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SUBMISSION

Congestion Management Program

Statement of Approach

14 September 2006

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1. Introduction

1.1 AEMC Congestion Management Review
Total Environment Centre (TEC) agrees with the opening statement in the Statement of Approach (SOA) that, "The effective management of congestion is critical to the efficient operation of the National Electricity Market (NEM)". TEC is mainly concerned with the overall direction and management of congestion policy as well as specific Rule changes.

A significant oversight in the SOA is consideration of congestion management in relation to distribution networks. We understand that this was not included in the original Ministerial Council on Energy (MCE) directive, but distribution regulation is due to go to the national level next year. Therefore, in any assessment of future management this branch of the NEM should play an important role, since congestion in these networks has the potential to have an effect on the whole system. Congestion effects are not solely limited to transmission and generation and it is short-sighted to neglect distribution in future planning.

The Australian Energy Regulator (AER) is also reviewing transmission congestion[1] – in terms of market impact – and has produced indicators to assess the costs of congestion. The proposed indicators are: total cost of constraints, the outage cost of constraints and the marginal cost of constraints. It is not clear how the intersection between pricing as discussed by the Australian Energy Market Commission (AEMC) will intersect with the costs presented by the AER. TEC recommends that a joint paper be produced at some stage presenting the linkages and divergences between the two approaches – this would assist with clarity and comprehension for the interested public and consumer organisations.

Information disclosure, as noted in the SOA, is a major barrier, particularly to embedded generators and demand management (DM[2]) providers. NSW currently requires distribution networks to investigate and report on cost-effective non-network solutions to network constraints and the guidance for compliance with this licence condition is provided by the NSW DM Code of Practice. The national regulator should adopt similar reporting requirements for both transmission network service providers (TNSPs) and distribution network service providers (DNSPs) to improve the consideration of non-network solutions and smaller, renewable energy generators and, in turn, reduce unnecessary costs for consumers. Detailed and clear information about forecast constraints and reliability shortfalls is an essential tool to allow the DM and embedded generation market to respond appropriately and in good time to potential opportunities.

[1] Australian Energy Regulator, *Indicators of the Market Impact of Transmission Congestion – Decision*, June 2006

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

In regards to the many forms of DM, the National Electricity Rules state that: "The regulatory regime to be administered by the AER must ... also have regard to the need to:

> (1) provide Transmission Network Service Providers with incentives and reasonable opportunities to increase efficiency;
>
> (2) create an environment in which generation, energy storage, demand side options and network augmentation options are given due and reasonable consideration;"[3]

To date, these requirements have not been met since demand-side options are certainly not being "given due and reasonable consideration". DM can be a particularly effective means of managing congestion. However, as it has not been pursued in a rigorous, serious fashion across the NEM, major opportunities exist for improvement. SA and NSW have comparatively the best mechanisms in place, but these are still far from perfect, and they only relate to distribution network service providers (DNSPs).

There is a range of demand side responses – in the broad sense of the term – which can relieve congestion. Promotion of energy efficiency (in buildings and appliances, for example), active demand side responses such as load shifting or curtailment, and the use of on-site generation can all contribute. There needs to be considerably more work done in detail on the actual benefits and reliability contributions brought by DM, with a serious body of case studies developed to give future guidance regarding magnitude, timing and costs. A DM industry needs to be fostered and proper assessment made of wholesale and retail cost savings.

There are institutionalised barriers to DM within the NEM, since it is in the interests of generators and network businesses to promote the consumption of more electricity and thus increase their revenue than to foster reduced demand in any form. The full range of benefits of DM are nowhere near being realised within the NEM.

1.2 Recommendations

We have focused our recommendations in this submission on two major points raised in the Statement of Approach as critical features of a congestion management regime, that is, information disclosure and incentives to address congestion. They are, in summary:

- Any Review must consider distribution as well as transmission since these networks can equally be constrained. If the AEMC is trying to develop a holistic approach across the NEM – as they are clearly interested in doing – then distribution must be included in the mix. The DNSPs are going to be regulated at the national level eventually, even if the process is somewhat delayed.
- The Rules should refer to a Demand Management (DM) Code of Practice for transmission and distribution networks, with the NSW model to be adopted as a minimum (including the protocol for disclosure of information).
- Networks should be obligated to *implement* non-network solutions where more cost effective than augmentation.

[3] National Electricity Rules, Section 6.2.3

- Incentives should be developed to encourage cost-effective network DM, in return for network businesses earmarking a specific minimum spending level for DM. Alternatively a "D" factor system could be applied, as in NSW, which is intended to promote DM by networks through the use of incentives.
- The AEMC could develop a methodology to identify the reliability benefits of DM in relation to congestion.
- The AEMC should develop clear protocols and incentives for NEMMCO arrangements with large end users for load shedding when congestion is forecast.
- Metrology procedures should be nationally regulated and a standardised system of interval metering should be installed across the NEM. The metering system should be based on advanced interval meters ("smart" meters) with the capacity for remote communication.
- The NSPs should be required to seek embedded generation as well as DM solutions to network constraints before considering network augmentation. This should be done by issuing standard offers as well as Requests for Proposals (RFP).
- Detailed information should be required of NSPs as the annual public disclosure of information on emerging network constraints is essential to the development of non-network responses and to provide the opportunity for small, renewable energy generators to participate in the market.

2 Demand management

2.1 Benefits of demand management

DM in all its forms is essential in any suite of actions for alleviating congestion management across the NEM, both within transmission and distribution networks. The NEL Objective is set up to cater for "the long term interests of consumers" and, in particular, on the "efficient use of electricity"; without effective DM this is not being achieved.

It can be argued that the long term interests of consumers takes account of the prevention of climate change caused by greenhouse emissions from fossil fuel generation, which includes both indirect environmental interests as well as the avoidance of unnecessary energy and other costs that will be incurred as the cost of emissions rises.

The value of DM is acknowledged in the Statement of Approach, as it has been in most issue papers and statements about the energy market reform program. However, there are very few concrete recommendations for DM emerging and it is generally presented as a side issue rather than as a fundamental mechanism. It is also rarely clear – in the SOA as in other documents – whether the whole range of DM opportunities is being referred to or a subset of these. The Statement lists "demand-side alternatives" but does not define what these would include: the failure to appropriately define demand-side alternatives reflects the lack of seriousness with which the SOA deals with DM.

A report for Energy SA[4] gives a useful list of examples of demand side management opportunities, most of which are relevant to this review:

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

- energy efficiency programs
- load shifting
- load curtailment
- tariff structures and metering
- embedded generation, including fuel switching issues
- network constraints, which provide opportunities for DM.

The report goes on to suggest that, "Demand Side Management activities ... are often the only effective short term tool for overcoming supply side and distribution system inadequacies."[5] These inadequacies include, in particular, congestion problems.

A primary advantage of DM is the facility to ease the load on the system. As an alternative to augmentation, DM has the potential to reduce both the quantity and price of electricity used. Better utilisation of existing assets and deferral of the need for new capital expenditure (and consequently operating expenditure as well) by the networks can be gained through reversing the increasing ‘peakiness’ of electricity use. This peakiness results in the inefficient utilisation of network assets and is exemplified by EnergyAustralia’s claim that "the top 10 per cent of capacity is utilized less than one per cent of the time ..."[6]

In terms of benefits, the NSW Department of Energy, Utilities and Sustainability has also acknowledged that, "It is recognised that demand reduction can provide long term network benefits, not only when the system constraint occurs. This is because such demand reduction can reduce the need for future network augmentation under a wide range of plausible future scenarios. The essence of cost-effective network demand reduction is the postponement of a known capital expenditure and funding the demand reduction option from the avoided distribution [or transmission] costs."[7]

The AEMC has previously acknowledged[8] potential benefits arising from the development of demand management and other energy sources, that is, that by utilising these:

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

The most important solutions for establishing a robust demand-side presence in the electricity market – and which must be given proper consideration in this review – include:

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[5] Energy SA, *Demand Side Management – Benefits to Industry & the Community*, 2001, p 5
[6] Independent Pricing and Regulatory Tribunal of New South Wales, *Inquiry into the Role of Demand Management and Other Options in the Provision of Energy Services – Final Report*, October 2002, p 60
[7] Department of Energy, Utilities and Sustainability, *Demand Management for Electricity Distributors – NSW Code of Practice*, September 2004, p 21
[8] Australian Energy Market Commission, *Review of the Electricity Transmission Revenue and Pricing Rules – Transmission Pricing: Issues Paper*, November 2005, p 32

- establish a DM funding mechanism
- establish a DM code of practice
- ensure networks investigate and implement DM as an alternative to network augmentation where cost effective
- establish incentives throughout the NEM for the implementation of DM and the use of small, local generators based on alternative energies
- ensure networks disclose information on impending constraints in a timely manner.

We also recommend that, since NSPs are not yet fully experienced in DM measures, the AEMC pursue the feasibility of a transitional mechanism. Generous incentives should be developed to encourage cost-effective network DM. Given the large technical and economic potential for DM, between 10% and 25% of the projected network capital expenditure should be specifically earmarked for cost-effective DM projects. This funding should be allowed only on "use it or lose it" terms, and could step up from an initial small percentage, increasing as networks become more adept at facilitating DM, then gradually reducing as the potential for DM is utilised.

The aims would be to remove risk, such as by allowing NSPs to become familiar with DM techniques for meeting time and load targets, and develop strategies for maintaining service and reliability requirements wherever DM does not meet the required targets. This could include milestones for NSPs to develop DM implementation plans as well as exit strategies to allow alternative measures to be undertaken. Such a transitional mechanism could include procedures for the NSP to interact with the AER in finding solutions for such situations on a case-by-case basis.

Subsequently a “D” factor system could be applied, as in NSW, which is intended to promote DM by networks through the use of incentives – that is, the TNSP or DNSP must demonstrate that its DM implementation costs are less or equal to the avoided distribution costs before it can pass through any costs to customers. Such a mechanism would need to provide recovery of direct costs, recovery of lost revenue and recognition of the reduced return on capital. In cases where the non-network solution proved to be inadequate, there would need to be provision for the recovery of costs.

Additionally, we recommend that the AEMC considers the benefits of allowing DM aggregation as a service outside Prescribed and Negotiated Transmission Services. The AEMC could also consider whether DM aggregation should be regulated under Chapter 6 of the Rules.

2.2 NEMMCO arrangements

Direct load shedding arrangements with large end users – one of the forms of DM – have the potential for significantly easing constraints during critical peak periods. NEMMCO has the power to intervene in this situation and can make arrangements and offer incentives in advance of a perceived constraint. As an independent body, it is appropriate for NEMMCO to be able to institute these kinds of provisions. The efficiency benefits – and reliability of supply – outweigh any reasonable payments made to such consumers. So far this strategy has been under-utilised by NEMMCO and there seems to be few clear protocols or particular incentives for NEMMCO to enter into these arrangements. This is an avenue for the AEMC to provide greater guidance, including in relation to the protocols for potential payment of incentives to these consumers.

NEMMCO's powers could be enhanced by the development of a methodology by the AEMC for assessment of the reliability impacts of DM (and other network and non-network solutions) at an appropriate level of accuracy. These reliability impacts should also be explicitly incorporated into the assessment of capital and operational expenditure.

2.3 Interval meters and tariffs

The proper implementation of tailored price mechanisms in response to interval metering (providing the meters are advanced, interactive meters) would also assist with addressing congestion problems. The MCE has given the go-ahead for the use of "smart" meters across the NEM, but the specific type and timing has been left to the jurisdictions. This means that there is no real certainty for investors in all areas of the NEM – from generators through to retailers – and this situation really needs to be clarified. Interactive meters and varied tariff plans will increase the importance of DM within the NEM as customers implement their greater range of choice, with the potential for reduction not only of peak loads but also base loads.

Metrology procedures should be nationally regulated to allow consistency for all parties. Furthermore, a standardised system of interval metering should be installed across the NEM. The metering system should be based on the best available, which currently is advanced interval meters ("smart" meters). There are many benefits which can arise from the use of advanced meters. Demand management is the most obvious, with the possibility for load shifting and load reduction once end users can readily keep track of their consumption. The User Participation Working Group presented a number of other potential benefits[9]:

- *Avoided capital costs of new generation and network capacity;*
- *Avoided variable costs of energy generation;*
- *Avoided manual meter reading costs;*
- *Improved operational network management including near real-time measurement of network losses;*
- *Reduced greenhouse gas emissions from a reduction in peak demand (where there is not a shift in consumption to more emission intensive generation at another time of day) …*

It is critical to install state-of-the-art technology that has the capacity for remote control technologies and communications, since retrofitting in the future would add a significant cost for consumers and create another unnecessary barrier to DM. Advanced interval meters allow for remote communication which can give the end user up-to-date information on their consumption. Smart meters also provide the capacity for targeted systems and appliances to be shut down when necessary (remote load control). They therefore allow for both demand management and load shifting, and thus a potential reduction in the need for augmentation of the whole system to deal with peaks. It is therefore essential that the national regulator ensures that consistent and up-to-date technology is adopted across the NEM.

[9] User Participation Working Group, *Common Principles for the Assessment of Interval Meters: Overview paper*, Report to the Ministerial Council on Energy Standing Committee of Officials, June 2005, pp 7-8

2.4 Alternatives to augmentation

Although the Rules and jurisdictional regulations require NSPs to investigate DM alternatives, these should be improved upon by ensuring that networks implement DM opportunities when they are found to be more cost-effective than network augmentation. In a competitive market, the failure of NSPs to weigh up non-network and alternative generation options goes against the intentions of the National Electricity Law and adds unnecessary costs for consumers. At the very least, there should be proper provisions for recovery of DM implementation; and some way of checking that they have been genuinely investigated, rather than the NSP just going through a paper exercise.

Therefore, there must be incentives for DM to counter the massive incentives and cultural bias for NSPs to sell more electricity. Such incentives should ensure that networks are able to recoup revenue for both the cost of carrying out demand management and for the lost revenue of sales that would have been made had an augmentation gone ahead. The purpose is to reduce congestion and promote consideration of more efficient non-network solutions. Equally, if the non-network solution is implemented but then fails, there should be a compensation mechanism for cost recovery.

There is currently a lack of clarity from regulators regarding the recovery of DM spending. This creates uncertainty for networks investigating DM solutions to network constraints. The national regulator should therefore clearly set out the circumstances in which networks can recover the costs of implementing DM. There is currently no guidance for the treatment of expenditure on non-network solutions to constraints. This issue has been identified repeatedly as one of the key barriers to investment in non-network solutions. To encourage NSPs to undertake cost-effective expenditure on non-network solutions, there is clearly a need to provide certainty as to the way in which those expenditures will be treated and the rate of return that those expenditures could be expected to deliver.

There are good reasons for deferring augmentation:

> *Because networks account for about 50% of electricity costs, and the bulk of those costs are fixed capital costs, numerous benefits follow if network investment can be decreased. ... an immediate effect of obtaining energy efficiency and of managing demand is to reduce or defer network investment. The attractiveness of this is greatly enhanced in the present situation where peak demand is growing faster than energy sales.*[10]

3 Other incentives

3.1 Embedded generation

The removal of barriers to localised, embedded generation that could reduce congestion needs to be adequately addressed. Additional benefits and advantages of embedded generation include:

- improved supply reliability through generation diversity;
- reduced dependence on a small number of large remotely located generators;

[10] McDonell, G, *COAG's Quandary: What to do with the Energy Markets Reform Program?* February 2005, p 36

- generation closer to customers resulting in improved power quality and reduced network losses;
- reduced greenhouse gas emissions resulting from reduced network losses;
- reduced greenhouse gas emissions due to the potential for greater output from renewable energy sources;
- avoided network augmentation costs; and
- the ability to more efficiently provide electricity at times of peak demand (in the case of solar photovoltaics, due to localised generation output matching times of peak demand).

The NSPs should be required to seek embedded generation as well as DM solutions to network constraints before considering network augmentation. In the case of minor augmentations, this should be done by issuing a standard offer as opposed to a Request for Proposal (RFP). Negotiation of provision for embedded generation, if at all, is often carried out through an RFP process, in which both transaction costs and risks for small embedded generators can be high.

3.2 Standard offers

The introduction of the standard offer is also a means of reducing these costs and uncertainties, thereby facilitating the capture of demand reduction opportunities that may arise in response to forecast network congestion.

"Standard offers specify the conditions for the provision of demand in advance. Standard offers are usually made on fixed prices, take it or leave it, first come first served basis."[11] They support the development of the DM services market by reducing risks of both negotiating with networks and of guaranteeing load reductions within the spot market. Standard offers could also provide the means for networks to capture opportunities for demand reduction that may arise several years prior to going to the market for non-network solutions that would otherwise be lost. The issuing of a standard offer would be advantageous for smaller EG and new entrants to the market by reducing complexity and removing the competitive advantage enjoyed by incumbent and larger participants.

3.3 Use of system rebates

Another barrier is the application of use of system (UoS) rebates. These are intended to recompense local generators requiring lower use of the networks by virtue of location closer to load points. However, embedded generation offers a range of benefits not entirely reflected in the current method of calculating avoided UoS rebates. In particular, embedded generation offers value to an NSP through its potential to enable the deferral of new augmentation. Embedded generation also offers the benefit of reducing environmentally damaging greenhouse gas emissions, the cost of which is currently externalised in the NEM. The value of UoS rebates should include the full value of deferral of new network augmentations.

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

[11] Department of Energy, Utilities and Sustainability, *Demand Management for Electricity Distributors – NSW Code of Practice*, September 2004, p 21

- o financing charges
- o capital depreciation.

3.4 Connection costs

A further barrier to embedded generation relates to connection costs, since proponents of embedded generation alternatives to augmentation seem to be penalised in the sense that they may be expected to pay for more than specific connection costs. The current regulations allow for new generators to pay only shallow connection costs, that is, to cover the costs of assets directly required by a new connection. This applies equally to large, remote generators as to those situated closer to load points. This is the theory.

In practice, however, it appears that smaller, local generators may be charged for upgrades to the network, where the extra load necessitates some augmentation of the system beyond those required specifically for the new connection (deep connection costs). That is, they are subsidising the transmission and distribution sector by paying deep connection costs, in contrast to established (large) generators who are paying shallow connection costs.

This contravenes the general principle of paying shallow costs and, moreover, the spirit of "open access" the NEM is based on.

4 Information disclosure

To date, lack of information has proved a significant barrier within the NEM, both in terms of accountability of the regulator and restriction of entry by competitors (such as DM providers and embedded generators). There are problems with current reporting on perceived potential constraints, despite the publication by NEMMCO of an annual Statement of Opportunities (SOO) and the Annual National Transmission Statements (ANTS). The annual public disclosure of information on emerging network constraints is essential to the development of non-network responses to these constraints and to provide the opportunity for small, renewable energy generators to participate in the market. To encourage the uptake of cost-effective non-network (including embedded generation) alternatives to transmission augmentation, such information should be required of NSPs.

Disclosure of information is fundamental to transparency and certainty of decision making, and it relies not on quantity but quality. A transparent process will provide greater certainty for all stakeholders (regulator, NSPs and consumers) as well as potential investors. NSPs should also provide information on their expenditure on DM, alongside opportunities they have investigated and the potential value of deferrals of augmentation.

A useful model here is the Disclosure Protocol from the NSW Demand Management Code of Practice[12]. The purpose of such a protocol is presented as:

> *To inform the market in a timely manner, regular public reports on the status of the network are required. A standardised Disclosure Protocol is intended to ensure*

[12] Department of Energy, Utilities and Sustainability, *Demand Management for Electricity Distributors – NSW Code of Practice,* September 2004; the Disclosure Protocol is on pp11-14

> *that distributors provide all necessary information in a clear and consistent form, without wasting effort in providing unnecessary information.*[13]

The protocol includes features such as planning guidelines, for describing the basis for load forecasts and describing the system planning guidelines. It includes pro forma spreadsheets, requests for maps and summary table requests to assist with clarity of presentation and so there is some standardisation of the information lodged.

South Australia also has a system of information disclosure, though at a lower level of detail than that for NSW. As part of Electricity Industry Guideline No. 12[14], ESCOSA requires ETSA Utilities to "regularly disclose information on possible network constraints", including the provisions that, "ETSA Utilities must publish an annual Electricity System Development Plan (ESDP). The ESDP must identify in detail any actual and forecast constraints on ETSA Utilities' network."

All TNSPs (and in the future distribution and retail businesses) need to publicly provide clear, detailed information on areas facing constraints – or predicted to do so – in a reasonable timeframe (5, 10 and 15 years ahead) to allow DM providers to offer alternatives to augmentation. Such information should be required in order to encourage the uptake of alternatives to network augmentation and to ensure least-cost provision for consumers and an efficient NEM. Lack of quality information can inhibit new entrants to the market.

[13] Department of Energy, Utilities and Sustainability, *Demand Management for Electricity Distributors – NSW Code of Practice,* September 2004, p 11
[14] Essential Services Commission of South Australia, *Demand Management for Electricity Distribution Networks*, *Industry Guideline No. 12*, September 2003, p 7