FINAL REPORT

# NEM Regional Boundary Issues: Modelling Report

Submitted to

MCE

Prepared by:

**Charles River Associates (Asia Pacific) Pty Ltd**
Level 31, Marland House, 570 Bourke Street
Melbourne, VIC 3000, Australia
Tel: + 61 3 9606 2800   Fax: + 61 3 9606 2899

**16 September 2004**

# DISCLAIMER

*Charles River Associates (Asia Pacific) Ltd and its authors make no representation or warranty as to the accuracy or completeness of the material contained in this document and shall have, and accept, no liability for any statements, opinions, information or matters (expressed or implied) arising out of, contained in or derived from this document or any omissions from this document, or any other written or oral communication transmitted or made available to any other party in relation to the subject matter of this document.*

# TABLE OF CONTENTS

# 1. INTRODUCTION

This report presents the findings of our analysis that addresses three key issues:

1. Significance of intra- and trans-regional constraints i.e., how often they bind;
2. What impact do they have on regional reference node prices (RRP) including the impact on volatile price outcomes; and
3. Dynamic nature of the constraints.

We have looked at these issues both from historic perspectives i.e., how often constraints did bind and what implication do such binding constraints have in terms of nodal/local prices, as well as likely impact of projected generic transmission constraints on zonal prices and regional boundary issues.

The analysis here in part relies on the theory of constraint orientation and nodal-zonal equivalence that we have extensively discussed the accompanying paper titled *NEM Regional Boundary Issues: Theoretical Framework*.

Our analysis has relied primarily on data received from NEMMCO, but we have also relied other public sources including NEMMCO's Statement of Opportunity (SOO, 2003) and various annual planning reports of transmission companies among other things.

Analysis of transmission constraints — that are inherently complex, rely to a large extent on real-time information and are continuously evolving — is a massive undertaking. Although we have used actual NEM data wherever possible in this analysis, the very nature of transmission constraints and to an extent limited time and scope of this study, makes the inferences and conclusions of this analysis illustrative rather than definitive. We have not attempted to define precisely the location for any new regional boundaries – rather our objective is to illustrate the core issues in the NEM context to develop a preliminary understanding of the materiality of regional boundaries.

# 2. PROJECTION OF INTRA/TRANS REGIONAL CONSTRAINT IMPACTS AND ASSOCIATED NODAL PRICE ANALYSIS

The analytical approach used here is designed to illustrate the fact that if intra-regional constraints are formulated in a way that captures the underlying physical limitations and security constraints on the network, then the derived nodal prices in a NEM-type regional model will be equal to those one would expect under a NEM model with a fuller nodal representation.

Inferring nodal prices in this way can provide us with the following information, which is useful when weighing up any possible changes to the criteria used for assessing regional boundaries in the NEM:

- Nodal price differences and the volatility of nodal prices within existing NEM regions;
- Location, number of and types of binding intra-regional constraints;
- Frequency with which constraints bind; and
- Economic costs of binding constraints — as captured in the short-run by the dispatch algorithm.

This information will also inform our thinking on the pros and cons of various ways of managing transmission related risks — using instruments such as FTRs, constraint side-payments, and gatekeeper contracts — which, firstly, need to be addressed as part of the brief; and, secondly, are likely to be required in one form or another across the spectrum of options we are considering; ranging from the status quo to full nodal pricing.

The analysis relies on the existing constraint set in PLEXOS, described below, which has a limited number of intra-regional constraints. Consequently, the number of nodal prices that can be inferred from the model are limited by the number of intra-regional constraints represented in PLEXOS and the frequency with which they bind. Increasing the number of frequently binding intra-regional constraints represented in the PLEXOS NEM–model would allow a larger number of implied nodal prices to be forecast. However, this requires additional data from NEMMCO on binding intra-regional constraints and the form of those constraints. We have conducted analysis on historic generic constraints that is presented in section 4.

## 2.1. PLEXOS Constraint Set

The generic transmission constraints in PLEXOS's current data base (NEM DA NEM v3.1) were developed for the 2003 Annual Interconnector Review (AIR 2003) [1]. PLEXOS was one of the models used to prepare the 2003 Annual Interconnector Review, which is part of the Statement of Opportunities 2003 (SOO 2003).[2] There are approximately 100 or so "SD_XX" constraints in PLEXOS, which are taken from the NEMMCO supply-demand calculator that was issued as part of the SOO 2003. We understand that the constraint set in PLEXOS was developed in cooperation with NEMMCO and ESIPC and has been tested and used.

Our investigations have confirmed the transmission constraint set currently in PLEXOS refers mainly to inter-regional flow constraints, but includes a small number of intra-regional constraints which TNSPs/NEMMCO say have a significant effect on inter-regional power flows. Some voltage and stability constraints are also included. This is consistent with the objectives of the Annual Interconnector Review, which concentrates on inter-regional transfer capability; and, as a consequence, focuses on inter-regional network constraints rather than intra-regional constraints.

Beyond that, intra-regional constraints are not represented; except for Queensland, where there are thermal limit constraints on intra-regional flows between the 5 nodes in 5-node QLD model.

Given that this is the case, the existing "Reliability 2003" constraint set in PLEXOS is of limited use in inferring nodal prices using approach 1). In order for a larger set of intra-regional nodal prices be inferred using approach 1), a larger set of intra-regional constraints would have to be developed by CRA — using information from NEMMCO or the TNSPs. The historical information on binding intra-regional constraints, provided by NEMMCO and analysed in section 4, is of great assistance to such an endeavour because it would allow us to understand which intra-regional constraints drive price differences and the formulation of those constraints.[3]

1 IRPC (Inter Regional Planning Committee) 2003, *Annual Interconnector Review 2003*, IRPC, Version 2, 31 July 2003. Issued as part of: NEMMCO 2003, *Statement of Opportunities 2003*, NEMMCO, Melbourne.

2 The Electricity Supply Industry Planning Council (ESIPC) contracted Drayton Analytics to assist it with the AIR 2003 analysis — see Chapter 10 of NEMMCO's *Statement of Opportunities 2003* and AIR 2003.

3 Alternatively, one could use the QLD 5-node model in PLEXOS to illustrate some of the differences in nodal price volatility under a 5-node model dispatch for QLD versus a 1-node model for QLD.

## 2.2. Methodology

- SRMC run of PLEXOS in ST mode, using 10% POE load forecast from SOO 2003, and PLEXOS constraint set developed for 2003 Annual Interconnector Review.

- Forecast financial year 2003-04 and 2004-05 regional reference prices; along with transmission constraints' activity, hours binding and shadow prices.

- Infer any nodal prices on binding intra-regional constraints for which hours binding is significant.

- Plot RRN price duration curve against inferred nodal prices to show differences in price volatility between relevant RRN and intra-regional nodes.

## 2.3. Caveats That Apply

Significant caveats apply in that the modelling analysis:

- Assumes a short run marginal cost based bidding behaviour that may generally reflect an idealised dispatch and price outcome which may differ from generator bidding observed in reality;

- Generic constraint right hand side (RHS) terms may typically comprise a number of dynamic terms that would in reality vary over time. We have instead treated them as a static term that do not change over time. As a consequence the constraint may be more, or less, binding than it might have done in reality;

- Our modelling framework does not recognise specific periods or conditions under which a constraint applies and our assumption is that the select set of constraints effectively apply all the time. This may generally overestimate the number of binding hours, although the limited representation of network outages in a long term market simulation model would imply the impact of any binding instance may be less severe; and

- The fact that only a select set of constraints are included in the analysis leaves the possibility that there are possibly other constraints that are more severe than the select set of constraints. This would generally mean that the selected set of constraints may in our analysis be binding for more number of hours than in reality.

These caveats suggest that the present analysis at best is illustrative to get a preliminary understanding of the spatial and temporal variation of forward nodal prices.

## 2.4. Discussion of Results

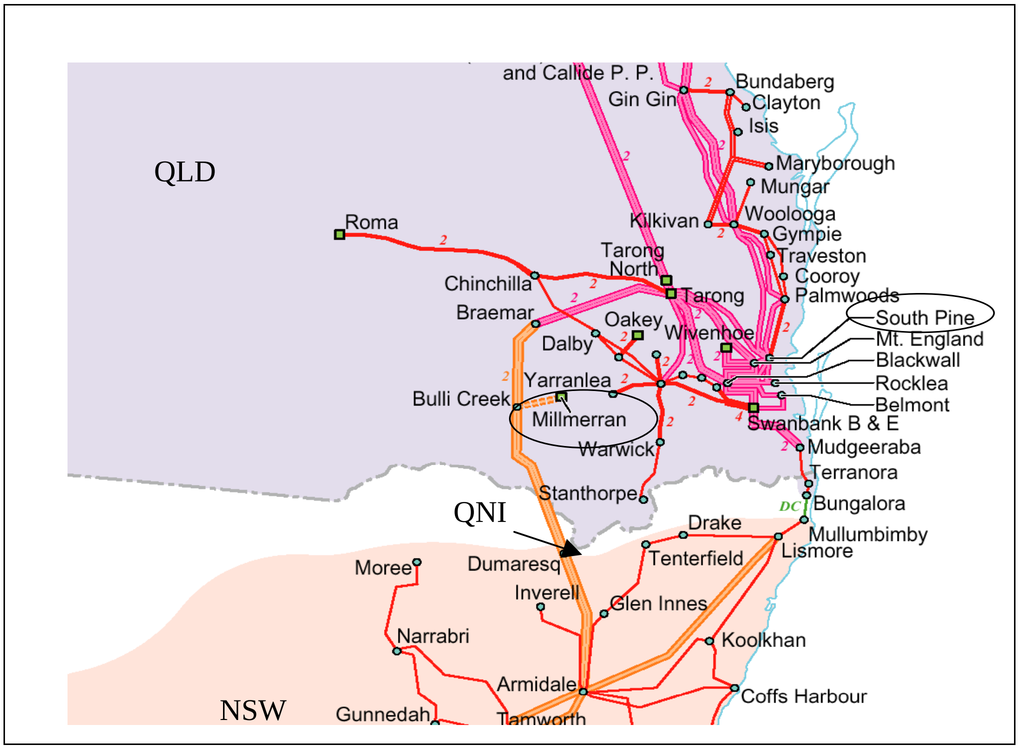
An interesting transmission constraint in the PLEXOS database is SD_105, which jointly limits flow on QNI and the output of Millmerran power station's units 1 and 2. Constraint SD_105 forms part of the "Tarong" constraint set, which can restrict northwards flow on QNI and the output of a number of generators in South and Central Queensland. It is thus both an inter-regional constraint and an intra-regional constraint, with its intra-regional nature making it a good candidate for the exercise of inferring Millmeran's nodal price. The form of the constraint is outlined below; and, as can be seen, the flow on QNI and generation of Millmeran units MPP1 and MPP2 appear on the left hand side of the constraint and all terms have a coefficient of one.

*SD_105, Q>BRTX1-2, QLD NSW Constraint Equation*

*1*Flow(NSW-QLD) + 1*Generation(MPP1) + 1*Generation(MPP2) <= 1025*

The map of South East Queensland shows the location of Milmerran on the QLD-NSW interconnector and South Pine, the Regional Reference Node (RRN) for Queensland (see Figure 1).

**Figure 1: Map of South East Queensland Transmission Network**




*Source:* NEMMCO

The constraint is forecast to bind for 45% of the time in 2003-04, but comes down to 28% of the time on 2004-05 (see Table 1); and more importantly, perhaps, the average constraint shadow price falls from $32 to $2.6. These two things suggest that the constraint binds less frequently and with a much lower impact on nodal prices at the constrained-off node and hence the existing regional boundaries might need to be realigned — particularly in 2003-04. Reflecting this, the annual average nodal price for Millmerran differs significantly from that for South Pine in 2003-04, but less so in 2004-05. This reduction in this price divergence can also be seen when the price duration curves of each node are plotted against each other (see Figure 2 and Figure 3).

There are number of possible reasons behind the narrowing of the price divergence between South Pine and Millmerran from 2003-04 to 2004-05, including: transmission upgrades with Queensland designed to reduce intra-regional congestion (e.g. Tarong-Blackwall); the changing pattern of dispatch; and the changing interaction of SD_105 with other constraints.

For our purposes here, it is not necessary to investigate which of these possible causes is driving the results; but simply to draw attention to the fact that the tightness of the constraint can change over time and that this is important when considering the issue of the lifecycle of a constraint and the sensibility of creating new regions when there is a risk that a constraint which binds for a large proportion of the time in one year may not do so in future, as patterns of load and generation — together with the network — evolve over time.

**Table 1: Projected Queensland RRP, Constraint SD_105 Shadow Price and Implied Nodal Price at Millmerran, 2003-04 and 2004-05 (a)**

| | 2003-04 | | 2004-05 | |
|---|---|---|---|---|
| | South Pine (QLD RRN) | Millmerran | South Pine (QLD RRN) | Millmerran |
| Time-weighted annual average price ($/MWh) | 49.04 | 17.00 | 25.72 | 23.12 |
| Constraint SD_105 Shadow Price ($) | n/r | -32.04 | n/r | -2.60 |
| Constraint SD_105 Hours Binding | n/r | 3998 | n/r | 2501 |
| Constraint SD_105 % Hours Binding | n/r | 45.51 | n/r | 28.60 |
| Hours in year (b) | 8784 | 8784 | 8760 | 8760 |

*Source:* CRA projection

*a.* Financial year starting 1 July and ending 30 June of following calendar year.

*b.* Financial year 2003–04 has an extra 24 hours than normal because it includes leap–year day 29 February 2004.

*c.* n/r = not relevant

**Figure 2: Forecast Cumulative Price Distribution, Queensland RRN and Milmerran Node, FinYear 2003-04**

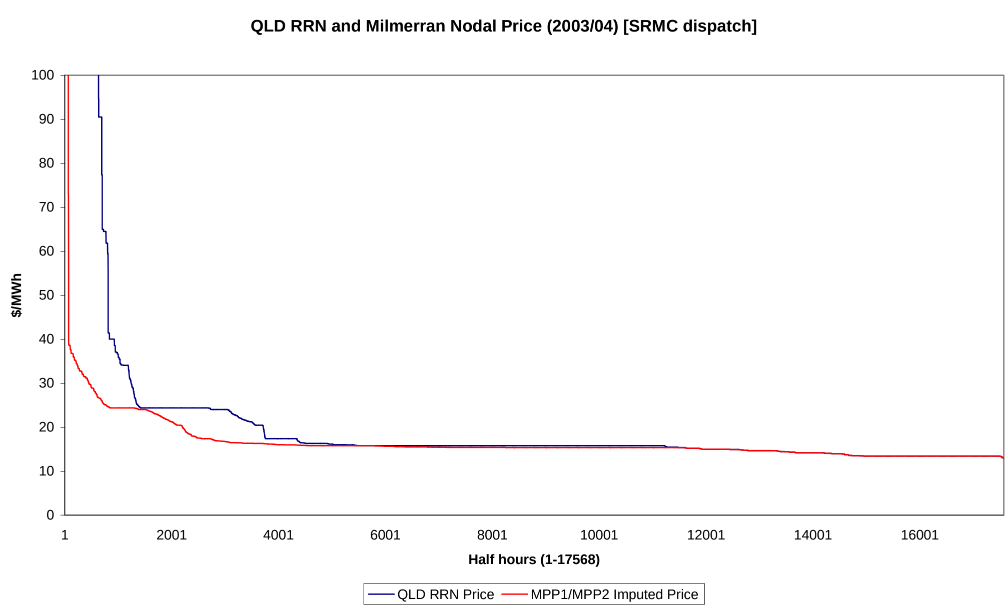
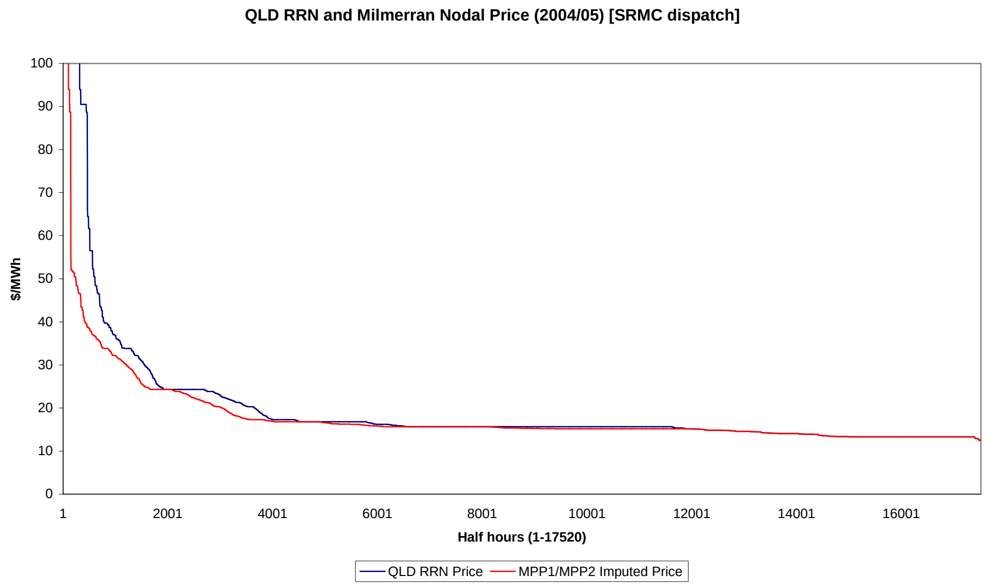


**Figure 3: Forecast Cumulative Price Distribution, Queensland RRN and Milmerran Node, FinYear 2004-05**



# 3. FURTHER DISCUSSION ON FORWARD NODAL PRICES AND ILLUSTRATIVE ANALYSIS FOR QUEENSLAND REGION

## 3.1. CONSTRAINTS WITHIN QUEENSLAND

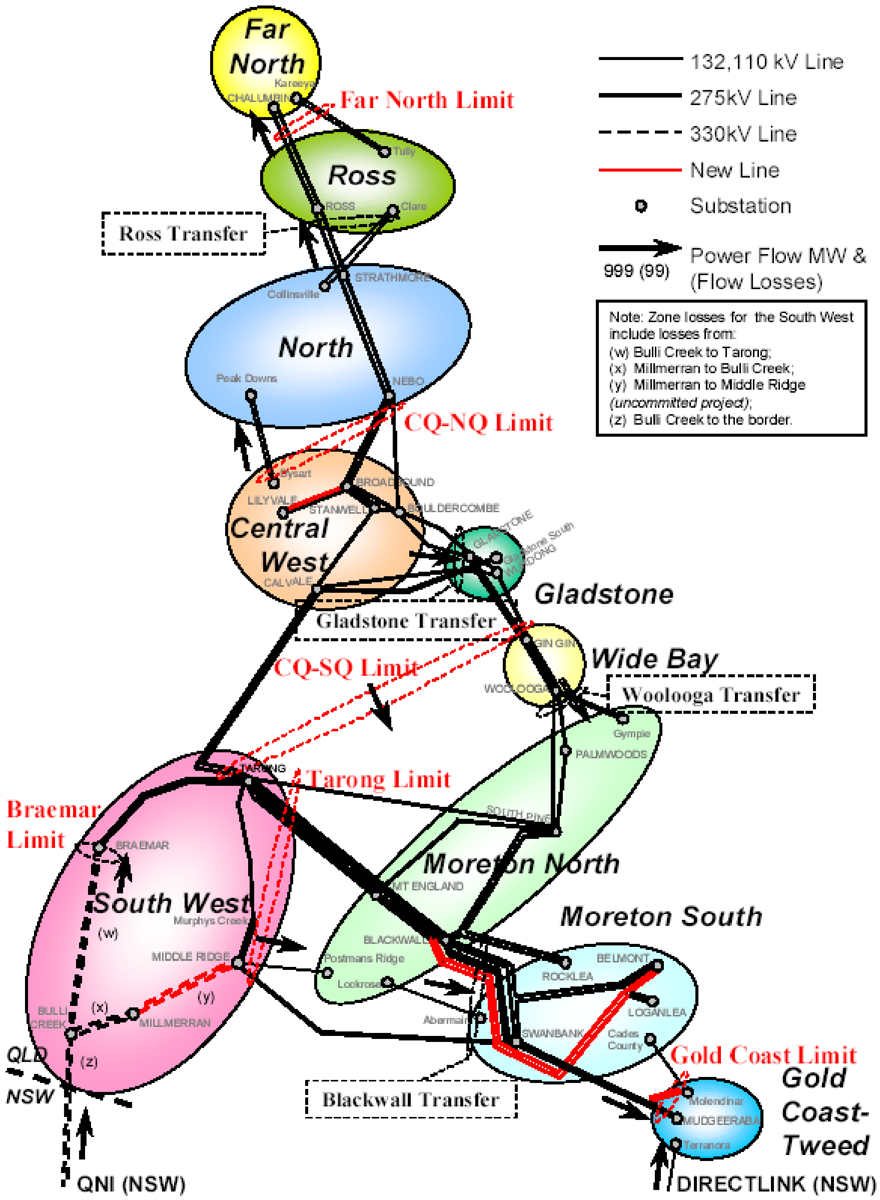
We have carried out further analysis focusing on Queensland region since a number of prior discussions including Powerlink's annual reports and our own analysis of constraints has pointed to a few key constraints in the region.

We have constructed our analysis around the key sub-zones within Queensland as described in Powerlink's annual report (see Figure 1).

In particular, we have focused on five aspects:

1. Develop an understanding of the likely price variations arising out of the key generic constraints that have occurred in the last few years;
2. How different sub-zonal prices within Queensland are likely to be under the power flow conditions/limits derived through power flow analysis by Powerlink;
3. How such variations are affected if such flow limits are relaxed;
4. How the sub-zonal prices vary across different load conditions (summer vs. winter months); and
5. Whether the sub-zonal prices are likely to vary significantly with load/generation profile changes even in the near term e.g., over the next 2-3 years.

**Figure 4: Queensland Transmission Network Zones and Constraints**




***Source***: **Powerlink Queensland, *Annual Planning Report 2003*, Appendix A, Figure A1, p.80**

## 3.2. CAVEATS THAT APPLY

Significant caveats apply in that the modelling analysis:

- As for the previous analysis, the present intra-regional analysis for Queensland also relies on SRMC bidding behaviour;
- It is a standalone analysis for Queensland region with interconnection to NSW treated as fixed[4];
- This analysis is performed on a simple dispatch model that does not recognise random outage of generators and accurate maintenance plan – outages are dealt with using a derate of generator capacity;
- A simplistic treatment for co-optimisation of reserve is considered – an aggregate spinning reserve for each generator is co-optimised to meet the total contingency reserve for Queensland rather than individual FCAS categories; and
- Hydro energy constraints are treated as monthly GWh limit (for Barron Gorge and Kareeya units).

We expect that the above limitations generally mean the outcomes of the modelling analysis — at least as far as absolute level of prices are concerned — are useful only to illustrate the effects of intra-regional constraints; and, more importantly, the effects of intra-regional constraints under different constraint sets and weather conditions.

4 Such assumptions are however consistent with the assumptions in Powerlink’s power flow analyses.

**Table 2: Summary of Generator Coefficients in Key Queensland Constraints**[5]

| Constraint | Far North Voltage Stability | Central to South Voltage Stability | Tarong Voltage Stability |
|---|---|---|---|
| **Historic Binding Instances (Apr'02-Mar'03)** | **24** | **54** | **5** |
| Barron Gorge | -0.59 to –0.62 | | |
| Kareeya | -0.79 to –1.02 | | |
| Collinsville | +0.0245 | | |
| Mt Stuart | +0.0058 | | |
| Townsville | +0.0194 | | |
| Gladstone | | +0.07 to +0.11 | |
| | | | -0.042 to –0.05 |
| Roma | | | +0.37 to +0.45 |
| SwanBankD-E | | | -0.33 to –0.42 |
| Tarong and Tarong North | | | +0.51 to +0.59 |
| Wivenhoe | | | -0.35 to –0.42 |
| Callide B and C | | | +0.09 to +0.10 |
| Oakey | | | +0.55 to +0.65 |
| Millmerran | | | +0.45 to +0.52 |

If these constraints in Table 2 are binding, they can create quite strong pricing effects – for example:

5 As reported in Powerlink Annual Planning Report 2003. The form of the constraint changes from time to time and also these are by no means the only constraints and hence these are used primarily for illustration. Discussion on specific constraints that were binding is included in a subsequent section on historic generic constraints analysis.

- Far North voltage stability constraint can separate prices between Far North and Ross regions with prices in the former region going up significantly by up 102% and those in the Ross region dropping slightly by a couple of dollars;

- Gladstone appears in both Central to South and Tarong constraints and depending upon which one of these is binding, prices in Gladstone zone can be higher, or lower than the reference node prices; and finally

- The Tarong constraint can create complex price separation effects across Central-West, South-West, Moreton-North and Moreton-South zones with prices in Tarong, Callide, Oakey, Millmerran, Roma being on one side of the constraint go down significantly and those on the Moreton side go up significantly.

## 3.3. Sub-zonal Prices within Queensland

In order to derive an estimate of the sub-zonal prices within Queensland – we have used a zonal dispatch model of Queensland that:

- Is derived from the detailed network data provided to us by NEMMCO;

- Conform to the grouping of nodes according to Powerlink's definition of transmission zones shown in Figure 4;

- Uses the inter-zonal flow limits based on power flow results for fiscal years 2004/05 and 2005/06 described in Powerlink's annual planning report, which reflect thermal as well as other security limits including limits on groups of lines (e.g., Central to South transfer limits due to stability etc);

- Uses a short run marginal cost bidding behaviour for medium load growth and 50% probability of exceedance peak load condition; and

- Performs a half-hourly transmission constrained dispatch simulation for summer (January) and winter (July) months in 2004 and 2005.

**Table 3: Queensland Inter-zonal Power Flows That Form the Basis for the Flow Limits (MW)**[6]

| | 2004/05 | | 2005/06 | |
|---|---|---|---|---|
| | Winter/July | Summer/Jan | Winter/July | Summer/Jan |
| Far North (Voltage) | 161 | 229 | 169 | 243 |
| CQ-NQ (Dynamic stability) | 825 | 930 | 881 | 921 |
| Gladstone (Thermal) | 986 | 804 | 1035 | 779 |
| CQ-SQ (Transient, Voltage) | 536 | 1167 | 677 | 1437 |
| Tarong (Voltage) | 2630 | 2949 | 2714 | 3059 |
| Gold-Coast (Voltage, Thermal) | 625 | 664 | 642 | 694 |

Source: Powerlink annual planning report, Appendix A, p. 76-77

Sub-zonal prices and their standard deviation for a typical summer (1,488 half-hourly prices for January) and a typical winter (July) months are presented in Table 4 and Table 5.

6 Assumes QNI IMPORT=300 MW and DIRECTLINK IMPORT=0.

**Table 4: Queensland Estimated Average Zonal Prices and Standard Deviation of Prices for a Typical Summer and Winter Month in 2004/05**

| | Transfer limit at base flow[7] | | Transfer limit = 150% of base flow | |
|---|---|---|---|---|
| | Summer/Jan | Winter/July | Summer/Jan | Winter/July |
| Far North | 73.5 (25.8) | 16.4 (2.0) | 16.8 (0.6) | 17.5 (2.6) |
| Ross | 58.9 (32.7) | 16.1 (2.0) | 16.5 (0.6) | 17.3 (2.6) |
| North | 15.3 (0.6) | 15.8 (1.8) | 16.0 (0.6) | 17.0 (2.5) |
| Central-West | 14.5 (0.1) | 15.3 (1.8) | 15.5 (0.6) | 16.4 (2.5) |
| Gladstone | 16.0 (0.5) | 16.5 (1.8) | 15.9 (0.6) | 16.8 (2.6) |
| WideBay | 21.6 (5.0) | 18.6 (4.3) | 19.5 (3.4) | 17.7 (2.8) |
| South-West | 21.8 (5.1) | 18.7 (4.4) | 19.5 (3.5) | 17.5 (2.8) |
| Moreton-North | 19.9 (4.8) | 17.4 (4.6) | 19.1 (3.4) | 17.3 (2.8) |
| Moreton-South | 22.3 (5.3) | 20.6 (4.2) | 19.9 (3.6) | 18.0 (2.9) |
| Goldcoast-Tweed | 38.0 (28.6) | 29.5 (20.6) | 20.2 (3.6) | 18.2 (2.9) |
| **QLD load-weighted average price** | **24.8 (7.7)** | **19.9 (5.8)** | **18.3 (2.8)** | **17.4 (2.7)** |

Note: Numbers in the parenthesis are the standard deviation of half-hourly prices for the month

7 It should be noted that the base power flows do not constitute by any means an upper bound on flows, but our intent here is more to explore what price outcomes are expected *if* flows matched the base power flow conditions. We also acknowledge that Powerlink clearly mentioned that such base power flow conditions are not intended to represent market outcomes. However, it provides the only benchmark for power flows on the Queensland network that reflect all transmission related constraints including stability, reactive power etc, that we could use in this instance to discuss sub-zonal prices. In reality, flows can indeed go beyond the base power flow levels and we have constructed scenarios by relaxing the flows to up by 50%.

**Table 5: Queensland Average Zonal Prices and Standard Deviation of Prices for a Typical Summer and Winter Month in 2005/06**

| | Transfer limit at base flow | | Transfer limit = 150% of base flow | |
|---|---|---|---|---|
| | Summer/Jan | Winter/July | Summer/Jan | Winter/July |
| Far North | 17.3 (0.6) | 24.0 (21.9) | 17.1 (0.6) | 17.9 (2.8) |
| Ross | 16.2 (0.8) | 23.7 (21.7) | 16.8 (0.6) | 17.7 (2.8) |
| North | 15.8 (0.7) | 16.1 (1.9) | 16.4 (0.6) | 17.2 (2.7) |
| Central-West | 15.0 (0.3) | 15.5 (1.8) | 15.8 (0.6) | 16.7 (2.6) |
| Gladstone | 16.3 (0.5) | 16.5 (1.8) | 16.2 (0.6) | 17.1 (2.6) |
| WideBay | 21.9 (5.4) | 16.6 (1.8) | 19.6 (3.1) | 17.3 (2.7) |
| South-West | 22.1 (5.5) | 16.7 (1.9) | 19.5 (3.1) | 17.2 (2.7) |
| Moreton-North | 20.5 (5.4) | 15.8 (1.8) | 19.2 (3.1) | 17.0 (2.7) |
| Moreton-South | 22.7 (5.6) | 20.3 (4.0) | 20.0 (3.2) | 17.6 (2.8) |
| Goldcoast-Tweed | 32.5 (23.0) | 29.1 (22.2) | 20.2 (3.2) | 17.8 (2.8) |
| **QLD load-weighted average price** | **20.8 (5.2)** | **19.2 (6.25)** | **18.4 (2.1)** | **17.3 (2.7)** |

Note: Numbers in the parenthesis are the standard deviation of half-hourly prices for the month

We observe that:

1. Under relatively stressed conditions e.g., summer peak and limited flow capacity – significant price separation can occur across the sub-zones and prices within some of the sub-zones such as Far North and Gold-Coast that have limited local generation can experience major price spikes leading to high volatility in prices;

2. However, a relatively small change in transfer capability (e.g., 100-200 MW for Far North and Gold-Coast) can lead to a dramatic drop in both price level/volatility – this is evident from a comparison of the results across the two power flow limit scenarios as well as the results for fiscal year 2004/05 and 2005/06; and

3. On the other hand, there seems to be a far less extreme but sustained price difference across the Central and Southern sub-zones during summer – this occurs due to the CQ-SQ transfer limit.

# 4. ANALYSIS OF HISTORIC GENERIC CONSTRAINT SHADOW PRICES

## 4.1. OVERVIEW

We have demonstrated an effective equivalence between nodal and zonal market theory, in that, provided the zonal model constraints are correctly oriented, we can:

- Produce the correct nodal price for any reference node; and then
- Derive a full set of nodal prices from:
  - That reference price;
  - The shadow prices on the binding constraints in that model; and
  - The nodal constraint coefficients in those binding constraints.

We have applied this equivalence to impute generator nodal prices in the NEM using historic generic constraint data obtained from NEMMCO. The constraint data comprises:

- All five minute instances of binding generic constraints in the NEM from Jan 1, 2003 to April 27, 2004; including:
  - Shadow price /marginal value of the constraint;
  - Violation (if any);
  - Right hand side (RHS) terms; and
  - Description of the constraint including the flow and generation variable coefficients (or, the so-called left hand side LHS terms), nature of the constraint, and sign of the constraint.

There were just over 100,000 total instances (5-minute periods) of binding generic constraints over the 16 month period, of which only 11,842 involved constraints that included a generator LHS term and the total number of generators involved on the LHS of all binding constraints is 126. In our analysis we have ignored the following types of generic constraints:

- Constraints that are effectively inter-regional that will create price difference across regions and hence not appropriate for intra-regional/nodal prices;
- Constraints that relate to outage conditions;

- Constraints that relate to control issues and are effectively in the domain of ancillary services;

- Constraints that relate to non-conformance; and

- Constraints that are overridden by network support contracts.

The number of binding instances after dropping these constraints is 5,391.The marginal value of constraints, duration of binding constraints, violation level and the generator coefficients vary significantly across the generators.

We have imputed the (absolute) differential of regional reference node prices and the generator nodal price i.e., if the generators were to receive a nodal price, how different those prices were likely to be from the RRP they actually received.  This analysis is intended to give an indication of the mean impact of such differential as well as the volatility of such differential.

## 4.2. CAVEATS THAT APPLY

Significant caveats apply that should be borne in mind:

- As we have stated previously, the nodal price derivation relies on the assumption that the constraints have been correctly represented *and* these constraints has been oriented toward the relevant reference nodes –to the extent this is not true, the nodal prices derived would be incorrect. In particular, we reiterate the points that have been discussed in the theory paper:

  - If a constraint has both nodal energy only (NEO) and non-NEO terms in it, only the NEO part of the constraint coefficient should be used in transforming the constraint, leaving the non-NEO part of the coefficient as it is.  However, the information to make a distinction between NEO and non-NEO parts of the historic generic constraints is not available and to the extent constraints have a non-NEO component in it, the results of the analysis will be inaccurate to a degree; and

  - An implicit assumption that we make all along is that the constraint correctly *represents* the generator terms on the left hand side of the constraint (i.e., treats relevant generation terms as *variables* in the optimisation). If the constraint form, however, treats them as part of the constant term on the right hand side of the constraint, nodal prices for such generators cannot be calculated;

- There are certain technical issues that potentially obscure the analysis:

    - Violation of generic constraints that typically lead to extremely high/low marginal value of the constraint. The implied nodal price may therefore be also very high/low and perhaps more importantly in the present context the nodal price to RRP *differential* may be very high/low[8]. However, it is not clear how the constraint would be managed in a nodal regime and whether such capped/uncapped differential is realistic or not. We have recalculated two sets of differentials that eliminate the extreme price excursions so that one can at least form an understanding of how important these excursions are;

    - Degeneracy of the underlying linear program problem may lead to ambiguity in the estimation of the constraint shadow prices and it is difficult to isolate such cases; and

    - There are instances of Over Constrained Dispatch (OCD) that effectively relaxes a violated constraint and re-calculates prices[9];

- Imputed nodal prices do not reflect transmission losses — they only reflect the costs associated with binding generic constraints; and

- Nodal prices would also be affected by the likely change in generators offer behaviour to the extent that such behaviour in a modelled market might differ from that in the NEMs existing regional model. We have made no attempt to correct for any such potential discrepancy.

These caveats suggest that the present analysis is best viewed as illustrative of the spatial and temporal variation of nodal prices.

## 4.3. Imputed Generator Nodal Price Differential from Regional Reference Node Price

Table 7 describes the mean and standard deviation of the (absolute) price differential of generator node and the associated RRP for Jan'03-Apr'04.

Since the generic constraint violation penalties are typically very high in the order of hundreds of thousands, we eliminated all instances of generic constraint violation and associated price differentials that exceed 10,000. In order to develop insight about the impact price spikes have, we further calculated mean and standard deviation of price differential that excluded all instances where prices were above 100.

---

8 Although if we were to assume an effective VoLL limit would apply to nodal prices, we could limit the nodal prices/deviations to 10,000.

9 We understand from NEMMCO though that such instances are relatively rare at least for the duration of the historic data we have used for this study and therefore unlikely to have a major impact on the outcomes of our analysis.

Summary of nodal price to RRP differential is presented in Table 6. Table 7 presents detailed price differences by generator nodes for all price difference instances up to $10,000/MWh and Table 8 shows nodal price differences that are below $100/MWh.

**Table 6: Summary of Price Impacts by Region**

| Region | Sub-region | Key Generators Involved | Average Price Differential Impact |
|---|---|---|---|
| QLD | Far North/Ross | Mt Stuart, Kareeya, Yabulu | 17[10] |
| | North | Collinsville | 2 |
| VIC | LaTrobe Valley | Jeeralang, Hazelwood, Yallourn | 3-4 |
| NSW | Hunter | Eraring, Bayswater, Liddell, Loy Yang | 0.4-1.2 |
| | New Castle | Vales Point | 1.2 |
| SNOWY | Tumut | NLTS/NUTS | 0.2-0.3 |

Key observations include:

- Mean price differentials (excluding >10,000) are quite significant for some of the QLD and VIC generators at $3 or more;
- However, such mean price differential is primarily an impact of a few binding instances with a very high shadow price. This is evident from the small number of hours for constraints bind with very high average price difference and mean differential excluding >100 price events (in Table 9) which is insignificant for all the generator nodes;
- Nodal prices essentially are very close to RRP for most instances and significant intra-regional constraints bind very infrequently but leads to extreme price spikes as is evident from:
    - Extremely high standard deviation (Table 7); and
    - A major drop in mean differential when the price spike events (i.e., >100) are removed (Table 8); and

10 Extreme price impacts primarily due to North Queensland constraint effects that are infrequent but has a very high shadow price – see the subsequent discussion on constraints involving Mt Stuart PS.

- We reiterate the extreme variability in nodal prices by noting that although the mean price differential is generally of the order of a few cents, the standard deviation is still reasonably significant at a couple of dollars suggesting that the nodal prices can be moderately higher/lower when constraints are binding.

**Table 7 Summary of Nodal Price Deviation (from RRP) – Excluding > 10000 prices**

| | | Nodal Price Difference Relative to RRN, All Periods | | Nodal Price Difference Relative to RRN, Binding Periods | | |
|---|---|---|---|---|---|---|
| | | Average | Standard Deviation | Average | Binding Instances | Binding Periods as % all Periods |
| | | $/MWh | $/MWh | $/MWh | Hours | % |
| Mt Stuart PS Unit 2 | QLD1 | 87.61 | 928.3 | 6956.25 | 146.0 | 1.26% |
| Mt Stuart PS Unit 1 | QLD1 | 39.63 | 627.1 | 7688.78 | 59.8 | 0.52% |
| Hazelwood PS Unit 1 | VIC1 | 4.10 | 66.2 | 386.20 | 123.2 | 1.06% |
| Hazelwood PS Unit 2 | VIC1 | 4.10 | 66.2 | 386.20 | 123.2 | 1.06% |
| Hazelwood PS Unit 6 | VIC1 | 4.10 | 66.2 | 386.20 | 123.2 | 1.06% |
| Hazelwood PS Unit 7 | VIC1 | 4.10 | 66.2 | 386.20 | 123.2 | 1.06% |
| Hazelwood PS Unit 8 | VIC1 | 4.10 | 66.2 | 386.20 | 123.2 | 1.06% |
| Jeeralang A PS Unit 1 | VIC1 | 4.10 | 66.2 | 386.20 | 123.2 | 1.06% |
| Jeeralang A PS Unit 2 | VIC1 | 4.10 | 66.2 | 386.20 | 123.2 | 1.06% |
| Jeeralang A PS Unit 3 | VIC1 | 4.10 | 66.2 | 386.20 | 123.2 | 1.06% |
| Jeeralang A PS Unit 4 | VIC1 | 4.10 | 66.2 | 386.20 | 123.2 | 1.06% |
| Jeeralang B PS Unit 1 | VIC1 | 4.10 | 66.2 | 386.20 | 123.2 | 1.06% |
| Jeeralang B PS Unit 2 | VIC1 | 4.10 | 66.2 | 386.20 | 123.2 | 1.06% |
| Jeeralang B PS Unit 3 | VIC1 | 4.10 | 66.2 | 386.20 | 123.2 | 1.06% |
| Morwell PS G4 | VIC1 | 4.10 | 66.2 | 386.20 | 123.2 | 1.06% |
| Morwell PS G5 | VIC1 | 4.10 | 66.2 | 386.20 | 123.2 | 1.06% |
| Morwell PS G1, 2 and 3 | VIC1 | 4.10 | 66.2 | 386.20 | 123.2 | 1.06% |
| Bairnsdale Power Station | VIC1 | 4.10 | 66.2 | 386.20 | 123.2 | 1.06% |
| Bairnsdale Power Station Generator Unit 2 | VIC1 | 4.10 | 66.2 | 386.20 | 123.2 | 1.06% |
| Yallourn W PS 220 Unit 1 | VIC1 | 3.17 | 56.3 | 404.48 | 90.8 | 0.78% |

| | | Nodal Price Difference Relative to RRN, All Periods | | Nodal Price Difference Relative to RRN, Binding Periods | | |
|---|---|---|---|---|---|---|
| | | Average | Standard Deviation | Average | Binding Instances | Binding Periods as % all Periods |
| Collinsville PS Unit 1 | QLD1 | 1.89 | 133.8 | 942.95 | 23.3 | 0.20% |
| Collinsville PS Unit 2 | QLD1 | 1.89 | 133.8 | 942.95 | 23.3 | 0.20% |
| Collinsville PS Unit 3 | QLD1 | 1.89 | 133.8 | 942.95 | 23.3 | 0.20% |
| Collinsville PS Unit 4 | QLD1 | 1.89 | 133.8 | 942.95 | 23.3 | 0.20% |
| Collinsville PS Unit 5 | QLD1 | 1.89 | 133.8 | 942.95 | 23.3 | 0.20% |
| Barcaldine PS | QLD1 | 1.56 | 47.0 | 640.31 | 28.3 | 0.24% |
| Yabulu PS | QLD1 | 1.56 | 122.6 | 1165.54 | 15.5 | 0.13% |
| Barron Gorge PS Unit 1 | QLD1 | 1.49 | 119.6 | 1117.92 | 15.4 | 0.13% |
| Barron Gorge PS Unit 2 | QLD1 | 1.49 | 119.6 | 1117.92 | 15.4 | 0.13% |
| Kareeya PS Unit 1 | QLD1 | 1.49 | 119.6 | 1117.92 | 15.4 | 0.13% |
| Kareeya PS Unit 2 | QLD1 | 1.49 | 119.6 | 1117.92 | 15.4 | 0.13% |
| Kareeya PS Unit 3 | QLD1 | 1.49 | 119.6 | 1117.92 | 15.4 | 0.13% |
| Kareeya PS Unit 4 | QLD1 | 1.49 | 119.6 | 1117.92 | 15.4 | 0.13% |
| Mackay GT | QLD1 | 1.41 | 116.6 | 1078.57 | 15.2 | 0.13% |
| Vales Point 330 Unit 5 | NSW1 | 1.27 | 96.5 | 2899.04 | 5.1 | 0.04% |
| Vales Point 330 Unit 6 | NSW1 | 1.27 | 96.5 | 2899.04 | 5.1 | 0.04% |
| Munmorah 330 Unit 3 | NSW1 | 1.27 | 96.5 | 2898.88 | 5.1 | 0.04% |
| Munmorah 330 Unit 4 | NSW1 | 1.27 | 96.5 | 2898.88 | 5.1 | 0.04% |
| Eraring 330 Unit 1 | NSW1 | 1.27 | 96.5 | 2898.80 | 5.1 | 0.04% |
| Eraring 330 Unit 2 | NSW1 | 1.27 | 96.5 | 2898.80 | 5.1 | 0.04% |
| Eraring 500 Unit 3 | NSW1 | 1.22 | 96.9 | 2886.40 | 4.9 | 0.04% |
| Eraring 500 Unit 4 | NSW1 | 1.22 | 96.9 | 2886.40 | 4.9 | 0.04% |
| Bayswater 330 Unit 1 | NSW1 | 1.14 | 81.8 | 2273.48 | 5.8 | 0.05% |
| Bayswater 330 Unit 2 | NSW1 | 1.14 | 81.8 | 2273.48 | 5.8 | 0.05% |
| Bayswater 330 Unit 3 | NSW1 | 1.14 | 81.8 | 2273.48 | 5.8 | 0.05% |
| Bayswater 330 Unit 4 | NSW1 | 1.14 | 81.8 | 2273.48 | 5.8 | 0.05% |

| | | Nodal Price Difference Relative to RRN, All Periods | | Nodal Price Difference Relative to RRN, Binding Periods | | |
|---|---|---|---|---|---|---|
| | | Average | Standard Deviation | Average | Binding Instances | Binding Periods as % all Periods |
| Liddell 330 Unit 1 | NSW1 | 1.14 | 81.7 | 2267.32 | 5.8 | 0.05% |
| Liddell 330 Unit 2 | NSW1 | 1.14 | 81.7 | 2267.32 | 5.8 | 0.05% |
| Liddell 330 Unit 3 | NSW1 | 1.14 | 81.7 | 2267.32 | 5.8 | 0.05% |
| Liddell 330 Unit 4 | NSW1 | 1.14 | 81.7 | 2267.32 | 5.8 | 0.05% |
| Kangaroo Valley - Bendeela (Shoalhaven) 330 | NSW1 | 0.83 | 77.1 | 3733.83 | 2.6 | 0.02% |
| Wallerawang 330 Unit 7 | NSW1 | 0.77 | 62.8 | 1538.06 | 5.8 | 0.05% |
| Wallerawang 330 Unit 8 | NSW1 | 0.77 | 62.8 | 1538.06 | 5.8 | 0.05% |
| Mt Piper 330 PS Unit 1 | NSW1 | 0.61 | 56.3 | 1236.53 | 5.8 | 0.05% |
| Mt Piper 330 PS Unit 2 | NSW1 | 0.61 | 56.3 | 1236.53 | 5.8 | 0.05% |
| Loy Yang A PS Unit 1 | VIC1 | 0.42 | 21.0 | 894.71 | 5.5 | 0.05% |
| Valley Power Unit 4 | VIC1 | 0.42 | 21.0 | 894.71 | 5.5 | 0.05% |
| Valley Power Unit 5 | VIC1 | 0.42 | 21.0 | 894.71 | 5.5 | 0.05% |
| Valley Power Unit 6 | VIC1 | 0.42 | 21.0 | 894.71 | 5.5 | 0.05% |
| Loy Yang A PS Unit 2 | VIC1 | 0.42 | 21.0 | 894.71 | 5.5 | 0.05% |
| Loy Yang A PS Unit 3 | VIC1 | 0.42 | 21.0 | 894.71 | 5.5 | 0.05% |
| Loy Yang A PS Unit 4 | VIC1 | 0.42 | 21.0 | 894.71 | 5.5 | 0.05% |
| Loy Yang B PS Unit 1 | VIC1 | 0.42 | 21.0 | 894.71 | 5.5 | 0.05% |
| Loy Yang B PS Unit 2 | VIC1 | 0.42 | 21.0 | 894.71 | 5.5 | 0.05% |
| Valley Power Unit 1 | VIC1 | 0.42 | 21.0 | 894.71 | 5.5 | 0.05% |
| Valley Power Unit 2 | VIC1 | 0.42 | 21.0 | 894.71 | 5.5 | 0.05% |
| Valley Power Unit 3 | VIC1 | 0.42 | 21.0 | 894.71 | 5.5 | 0.05% |
| Millmerran Energy Trader | QLD1 | 0.24 | 15.4 | 278.60 | 10.2 | 0.09% |
| Millmerran Energy Trader | QLD1 | 0.24 | 15.4 | 278.60 | 10.2 | 0.09% |
| Aggregate Generator - Snowy | SNOWY 1 | 0.20 | 27.7 | 109.06 | 21.1 | 0.18% |

**Table 8: Summary of Nodal Price Deviation (from RRP) – Excluding > 100 prices**

| | | Nodal Price Difference Relative to RRN, All Periods | | Nodal Price Difference Relative to RRN, Binding Periods | | |
|---|---|---|---|---|---|---|
| | | Average | Standard Deviation | Average | Binding Instances | Binding Periods as % all Periods |
| | | $/MWh | $/MWh | $/MWh | Hours | % |
| Mt Stuart PS Unit 2 | QLD1 | 0.11 | 2.5 | 39.60 | 31.7 | 0.27% |
| Mt Stuart PS Unit 1 | QLD1 | 0.01 | 0.8 | 14.11 | 11.9 | 0.10% |
| Hazelwood PS Unit 1 | VIC1 | 0.18 | 2.8 | 26.04 | 77.9 | 0.67% |
| Hazelwood PS Unit 2 | VIC1 | 0.18 | 2.8 | 26.04 | 77.9 | 0.67% |
| Hazelwood PS Unit 6 | VIC1 | 0.18 | 2.8 | 26.04 | 77.9 | 0.67% |
| Hazelwood PS Unit 7 | VIC1 | 0.18 | 2.8 | 26.04 | 77.9 | 0.67% |
| Hazelwood PS Unit 8 | VIC1 | 0.18 | 2.8 | 26.04 | 77.9 | 0.67% |
| Jeeralang A PS Unit 1 | VIC1 | 0.18 | 2.8 | 26.04 | 77.9 | 0.67% |
| Jeeralang A PS Unit 2 | VIC1 | 0.18 | 2.8 | 26.04 | 77.9 | 0.67% |
| Jeeralang A PS Unit 3 | VIC1 | 0.18 | 2.8 | 26.04 | 77.9 | 0.67% |
| Jeeralang A PS Unit 4 | VIC1 | 0.18 | 2.8 | 26.04 | 77.9 | 0.67% |
| Jeeralang B PS Unit 1 | VIC1 | 0.18 | 2.8 | 26.04 | 77.9 | 0.67% |
| Jeeralang B PS Unit 2 | VIC1 | 0.18 | 2.8 | 26.04 | 77.9 | 0.67% |
| Jeeralang B PS Unit 3 | VIC1 | 0.18 | 2.8 | 26.04 | 77.9 | 0.67% |
| Morwell PS G4 | VIC1 | 0.18 | 2.8 | 26.04 | 77.9 | 0.67% |
| Morwell PS G5 | VIC1 | 0.18 | 2.8 | 26.04 | 77.9 | 0.67% |
| Morwell PS G1, 2 and 3 | VIC1 | 0.18 | 2.8 | 26.04 | 77.9 | 0.67% |
| Bairnsdale Power Station | VIC1 | 0.18 | 2.8 | 26.04 | 77.9 | 0.67% |
| Bairnsdale Power Station Generator Unit 2 | VIC1 | 0.18 | 2.8 | 26.04 | 77.9 | 0.67% |
| Yallourn W PS 220 Unit 1 | VIC1 | 0.10 | 1.8 | 19.68 | 56.3 | 0.49% |
| Collinsville PS Unit 1 | QLD1 | 0.06 | 2.1 | 38.07 | 19.5 | 0.17% |
| Collinsville PS Unit 2 | QLD1 | 0.06 | 2.1 | 38.07 | 19.5 | 0.17% |
| Collinsville PS Unit 3 | QLD1 | 0.06 | 2.1 | 38.07 | 19.5 | 0.17% |

| | | Nodal Price Difference Relative to RRN, All Periods | | Nodal Price Difference Relative to RRN, Binding Periods | | |
|---|---|---|---|---|---|---|
| | | Average | Standard Deviation | Average | Binding Instances | Binding Periods as % all Periods |
| Collinsville PS Unit 4 | QLD1 | 0.06 | 2.1 | 38.07 | 19.5 | 0.17% |
| Collinsville PS Unit 5 | QLD1 | 0.06 | 2.1 | 38.07 | 19.5 | 0.17% |

Further insights into the extremely high mean price differentials for Mt Stuart units can be derived from the detailed constraint data presented in Table 9. A few constraints that bind for a very limited number of instances have extremely high shadow price over $100,000 – although all of these instances are moved in calculating the mean price differentials. Nevertheless, there are high price differentials just below $10,000 mark that causes the average price differential to go up significantly.

There are other aspects of Mt Stuart constraints that are worth noting in this context:

- The physical drivers of the constraints seem to vary e.g., outage conditions, voltage, stability limits, other special discretionary limits, etc;

- Intra-QLD constraints fall into two extreme categories e.g., constraint # 583, 351, 123 etc are both infrequent and have low shadow prices, and constraint # 50, 302, 281 etc occurred very rarely but have extreme impacts. It would be extremely difficult to predict whether these conditions are likely to occur in a similar manner in the future. We have ignored outage related constraints #302 and #281 in our analysis accordingly; and

- It is also interesting to note that the sign of the constraints in which the generator terms appear are different across the constraints implying that the price differential can be positive or negative i.e., nodal prices can be (substantially) higher or lower relative to the RRP.

## Table 9: Constraint Data for Mt Stuart Units

| ` | Constraint # | Coeff | Description | Binding periods | Sign | AverageShadowPrice |
|---|---|---|---|---|---|---|
| Mt Stuart PS Unit 1 | 50 | 1 | Qld,transfer into Ross(H13Ross+fdrs7127/ 8at T37Coll.PS)<=520MW | 10 | >= | 360998 |
| Mt Stuart PS Unit 1 | 302 | 1 | Qld,Ross limit of 500MW | 11 | >= | 327321 |
| Mt Stuart PS Unit 1 | 281 | 1 | Qld,Out=Ross_SVC, Ross(H13Ross+fdrs7128 & 7208)uvLmt<=600MW | 8 | >= | 200000 |
| Mt Stuart PS Unit 1 | 377 | 1 | Out=132kV fdr7150 Lilyvale-Dysart+ H11 Nebo SVC, Voltage stability C-N Lmt <= 820MW | 4 | >= | 200000 |
| Mt Stuart PS Unit 1 | 409 | 1 | Qld,Out=Ross_SVC+Nebo_SVC, Ross(H13Ross+fdrs7128 & 7208) uvLmt<=500MW | 5 | >= | 200000 |
| Mt Stuart PS Unit 1 | 410 | 1 | Qld,Out=Ross_SVC, Ross(H13Ross275kV Infeed+132kV fdrs 7128 & 7208)uvLmt<=600MW | 7 | >= | 200000 |
| Mt Stuart PS Unit 1 | 534 | 1 | QLD,Outage one, fdr 821/or Discretionary limit(CNtf 630) | 4 | >= | 200000 |
| Mt Stuart PS Unit 1 | 301 | 1 | QLD, C-N Stab.trf Lmt 930(including Dysart infeed) | 39 | >= | 134886 |
| Mt Stuart PS Unit 1 | 231 | 1 | QLD,Out=Nil,CQ-NQ T.Stab Lmt = ( 985 - f(# of NQhyd SCs)) | 70 | >= | 116044 |
| Mt Stuart PS Unit 1 | 270 | 1 | Qld,Out= 879 or 880,RossTr.StabLmt<=225MW, 2L-Gfault on 880/879 | 133 | >= | 89992 |
| Mt Stuart PS Unit 1 | 207 | 0.48 | CHIMERA, Qld - Tarong Limit, 0.8*(margin) Qld Gen on LHS | 14 | <= | 44347 |
| Mt Stuart PS Unit 1 | 543 | 1 | Qld, QMSP1 GT Online for Powerlink NSA for C-N Limit control | 433 | >= | 13048 |
| Mt Stuart PS Unit 1 | 309 | 1 | Qld, QMSP1 GT Online for Powerlink NSA for C-N Limit control | 107 | >= | 11740 |
| Mt Stuart PS Unit 1 | 51 | 1 | Qld Central-South <=1700MW discretionary | 3 | <= | 2064 |
| Mt Stuart PS Unit 1 | 379 | 1 | Out=132kV fdr7150 Lilyvale-Dysart+ H11 Nebo SVC, Voltage stability C-N Lmt <= 820MW | 16 | >= | 880 |
| Mt Stuart PS Unit 1 | 594 | 0.48 | QLD-TRLmt(opt1)<=Calc.MW(Tar cutset), for QNI -veRes, Max forced ramp back f(QNI-Q_N mw) 200MW | 8 | <= | 244 |
| Mt Stuart PS Unit 1 | 565 | 0.48 | QLD-TRLmt(opt1)<=Calc.MW(Tar cutset), for QNI -veRes, Max forced ramp back f(QNI-Q_N mw) 150MW | 19 | <= | 211 |
| Mt Stuart PS Unit 1 | 253 | 1 | QLD, C-N Stab.trf Lmt 940(including Dysart infeed) | 1 | >= | 79 |
| Mt Stuart PS Unit 1 | 587 | 0.48 | QLD-TRLmt(opt1)<=Calc.MW(Tar cutset), for QNI -veRes, Max forced ramp back f(QNI-Q_N mw) 150MW | 8 | <= | 47 |
| Mt Stuart PS Unit 1 | 123 | 1 | Qld Central-South <=1900MW discretionary | 110 | <= | 22 |
| Mt Stuart PS Unit 1 | 351 | 1 | Qld Central-South <=2000MW discretionary | 17 | <= | 9 |
| Mt Stuart PS Unit 2 | 50 | 1 | Qld,transfer into Ross(H13Ross+fdrs7127/ 8at T37Coll.PS)<=520MW | 10 | >= | 360998 |
| Mt Stuart PS Unit 2 | 302 | 1 | Qld,Ross limit of 500MW | 11 | >= | 327321 |
| Mt Stuart PS Unit 2 | 281 | 1 | Qld,Out=Ross_SVC, Ross(H13Ross+fdrs7128 & 7208)uvLmt<=600MW | 8 | >= | 200000 |
| Mt Stuart PS Unit 2 | 377 | 1 | Out=132kV fdr7150 Lilyvale-Dysart+ H11 Nebo SVC, Voltage stability C-N Lmt <= 820MW | 4 | >= | 200000 |
| Mt Stuart PS Unit 2 | 409 | 1 | Qld,Out=Ross_SVC+Nebo_SVC, Ross(H13Ross+fdrs7128 & 7208) uvLmt<=500MW | 5 | >= | 200000 |
| Mt Stuart PS Unit 2 | 410 | 1 | Qld,Out=Ross_SVC, Ross(H13Ross275kV Infeed+132kV fdrs 7128 & 7208)uvLmt<=600MW | 7 | >= | 200000 |
| Mt Stuart PS Unit 2 | 534 | 1 | QLD,Outage one, fdr 821/or Discretionary limit(CNtf 630) | 4 | >= | 200000 |
| Mt Stuart PS Unit 2 | 301 | 1 | QLD, C-N Stab.trf Lmt 930(including Dysart infeed) | 39 | >= | 134886 |
| Mt Stuart PS Unit 2 | 231 | 1 | QLD,Out=Nil,CQ-NQ T.Stab Lmt = ( 985 - f(# of NQhyd SCs)) | 70 | >= | 116044 |
| Mt Stuart PS Unit 2 | 270 | 1 | Qld,Out= 879 or 880,RossTr.StabLmt<=225MW, 2L-Gfault on 880/879 | 133 | >= | 89992 |
| Mt Stuart PS Unit 2 | 207 | 0.48 | CHIMERA, Qld - Tarong Limit, 0.8*(margin) Qld Gen on LHS | 14 | <= | 44347 |
| Mt Stuart PS Unit 2 | 310 | 1 | Qld, QMSP2GT Online for Powerlink NSA for C-N Limit control | 740 | >= | 11014 |
| Mt Stuart PS Unit 2 | 544 | 1 | Qld, QMSP2GT Online for Powerlink NSA for C-N Limit control | 847 | >= | 9245 |
| Mt Stuart PS Unit 2 | 51 | 1 | Qld Central-South <=1700MW discretionary | 3 | <= | 2064 |
| Mt Stuart PS Unit 2 | 379 | 1 | Out=132kV fdr7150 Lilyvale-Dysart+ H11 Nebo SVC, Voltage stability C-N Lmt <= 820MW | 16 | >= | 880 |
| Mt Stuart PS Unit 2 | 594 | 0.48 | QLD-TRLmt(opt1)<=Calc.MW(Tar cutset), for QNI -veRes, Max forced ramp back f(QNI-Q_N mw) 200MW | 8 | <= | 244 |
| Mt Stuart PS Unit 2 | 565 | 0.48 | QLD-TRLmt(opt1)<=Calc.MW(Tar cutset), for QNI -veRes, Max forced ramp back f(QNI-Q_N mw) 150MW | 19 | <= | 211 |
| Mt Stuart PS Unit 2 | 253 | 1 | QLD, C-N Stab.trf Lmt 940(including Dysart infeed) | 1 | >= | 79 |
| Mt Stuart PS Unit 2 | 587 | 0.48 | QLD-TRLmt(opt1)<=Calc.MW(Tar cutset), for QNI -veRes, Max forced ramp back f(QNI-Q_N mw) 150MW | 8 | <= | 47 |
| Mt Stuart PS Unit 2 | 123 | 1 | Qld Central-South <=1900MW discretionary | 110 | <= | 22 |
| Mt Stuart PS Unit 2 | 351 | 1 | Qld Central-South <=2000MW discretionary | 17 | <= | 9 |