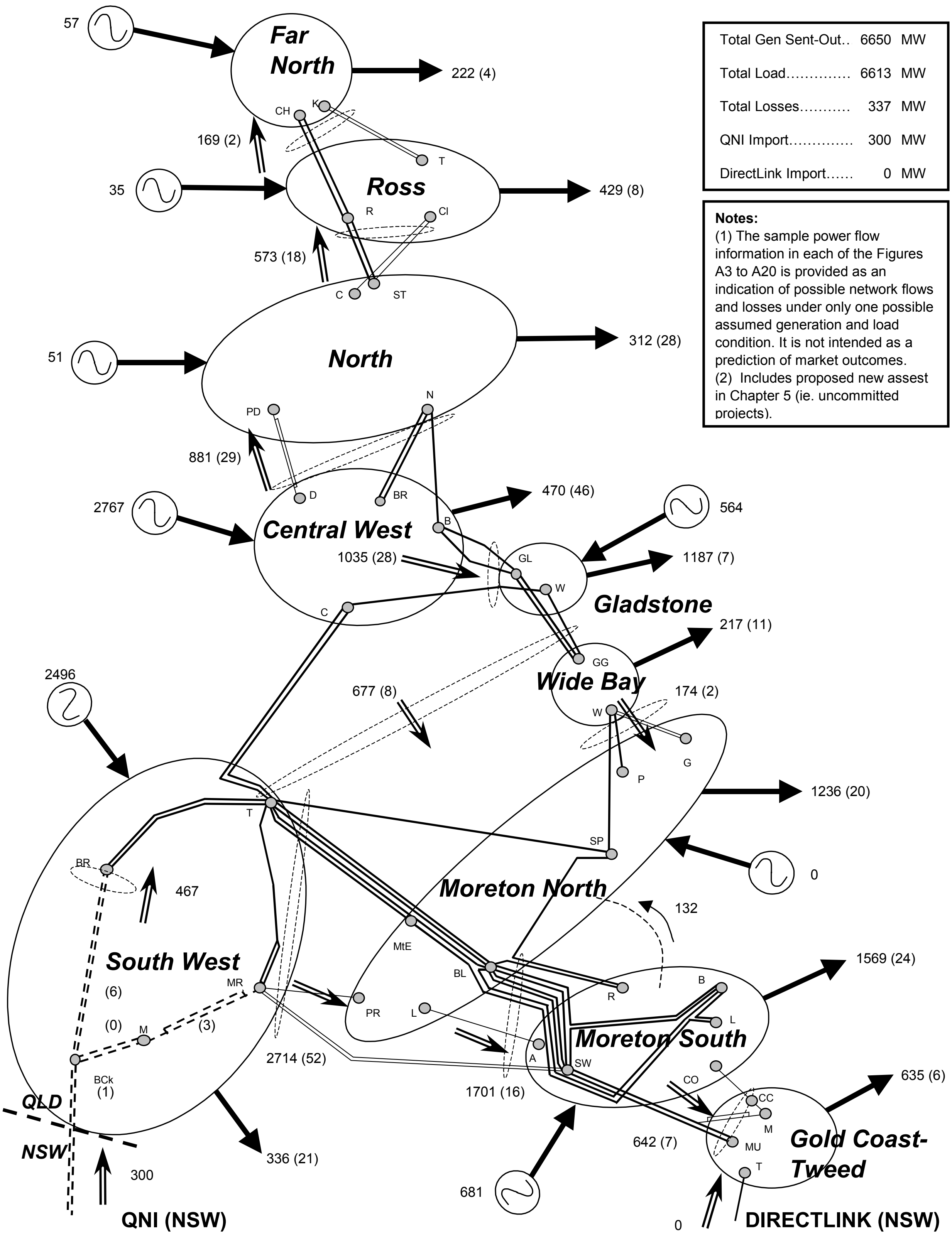


Figure A10: Winter 2005 Qld Peak Zero QNI Flow

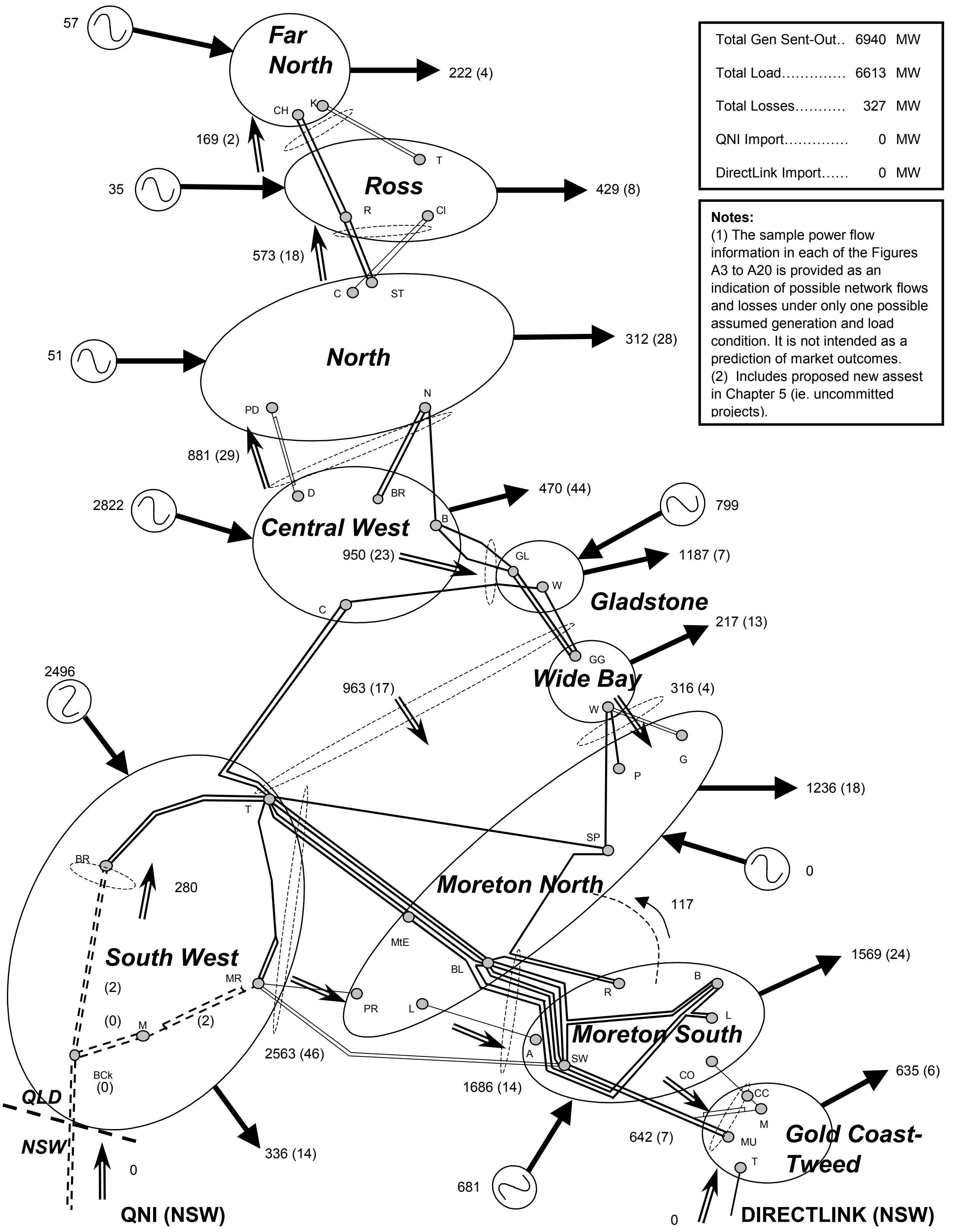


Figure A11: Winter 2005 Qld Peak 300MW Export QNI Flow

Total Gen Sent-Out..	7242	MW
Total Load.............	6613	MW
Total Losses...........	329	MW
QNI Import.............	-300	MW
DirectLink Import......	0	MW

Notes:
(1) The sample power flow information in each of the Figures A3 to A20 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.
(2) Includes proposed new assest in Chapter 5 (ie. uncommitted projects).

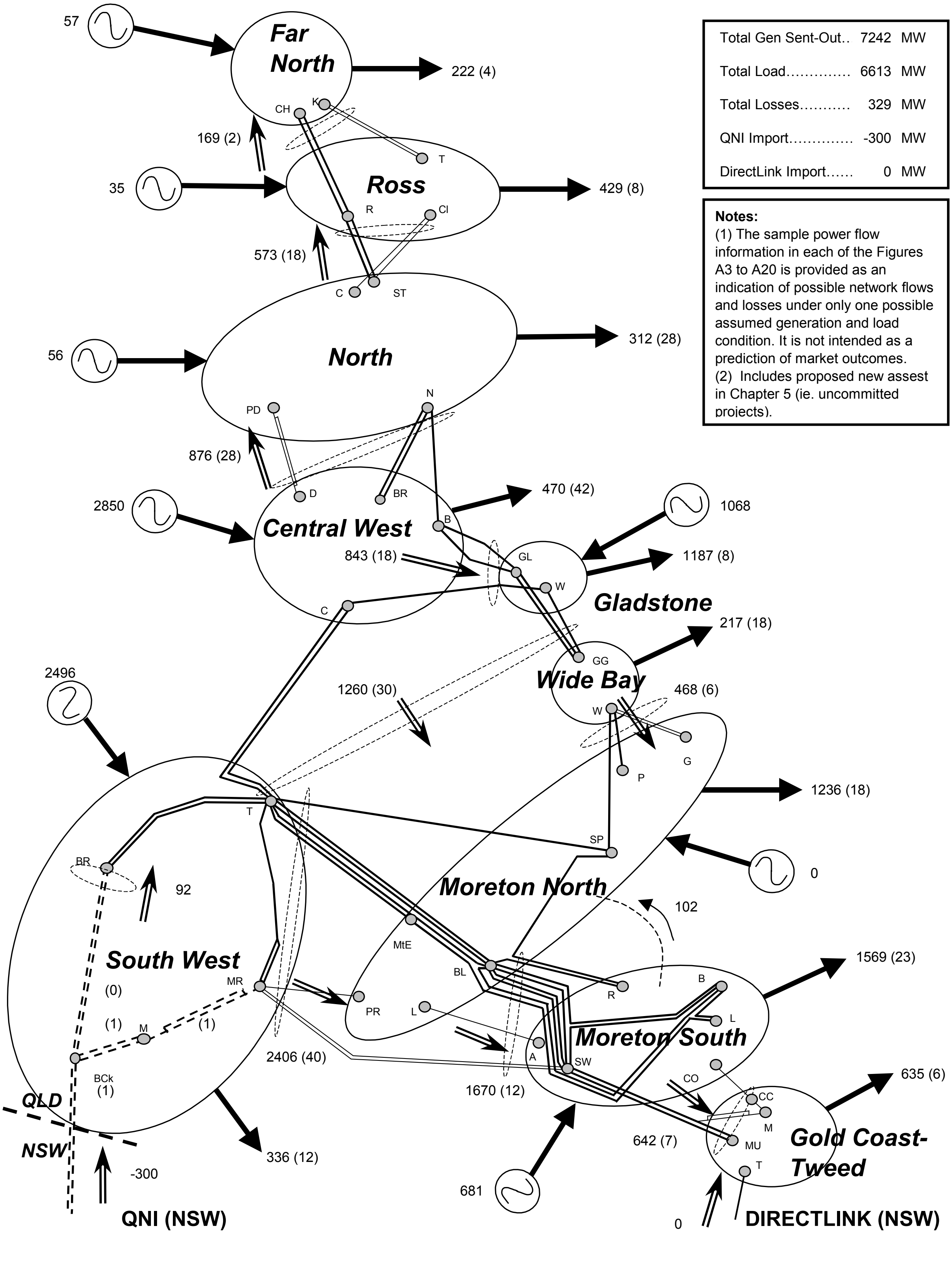


Figure A12: Summer 2003/04 Qld Peak 300MW Import QNI Flow

Total Gen Sent-Out..	6918	MW
Total Load………….	6814	MW
Total Losses……….	404	MW
QNI Import………….	300	MW
DirectLink Import……	0	MW

Notes:
(1) The sample power flow information in each of the Figures A3 to A20 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.
(2) Includes proposed new assest in Chapter 5 (ie. uncommitted projects).

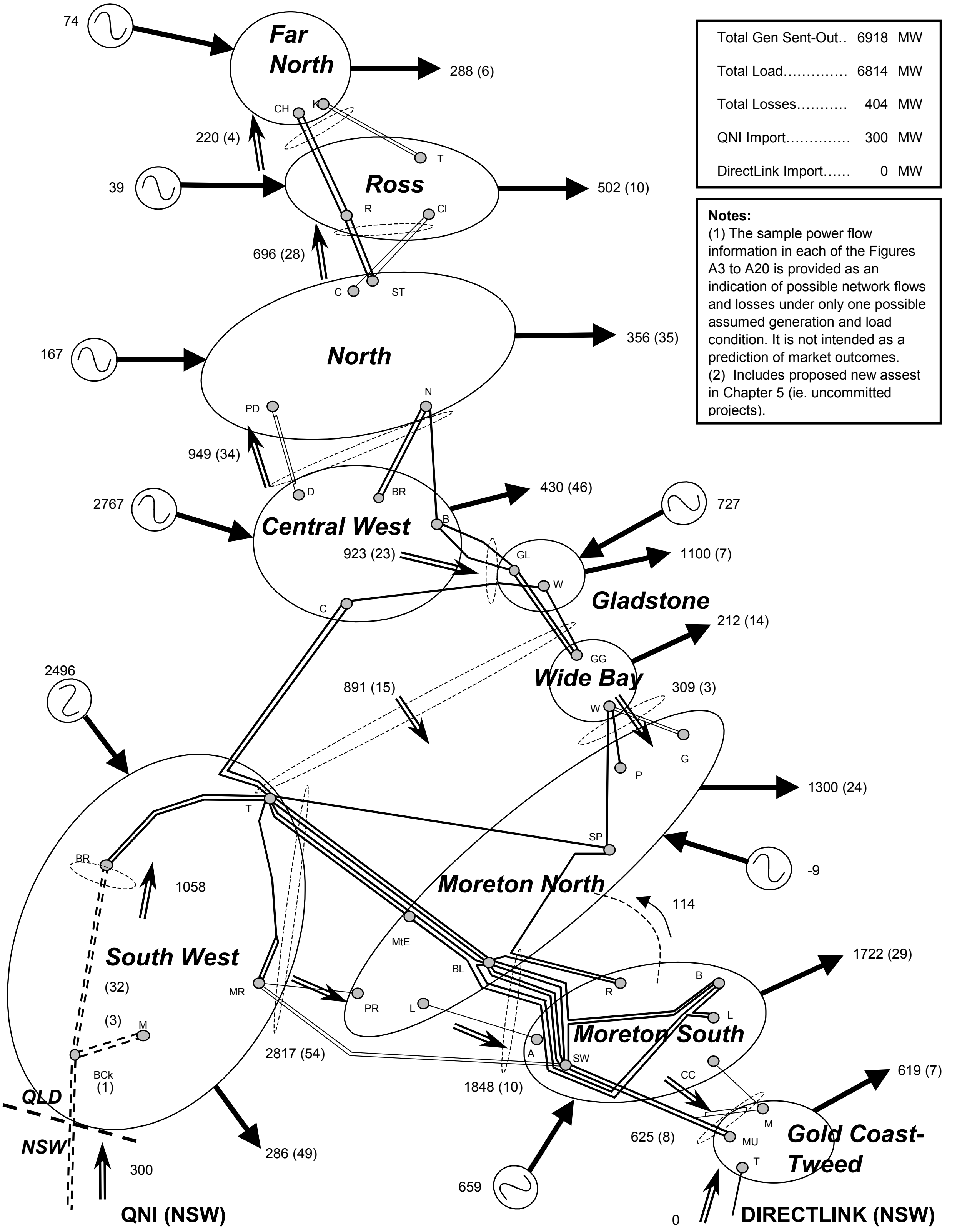
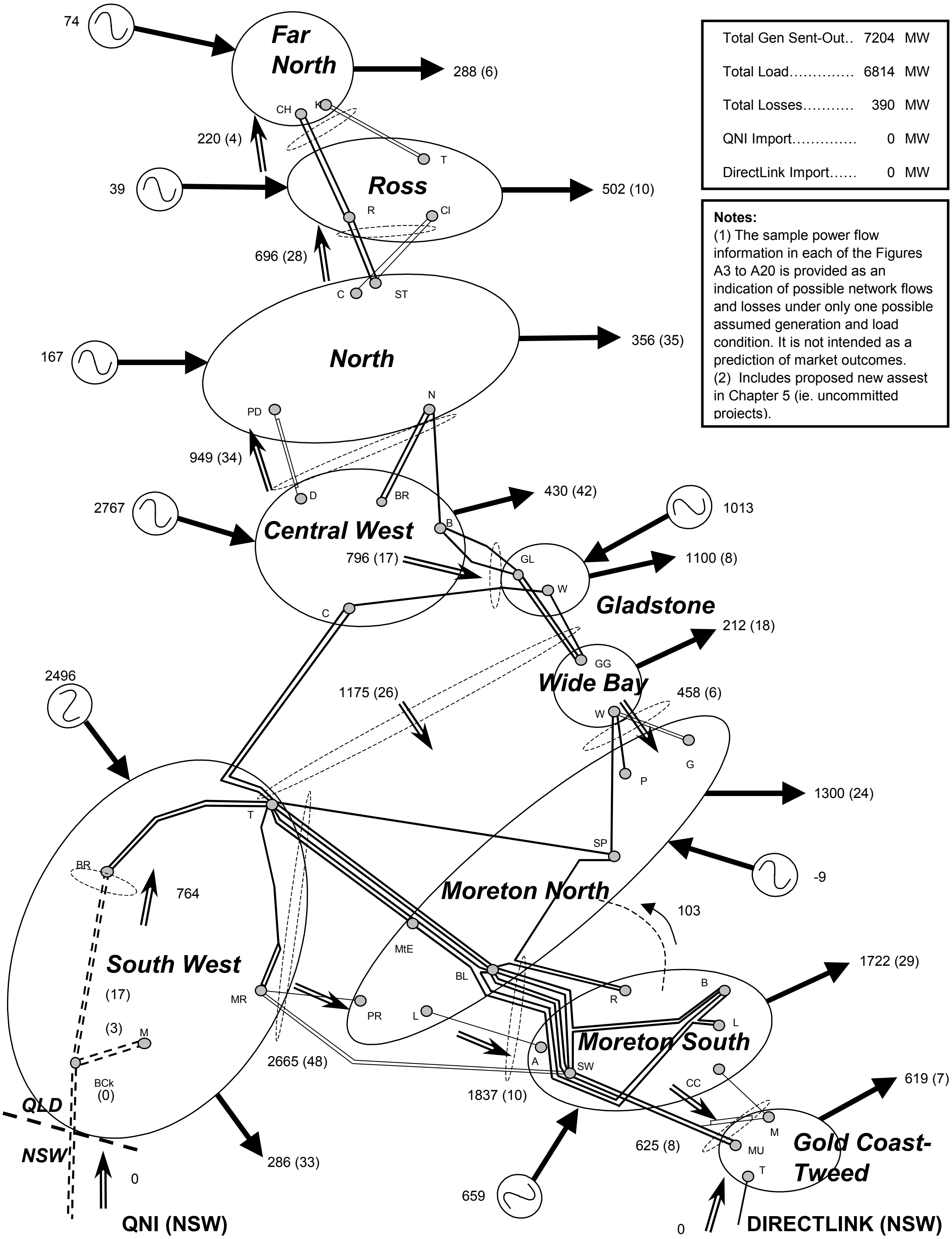


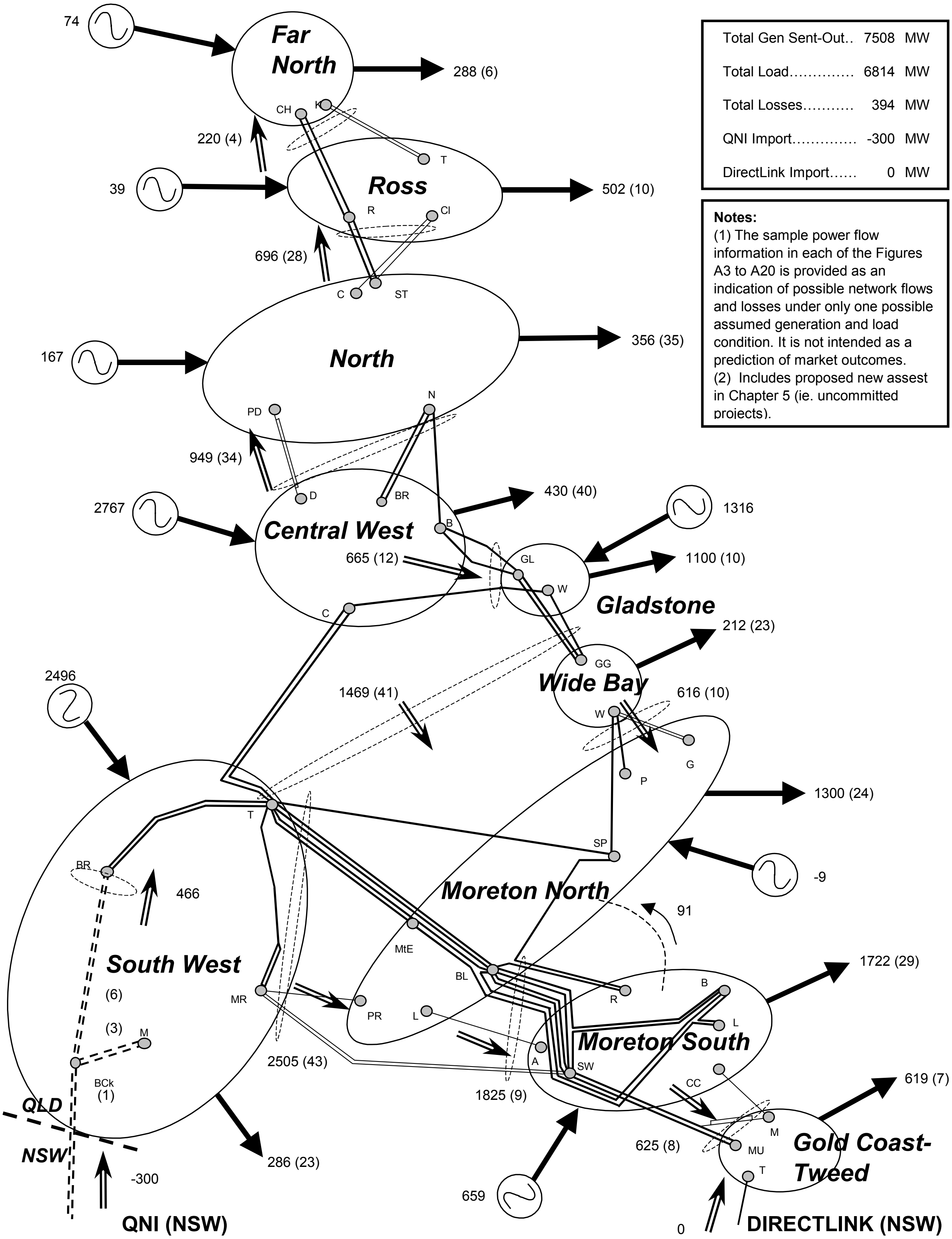
Figure A13: Summer 2003/04 Qld Peak Zero QNI Flow



Total Gen Sent-Out..	7204	MW
Total Load.............	6814	MW
Total Losses...........	390	MW
QNI Import.............	0	MW
DirectLink Import......	0	MW

Notes:
(1) The sample power flow information in each of the Figures A3 to A20 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.
(2) Includes proposed new assest in Chapter 5 (ie. uncommitted projects).

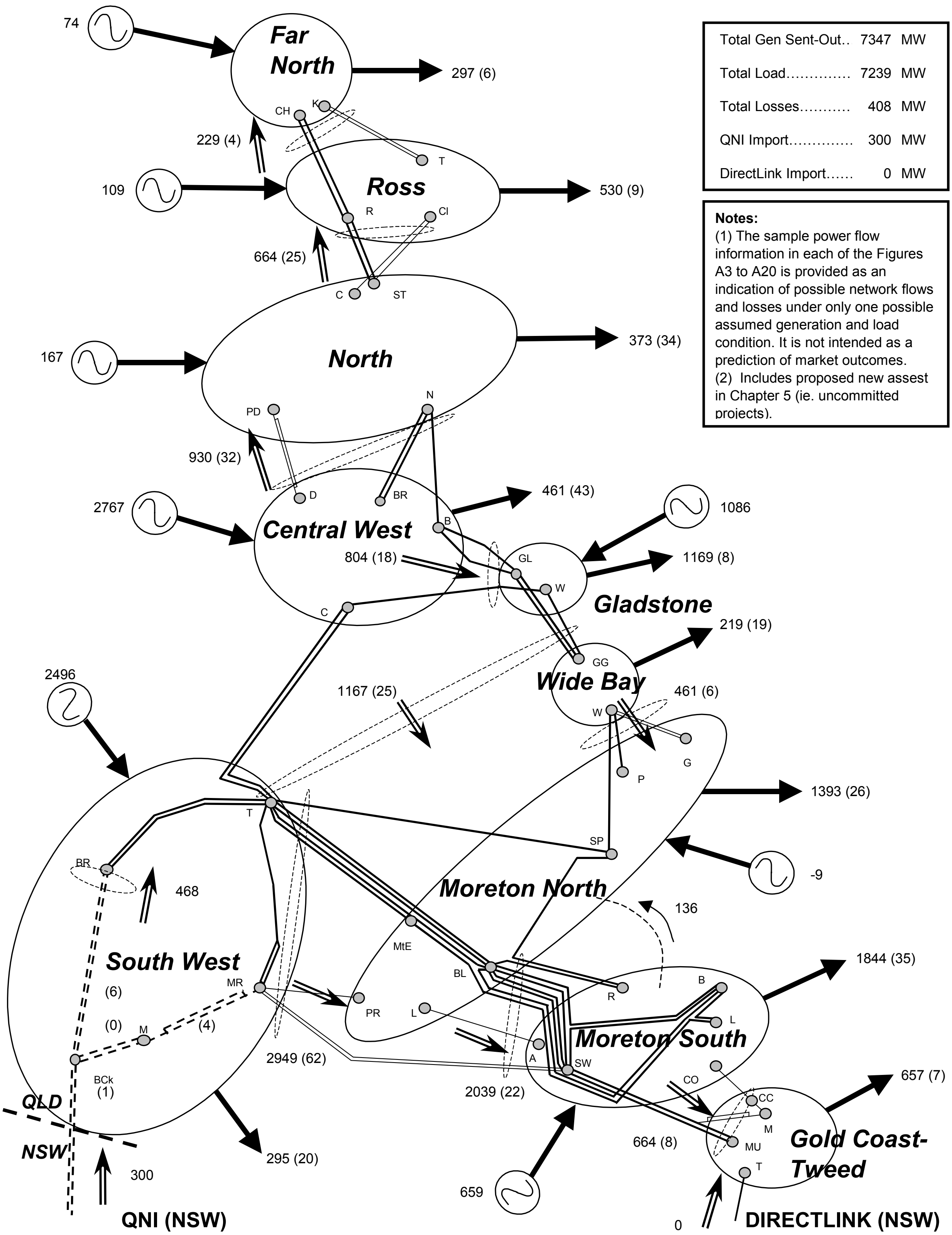
Figure A14: Summer 2003/04 Qld Peak 300MW Export QNI Flow



Total Gen Sent-Out..	7508 MW
Total Load.............	6814 MW
Total Losses...........	394 MW
QNI Import.............	-300 MW
DirectLink Import......	0 MW

Notes:
(1) The sample power flow information in each of the Figures A3 to A20 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.
(2) Includes proposed new assest in Chapter 5 (ie. uncommitted projects).

Figure A15: Summer 2004/05 Qld Peak 300MW Import QNI Flow



Total Gen Sent-Out..	7347	MW
Total Load………….	7239	MW
Total Losses………..	408	MW
QNI Import………….	300	MW
DirectLink Import……	0	MW

Notes:
(1) The sample power flow information in each of the Figures A3 to A20 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.
(2) Includes proposed new assest in Chapter 5 (ie. uncommitted projects).

Figure A16: Summer 2004/05 Qld Peak Zero QNI Flow

Total Gen Sent-Out..	7648	MW
Total Load.............	7239	MW
Total Losses...........	409	MW
QNI Import..............	0	MW
DirectLink Import......	0	MW

Notes:
(1) The sample power flow information in each of the Figures A3 to A20 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.
(2) Includes proposed new assest in Chapter 5 (ie. uncommitted projects).

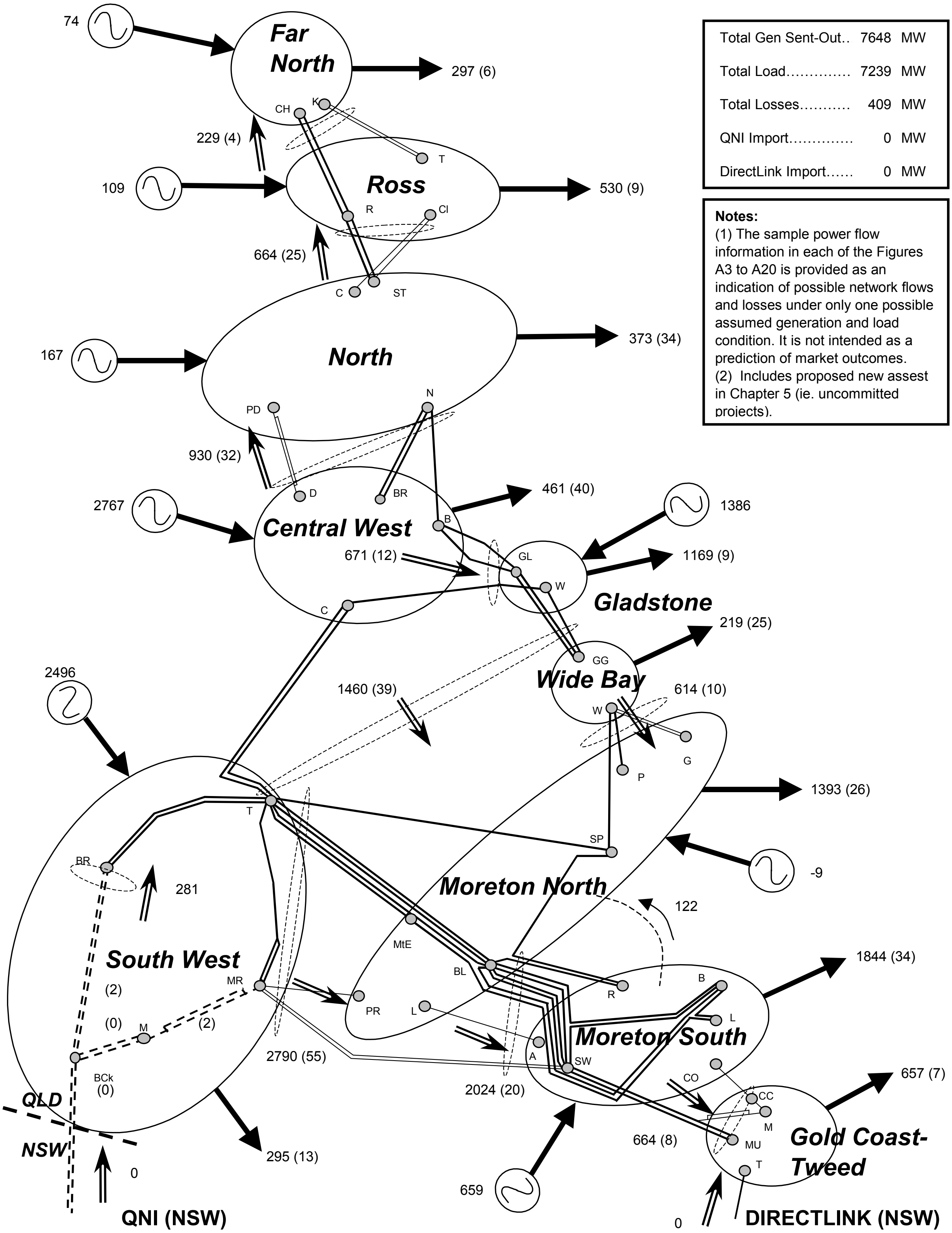
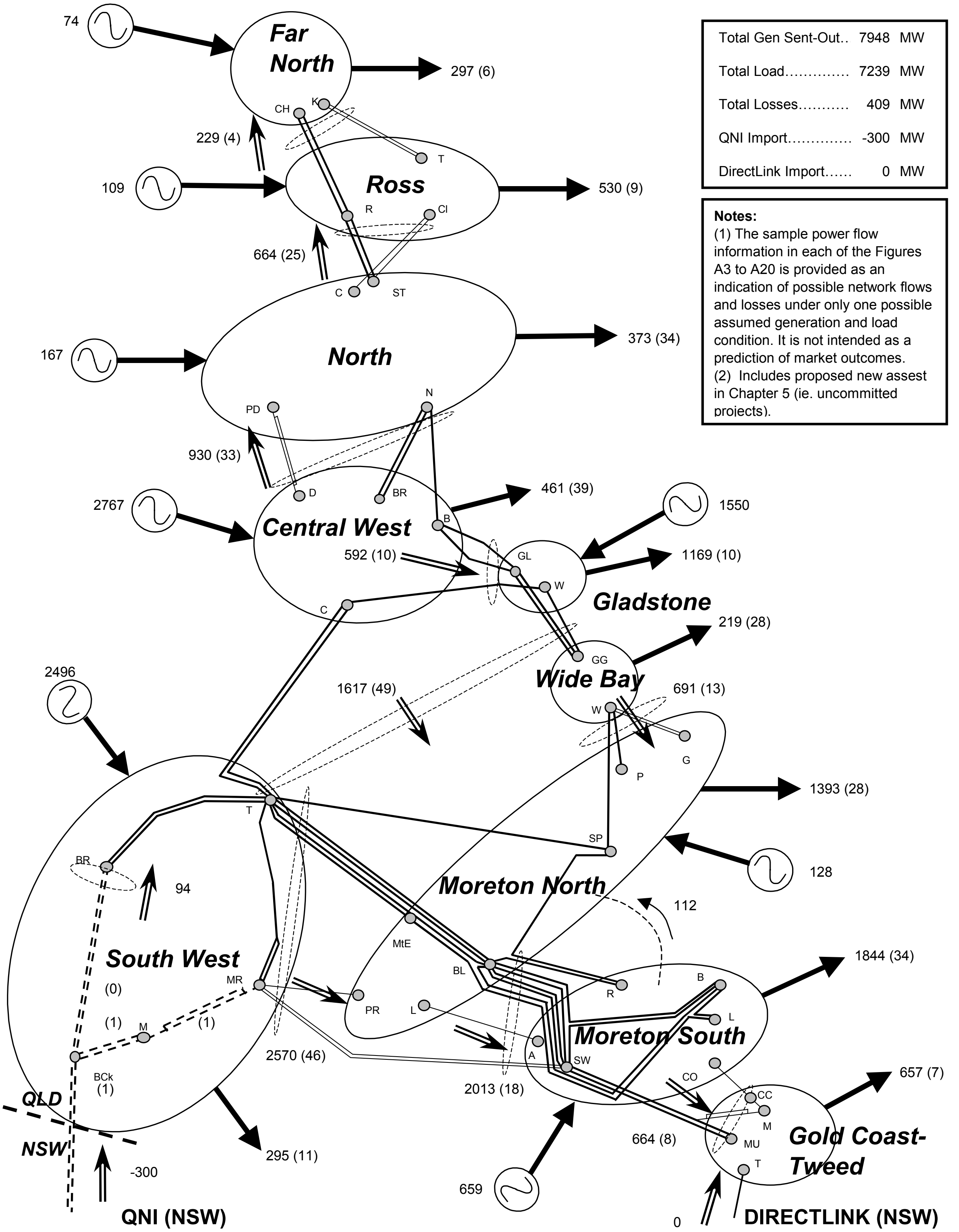


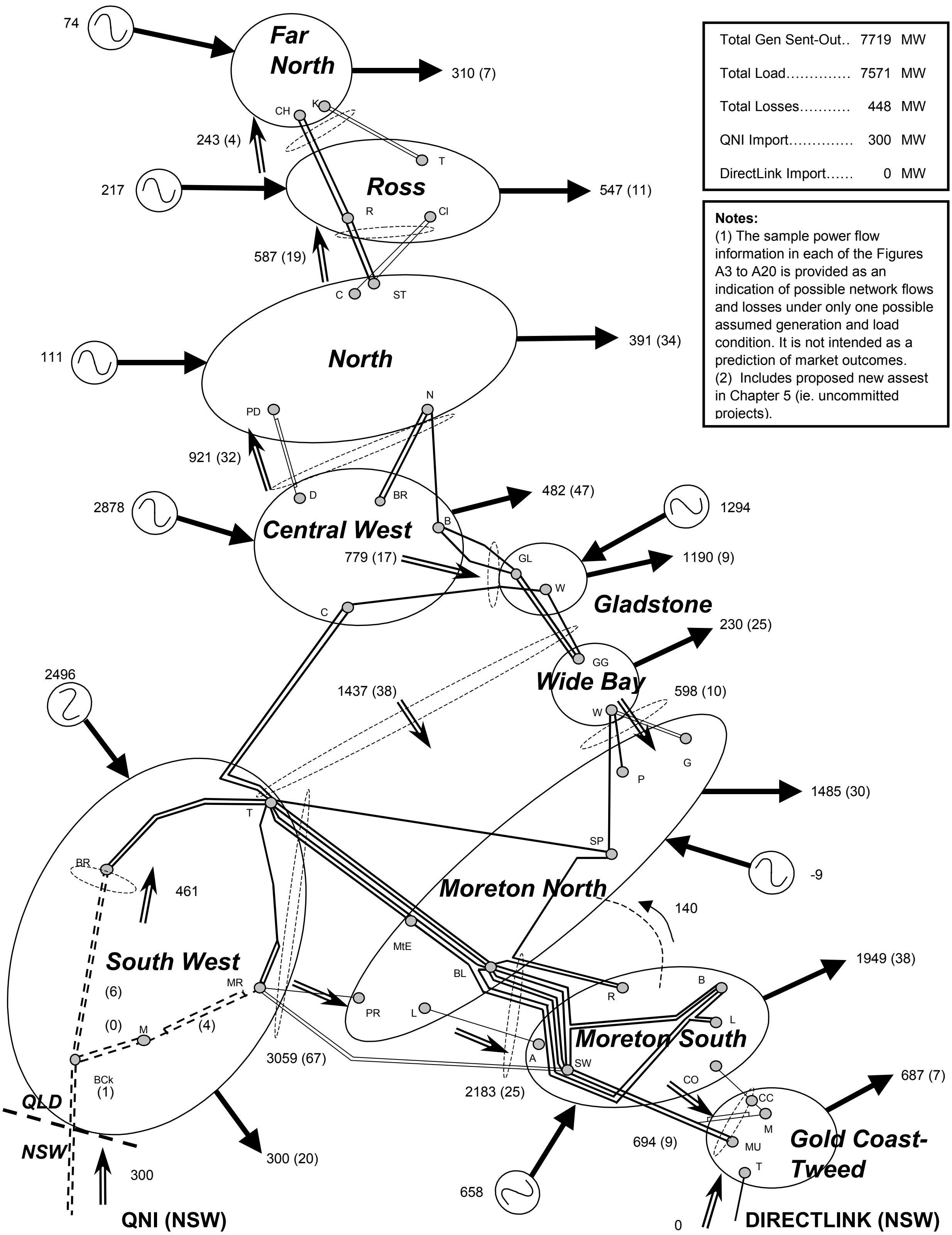
Figure A17: Summer 2004/05 Qld Peak 300MW Export QNI Flow



Total Gen Sent-Out..	7948	MW
Total Load…………..	7239	MW
Total Losses………..	409	MW
QNI Import…………..	-300	MW
DirectLink Import……	0	MW

Notes:
(1) The sample power flow information in each of the Figures A3 to A20 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.
(2) Includes proposed new assest in Chapter 5 (ie. uncommitted projects).

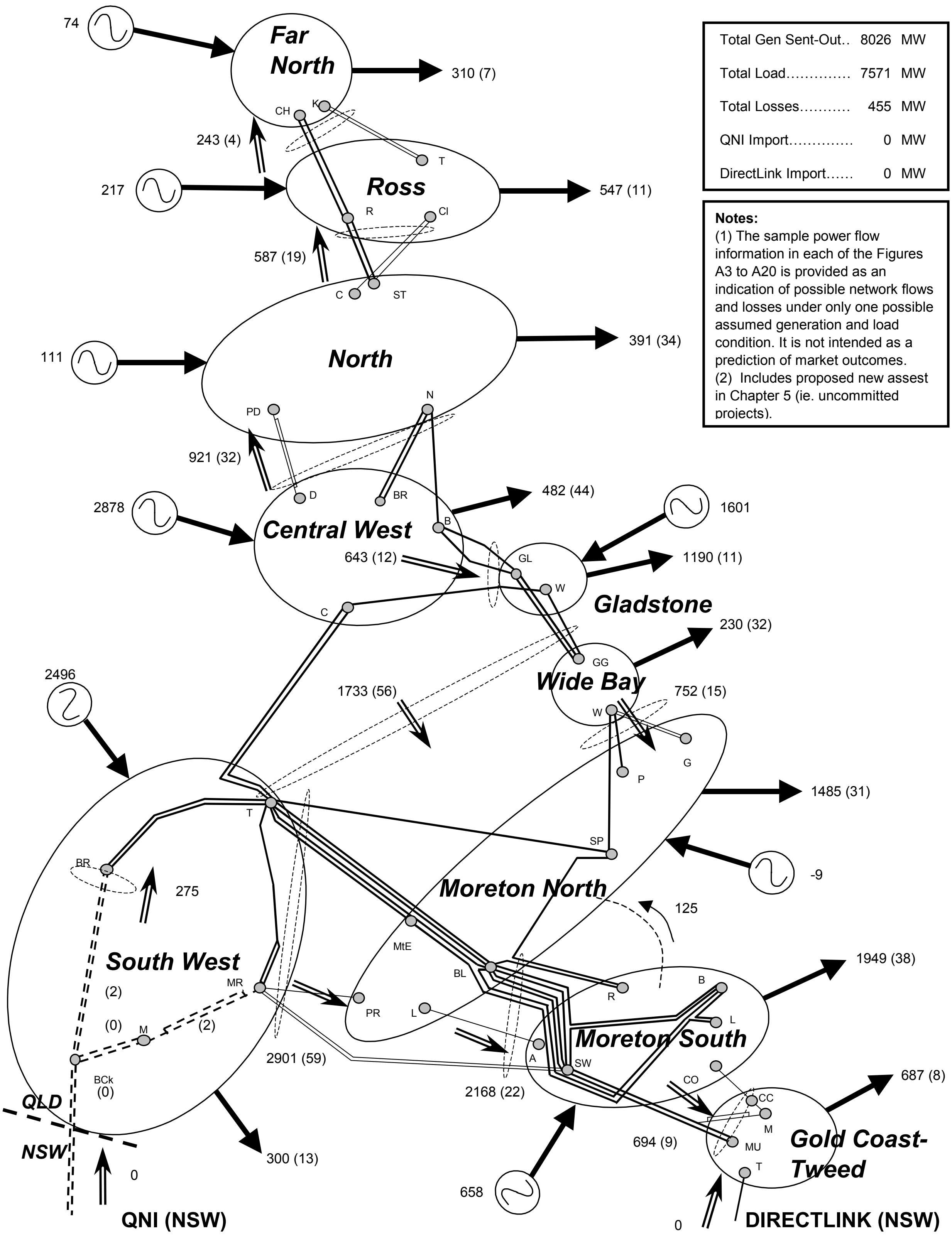
Figure A18: Summer 2005/06 Qld Peak 300MW Import QNI Flow



Total Gen Sent-Out..	7719 MW
Total Load.............	7571 MW
Total Losses...........	448 MW
QNI Import.............	300 MW
DirectLink Import......	0 MW

Notes:
(1) The sample power flow information in each of the Figures A3 to A20 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.
(2) Includes proposed new assest in Chapter 5 (ie. uncommitted projects).

Figure A19: Summer 2005/06 Qld Peak Zero QNI Flow



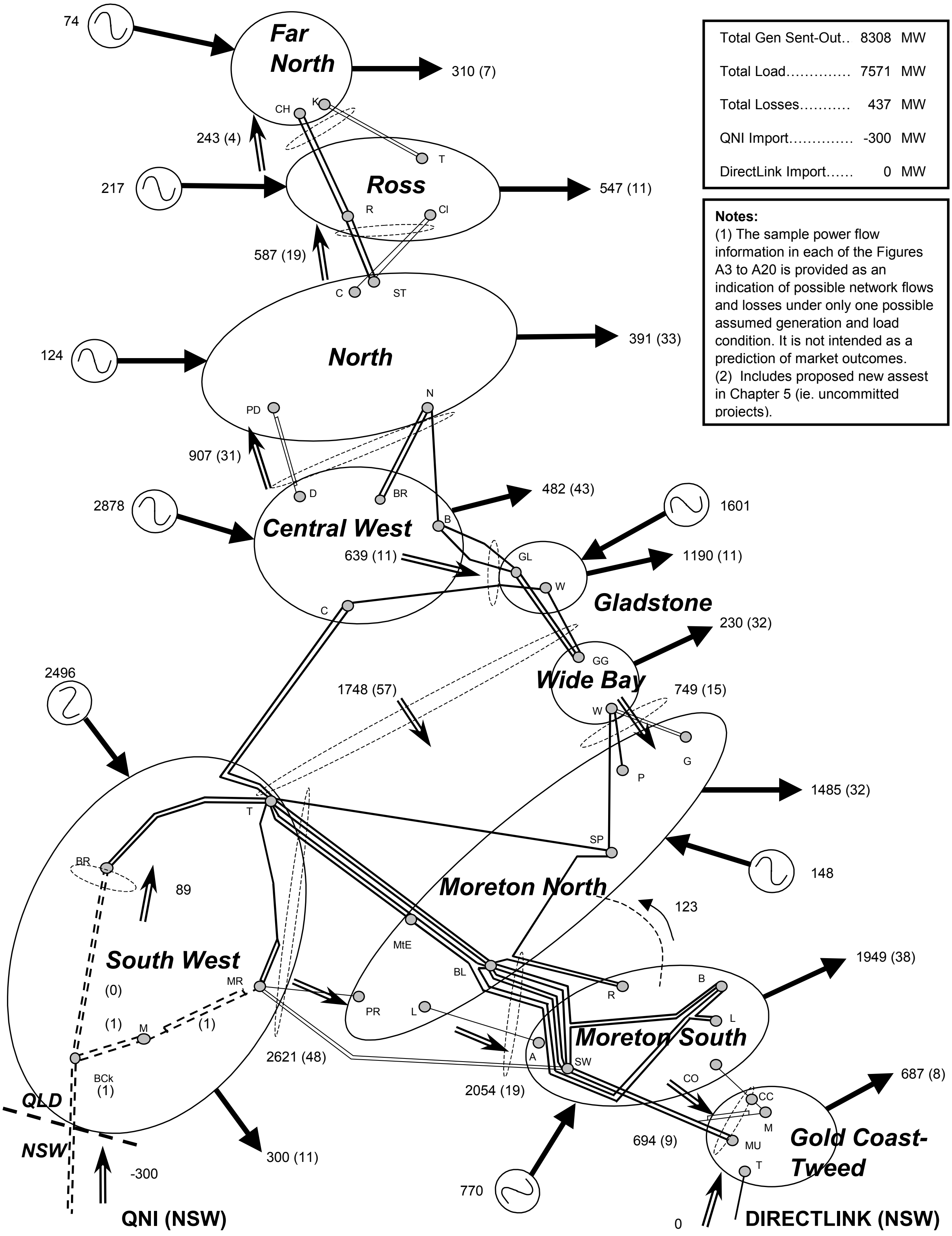
Total Gen Sent-Out..	8026 MW
Total Load………….	7571 MW
Total Losses……….	455 MW
QNI Import………….	0 MW
DirectLink Import……	0 MW

Notes:
(1) The sample power flow information in each of the Figures A3 to A20 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.
(2) Includes proposed new assest in Chapter 5 (ie. uncommitted projects).

Figure A20: Summer 2005/06 Qld Peak 300MW Export QNI Flow

Total Gen Sent-Out..	8308 MW
Total Load………….	7571 MW
Total Losses………..	437 MW
QNI Import………….	-300 MW
DirectLink Import……	0 MW

Notes:
(1) The sample power flow information in each of the Figures A3 to A20 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.
(2) Includes proposed new assest in Chapter 5 (ie. uncommitted projects).



APPENDIX B: LIMIT EQUATIONS

Note: Limit Equations are valid at time of publication of this Annual Planning Report. The equations are continually under review and are revised from time to time to take account of changing market, climatic and network conditions.

Please contact Powerlink to confirm the latest form of the relevant limit equation.

Table B1: Far North Queensland Voltage Stability Equations

Measured Variable	Coefficient Equation 1 Chalumbin-Woree Contingency	Equation 2 Ross-Chalumbin Contingency
Constant Term (Intercept)	221.9	252.0
Summated generation at Barron Gorge	-0.5941	-0.626
Number of Barron Gorge units on-line (generating)	14.2359	11.2428
Number of Barron Gorge units on-line (synchronous condenser)	24.5456	17.3656
Summated generation at Kareeya (including K5)	-1.0201	-0.7917
4 Kareeya units on-line (0 or 1) (excl K5)	28.69	26.9103
3 Kareeya units on-line (0 or 1) (excl K5)	21.51	18.2581
2 Kareeya units on-line (0 or 1) (excl K5)	14.20	9.4847
1 Kareeya units on-line (0 or 1) (excl K5)	6.35	0
132kV Capacitor Bank at Innisfail (MVArs at the nominal voltage of 132kV)	0.2708	0.4219
132kV Capacitor Banks at Cairns (MVArs at the nominal voltage of 132kV)	0.3732	0.4595
Chalumbin Reactors (MVArs at the nominal voltage of 132kV)	0.0605	0
Availability of Chalumbin 132kV Cap Bank (available=1, unavailable=0)	0	18.3
Summated generation at Collinsville	0	0.0245
Summated generation at Mt Stuart	0	0.0058
Number of Mt Stuart units on-line	0	1.8413
Generation at Townsville PS	0	0.0194
Number of Townsville PS units on-line	0	1.655

Table B2: Central to North Queensland Dynamic Stability Equation

Measured Variable	Coefficient
Constant Term (Intercept)	985
Number of Barron and Kareeya units on-line in sync cond mode	-10

Note:

At the time of publication of this report the CQ-NQ transfer was limited to a maximum of 930MW due to a sustained outage of the Nebo SVC.

Table B3: Central to South Queensland Voltage Stability Equations

Measured Variable	Coefficient	
	Equation 1 (1) **Calvale-Tarong Contingency**	**Equation 2** (2) **Calvale-Tarong Contingency**
Constant Term (Intercept)	1267.2	1277.3
Summated generation at Gladstone units 1, 2, 5 & 6	0.0812	0.0731
Number of Gladstone units on-line connected to the 275kV bus (ie. units 1, 2, 5 and 6)	70.3649	72.2846
Summated generation at Gladstone units 3 and 4	0.1152	0.1062
Number of Gladstone units on-line connected to the 132kV bus (ie. units 3 and 4)	73.3362	75.8105
Number of Callide B units on-line	54.0629	47.7783
Number of Callide C units on-line	86.2947	74.2664
(Calvale 275kV p.u. voltage – 1.07) x 1000	0.8860	1.1843
(Gladstone 275kV p.u. voltage – 1.07) x 1000	-1.5181	-1.5421
Equation Lower Limit	1800	1800
Equation Upper Limit (Transient instability threshold)	2000	2000

Note:

(1) Equation that preserves the required MVAr margin at Calvale 275kV.
(2) Equation that preserves the required MVAr margin at Gladstone 275kV.

Table B4: Tarong Voltage Stability Equations

Measured Variable	Coefficient Equation 1 Calvale-Tarong Contingency	Equation 2 Woolooga-Palmwoods Contingency	Equation 3 Blackwall-Belmont Contingency
Constant Term (Intercept)	1343	1457	1520
Power transfer on QNI (MW – positive is import into Qld)	0.5559	0.4945	0.4785
Summated DirectLink power transfer (MW – positive is import into Qld)	-0.1390	-0.1485	-0.1319
Summated DirectLink reactive power (MVAr – positive is import into Qld)	0.3012	0.3889	0.4546
Number of Swanbank B units on-line	11.3130	12.0139	13.6494
Number of Swanbank E units on-line	30.9809	43.8852	44.4204
Summated generation at Roma PS	0.4481	0.3726	0.4276
Summated generation at Swanbank B, D and E	-0.3364	-0.3660	-0.4182
Summated generation at Gladstone 275kV and Gladstone 132kV	-0.0501	-0.0443	-0.0419
Summated generation at Tarong/Tarong North PS	0.5902	0.5461	0.5128
Summated generation at Wivenhoe PS	-0.3561	-0.3923	-0.4201
Summated generation at Callide B and Callide C	0.1032	0.0929	0.0978
Summated generation at Oakey PS	0.6480	0.6052	0.5540
Summated generation at Millmerran PS	0.5192	0.4655	0.4550
Number of Wivenhoe synchronous condensors units on-line	31.1871	38.0318	32.9781
Number of Wivenhoe generating units on-line	26.8034	34.0100	29.1323

Table B5: Gold Coast Voltage Stability Equation

Measured Variable	Coefficient Swanbank-Mudgeeraba Contingency
Constant Term (Intercept)	447.2
Number of Wivenhoe units on-line	10.461
Number of Swanbank B and E units on-line	9.7254
Blackwall SVC Reactive Power Margin (250 – Q output)	0.4354
(Blackwall 275kV voltage p.u. – 1.06) x 10000	0.0943
Summated MVAr flow through the Mudgeeraba transformers (measured at the 275kV side) squared and divided by 200	-0.9282
Summated MW flow on DirectLink (measured at Terranora – positive is import into Qld)	-0.4452
Summated MVAr flow on DirectLink (measured at Terranora – positive is import into Qld)	-0.1556

Table B6: Braemar Thermal Equation

Measured Variable	Coefficient
Constant Term (Intercept)	1025

APPENDIX C: ESTIMATED MAXIMUM SHORT CIRCUIT LEVELS

Table C1: Estimated Maximum Short Circuit Levels – Southern Queensland

In Powerlink Transmission Network 2003 to 2005 (1)

Location	Voltage kV	Lowest Switchgear Rating (kA) (2)	3 Phase kA			Single Phase (kA)		
			2003	2004	2005	2003	2004	2005
Abermain	110.0	31.5	14.30	13.64	13.64	13.21	12.96	12.96
Ashgrove West	110.0	25.0	21.32	21.39	21.39	22.21	22.28	22.28
Belmont	275.0	31.5	14.97	15.07	15.08	15.01	15.27	15.27
Belmont (3) (4)	110.0	25.0	24.87	25.04	25.05	29.00	29.14	29.14
Blackwall	275.0	50.0	21.27	21.45	21.46	23.31	23.54	23.55
Braemar	330.0	50.0	10.14	10.49	10.49	9.83	10.13	10.13
Braemar	275.0	50.0	12.26	12.56	12.56	12.16	12.45	12.45
Bulli Creek	330.0	50.0	11.25	12.61	12.61	10.15	11.11	11.11
Bulli Creek	132.0	40.0	4.20	4.27	4.27	4.54	4.61	4.61
Loganlea	275.0	50.0	11.98	12.24	12.24	11.23	12.05	12.06
Loganlea	110.0	25.0	18.12	20.90	20.90	19.38	23.39	23.39
Middle Ridge	330.0	NO CB	-	9.93	9.93	-	9.56	9.56
Middle Ridge	275.0	40.0	5.27	11.33	11.33	5.22	11.44	11.44
Middle Ridge (5)	110.0	18.3	12.76	18.55	18.55	14.37	21.34	21.34
Millmerran Switch Yard	330.0	50.0	11.17	13.56	13.57	13.04	15.68	15.68
Molendinar	275.0	40.0	7.55	7.60	7.60	7.23	7.29	7.29
Mt England	275.0	31.5	20.48	20.65	20.67	20.71	20.88	20.89
Mudgeeraba	275.0	31.5	7.50	7.55	7.55	7.72	7.83	7.83
Mudgeeraba	110.0	19.3	13.26	13.38	13.39	15.98	16.33	16.33
Murarrie	110.0	25.0	16.02	16.27	16.27	14.97	15.16	15.17
Oakey	110.0	40.0	9.16	10.21	10.21	10.28	11.16	11.16
Palmwoods	275.0	31.5	8.06	8.08	8.08	8.13	7.99	8.00
Palmwoods	132.0	21.8	12.38	12.40	12.40	14.44	14.47	14.47
Palmwoods	110.0	NO CB	5.52	5.52	5.52	5.81	5.81	5.81
Redbank Plains	110.0	31.5	14.05	14.09	14.09	11.86	11.89	11.89
Richlands	110.0	18.3	11.29	11.35	11.35	11.50	11.55	11.55
Rocklea	275.0	40.0	12.53	12.59	12.60	11.50	11.55	11.55

Location	Voltage kV	Lowest Switchgear Rating (kA) (2)	3 Phase kA			Single Phase (kA)		
			2003	2004	2005	2003	2004	2005
Rocklea	110.0	40.0	22.04	22.16	22.16	25.18	25.30	25.31
Runcorn	110.0	21.9	14.64	14.80	14.80	14.22	14.34	14.34
South Pine	275.0	31.5	17.73	17.84	17.86	17.98	18.08	18.09
South Pine (4)	110.0	25.0	25.80	25.88	25.89	29.59	29.68	29.69
Swanbank A (3)	110.0	18.3	13.53	16.04	16.04	12.07	14.30	14.30
Swanbank B	275.0	31.5	20.23	20.39	20.40	23.41	23.62	23.63
Swanbank E	275.0	40.0	19.73	19.88	19.89	22.42	22.61	22.62
Tangkam	110.0	40.0	10.38	11.98	11.98	10.11	11.14	11.14
Tarong	275.0	31.5	27.12	27.55	27.57	29.42	29.95	29.97
Tarong	132.0	31.5	5.15	5.15	5.15	5.51	5.52	5.52
Tarong	66.0	21.9	13.81	13.84	13.84	15.17	15.20	15.20
Tennyson	110.0	40.0	14.63	14.68	14.68	14.27	14.31	14.31
Upper Kedron	110.0	40.0	22.75	22.77	22.78	18.99	19.02	19.02
West Darra	110.0	19.3	14.12	14.14	14.15	10.31	10.33	10.33
Woolooga	275.0	31.5	9.11	9.13	9.15	8.35	8.36	8.37
Woolooga	132.0	21.9	12.39	12.41	12.42	13.20	13.22	13.23

Notes:

(1) Short circuit levels are estimated maximum levels assuming 110% of nominal voltage behind sub-transient reactance, neglecting loads, shunt admittances and other passive elements.
(2) Powerlink switchgear ratings – no account taken of distribution switchgear.
(3) Analysis for these locations allows for operation with open points to keep short circuit levels below switchgear ratings.
(4) The lowest rated circuit breaker(s) at these locations are required to interrupt short circuit current which is less than the maximum fault current and below the circuit breaker rating.
(5) Powerlink will undertake refurbishment to upgrade all necessary switchgear before the end of 2004.

Also note that:

(6) Fault level contributions to the Powerlink network from sugar mills, other than Invicta and Rocky Point, are not included in these tables.
(7) Fault level contributions to the Powerlink network from embedded non-scheduled generators, other than Bulwer Island (BIEP) and Queensland Nickel, are not included in these tables. Excluded generators include, but may not be limited to, Windy Hill wind generators, Wivenhoe small hydro generator, Stapylton biomass, and possible Moranbah coal seam methane gas turbines.

Table C2: Estimated Maximum Short Circuit Levels – Central Queensland

In Powerlink Transmission Network 2003 to 2005 (1)

Location	Voltage (kV)	Lowest Switchgear Rating (kA) (2)	3 Phase (kA)			Single Phase (kA)		
			2003	2004	2005	2003	2004	2005
Baralaba	132.0	15.3	4.03	4.14	4.35	3.45	3.51	3.64
Biloela	132.0	12.3	5.54	7.48	8.64	4.98	6.45	7.28
Blackwater	132.0	12.3	3.26	3.48	3.53	3.87	4.14	4.33
Bouldercombe	275.0	31.5	16.18	16.19	16.35	15.81	15.82	15.93
Bouldercombe	132.0	25.0	10.11	10.11	10.20	11.49	11.49	11.57
Broadsound	275.0	21.9	8.94	9.01	9.06	6.34	6.65	6.68
Callemondah	132.0	31.5	20.36	20.43	20.77	20.74	20.56	20.80
Callide A Power Station (3)	132.0	12.3	10.60	10.58	10.00	10.43	10.42	11.06
Calvale	275.0	31.5	19.73	19.76	20.17	22.11	22.13	22.58
Calvale	132.0	NO CB	10.59	10.57	12.99	10.58	10.56	13.55
Dingo	132.0	31.5	2.20	2.26	2.30	2.43	2.48	2.52
Dysart	132.0	19.9	3.84	4.00	4.03	4.49	4.63	4.66
Egans Hill	132.0	NO CB	6.55	6.55	6.58	6.75	6.75	6.77
Gin Gin	275.0	31.5	10.21	10.23	10.27	8.18	8.19	8.20
Gin Gin	132.0	21.9	8.56	8.57	8.58	8.60	8.61	8.61
Gladstone	275.0	31.5	19.19	19.30	19.52	21.72	21.76	21.95
Gladstone (4)	132.0	31.5	25.81	25.94	26.39	31.41	31.55	32.00
Gladstone South	132.0	40.0	16.88	16.91	17.33	16.80	16.69	16.97
Grantleigh	132.0	31.5	2.44	2.44	2.45	2.55	2.55	2.55
Gregory	132.0	31.5	5.86	7.71	7.74	6.96	8.95	8.98
Korenan	132.0	31.5	2.39	2.39	2.39	1.65	1.65	1.65
Lilyvale	275.0	31.5	3.51	4.91	4.93	3.65	4.93	4.94
Lilyvale	132.0	25.0	6.06	8.04	8.08	7.33	9.58	9.62
Moura	132.0	12.3	3.57	3.75	3.97	3.89	4.04	4.22

Location	Voltage (kV)	Lowest Switchgear Rating (kA) (2)	3 Phase (kA)			Single Phase (kA)		
			2003	2004	2005	2003	2004	2005
Norwich Park	132.0	40.0	3.03	3.25	3.26	2.39	2.49	2.49
Rockhampton	132.0	12.3	6.62	6.62	6.65	6.96	6.96	6.98
Rocklands	132.0	40.0	6.19	6.19	6.22	5.57	5.58	5.59
Stanwell Switch Yard	275.0	31.5	17.33	17.36	17.52	19.03	19.06	19.20
Stanwell Switch Yard	132.0	31.5	4.97	4.97	4.99	4.63	4.63	4.64
Wurdong	275.0	31.5	15.47	15.53	15.70	14.85	14.87	14.98

Notes:

(1) Short circuit levels are estimated maximum levels assuming 110% of nominal voltage behind sub-transient reactance, neglecting loads, shunt admittances and other passive elements.

(2) Powerlink switchgear ratings – no account taken of distribution switchgear.

(3) Analysis for these locations allows for operation with open points to keep short circuit levels below switchgear ratings.

(4) The lowest rated circuit breaker(s) at these locations are required to interrupt short circuit current which is less than the maximum fault current and below the circuit breaker rating.

(5) Powerlink will undertake refurbishment to upgrade all necessary switchgear before the end of 2004.

Also note that:

(6) Fault level contributions to the Powerlink network from sugar mills, other than Invicta and Rocky Point, are not included in these tables.

(7) Fault level contributions to the Powerlink network from embedded non-scheduled generators, other than Bulwer Island (BIEP) and Queensland Nickel, are not included in these tables. Excluded generators include, but may not be limited to, Windy Hill wind generators, Wivenhoe small hydro generator, Stapylton biomass, and possible Moranbah coal seam methane gas turbines.

Table C3: Estimated Maximum Short Circuit Levels – Northern Queensland

In Powerlink Transmission Network 2003 to 2005 (1)

Location	Voltage (kV)	Lowest Switchgear Rating (kA) (2)	3 Phase (kA)			Single Phase (kA)		
			2003	2004	2005	2003	2004	2005
Alan Sherriff	132.0	31.5	8.33	9.51	9.67	8.48	10.54	10.77
Alligator Creek	132.0	31.5	3.42	3.42	3.51	3.94	3.96	4.05
Burton Downs	132.0	19.3	4.27	4.29	4.43	4.10	4.33	4.42
Cairns	132.0	12.1	4.99	4.96	4.94	6.41	6.50	6.47
Cardwell	132.0	19.3	2.64	2.64	2.63	2.09	2.10	2.13
Chalumbin	275.0	21.9	3.25	3.23	3.22	3.51	3.51	3.50
Chalumbin	132.0	31.5	6.33	6.30	6.28	7.33	7.32	7.29
Clare	132.0	8.8	6.32	6.23	6.23	6.03	6.00	5.98
Collinsville	132.0	15.3	10.92	10.81	10.82	12.01	11.97	11.97
Coppabella	132.0	31.5	2.72	2.73	2.77	3.08	3.09	3.13
Dan Gleeson	132.0	40.0	8.85	9.09	9.23	9.25	9.90	10.30
Edmonton	132.0	31.5	-	4.80	4.77	-	6.00	5.97
Garbutt (4)	132.0	8.8	9.28	8.83	8.97	9.85	9.58	9.76
Ingham	132.0	10.9	2.75	2.76	2.78	2.27	2.28	2.44
Innisfail	132.0	10.9	4.22	4.18	4.15	4.63	4.60	4.57
Invicta	132.0	16.2	4.82	4.67	4.66	4.38	4.34	4.32
Kamerunga	132.0	21.9	3.84	3.82	3.80	4.59	4.59	4.57
Kareeya	132.0	10.9	6.32	6.29	6.27	7.42	7.40	7.37
Kemmis	132.0	31.5	4.60	4.61	4.83	4.92	5.32	5.53
Mackay	132.0	21.9	4.51	4.50	4.62	5.10	5.18	5.28
Moranbah	132.0	15.3	5.29	5.35	5.48	6.37	6.44	6.56
Moranbah South	132.0	40.0	4.19	4.23	4.31	4.13	4.16	4.21
MT McLaren	132.0	31.5	1.82	1.83	1.84	2.02	2.03	2.03
Nebo	275.0	31.5	6.51	6.50	6.54	6.99	7.01	7.21
Nebo	132.0	21.9	8.32	8.32	9.43	9.34	9.43	10.87
Newlands	132.0	31.5	3.02	3.02	3.03	3.01	3.01	3.01
North Goonyella	132.0	19.3	3.07	3.09	3.11	2.42	2.42	2.43

Location	Voltage (kV)	Lowest Switchgear Rating (kA) (2)	3 Phase (kA)			Single Phase (kA)		
			2003	2004	2005	2003	2004	2005
Oonooie	132.0	31.5	2.56	2.56	2.61	3.02	3.02	3.07
Peak Downs	132.0	40.0	4.14	4.23	4.28	3.80	3.85	3.88
Pioneer Valley	132.0	40.0	4.12	4.12	4.24	4.18	4.70	4.80
Proserpine	132.0	19.7	3.38	3.37	3.38	3.65	3.65	3.65
Ross	275.0	21.9	5.18	5.13	5.17	6.01	6.00	6.03
Ross	132.0	31.5	11.14	11.03	11.23	12.77	12.80	12.99
Strathmore	275.0	50.0	5.66	5.61	5.62	5.19	5.08	5.08
Strathmore	132.0	31.5	10.39	10.24	10.25	10.69	10.69	10.68
Townsville South	132.0	21.9	11.08	10.78	10.99	13.59	13.47	13.65
Townsville GT PS	132.0	31.5	8.15	8.46	8.46	9.01	9.51	9.52
Tully	132.0	31.5	3.17	3.17	3.15	2.98	2.98	2.97
Turkinje	132.0	15.7	3.74	3.73	3.71	4.26	4.26	4.23
Wandoo	132.0	40.0	3.73	3.73	3.93	2.76	2.77	2.87
Woree	275.0	N0 CB	2.34	2.33	2.32	2.68	2.71	2.70
Woree	132.0	31.5	5.01	4.98	4.96	6.40	6.52	6.49

Notes:

(1) Short circuit levels are estimated maximum levels assuming 110% of nominal voltage behind sub-transient reactance, neglecting loads, shunt admittances and other passive elements.

(2) Powerlink switchgear ratings – no account taken of distribution switchgear.

(3) Analysis for these locations allows for operation with open points to keep short circuit levels below switchgear ratings.

(4) The lowest rated circuit breaker(s) at these locations are required to interrupt short circuit current which is less than the maximum fault current and below the circuit breaker rating.

(5) Powerlink will undertake refurbishment to upgrade all necessary switchgear before the end of 2004.

Also note that:

(6) Fault level contributions to the Powerlink network from sugar mills, other than Invicta and Rocky Point, are not included in these tables.

(7) Fault level contributions to the Powerlink network from embedded non-scheduled generators, other than Bulwer Island (BIEP) and Queensland Nickel, are not included in these tables. Excluded generators include, but may not be limited to, Windy Hill wind generators, Wivenhoe small hydro generator, Stapylton biomass, and possible Moranbah coal seam methane gas turbines.

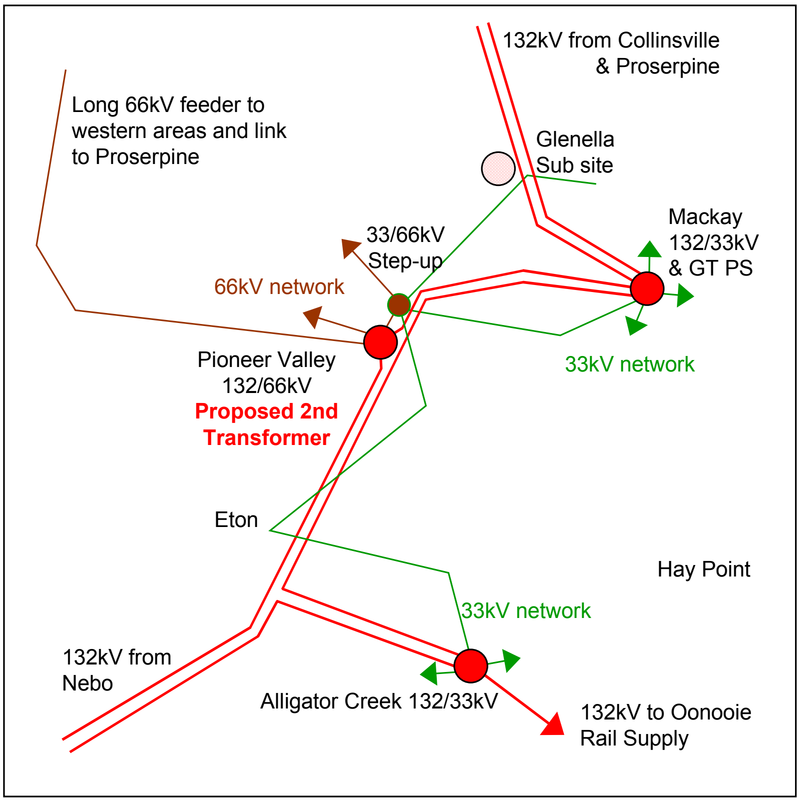
APPENDIX D: PROPOSED NEW SMALL NETWORK ASSETS

D.1 Pioneer Valley Transformer Reinforcement

Project Name: Pioneer Valley Transformer Reinforcement
Proposed Timing: October 2004
Estimated Cost: $3.5 million

Background
Load in the Mackay area is growing at 2% p.a. and has now reached 180MVA. This load is supplied from substations at Mackay, at Pioneer Valley (20km to the west of Mackay), at Alligator Creek (22km to the south of Mackay) and includes rail load at Oonooie (south of Alligator Creek). The network in this area is shown in Figure D1.

Figure D1: Pioneer Valley Transformer Reinforcement



Pioneer Valley substation is expected to supply an increasing proportion of this load in the future, due to substantial load growth in the areas to the west of Mackay. Pioneer Valley load is forecast to increase at 5% p.a.

Pioneer Valley substation supplies load via a single 132/66kV transformer. In the event of an outage of this single transformer, load is transferred to the adjacent 132/33kV substations at Mackay and Alligator Creek with a minor amount transferable at 66kV to Proserpine. However, the 33kV networks from Mackay and Alligator Creek and the 33/66kV step-up transformer substation near Pioneer Valley cannot support all Pioneer Valley 66kV load from 2004/05 onwards. Without corrective action Ergon Energy and

Powerlink will be unable to meet reliability obligations under a credible single contingency. The connection agreement between Powerlink and Ergon Energy includes obligations regarding the reliability of supply as required under Clause S5.1.2.2 of the National Electricity Code. Powerlink's transmission authority also includes reliability of supply obligations. Capacity to the Mackay area is required to be provided such that forecast peak demand can be supplied with the most critical element out of service, ie. N-1. For this reason, solutions to this emerging network limitation are classified as a reliability augmentation.

All regulated network augmentations are required to satisfy the Regulatory Test promulgated by the ACCC. For a reliability augmentation, this test requires that a proposed solution minimise the net present value cost of meeting objective performance standards compared with other feasible alternatives.

Powerlink has conducted a joint planning investigation with Ergon Energy to identify the minimum cost solution to augmenting the supply to the Mackay and Pioneer Valley area.

Network Options Considered

Option 1: Additional transformer at Pioneer Valley
A feasible network solution to the emerging supply limitation at Pioneer Valley and adjacent substations is to install a second 132/66kV transformer (80MVA) at the existing Pioneer Valley substation by October 2004 at a cost of $3.5 million.

Construction of this option will need to commence in September 2003 in order to meet the required commissioning date of October 2004.

Option 2: New substation at Glenella
A second network option which could address the emerging limitation is the establishment of a new 132/66kV substation at Glenella, approximately 7 kilometres north west of Mackay, by October 2004. The substation establishment would cost $5.4 million to Powerlink and $4.0 million to Ergon. Rebuilding of an existing 33kV feeder between Glenella and Pioneer Valley to 66kV would also be required at a cost to Ergon of $1.1M.

Construction of this option would need to commence in September 2003 in order to meet the required commissioning date of October 2004.

Other Options Considered
Reinforcement of the Mackay 132/33kV substation transformer capacity is not considered a viable option as the Mackay site has reached space and access limitations. In any case this option would also require new 33kV feeders to Pioneer Valley and substantial upgrade of 33/66kV step-up transformer capacity at Pioneer Valley. Accordingly, this option would be at substantially higher cost than Option 1 or Option 2.

For similar reasons an option to upgrade Alligator Creek 132/33kV substation, together with new 33kV feeders to Pioneer Valley and upgrade of 33/66kV step-up capacity, would be at much higher cost than Option 1 or Option 2.

Non-Network Options Considered
Powerlink and Ergon Energy are not aware of any demand side management initiatives, local generation development or other non-network solutions which could address the identified limitation.

The Mackay gas turbine supplies into the 33kV bus at Mackay and therefore cannot assist in supplying the load at risk during an outage of the Pioneer Valley transformer.

Summary of Options and Economic Analysis
Only two options are feasible ways of overcoming the supply limitations in the Mackay and Pioneer Valley area at reasonable cost by the required timing of October 2004. These are Option 1, the installation of an additional transformer at Pioneer Valley and Option 2, the establishment of a new substation at Glenella. The net present value cost of each of these options was calculated over a period of 15 years. The economic analysis is included in Table D3 and the outcome is summarised in Table D1 below.

Table D1: Summary of Economic Analysis for Medium Growth for Pioneer Valley Transformer Reinforcement

Options	Net Present Value Cost	Ranking
1. Additional transformer at Pioneer Valley	$2.2 million	1
2. New substation at Glenella	$6.6 million	2
3. Non-network options	N/A	N/A

No alternative market scenarios were considered in the financial analysis as the project is required to be in service in 2004 to meet forecast demand in the 2004/05 summer.

The sensitivity of the net present value calculations to key input variables such as the discount rate and capital costs (variation of ±10%) have been examined and the results are summarised in Table D2. Sensitivity to the commissioning date was not examined as both options are required to be in service by October 2004 to meet forecast peak load in the 2004/05 summer.

Table D2: Results of Sensitivity Analysis for Pioneer Valley Transformer Reinforcement

		Discount Rate					
		8%		10%		12%	
		Best ranked option	Frequency of wins	Best ranked option	Frequency of wins	Best ranked option	Frequency of wins
Scenario A	Medium Growth	1	100%	1	100%	1	100%

Option 1, the additional transformer at Pioneer Valley, minimises the net present value cost of addressing the supply limitation in the area and as such is considered to satisfy the Regulatory Test.

The project has no material impact on other transmission networks.

Recommendation
It is recommended that an additional 132/66kV transformer with 80MVA nameplate rating be installed at Pioneer Valley substation by November 2004 to address the emerging supply limitation in the area.

Table D3: Cash Flow for Pioneer Valley Transformer Reinforcement

SCENARIO A		**Medium Growth Forecast**														
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	($ millions)	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18
Option 1		***Additional Transformer at Pioneer Valley***														
TUOS		0.000	0.000	0.404	0.398	0.391	0.385	0.379	0.372	0.366	0.359	0.353	0.346	0.340	0.334	0.327
NPV of TUOS	$2.2															
Option 2		***New Substation at Glenella***														
TUOS		0.000	0.000	1.213	1.193	1.174	1.155	1.136	1.116	1.097	1.078	1.058	1.039	1.020	1.001	0.981
NPV of TUOS	$6.6															

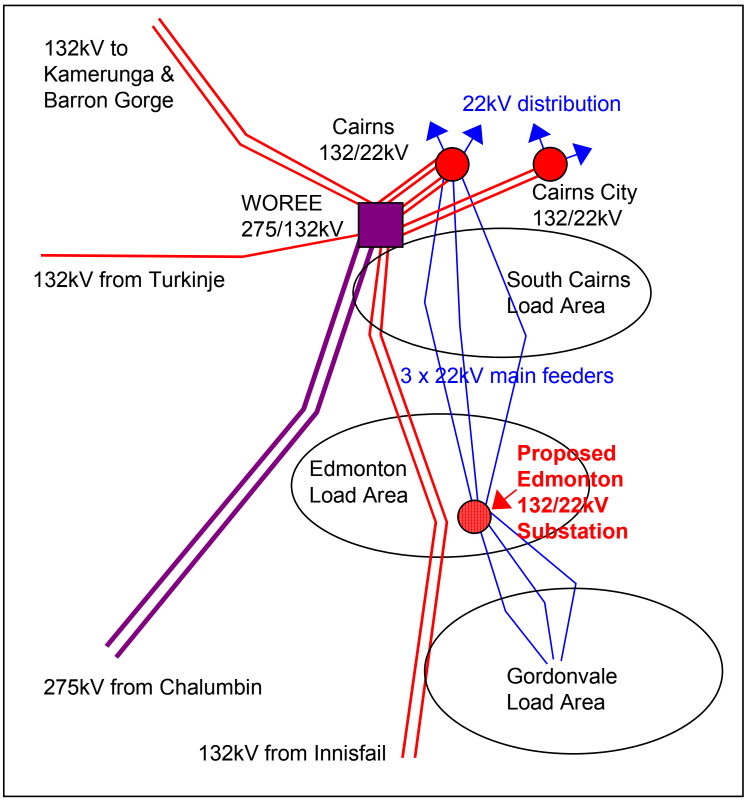
D.2 Edmonton Substation Establishment

Project Name: Edmonton Substation Establishment
Proposed Timing: October 2004
Estimated Cost: $8.5 million

Background
Load in the Cairns area is forecast to grow by 4% p.a. over the next five years including sustained growth in the suburban area to the south of the city between Cairns and Gordonvale.

Electricity supply to these areas to the south of Cairns is presently supplied from the Powerlink Queensland Cairns bulk supply substation via three Ergon Energy 22kV feeders between Cairns and the Gordonvale switching station, via a new 22kV switching station at Edmonton. Presently 11,000 customers with an aggregate demand of 25.5MW are supplied from these feeders. The majority of this load is in and around the Edmonton area. The supply arrangements are shown in Figure D2.

Figure D2: Edmonton Substation Establishment



The existing transmission and distribution system in the Cairns and Edmonton area is currently approaching both thermal and statutory voltage limits. Load growth forecasts predict that the voltage and plant thermal limitations will be exceeded by late 2004. Without corrective action Powerlink and Ergon Energy will be unable to maintain reliability of supply under some credible contingencies. The connection agreement between Powerlink and Ergon Energy includes obligations regarding the reliability of supply as required under Clause S5.1.2.2 of the National Electricity Code. Powerlink's transmission authority also includes reliability of supply obligations. Capacity to the

Cairns area is required to be provided such that forecast peak demand can be supplied with the most critical element out of service, ie. N-1. For this reason, solutions to this emerging network limitation are classified as a reliability augmentation.

All regulated network augmentations are required to satisfy the Regulatory Test promulgated by the ACCC. For a reliability augmentation, this test requires that a proposed solution minimise the net present value cost of meeting objective performance standards compared with other feasible alternatives.

Powerlink has conducted a joint planning investigation with Ergon Energy to identify the minimum cost solution to augmenting the supply to the Edmonton area.

Network Options Considered

Option 1: Staged installation of two transformers at Edmonton

A feasible network solution to the emerging supply limitations at Edmonton is the establishment of a bulk supply point and installation of a single 50MVA 132/22kV transformer at the Edmonton 22kV switching station by November 2004. The existing 132kV network will need to be extended approximately 1.7 kilometres from the Woree-Innisfail transmission line to Edmonton and a 132kV switchyard established at the Edmonton site. A second 132/22kV 50MVA transformer would need to be installed by November 2006.

Works would be required in the 22kV network to maintain operation of the load control system.

Additional works would be required in the 22kV network to facilitate supply restoration in the event of the loss of the single Edmonton transformer.

The capital cost of this option is $7.2 million to Powerlink and $0.7 million to Ergon in 2004/05, and an additional $1.4 million to Powerlink and $0.1 million to Ergon in 2006/07.

Construction of this option will need to commence in September 2003 in order to meet the required commissioning date of November 2004.

Option 2: Simultaneous installation of two transformers at Edmonton

This option is similar to Option 1 except that the second 50MVA transformer would be installed at the same time as the first transformer by November 2004. The 132kV feeder and substation works are the same as for Option 1.

No additional works would be required in the 22kV network to facilitate supply restoration in the event of the loss of the single Edmonton transformer as two transformers will be installed at the same time.

The capital cost of this option is $8.5 million to Powerlink and $0.6 million to Ergon in 2004/05.

Construction of this option will need to commence in September 2003 in order to meet the required commissioning date of November 2004.

Option 3: Installation of additional transformer at Cairns

This option involves installing an additional (fourth) 50MVA transformer at Cairns and rebuilding the three 22kV feeders from Cairns to Edmonton switching station with higher capacity conductor by November 2004.

Rebuilding the 22kV feeders would only enable a relatively minor increase in capacity to the area and accordingly, this option will require further corrective action to address the emerging network limitations in the area. Anticipated projects required to maintain supply reliability include a 132/22kV connection with a single 50MVA transformer at Edmonton by November 2008, with a second 50MVA transformer required by 2010.

The capital cost of this option is $5.0 million.

The capital cost of the anticipated future projects is $6.8 million in 2008/09 for the 132/22kV connection with a single 50MVA transformer at Edmonton and $1.5 million in 2010/11 for a second 50MVA transformer.

Construction of this option will need to commence in September 2003 in order to meet the required commissioning date of November 2004.

Other Options Considered

The alternative of establishing the 132/22kV substation near the Gordonvale 22kV switching station rather than at Edmonton would be more expensive since the distance from the existing 132kV Woree-Innisfail feeder is much greater. In addition the main load centre surrounds the Edmonton area and not Gordonvale, thus the network losses would be higher. Accordingly, this alternative was not considered further.

Non-Network Options Considered

Powerlink and Ergon are not aware of any demand side management initiatives, local generation developments or other non-network solutions which could address the identified limitation. It is assumed that Ergon's existing load control system will continue in operation but the effect of this system is already incorporated in demand forecasts.

Summary of Options and Economic Analysis

There are three options which are feasible ways of overcoming the supply limitations in the area south of Cairns. The net present value cost of each of these options was calculated over a period of 15 years. The outcome associated with these options for the medium growth forecast is summarised in the table below.

Table D4: Summary of Economic Analysis for Medium Growth for Edmonton Substation Establishment

Options	Net Present Value Cost	Ranking
1. Staged installation of two transformers at Edmonton	$5.7 million	1=
2. Simultaneous installation of two transformers at Edmonton	$5.7 million	1=
3. Installation of additional transformer at Cairns	$5.9 million	3
4. Non-network options	N/A	N/A

High and low demand growth scenarios were also considered. There are bagasse fuelled generators to the south of Cairns associated with sugar mills but these generators are embedded in the distribution network and their output is already accounted for in the demand forecasts underlying this analysis. Apart from bagasse there are no fuel supplies in the Cairns area, which can be expected to support a new generator in that area in the foreseeable future. As a result no generation investments were considered in formulating scenarios for the economic analysis.

Detailed economic analysis and the results of these scenarios are shown in Tables D5 and D7.

Table D5: Summary of NPV Analysis and Ranking for Edmonton Substation Establishment

		Option One		Option Two		Option Three	
		NPV $millions	Ranking	NPV $millions	Ranking	NPV $millions	Ranking
Scenario A	Medium Growth	5.7	1=	5.7	1=	5.9	3
Scenario B	High Growth	5.8	2	5.7	1	6.0	3
Scenario C	Low Growth	5.6	2	5.7	3	5.4	1

The sensitivity of the net present value calculations to key input variables such as the discount rate and capital costs (variations by ±10%) have been examined and the results are summarised in Table D6. Sensitivity to the commissioning date was not examined as the initial stage of all three options is required to be in service by November 2004 to meet forecast peak load in the 2004/05 summer.

Table D6: Results of Sensitivity Analysis for Edmonton Substation Establishment

		Discount Rate					
		8%		10%		12%	
		Best ranked option	Frequency of wins	Best ranked option	Frequency of wins	Best ranked option	Frequency of wins
Scenario A	Medium Growth	1	100%	2	100%	2	100%
Scenario B	High Growth	2	100%	2	100%	2	100%
Scenario C	Low Growth	3	100%	3	100%	3	100%

The result of the net present value analysis is that Option 2 involving the establishment of a 132/22kV substation at Edmonton in 2004 minimises the net present value cost of addressing the supply limitation in the area, in the majority of scenarios, and as such is considered to satisfy the Regulatory Test.

This project has no material impact on other transmission networks.

Recommendation
It is recommended that a 132/22kV substation with two 50MVA transformers be established at Edmonton by November 2004, to address 22kV network supply limitations to the south of Cairns.

Table D7: Cash Flow for Edmonton Substation Establishment

SCENARIO A - Medium Growth Forecast

	($ millions)	1 2003/04	2 2004/05	3 2005/06	4 2006/07	5 2007/08	6 2008/09	7 2009/10	8 2010/11	9 2011/12	10 2012/13	11 2013/14	12 2014/15	13 2015/16	14 2016/17	15 2017/18
Option 1		***Staged installation of two transformers at Edmonton***														
TUOS		0.000	0.000	0.912	0.898	1.057	1.039	1.022	1.005	0.988	0.970	0.953	0.936	0.918	0.901	0.884
NPV of TUOS	$5.7															
Option 2		***Simultaneous installation of two transformers at Edmonton***														
TUOS		0.000	0.000	1.051	1.034	1.018	1.001	0.984	0.967	0.951	0.934	0.917	0.901	0.884	0.867	0.850
NPV of TUOS	$5.7															
Option 3		***Installation of additional transformer at Cairns***														
TUOS		0.000	0.000	0.572	0.563	0.554	0.544	1.267	1.247	1.384	1.361	1.338	1.314	1.291	1.268	1.245
NPV of TUOS	$5.9															

SCENARIO B - High Growth Forecast

	($ millions)	1 2003/04	2 2004/05	3 2005/06	4 2006/07	5 2007/08	6 2008/09	7 2009/10	8 2010/11	9 2011/12	10 2012/13	11 2013/14	12 2014/15	13 2015/16	14 2016/17	15 2017/18
Option 1		***Staged installation of two transformers at Edmonton***														
TUOS		0.000	0.000	0.912	1.071	1.054	1.037	1.019	1.002	0.985	0.968	0.950	0.933	0.916	0.898	0.881
NPV of TUOS	$5.8															
Option 2		***Simultaneous installation of two transformers at Edmonton***														
TUOS		0.000	0.000	1.051	1.034	1.018	1.001	0.984	0.967	0.951	0.934	0.917	0.901	0.884	0.867	0.850
NPV of TUOS	$5.7															
Option 3		***Installation of additional transformer at Cairns***														
TUOS		0.000	0.000	0.583	0.574	0.565	0.555	1.326	1.477	1.453	1.428	1.404	1.380	1.355	1.331	1.306
NPV of TUOS	$6.0															

SCENARIO C - Low Growth Forecast

	($ millions)	1 2003/04	2 2004/05	3 2005/06	4 2006/07	5 2007/08	6 2008/09	7 2009/10	8 2010/11	9 2011/12	10 2012/13	11 2013/14	12 2014/15	13 2015/16	14 2016/17	15 2017/18
Option 1		***Staged installation of two transformers at Edmonton***														
TUOS		0.000	0.000	0.912	0.898	0.883	1.042	1.025	1.008	0.990	0.973	0.956	0.939	0.921	0.904	0.887
NPV of TUOS	$5.6															
Option 2		***Simultaneous installation of two transformers at Edmonton***														
TUOS		0.000	0.000	1.051	1.034	1.018	1.001	0.984	0.967	0.951	0.934	0.917	0.901	0.884	0.867	0.850
NPV of TUOS	$5.7															
Option 3		***Installation of additional transformer at Cairns***														
TUOS		0.000	0.000	0.583	0.574	0.565	0.555	0.546	1.317	1.295	1.273	1.425	1.400	1.376	1.351	1.327
NPV of TUOS	$5.4															

D.3 *Loganlea 275/110kV Transformer Augmentation*

Project Name: Loganlea 275/110kV Transformer Augmentation
Proposed Timing: October 2004
Estimated Cost: $5.7 million

Background
The Belmont and Loganlea 275/110kV substations provide electricity supply at 110kV to the south east area of Brisbane. This covers an area from the Brisbane River between Woolloongabba and the river mouth to Beenleigh in the south. It also extends across the river into Fortitude Valley, Newstead, Bowen Hills and surrounding suburbs. The area is supplied by four 275/110kV transformers at Belmont substation (2 x 250MVA, 2 x 200MVA) and one 375MVA 275/110kV transformer at Loganlea substation.

Planning studies show that the Belmont transformers are forecast to overload in the summer of 2004/05 in the event of loss of the single Loganlea transformer. Anticipated transformer loadings at Belmont substation over the coming years for peak demand are detailed in the following table.

	Transformer Rating	2003/04 MVA	2004/05 MVA	2005/06 MVA	2006/07 MVA
Loss of Loganlea transformer	275MVA (emergency)	262	287	312	315

Without corrective action Powerlink will be unable to maintain reliability of supply under some credible contingencies. The connection agreement between Powerlink and Energex includes obligations regarding the reliability of supply as required under Clause S5.1.2.2 of the National Electricity Code. Powerlink's transmission authority also includes reliability of supply obligations. Capacity to the Brisbane area is required to be provided such that forecast peak demand can be supplied with the most critical element out of service, ie. N-1. For this reason, solutions to this emerging network limitation are classified as a reliability augmentation.

All regulated network augmentations are required to satisfy the Regulatory Test promulgated by the ACCC. For a reliability augmentation, this test requires that a proposed solution minimise the net present value cost of meeting objective performance standards compared with other feasible alternatives.

Network Options Considered

Option 1: Loganlea 275/110kV Transformer Augmentation
A feasible option is the installation of a second 275/110kV transformer at Loganlea. Space allowance was made for installation of a second transformer at this site during its establishment.

Estimated cost for provision of a second 375MVA 275/110kV transformer, including associated 275kV and 110kV switchgear, is $5.7 million.

Construction of this option will need to commence in September 2003 in order to meet the required commissioning date of October 2004.

Option 2: Establishment of a new 275/110kV Substation
For comparison purposes a new 275/110kV substation with one 375MVA transformer established in a suitable location where minimum lineworks (at 275kV or 110kV) were required would cost at least $12.9 million.

Construction of such an option would need to commence immediately in order to meet the required commissioning date of October 2004.

Other Options Considered
Addition of a fifth transformer at Belmont was not considered feasible because the Belmont substation does not have sufficient space to allow connection of an additional transformer, along with the necessary switchgear. In addition, the impact on equipment fault ratings would necessitate 110kV plant replacement at Belmont and adjacent substations. For these reasons this option was not considered further.

Non-Network Options Considered
Powerlink is not aware of any demand side management initiatives, local generation developments or other non-network solutions which could address the identified limitation. It is assumed that Energex's existing load control system will continue in operation but the effect of this system is already incorporated in the demand forecasts.

Summary of Options and Economic Analysis
There are two options, which are feasible ways of overcoming the supply limitations in the south eastern area of Brisbane. The net present value cost of each of these options was calculated over a period of 15 years. The results of this economic analysis are included in Table D10 and is summarised in Table D8 below for the medium growth forecast.

Table D8: Summary of Economic Analysis for Medium Growth for Loganlea 275/110kV Transformer Augmentation

Options	Net Present Value Cost	Ranking
1. Loganlea 275/110kV Transformer Augmentation	$3.6 million	1
2. Establishment of a new 275/110kV substation	$8.1 million	2
3. Non-network options	N/A	N/A

No alternative market scenarios were considered in the financial analysis as the project is required to be in service in 2004 to meet forecast demand in the 2004/05 summer.

The sensitivity of the net present value calculations to key input variables such as the discount rate and capital costs (variation ±10%) have been examined and the results are summarised in Table D9.

Table D9: Results of Sensitivity Analysis for Loganlea 275/110kV Transformer Augmentation

		Discount Rate					
		8%		10%		12%	
		Best ranked option	Frequency of wins	Best ranked option	Frequency of wins	Best ranked option	Frequency of wins
Scenario A	Medium Growth	1	100%	1	100%	1	100%

The Loganlea 275/110kV Transformer Augmentation minimises the net present value cost of addressing the supply limitation in the area and as such is considered to satisfy the Regulatory Test.

This project has no material impact on other transmission networks.

Recommendation

It is recommended that a second 375MVA 275/110kV transformer, including associated 275kV and 110kV switchgear be installed at Loganlea by October 2004, to address supply limitations in the south of Brisbane.

Table D10: Cash Flow for Loganlea 275/110kV Transformer Augmentation

SCENARIO A - Medium Growth Forecast																
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	($ millions)	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18
Option 1		***Loganlea 275/110kV Transformer Augmentation***														
TUOS		0.000	0.000	0.657	0.646	0.636	0.625	0.615	0.604	0.594	0.584	0.573	0.563	0.552	0.542	0.531
NPV of TUOS	$3.6															
Option 2		***Establishment of a new 275/110kV substation***														
TUOS		0.000	0.000	1.488	1.465	1.441	1.417	1.394	1.370	1.346	1.323	1.299	1.275	1.252	1.228	1.204
NPV of TUOS	$8.1															

D.4 Rockhampton 40MVAr, 132kV Shunt Capacitor Bank

Project Name: Rockhampton 40MVAr, 132kV Shunt Capacitor Bank
Proposed Timing: October 2005
Estimated Cost: $1 million

Background
The City of Rockhampton, the Capricorn Coast and surrounding rural towns are supplied from the Rockhampton and Egans Hill substations. These in turn are supplied from Bouldercombe substation via one transmission circuit to Egans Hill and two circuits to Rockhampton. The electrical loading for Rockhampton is forecast to grow at an average of 2.7% p.a. over the next five years. This load growth means that from late 2005 onwards, an outage of one of the Bouldercombe to Rockhampton circuits will cause flow on the remaining circuit to exceed its summer emergency rating of 115MVA. The table below shows the forecast line loadings. Feeder overloads may occur during contingencies from 2004/05 onwards. Ergon Energy have advised that they can manage the overloads via operational strategies for the 2004/05 summer only. Therefore, the timing for corrective action is prior to the summer 2005/06.

	2003/04 (MVA)	2004/05 (MVA)	2005/06 (MVA)	2006/07 (MVA)	2007/08 (MVA)	2008/09 (MVA)
Bouldercombe-Rockhampton circuit power flow for one line out of service	113	122	127	135	142	145

Higher transmission line loading produces greater reactive power losses, increasing the need for additional capacity. Powerlink assumes connected parties will meet their power factor requirements in the Code. In addition, the analysis conducted assumes that existing levels of reactive support continue to be provided by generators, either under their code obligations or as ancillary services under contract to NEMMCO. The net effect of this is a requirement to increase reactive capability in the Rockhampton area.

The Connection Agreement between Powerlink and Ergon Energy includes obligations regarding reliability of supply as required under Clause S5.1.2.2 of the National Electricity Code. Powerlink's transmission authority also includes reliability of supply obligations. Capacity must be provided to the Rockhampton area such that forecast peak demand can be supplied with the most critical element out of service, ie. N-1. Without corrective action, Powerlink will be unable to meet these obligations. Therefore the proposed solution is classified as a reliability augmentation.

All regulated network augmentations are required to satisfy the Regulatory Test promulgated by the ACCC. For a reliability augmentation, this test requires that a proposed solution minimise the net present value cost of meeting objective performance standards compared with other feasible alternatives.

Network Options Considered

Option 1: Capacitor Bank
Option 1 is for Powerlink to install a 40MVAr 132kV shunt capacitor bank at Rockhampton by late 2005. This is the maximum that can be installed on the Rockhampton 132kV bus without violating the maximum voltage fluctuation levels

required by the Code when the capacitor bank is switched in or out. It is envisaged that the capacitor bank would be switched in and out once or twice per day.

Option 1 will reduce loading on the Bouldercombe-Rockhampton line but further corrective action to address the emerging network limitations in the area will be required in future. Anticipated projects to maintain supply reliability include the installation by Ergon Energy of an additional 20MVAr reactive plant in the Ergon distribution network in late 2006. By late 2008, the transmission line loading will again exceed the rating on the Bouldercombe to Rockhampton feeders and at this time, a new 132kV transmission line from Bouldercombe to Pandoin is anticipated to be required.

The capital cost of this option is $1.0 million to Powerlink.

The anticipated capacitor banks in 2006 to be installed by Ergon will cost $1.2 million. The capital cost of the anticipated line project in 2008 is $16 million to Powerlink and $2 million to Ergon.

Construction of this augmentation would be scheduled to commence in December 2003 to meet the required commissioning date of October 2005.

Option 2: Advance Construction of 132kV Line
The emerging limitation can be addressed by advancing construction of a new 132kV transmission line between Bouldercombe and Pandoin, near Rockhampton (approximately 40km) to late 2005/06.

The capital cost of this option is $16 million to Powerlink and $2 million to Ergon. Cost of the transmission line includes a 132/66kV transformer and switchgear at Pandoin.

Construction of this augmentation would be scheduled to commence in September 2003 in order to meet the required commissioning date of October 2005.

Option 3: SVC
A further network option, which could feasibly address the emerging network limitation is the installation of a 132kV static var compensator (SVC) at Rockhampton by late 2005. The SVC would need to have a reactive range of 0 +60MVAr to achieve the same benefits as the capacitor banks described in Option 1. As for Option 1, by late 2008 the transmission line loading will exceed the rating on the Bouldercombe to Rockhampton feeders and at this time, a new Bouldercombe to Pandoin 132kV feeder is anticipated to be required.

The capital cost of this option is $8.5 million. The capital costs of the anticipated line project in 2008 are $16 million to Powerlink and $2 million to Ergon.

Construction of this augmentation would be scheduled to commence in December 2003 to meet the required commissioning date of October 2005.

Option 4: Customer-connected Capacitor Banks
It would be feasible that customers in the Rockhampton area could install capacitor banks to overcome the network loading limitations. However, Powerlink and Ergon Energy have no knowledge of any proposals for such customer-connected capacitor banks to be installed.

Option 5: Uprate the Existing Bouldercombe to Rockhampton Feeders
Another option to address the Bouldercombe to Rockhampton line overloading is to uprate the existing double circuit lines. This will involve taking both circuits out of service for an extended period during construction of new towers to raise the conductor height. This is not feasible, as the Rockhampton area would be supplied via the Egans Hill feeder only during this time, and loss of this would result in complete loss of supply to the Rockhampton area.

Non-Network Options Considered
Powerlink is not aware of any demand side management initiatives, local generation developments or other non-network solutions, which could address the identified limitation by the required timing of October 2005.

Summary of Options and Economic Analysis
There are three feasible options that are capable of overcoming the transmission line overload limitations in the Rockhampton area by the required timing of October 2005. The net present value cost of each of these options was calculated over a period of 15 years. The economic analysis is included in Table D14. The costs and outcomes associated with these options for the medium growth forecast are summarised in Table D11 below.

Table D11: Summary of Economic Analysis for Medium Growth for Rockhampton 40MVAr 132kV Shunt Capacitor Bank

Options	Net Present Value Cost	Ranking
1. Rockhampton Capacitor Bank	$7.5 million	1
2. Advancement of Bouldercombe-Pandoin 132kV line	$9.9 million	2
3. Rockhampton SVC	$11.1 million	3
4. Customer connected capacitor banks	N/A	N/A
5. Uprate existing Bouldercombe to Rockhampton feeders	N/A	N/A
6. Non-network options	N/A	N/A

A range of market scenarios were also considered including demand growth at rates associated with high and low range estimates of economic growth rates in Australia. Economic analysis is in Table D14 and the results of these scenarios are summarised in Table D12. The possible introduction of coal seam methane generation in the Rockhampton area is expected to produce similar results as low demand growth rates. As a result, no generation investments were considered in formulating scenarios for the economic analysis.

Table D12: Summary of NPV Analysis and Ranking for Rockhampton 40MVAr 132kV Shunt Capacitor Bank

		Option One		Option Two		Option Three	
		NPV $millions	Ranking	NPV $millions	Ranking	NPV $millions	Ranking
Scenario A	Medium Growth	7.5	1	9.9	2	11.1	3
Scenario B	High Growth	8.7	1	9.9	2	12.1	3
Scenario C	Low Growth	6.5	1	9.9	2	10.1	3

The sensitivity of the net present value calculations to key input variables such as the discount rate and capital costs (variation of ±10%) have been examined and the results are summarised in Table D13. Sensitivity to the commissioning date was not examined, as the initial stage of all three options is required to be in service by October 2005 to meet forecast peak load in the 2005/06 summer.

Table D13: Results of Sensitivity Analysis for Rockhampton 40MVAr 132kV Shunt Capacitor Bank

		Discount Rate					
		8%		10%		12%	
		Best ranked option	Frequency of wins	Best ranked option	Frequency of wins	Best ranked option	Frequency of wins
Scenario A	Medium Growth	1	100%	1	100%	1	100%
Scenario B	High Growth	1	100%	1	100%	1	100%
Scenario C	Low Growth	1	100%	1	100%	1	100%

The result of the analysis is that Option 1, the installation of new capacitor banks in the Rockhampton area minimises the net present value cost of addressing the network limitation in all cases, and as such is considered to satisfy the Regulatory Test.

This project has no material impact on other transmission networks.

Recommendation

It is recommended that 40MVAr of shunt capacitance be installed into the Rockhampton area 132kV network by October 2005, to address the transmission overload limitations in the area.

Table D14: Cash Flow for Rockhampton Capacitor Bank

SCENARIO A - Medium Growth Forecast

		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	($ millions)	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18
Option 1		***Capacitor banks***														
TUOS		0.000	0.000	0.000	0.120	0.257	0.253	2.328	2.291	2.253	2.216	2.179	2.142	2.105	2.067	2.030
NPV of TUOS	$7.5															
Option 2		***Advance construction of 132kV Line***														
TUOS		0.000	0.000	0.000	2.079	2.046	2.013	1.980	1.947	1.914	1.881	1.847	1.814	1.781	1.748	1.715
NPV of TUOS	$9.9															
Option 3		***SVC***														
TUOS		0.000	0.000	0.000	0.982	0.966	0.951	3.014	2.965	2.917	2.868	2.819	2.770	2.722	2.673	2.624
NPV of TUOS	$11.1															

SCENARIO B - High Growth Forecast

		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	($ millions)	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18
Option 1		***Capacitor banks***														
TUOS		0.000	0.000	0.000	0.259	0.255	2.330	2.293	2.255	2.218	2.181	2.144	2.107	2.069	2.032	1.995
NPV of TUOS	$8.7															
Option 2		***Advance construction of 132kV Line***														
TUOS		0.000	0.000	0.000	2.079	2.046	2.013	1.980	1.947	1.914	1.881	1.847	1.814	1.781	1.748	1.715
NPV of TUOS	$9.9															
Option 3		***SVC***														
TUOS		0.000	0.000	0.000	0.982	0.966	3.030	2.981	2.932	2.883	2.835	2.786	2.737	2.689	2.640	2.591
NPV of TUOS	$12.1															

SCENARIO C - Low Growth Forecast

		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	($ millions)	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18
Option 1		***Capacitor banks***														
TUOS		0.000	0.000	0.000	0.120	0.118	0.255	0.251	2.326	2.289	2.251	2.214	2.177	2.140	2.103	2.066
NPV of TUOS	$6.5															
Option 2		***Advance construction of 132kV Line***														
TUOS		0.000	0.000	0.000	2.079	2.046	2.013	1.980	1.947	1.914	1.881	1.847	1.814	1.781	1.748	1.715
NPV of TUOS	$9.9															
Option 3		***SVC***														
TUOS		0.000	0.000	0.000	0.982	0.966	0.951	0.935	2.998	2.950	2.901	2.852	2.804	2.755	2.706	2.657
NPV of TUOS	$10.1															

D.5 Shunt Capacitor Banks for South East Queensland

Project Name: Shunt Capacitor Banks for South East Queensland
Proposed Timing: October 2004 and October 2005
Estimated Cost: $4.2 million

Background
The load in south east Queensland has been growing at around 5% p.a. and is expected to increase at a higher rate of 6 to 7% p.a. for the next 3 years. The table below shows the expected local area peak demand growth for south east Queensland over the next three years based on the 2003 medium growth forecast. This load growth forecast is higher than the equivalent 2002 forecast.

	2003/04	2004/05	2005/06
SEQ Load Growth MW (p.a.)	222	255	229
Corresponding additional MVAr requirement (due to load growth only)	111	128	115

This forecast growth assumes that connected parties will meet their power factor requirements in the Code. In addition, the analysis conducted assumes that existing levels of reactive support continue to be provided by generators, either under their code obligations or as ancillary services under contract to NEMMCO.

The following table shows the additional reactive demand for the 2003 forecast, above that included in the 2002 forecast. These levels are due to load growth only. Additional reactive support above these levels would be required to compensate for reactive power losses in the transmission system due to increased transmission line loading.

	2003/04	2004/05	2005/06
Additional reactive demand (MVAr) expected for SEQ above the 2002 forecast (due to load growth only)	25	36	23

The net effect of this is a requirement to increase reactive capability in south east Queensland over the next two years. In Powerlink's 2002 Annual Planning Report, the need for additional reactive support in south east Queensland was identified. A new 120MVAr shunt capacitor bank was planned for Mt England to be commissioned by October 2004. It is proposed to advance the committed capacitor bank at Mt England to target commissioning in December 2003 to help meet the increased load growth identified in the 2003 load forecast. However, additional reactive capability will be required to meet reactive demand requirements in 2004 and 2005 (no new network assets have previously been proposed to address the forecast 115MVAr south east Queensland reactive demand in 2005).

Powerlink is required to take action to keep pace with growing reactive power demand. In particular, the voltage stability criteria outlined in Clause S5.1.8 of the National Electricity Code requires '*that an adequate reactive power margin must be maintained at every connection point in a network with respect to the voltage stability limit as determined from the voltage/reactive load characteristic at that connection point*'. In line with this requirement, a reactive margin of 1% of the maximum fault level (in MVA) at each connection point is required.

In addition, the Connection Agreement between Powerlink and Energex includes obligations regarding reliability of supply as required under Clause S5.1.2.2 of the National Electricity Code. Powerlink's transmission authority also includes reliability of supply obligations. Voltage support must be provided in south east Queensland such that forecast peak demand can be supplied with the most critical element out of service, ie. N-1.

Without corrective action, Powerlink will be unable to meet these obligations. Therefore the proposed solution is classified as a reliability augmentation.

All regulated network augmentations are required to satisfy the Regulatory Test promulgated by the ACCC. For a reliability augmentation, this test requires that a proposed solution minimise the net present value cost of meeting objective performance standards compared with other feasible alternatives.

Network Options Considered

Planning studies have shown the above criteria can be met in 2004 and 2005 by the addition of 200MVAr of reactive capacity (provided it is distributed to support connection points throughout south east Queensland) based on the most critical transmission contingency.

Option 1: Capacitor Banks

Option 1 is to install shunt capacitor banks throughout the south east Queensland network to meet the increased reactive demand for 2004 and 2005. Sites have been chosen as those most effective with available space in the substations to accommodate a new capacitor bank.

2004 – Molendinar Capacitor Bank

A 50MVAr, 110kV shunt capacitor bank is proposed to be installed at Molendinar substation by October 2004 to meet the increased reactive demand identified for 2003/04 in Powerlink's 2003 load forecast.

The capital cost of this capacitor bank is $1.0 million.

Construction of this augmentation would be scheduled to commence in August 2003 to meet the required commissioning date of October 2004.

2005 – Ashgrove West & Murarrie Capacitor Banks

An additional 115MVAr reactive capacity is required in south east Queensland in 2005. This is due to load growth alone, so the actual reactive requirement allowing for reactive power losses will be even higher.

A 50MVAr, 110kV shunt capacitor bank is proposed to be installed at Ashgrove West substation by October 2005. The capital cost of this capacitor bank is $1.1 million.

In addition, two 50MVAr, 110kV shunt capacitor banks are proposed for installation at Murarrie substation by October 2005. The capital cost of the two capacitor banks is $2.1 million.

Construction of the Ashgrove West and Murarrie capacitor banks would be scheduled to commence in December 2003 to meet the required commissioning date of October 2005.

The total capital cost of the shunt capacitors to meet the reactive capacity demand in south east Queensland over 2004 and 2005 is $4.2 million.

Option 2: SVC
The increased reactive demand could also be met by the installation of a static var compensator (SVC) in the south east Queensland network by late 2004. The SVC would need to have a reactive range of 0 +200MVAr to achieve the same benefits as the capacitor banks described in option 1.

The capital cost of this option is $11 million.

Construction of this augmentation would be scheduled to commence in August 2003 to meet the required commissioning date of October 2004.

Option 3: Customer Connected Capacitor Banks
It would be feasible that customers in the south east Queensland area could install capacitor banks to overcome the network loading limitations. However, Powerlink has no knowledge of any proposals for such customer-connected capacitor banks to be installed.

Non-Network Options Considered
Powerlink is not aware of any demand side management initiatives, local generation developments or other non-network solutions that could address the identified limitations by the required timings of October 2004 and October 2005.

Summary of Options and Economic Analysis
There are two feasible options that are capable of supplying the additional reactive demand in south east Queensland by the required timings of October 2004 and October 2005. The net present value cost of each of these options was calculated over a period of 15 years. The economic analysis is included in Table D18. The costs and outcomes associated with these options for the medium growth forecast are summarised in Table D15.

Table D15: Summary of Economic Analysis for Medium Growth for Shunt Capacitor Banks for South East Queensland

Options	Net Present Value Cost	Ranking
1. Shunt capacitor banks	$2.4 million	1
2. SVC	$6.9 million	2
3. Customer connected capacitor bank	N/A	N/A
4. Non-network options	N/A	N/A

A range of market scenarios was also considered including demand growth at rates associated with high and low range estimates of economic growth rates in Australia. Economic analysis and the results of these scenarios are in Tables D16 and D18. The possible introduction of new generation in south east Queensland is expected to produce similar results as low demand growth rates. As a result, no generation investments were considered in formulating scenarios for the economic analysis.

Table D16: Summary of NPV Analysis and Ranking for Shunt Capacitor Banks for South East Queensland

		Option one		Option two	
		NPV $millions	Ranking	NPV $millions	Ranking
Scenario A	Medium Growth	2.4	1	6.9	2
Scenario B	High Growth	2.8	1	6.9	2
Scenario C	Low Growth	2.1	1	6.9	2

The sensitivity of the net present value calculations to key input variables such as the discount rate and capital (variation of $\pm$10%) costs have been examined and the results are summarised in Table D17. Sensitivity to the commissioning date was not examined, as the initial stage of all three options is required to be in service by October 2004 to meet forecast peak load in the 2004/05 summer.

Table D17: Results of Sensitivity Analysis for Shunt Capacitor Banks for South East Queensland

		Discount Rate					
		8%		10%		12%	
		Best ranked option	Frequency of wins	Best ranked option	Frequency of wins	Best ranked option	Frequency of wins
Scenario A	Medium Growth	1	100%	1	100%	1	100%
Scenario B	High Growth	1	100%	1	100%	1	100%
Scenario C	Low Growth	1	100%	1	100%	1	100%

The result of the analysis is that option 1, the installation of various capacitor banks throughout south east Queensland, minimises the net present value cost of addressing the network limitation in all cases, and as such is considered to satisfy the Regulatory Test.

This project has no material impact on other transmission networks.

Recommendation
It is recommended that a 50MVAr 110kV capacitor bank at Molendinar be implemented by October 2004. In addition, a 50MVAr 110kV capacitor bank at Ashgrove West and two 50MVAr 110kV capacitor banks at Murarrie substations be implemented by October 2005, to meet the increased reactive demand in south east Queensland.

Table D18: Cash Flow for Shunt Capacitor Banks for South East Queensland

SCENARIO A - Medium Growth Forecast

	($ millions)	1 2003/04	2 2004/05	3 2005/06	4 2006/07	5 2007/08	6 2008/09	7 2009/10	8 2010/11	9 2011/12	10 2012/13	11 2013/14	12 2014/15	13 2015/16	14 2016/17	15 2017/18
Option 1		***Capacitor banks***														
TUOS		0.000	0.000	0.119	0.477	0.470	0.462	0.454	0.447	0.439	0.431	0.424	0.416	0.409	0.401	0.393
NPV of TUOS	$2.4															
Option 2		***SVC***														
TUOS		0.000	0.000	1.271	1.250	1.230	1.210	1.190	1.169	1.149	1.129	1.109	1.089	1.068	1.048	1.028
NPV of TUOS	$6.9															

SCENARIO B - High Growth Forecast

	($ millions)	1 2003/04	2 2004/05	3 2005/06	4 2006/07	5 2007/08	6 2008/09	7 2009/10	8 2010/11	9 2011/12	10 2012/13	11 2013/14	12 2014/15	13 2015/16	14 2016/17	15 2017/18
Option 1		***Capacitor banks***														
TUOS		0.000	0.000	0.510	0.502	0.494	0.486	0.478	0.470	0.462	0.453	0.445	0.437	0.429	0.421	0.413
NPV of TUOS	$2.8															
Option 2		***SVC***														
TUOS		0.000	0.000	1.271	1.250	1.230	1.210	1.190	1.169	1.149	1.129	1.109	1.089	1.068	1.048	1.028
NPV of TUOS	$6.9															

SCENARIO C - Low Growth Forecast

	($ millions)	1 2003/04	2 2004/05	3 2005/06	4 2006/07	5 2007/08	6 2008/09	7 2009/10	8 2010/11	9 2011/12	10 2012/13	11 2013/14	12 2014/15	13 2015/16	14 2016/17	15 2017/18
Option 1		***Capacitor banks***														
TUOS		0.000	0.000	0.119	0.117	0.475	0.468	0.460	0.452	0.445	0.437	0.430	0.422	0.414	0.407	0.399
NPV of TUOS	$2.1															
Option 2		***SVC***														
TUOS		0.000	0.000	1.271	1.250	1.230	1.210	1.190	1.169	1.149	1.129	1.109	1.089	1.068	1.048	1.028
NPV of TUOS	$6.9															

D.6 *Nebo 275kV Transformer Augmentation*

Project Name: Nebo 275kV Transformer Augmentation
Proposed Timing: October 2004
Estimated Cost: $7.7 million

Background
Nebo substation is a major 275kV injection point supplying the 132kV network from two 275/132kV, 220MVA transformers. These transformers already have fans fitted and can't be uprated any further by that mechanism. Nebo 275/132kV transformers supply the Mackay area and a significant portion of the central Queensland mining and rail load. Lilyvale 275/132kV substation also provides transformation capacity for supply to the central Queensland mining and rail load.

The existing 275/132kV transformer capacity at Nebo for supply into the Mackay and central Queensland 132kV network is currently approaching thermal limits. Based on load growth forecasts, it has been determined that, by late 2004, plant thermal ratings will be exceeded, in the event of a transformer outage at Nebo at a time of peak demand.

Without corrective action Powerlink will be unable to maintain reliability of supply under some credible contingencies. The connection agreement between Powerlink and Ergon Energy includes obligations regarding the reliability of supply as required under Clause S5.1.2.2 of the National Electricity Code. Powerlink's transmission authority also includes reliability of supply obligations. Capacity to Mackay and central Queensland is required to be provided such that forecast peak demand can be supplied with the most critical element out of service, ie. N-1. For this reason, solutions to this emerging network limitation are classified as a reliability augmentation.

All regulated network augmentations are required to satisfy the Regulatory Test promulgated by the ACCC. For a reliability augmentation, this test requires that a proposed solution minimise the net present value cost of meeting objective performance standards compared with other feasible alternatives.

Network Options Considered

Option 1: Install a third 250MVA 275/132kV transformer at Nebo
A feasible network solution to the emerging supply limitations at Nebo is the installation of a third 275/132kV transformer (250MVA) at the Nebo substation by October 2004.

This option will require further corrective action to address the emerging network limitations in the area. Additional transformation capacity to supply central Queensland would be required by October 2010. This need could most efficiently be supplied by uprating the transformers at Lilyvale in 2010 and then adding a third transformer at Lilyvale in 2013.

The capital cost of this option is $5.9 million.

The capital cost of the anticipated future projects is $0.1 million for uprating of the Lilyvale transformers in 2010 and $7.1 million for installation of a 3rd Lilyvale transformer in 2013.

Construction of this option will need to commence in August 2003 in order to meet the required commissioning date of October 2004.

Option 2: Transfer the second Lilyvale transformer to Nebo and install a new transformer at Lilyvale

This option would replace the existing 200MVA 275/132kV transformer at Lilyvale with a new 375MVA transformer by October 2004. Upgrade of substation equipment at Lilyvale is required to match the higher transformer capacity. This increase in transformer capacity at Lilyvale would defer the need for additional transformer capacity at Nebo for a year until October 2005.

The transformer removed from Lilyvale would be uprated to 250MVA by fitting fans, and installed as a third transformer at Nebo by October 2005.

This option would push the need for further 275/132kV transformer capacity augmentation in central Queensland out beyond the forecast period.

The capital cost of this option is $7.7 million.

Construction of this option will need to commence in August 2003 in order to meet the commissioning date of October 2004.

Non-Network Options Considered

Operation of the Mackay gas turbine generator was considered as a means to defer the need for this augmentation. The maximum summer capacity of the generator is 30 MW, which is not sufficient to defer the need for corrective action by one year.

Powerlink is not aware of any demand side management initiatives, other committed local generation developments or other non-network solutions which could address the identified limitation in the required timeframe.

Summary of Options and Economic Analysis

There are two options, which are feasible ways of overcoming the supply limitations in the Mackay and central Queensland area. The net present value cost of each of these options was calculated over a period of 15 years. The economic analysis is included as Table D22. The outcomes associated with these options are summarised in Table D19 below for medium demand forecast with 20MW of new generation in the Lilyvale area.

Table D19: Summary of Economic Analysis for Medium Growth for Nebo 275kV Transformer Augmentation

Options	Net Present Value Cost	Ranking
Install a third 275/132kV transformer at Nebo	$4.6 million	2
Transfer the second Lilyvale transformer to Nebo and install a new transformer at Lilyvale	$4.5 million	1
Non-network options	N/A	N/A

Varying demand growth scenarios were considered. Three Scenarios were considered:

a) Medium demand growth with 20MW of new coal seam methane fired generation in the area,
b) High demand growth with 20MW of new coal seam methane fired generation in the area, and
c) Medium demand growth with 60MW of new coal seam methane fired generation in the area.

Economic analysis and the results of these scenarios are in Tables D20 and D22.

Table D20: Summary of NPV Analysis and Ranking for Nebo 275kV Transformer Augmentation

		Option One		Option Two	
		NPV $millions	Ranking	NPV $millions	Ranking
Scenario A	Medium Demand and 20MW of New Generation	4.6	2	4.5	1
Scenario B	High Demand and 20MW Additional Generation	5.2	2	4.5	1
Scenario C	Medium Demand and 60MW of Additional Generation	4.1	1	4.5	2

The sensitivity of the net present value calculations to key input variables such as the discount rate and capital costs (variation of ±10%) have been examined and the results are summarised in Table D21. Sensitivity to the commissioning date was not examined as the initial stage of both options is required to be in service by October 2004 to meet forecast peak load in the 2004/05 summer.

Table D21: Results of Sensitivity Analysis for Nebo 275kV Transformer Augmentation

		Discount Rate					
		8%		10%		12%	
		Best ranked option	Frequency of wins	Best ranked option	Frequency of wins	Best ranked option	Frequency of wins
Scenario A	Medium Demand and 20MW of New Generation	2	100%	2	100%	1	100%
Scenario B	High Demand and 20MW Additional Generation	2	100%	2	100%	2	100%
Scenario C	Medium Demand and 60MW of Additional Generation	1	100%	1	100%	1	100%

The result of the net present value analysis is that Option 2 minimises the net present value cost of addressing the supply limitation in the area, in most scenarios, and as such is considered to satisfy the Regulatory Test.

This project has no material impact on other transmission networks.

Recommendation
It is recommended that the existing 200MVA 275/132kV transformer at Lilyvale be replaced with a new 375MVA transformer by July 2004 and that the transformer removed from Lilyvale be uprated to 250MVA and installed as a third transformer at Nebo by October 2005, to address transformer capacity limitations in the Mackay and central Queensland area.

Table D22: Cash Flow for Nebo 275kV Transformer Augmentation

SCENARIO A - Medium Demand Forecast and 20MW of New Generation

		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	($ millions)	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18
Option 1		***Install a third 275/132kV Transformer at Nebo***														
TUOS		0.000	0.000	0.676	0.666	0.655	0.644	0.633	0.623	0.625	0.614	0.603	1.415	1.391	1.367	1.343
NPV of TUOS	$4.6															
Option 2		***Transfer Lilyvale Transformer to Nebo***														
TUOS		0.000	0.000	0.456	0.883	0.869	0.855	0.840	0.826	0.812	0.798	0.784	0.770	0.755	0.741	0.727
NPV of TUOS	$4.5															

SCENARIO B - High Demand Forecast and 20MW Additional Generation

		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	($ millions)	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18
Option 1		***Install a third 275/132kV Transformer at Nebo***														
TUOS		0.000	0.000	0.676	0.666	0.655	0.657	0.646	0.635	0.624	1.437	1.412	1.388	1.364	1.340	1.316
NPV of TUOS	$5.2															
Option 2		***Transfer Lilyvale Transformer to Nebo***														
TUOS		0.000	0.000	0.456	0.883	0.869	0.855	0.840	0.826	0.812	0.798	0.784	0.770	0.755	0.741	0.727
NPV of TUOS	$4.5															

SCENARIO C - Medium Demand Forecast and 60MW of Additional Generation

		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	($ millions)	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18
Option 1		***Install a third 275/132kV Transformer at Nebo***														
TUOS		0.000	0.000	0.676	0.666	0.655	0.644	0.633	0.623	0.612	0.601	0.590	0.592	0.581	1.394	1.370
NPV of TUOS	$4.1															
Option 2		***Transfer Lilyvale Transformer to Nebo***														
TUOS		0.000	0.000	0.456	0.883	0.869	0.855	0.840	0.826	0.812	0.798	0.784	0.770	0.755	0.741	0.727
NPV of TUOS	$4.5															

D.7 *Alligator Creek 20MVAr, 132kV Shunt Capacitor Bank*

Project Name: Alligator Creek 20MVAr, 132kV Shunt Capacitor Bank
Proposed Timing: October 2004
Estimated Cost: $1.1 million

Background
The Mackay area includes the Nebo, Alligator Creek, Oonooie, Pioneer Valley and Mackay substations. The Mackay area load is forecast to increase at 2% p.a.

From late 2004 onwards, an outage of the Nebo to Alligator Creek circuit during peak summer demand periods will result in the voltage level at Oonooie dropping below the statutory voltage levels required by the Code. Oonooie is a railway substation and the low voltage level experienced for the above contingency condition is worsened by a coincident large train load. Therefore to prevent violating statutory voltage levels, corrective action is required prior to the summer 2004/05.

Analysis assumes connected parties will meet their power factor requirements in the Code. In addition, the analysis conducted assumes that existing levels of reactive support continue to be provided by generators, either under their code obligations or as ancillary services under contract to NEMMCO. The net effect of this is a requirement to increase reactive capability in the Mackay area.

The Connection Agreement between Powerlink and Ergon Energy includes obligations regarding reliability of supply as required under Clause S5.1.2.2 of the National Electricity Code. Powerlink's transmission authority also includes reliability of supply obligations. Voltage support must be provided to the Mackay area such that the forecast peak demand can be supplied with the most critical element out of service, ie. N-1. Without corrective action, Powerlink will be unable to meet these obligations. Therefore the proposed solution is classified as a reliability augmentation.

All regulated network augmentations are required to satisfy the Regulatory Test promulgated by the ACCC. For a reliability augmentation, this test requires that a proposed solution minimise the net present value cost of meeting objective performance standards compared with other feasible alternatives.

Network Options Considered

Option 1: Capacitor Bank
Option 1 is to install a 20MVAr 132kV shunt capacitor bank at Alligator Creek by late 2004. This is the maximum size that can be installed on the Alligator Creek 132kV bus without violating the maximum voltage fluctuation levels stated in the Code during energisation. While the capacitor bank will help to support the voltage levels at Oonooie during N-1 conditions, it will not change normal voltage levels due to the action of the existing balancing static var compensator at Oonooie.

Option 1 will require further corrective action to address emerging network limitations in the area. An anticipated project to maintain supply reliability in the Mackay area is the construction of a new line by late 2007, when the loading on the Nebo to Pioneer Valley circuit will exceed its emergency rating for a single credible contingency (ie. N-1). It is anticipated a new 132kV line from Nebo to Pioneer Valley would be required in late 2007.

The capital cost of this capacitor bank option is $1.1 million.

The capital cost of the anticipated line project in 2007 is $20 million.

Construction of the proposed augmentation would be scheduled to commence in August 2003 to meet the required commissioning date of October 2004.

Option 2: Advance Construction of 132kV Line
The emerging limitation can be addressed by advancing the construction of a new 132kV transmission line between Nebo and Pioneer Valley to late 2004/05.

The capital cost of this option is $20 million.

This option is included for comparison purposes, as it is unlikely it could be commissioned before the required date of October 2004. Construction would need to begin as soon as possible (ie. August 2003).

Option 3: SVC
A further network option, which could feasibly address the emerging network limitation is the installation of a 132kV static var compensator (SVC) at Alligator Creek by late 2004. The SVC would need to have a reactive range of 0 +20MVAr to achieve the same benefits as the capacitor bank described in option 1. As for option 1, by late 2007 the power loading will exceed the line rating on the Nebo to Pioneer Valley circuit and at this time, a new Nebo to Pioneer Valley 132kV line is expected to be required.

The capital cost of this SVC option is $8.5 million.

The capital cost of the anticipated line project in 2007 is $20 million.

Construction of this proposed augmentation would be scheduled to commence in August 2003 to meet the required commissioning date of October 2004.

Non-Network Options Considered
Consideration was given to obtaining reactive support from the Mackay gas turbine operating as a synchronous condenser. This would need to be run precontingent at times of peak load. Oonooie peak train loads can occur at any time. Therefore the gas turbine would need to be operated for long periods to ensure all peak loads were covered. A network support option as solution to the Oonooie low voltage problem has not found to be economic in the light of the extensive running regime required.

Powerlink is not aware of any demand side management initiatives, other local generation developments or other non-network solutions that could address the identified limitation by the required timing of October 2004.

Summary of Options and Economic Analysis
There are three feasible options that are capable of overcoming the voltage limitation at Oonooie by the required timing of October 2004. The net present value cost of each of these options was calculated over a period of 15 years. The economic analysis is included in Table D26. The costs and outcomes associated with these options for the medium growth forecast are summarised in Table D23 below.

Table D23: Summary of Economic Analysis for Medium Growth for Alligator Creek 20MVAr, 132kV Shunt Capacitor Bank

Options	Net Present Value Cost	Ranking
1. 20MVAr 132kV capacitor bank at Alligator Creek	$9.0 million	1
2. Advance construction of 132kV line	$12.5 million	2
3. 0 to +20MVAr SVC at Alligator Creek	$13.6 million	3
4. Network Support from the Mackay Gas Turbine	N/A	N/A
5. Non-network options	N/A	N/A

A range of market scenarios was also considered including demand growth at rates associated with high and low range estimates of economic growth rates in Australia. The results of these scenarios are summarised in Table D24. The possible introduction of new generation in the Mackay area is expected to produce similar results as low demand growth rates. As a result, no generation investments were considered in formulating scenarios for the economic analysis.

Table D24: Summary of NPV Analysis and Ranking for Alligator Creek 20MVAr, 132kV Shunt Capacitor Bank

		Option one		Option two		Option three	
		NPV $millions	Ranking	NPV $millions	Ranking	NPV $millions	Ranking
Scenario A	Medium Growth	9.0	1	12.5	2	13.6	3
Scenario B	High Growth	10.3	1	12.5	2	14.9	3
Scenario C	Low Growth	7.8	1	12.5	3	12.4	2

The sensitivity of the net present value calculations to key input variables such as the discount rate and capital costs (variation of ±10%) have been examined and the results are summarised in Table D25. Sensitivity to the commissioning date was not examined, as the initial stage of all three options is required to be in service by October 2004 to meet forecast peak load in the 2004/05 summer.

Table D25: Results of Sensitivity Analysis for Alligator Creek 20MVAr, 132kV Shunt Capacitor Bank

		Discount Rate					
		8%		10%		12%	
		Best ranked option	Frequency of wins	Best ranked option	Frequency of wins	Best ranked option	Frequency of wins
Scenario A	Medium Growth	1	100%	1	100%	1	100%
Scenario B	High Growth	1	100%	1	100%	1	100%
Scenario C	Low Growth	1	100%	1	100%	1	100%

The result of the analysis is that Option 1, the installation of a 132kV 20MVAr capacitor bank at Alligator Creek minimises the net present value cost of addressing the network limitation in all cases, and as such is considered to satisfy the Regulatory Test.

This project has no material impact on other transmission networks.

Recommendation

It is recommended that a 20MVAr 132kV capacitor bank at Alligator Creek be implemented by October 2004, to address voltage control limitations at Oonooie.

Table D26: Cash Flow for Alligator Creek 20MVAr, 132kV Shunt Capacitor Bank

SCENARIO A - Medium Growth Forecast

		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	($ millions)	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18
Option 1		***Capacitor bank***														
TUOS		0.000	0.000	0.123	0.121	0.119	2.427	2.389	2.350	2.311	2.273	2.234	2.195	2.156	2.118	2.079
NPV of TUOS	$9.0															
Option 2		***Advance construction of 132kV Line***														
TUOS		0.000	0.000	2.310	2.273	2.237	2.200	2.163	2.126	2.090	2.053	2.016	1.979	1.943	1.906	1.869
NPV of TUOS	$12.5															
Option 3		***SVC***														
TUOS		0.000	0.000	0.982	0.966	0.951	3.245	3.193	3.140	3.088	3.035	2.983	2.931	2.878	2.826	2.774
NPV of TUOS	$13.6															

SCENARIO B - High Growth Forecast

		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	($ millions)	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18
Option 1		***Capacitor bank***														
TUOS		0.000	0.000	0.123	0.121	2.429	2.391	2.352	2.313	2.275	2.236	2.197	2.158	2.120	2.081	2.042
NPV of TUOS	$10.3															
Option 2		***Advance construction of 132kV Line***														
TUOS		0.000	0.000	2.310	2.273	2.237	2.200	2.163	2.126	2.090	2.053	2.016	1.979	1.943	1.906	1.869
NPV of TUOS	$12.5															
Option 3		***SVC***														
TUOS		0.000	0.000	0.982	0.966	3.261	3.208	3.156	3.103	3.051	2.999	2.946	2.894	2.842	2.789	2.737
NPV of TUOS	$14.9															

SCENARIO C - Low Growth Forecast

		1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**
	($ millions)	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18
Option 1		***Capacitor bank***														
TUOS		0.000	0.000	0.123	0.121	0.119	0.117	2.426	2.387	2.348	2.309	2.271	2.232	2.193	2.155	2.116
NPV of TUOS	$7.8															
Option 2		***Advance construction of 132kV Line***														
TUOS		0.000	0.000	2.310	2.273	2.237	2.200	2.163	2.126	2.090	2.053	2.016	1.979	1.943	1.906	1.869
NPV of TUOS	$12.5															
Option 3		***SVC***														
TUOS		0.000	0.000	0.982	0.966	0.951	0.935	3.229	3.177	3.125	3.072	3.020	2.967	2.915	2.863	2.810
NPV of TUOS	$12.4															