Mr John Pierce
Chairman
Australian Energy Market Commission
PO Box A2449
SYDNEY SOUTH NSW 1235

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Dear Mr Pierce

TRANSMISSION FRAMEWORKS REVIEW – SUPPLEMENTARY SUBMISSION

CS Energy, Delta Electricity, Eraring Energy, Macquarie Generation, Snowy Hydro, Stanwell Corporation and Tarong Corporation (the 'Northern Group') have prepared the following brief set of additional comments on the Transmission Frameworks Review (TFR) Issues Paper to address some of the statements made by the Australian Energy Markets Operator (AEMO) in its initial response to the review (7 October 2010). We hope that the Commission has the time and opportunity to consider the following comments.

AEMO's submission to the TFR documents a number of examples of network constraints over the past 12 months that have resulted in congestion in the transmission system in different parts of the National Electricity Market (NEM). The discussion below focuses on two of AEMO's particular examples.

We do not dispute AEMO's description of these events. However, we do not believe that AEMO has adequately detailed the underlying causes of congestion during these periods nor provided sufficient background information that would inform the Commission's analysis of these case studies. Claims of a significant and ongoing congestion problem without any context or history can be misleading.

Using the case studies as evidence of a material problem, AEMO outlines a number of new mechanisms that it considers may improve dispatch outcomes. The Northern Group takes the opposite view. As outlined in our initial submission to the TFR, we do not consider that congestion is a major or persistent problem in the NEM requiring a redesign of regulatory arrangements. We have attempted to look at the underlying causes of congestion in the examples put forward by AEMO. In each case, there was a mix of factors that combined to trigger transmission constraints. We believe that AEMO should have provided some explanation of these factors and detailed its role in these events.

In the discussion below we provide a review AEMO's examples providing more context behind the events. We also provide further comments on AEMO's views on power system security and its proposed solutions for addressing network congestion.

A closer look at AEMO's case studies

AEMO looks at market events on a number of different cut-sets on a number of trading days. We have focused on the two following examples:

1. 70 and 71 transmission lines between Mt Piper and Wallerawang power stations (the focus of much of AEMO's analysis); and
2. Murray to Dederang constraint,

AEMO have described these constraints as "relatively minor network congestion incidents".[1] We are not of the same view. All these congestion incidents resulted from constraints on major transmission lines to major load centres from large generation centres either under outage conditions or during periods of major transmission upgrades. While congestion is likely during these times, it raises a number of questions: is the congestion material, is it transitory or permanent, and could it be managed by better planning and operating practices?

Each of AEMO's examples are discussed below as well as comments responding to AEMO's views on

1. <u>Mt Piper to Wallerawang - 70/71 line constraint</u>

The Northern Group provided some background material on the 70/71 line constraints in our first submission to the TFR (Appendix B, 29 September 2010). We observed that:

- The 500kV upgrade to the western ring in NSW was a major investment project. The upgrade did cause temporary constraint issues on the 70/71 lines but the problem has since passed. The system would need to experience concurrent multiple generator and transmission outages before there were any future binding constraints in this key part of the NSW transmission network.
- An issue identified by TransGrid during the upgrade planning was the unsatisfactorily low fault limits on the current transformers on the bay coupler circuit breakers at TransGrid's Wallerawang and Mt Piper switchyards. These transformers needed replacing as part of the upgrade works to utilise the full ratings of TL70/71. Had this taken place earlier, network congestion would most likely have been avoided.
- The sequencing of the conversion could have been managed more efficiently to reduce the impact on the market. Had the two 330 kV transmission lines between Mt Piper and Marulan been converted to 500kV line prior to the works undertaken to convert the Bayswater to Mt Piper transmission lines to 500kV lines and the commissioning of the new transmission line (TL70) between Mt Piper and Wallerawang, the market could have avoided network constraint issues with the new TL70/71 cut-set.

[1] AEMO, Submission to Issues Paper, page 20.

- AEMO undertakes the Energy Adequacy Assessment Projection on a quarterly basis. Using this information, AEMO would have been aware of the energy limits at Wallerawang due to ongoing drought conditions. AEMO could have advised TransGrid to sequence the conversion of the 330kV to 500kV works in a way that would minimise the impact on the spot market.
- Alternatively, TransGrid could have procured a network support agreement with Wallerawang to operate at higher loadings during periods when AEMO forecast congestion on the 70/71 cut-set. The agreement would have compensated Wallerawang for the high opportunity cost of available water supplies at the time.

In looking at the 70/71 line constraints AEMO primarily focus on events occurring on 10 August 2010 and 7 December 2009.

10 August 2010

AEMO's analysis of market events on 10 August 2010 (Appendix E) states that "the event was triggered by a network reconfiguration that unexpectedly, and briefly, invoked a lower rating on the Mt Piper-Wallerawang constraint".[2] The Northern Group considers that a primary cause of this event was AEMO's step change in the rating of the Mt-Piper to Wallerawang lines (70/71 lines). We are of the view that had AEMO used its standard operating procedure for ramping the reduction in line ratings the impact of this event could have been moderated or avoided.

Furthermore, during the congestion events that day on 70/71 cut-set there was an outage of TL36 Mt Piper to Marulan on the transmission system that compounded the effect of limits on 70/71 as this outage resulted in additional flow across the 70/71 cutset.

All the 70/71 line constraint market incidents referred to by AEMO are directly related to the major transmission upgrade works in NSW (330 kV to 500 kV western ring conversion). The Northern Group acknowledges that there is a case for improved co-ordination between the energy market and TNSP planning and operation during major transmission upgrades involving staging works. Part of any solution could involve AEMO/TNSP procuring relevant short-term network support agreements.

7 December 2009

AEMO states that the "gross customer settlement" total in the absence of actual rebids for the incident described in Appendix B (7 December 2009) would have been at least $300 million below the actual outcome. "Gross customer settlement" is not part of the market central dispatch objective (reference 3.8.1 of the market rules) which aims to maximise the value of trade. It is also not clear why AEMO choose to do the re-run based on dispatch bids at 6.30am for this particular trading day and not at a time closer to when the constraint bound.

[2] AEMO, page 56

AEMO demand forecasting errors were one factor in bidding changes on 7 December 2009. In this case the pre-dispatch demand issued at 6:30am (across all NEM regions) was significantly *less* than the demand that actually occurred during that day. At one trading interval during the day (13:30), the cumulative NEM demand was *807 MW higher* than forecast at the 06:30 pre-dispatch run (with actual demand for NSW 536 MW higher than forecast).

Further, the AEMO analysis ignores contractual positions between all affected market participants. It is commonly accepted that most base to intermediate merit generators are heavily contracted and most retailers are also highly contracted. Hence the net effect of the spot prices associated with this incident would be significantly moderated by contractual obligations.

The economic impact of these constraints would be the difference in marginal fuel costs between generators constrained off versus those that generated when the constraint was binding. For the event on the 7 December 2009, an examination of the output of the Victorian brown coal generators (which have the cheapest thermal short run marginal costs) showed that their output was constant and their plant was not constrained. Of those generators affected,(predominantly NSW and Qld), nearly all of these generators have similar short run marginal costs or opportunity costs. The actual economic cost of the changed mix of generation would have been negligible as a proportion of total trade.

2. <u>Murray to Dederang constraint</u>

For the 22 April 2010 Murray to Dederang market event there were *three* separate major transmission related outages (coinciding with some 1,000 MWs of generation outages in Victoria):

- Basslink forced outage from 17 April 2010 (prior to the events);
- Dederang to South Morang line planned outage; and
- Dederang/South Morang transformer planned outage.

This event demonstrates poor transmission outage planning, co-ordination and approval processes rather than issues with market design. This example provides a solid argument for improved planning and coordination of transmission outages and possibly sharper incentives on TNSP's for minimising the market impacts of outages.

The event of 22 April 2010 highlights that improved communication between AEMO and the relevant TNSP would have resulted in avoiding taking out of service either the Dederang to South Morang line or the Dederang/South Morang transformer thereby reducing the impact of the Basslink forced outage. It is unclear why such significant transmission outages were allowed to proceed at the same time as the Basslink forced outage and significant generation outages.

Power system security

AEMO's analysis focuses on the use of ramp rates to maintain generator outputs. There is no evidence that the system was insecure as a result of the use of low rate of change ramp rates in any of the case studies. AEMO acknowledges this in its submission … "the appendices show no evidence of the power system becoming technically insecure due to low ROCs"[3]

AEMO was closely involved in the AER rule change proposal on technical parameters. The process recommended the use of 3MW/minute per dispatchable unit as a sufficient ramp rate in order for the system operator to manage the system in a secure and reliable state.

The Northern Group is concerned by AEMO's comments that rebidding by a large number of generators *may* lead to the system being insecure. One of the main reasons for a large number of generators to be affected by a constraint is the co-optimising of interconnector and intra-regional generation terms in constraint equations. This formulation, (known as 'Option 4' from the 2002 review of intra-regional constraint formulation), was selected largely on the basis of improving system security, because the dispatch engine would be able to adjust interconnectors (representing inter-regional generation) to resolve an intra-regional constraint. It was AEMO itself that recommended this option, even though a number of participants advised that it would result in more significant changes in dispatch and accumulation of negative settlement residues.

AEMO'S proposed solution for network congestion

AEMO identifies a range of proposed mechanisms for managing network congestion including prohibiting certain bids, defining generator access to the market, compensation based on an audit of generator costs, and smaller regions. AEMO notes some of the difficulties with implementing these options. AEMO has indicated some degree of support for a generalised CSP/CSC arrangement with rights allocated according to presented availability as a way of minimising the incentive for disorderly bidding and the resultant problem of mispricing. AEMO recommends that the AEMC undertake a detailed analysis of the costs and benefits of such a mechanism.

Importantly, AEMO does not to consider the wider and more perverse impacts on the financial market of such mechanisms.

Specifically under the CSP/CSC proposal, it would be triggered at any time when significant constraints emerge. We are of the view that a generalised CSP/CSC poses far greater risks to market participants than the current arrangements. Under such a scheme, participants would not have confidence of their level of transmission rights (CSCs) to be settled at their RRN. This allocation or "rationing" would happen in real time depending on which constraint is binding. Participants would only know their actual allocation of CSCs after the event. This allocation is dependent on the actual transmission line rating and the bidding behaviour of competitors. As such the scheme would significantly increase the cost and complexity of operating, trading and contracting.

[3] AEMO page 24

Conclusion

We have a number of specific concerns with AEMO's analysis:

- AEMO's examples are based on either major network outage conditions or transitionary upgrade works to major parts of the transmission network. None of the examples involved system normal conditions.

- Most of the generators in these examples face similar fuel or opportunity costs indicating that dispatch inefficiencies would be a small fraction of the reported costs in AEMO's analysis.

- The use of "gross customer settlement" is an inappropriate measure of the cost of congestion, as it does not take account of contractual positions between all affected market participants .

- Financial markets are the key mechanism for managing risks in the NEM. The "solutions" identified by AEMO may have a minor impact on productive efficiency but would present significant risk management issues for participants and limit market liquidity. This would result in increased costs to customers which are likely to be greater than any benefits resulting from AEMO's proposals.

- Better co-ordination and communication between AEMO and the relevant TNSPs, and better operational procedures within AEMO (such as avoiding step changes in transmission ratings without adequately informing the Market), could have significantly reduced the impact on the spot market of these constraints.

AEMO's focus on the 70/71 cut-set does not make the case for a significant change to congestion management arrangements in the NEM. This was a one-off project involving a major strengthening of the NSW system that could have been staged and organised in a way to avoid or minimise congestion problems. AEMO's analysis has not demonstrated the extent of network congestion across the market or quantified the actual economic cost of these events.

RUSSELL SKELTON
MANAGER MARKETING & TRADING
MACQUARIE GENERATION

ON BEHALF OF THE NORTHERN GROUP

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