AEMC Review of the Electricity Transmission Revenue and Pricing Rules

Response to the Transmission Pricing Issues Paper

-from-

TRUenergy
NRG Flinders
International Power
Loy Yang Marketing Management Co

December 2005

1. Introduction

1.1. *Scope and Purpose*

This submission represents the views of the following companies, “The Group”:

- TRUenergy;
- International Power;
- Loy Yang Marketing Management Co; and
- NRG Flinders.

The Group owns the majority of Victorian and South Australian generation capacity and will be approaching this review with prime consideration of the interplay between the regulated transmission network and the competitive national electricity market.

The Group previously provided a submission on the AEMC Scoping Paper for the Chapter 6 Review and also on the AEMC Issues Paper on TNSP Revenue Requirements. This submission draws and builds upon those earlier submissions to the extent relevant to Transmission Pricing.

1.2. *A Generator Perspective*

This submission focuses on the need to ensure that new entrant generators bear the full incremental costs of transmission which their investment decisions bring about. These costs may arise from new augmentation, new or increased congestion or a combination of these. When faced with these costs, a rational investor will choose a generation location which minimizes the *delivered* cost of electricity – ie generation plus transmission costs – and which is therefore efficient for the market as a whole and to the long-term benefit of the consumer.

Our focus on new generators is not to let us existing generators “off the hook”. It is because the main source of inefficiency in the use of and development of the transmission network under the current arrangements is the locational decision: which, for existing generators, has long since been made.

Another theme of this submission is the need to establish and allocate generator “access rights”. We realize that the AEMC has decided that such considerations should be outside the scope of this review. However, we believe that access rights are critical to the establishment of an efficient transmission pricing regime and that, by not considering these, the AEMC is limiting itself to “second best” solutions.

1.3. *Structure of this Submission*

Section 2 discusses the need to distinguish prices charged to existing and new entrant generators, based on SRMC and LRMC, respectively. Sections 3 and 4 consider how to establish LRMC prices, in the scenarios where the new generator does not, or does, cause new transmission augmentation, respectively.

Section 5 looks at access rights, in the context of transmission pricing and more generally. Section 6 considers historical and prospective generation locational decisions which may be economically inefficient. Section 7 considers transmission pricing for existing generators. Finally, section 8 considers some subsidiary issues.

2. Efficiency Considerations

As noted in our previous submission [1] we agree with the AEMC that the NEM Objective means that the prime objective of the AEMC review should be the promotion of economic efficiency. In the context of transmission pricing[2], the relevant efficiency "element" is allocative efficiency: prices should reflect marginal cost.[3]

We agree with the discussion in the Issues Paper of the different meanings and roles of short-run marginal cost (SRMC) and long-run marginal cost (LRMC)[4]. That is:

- SRMC is composed of transmission losses and congestion costs and should be seen by users when they are making short-term, operational decisions; and
- LRMC is composed of SRMC plus the costs of transmission augmentation and should be seen by users when they are making long-term, investment decisions

The Issues Paper considers transmission pricing to be a choice or trade-off between pricing at SRMC and pricing at LRMC. This may be true in relation to demand, but it is not the case for major generation. Because generation projects are discrete and identifiable, it is straightforward – in principle – to levy different prices on generators depending upon whether they are making investment or operational decisions, as follows:

- a new generator deciding to connect[5] to the transmission grid is making a long-term investment decision and should be faced with LRMC-based transmission prices; but
- an existing generator deciding its level of output is making a short-term operational decision and should be faced with SRMC-based transmission prices.

[1] Response to the Revenue Requirements Issues Paper, November 2005
[2] In this submission, by "transmission pricing" we mean the rate at which *all* charges that relate to transmission costs are levied, including TUoS prices and the locational element of NEM spot prices. When considering just those charges levied by the TNSP we refer to TUoS prices and connection charges.
[3] As explained on P32 of the issues paper.
[4] As summarized at the bottom of P35 of the Issues paper
[5] This would also apply to an existing generator making a substantial investment decision – for example the significant expansion of generating capacity at an existing generation site

Thus:

- new generation should be faced with a one-off charge, reflecting the difference between LRMC and SRMC, which we shall refer to as "deep connection"[6]
- once connected, generators should pay an SRMC-based transmission price

On the demand-side, it is not possible to distinguish between "new" and "existing" end-users in this way. Even if one were to levy deep connection charges on a DNSP, that DNSP would have no basis for deciding which "new" customers to pass that charge on to.

In the following two sections we consider the efficient price signals that should be seen by new generators:

- firstly, where the new generator does not cause augmentation of the transmission system, and so LRMC effectively "collapses" to SRMC;
- secondly, where the generator does cause augmentation, and so SRMC must be supplemented with a "deep connection charge" to efficiently signal LRMC

In section 7 we then go on to consider efficient pricing for existing generators, based on the principle that these should be charged transmission SRMC.

[6] This charge could be amortised over the life of the generator, just as the (shallow) connection charge is under the existing arrangements

3. New Generator with No Augmentation

3.1. *Nodal Pricing*

The SRMC of transmission of energy between two nodes on a network is well-understood to be the difference in the “locational marginal prices” (LMPs) at those two nodes[7]. LMP is defined to include the marginal cost of congestion and losses, based on the offer prices of dispatched generators. If there is no congestion, LMP just reflects marginal losses. In this sense, setting the price of transmission for existing generators is straightforward in principle.

Of course, in practice, such a “nodal pricing” regime is far from straightforward, due to issues such as transaction costs, market power, forward market liquidity and, not least, opposition from most governments and market participants.
In making these observations, we are not proposing nodal pricing. We simply wish to make the point that, to the extent that the current regionally-based NEM prices differ materially from LMP and these differences are expected to endure, inefficiencies may arise in generation investment decisions. Such differences will arise primarily due to intra-regional congestion.

3.2. *Inefficient Allocation of Congestion Costs*

This potential inefficiency is seen in Example 1 (see Box). Because, in this example, intra-regional congestion is not efficiently priced – but is instead shared between the existing generators and the new generator – the investor decides, inefficiently but rationally, to locate remotely from the load centre. The Issues Paper also notes this problem:

> Where constraints arise within regions, the cost is smeared across the relevant region and participants may not receive efficient signals[8]

The Issues Paper does not offer any solutions to this problem. One potential solution, the introduction of a new region, has already been effectively ruled out by the MCE. We offer an alternative. Since the problem is one of “smearing” of congestion costs, the solution lies in reallocating these additional congestion costs to the new generator. This can either be done by:

- modifying and enhancing existing provisions for Generator Access; or
- introducing new intra-regional congestion management mechanisms, as envisaged by the MCE.

These alternatives are discussed in the next two sections below.

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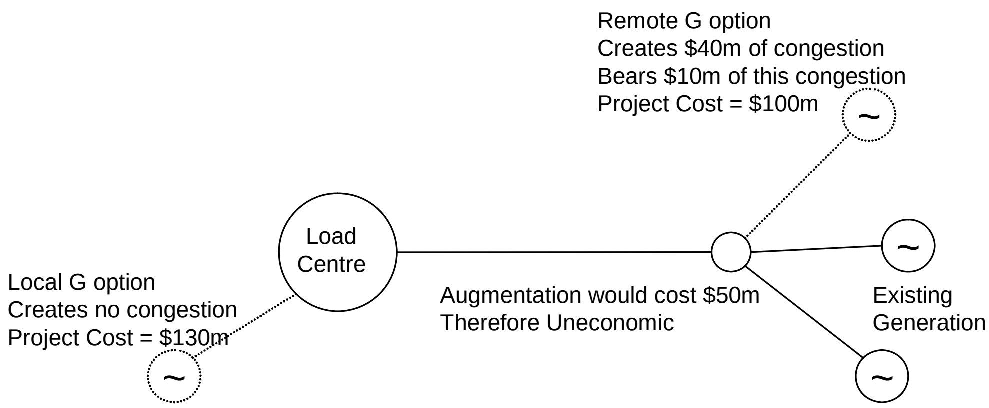
[7] LMP is the marginal value of generation (which equals the marginal cost of load) at a transmission node.
[8] Issues Paper P38

Example 1: Investment that creates intra-regional Congestion



- Augmentation is uneconomic, irrespective of the generation investment
- The remote option costs the investor $100m + $10m = $110m,
- The local option costs the investor $130m
- The remote option costs the market as a whole $100m + $40m = $140m,
- The local option costs the market as a whole $130m
- Therefore, the investor will inefficiently choose the remote option

3.3. *Access Arrangements for Generators*

Clause 5.5 of the National Electricity Rules (NER) provides that: a TNSP must negotiate with a generator who requests a level of “power transfer capability” to reach an agreement where:

- the generator pays for the costs of any augmentation required to provide that access and for other costs “reasonably incurred” by the TNSP;
- the TNSP compensates the generator where access falls below the agreed level;
- the generator pays compensation to the TNSP whenever it constrains access for other generators

These provisions have never been used because, as they stand, they are critically flawed. In particular:

- there is no provision for other generators, not contracted with the TNSP under NER 5.5, to provide compensation where they constrain other generators;

- it is unclear to what extent TNSP revenue and costs from such an arrangement are regulated[9]
- there is no “baseline” for existing generators who have not entered into any clause 5.5 agreement, to determine how much they should be compensated if their access is constrained.

The underlying objectives of clause 5.5 seem to be:

- to allow existing generators to contract with a TNSP to establish access rights on existing transmission capacity;
- to require that new generators – or existing generators wishing to obtain additional access – pay for the cost of any consequential augmentation; and
- to ensure that generators who are dispatched above their access level compensate any other generators who are constrained below their access level as a result.

If these objectives were able to be realised – by fixing up clause 5.5 – this would address the problems of inefficiency identified in Section 3.2, above.

3.4. *Intra-regional Congestion Management*

The philosophy behind clause 5.5 is that any mechanism that is required to price, allocate and manage intra-regional congestion should be established through voluntary negotiations between the relevant TNSP and generators. This was in the context that such congestion would generally not be substantial or enduring since, if it were, a boundary change would result and the congestion would be managed through inter-regional pricing arrangements.

In the light of recent initiatives by the MCE to “stabilise” regional boundaries – and by implication to tolerate more substantial and enduring intra-regional congestion – consideration has turned to establishing intra-regional congestion management frameworks through the spot market itself.[10] Indeed, the MCE has recently requested[11] that the AEMC conduct a review in this area.

An earlier review[12], undertaken by CRA for the MCE, proposed an arrangement of constraint support pricing (CSP) and constraint support contracts (CSC)[13]. Without wishing to pre-empt the outcomes of the review, it is not unlikely that the AEMC will propose a CSP/CSC mechanism or something similar which has the features of:

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[9] NER clause 6.5.3(a) indicates some costs/revenues are regulated, some are unregulated and some are not specified to be either
[10] ie through NER Chapter 3 rather than NER Chapter 5.
[11] Letter to AEMC Chairman from the MCE Chairman, dated 5th October 2005
[12] NEM Transmission Boundary Structure, CRA, September 2004
[13] ibid Appendix B

- levying, at the margin, intra-regional congestion prices on generators; and
- some form of "contract" or "right" that determines the extent to which a generator would be protected from its exposure to that congestion price for all of its output

In such a mechanism, by allocating the congestion rights to existing generators only, it would be possible to ensure that new generators faced the full cost of the additional congestion that they create, thus correcting the inefficiencies seen in Section 3.2.

3.5. *Combining congestion management with generator access*

The congestion management framework described above fills in some of the gaps in the clause 5.5 approach. In particular, it allows for relevant generators to be mandated to participate in such a mechanism. It also establishes formal algebra for pricing and allocating congestion costs.

On the other hand, at least as it has been developed so far, the CSP/CSC approach has its own gaps. In particular, it fails to articulate how access rights (through CSCs or similar) would be allocated to generators and whether (and if so, how much) generators would be obliged to pay to obtain such rights. Furthermore, it is not clear whether new generators, which caused the congestion, would be allocated CSCs[14], thus negating the long-run efficiency benefits noted above.

In clause 5.5, these issues are resolved through negotiation and so the issue of distinguishing "new" and "existing" generators becomes straightforward: either generators have contracted with the TNSP for access rights, or they have not.

As such, clause 5.5 and CSP/CSC are somewhat complementary. CSP/CSC can provide the formal arrangement for pricing intra-regional congestion (through CSPs) to all generators, whereas clause 5.5 provides a framework for access rights (through CSCs) to be efficiently priced and allocated.

3.6. *SRMC Pricing in TUoS*

The AEMC may well deem such considerations to be outside the scope of their review, which is focused on the issue of how to collect TNSP revenue from users rather than transmission pricing *per se*. Nevertheless, as the Issues Paper notes

> If the Commission's sole concern is economic efficiency in the short-run, the only role of the transmission pricing regime is to set prices to reflect all expected transmission constraints and losses not already reflected in the wholesale market.[15]

Whilst, in principle, it may be possible to price intra-regional congestion into TUoS[16] as the above quote suggests, we think this would be inappropriate. This is

[14] For example, in the situation where CSPs/CSCs were not established until after the new generator had connected, the new generator may in fact be treated as an "existing" generator and allocated CSCs accordingly
[15] Issues Paper P38

partly for practical reasons, but primarily because such TUoS prices, even if they could provide efficient long-run signals to new generators, would still not encourage existing generators to operate efficiently, as we discuss in section 7.1.

Instead, we consider that, for generators:

- SRMC should be priced through the wholesale market, where necessary through a new intra-regional congestion management mechanism;
- new generators – where they do not cause any transmission augmentation - should be exposed to this SRMC on the whole of their output, and should not be protected from this price through the allocation of rights or contracts; and
- there should be no attempt to signal SRMC to new[17] generators through TUoS prices.

3.7. *Conclusions*

To summarise, the existing arrangements are inefficient because transmission SRMC variations within a region – arising due to material and enduring intra-regional congestion – are not signalled to generation entrants.

There are two possible routes for addressing this problem:

- through a new intra-regional congestion management mechanism, along the lines of the CSP/CSC scheme proposed by CRA;
- by fixing the provisions for negotiating access rights set out in clause 5.5 of the Code

We note that any arrangements for establishing pricing efficiency must include both congestion pricing (eg CSPs) and congestion allocation (eg CSCs). In this respect, a hybrid approach appeals to us where:

- congestion is priced through the wholesale market (ie chapter 3); and
- congestion is allocated based on access rights negotiated and agreed through an enhanced clause 5.5

[16] By "TUoS" we mean by being allocated a share of network costs through the Chapter 6 pricing process, not the "negotiated TUoS" described in NER 5.5.

[17] or, as we discuss in section 7.1, existing generators

4. New Generator Causes Augmentation

4.1. *The Regulatory Test*

As the Issues Paper notes, augmentation on the shared network is limited to projects which the Regulatory Test shows to be economic or necessary[18]. The connection of new generation will change the economics of transmission and may lead to some augmentation projects passing the Regulatory Test which would otherwise have failed and therefore lead to such projects being built or brought forward. To all intents and purposes, the new generator has caused the augmentation, even though it may not have requested or proposed such augmentation.

The Issues Paper argues – and an example in Appendix 1 of the Issues Paper is intended to illustrate – that the "search for efficiency" embedded in the Regulatory Test will ensure that generation investment decisions are efficient. Essentially, the argument is that the generation investment implicitly becomes a part of the augmentation project that is subjected to the Test, because (in the example) it can only proceed if the augmentation proceeds.

Implicitly, the Issues Paper assumes that the generator asks the TNSP the question "does the augmentation pass the regulatory test?" *before* it commits to the generation investment. With this timing, the Issues Paper is correct to deduce that the augmentation (and thus the generation investment) will only proceed if it is efficient.

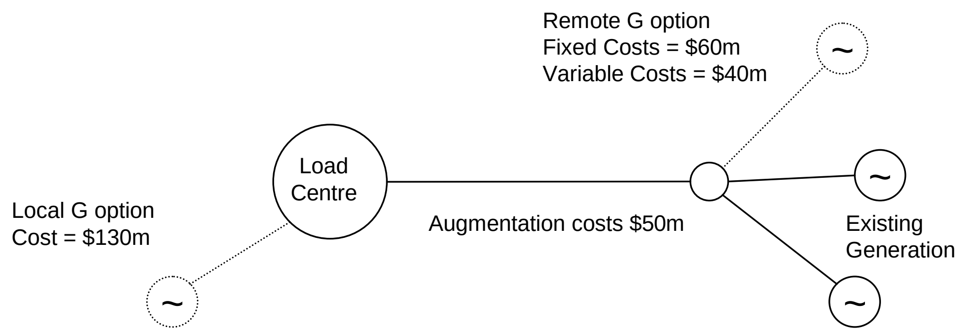
However, the generator may instead ask the question[19]: "will this augmentation pass the regulatory test once I commit to the generation investment?" The answer to this question may be different, because once committed, a generator's fixed costs are regarded as sunk and are not relevant to the regulatory test appraisal[20].

Example 2 (see Box) extends the Issues Paper example to show how the answers to the two questions above may be different. It is apparent, then that, by committing its investment prior to the Regulatory Test, a generator may be able to ensure that the augmentation will pass the Test, even where the generation investment decision is inefficient compared to a local generation alternative.

Thus, a generator will commit where it knows that its commitment will *cause* the necessary augmentation to pass the Test and proceed. In such a situation, it need not factor the cost of the augmentation into its investment decision.

[18] ie to meet reliability standards
[19] Of course, the investor doesn't really need to ask the TNSP. It can do the analysis itself.
[20] In fact, the sunk costs are included in both the "with augmentation" and the "without augmentation" scenarios and so do not affect the Test result.

Example 2: Locational Signals from the Regulatory Test



Assume that generation from the remote option can only be delivered to the load centre if the augmentation proceeds.

*Scenario 1: The Regulatory Test is taken **before** the investor commits to either option*

- with the augmentation, the investor will choose the remote option: total cost to market = aug cost ($50m) + remote gen project cost ($100m) = $150m
- without the augmentation, the investor will choose the local option: total cost to market = local gen project cost ($130m)
- The "with" cost exceeds the "without" cost and the augmentation therefore fails the Regulatory Test
- The outcome will be to build the local option: the efficient solution

*Scenario 2: The Test is taken **after** the investor has committed to the remote option*

- with the augmentation, the investor will choose to *operate* the remote option: total cost to market = aug cost ($50m) + remote gen project cost ($100m) = $150m
- without the augmentation, the investor cannot *operate* the remote option and so it (or another investor) must also build the local option and leave the remote generator idle: total cost to market = remote gen fixed costs ($60m) + local gen project cost ($130m) = $190m
- The "without" cost exceeds the "with" cost and the augmentation therefore passes the Regulatory Test
- The outcome will be to build the remote option and the augmentation: an inefficient solution

4.2. *Deep Connection*

Example 2 demonstrates that, assuming that there is a need for new generation *somewhere*, a committed new generator could expect that transmission augmentation required to transport its output to the market will pass the regulatory test[21], *wherever* it decides to locate. It is apparent, therefore, that the existence of the Regulatory Test alone does not give rise to efficient locational pricing signals for new generation, contrary to what is suggested in the Issues Paper.

[21] This should be the case, in general, so long as the augmentation (on a $/MW basis) does not exceed the fixed costs of new, local generation. This would normally be the case.

On the other hand, if a generator is required to pay – through a "deep connection charge" for the cost of the additional economic augmentation which it causes – then it *will* locate efficiently, since it bears all of the costs of *delivered* energy at the relevant market, irrespective of where it locates. In Example 2, the cost to the investor of the remote option would be $150m, exceeding the cost of the local option.

Thus, for the potential investor, generation planning involves looking at the total cost of *delivered* energy (ie generation plus transmission) for a range of development options and choosing the option with lowest cost. This contrasts with the scenario envisaged in the Issues Paper example, where it is the TNSP who – through the Regulatory Test – seeks the lowest delivered cost. We do not believe it is the intent of the Regulatory Test – or of NEM regulation generally – that the TNSP becomes responsible for central planning of transmission *and* generation.

In determining deep connection charges, transmission planning scenarios "with" and "without" the new generator should be compared. The new generator should be charged for additional[22] augmentation or augmentation brought forward, and should be credited for augmentation cancelled or deferred.

4.3. *Free Riding*

The Issues Paper notes:

> The risk of third parties gaining the benefits of investment by the connecting party (ie "free riding") may deter connecting parties from being willing to pay for such investment. If given no choice but to pay such costs, prospective connecting parties may be inefficiently deterred from connecting[23].

It notes that the free riding problem can be addressed through awarding access rights to the new generator, commensurate with the deep connection charges. It is unfortunate then that the AEMC has already ruled consideration of access rights out of the review[24], leaving it with a choice between shallow connection charges (and inefficiency) or free-riding (and inefficiency).

We would argue that access rights *should* be established, avoiding such a dilemma. We would further argue that the access rights relating to deep connection should be part of a comprehensive framework which would also address the issue of congestion pricing discussed in section 3. Ad hoc and heuristic access rights – such as the "3-year rule" used by VENCorp[25] - are as likely to deter efficient behaviour as promote it: for example, a 3-year rule may just cause future generators to inefficiently delay their connection beyond the 3-year window.

[22] ie augmentation in the "with" scenario but not the "without" scenario
[23] Issues Paper, P45
[24] ibid, P37
[25] ibid, P46

NER clause 5.5 envisages a generator paying "negotiated use of system charge" for a "voluntary" augmentation and receiving corresponding access rights. A similar process would operate in relation to deep-connection charges, although in this case the augmentation is "mandatory" in the sense that it must proceed if it passes the Regulatory Test. Indeed, it would be curious if a generator received access rights in relation to voluntary augmentation but not in relation to mandatory augmentation.

4.4. *Conclusions*

Under the existing arrangements – and not withstanding claims in the Issues Paper to the contrary - a generator may locate inefficiently, knowing that any consequential (once the new generation is committed) efficient transmission augmentation will be paid for by others. To correct this inefficiency, new generators should face a "deep connection" charge, based on the additional efficient transmission augmentation which their new generation gives rise to.

Generators paying a deep connection charge should be entitled to receive appropriate access rights; in the same way that clause 5.5 currently provides that a generator funding "voluntary" augmentation receives rights.

These changes will establish a consistent approach to "mandatory" and "voluntary" augmentation, in that:

- all generators will receive at least an "efficient[26]" level of access, paying for the corresponding augmentation and receiving the corresponding access rights;
- if they request it, a generator may receive an "enhanced" level of access, paying for the additional augmentation and receiving the additional access rights.

[26] As determined by application of the Regulatory Test

5. Access Rights

5.1. *Cutting the Knot*

The discussion above has emphasised the role of access rights in an efficient transmission pricing framework for generation. Such rights allow the framework to distinguish between new generation – whose investment and locational decisions are giving rise to substantial additional transmission costs – and existing generation, whose investment is "sunk".

Without access rights, there is no distinction between "existing" and "new" generation[27]. One would then be left with the dilemma of pricing at SRMC (and having inefficient generation investment) or pricing at LRMC (and having inefficient generation operations). Access rights allow the Gordian knot to be cut and efficiency to improve as a result.

We believe transmission access rights have many strengths, not just in improving transmission price signalling but also in adding certainty and stability to the NEM. In the next section, we consider all of these strengths. The following section considers and refutes putative weaknesses that have been put forward by others.

5.2. *Strengths of Access Rights*

An access rights regime has many advantages over the status quo:

- it can ensure that new generators bear the full cost of the additional congestion that they create;
- it supports a deep connection charging regime, by preventing free-riding problems;
- it will promote voluntary augmentation;
- it can facilitate the introduction of new congestion management mechanisms; and
- it can improve certainty, and thus lower the costs, for existing and new generation.

The first two advantages have been discussed above. The remainder are described below.

Voluntary Augmentation

As discussed in section 3.3, above, Clause 5.5 of the NER is intended to provide a framework within which an enhanced level of access could be arranged for the

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[27] In fact, all generators enjoy some rights of access under the current arrangements: for example the right to be dispatched where sufficient transmission capacity exists. However, the term "access rights" is generally taken to mean rights which are allocated differentially between different generators and this is the sense in which we use the term in this submission. Thus, without such rights, one cannot differentiate between generators at a common location.

cost of the necessary augmentation. However, this intent will not be realised until a mechanism for defining and allocating access to the existing network is established.

Facilitate Congestion Management Mechanisms

CSCs were proposed by CRA as a mechanism to mitigate the impact on generation of a new CSP regime. Concerns about commercial impact are one of the reasons why the proposed process for establishing a new regional boundary is so protracted[28]. The advantage of a CSP/CSC regime is that it can be introduced quickly, but this is only possible because of the CSCs. In general, access rights will provide for an easier and faster transition to any new congestion management regime.

Improves Certainty

Our previous submission[29] discussed the concept of "efficient certainty". Greater certainty reduces the cost of capital and therefore reduces the cost of electricity and promotes the NEM objective.

A major uncertainty for generators – existing and new – is the future level of access to the market, which depends upon future transmission augmentation and new generation connection. Access rights which define and preserve existing levels of access would reduce this uncertainty.

It might be argued that this uncertainty could, in itself, contribute to efficiency, because the more remote a generator is from a load centre, the greater this uncertainty. In the absence of other transmission pricing this view may be correct. However, pricing through graduated levels of risk is a second best solution. Risk is a real cost, which will feed through to the consumer in higher electricity prices and so uncertainty cannot be part of an efficient pricing signal. Efficient pricing, on the other hand, is simply a transfer payment, which does not create higher long-term customer prices.

5.3. *Putative Weaknesses of Access Rights*

Other stakeholders – including the AEMC in its Issues Paper – have put up problems with access rights, such as:

- it is inconsistent with open access;
- it is inconsistent with non-firm access;
- it create a barrier to entry for new generators;
- it provides a wealth transfer to existing generators;
- it is inconsistent with Regional Pricing; and
- it is too hard to design and implement.

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[28] Rule Change Request – Reform of Regional Boundaries. Letter from the Chair of the MCE to the chair of the AEMC (not dated)

[29] on the AEMC Issues Paper on TNSP Revenue Requirements

- it will cause rights holders to frustrate augmentation

These problems are discussed and refuted below

Inconsistent with Open Access

It is often said that access rights are inconsistent with open access[30]. This argument betrays a confusion between common carriage (which is a certain *type* of open access regime) and open access itself.

For example, most gas transportation services in Australia operate on a "contract carriage" regime, where users (ie shippers) contract with the gas transporter to obtain capacity rights. Such a model has been designed to be consistent with the open access requirements of the Trade Practices Act in Australia.

This is not to say that the contract carriage model would be appropriate in electricity. It is just an example that demonstrates that access rights, *per se*, are not inconsistent with open access.

Inconsistent with Non-firm Access

It has also been suggested that access rights would require TNSPs to provide firm access[31] to rights holders and this would be inconsistent with the current arrangements where generator access is provided according to the Regulatory Test.

Again, this assumption is incorrect. Access rights simply specify rights of particular users to access *existing* transmission capacity, whether this is firm or non-firm. It would not change the transmission investment framework, except indirectly, as noted earlier, by promoting voluntary augmentation.

Creates a Barrier to Entry

Another argument made is that providing rights to access existing capacity to existing generators would create a barrier to entry for new generators. However, as the examples above demonstrate, a rights framework would simply ensure that a new generator bears the full incremental transmission costs (whether of augmentation or congestion) that it causes, would therefore choose a location which optimises the *delivered* cost of energy and by doing so improves market efficiency, to the long-term benefit of consumers.

Therefore, whilst rights may increase the entry cost for new generators, this is an efficient price signal rather than an entry barrier. Furthermore, from a customer perspective, a generator "entering" in the wrong location may be no better than not entering at all, if it simply causes other generators to be constrained.

[30] The Issues Paper seems to imply that the AEMC also believes this. For example it says that "the open (non-firm) access regime" is outside the scope of the review (P10) and goes on to conclude that "the creation of property rights over the shared network will [therefore] not be considered" (P37). We infer from this that the AEMC considers that a regime with property rights is no longer a "non-firm, open access regime".

[31] See previous footnote

Wealth Transfer

It has been argued that if existing generators were to receive access rights without making an explicit additional payment for them, this would amount to a "wealth transfer" from prospective generators to existing generators.

Firstly, even if there were a wealth transfer, this would be somewhat hypothetical in the sense that the prospective generators from which wealth is notionally being transferred do not actually exist at present. There is no transfer of wealth from other existing players, since no-one is actually *worse* off.

Secondly, the amount of wealth transfer depends upon what "counterfactual" is assumed for the status quo. We would argue that the intent of the market design was that existing generators *do* have access rights[32] to the existing intra-regional transmission capacity, even if the absence of any intra-regional congestion mechanism currently means there is no way for these rights to be currently manifested. The establishment of a formal regime of access rights simply removes the current uncertainty about how these existing rights will be preserved.

For example, the Snowy derogation, supported and promoted by the MCE, provides some access rights (through allocation of a CSC) to Snowy Hydro which it makes no payment for. In general, the CSP/CSC concept involves allocating rights to existing generators[33].

Thirdly, even if it were to involve a wealth transfer, this would be acceptable if at the same time it promoted economic efficiency. The NEL requires that the AEMC makes rule changes which promote the NEM objective. It does not say that the AEMC must avoid wealth transfers arising from rule changes.

Holders will frustrate augmentation

The Issue Paper notes

> It is worth noting that…the presence of property rights can create strong incentives for the owners of these rights to protect their value. This may work against the long term interests of the market if market participants are given incentives to frustrate the development of the grid.[34]

It is true that commercial organisations will try to protect and enhance the value of their investment portfolio. However, this portfolio encompasses *all* of a generator's physical and financial assets, not just any transmission access rights. Thus, generators *currently* have an incentive to support augmentations which (eg by relieving export constraints) enhance the value of their generation and frustrate augmentations which (eg by relieving import constraints) diminish its value.

Indeed, to the extent that access rights actually hedge generators against the impact of augmentation decisions – by providing them with a level of access which is not directly affected by future augmentation – this is likely to make generators less, rather than more, interested in augmentation proposals. In short, the AEMC

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[32] Or at least, pursuant to clause 5.5, should be able to obtain them at nominal cost

[33] Although CRA made no conclusions about whether or not such rights should be paid for.

[34] Issues Paper, P46

has considered only one element of the portfolio (access rights) rather than the portfolio as a whole.

In any case, the Regulatory Test process is designed to prevent self-interested parties from frustrating economic augmentation.

5.4. *Treatment of Access Rights in the AEMC Review*

The AEMC has stated that transmission property rights are not to be included in the scope of this review. Although we disagree with this decision, we can understand it, given the practical need to manage the scope of the review.

Nevertheless, we are concerned that any review findings which are predicated on the status quo in relation to access rights will, firstly, be "second best" (as we demonstrate above) and, secondly, subject to change when explicit access rights are introduced (as we expect them to be) as part of the review of intra-regional congestion management[35].

There are three possible approaches to this issue:

- ignore these future reviews (as the Issues Paper implies);
- delay completion of the review (or at least, those aspects which depend upon access rights) until the Congestion Management review is complete; or
- complete this review as planned, but note where findings are contingent on the status quo in relation to access rights and how, at a high level, these may change if and when access rights are introduced.

We would support the latter approach. It allows the current review to proceed in a timely manner, but takes due account of future reviews. It also allows useful reforms – such as deep connection charging – to be recommended, subject to the future development of access rights. In particular, it will at least recognise the crucial linkage between transmission pricing and access rights and allow these two areas to be reconciled at a later date. It may also potentially lead the AEMC to find that, in some instances, existing transmission pricing arrangements should continue until the issue of access rights has been resolved, rather than introducing new, "second best" arrangements in the interim.

5.5. *Conclusions*

Generator access rights are critical to establishing efficient transmission pricing for generators. In deciding to place them outside the scope of its review, the AEMC has limited itself to "second best" solutions which are likely to need revisiting once access rights are established (as we believe they will be) in future market reviews requested by the MCE[36].

[35] Indeed, the Issues Paper notes (P11) that the AEMC will take note of potential changes to the regulatory arrangements "where [these] are currently being reviewed". It is not clear whether this description would apply to the Congestion Management review, which has yet to formally commence.
[36] eg the review of intra-regional congestion management

6. Examples of Inefficient Generation Investment

The discussion above notes that existing arrangements do not provide an efficient, LRMC price signal for new generation investors and, as a result, may lead to inefficient investment decisions. In this section, we consider some historical investment decisions which may have been inefficient.

The group does not have access to sufficient information to make a robust claim that these real cases were actually inefficient. These examples are presented anecdotally as a demonstration that the investment regime may well have delivered sub-optimal outcomes.

Although these examples are isolated, as market participants we have noted similar elements affecting many other investment projects and would describe these as endemic characteristics of the NEM.

6.1. *South Eastern SA*

The Victoria-South Australian interconnector is effectively comprised of the long transmission path from Heywood in Victoria to Tailem Bend near Adelaide. Each segment of the lines was constructed to efficiently transfer about 500MW across the full distance without spare capacity on any segment.

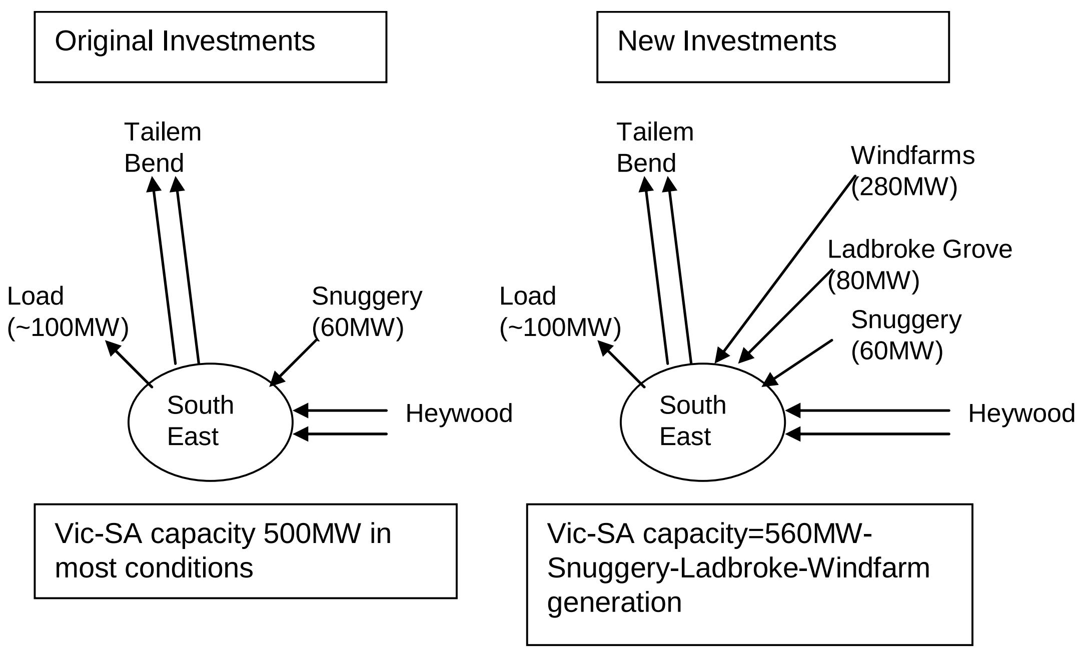

Figure 1: Stylised representation of power system in South Eastern SA

Ladbroke Grove power station is located close to the gas field that fuels it, on the SA-Vic interconnector in the south east of South Australia (See Figure1). This would have been optimal for the investor, as it minimises the cost of gas transmission and also enables LGPS to receive the SA price, which would generally be higher than the Victorian price.

As a result of its location, there is now congestion between the South East and Adelaide. A feature of regional pricing is that local generation has precedence over the interconnector flow, i.e. Victorian generation[37]. When these generators operate they act to constrain the Vic-SA interconnector and therefore constrain off Victorian or NSW generation. Thus, it creates additional congestion costs but does not bear these.

It may be the case that an efficient decision would have been to locate closer to Adelaide and build a gas pipeline. Typically, gas transportation is cheaper than electricity transportation and central planners usually locate gas-fired power stations at load centres.

Consider the Ladbroke Grove investment from the perspective of the long-term interest of Adelaide consumers: they have received no benefit of this power station – from either added security or enhanced competition - as its generation has simply displaced other generation that the consumer previously had access to. Furthermore, Ladbroke Grove's ability to displace other generation does not imply that it is more efficient, as the regional model does not permit fair competition between them.

A number of windfarms are also being developed in this area, including three staged projects near Lake Bonney totalling up to 280MW. As with Ladbroke Grove, this generation further impacts Victorian imports, although the windfarms will not bear the cost of this and will receive the SA price. As non-scheduled generation, the output of these units also receives priority over all scheduled generation output at present, worsening the congestion impact.

Windfarms need to locate where it is windy. However, if the windfarm investors had borne the full cost of the additional congestion that they create, they may well have decided to locate their windfarms elsewhere on the SA network: there are numerous alternative windy - but also uncongested - network locations.

The SA TNSP is now conducting regulatory tests on upgrading the South-East to Tailem Bend capacity. As the generation investments will be committed (i.e. sunk) during the test, it is very likely that such an upgrade will appear as an efficient investment. However had an assessment been taken prior to commitment, the costs of a gas pipeline and windfarm relocation would likely have been lower than the cost of a new line (cf Example 2 in section 4.1, above)

[37] This is a feature of most dispatch representations, including "direct physical" or "option 4" that is being rolled out NEM-wide. This is because the local generator can always offer at a price lower than the inter-regional generator without risk of settlement price impact.

6.2. *Victoria*

Basslink has chosen to connect to the mainland grid in the Latrobe Valley. This has brought forward an augmentation from Latrobe to Melbourne. Essentially, the Basslink transmission path goes all the way to Melbourne, but the Basslink investor only pays for the portion to Latrobe.

Other routes were considered for Basslink, some of which involved a connection to the mainland grid much closer to Melbourne. If the Basslink investor had been levied a deep connection charge – representing the cost of the Latrobe-Melbourne augmentation – it may have chosen a different route or connection point for Basslink.

6.3. *Queensland*

Kogan Creek is a prospective new generation project in Southern Queensland. It is unusual in that it has a single, 750MW unit, which is much larger than existing generating units in the area. The result of this decision will be to create new stability constraints which will reduce the capacity of QNI by 250MW. Transgrid has proposed augmentation work to offset this reduction[38] .

Under a deep connection charging framework, the Kogan Creek investor would bear the cost of the Transgrid augmentation. This may have caused it to reconsider its decision on unit size.

6.4. *Conclusions*

The examples above illustrate at least the *potential* for inefficient generation investment and location under the current arrangements. In practice, of course, nobody knows whether investment is actually inefficient, as only the generation investor knows the generation costs and nobody has the obligation or incentive to determine the incremental transmission costs.

As existing spare transmission capacity is depleted and economic augmentation and intra-regional congestion become more widespread, we expect these inefficiencies to become more prevalent unless and until deficiencies in the transmission pricing regime are corrected.

[38] Transgrid APR 2005 p49

7. Transmission Pricing for Existing Generators

7.1. *Pricing Efficiency*

This submission has so far focused on providing appropriate pricing signals for new generators: ie prices which reflect transmission LRMC. This begs the question of how existing generators should be treated.

As existing generators are not making long-run investment decisions, but continue to make short-run operational decisions, they will behave efficiently if faced with a price signal reflecting transmission SRMC. As noted above, in the absence of intra-regional congestion, the current, regionally-based wholesale price incorporates a good approximation of the transmission SRMC. Thus, any additional price signal – for example through TUoS charges – will *reduce* pricing efficiency.

We have already noted that the management of intra-regional congestion is the subject of a future AEMC review, which we expect to result in generators seeing a price, at the margin, that better approximates transmission SRMC. With this enhancement, pricing to existing generators should be reasonably efficient and any additional TUoS price will be counterproductive and reduce efficiency.

An alternative approach would be to attempt to reflect SRMC in the presence of intra-regional congestion through the design and application of generator TUoS charges. We believe such an approach would be unsuccessful and inefficient, since TUoS prices are established annually based on expected generation-demand patterns, whereas SRMC changes in real-time based on actual conditions.

7.2. *Revenue Recovery*

The AEMC notes that, since application of efficient prices does not generally recover sufficient TNSP revenue, it may be necessary to levy an additional, inefficient price component (ie a “tax”) to recover the remaining revenue. We agree with the AEMC that the design of this tax should be based on Ramsey pricing principles[39] to minimise its impact on market efficiency. The generation sector is the part of the market most responsive to transmission prices because their output is highly sensitive to their costs (ie they will not generate if costs exceed the wholesale price). Thus, levying the tax on generators would contravene Ramsey Pricing principles and cause efficiency to be reduced.

7.3. *Conclusions*

Existing generators already face pricing signals approximating transmission SRMC through the wholesale market, and should not also be charged TUoS prices, for efficiency or revenue recovery reasons. Transmission pricing inefficiency only arises due to intra-regional congestion and this should be addressed through improved congestion pricing coupled with a formal access rights regime.

[39] ie that the tax should be inversely proportional to the price elasticity of demand

8. Other Issues

8.1. *The 2% limit on year-on-year changes to TUoS Usage Prices*

The apparent intent of the NER is to limit annual increases in individual TUOS Usage prices to 2% of the average. However, the wording of the relevant clause (6.5.5(a)) also acts to prevent downward movements, which makes little economic sense. This removes any incentive for the network user to make cost efficient decisions in order to reduce its exposure to network costs, since it is largely unable to realise price reductions. This anomaly appears to be a simple drafting error, and could easily be corrected with the appropriate wording.

8.2. *Avoided TUoS*

There are a number of shortcomings in the ability of generators to attract payments for avoided TUOS. In concept, a NSP can contract with a generator to offset a new network investment. However, in practice the NSP does not share in the efficiency benefits of the generator and is therefore has not incentive to promote such arrangements. It is difficult to enforce the concept entirely through regulatory rules due to informational asymmetry.

8.3. *General Pricing Principles*

We consider that, to the extent that they are not inconsistent with efficiency, TUoS pricing (for loads) should conform to the following general principles:

- *stability*: any changes from year to year should reflect corresponding changes in LRMC;
- *consistency*: prices should be determined based on a single methodology applied across the entire transmission network, rather than on separately-applied – and sometimes different – methodologies in each State;
- *simple and transparent*: allowing any user to model and understand current and future TUoS Prices

9. Conclusions

We agree with the Issues Paper, that generators making long-term investment decisions should be faced with the long-run incremental cost of transmission. This does not happen under the existing arrangements: incremental augmentation costs are smeared across the demand-side, whereas incremental congestion costs are primarily smeared across generators.

The key to proper allocation of incremental transmission costs is the establishment of an access rights regime. New generators would be allocated access rights only where these can be provided from existing transmission capacity (without degrading existing generator access) or where the generator contributes to the cost of augmentation. Generators without access rights would bear the full cost of congestion that they create, ensuring that generators with access rights bear these costs only at the margin.

The access rights approach is not radical, nor is it inconsistent with the current market or regulatory framework. Indeed, the existing Rules provide for access rights to be acquired by generators from TNSPs, and MCE reviews have envisaged the establishment of access rights through Constraint Support Contracts, some of which have already been allocated to Snowy Hydro on a trial basis.

Without access rights, any transmission pricing regime cannot effectively distinguish between existing and prospective generators and must price to them on the same basis. Such a restriction would leave the AEMC with the unenviable dilemma of either pricing SRMC to all generators – and accepting that this may lead to inefficient location of new generation – or pricing to LRMC to all generators and distorting generation operation. We therefore urge the AEMC to consider solutions involving access rights as part of this review.