grid australia
BACKBONE OF THE NEM

11 March 2011

Mr John Pierce
Chairman
Australian Energy Market Commission
Level 5, 201 Elizabeth Street
Sydney NSW 2000

Via website: www.aemc.gov.au

Dear John,

Inter-regional Transmission Charging Draft Rule – Supplementary Submission

On 25 February 2011, Grid Australia made a submission in response to the Australian Energy Market Commission (AEMC) Inter-regional Transmission Charging Draft Rule Determination.

Grid Australia understands that the Australian Energy Market Operator (AEMO) lodged a confidential submission with the AEMC before the closing date for submissions of 25 February 2011 and that this submission was not published. Further that on 7 March 2011 a revised submission from the AEMO was published on the AEMC's website with those matters considered confidential by AEMO removed.

Grid Australia is concerned that the extremely late publication of the non-confidential version of the AEMO submission may lack transparency to registered participants and other interested parties and may limit the ability for critical review of this document. Consequently Grid Australia would like to highlight a number of points of concern raised by our members with respect to the content of this submission, which may assist the AEMC.

Grid Australia agrees that the introduction of an inter-regional charging mechanism is a significant step forward in the evolution of the NEM. While significant, Grid Australia considers it is a step which can be logically and effectively pursued without the wholesale change to pricing methodologies suggested by AEMO.

The need for consistency

AEMO suggests a number of material inconsistencies exist in the way TNSPs conduct transmission pricing under chapter 6A of the Rules and further that the level of transparency in this area is inadequate. Grid Australia does not support this view as set out in the comments below.

The role of replacement costs

Among other matters, Chapter 6A of the Rules sets out the basis for the determination of revenues that may be earned by TNSPs, and establishes the principles that must be applied by a TNSP in setting prices that allow the recovery of that revenue.

The former is determined with reference to the value of the regulated asset base which is determined on depreciated actual costs[1] while the latter is allocated based on the replacement costs of assets used for the provision of the classes of prescribed transmission services.

The AEMO submission suggests inconsistencies may exist in replacement cost models used by TNSPs and suggests that this is a matter of concern. The implication is that quite minor variances in unit rates between regions could have a material impact on the calculation of the load impact charges. This is not the case.

The replacement costs of assets providing the various classes of prescribed transmission services are used to determine the ratios (the attributable cost shares) by which the annual aggregate revenue requirement (AARR) is split to derive the annual service revenue requirement (ASRR) for to each category of prescribed transmission service[2].

The ASRRs for each class of prescribed transmission service are then ultimately allocated to connection points based on the ratios of the replacement costs[3].

Under the current and proposed arrangements, while it is important that the replacement costs are consistent within a region, variances in unit rates between regions should not materially affect the load export charges. By way of example, if South Australia increased its unit rates by 20% or decreased them by 20% the replacement cost ratios used to allocate revenues would be unaffected as would the load export charges calculated.

On 10 February 2011, AEMO and Grid Australia members attended a TPRICE workshop in Melbourne lead by Roger Bolden, the author of TPRICE. The replacement cost models used by the various TNSPs, including SP AusNet which provides its data to AEMO for calculating the Victorian transmission prices, were discussed. Consensus at this meeting was that varying unit rates applied would have no impact on the load export charges.

The impact of modified CRNP methodology

The adoption of the modified CRNP methodology is specifically provided for in the Rules and the AER has approved the adoption of modified CRNP methodology by ElectraNet and Transend. In the case of ElectraNet this step was taken in consultation with NECA who was supportive of the move.

The principal reason a TNSP may adopt the modified methodology is to provide appropriate locational signals to increase the utilisation of more lightly loaded lines in remote areas. The

[1] Having previously been established on depreciated replacement cost based valuations under the old Chapter 6.

[2] 6A.23.2

[3] 6A.23.3

modified CRNP methodology replaces the arbitrary 50:50 split between the locational and non-locational components of prescribed TUOS services with a split determined by the effective utilisation of the network.

Grid Australia does not consider that the modified CRNP methodology materially impacts on the calculation of the load export charges.

Consistency of TPRICE application

At the recent TPRICE workshop, Roger Bolden presented his analysis of the current settings for TPRICE used by those TNSPs present. With the exception of the Victorian region using the 10 day energy versus the use of 365 day capacity method of cost allocation, in the rest of the NEM there were no differences between in the application of TPRICE which would impact on price calculations. This included consistency in the usage of the "zeroreverse" and "alphascale" settings questioned by AEMO in its submission.

Grid Australia supports the need for consistency in this area.

Economic Considerations

AEMO has made a number of observations based on its comparison of the application of the 10 day energy method currently used by AEMO in Victoria and the 365 day capacity method used in all other NEM regions.

The old Chapter 6 of the Rules set out the principles that applied in determining the sample of operating conditions to be considered. Of particular note was the requirement that operating conditions to be used are to include at least 10 days with high system demand, to ensure that loading conditions, which impose peak flows on all transmission elements, are captured. This requirement clearly did not preclude the use of a broader dataset.

Schedule 6A.3.2(3) of the Rules is less prescriptive than the old Chapter 6 Rule, requiring that the allocation of dispatched generation to loads be over a range of actual operating conditions from the previous financial year and that the range of operating scenarios be chosen so as to include the conditions that result in most stress on the transmission network and for which network investment may be contemplated.

Clause 2.2(a) of the AER pricing methodology guidelines requires that prices for the recovery of the locational component of prescribed TUOS services are based on demand at times of greatest utilisation of the transmission network and for which network investment is most likely to be contemplated in accordance with clause 6A.23.4(e) of the Rules.

The use made of the network by particular loads and generators will vary considerably depending on the load and generation conditions on the network. For this reason a number of operating scenarios are examined with different load and generation patterns. In selecting those operating scenarios it is important to recognise that the operating conditions that impose most stress on particular network elements may occur at times other than for system peak demand.

The TPRICE capacity method of cost allocation (used consistently in all NEM regions other than Victoria) automatically captures the peak loading conditions on network elements from the sample of operating conditions analysed.

Grid Australia notes that the use of the full year of operating data (i.e. 365 days of half hourly data) avoids the exercise of discretion concerning an appropriate set of operating conditions and removes the ability to inadvertently pick winners and losers in the calculation of locational prices.

Locational signals – signal to avoid system peaks

AEMO argues that large users will seek to avoid usage of the transmission system during time of system peak in return for the possibility of reduced locational charges arising from the 10 day energy method.

Grid Australia does not support this proposition and considers that appropriate time of use signalling for large users exists in the energy market as times of system peak demand typically coincide with high pool prices. Demand side participation options also exist. From a market design point of view, locational signalling through transmission pricing is a second order consideration for large users compared to real-time price signals provided in the energy market.

Locational Signals – locating closer to generation

The 365 day capacity method will identify those times when major loads located in proximity to major generators are drawing on the broader network due to local generator outages or bidding behaviours.

In performing system studies to determine the requirement for system augmentations these conditions are explicitly modelled as generators do not run constantly and customers expect supply continuity in these circumstances.

Accordingly a much broader range of operating conditions is required to capture all conditions for which network investment is likely to be contemplated.

Allocations to interconnectors

The 10 system peak days used in Victoria would be expected to coincide with periods of high import and low export from the region.

In moving from the 10 day energy to the 365 capacity methodology it is to be expected that higher charges will be seen at the points of connection to adjacent regions. Grid Australia notes that this is consistent with the intent of the proposed inter-regional transmission charging regime.

Lessening of the effectiveness of avoided TUOS

TUOS charges are only truly "avoided" if the requirement for network investment is genuinely deferred. This is consistent with the generator contracting to provide a “peak lopping” service which allows a distributor to reduce its peak demand requirements and hence its transmission charges.

AEMO has not demonstrated a case, nor has it made clear what other mechanisms would allow an embedded generator’s behaviour to be linked to the avoidance of transmission investment.

Other issues

Overall, Grid Australia considers that the AEMC’s draft decision is proportionate to the ‘problem’ being solved in that it implements an inter-regional transmission charging regime that will provide incremental benefits by introducing incremental change to existing arrangements. More significant changes are not required to enable the implementation of a load export charge based on the locational component of prescribed transmission prices, or could be expected to deliver materially greater benefits.

Grid Australia also observes that in its experience, transmission network customers want to deal with someone who has a keen interest in the impact that price setting has on their businesses. This appears at odds with the AEMO concept of pricing being undertaken by a 'disinterested party'.

Grid Australia would welcome the opportunity to clarify the content of this supplementary submission with the AEMC as required.

For further information please contact Bill Jackson on (08) 8404 7969 or me on (08) 8404 7983.

Yours sincerely,

Rainer Korte

Rainer Korte
Chairman
Grid Australia Regulatory Managers Group