1 February 2008

Dr John Tamblyn
Chair
Australian Energy Market Commission
PO Box H166
AUSTRALIA SQUARE NSW 1215

Dear Dr Tamblyn

AEMC RULE CHANGE PROPOSAL - DEMAND MANAGEMENT

Energy Networks Association (ENA) welcomes the opportunity to respond to the Australian Energy Market Commission's (AEMC) consultation on Total Environment Centre's (TEC) proposed rule change relating to the application of demand management to transmission networks and the wholesale markets.

ENA and its member companies are actively engaged in demand management issues and provide the following attached comments on this draft Rule proposal.

Please feel free to contact me if you have any queries relating to this submission.

Yours sincerely

Andrew Blyth
Chief Executive

AEMC RULE CHANGE PROPOSAL - DEMAND MANAGEMENT

ENA Submission

1 February 2008

Key messages

- ENA supports a regulatory approach which places demand management on an equal footing with established infrastructure-based approaches to energy supply.
- ENA would be opposed to TEC proposals being advanced in isolation of a more comprehensive policy review of the wider issues and other potential changes to the *NER*.
- Single most effective way to encourage demand management is to ensure the regulatory regime provides incentives for network businesses to adopt these options.
- In any future comprehensive review, AEMC is encouraged to consider appropriate mechanisms to manage reliability risk posed by demand management so that network businesses are not disproportionately penalised for adopting non-network solutions.

Introduction

Energy Networks Association (ENA) welcomes the opportunity to respond to the Australian Energy Market Commission's (AEMC) consultation on Total Environment Centre's (TEC) proposed rule change relating to the application of demand management to transmission networks and the wholesale markets.

The Rule proposal submitted by TEC seeks to facilitate the increased use of demand management by placing requirements and incentives on supply side participants to investigate and then undertake demand side solutions as the preferred, primary option. While the proposals directly address arrangements for transmission networks, the intention is for the same principles to apply to the Rules and future determinations for distribution networks. The ENA provides in this submission the perspective of Australian electricity distribution networks to the proposals and their applicability to barriers to demand management that apply in a distribution context.

The current *National Electricity Rules* (clause 6.6.3) applying to distribution businesses provide for, but do not require the AER to develop a demand management incentive scheme. The issue of whether the rules should provide a positive requirement to develop such a model was a matter closely considered in a range of public consultation processes accessible to a wide range of stakeholders. MCE ultimately agreed to a set of rules formally made on 16 December 2007 which clearly provides the AER with discretion in the development of the scheme.

The AEMC has an absolute requirement to assess this particular proposal on its merit in accordance with the NEL objective. ENA would be concerned, however, if elements of recent policy outcomes were amended outside of the context of a holistic review of these provisions, and considers that in the absence of any practical experience with the newly amended Electricity Rules it will be difficult to establish that the alternative proposed will better meet the NEL objective.

ENA acknowledges the work of TEC; however, a number of comments made by TEC towards distribution network businesses are deficient. This submission seeks to address those comments as they apply to distribution businesses only, but elements of the TEC's proposals also appear to fail to adequately consider the existing regulatory framework, and approach incentives applying to demand management in an electricity transmission context.

In this response, ENA has elected to provide comment on the concepts and proposals presented in the TEC submission, and not directly comment on the wording proposed. ENA believes that this clarity is essential before drafting proceeds.

Given the importance of demand management and its role in the energy sector, we caution the AEMC against adopting any element of the *Rule* proposal without careful consideration of the information and other perspectives contained in this and other industry submissions.

Energy Networks Association

Energy Networks Association is the national representative body for gas and electricity distribution network businesses. Energy network businesses deliver electricity and gas to over 12 million homes and businesses across Australia through approximately 800 000 kilometres of electricity lines and 75 000 kilometres of gas distribution pipelines. These distribution networks are valued at more than $35 billion, and each year energy network businesses undertake capital investment of more than $5 billion in network reinforcement, expansions and extensions.

Demand Management Policy Overview

Electricity distribution businesses, through their direct connection to the customer, are in a unique position in the electricity market to identify demand management opportunities and deliver successful demand management programs and approaches. These programs can deliver value to individuals, and the whole community through decreased investment in generation and network infrastructure, lower energy prices, and potentially lower greenhouse gas emissions.

The integration of demand management into mainstream energy supply and network planning is progressing and puts demand management on an equal footing with established infrastructure-based approaches to energy supply.

The underlying incentives to pursue the most efficient options to deliver regulatory requirements are part of the fundamental regulatory structure. Central to these incentives is a regulatory approach which allows network businesses to retain for a period the benefits arising from the operating and capital efficiencies they achieve, after which the benefits pass through to customers. This approach is considered to offer strong incentives for efficient network service delivery, such as not to require prudency review of expenditure. This regulatory approach has proved successful and has delivered considerable operational and capital efficiency benefits to customers.

This incentive based approach has been formalised in the new *National Electricity Rules* to apply to network business. The purpose of the approach is to reproduce, to the extent possible, the production and pricing outcomes that would occur in a workably competitive market in circumstances where the development of a competitive market is not economically feasible.

Demand management activities seek to influence the patterns of energy consumption including the amount and rate of energy used, the timing of energy use and the source and location of energy supply. Network-driven demand management aims to slow the growth of peak energy demand with a view to improving the utilisation of network assets, delivering savings to customers and increasing service reliability.

Reform to policy and regulatory action is needed to advance demand management in four key areas which are:

Network demand management policy focus

A long term policy commitment, backed by market and regulatory reform, would give network businesses confidence to support demand management research, commit to significant investment, and build capacity and understanding amongst end users, without the risk of stranding that effort and investment as a result of regulatory or policy change. Policies must be appropriately targeted at addressing the issues and barriers facing network businesses in pursuing demand management. Policy-makers must also be clear about the outcomes that are sought from reform, which can have a relatively narrow focus on network capital investment efficiency, or can encompass supply chain wide efficiency or broader community benefits.

Economic regulation

The economic regulatory regime can have a significant impact on incentives faced by network businesses for pursuing network demand management. In many cases, the regulatory regime can give rise to significant disincentives for network businesses to use demand side approaches to manage risk and defer network investment. Important areas of reform in this respect include the relative incentives embedded in the regulatory regime for capital and operating expenditure, increased risks posed by the effective *ex poste* consideration of demand management expenditure, foregone revenue risks where networks are regulated under a price cap, and the extent to which network businesses can access efficiency benefits.

Addressing these issues, through changes in regulatory approach or the introduction of specific incentives or mechanisms to neutralise their effect, would mean that demand management options could compete with network-build options on an equal basis.

Distribution network planning and reliability

The approach to network planning (as well as uncertainty over the reliability of non-network elements for use in network planning) can act as barriers to the full adoption of demand management alternatives. Shortfalls in knowledge and experience in demand management can mean that demand management and network infrastructure options sometimes cannot be directly compared, particularly with regard to their reliability characteristics in network planning. Strong regulatory incentives for reliability can also act as a barrier where demand management options are less reliable than network build options, or where reliability characteristics are unknown.

Approaches to address these issues include allowing greater scope for network businesses to undertake pilots and trials, and support for research and development to build knowledge and understanding in how to integrate demand management into everyday network planning and development. The regulatory regime can also assist demand management by ensuring that the relative incentives for demand management are considered in the development of reliability incentive schemes.

Improving information and understanding

The lack of practical experience and empirical evidence to support the efficacy, cost and reliability of some demand management projects limits their use by network businesses. Policies and approaches to improve information and understanding of network businesses, like those mentioned above for network planning, will assist in integrating demand management options into energy supply planning and development.

Education programs on the balance between price, service and demand can assist in improving community understanding of the reasons behind demand management programs and the benefits available for customers in taking part in these programs. This is a potential role for government.

Areas of policy intersection and implementation issues

Demand management policy and regulatory reform cannot be conducted in isolation of other energy market developments. Key areas of policy intersection include electricity retail price regulation, provision of advanced metering, and energy efficiency and greenhouse initiatives. Integrated policy development in all of these areas can assist in removing barriers for network demand management.

The recommendations outlined in this submission are directed at achieving a balanced policy and regulatory approach to network demand management, by removing policy and regulatory barriers. There is a case to put in place positive incentives for demand management to assist in the development of this industry, build expertise in Australia, and advance demand management as an alternative to network infrastructure options. This will ultimately be a decision for governments, based on policy priorities for the future direction for the electricity market.

TEC states that 'demand management' includes all of demand response, demand side management, demand side response, energy efficiency and non-network solutions. This blanket categorisation fails to address which of these demand management areas are the practical solutions to network constraint problems and represent a major deficiency in the Rule change that needs to be articulated and clarified in the proposal.

There are a number of repeated comments throughout the TEC document that infer that supply side initiatives are inefficient and that demand management solutions are more cost efficient. The Rules need to make certain (not in the TEC proposal) that supply side and demand-side proposals are considered on an equal footing where practical (ie not disproportionately costly for the expected benefits) to ensure prudency and efficiency. This equal footing must make sure that demand management proposals do not have an increased risk profile and have the capability to realise the objectives so as to ensure customer satisfaction and reliability of supply.

Total Environment Centre Proposal 1

- *That when planning, network operators consider DM solutions before network augmentation alternatives so that DM is implemented when it is a more cost effective option than augmentation*

TEC claims that an overall bias towards network augmentation over a demand management response to constraints is found throughout the *National Electricity Rules*, particularly in Chapter 5. TEC believes that this bias is both general in its language, and specific, in the Rules that guide the networks' planning processes without attempting to correct the bias towards inefficient augmentation.

TEC asserts demand management is currently under-utilised, resulting in inefficient investment in and use of electricity in the National Electricity Market. By creating a bias towards demand management in the Rules at the initial planning stage, TEC believes this Rule change will assist with the increased delivery of demand management.

TEC proposed changes that are designed to ensure that networks thoroughly consider demand management solutions before network augmentation alternatives so that in TEC's view, demand management is implemented when it is more cost-effective than augmentation.

<u>ENA Response</u>

ENA considers TEC's suggested amendments to Rule 5.6.2 that seek to strongly reinforce a disposition to demand management may not deliver the benefits to customers that TEC intends.

Electricity distribution businesses, like all businesses, have a fiduciary obligation to maximise possible returns to investors within the applicable policy and regulatory regime. Distribution businesses operate under a regulatory regime that uses incentives to maximise the efficiency of network investment, while at the same time providing incentives to maintain or improve network reliability. Network investment, including any investment in demand side resources, must fit within the potentially competing regulatory objectives of cost minimisation and network reliability.

Network business planning is about bringing together potential network elements, infrastructure investment options and demand scenarios to deliver an energy supply system that meets relevant network reliability, safety and security requirements. Demand forecasts are a critical part of this process, as they determine whether reliability, safety and security requirements are likely to be breached.

The network planner has essentially two options to deliver safe and secure supply:

- manage demand by reducing load or changing network utilisation patterns; or
- investing in increased capacity in the network to meet forecast demand.

Deciding between these two options, however, is not simply a matter of choosing the least cost option.

Many demand management options have different reliability characteristics to network augmentation. Even where these reliability characteristics are known, they can be less reliable than the comparable network option they are seeking to displace. They can therefore adversely impact energy delivery and customer service outcomes and increase the network business' exposure to any service penalties that may result if the demand management solution fails. This means that the network demand management opportunities will incur additional risk costs as a result of that decreased reliability. Where the reliability characteristics of the demand management option are unknown, the risk costs can be even higher. These risk costs must be built into the business case assessment of demand management projects.

This places requirements on demand management approaches in order for them to effectively and reliably defer network expenditure. For a network demand management opportunity to be viable, four conditions must be satisfied:

- the network area must be constrained and in need of additional investment
- the demand management option must be sized correctly to defer augmentation
- there must be sufficient time to deploy the demand management option; and
- the demand management option must be reliable enough to deliver the required energy delivery/customer service outcomes.

Once these issues are addressed, the relative cost of the project cost can be taken into account. Service incentive penalties arising from reliability risk can increase this cost significantly.

As stated previously, cost is not the only consideration for network providers. Network planning processes should and do consider all viable network and non-network solutions in parallel, to ensure consumers benefit from the most efficient network development possible.

ENA recommends that in its forthcoming review into demand management the AEMC consider appropriate mechanisms to manage the reliability risks imposed by demand management projects so that distribution businesses are not disproportionately penalised for adopting demand management projects to defer network expenditure.

Total Environment Centre Proposal 2

- *Requiring transmission network owners to publish robust data on upcoming network constraints that are relevant and useful to DM service providers*

TEC states that transmission networks should be required to publish robust data on upcoming constraints that are relevant and useful to demand management service providers. This would serve to inform the demand management market of coming opportunities and enable it to respond in a timely manner. TEC draws on the NSW *Demand Management Code of Practice for Electricity Distributors* and the *South Australian Guideline 12* to provide precedents for information disclosure by distributors. TEC also highlights that NSW has recognised the benefits of robust information provision in relation to distribution networks through the Demand Management Code of Practice for Electricity Distributors.

TEC proposes that the Rules should require that Annual Planning Reports include detailed information about the current and future capacity of the transmission network and current projected demand and possible options to address any emerging constraints. Further, the Rules should also require both distribution and transmission networks to report annually on demand management activities undertaken in relation to; expenditure, peak demand and energy consumption reductions, value of electricity sales foregone, value of capital and operating expenditure avoided or deferred, and efforts to identify and procure cost effective demand management. These reports are to be made publicly available.

<u>ENA Response</u>

A recent NERA/Allen paper, *Network Planning and Connection Arrangements*[1], proposed that distribution network businesses publish extensive information on coming network constraints, the expected cost of augmentations, areas of significant spare capacity on the network, and average and marginal distribution loss factors for points in the network. It also proposed that distribution network businesses conduct cost-benefit analyses of proposed projects over $0.5 million and requests for proposals (RFPs) for projects over $2 million. These obligations intended to improve opportunities for non-network project proponents and prospective distributed generators to propose alternatives to augmentation.

ENA considers such arrangements would impose a disproportionate and costly regime on distribution network businesses that is not justified by the benefits available for customers from that regime. Further, such arrangements would act to undermine the incentives for these businesses to create innovative solutions to network augmentations.

There is currently in place a detailed information disclosure and planning regime in South Australia. However, the South Australian regime was recently reviewed in light of the fact that, despite ETSA Utilities being in full compliance with the disclosure and planning

23

[1] *MCE Bulletin 99, released 22 August 2007. Note this paper was a discussion paper and did not represent the views of the MCE. Similarly, ENA and its members did not support many elements of this paper.*

requirements, no project proposals had successfully been adopted to defer a network augmentation.[2] This fact is also recognised in the NERA/Allen Paper.[3]

Given the lack of tangible benefits from the South Australian arrangements, it is difficult to understand the justification for expanding essentially identical arrangements to the rest of the National Electricity Market. As noted above, the provision of extensive information to the market does not change the underlying incentive characteristics of the regulatory regime, which fundamentally dictate the case for pursuing non-network options. Instead the proposed approach will impose costs on to network businesses which will ultimately be passed on to customers.

Lack of proportionality of arrangements to benefits available

The number of projects that will be subject to detailed analysis in each business in NSW and Queensland is 2-5 times greater than the total number of electricity transmission projects that have undergone similar analysis in the past 12 months. Across Australia, these obligations, on conservative estimates, would mean approximately 150-180 RFPs issued each year by distributors. The projects outlined here relate only to demand-related projects. If all larger projects were subject to these arrangements, the number of RFP processes would be significantly larger again.

The NERA/Allen paper also notes that ESCOSA estimates the cost of issuing an RFP is $30,000-35,000. If this estimate is correct, then the costs faced by distribution network businesses of this obligation are likely to be in the order of $5-6 million a year. Costs under any type of comparable scheme would need to be recovered from household and business consumers through network tariffs. Given the limited success of these arrangements in delivering benefits through non-network options, it would appear that there is little justification for introducing these onerous arrangements on a national basis.

There may be a case however for further work through MCE processes streamlining jurisdictional approaches by developing a single national approach for providing planning and demand management information to the market. A nationally consistent approach could simplify approaches for proponents and facilitate understanding of the potential for demand management programs. These arrangements, however, must be carefully balanced against the costs imposed by detailed and prescriptive arrangements, to ensure they deliver net benefits to customers and they are matters best considered under the future AEMC review in this area.

ENA accepts the premise that the market would benefit from some level of information disclosure and planning requirements on network businesses regarding coming constraints and proposed augmentations. Finding the appropriate level of information disclosure requires more careful consideration. To be successful, it is critically important that the information disclosure and planning regime be focused on stakeholder requirements, and

23

[2] *Essential Services Commission of South Australia, Review of Electricity Industry Guideline 12: Demand Management for Electricity Distribution networks, Discussion Paper, July 2006, pg.9.*

[3] *NERA/Allen, Network Planning and Connection Arrangements, pp. 19-20.*

look more broadly at network planning and reporting, rather than focusing entirely on non-network alternatives - one small aspect of network planning.

It is critically important that these planning requirements do not impose costs that are disproportionate to the benefits expected from the regime. The single most effective way to encourage demand management is to ensure that the regulatory regime provides incentives for network businesses to investigate and adopt these options. Information to the market may improve the transparency of network business activity, but not the underlying economic case for adopting demand management alternatives to network investment.

ENA recommends AEMC consider developing a nationally consistent planning information disclosure and planning regime for network businesses that is proportionate to the expected benefits of that regime. ENA notes that in NSW this level of detail is placed in a "Code of Practice for Demand Management". We also note that many transmission (and distribution) businesses already provide much of this information through their published Planning and Network Management Plans.

Total Environment Centre Proposal 3

- *Requiring the AER to design a demand management incentive scheme*

TEC claims that networks consistently overlook or ignore demand management when considering how to respond to demand growth. This, they argue, is partly caused by the failure of the Rules to provide adequate incentives for network demand management. In recognition of the failure of networks to invest in cost-effective demand management, TEC calls for an explicit provision for the Australian Energy Regulator to develop and implement a demand side incentive scheme.

<u>ENA Response</u>

The current *National Electricity Rules* (clause 6.6.3) applying to distribution businesses provide for, but do not require the AER to develop a demand management incentive scheme.

The issue of whether the rules should provide a positive requirement to develop such a model was a matter closely considered in a range of public consultation processes accessible to a wide range of stakeholders. MCE ultimately agreed to a set of rules formally made on 16 December which clearly provides the AER with discretion in the development of the scheme. The AEMC has an absolute requirement to assess this particular proposal on its merit in accordance with the NEL objective. ENA would be concerned, however, if elements of recent policy outcomes were amended outside of the context of a holistic review of these provisions, and considers that in the absence of any practical experience with the newly amended Electricity Rules it will be difficult to establish that the alternative proposed will better meet the NEL objective.

Demand management projects require significant business commitment and investment in consumer education to be successful. Network businesses seek a balanced policy and regulatory approach to demand-side and investment options, so that policy and regulatory issues do not undermine the ability of demand-side resources to compete with infrastructure investment options on an equal footing. There is a case for positive incentives for demand management to be put in place to build expertise in Australia and facilitate the development of a demand management service provider market. These positive incentives could be achieved in a number of ways. For example, specific demand management projects could be encouraged through dedicated project funds and grants. This may be particularly appropriate where the benefits of demand management are likely to accrue to the wider community, or where there are significant gains to be made through education, training and information dissemination from the demand management project.

Another approach could involve positive incentives through the regulatory regime to pursue demand management projects. The New South Wales D-factor approach limits recognition of demand management projects to an upper cost threshold equivalent to the value of deferred network expenditure. A higher threshold for demand management projects, ie taking account of contributions that projects make to other types of demand management, could also be adopted to support a wider set of possible demand management projects.

A key characteristic of the cost recovery mechanism is that it balances the risk exposure faced by businesses for demand management compared to network investment, by ensuring that a prudent demand management project will recover its costs regardless of whether expected demand management efficiencies are achieved. This approach matches the reasonable expectation that network businesses have that capital expenditure will not be optimised out of the regulatory asset base. Without demand management cost pass through, network businesses are reliant on actual delivery of efficiency benefits, which is a high risk proposition. This places a much higher and unnecessary risk premium on demand management projects. Avoiding this extra risk delivers a more balanced regulatory regime. Specific incentives targeted at increasing the value of demand management options, including enhanced or accelerated cost recovery could be developed to assist in the development of demand management capability within network businesses and facilitate the development of a demand management service provider market.

Network businesses may face a disincentive to pursue demand management projects leading to risks that they will under recover allowable revenue, when they are regulated under a price cap, unless the regulatory arrangements and demand management incentive scheme have regard for the network entities' form of price control[4]. This means that mechanisms to remove this disincentive are a necessary component of the regulatory regime for both price and non-price demand side response.

ENA recommends that the AEMC consider the introduction of a framework and model for specific positive incentives for demand management to assist in the development of demand management capability within network businesses and facilitate the developments of a demand management service provider market.

23

[4] *For example, NER s6.6.3 (b) (2) requires the AER to have regard for distributors' form of price control when implementing a demand management incentive scheme.*

Total Environment Centre Proposal 4

- *Including a clear specification of the circumstances in which transmission network owners can recover expenditure on demand side activities*

The absence of an incentive mechanism for demand side activities is exacerbated by the lack of certainty regarding the ability of networks to recover demand management expenditure, according to TEC. The TEC claim (but do not provide supporting evidence) that this lack of certainty is exacerbated by networks' propensity to not properly investigate and implement demand management.

The solution proposed by TEC is one in which networks can recover expenditure on demand side activities. Networks must be able to include a return of and return on demand management expenditure, including recognition of the *opex/capex* trade-off that demand management activities entail and the implications of this for network revenue.

ENA Response

Demand management projects can involve significant substitution of operating expenditure for capital expenditure. This can lead to disincentives to pursue demand management, as operating and capital costs are not treated equally under current economic regulatory regimes, leading to a potential disincentive to pursue demand management projects.

A balanced approach would require a mechanism to compensate businesses where operating costs replace capital costs. Any approach adopted could have far reaching impacts on the broad regulatory incentives faced by network businesses. It can also influence other factors such as accounting, taxation and regulatory reporting. The approach that is ultimately adopted to balance incentives for capital and operating efficiency requires careful regulatory policy consideration.

ENA recommends AEMC consider including in the *National Electricity Rules* appropriate mechanisms for balancing the differing economic incentives between capital and operating expenditure which influence network business decisions to pursue demand management options as an alternative to network augmentations. This and other issues below, however, would be best addressed in a systematic and comprehensive way through the forthcoming AEMC review of this policy area.

In this regard, ENA notes that clause 6.5.8 of the NER requires the AER to develop an efficiency benefit sharing scheme (EBSS to share efficiency gains with consumers). The AER has recently released an issues paper on an EBSS including consideration of the substitution of *capex* for *opex*, and the interaction with demand side issues. Careful consideration of such proposed changes to the Rules are essential to ensure that the integrity of economic regulations is maintained and conformity with national electricity objectives is preserved.

ENA is opposed to the AEMC responding to the TEC proposal in isolation of other contemplated changes to the NER such as the above.

***Ex ante* rather than *ex post* consideration of costs associated with demand management**

The economic regulatory regime allows any capital expenditure approved as part of the regulatory price determination to attract a return. At the end of each regulatory period, actual capital expenditure is rolled forward as the starting asset base for the new period.

This capital expenditure is not subject to *ex post* prudency assessment, as network businesses face an incentive to minimise expenditure through the regulatory regime. Therefore, network businesses do not generally face optimisation risks of capital assets, except where those assets are made obsolete or are stranded. This means that most investments in capital are assured of making a return (though the level of the return is subject to the risk that WACC parameters will change in future regulatory decisions). This widely accepted *ex ante* approach has been incorporated into the new *National Electricity Rules* for transmission and distribution regulation.

A balanced approach to network demand management requires a similar approach for capital and operating costs related to demand management projects. Such an approach may involve the regulatory regime including a mechanism to allow the recovery of costs related to demand management projects. This cost recovery approach would balance the risk exposure faced by businesses for network demand management compared to network investment, by ensuring that a prudent demand management project will recover its costs regardless of whether expected demand management efficiencies are achieved. This approach matches the reasonable expectation that network businesses have when investing in poles and wires infrastructure - that capital and operating expenditure will be recovered and capital assets will not be optimised out of the regulatory asset base.

Without this type of demand management cost pass through, network businesses are reliant on actual delivery of efficiency benefits to cover the investment costs, which is a high risk proposition and akin to an *ex poste* prudency assessment on expenditure. This places a much higher risk on demand management projects without commensurate return. Avoiding this extra risk would deliver a more balanced regulatory regime.

ENA recommends in the future that the AEMC consider including in the *National Electricity Rules* a mechanism to balance the infrastructure investment risks faced by network businesses when they invest in non-network options, such that the risk is identical to investing in network options. A possible mechanism to achieve this may be a demand management cost pass through mechanism.

Total Environment Centre Proposal 5

- *Requiring that DM activities are prioritised and properly integrated into revenue determinations*

TEC assert that networks consistently overlook or ignore demand management when considering how to respond to demand growth. It is claimed that this is due to a regulatory approach that sanctions a bias towards supply side options and is embedded in the current revenue determination process. The TEC's solution is to require prioritisation of demand management activities to ensure they are prioritised, properly investigated and integrated into revenue determinations.

<u>ENA Response</u>

The first step is the incentivised regulatory framework.

To avoid perverse incentives to only pursue demand management towards the start of a regulatory period, access to efficiencies should be independent as to the stage of the regulatory review period. The precise approach adopted to address this efficiency incentive can include carry-over mechanisms that allow distributors to access benefits of avoided network investment for an appropriate period of time, but could also be related to broader incentives adopted to balance capital and operating expenditure. The approach adopted will require careful regulatory policy consideration.

As outlined in the response to proposal 4, a balanced approach to network demand management requires a similar approach for capital and operating costs related to demand management projects. Such an approach may involve the regulatory regime including a mechanism to allow the recovery of costs related to demand management projects. This cost recovery approach would balance the risk exposure faced by businesses for network demand management compared to network investment, by ensuring that a prudent demand management project will recover its costs regardless of whether expected demand management efficiencies are achieved. This approach matches the reasonable expectation that network businesses have when investing in poles and wires infrastructure that capital and operating expenditure will be recovered and capital assets will not be optimised out of the regulatory asset base.

ENA therefore supports a regulation "neutral" regime applying to choice of network or non-network solutions. We strongly oppose the TEC approach to rewrite the rules in favour of demand side management.

Total Environment Centre Proposal 6

- *In the context of DM expenditure, that there is recognition of the potential use and value of small scale demand side activities in providing long term benefits*

TEC states that a major barrier to the implementation of demand management by networks concerns the inability of networks to recover expenditure on modest demand management investments. Such expenditure may not directly contribute to the alleviation of a particular constraint at a particular time, but it is likely that accumulating savings will. TEC claim that it is therefore illogical that modest demand management activities be excluded from revenue determinations simply because they are not linked to a specific constraint.

<u>ENA Response</u>

ENA agrees with the underlying concern expressed by TEC, however, the exclusion of smaller scale projects from revenue determinations arises from an assessment of the relative costs and benefits, and practically, of seeking to integrate a potentially wide range of smaller scale projects into the determination. A prescriptive requirement lowering the threshold may well have significant compliance costs that outweigh the long term benefits.

Total Environment Centre Proposal 7

- *Including prudency reviews to assess the extent to which transmission network operators have implemented an adequate level of demand management*

TEC suggests that networks consistently overlook or ignore demand management when considering how to respond to demand growth. To that end, prudency reviews that assess past and projected capital expenditure should be undertaken and conducted by experts with a demonstrated balanced understanding of theory and practice of demand management. Furthermore, revenue should be disallowed for expenditure that ignores cost-effective demand management – providing a useful incentive for networks to avoid inefficient network augmentation.

<u>ENA Response</u>

ENA member companies are Australian leaders in the area of demand management particularly as it applies to network management. To suggest that there are external experts who could fulfill such a specialised role is unrealistic and supported by the experience of regulatory reviews in Australia. This view is also supported by the low level of responses that network companies have had to demand management proposals to date. Further, there are statements in this section regarding revenue being disallowed for network companies. Incentive (not disincentive) schemes are required and ENA refers to previous comments on this matter.

Incentives for network businesses to pursue the most efficient options to deliver regulatory requirements like service reliability are part of the fundamental regulatory structure. Central to these incentives is the *ex ante* regulatory approach, which allows network businesses to retain for a period the benefits arising from any efficiencies in capital expenditure achieved while meeting regulatory requirements. This approach is considered to offer sufficient incentives such as not to require *ex post* prudency review of expenditure. This regulatory approach has proved successful and has delivered considerable capital efficiency benefits to customers.

The approach is centred, however, on the assumption that achieving efficiency involves choosing the least cost option between alternatives with similar, and known, reliability characteristics, or optimising reliability and efficiency, in line with the incentives offered through the regulatory regime. Decisions between alternatives become difficult when the reliability characteristics of an alternative, potentially cheaper option are unknown, as the optimisation calculation between price and reliability cannot be made. This is often the case with non-network demand management projects. However, the approach advocated by the TEC of instituting *ex post* reviews of capital expenditure to subjectively assess with the benefit of hindsight whether a network delivered the 'optimum' level of demand management in any given location would undermine the operation of incentive based regulation, and be unworkable in any practical sense.

Total Environment Centre Proposal 8

- *Including specification, within the Regulatory Test, that DM options must be investigated before augmentation options*

TEC believes that in order to reverse the bias towards augmentation options and the neglect of demand side solutions, it is critical that the Rules specify that demand management options must be investigated <u>before</u> augmentation options. TEC claims that this is likely to ensure that a more appropriate level of networks' resources and attention are directed to demand management before augmentation planning is underway. The Regulatory Test should not assume that the interests of those who produce, transport and consume electricity are aligned. The Regulatory Test should reflect the National Electricity Law Objective by ensuring that the long-term interests of consumers are the priority.

<u>ENA Response</u>

ENA considers that it is not appropriate to review or change the Regulatory Test as part of this TEC Rule Change Proposal given that the AEMC's National Transmission Planner review is already underway and includes a holistic review of the Regulatory Test for transmission entities. Furthermore, distributors have requested that there be a clear policy statement by the MCE as to its intended objective and purpose for distributors applying the Regulatory Test, and then a subsequent AEMC review of the Regulatory Test (and possible development of a separate test) for distributors. It would therefore be premature for the existing Regulatory Test – which applies to both transmission and distribution – to be amended as part of the TEC Rule Change Proposal.

The existing Regulatory Test already provides that the Regulatory Test must be undertaken when a network business is evaluating a network augmentation that is likely to cost >$1m. The Test rules require that demand management and all other viable options be given consideration. It is the ENA's view that this consideration should remain balanced and not pre-prioritise (or give additional weighting to) any particular option.

As previously noted ENA supports efficient network planning processes that allow for the parallel consideration of all efficient, technical and commercially feasible projects to meet the objective of the safe and economic provision of electricity. ENA does not consider that altering the regulatory test to require consideration in isolation of one set of non-network options meets this principle, or would be effective in delivering the TEC's objective of removing biases in the current regulatory framework affecting demand management.

The ENA considers a wider range of steps and measures would better meet the TEC's objectives, and should be considered in the forthcoming comprehensive review by the AEMC of demand management issues. Some background to some of these steps and measures is provided below.

Recovery of foregone revenue

Demand management projects usually mean selling less energy. Networks may face a disincentive to pursue demand management projects that lead to risks that they will not fully recover allowable revenue, when they are regulated under a price cap. This can be a significant disincentive for demand management as it increases the costs of potential projects. It also creates different incentives across network businesses depending on whether they are regulated under a price or revenue cap. ENA notes that transmission businesses can only have a revenue cap. ENA also draws attention to its earlier comments that for distributors, there is already an onus on the AER to have regard for the form of price control when fixing a demand management incentive scheme.

While allowing a range of regulation options in the *National Electricity Rules* may be appropriate in respect of determining the best approach for the network in question, the regulatory regime must recognise through an alternative mechanism the influence of the form on regulation decision on incentives to pursue demand management.

A mechanism for recovery of foregone network revenue (where regulated under a price cap) from both tariff and non-tariff based demand management projects would remove distortions in demand management incentives arising from differences between revenue and price caps.

This would have the effect of neutralising the revenue impact on network businesses of lower energy throughput that results from demand management under a weighted average price cap. It would also remove the perverse outcome whereby network businesses face differing incentives for demand management across different jurisdictions under a national regulatory framework.

ENA recommends AEMC consider including in the *National Electricity Rules* a mechanism to allow the recovery of foregone revenue from demand management projects for businesses operating under the price cap form of regulation.

Access to efficiency benefits

A key value of demand management for network businesses comes from its ability to defer network expenditure. This value derives from the net present value of that deferred network expenditure. The longer businesses are able to retain these efficiencies, before they are passed on to customers, the more value they have.

For incentives for demand management to work, it is critical that network businesses can access the net present value of money not spent on the network for a period, before these efficiencies are passed on to customers. This period can be shortened where efficiencies are made towards the end of a regulatory period.

As stated under our response to proposal 5, to avoid perverse incentives to only pursue demand management towards the start of a regulatory period, access to efficiencies should be independent as to the stage of the regulatory review period. The precise approach adopted to address this efficiency incentive can include carry-over mechanisms that allow distributors to access benefits of avoided network investment for an appropriate period of time, but could also be related to broader incentives adopted to balance capital and operating expenditure. The approach adopted will require careful regulatory policy consideration.

ENA recommends AEMC consider including in the *National Electricity Rules* a mechanism to ensure that incentives to pursue demand management arising from access to efficiency benefits are independent of the time of the next price review. Taken together, the mechanisms recommended should remove some of the disincentives facing network businesses in pursuing demand management options.

Total Environment Centre Proposal 9

- *Including a mechanism for setting the price of demand side response activities within the market pool.*

TEC argues that there is currently no mechanism for setting the price of demand side response activities within the market pool. This, they claim, is inhibiting the development of a mature demand management aggregation market, which could provide extensive network support, facilitate greater efficiency and therefore reduce costs for consumers. Setting a price for demand management in the market pool will encourage greater investment in demand management and facilitate growth of demand management aggregation as a market commodity. Creating an effective bidding market for demand side response services will encourage greater uptake, delivering more efficient investment in and use of electricity towards the long-term interests of consumers.

ENA Response

The changes required to integrate demand side strategies into the energy market can not, and will not, happen overnight. More efficient price signalling is an important step, but alone is not enough to deliver efficient demand management.

Different demand management approaches and technologies may be more appropriate to one type of demand management than another. Network demand management requires a high degree of “firmness” of peak reduction to ensure that system security is not jeopardised through the reliance on demand side resources. Approaches suitable for network demand management typically have an automated element, such as power factor correction equipment installed by the network business, or direct load control and load cycling which is controlled by the distributor. Price based approaches alone, however, may offer only modest benefits to network businesses trying to achieve network demand management. This is because price based responses rely on customers acting in response to price signals. This voluntary approach may produce changes in behaviour on days of normal weather, but this response may be less reliable when weather conditions are extreme.

1 February 2008

Energy Networks Association
Level 3, 40 Blackall Street, Barton ACT 2600
Telephone: (02) 6272 1555 Facsimile (02) 6272 1566
Email: info@ena.asn.au Website: www.ena.asn.au