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SUBMISSION

Review of the Electricity Transmission Revenue and Pricing Rules: Transmission Pricing

Issues Paper

30 December 2005

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Transmission Pricing

1. Introduction

1.1 Key themes

Total Environment Centre welcomes another opportunity for input to the Review of the Electricity Transmission Revenue and Pricing Rules. This submission builds on our previous paper on Revenue Requirements. We have addressed a selection of the questions within the Issue Paper on Pricing on the basis of our particular concerns, bearing in mind key themes identified by the AEMC[1]:

- The rationale for regulation
- The relationship between discretion and transparency
- Taking account of other aspects of NEM arrangements.

We reiterate that the National Electricity Market is inappropriately focused on the supply of electricity at the expense of a focus on the provision of energy services, including demand side or other non-network approaches. Little has changed in that regard since the Parer report[2] noted:

> *A key feature of competitive markets is the active participation of both the supply and demand sides. Without this, competition is blunted and the potential for the exercise of market power is enhanced. ... Many submissions to the Review contended that demand side involvement in the NEM is under-developed.*

Furthermore,

> *In the NEM, the wholesale market mechanism is supply side focussed. It has been designed to accommodate the needs of generators in recognition that it manages both the market bidding and system dispatch processes. Generators are the key system clients by necessity as they are compelled to use the NEM. Consequently, the information technology architecture has been constructed to ensure effective interfacing with the physical requirements of the generation sector more than for the retail or demand side of the market.*[3]

Thus end users are overlooked. Systems of charging obscure transmission prices, and without explanations end-users are not able to react to price signals. This can undermine the efficiency of the whole NEM, with particular difficulties being created for embedded

[1] Australian Energy Market Commission, *Review of the Electricity Transmission Revenue and Pricing Rules – Transmission Pricing: Issues Paper*, November 2005, p 10
[2] Commonwealth of Australia, *Towards a Truly National and Efficient Energy Market*, 2002, p 173
[3] Commonwealth of Australia, *Towards a Truly National and Efficient Energy Market*, 2002, p 174

generation. A similar principle applies to large, remote generators. The Parer report[4] suggested that:

> *Exposing market participants to cost-reflective network prices is also important to create appropriate commercial incentives to encourage the efficient use and development of networks. Its importance is magnified in remote areas and within embedded networks where total network charges can represent a substantial proportion of delivered electricity costs. ... It has been suggested that incumbent generators' lack of exposure to TUOS may distort efficient investment decisions between remote and embedded generation, undermining the competitiveness of embedded generation.*

Thus the competitive intent and the goal of efficiency are undermined and consumers' interests largely ignored. In regard to the introduction of competitive electricity markets worldwide, it has been posited that,[5]

> *In most instances, however, consumers have very little influence on the design of these electricity markets. Committees composed of representatives from generators, transmission, and distribution companies, retailers, and regulators take most decisions. ... Possibly as a consequence of this lack of representation, most electricity markets do not treat consumers as a genuine demand side capable of making rational decisions but simply as a load that needs to be served under all conditions.*

These weaknesses together have resulted in:

- enormous and unnecessary costs of network investment;
- the erasure of accurate price signals throughout the NEM, including transmission networks;
- neglect of consumer interests;
- barriers to distributed generators (embedded generation) and demand management (DM) providers; and,
- a greenhouse gas emission intense electricity system that brings with it a disproportionate risk of future carbon liabilities.[6]

1.2 Demand management and the NEM

DM [7] must be recognised at a national level as a feasible and cost-effective alternative to augmentation. There is a heavy reliance on large coal-fired generators in much of Australia, with coal representing 42% of total primary energy consumption in 2003-04

[4] Commonwealth of Australia, *Towards a Truly National and Efficient Energy Market*, 2002, p 132
[5] Kirschen, D.S., "Demand-Side View of Electricity Markets", in *IEEE Transactions on Power Systems,* Vol. 18, No.2, 2003, p 520
[6] Total Environment Centre, *Submission: Review of the Electricity Transmission Revenue Pricing Rules Scoping Paper*, August 2005
[7] 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.

(mainly used to generate electricity).[8] This consumption creates enormous environmental impacts, which DM can go some way to alleviating – as TransGrid acknowledges on their website:

> *The advantages of local generation and DSM options are that they may:*
>
> - *Reduce, defer or eliminate the need for new transmission or distribution investment; and/or*
> - *Reduce, defer or eliminate the costs and environmental impacts of construction and operation of fossil fuel based power stations. In particular they may reduce emissions of greenhouse gases such as CO2 and noxious gases such as NOX and SOX.*[9]

Economic efficiency is central to the NEM. To achieve this there must be equal emphasis on demand and supply as the basis of standard economic regulation. DM and energy efficiency must therefore be given high priority and be integrated in uniform national regulation.

The Council of Australian Governments (COAG) and the Ministerial Council on Energy (MCE) have regularly endorsed the importance of demand management. For instance, in 1992 the National Grid Management Protocol promoted DM as being integral to the creation of an efficient and cost-effective electricity system; one of the objectives was, "to provide a framework for long-term least cost solutions to meet future power supply demands including appropriate use of demand management"[10] and this was further emphasised, "Demand Management and renewable energy options are intended to have **equal opportunity** alongside conventional supply side options to satisfy future requirements." [11] In 2002, the Parer Report[12] again emphasised the importance of demand management and recommended several measures to improve demand side participation. Subsequent MCE communiqués over 2004 and 2005 have specifically highlighted the need for greater energy efficiency. More recently, the Commonwealth has also highlighted the importance of DM: "To improve Australia's energy efficiency performance, the Australian Government will: improve price signals for demand side management as part of reforming Australia's energy markets ..." [13]

CRA in a report for VENCorp[14] listed a range of benefits stemming from demand response:

- *Act as a check on the market power of suppliers ...*
- *Reduce final prices to consumers ...*

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8 Australian Bureau of Agricultural and Resource Economics (ABARE), *Energy Update, 2005 – Australian energy consumption and production, 1973-74 to 2003-04,* June 2005, p 3
9 Transgrid, *Environment & Community – Demand Management*, http://www.transgrid.com.au/Demand_Management.htm, accessed 22.11.05
10 National Grid Management Council, *National Grid Protocol*, First Issue, December 1992
11 National Grid Management Council, *National Grid Protocol*, First Issue, December 1992, p iii; our emphasis
12 Commonwealth of Australia, *Towards a Truly National and Efficient Energy Market*, 2002, p 33
13 Commonwealth of Australia, *Securing Australia's Energy Future*, 2004, p 105
14 Charles River Associates, *Electricity Demand Side Management Study – Review of Issues and Options for Government*, Report for VENCorp, 2001, p 1

- *Reduce the threat of and/or need for Government intervention in the market to maintain power system reliability at politically and socially acceptable levels.*

- *Reduce the need for investment in very low duty peaking plant.*

- *Provide a more stable regulatory and market environment for new investment decisions regarding energy infrastructure.*

The EUAA gave further suggestions for the benefits of a properly functioning demand side response sector in the NEM[15]:

- *A more predictable, stable, and efficient electricity market by facilitating a demand side response;*

- *A lower risk to the security of the interconnected power system;*

- *A lower cost of hedges and managing risk by market participants …*

- *An improved asset utilisation across the electricity system (NSPs and generators will gain an improvement due to flatter load profile and this should be reflected in lower regulated fees over time);*

- *Improvements in market liquidity; and*

- *Some energy conservation in response to high prices reduces emissions due to a reduction in network losses and more efficient use of existing base load generators, as well as in promoting the increased use of energy efficiency.*

In terms of benefits, the NSW Department of Energy, Utilities and Sustainability has also acknowledged that, "It is recognised that demand reduction can provide long term network benefits, not only when the system constraint occurs. This is because such demand reduction can reduce the need for future network augmentation under a wide range of plausible future scenarios. The essence of cost-effective network demand reduction is the postponement of a known capital expenditure and funding the demand reduction option from the avoided distribution [or transmission] costs."[16]

The lack of incentive mechanisms for the implementation of non-network solutions is resulting in inefficient, peak-demand driven transmission infrastructure investments. Incentive mechanisms for the pass-through of DM costs are needed to counter the inappropriate and inefficient focus on the supply-side of energy service provision in the NEM. There are incentives that can be offered to networks to implement non-network solutions. For instance, as IPART declared, "it would be appropriate for DNSPs to fund non-tariff demand management implementation costs out of the cost savings that arise from the deferral of capital expenditure that results from the demand management projects, rather than passing through these costs to end users. Where the deferral benefits accrue within a regulatory period, these costs savings retained in full by the

[15] Fraser, R., *Demand Side Response in the National Electricity Market – Case Studies*, Energy Users Association of Australia, 2005, p 26
[16] Department of Energy, Utilities and Sustainability, *Demand Management for Electricity Distributors – NSW Code of Practice*, September 2004, p 21

DNSP and so would be available to it to cover the demand management implementation costs."[17] This could equally be extrapolated to TNSPs.

Integral to the regulation of TNSP revenue and pricing are the planning processes that TNSPs are required to undertake under the Rules. Currently, TNSPs are not **required** to solicit proposals for alternative non-network solutions before deciding to augment their networks. This creates a barrier to cost-effective non-network solutions and thwarts the potential for networks to operate more efficiently by reducing their capital expenditure through the avoidance of network augmentations.

1.3 Scope of this submission

We have concentrated on specific issues and addressed them in terms of the questions posed in the paper. This has meant some reordering of the questions, but in general we have followed the scheme of the AEMC paper. The discussion below focuses on:

- Regulation of transmission pricing
- Connection costs
- Transmission use of system charges.

2. Regulation of transmission pricing

Question 1. Should transmission prices be regulated and why?

The current system of pricing has been described as:

> *regulators determine the efficient costs to provide a particular service (usually in a forward looking manner – for example, for the next five years) and this generates the maximum allowable revenue that a business can generate. This model is known as the building blocks approach to price regulation. Very significantly, these efficient costs include the costs on and of capital, in addition to operational expenditures.*
> *Based on the maximum allowable revenue, prices of individual services are then calculated by using, for example, forecasted demand or the quantities observed in previous periods. That is, prices are linked to costs through the maximum allowable revenue and the demand function."*[18]

Thus pricing within the transmission sector relies on the linkage to revenue. Revenue is capped by the national regulator and it is important that transmission prices continue to be regulated at the Federal level, particularly in a national system. There is the opportunity for TNSPs to operate across jurisdictions – either as transmission providers or market network service providers – and fairness of decision making dictates that there be

[17] Independent Pricing and Regulatory Tribunal of New South Wales, *NSW Electricity Distribution Pricing 2004/05 to 2008/09 – Final Report*, June 2004, p 93
[18] Breunig, R., Stacey, S., Hornby, J., Menezes, F. M., *The Australian National University Working Papers in Regulatory Economics – Price Regulation in Australia: How consistent has it been?* Working Paper 2005 No. 1, Australian Centre of Regulatory Economics & The Australian National University, 2005, p 4

consistency in pricing decisions. As TEC has stated previously, it is not sufficient to leave it to the AER's discretion as this can lead to greater inconsistency. The Rules are a substantial and sophisticated set of directions for the NEM; it would be an oversight not to include transmission pricing within their ambit, with details set out as far as is practicable.

TNSPs, in part due to the scale of the investment necessary, form natural monopolies and are thus anti-competitive in essence. This is contrary to the spirit of the NEM, and therefore to reduce regulation of the TNSPs would allow the further entrenchment of their monopoly. The form of regulation should be retained. TEC is in favour of clear directions being set out in the Rules with limited discretionary powers for the AER, to promote certainty for all stakeholders. For the same reason the Rules should be neutral as to classes of users. A transparent decision-making system depends on consistency of approach.

Equally, use of system charges and rebates should also be regulated; at the very least a methodology for deriving such charges should be included in the Rules.

These principles also apply to:

> *Question 2. If regulation is required what form should this take? For example, should it be less prescriptive and involve greater transparency or be more prescriptive?*
>
> *Question 3. What role, if any, should the AER have in determining the nature and form of price regulation?*

Question 36. To what extent is it necessary or worthwhile to prescribe transmission pricing structures in the Rules in order to promote the NEM objective?

The AEMC posits that transmission prices may play a signalling role. For an efficient system under the NEM Objective, there **should** be price signals at all levels, including transmission. In the broad framework of prescription (with only limited discretion for TNSPs and the AER), dynamic efficiency would better suit the NEM Objective, with the potential for price signals. If a methodology for time-of-use charges could be devised for the transmission sector, DM approaches could be better utilised to respond accordingly. A more prescribed system for pricing could also reduce variation across jurisdictions, and aid in TNSPs allocating prices more efficiently.

These considerations would not be addressed by applying fixed charges, which necessitate instead some form of pricing that includes the demand side in the equation. Sustainability requires an approach that has it eye on the long term – as the NEL Objective requires.

These principles also apply to:

> *Question 37. Would it be appropriate to provide guidance to TNSPs on what pricing should achieve instead of prescribing the structure? If prescription is required, which charges should have price structures prescribed in most detail?*

> *Question 38. Should the degree of pricing structure prescription vary depending on the relevant class of network user paying the charge? If so, how could this be implemented?*
>
> *Question 39. How much discretion over charging structures should be left to the TNSP and the AER?*

Question 15. Do the current pricing arrangements appropriately cover alternatives which contribute to the avoidance or postponement of transmission augmentation?

TEC fully endorses the AEMC statements[19] regarding the development of demand management and other energy sources, that is, that by utilising these:

> *transmission can avoid the need for, or can itself be avoided by, the development of local generation, DSM and non-electricity options. Therefore, transmission regulation and pricing should ensure transmission does not `crowd out' alternatives. The Commission considers it important for transmission regulatory arrangements to be structured in a way that ensures that there is an appropriate opportunity for alternatives.*

Although in principle it is suggested in the Rules that TNSPs investigate non-network alternatives to postponement or augmentation, they are not **obliged** to do so, nor are they required to implement them after investigation if they are found to be cost effective. There should be an obligation imposed on TNSPs to implement alternatives where cost effective. If they do not do so, then any such augmentation works should not be included in the regulated asset base and consequently should not flow on to pricing.

Negotiation of DM provision, if at all, is often carried out through a request for proposals process, in which both transaction costs and risks for DM service providers can be high. A similar problem is embedded in the system for local generation and alternative energy sources, which are often developed by smaller companies than the monopoly TNSPs. The introduction of the standard offer is one means of reducing these costs and uncertainties, thereby facilitating the capture of demand reduction opportunities that may arise in response to forecast network congestion.

"Standard offers specify the conditions for the provision of demand in advance. Standard offers are usually made on fixed prices, take it or leave it, first come first served basis."[20] They support the development of the DM services market by reducing risks of both negotiating with networks and of guaranteeing load reductions within the spot market. Standard offers could also provide the means for networks to capture opportunities for demand reduction that may arise several years prior to going to the market for non-network solutions that would otherwise be lost.

Question 20. Given current distribution network pricing arrangements, is it appropriate to prescribe transmission pricing structures in the Rules?

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[19] Australian Energy Market Commission, *Review of the Electricity Transmission Revenue and Pricing Rules – Transmission Pricing: Issues Paper*, November 2005, p 32
[20] Department of Energy, Utilities and Sustainability, *Demand Management for Electricity Distributors – NSW Code of Practice*, September 2004, p 21

The current distribution network pricing arrangements are quite likely to change – at least in some features – when they become regulated at the national level. It is not appropriate to consider transmission pricing in the light of distribution pricing because of the uncertainty of future arrangements, but rather to consider what is most appropriate for transmission pricing in and of itself. Transmission pricing and revenue have been regulated in the past – firstly by the jurisdictions, then at a national level – because these businesses form natural monopolies. This has resulted in their regulation for two main reasons – because such monopolies are anti-competitive, and at the same time they are delivering what is considered to be an essential service, thus supply must be secured.

Question 21. If so, should prescription be limited to prices for particular network users?

Although there currently is the potential for DNSPs to obscure transmission pricing signals, discriminating between network users is not the basis for consistent, fair and transparent government. If there is a structure/methodology in place in the Rules for signalling time of use and locational constraints etc, then this will apply to large or small loads/generators, remote or local. Once the whole system is based on transparent pricing, then DNSPs (which will be regulated at the national level in the future) will also be required to reflect this in their charges, Moreover, some DNSPs are already doing this with the beginning of the roll-out of interval meters.

3. Connection costs

Question 6. Is the allocation of network costs between the connection and shared network categories in the Rules broadly appropriate?

Broadly, yes. However, in practice proponents of embedded generation alternatives to augmentation seem to be penalised in the sense that they may be expected to pay for more than specific connection costs. That is, they are subsidising the transmission sector by paying deep connection costs, in contrast to established (large) generators who are paying shallow connection costs. The current system allows for new generators to pay only shallow connection costs, that is, to cover the costs of assets directly required by a new connection. This applies equally to large, remote generators as to those situated closer to load points.

This is the theory. In practice, however, it appears that 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 contravenes the general principle of paying shallow costs and, moreover, the spirit of "open access" the NEM is based on. It is more of a problem in the distribution network, but still poses a challenge for transmission.

Thus a major disincentive for consideration of embedded generation alternatives is financial, not only due to the risk of paying deep connection costs but also because it may be regarded unfavourably TNSPs. DG may reduce the need for transmission network services, which can be perceived as threatening the revenue base.

A balance needs to be struck to allow smaller generators easy access to the system, while providing for generators remote from the load points to contribute to the true costs of providing transmission network services.

Any solution should be prescribed in the Rules, to promote clarity and equity of access.

Question 22. Should NEM connection charges continue to be based on a shallow connection approach or should a deep connection approach be adopted?

There is some argument for charging generators for more than just the costs associated with their connection into the system; if there were no established transmission system, there would be no conduit for the generators to sell their product. What is particularly inappropriate, however, is the differential in charging for major generators and embedded generators; the charges should be based on the same principles (as discussed above).

Question 23. If a shallow connection approach is broadly to be maintained, are there any circumstances where connecting parties should pay for up or downstream upgrades to the shared network?

Upgrades are part of the expansion of the network system, and thus TNSPs can effectively recover the costs by the increase in their regulated asset base (since they can then recover the costs through their prices). However, to encourage competition and the entry of small/local generators, exceptions could be made where it can be proven that the new connection will lead to a substantial constraint or expenditure (such as a large generator, or one in a remote location).

A further exception could be made where an alternative energy source/generator is being proposed (non fossil fuel, for instance). If there were an identified trigger mechanism for such a proposal, then alternative arrangements could be made by the Federal government to arrange for funding the augmentation.

Question 24. If a deep connection approach is to be adopted in the NEM, how should it be formulated?

The most satisfactory and equitable arrangement – to honour the spirit of open access – would be for deep connection costs to apply only to large generators entering the system. If the NEM is truly designed to assist the entry of a variety of types of energy and participants, then small and/or local generators should not be expected to foot the bill for supporting large, remote generators which are usually powered by fossil fuels. Thus prescriptions could be designed whereby such generators could be expected to contribute to the costs of augmentation – of course, after non-network solutions have been investigated and implemented where cost-effective.

Existing large, remote generators must contribute in some fashion if a deep connection methodology is adopted. Those of this type would have already benefited from the shallow connection approach in the past. It is also manifestly unreasonable to force a small, local generator to pay the full extent of deep connection costs when it may only be adding a minor extra load to the network.

Question 25. Is a deep connection approach compatible with the open access transmission regime of the NEM (which is not a subject of the present Review)? If so, how should potential "free-rider" effects be managed?

Demand management can come into its own here. On the basis that shallow connection costs will be maintained – since a blanket prescription for deep connection costs to be paid is indeed against the principle of the open access regime – a new generator connecting into the grid may potentially lead to constraints. Current participants in the network can be approached to assist in dealing with such constraints, and be encouraged to take up non-network solutions. Considering that they too have paid shallow costs originally, there is no good reason why a newcomer should be required, in effect, to cover the costs that these original participants have necessitated. “Free rider” thus becomes a loaded term with no meaning.

The annual public disclosure of information on emerging network constraints can assist in these cases. An excellent model for the disclosure of such information is currently part of the NSW DM Code of Practice. The DM Code of Practice contains a Disclosure Protocol that is intended to ensure that distributors provide all necessary information in a clear and consistent form, without wasting effort in providing unnecessary information. Other jurisdictions (such as South Australia) also encourage disclosure of information on potential constraints.

4. Transmission Use of System (TUOS) charges

Question 14. Is it appropriate to prescribe arrangements for TUoS rebates in the Rules? If so, could the existing arrangements be refined and how?

Again, we would argue for a prescriptive system with requirements set out in the Rules. TUoS rebates are intended to recompense local generators requiring lower use of the transmission network – and hence lower usage charges for DNSPs – by virtue of location closer to load points. However, embedded generation (or DG) offers a range of benefits not entirely reflected in the current method of calculating avoided TUoS rebates. In particular, embedded generation offers value to a TNSP through its potential to enable the deferral of new transmission augmentation. Embedded generation also offers the benefit of reducing environmentally damaging greenhouse gas emissions, the cost of which is currently externalised in the NEM. The value of TUoS rebates should include the value of deferral of new network augmentations as well as the following:

- Annual operating cost of the deferred augmentation
- Total annual net cost of servicing the capital expenditure of the deferred augmentation including:
    - financing charges
    - capital depreciation.

As stated in the AEMC paper, "It follows that to the extent embedded generators help avoid or delay transmission augmentation, they receive a rebate based on the long run marginal value of their contribution."[21] Including the full value of deferral of network augmentations in the calculation of TUoS rebates would provide more accurate price signals across the NEM. Such an approach would also encourage TNSPs to more fully utilise the benefits of non-network solutions, by making the true costs – and long run

[21] Australian Energy Market Commission, *Review of the Electricity Transmission Revenue and Pricing Rules – Transmission Pricing: Issues Paper*, November 2005, p 29

costs – more transparent since it also presents an opportunity for recognition of long-term effects.

If the connection into the network – or DSM or other non-network options – contributes to the cost-effectiveness or reliability of the system in some way, then there should be payment in kind from the TNSP via rebates since it is to the financial benefit of the TNSP in the long term.

These principles also apply to:

> *Question 33. Should avoided TUoS rebates be retained in the Rules or left for negotiation between the DNSP and connected party?*
>
> *Question 34. Is the appropriateness of TUoS rebates contingent on whether generators pay shared use of system charges?*
>
> *Question 35. If TUoS rebates are retained, what charges should they comprise?*
>
> *Question 16. Should TUoS rebates also apply to generators connected to the transmission network, DSM or other non-electricity options? Does this depend on whether generators generally pay shared transmission costs?*

4.2 TUoS discounts

Question 12. Is it appropriate to provide scope for TUoS discounting in the Rules?

Where a large industrial user – or generator on their behalf – is requesting a discount for TUoS charges, it would be appropriate to offer a conditional discount, that is, that the user investigate energy efficiency and time of use alternatives to avoid contributing to the base load and/or peak demand on the system. A discount could be offered on condition that the user implements the alternative/s if found to be cost-effective. Otherwise, no discounts should be offered since these only contribute to promoting demand and other users will have to wear the costs unless the TNSP absorbs them which is unlikely and inequitable. These considerations should be set out in the Rules, not left to the discretion of the AER. This also applies to:

> *Question 13. If so, could the existing arrangements be refined and how?*
>
> *Question 30. How much discretion should TNSPs have to discount charges?*
>
> *Question 31. Should TNSPs be entitled to recover the cost of discounts from other loads?*
>
> *Question 32. Should any conditions for recovering the cost of discounts from other customers be prescribed in the Rules or left to the AER to determine? If so, what should be the general content of these Rules or AER discretions?*