Mr John Pierce
Chairman
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28 January 2012

Dear John

**EUAA submission on the First Interim Report of the Transmission Frameworks Review**

Thank you for the opportunity to contribute our views on the AEMC's First Interim Report ("the Report"). We acknowledge the complexity of issues dealt with in that Report.

The arrangements for the access to and use of transmission networks matter to energy users. These arrangements affect not just the efficient development and use of transmission assets, but also the efficient operation of the electricity market. Outcomes for energy users – both prices and the reliability of supply - are significantly affected by transmission access arrangements. For this reason it is important to strive to ensure that these arrangements are as efficient as possible.

The Report has described five possible "packages" of reforms and separately discusses concerns over transmission planning and transmission connection.

A feature of the Report is the AEMC's concern that stakeholders have not provided sufficient evidence of the existence and nature of the problems that the Review is to address. Indeed, notably absent from the Report is a coherent statement of these problems.

In our previous submissions to the AEMC on this review, we encouraged the AEMC to seek out and establish evidence of the problems. We consider that most stakeholders involved in this review will have sectional interests to promote and we suggest may not always be forthcoming with evidence that may jeopardise their interests. Furthermore, few of these stakeholders can be expected to have broader public policy perspectives or expertise in these issues. This of course does not mean that the evidence to justify reforms does not exist. To the contrary, it becomes all the more important that the AEMC develops its own views on the magnitude of relevant issues such as the economic cost of transmission congestion, the

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economic impact of incorrect generation location decisions and the costs of sub-optimal transmission planning and operation. We continue to believe that a solid base of evidence – whether empirical and quantitative or based on logical deductive reasoning - will be very valuable in making the case for difficult reforms, and in guiding the development and choice of solutions.

In the attachment to this letter we briefly summarise our views of the main issues relevant to this review. We then comment on the AEMC's proposed packages, and finally set out our views on solutions that we suggest the AEMC might consider further.

Yours sincerely

Roman Domanski
**Executive Director**

# Attachment to EUAA submission on the First Interim Report of the Transmission Frameworks Review

## Statement of the problem

The Australian Government has established renewable electricity targets, such that by 2020, 20% of Australia's electricity production will be sourced from renewable electricity sources.

Of the various competing renewable generation technologies, wind farms are by far the most technically mature, bankable and competitive. It is a straight-forward matter to calculate the necessary investment requirement in wind farms in order to achieve the Government's targets. Such calculation takes account of the legislated demand for Large Scale Generation Certificates (LGCs) established through the Renewable Energy Target, reasonable assumptions of the likely development of large scale solar, biomass and geothermal technologies and of voluntary demand for LGCs. This calculation suggests that around 8,000 to 10,000 MW of additional wind capacity will need to be commissioned over the next 8 years.

Assuming an installed cost of around $3m per MW of capacity, this results in an investment requirement in renewable generation alone of around $30bn. This is around five times as much as the total capital expenditure in fossil fuel generation plant that has been planned and developed in the 13 years since the start of the National Electricity Market in 1999.

From these data it is clear that one of the major challenges for the NEM's transmission access arrangements is to ensure that appropriate signals are provided of the cost of transmission access. Failure to do this could result in inefficient generation location decisions. Energy users, more than any other stakeholders will bear the resultant dead-weight losses.

We suggest that signals for efficient generation location are more important than they have been in the past. Specifically, it might be reasonable to suggest that Australia's abundance of fossil fuels (other than in Tasmania) has meant that it has been possible to locate the major sources of electrical generation relatively close to major demand centres. Broadly similar marginal production costs (using fossil fuels) has limited the economic value to be derived from regional interconnection. The introduction of large scale renewable generation changes this in two ways:

1. It establishes a significant difference between marginal production costs of competing technologies (essentially zero for renewables and high and rising for fossil fuel plant particularly after the imposition of emission prices); and
2. The costs of renewables are particular sensitive to location. For example, a wind farm with a 25% capacity has average (fully absorbed) production costs of $151/MWh compared to $131/MWh for a wind farm with a capacity factor of 30% (assuming 25 year life, $3m per MW and 10% real pre-tax cost of capital). In other words, wind farms located in areas of high wind resource ought to be willing to pay up to $20/MWh more for transmission augmentation in order to locate in areas of high wind resource.

From this it should be clear that it is now particularly important that generators are provided with appropriate price-based locational signals. The situation that pertains in the NEM that generators face no price-based locational signal (beyond the average cost of transmission losses) is, as far as we are aware, unique amongst electricity markets in the world. It is an aberration that ought to be addressed through this review. The AEMC has agreed with this in its review on the impact of climate change. The objective of providing appropriate locational signals to generators is reiterated at several points in the Assessment Framework of the Report. We agree with the AEMC in both instances and urge the AEMC to prioritise addressing this recognised flaw in the NEM's transmission frameworks.

A second focus area might be disorderly bidding. This might be expressed in both very low and very high spot prices that arise as a result of transmission congestion. The development of a reasonable estimate of the economic cost of transmission congestion has been problematic in the NEM. In Britain since 1993, not long after the development of the England and Wales Pool an Ex-post Unconstrained Schedule (EPUS) was developed in order to measure the cost of congestion (and other aspects of power system operation). It is not clear why such calculation has been possible and accepted in Britain but has not been possible or accepted in Australia? Perhaps it is related to the arrangements in the NEM that allows re-bidding at close to real time? Whatever the reason, without a reasonable estimate of the cost of transmission congestion it becomes more difficult to demonstrate the existence of a problem.

A second approach to this issue might be through anecdotal examination of congestion-related high (or negative) prices. We note that some market participants are quick to dismiss high spot prices related to transmission congestion on the basis that market participants (and energy users) have usually substantially hedged their exposure to spot prices. This ignores the effect of these high spot price events on average annual spot prices (which in turn affects future contract prices) and also the costs associated with spot market volatility. We point to the evidence on this provided by the AER and AEMO (and EUAA) related to transmission constraints on the Mt Piper-Wallerawang transmission line (which the Report has noted on Page 51). We encourage the AEMC to publish its own views on this.

## Comment on AEMC packages

**Package 1 ("open access regime")**

As we understand it, this package involves no meaningful change other than to strike out some clauses in the Rules related to negotiated firm access that are clearly unworkable and have never been used. While it is useful to eliminate unworkable rules, it is hard to see that this adds much value. This package does not address any of the material issues and therefore we suggest does not merit further consideration.

**Package 2 ("open access with congestion pricing")**

As we understand this package is based on ideas proposed on behalf of some Victorian generators four years ago. The main idea, as we understand it, is to introduce locational prices (the "Constraint Support Price") and also a compensation element (the "Constraint Support Payment").

We think there is merit in considering locational prices for generation settlement, as one way to reduce disorderly bidding. In this respect we agree that this proposal has merit and might be considered further. The second part of the package (the Constraint Support Payment - CSP) makes less sense to us. As we understand it the CSP will share out the settlement residues that arise when transmission constraints occur. These residues are created when users pay the higher Regional Reference Node price, while generators on the wrong side of a constraint receive their lower locational marginal prices. The proposal is that this residue will be distributed to these constrained-off generators on the basis of their share of the aggregate generation that is on the wrong side of a constraint. Such compensation would be made irrespective of whether the generator was dispatched. The promise of this arrangement is that it does not distort bidding decisions (because the compensation arises whether or not the generating unit was dispatched).

We do not support this proposal. It will result in generators that are not even available or scheduled to be dispatched, being compensated for being on the wrong side of a transmission constraint. This makes little sense to us. The NEM provides no guarantee of firm access. Generators currently make no contribution to the cost of developing or operating the transmission system (other than some contribution to the average cost of losses) and under the Rules they have no rightful claim to compensation for the risk of not being dispatched if they are on the wrong side of a transmission constraint. The CSP proposal will provide such compensation even for generators that are not available or dispatched. This seems to make little sense and would provide generators with (financially) firmer access rights than they currently enjoy. This benefit would be provided without any contribution from generators to use of system charges.

**Package 3 ("Generator reliability standards")**

Our understanding of this proposal is to introduce planning standards for generators in return for which generators would be liable for transmission use of system charges. These planning standards would not deliver financially firm access, but we understand are likely to provide greater confidence to generators in relation to their constraint risks. It is not clear from the Report what form such generation planning standards might take.

It is envisaged that with this package there might be a further reduction in the five-yearly fixed price regulatory form, through strengthening of the contingent project arrangements or unit cost allowances. We are wary about such proposals because they may weaken network service provider expenditure efficiency incentives even further from their already weak levels. We also note that the AEMC has suggested that issues of economic regulation will be examined through the rule change reviews currently under way. As such, proposals on contingent projects or unit cost allowances should be considered in that forum.

**Package 4 ("Regional optional firm access")**

Our understanding of this proposal is that generators will have the option to purchase firm access from transmission network service providers, through payment of use of system charges. In return for this, if there were binding transmission constraints, the constrained-off generators would have a claim to compensation (based on the difference between the regional reference price and location marginal price that applies at the constrained-off generators connection point). This compensation would be payable by those generators that elected not to purchase firm access. It would be based on the difference between the non-firm generators' LMP and the price at the regional reference node.

*Prima facie* this is an innovative and elegant way of providing incentives for generators to bid their opportunity costs, and a way for generators to reveal the value of firm access. However, the idea merits further development. How are access charges to be determined? To what extent will available compensation from non-firm generators exceed/fall short of the entitlement of the firm generators, and how is any surplus/shortfall to be disposed/funded? Will this option work with separately owned and controlled NSPs. These and other questions bear careful scrutiny in the elaboration of this package.

**Package 5 (national locational marginal pricing)**

As we understand it, this option is the (now) traditional formulation of locational marginal prices and financial transmission rights sold in primary markets by the system operators, and subsequently traded in secondary markets. This was an intriguing and novel idea a decade ago, and although we understand it has been implemented in some markets in the United States, its success in providing locational signals, and market and transmission efficiency is not yet clear. This model was considered in detail in Britain in 1999 in a project initiated by Ofgem (under Dr Eileen Marshall) and which involved extensive modelling by the National Grid Company. That modelling revealed that simultaneously feasible allocation of financial transmission access rights would result in very low auction proceeds for FTRs – with the remaining regulated transmission revenue still to be recovered through use of system charges (as might be expected since if the access rights are simultaneously feasible the system will by definition be unconstrained). In other words, this model would involve additional complexity for limited additional benefit. For this reason, its implementation was rejected in Britain. However regardless of this, in the NEM with several independent transmission network service providers it is likely to be impossible to allocate NEM-wide financial transmission rights without exposing network service providers to financial risks that they have no way of controlling. As such, it is not clear that this approach merits further discussion.

## Our suggestions on focus areas

We have identified a number of changes that should be reasonably simple to deliver in the sense that they do not require changes in industry structure, ownership or governance and which do not involve fundamental changes in institutions. Ranked in order of their delivery, they are as follows:

1. Simultaneous regulatory resets for transmission network service providers;
2. Marginal rather than average transmission loss factors for generators and load;
3. Use of system charges for generators;
4. Constrained-off payment for generators.

**Simultaneous regulatory resets for transmission network service providers**

This idea was proposed by the Electricity Reform Implementation Group (ERIG). We fully support this. It should significantly improve the regulatory assessment of transmission investments that cross regional borders (or affect inter-regional flows). It should also facilitate better comparative assessments of transmission network service provider expenditure efficiency. This approach seems to be straight-forward to achieve and we encourage the AEMC to consider it carefully.

**Marginal rather than average transmission loss factors**

Generators (and load) are currently adjusted for average losses. The NEM is meant to reflect marginal production costs and the use of average costs for transmission losses is inconsistent with this. Marginal losses will typically be twice the average level of losses. The use of marginal losses will strengthen locational investment and operating decisions and will also deliver a settlement surplus of around $200m per year (assuming marginal transmission losses of 4%, average transmission losses of 2% and average settlement prices of $50/MWh). This surplus could be allocated to TNSPs with a commensurate reduction in network service provider regulated revenues. Again, this change should be straight-forward to deliver.

**Use of system charges for generators**

As discussed earlier, it is an anachronism that generators are not charged for use of the transmission system. More generally, is there any other commodity market where producers are not exposed in some way to the costs and risks of transporting their product to their customers? LYMMCo and Truenergy have argued that generator use of system charges will be volatile, a comment which we note that the AEMC has repeated, apparently without questioning it. We suggest that the generators' argument is spurious. The volatility of the NEM spot prices is many orders of magnitude higher than the volatility of transmission charges will ever be. Producers have little difficulty in managing such market volatility, surely some annual variability in use of system charges can hardly be an issue. Furthermore, if the AEMC accepts the volatility argument by generators why should it not also apply to load in which case, on efficiency (and fairness) grounds, the AEMC should propose that users no longer pay use of system charges.

Other arguments that generators have used to reject use of system charges include the well-worn argument of sovereign risk and that generators will not respond to use of system charges since their investment is sunk. Neither of these withstand elementary inquiry: on the first, most generators ought to be able to recover all or most of their use of system charges and even if this is not the case on what basis can they have a reasonable claim against variation of input costs – would the same arguments apply if their gas and coal suppliers raised their prices? On the second, expansion and closure decisions will be affected by transmission use of system charges, and this should be particularly relevant for many incumbent fossil fuel suppliers after the imposition of an emission price.

**Constrained-off payments from generators**

The AEMC has proposed several mechanisms to deal with disorderly bidding related to attempts by generators to continue to be dispatched when transmission constraints bind. Our proposal is to make constrained-off payments based on the difference between the regional reference price and a constrained-off generator's estimated marginal production costs. Of course, such estimates might be contested, but the possible differences between regulatory estimates and actual production costs are likely to be small. This approach is no worse than directions payments for plant which is constrained on, which is an accepted approach in the NEM.

With such an approach, constrained-off generators would have no reason to bid below their estimated marginal production costs (since they will receive no greater compensation for this). Such an approach is likely to discourage bids below marginal production costs, thus helping to deliver efficient dispatch when transmission constraints bind. The cost of funding such constrained-off payments could be recovered through uplift fees charged to all generators on the basis of a $/MWh charge. It is noteworthy that in the British transmission uplift scheme, which has been in place since 1996, constrained-off payments account for the minority of constraint costs.

Compared to the other approaches that the AEMC has proposed, this approach would be much easier to deliver. Further detailed analysis will need to be done to develop and assess this approach.