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SUBMISSION

Transmission Pricing for Prescribed Transmission Services

Draft Rule Proposal

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Introduction

Transmission regulation review
Total Environment Centre (TEC) welcomes the opportunity for input into the transmission pricing review process.

We have restricted our recommendations here to selected issues, in particular:

- The Rules should refer to a Demand Management (DM) Code of Practice for distribution and transmission networks, with the NSW model adopted as a minimum (including the protocol for disclosure of information)
- Networks should be obligated to *implement* non-network solutions where more cost effective than augmentation.
- Setting a specific methodology for all network service providers would provide greater certainty and clarity (as the CPI-X building block methodology has done for revenue) than the proposed recommendation that pricing principles should rely on pricing methodology guidelines to be developed by the AER. There is so little concrete direction given that we cannot support the proposed recommendation at this stage. "Cost reflective network pricing" as a principle is desirable, particularly if all the true costs are considered, but it is not defined sufficiently in the draft Rule.
- Connection costs – TEC is not convinced that the principle of shallow connection costs is being applied equitably, especially in regard to small embedded generators. Large, remote generators generally lead to overall network augmentation, thus increasing costs for consumers. The generic principle of shallow connection costs therefore needs to be modified to be more flexible.
- The AEMC should undertake a review of TUoS rebates, with due public consultation, which they raised as a possibility in the Report (p 86[1]). A resolution acceptable to all stakeholders has clearly not been reached in this stage of the review, and the AEMC has not established sufficiently that the Rules are *not* the appropriate vehicle for clarifying the situation.

[1] Note: unless otherwise cited, all page numbers refer to – Australian Energy Market Commission, *Transmission Pricing for Prescribed Transmission Services: Rule Proposal Report*, 2006

Demand management and the NEM

Demand management (DM [2]) can take many forms and provide many benefits, for the long term interests of consumers, for enhancement of economic efficiency and for providing new avenues for competition. A report for Energy SA gives describes the advantages: "Demand Side Management activities have the potential to provide a low cost alternative to generation and transmission investments, and are often the only effective short term tool for overcoming supply side and distribution system inadequacies."[3] However, DM is not being seriously addressed as an alternative to the status quo in the energy market reform program, and in the Report it is only mentioned in a cursory manner (and some of these references are in quotes from TEC's previous pricing submission).

Incentives are needed to improve this situation, since the status quo is actively working against the uptake of DM. One such incentive could be to ensure that networks are able to recoup revenue for both the cost of carrying out demand management and for the lost revenue of sales that would have been made had an augmentation gone ahead (there is a useful model in NSW, the "D-factor"). The purpose is to promote consideration of more efficient non-network solutions and, conversely, to reduce the incentive for the networks to encourage excessive consumption of electricity.

An alternative – or complementary – method of promotion would be a requirement on NSPs of a specific minimum spending level for DM: between 10% and 25% of the projected network capital expenditure could be set aside for cost-effective DM projects, on "use it or lose it" terms.

Therefore, the most important solutions for giving DM its due recognition include:

- establish a DM code of practice
- establish a DM funding mechanism
- provide transparency of pricing in relation to demand and constraints – end users are currently unaware of the true price of their electricity.

Scope of this submission

We have restricted our comments in this submission to three main issues, to clarify our position in response to the draft Rule:

- Regulation of transmission pricing
- Connection costs
- TUoS rebates.

[2] DM in this submission can be read to include 'demand response', 'demand side management', 'demand side response', 'energy efficiency' and 'non-network solutions'. In general, DM can include both the management of peak loads and energy efficiency as a way of meeting capacity requirements most cost effectively. It includes a diverse array of activities that meet energy needs, including cogeneration, standby generation, fuel switching, interruptible customer contracts, and other load shifting mechanisms.

[3] Energy SA, *Demand Side Management – Benefits to Industry & the Community*, 2001, p 5

Regulation of transmission pricing

TEC supports the principle of "cost reflective network pricing" and it is encouraging that the AEMC has opted for transmission pricing to remain within the regulatory environment in view of "the weak commercial incentives of TNSPs to price efficiently" (p 30).

The guidelines set out in section 6A.4 of the draft Rule (particularly the Modified CRNP) address many of our concerns about locational and size differentials between generators and between loads. However, this should be taken up to the next step and a specific methodology ought to have been recommended to assist "efficient longer term investment decisions" (p 22) as well as "stability and predictability" (p 22). The argument has not been made convincingly that setting a methodology will limit efficiency.

One of the grounds for retaining the building block methodology for transmission revenue is that many stakeholders have become familiar with it and can follow the details. For instance, the Public Interest Advocacy Centre noted that: "The building blocks approach ... is readily understood by end-users. To put this another way, it is an approach which consumers have come to accept and support. The reasons for any change need to be argued clearly. ... the building block approach offers regulatory certainty both to the regulated entities and end-users."[4] They add that other methods "are lacking in transparency"; a common methodology also provides a baseline to judge one business against another. It is probable that the existing Rules regarding transmission pricing need amending, but simply setting guidelines seems to be an inadequate response.

Presumably the AER will expose its draft of pricing methodology guidelines for public consultation, but the AEMC's solution – to hand it over to the AER's discretion – does not promote certainty within the NEM and risks allowing the guidelines to fall into a policy void due to lack of direction. The draft Rule gives a reasonable coverage of guidelines – particularly the modified CRNP – but there is insufficient reason presented for *not* setting a methodology for TNSPs to follow. The AEMC has noted that it will, "set out principles for their implementation by TNSPs as they develop pricing methodologies". This leaves stakeholders up in the air as to final results and it limits transparency.

As we noted in the previous submission:

> A more prescribed system for pricing could also reduce variation across jurisdictions, and aid in TNSPs allocating prices more efficiently.

Connection costs

The principle of shallow connection costs essentially advantages large, remote generators. As quoted in the Report (p 38), the Group proposed a solution which would, "help ensure efficient locational decisions for new generation investment because generators would face the cost consequences of their actions." TEC would have to agree with the principle (even if not the solution) since the presence of a new, large generator

[4] Public Interest Advocacy Centre, *Submission on Transmission Revenue Requirements: Issues Paper,* November 2005

usually leads to wide-scale network augmentation; and we note that knowledge of a proposal for a new, large generator usually causes a transmission network operator to consider augmentation.

In contrast, smaller, local generators may be charged for upgrades to the network, where the extra load necessitates some augmentation of the system beyond those required specifically for the new connection (deep connection costs). This is inequitable when large, remote generators are only charged shallow connection costs. This contravenes the general principle of paying shallow costs and the spirit of "open access" the NEM is based on. It also encourages a less reliable system of large, remote generators over many small, distributed generators which offer increased whole of system reliability.

There needs to be a mechanism where small generators are not charged for augmentation, since they may only be tipping the balance, with large generators having contributed the major load; this is not an efficient or equitable system since it runs the risk of excluding competition. The VENCorp guidelines do go some way towards ameliorating this possibility – that is, establishing "the dividing line between costs that connecting parties should be obliged to pay for, and costs that should be passed on to transmission network users at large" (p 42) – and are worth further investigation.

The AEMC notes that it would welcome discussion of the appropriateness of VENCorp's guidelines, but it has not outlined a process to facilitate this.

Transmission Use of System rebates

We commend the AEMC for the extensive coverage of Transmission Use of System (TUoS) rebate issues in the Report. We are disappointed, however, that the AEMC has decided that the provisions in the Rules should essentially remain unchanged: "The effect of these changes is to preserve the status quo in relation to TUoS rebates." (p 87) This position is unsatisfactory and a good reason is given in the Report for this interpretation: "allowing the rebate to apply to demand side management and non-electricity alternatives as well as embedded generation, as these other options may also help defer or avoid the need for transmission investment ..." (p 81).

We reiterate our argument for revision of the Rules, as quoted in the Report (p 82) as embedded generation offers a range of benefits not are not reflected in the current method of calculating avoided TUoS rebates.

If the AEMC considers that a change in the Rules is not the way to amend inequitable compensation for avoided TUoS charges, then it would be helpful if an alternative route could be proposed.

A particular problem with the findings is that, once again, demand-side and non-network alternatives are sidelined. There is a real need to address their value to the NEM in some rigorous fashion, rather than saying, as the AEMC does, that the current situation will suffice. It is clear from submissions by other organisations referred to in the Report (such as Major Energy Users, United Energy and TransGrid, as reported in Section 7) that many participants are unsure whether the costs and benefits of these alternatives can be suitably remunerated under the current Rules. The problem is not only of interest to green/small consumers but to major users and NSPs as well. Furthermore, the Rules are the appropriate vehicle for this clarification because they form the benchmark for the NEM. The fact that these changes may not be straightforward (as the AEMC claims) is no excuse for avoiding them.

There are three options presented in the Report for further discussion. We are certainly not in favour of the status quo, but a modified version could work. Exclusion of payment to generators above 10MW is a suggestion that would deal with some of the problems of bias against embedded generators and demand management. It deserves further consideration.

However, we object to the suggestion of no rebate for small plants. This is clear discrimination against small generators (and was apparently suggested by large businesses). Of all generators to whom rebates would be necessary, small businesses are the ones to whom it would be most critical in financial terms. There might be some argument for foregoing TUoS rebates to householders who have micro-generation plants (such as photovoltaic generation). The rate of installation of small generators has been increasing and will continue to do so, so their contribution could be regarded as cumulative. The same faulty rationale is being applied here as has been applied to the reliability of wind generation which is that the generators are being viewed in isolation; in reality, one small generator may have a negligible effect but a number of them in close proximity will have a considerably larger effect. Since a small plant is contributing to a larger effect, it should still be considered worthy of a rebate. Thus, if a minimum size is to be applied at all because of administrative costs of calculation, it should only reasonably be applied to micro-generation (5kW or less[5]).

The whole issue of TUoS rebates is obviously open to a range of questions and the dialogue should be continued by the AEMC, which seems to be hinted at in the Report ("until a more appropriate opportunity for a full review occurs"). TEC recommends that this is undertaken sooner rather than later, otherwise the situation will become even further entrenched and further complicated.

[5] The draft *Code of Practice for Embedded Generation* released by the MCE suggested a specific category for micro-generation; in their submission to the draft (30.3.06), the Climate Action Network Australia (CANA) recommended that this be defined as generators up to 5kW capacity.