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The Chairman,
Australian Energy Market Commission,
PO Box H166,
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Submission by email: submissions@aemc.gov.au

TRANSMISSION PRICING FOR PRESCRIBED TRANSMISSION SERVICES: RULE PROPOSAL REPORT

Dear Dr Tamblyn,

The National Generator's Forum (NGF) commends the Australian Energy Market Commission (AEMC) on its in-depth consideration of transmission pricing issues and appreciates this opportunity to provide comment on the Transmission pricing for prescribed services Rule proposal.

Summary

The proposed price structure principles, supported by AER developed pricing guidelines and NSP pricing methodologies provide a sound regulatory framework for the efficient use of prescribed transmission services.

Whilst the NGF supports the framework and approach for the proposed pricing Rules it is concerned that relevant outcomes of the Congestion Management Review (CMR) may not be considered in time for inclusion in the new transmission pricing arrangements. As detailed later in this submission, the CMR may advocate stronger long term investment pricing signals or recommend the implementation of new arrangements for generator access to market. Both issues may require changes to the transmission pricing framework.

The NGF believes it is important for the AEMC to take account of potential outcomes of the CMR that may impact the transmission pricing framework and ensure the proposed pricing Rules will not influence or limit sensible changes to market arrangements related to congestion management or investment signaling.

This submission provides comment on those areas of the proposed pricing Rule that impact generation and includes some suggested improvements particularly in the areas of prescribed transmission service definition, Transmission Use of System (TUOS) rebates to embedded generators and regulation of the pricing of negotiated services.

Locational Investment signals

As concluded in Section 3.1.3 of the Rule proposal report, the AEMC is of the view that existing locational signals in the market (assumed to be connection charges, losses and likely regulatory test outcomes) are sufficient for new investment and there is not a strong case to move away from current allocation arrangements[1].

The NGF accepts this conclusion only in the context of the limited scope of the prescribed transmission services review. The NGF's submission[2] to the AEMC's transmission pricing issues paper dated 3 January 2006, advocated the need to consider efficient locational investment signals for market participants.

The CMR is considering arrangements for congestion management which support efficient investment in transmission, generation and demand side management. As noted in the CMR Issues Paper dated 3 March 2006, delivering improvements to dynamic efficiency requires clear signals about the location and extent of congestion. Such signals may well extend to locational transmission pricing arrangements.

Long term certainty of transmission access is an important issue for generators and it is hoped that the CMR will propose a range of initiatives that address shortcomings in NEM structure in this area. It is conceivable that part of the response to transmission access concerns may well be arrangements that allow generators to take some exposure to incremental prescribed transmission service costs in return for increased access certainty. Such an outcome would have considerable implications for the proposed transmission pricing approach.

As stated above, it is crucial that the AEMC does not implement any Rule that may either influence or limit the recommendations from the CMR.

Regulatory Framework

The NGF supports the tiered regulatory framework proposed by the AEMC which includes Rule principles, AER guidelines and Network Service Provider (NSP) methodologies. Whilst this approach provides a flexible regulatory framework for the unique needs of an NSP it also presents potential problems with regard to consistency of application across the NEM.

[1] One member, AGL, considers that the current practice of TNSPs and what the AEMC considers the current allocation arrangements of shared network augmentation costs is in fact a change to the Rules. Page 224 of the initial application for authorisation shows that a connecting party should pay its share of augmentation costs for all affected networks in addition to its connection assets.

[2] Stanwell Corporation did not support the NGF's pricing issues submission to the AEMC

The NGF strongly recommends the development of explicit guidelines to ensure a market participant will see the same pricing process and basic pricing methodologies regardless of which location in the NEM a transmission service is being sourced or negotiated.

As a general comment, the charging provisions appear to emphasise flexibility at the expense of consistency. While the principles / guidelines / methodologies framework is supported, increased emphasis should be given to charging consistency across regions, unless legitimate local circumstances require specific treatment, based on common criteria. For example, anomalies such as exorbitant locational prices on efficiently utilised radial lines in remote regions with no prospect of expansion (and therefore no legitimate congestion signal) should also be avoided. A maximum limit on individual transmission charges might be appropriate.

Pricing for Negotiated Services

In recasting the Rules, the AEMC has determined that negotiated transmission services should not be subject the same level of regulation as prescribed services. The NGF is of the view that where there is a clear absence of competitive services available, a strong regulatory framework is required. In the case where the Transmission Network Service Provider (TNSP) is the only service provider, a generator has an information disadvantage with regard to both design requirements and costs.

The NGF would welcome the inclusion of additional pricing Rules for negotiated services that ensure the generator and NSP can negotiate a transmission service on an equal footing.

Setting of Transmission Prices

The NGF concurs with the AMEC's reasoning in regard to sunk costs and supports maintaining the existing arrangements for sunk cost recovery. Any sunk cost allocation to generators would not deliver a positive influence on future behaviour and would likely distort efficient consumption and dispatch.

The NGF also welcomes the clarification of the basis for charging by including the principle of 'causer pays' in the Rules. Whilst there may be some difficulties associated with allocating costs between different prescribed services on a 'causer pays' basis, the alternate beneficiary's pays approach is not useful in this regard.

Definition of the Prescribed Transmission Service Categories.

It is noted that, whilst the AEMC has proposed to retain the existing cost allocation structure, it has created a "priority ordering" of services. Under this approach, costs that could potentially be attributed to more than one service category are firstly allocated to prescribed entry or exit services. This appears to be a clear departure from the status quo, and opens the risk of increases in connection charges, where such costs may be shared or proportionally allocated at present.

As noted in section 4.1.5 of the Rule Proposal Report, existing "legacy" entry and exit services that have been grandfathered remain within the scope of the prescribed transmission service category.

Cost Allocation Principles in the Draft Revenue Rule prevent historically shared costs associated with prescribed transmission services from being reallocated to negotiated transmission services. Existing 'legacy' generator connection costs are grandfathered as prescribed transmission services by Rule 11.5.11 and therefore denied this protection. It is the NGF's position that the same principle should apply to generator connection costs regardless of how historically determined. Shared network costs should not be reallocated to generator connection costs.

If an NSP modifies a 'legacy' asset (e.g. via a network reconfiguration or refurbishment project) it is unclear whether any increase in asset value also forms part of the Regulatory Asset Base (RAB), or would be deemed to be a negotiated transmission service. The treatment of increases in grandfathered asset value should be clarified. Any increase in asset value should not be allocated to existing generator connection costs where such projects are initiated to benefit users generally.

The NGF believes there would be benefit in providing a more precise interpretation of 'attributable' to ensure assets, previously treated as common service assets are not, reclassified as entry assets. Further, there appears to be nothing in the draft Rules which avoids the possibility that an asset boundary could be moved by a network reconfiguration, leading to cost shifting from shared services to connection services.[3] The proposed Revenue Rules also leave open this possibility, particularly for 'legacy' connection services which remain grandfathered as prescribed services.

<u>TUOS Rebates to Embedded Generators</u>

The NGF supports TUOS rebates for embedded generators to provide efficient locational signals for co-location of generation and load. If avoided TUOS payments were removed, generators would lose their incentives to build close to load. Load may lose incentives to locate close to pursue embedded generation deals.

It would be worth considering a number of possible adjustments to the current avoided TUOS arrangements to finetune the working of the arrangements.

At present, avoided TUOS is calculated and paid on the basis of the "with and without" test in clause 5.5. Under this arrangement, avoided TUOS is based on the saving in the variable (i.e. throughput) components of the TUOS charge at bulk supply points following the connection of embedded generators. The payment is made by the Distribution Network Service Provider (DNSP) to the generators embedded in its network behind the bulk supply points.

The first problem arising from this is that transmission pricing practices vary from State to State, and in some States (notably South Australia) charges are based very heavily on fixed capacity rather than on throughput. The savings in variable charges are low, and thus the benefits of avoided TUOS calculated under the 'with and without' test are heavily muted.

[3] There are currently a number of live examples of this problem across the NEM facing generators.

It has been argued that the current “with and without” test for calculating avoided TUOS payments in clause 5.5 of the NER may over-reward generation which does not in practice defer transmission capital expenditure but may under-reward generation which defers transmission capital expenditure.

Effectively, the current practice provides a payment equal to the saving in the throughput component of TUOS. This excludes the saving in the installation of capacity which is a large share (in South Australia, almost the entire share) of TUOS. Ideally, avoided TUOS payments for large generators should be paid at a rate which reflects the actual annualised savings achieved by the network augmentation deferral (calculated at current construction cost building block rates).

It is understood that the current approach was adopted because the more accurate method proved unworkable for small embedded generators. However, it is likely to be feasible for larger generators. The NGF is of the view that there is value in investigating whether there are alternative and more efficient mechanisms for calculating the size of the payment to large generators.

The use of capacity charges based on forecast usage with penalty payments if demand is understated also increases the risk of DNSPs that allow a TUOS rebate. These factors provide a clear financial disincentive for DNSPs to support such payments. Moreover, DNSPs have argued that, as they cannot predict the reduction in demand at the bulk supply point arising from the presence of the embedded generator, they do not make any savings.

It is understood that ETSA Utilities has stated South Australian generators cannot receive avoided TUOS as they can not in practice enable ETSA Utilities to reduce its exposure to TUOS Usage charges. This has effectively rendered the avoided TUOS arrangements redundant in South Australia.

By locating behind a bulk supply point, embedded generators avoid new transmission investment. Their presence thus primarily saves transmission capital investment rather than variable TUOS charges. Thus, it is arguable they should be paid avoided TUOS based on the value of the deferral of capital expendiure rather than on the basis of savings in variable TUOS charges.

The NGF recognises the relative simplicity of the current charging arrangements, and the fact that they provide generators with a locational signal even in circumstances where the network would not in any case need augmentation.

For small generators, the current charging arrangements may be appropriate. For larger generators, there should be scope to calculate the avoided TUOS payments based on the savings in capital costs. In terms of determining whether large generators avoid new transmission capex, it should be noted that, even where no augmentation is needed in the short term, an embedded generator may provide benefits in greater security of supply.

In any case, transmission investments are made on a 10 to 15 year timeframe (where new transmission capacity is built even though it may not be needed for the next 10 to 15 years because of the scales of economy in the construction of new transmission infrastructure), and so the benefits of embedded generation in terms of deferring new transmission investment should be assessed on the same timeframe.

The second problem is that avoided TUOS is paid by DNSPs. As avoided TUOS payments notionally reflect capital savings to transmission companies, it may be appropriate for them to be included by regulators as part of the capital base for TNSPs, and then earmarked and passed on as such by the DNSP.

A third problem is that the payments are only required to be made if the generator is located in the distribution network of a DNSP connected to the transmission network. DNSPs do not have to pay avoided TUOS to generators connected to inset networks within the DNSP's network. The DNSP in respect of the inset distribution network also does not have to pay avoided TUOS as it is not connected to the transmission system and therefore is not charged TUOS. The wording of clause 5.5 should be amended to provide for the DNSP connected to the transmission system to pass through TUOS savings from the presence of generators behind the transmission node.

The AEMC has questioned whether network support payments (NSPs) to embedded generators should be deducted from avoided TUOS payments to ensure there is no double payment to generators.

While NSPs and avoided TUOS payments are linked, there are differences. Avoided TUOS payments are aimed at passing on capital-related savings flowing from network deferrals. NSPs are payments to oblige generators to generate when they would not ordinarily be dispatched (because their bid price is above the pool price) but are required to be dispatched to avoid supply curtailments.

Without NSPs, generators would lose money whenever they were required under network support agreements to dispatch. In essence, they are akin to the operating costs associated with the operation of deferred networks (though it is true that they are calculated on a different basis). NSP generation compensates for the estimated differences in the cost of generation at times of local high demand compared with pool prices at those times.

NSPs are essentially an alternative to relying on constrained-on generation directions and subsequent calculation of compensation payments under the rules in clause 3.15, in particular 3.15.7, 3.15.7A, and 3.15.7B (contrast clause 3.9.7). They are preferable to constrained-on generation directions, as NSP payments are collected from intraregional participants rather than NEM participants, and the intraregional participants are the beneficiaries of the generation. Deducting NSPs from avoided TUOS payments would discourage generators from entering NSPs and instead relying on compensation flowing from constrained-on generation.

As a side point, the NGF considers that arrangements for network support payments and directed-on generation should be clarified in the rules as they are vague and do not lend themselves to proper integrated planning processes for delivery of transmission and distribution or embedded generation solutions. Problems arise because of the broad range for directed-on generation payments under clause 3.15 and the imprecision of comparing embedded and network solutions in terms of reliability outcomes.

The AEMC invites comment on whether to pay avoided TUOS to generators based on the generator's size (e.g. below or above 10MW). The NGF considers this is inappropriate. As noted above, the avoided TUOS rules were put in place to cater to ease the administrative burden for DNSPs and provide a simply method to calculate the avoided TUOS amount. It is a simple calculation based on TUOS charge rates, and should not be administratively burdensome to calculate in respect of small generators. The proposal to set a minimum threshold for calculating avoided TUOS payments is likely to involve a degree of arbitrariness in payment of avoided TUOS and result in DNSPs retaining savings in TUOS that should be destined for small generators.

Inter-regional TUOS Arrangements

The NGF supports the strengthening of inter-regional interconnection, where this is an economically efficient response to congestion. It notes that the main concern expressed by the AEMC is in relation to equitable cost recovery, rather than to the justification of transmission augmentation under the regulatory test.

The NGF does not have any firm views on alternative arrangements for the recovery of investment costs through Inter-regional TUOS sharing agreements, although the use of settlement residue auction proceeds as a payment between jurisdictions is not considered an adequate alternative.

We note that jurisdictions committed to commencing inter-network charging when determination of all TNSP revenue requirements were transferred to the ACCC. Subsequent changes to the methodology were rejected by the ACCC, and therefore no current method is available to be used. Given the jurisdictional involvement in the current arrangements, a policy direction from the MCE should be sought before any changes are considered.

The NGF notes the role of ERIG in achieving the COAG's objective of achieving a truly national approach to the future development of the electricity grid whilst considering the legitimate commercial interests of asset owners, and the need to promote investment that supports the efficient provision of transmission services.

Conclusion

Transmission plays a key role in facilitating the efficient operation of the NEM. The transmission services pricing framework should underpin the promotion of efficient resource allocation in transmission, generation and load responses over the longer term.

The proposed Rules for prescribed transmission services will deliver an improved pricing framework and support economic efficiency, but it is important that these Rules complement, and not undermine, proposals for new arrangements in other areas of NEM operation.

The NGF has also raised a number of concerns regarding the adequacy of the proposed Rules to;

- fully deliver on the intent of the stated principles as detailed in the Rule Proposal Report;

- ensure generators are not exposed to additional costs where there is no intention to change current regulation; and

- address shortcomings in the arrangements covering TUOS rebates to embedded generators.

The NGF trusts the AEMC will give due consideration to the concerns raised and review the relevant clauses of the proposed Rule for prescribed transmission services.

If you require clarification of the matters raised by the NGF please do not hesitate to contact me on (02) 6243 5120.

Yours faithfully,

John Boshier
Executive Director