13 April 2006

Dr John Tamblyn
Chairman
Australian Energy Market Commission
P O Box H166
AUSTRALIA SQUARE NSW 1215

Email: submissions@aemc.gov.au

Dear Dr Tamblyn

Congestion Management Review: Issues Paper

As an end use customer with an interest in, and some knowledge of, the National Electricity Market I am pleased to have this opportunity to comment on some of the issues raised in this paper.

Furthermore, as an end use customer I am keen to see an efficient electricity market in Australia with accurate price signals that would drive the development of the electricity supply system and the behaviour of both customers and suppliers of electricity.

My contact details are provided separately in the attached email if you wish to discuss these matters further.

My comments follow.

Yours sincerely,

John Hoddinott

Question 13

Does the current design of IRSR units impact the ability of participants to efficiently manage inter-regional price risk?

The SRA process was originally created to provide the funds to under-write inter-regional hedges and as such the SRA unit was never intended to be the instrument to directly manage inter-regional price risk.

There are a number of factors that limit the usefulness of the SRA units in this role and potentially restrict trade between regions. These factors include:

- the SRA units are specified as percentages of IRSR rather than in MWs – therefore they are not directly compatible with other hedging instruments;
- the SRA unit approximates a firm hedge only if the directional interconnector is congested at its nominal capacity. It performs badly when a significant price difference is due to transmission losses or the interconnector capacity is significantly below the nominal value;
- payments relate to the IRSR on specific directional interconnectors – therefore no payment is received if the relevant interconnector is out of service;
- if the relevant regional reference nodes are not in adjacent regions then it is necessary to specify the path (ie all of the directional interconnectors) needed to form a path between the relevant regional reference nodes. This may not be too difficult at the moment with a linear arrangement of regions, but it could be quite complex if, following a region boundary change, looped regions exist.

A potential issue may occur, if the CRA proposal for a CSP/CSC regime was implemented. In this case participants would manage their intra-regional price risk using CSCs, which are a hedging instrument specified in MWs, and their inter-regional price risk using SRA units. It would be preferable that all inter-locational price risk be managed using a single type of instrument. The financial transmission right (FTR) would be a suitable instrument – it enables the participant to specify the quantity of MWs to be hedged and the two locations whose price difference is creating the risk. The most common form of FTR is referred to as an obligation and should be compatible with the swap contract currently used for energy trading.

Even if the CSP/CSC regime was not implemented, an FTR could still be used. In this case the only locations that could be specified are regional reference nodes. Unlike the SRA unit the FTR is not path specific and is thus much easier for participants to use when hedging between non-adjacent regions.

Also of concern is the performance of the SRA mechanism and the benefits to end use customers.

According to NEMMCO's Settlement Residue Committee report for the period 1 July 2004 to 30 June 2005, the SRA has over the 6 years of its operation received $540M in auction proceeds from participants. These proceeds are then paid to the TNSPs who are obligated to use them to reduce network charges thus benefiting end use customers. During this same period the participants holding SRA units have received $756M. This suggests that end users may have lost $216M over 6 years from this process. The validity of this statement depends on how the participants have used the IRSR payments they have received and this information is not readily available.

Another view of SRA performance is the average return received by investors in the SRA. The SRA unit(s) has a term of three months. On average the proceeds every three months has been $22.5M and the return to participants has been $31.5M – this is an average return of 40% in three months. While the SRA unit is a risky product a quarterly return of 40% does seem excessive. This result may be attractive to speculators and a NECA survey in 2000 and found that approximately half the SRA units purchased were used for speculation. The current extent of speculative sales is unknown, but it would not be surprising to find that it was now in the majority. It is important to establish if the end use customer is gaining sufficient benefit from the SRA process to justify its existence.

Question 18

Is the proposed 'staged approach' to congestion management an appropriate framework? Is it the most effective response to those problems? Is it technically and commercially feasible?

The proposed staged approach including regional boundary changes, the pricing of material congestion and the possibility of building out this congestion if it is economic to do so appears to be a relatively simple and logical approach to the problems arising from significant congestion in the electricity transmission system. It is a central planning approach and as such, providing one necessary requirement is met, it should be an efficient solution to this problem.

The necessary requirement is an accurate prediction of where significant congestion is likely to occur. Modellers certainly have the techniques to determine these features of the transmission system provided their assumptions about the future are correct.

Similar work has been undertaken for the PJM system with less than satisfactory results. The following extract indicates the difficulty PJM had.

> *"The accumulating experience in PJM is well documented and amply illustrates the point. In one outside study intended to support the development of zonal pricing and decentralized congestion management through something like a flowgate model, a set of 28 constraints were identified as important and analyzed for the variations in the equivalent of a PTDF table. While 28 may seem a large number and difficult to deal with in assembling the capacity rights to use the transmission system, it turned out not to be large enough. In the event, the first six months of operation of locational pricing in PJM found 43 constraints actually binding. Most importantly, none of these actual constraints were in the list of 28*

> *supposedly easy-to-identify flowgates. This suggests the magnitude of the difficulties faced when predicting which constraints will be binding. And the list of real constraints continues to grow. Over the period January 1998 to April 2000, there were 161 unique constraints that produced congestion and different locational prices in PJM. Apparently a complete flowgate model would require purchase of at least 161 capacity rights to secure a single point-to-point transaction. And the list is growing."*[1]

Can we be confident that the NEM will not encounter similar difficulties? There has already been some NEM experience that indicates the difficulty of the problem. This occurred in the first few years of the SRA when reserve prices were being set and 3 different modellers were employed by NEMMCO to simultaneously forecast the IRSR. The modellers were asked to provide a single value of IRSR for each month for a given 12-month period. The values provided by the modellers varied considerably both from each other and from the actual IRSR that occurred.

These issues with forecasting have occurred when trying to forecast significant congestion less than 2 years into the future. With the inclusion of regional boundaries in this staged approach to congestion management the required forecast must extend out to approximately 10 years.

How accurate are these forecasts likely to be and what happens if the forecasts produce the incorrect regional boundaries and/or fail to identify materially significant congestion? Will the difficulty in forecasting reduce or even eliminate the benefits of regional pricing?

<u>Question 24</u>

To what extent will firming-up IRSRs facilitate inter-regional trade? What is the best approach to firming up IRSRs and how would this work?

The main issue to address in providing a firm inter-regional (or inter-locational hedge) is to determine which party (or parties) will be responsible for ensuring revenue adequacy.

In an FTR regime as briefly described before (and ignoring transmission losses), revenue adequacy is guaranteed from the settlement residue provided that all of the FTRs sold are simultaneously feasible for a given transmission network model and that the actual capacity of the transmission elements equals or exceeds the capacities specified in the model. Simultaneous feasibility means that it is possible to dispatch the generation so that all power transfers implied by the FTRs can be realised at the same time. It should be noted that in reality the generation never has to be dispatched in this manner, but only that it is possible to do so. The transmission network model forms part of the allocation algorithm and this algorithm may also include additional constraints to cater for other network limits such as stability.

---

[1] William W Hogan "Flowgate Rights and Wrongs" p20 – 20 August 2000

Ideally the capacities of the network elements and the magnitude of network limits should be specified and guaranteed (perhaps subject to some form of FM provision) by the asset owners. Effectively the network owner would be underwriting the FTR. I understand that in the market operated by the New York ISO, transmission network owners have a role in the provision of a firm(er) FTR type product.

Alternatively an independent party could be responsible for assigning network limits and operating the algorithm. This party would have to receive the best available estimates of these capacities from the asset owners together with all available information that could impact these values and then adjust them based on their assessment of the risk of the estimated capacity not being available. This party would most likely need to have the capability to manage large surpluses and deficits for sustained periods of time if a fully firm product was to be offered.

The replacement of the existing SRA process with an FTR regime enables a firmer product to be offered as the available settlement residues are pooled to ensure a payment is always available to the relevant FTR holders. This contrasts to the SRA unit where payments are related to the IRSR on specific links. The holder of an SRA unit trying to manage a significant inter-regional price risk would receive no payment if that link were unavailable when that price difference occurred.

When FTRs are being discussed, their development and operation in PJM is often cited as the example. If FTRs are discussed with respect to the NEM it is important to note that locational prices in PJM are determined exclusive of transmission losses. Thus the PJM approach cannot be readily transferred to the NEM.

Variations have been implemented or proposed for other markets that incorporate transmission losses. The approach adopted by the NYISO for their transmission congestion contracts (TCCs) provides a hedge for the congestion component only, of the locational price. The New Zealand proposal (by Transpower) uses an unbalanced FTR – ie the MWs specified at the injection or sending location are (usually) greater than the MWs specified at the withdrawal or receiving location. The difference between these MW quantities is an allowance for transmission losses associated with the transaction represented by the FTR. Another possibility is the inclusion of loss hedges in the allocation algorithm for “normal” FTRs. The allocation of these loss hedges would be subject to generator bids and the allocation of the FTRs, in turn, would be related to the allocation of the loss hedges[2].

Alternative congestion management arrangements

The issues paper (p47) suggested

[2] S.M. Harvey and W.W. Hogan “Loss Hedging Financial Transmission Rights” – 15 January 2002

> *"as an alternative to full nodal pricing it could be possible to introduce an arrangement where generators are settled according to nodal prices, while customers continue to pay for electricity based on zonal prices."*

This approach overcomes the forecasting issue raised in my response to question 18. It also has the advantage over the CSP/CSC proposal in that it is based on established theory and practice and as noted in the issues paper is being implemented elsewhere.

I expect that this approach requires nodal prices to be calculated at all transmission nodes, but additional processing is then used to determine the zonal price. To avoid settlement deficits it is likely that the zonal prices faced by customers would have to be a weighted average of the nodal prices applicable to the relevant transmission nodes. The zonal price would also be the price applicable to a non-physical trading hub for that zone. Price difference could then occur between generator nodes and trading hubs and also between trading hubs.

A FTR type product could be used to manage the price risks between any of these locations. The firmness of this product would be dependent on the same factors outlined above in my response to question 24 and the issue of how to allocate the FTRs (mainly from generator nodes to local trading hubs) would be resolved in a similar to manner to that used in allocating CSCs.

In my opinion this approach would be preferable to the proposed 'staged approach', but more investigation may be needed to verify its practicality.