AEMC REVIEW OF DEMAND-SIDE PARTICIPATION

IN THE NATIONAL ELECTRICITY MARKET - STAGE 2 ISSUES PAPER

ENA Submission

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Key Messages

ENA believes that for the potential for demand side participation (DSP) to be fully realised there needs to be:

- Recognition in the regulatory arrangements of the risks surrounding the uncertainties inherent in the outcomes of DSP,
- Incentives in the regulations which allow for consideration of DSP options on the same basis as alternatives,
- Support for cost reflective pricing as a useful but limited tool, and
- Incorporation of R&D expenditures into the regulators building blocks mechanism in determining revenue requirements.

Executive Summary

ENA welcomes this opportunity to respond to the Australian Energy Market Commission (AEMC) issues paper titled *"Review of Demand-Side Participation in the National Energy Market (NEM) Stage 2"* released on 18 May 2008.

ENA is the national representative body for gas and electricity distribution network businesses. Energy network businesses deliver electricity and gas to over 13 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 $45 billion, and each year energy network businesses undertake capital investment of more than $6 billion in network reinforcement, expansions and extensions.

ENA supports the paper's position that network service providers' obligations including reliability, security and quality of supply cannot be considered as impediments to DSP.

ENA believes there are significant opportunities for DSP but recognises progress in a number of areas is necessary to see further uptake and implementation of DSP. The main challenges identified by ENA are:

- strengthening incentives for DSP in the regulatory framework,
- the relative immaturity of the demand management DM) market,
- DM providers limited understanding of the network performance obligations,
- DM proponents lack of information about their proposals performance capability, cost and implementation time, and
- risks linked to the willingness of consumers to participate in DM.

ENA experience indicates that very few non-network solutions have been proposed in response to public calls for offers. The general rule is that successful DSP is realised through sponsorship by the distribution businesses (DBs) themselves. Therefore the key task, as ENA sees it, is to facilitate and encourage the adoptions of DM solutions by network owners.

<u>Economic Regulation of Networks</u>

ENA notes that the Rules provide for the Australian Energy Regulator (AER) to develop separate DM incentive schemes (DMIS) as part of its economic regulation of distribution role. ENA considers that such incentive schemes would encourage the consideration and implementation of DSP.

ENA believes that improving the business case for the DSP option is best achieved through the inclusion of aspects of the a D factor style scheme coupled with broader incentives which are not specifically related to the resolution of specified network constraints.

For example, it is appropriate that any impact of DSP on service incentive targets be factored into the financial analysis of individual DSP projects. One approach may be to apply a risk adjusted return to capital and operating expenditure incurred by DBs in taking up DSP solutions. The risk element would reflect the chance of incurring a service and reliability penalty relating to the DSP option relative to a network augmentation alternative**.**

The current relative low level of DSP utilisation could be boosted through more policy and regulatory support for research and development, including pilots and trials where there is no risk of incurring reliability penalties, that is, in non-live situations. 'Learning by doing' is the essential means of enabling network providers to fully understand the reliability risks of various DSP options. ENA supports full cost recovery of pilots and trials irrespective of whether the outcomes are applied to live situations. These costs should be regarded by the regulator as an integral component of the building block method in determining revenue required.

ENA considers that the regulatory decision on what pricing alternative to apply, be it a revenue cap, a price cap or some form of hybrid, should be considered on the merits of each case rather than be driven by achieving a DSP outcome. That is, the desire to decouple network returns from sales volumes should only be one consideration in deciding the outcome.

There is scope in the present regulatory framework to improve market outcomes through more efficient pricing structures. This will be facilitated by the 13 June Ministerial Council on Energy (MCE) decision in support of a distributor-led national smart meter roll out. Notwithstanding this, there are practical limits to the application of cost reflective pricing as they can only work if they are understandable, consistent over long periods of time, and reflect the demand for equity. For this reason the application of network sponsored DM projects must remain a critical element of any overall reform package.

Network Planning

ENA does not believe a regulation imposed consultation process can drive effective DSP. If DBs are appropriately incentivised they will proactively seek DSP solutions regardless of regulatory planning requirements.

However, where the fundamental incentive settings are correct the Regulatory Test provides a useful back stop to the internal process of project selection as well as providing a measure of transparency. Therefore ENA accepts that there should be some benefit derived from a level of planning requirement on DBs that is commensurate with the benefits, costs and limitations inherent of this approach.

The planning regime required needs to be broadly focused so that it covers all options, not just DSP. Further, the regime should only be implemented when a clear network requirement is identified, is strictly limited to dealing with stakeholder requirements, and provides detailed information provision to individual project proponents on a regulated fee for service basis.

Network Access and Connection Arrangements

ENA considers that avoided use of service costs (TUoS & DUoS) arrangements are demonstrably inefficient and flawed. Predetermined rebates for embedded generation risk cross subsidising one segment of the economy with no countervailing benefit and to the exclusion of other cost effective DM options. Therefore no specific rebates should be provided to embedded generator owners unless actual avoided costs can be demonstrated.

On the separate issue of embedded generation connection standards, ENA supports a nationally consistent connection arrangement. ENA believes that any review of connection arrangements must recognise that technical requirements for embedded generation connection may vary depending on the form of connection, the operating intentions and the type of generator. ENA backs the harmonisation and streamlining of connection processing arrangements as far as is practicably possible. ENA also supports the view that connection of embedded generators under the regulations should provide for full cost recovery (both in relation to shallow and deep costs).

Reliability

ENA's view is that resolving the issue of reliability is crucial to the successful integration of DSP into the NEM given the priority NEMMCO places on meeting reliability standards. Without a resolution of this issue DSP would be unlikely to achieve its potential irrespective of changes to the market framework. This is because DSP may not attract the further investment needed to allow demonstration of its certainty characteristics.

General Comment

Identifying solutions to the issues raised in the AEMC paper requires a clear understanding of:

- the nature and drivers of network investment, and
- the_mechanisms that have proven successful in achieving cost effective demand side options to date.

Distribution networks are comprised of a large number of discrete components that serve consumers in a particular geographic area. Some of the investment in these components is driven by growth of demand for electricity supply. A large component (in some areas) is driven by replacement of aged assets or the need for provision of basic connection services, and these investments will be required irrespective of growth or reduction in demand. This means that DSP is not relevant to a significant proportion of network investment, and the provision of additional capacity is often very inexpensive where it is a marginal cost on an investment with an underlying non-demand driver.

Nonetheless, there are significant opportunities for demand side options. Where this opportunity exists, the investment need is responding to the forecast peak demand on a particular element of the network. The timing of this forecast peak may not coincide with peak demand times on other elements, even those in the same chain of supply. For example a zone substation could be driven by a winter evening peak, while the sub transmission element to which it is connected peaks on summer afternoons. Demand drivers cannot be assumed to coincide across the system.

Further, investment in distribution networks is discontinuous. It would be common for a network element to require investment in a particular year and then not require any further attention for ten years or more.

The lumpy investment effect is what gives rise to the more significant opportunities for demand side options. In locations where significant supply investments would otherwise be required to service a small increase in demand, then the opportunity for demand side options to be cost effective is greatly enhanced.

In ENA's experience almost no network demand management projects have arisen from public calls for offers. Almost the entirety of successful network demand management activities have resulted from projects developed and sponsored by the network business itself. The 'Demand Management and Planning Project' in NSW found similarly that demand reduction opportunities required very intensive facilitation to bring projects to fruition, even when large amounts of money was made available. It is not surprising, in an arena characterised by location and time variable benefits where the nature of the demand to be controlled and consumers involved also changes from problem to problem, that a vibrant market for demand management responses has not developed.

In this type of environment, the key task is to ensure that the network owners see demand side options as an attractive alternative to be pursued, rather than an externally imposed obligation. This outcome is best achieved through regulatory arrangements which ensure DBs make technology neutral investment decisions.

RESPONSE TO QUESTIONS ASKED IN AEMC REVIEW STAGE 2

<u>CHAPTER2. ECONOMIC REGULATION OF NETWORKS</u>

2.1 The Balance of incentives may not encourage the efficient inclusion of demand side options

2.1.1 Why this may be a barrier or disincentive to DSP?

Your views on the impact that the service incentive targets and the associated incentive scheme may have on the incentives for the use of efficient DSP.

ENA Response

The incentive to meet service and reliability targets through the application of penalties where there is a shortfall in meeting targets acts as a discouragement to the adoption of DSP. This is acknowledged in the AEMC paper.

ENA believes that the way to address this issue is to add flexibility into the regulations so that the risks around firmness of electricity supply relating to DSP can be accommodated.

It is appropriate that any impact of DSP on service incentive targets be factored into the financial analysis of individual DSP projects. One approach may be to apply a risk adjusted return to capital and operating expenditure incurred by DBs in taking up DSP solutions. The risk element would reflect the chance of incurring a service and reliability penalty relating to the DSP option relative to a network augmentation alternative.

Your views on whether the regime, through the use of incentives such as the efficiency carry over mechanism (ECM), encourages network businesses to avoid operational expenditure that would be spent on DSP. Where you identify areas of concern we would welcome suggestions on how they could be addressed.

ENA Response

At its heart, network demand management (DM) is an economic trade-off between capital investment and operations costs. This occurs because the fundamental assumption in the regulatory framework is that networks earn a return on capital employed and merely recover operational costs. This has the tendency to create a perception that capital investment would be preferred to operating expenditure and could be a source of investment bias.

Where incentives are applied to minimise operating costs separately to the controls on capital costs, these would act as a disincentive to pursue non network solutions.

ENA recognises that ECM schemes could have unintended consequences including acting as a disincentive for DBs to adopt DSP. In this context ENA notes that in NSW, the AER has recently stated that spending on DM projects would be excluded from the operating expenditure incentive scheme. Combined with the decision to continue the D-factor DM incentive scheme, this has neutralised this issue effectively.

In ENA's view the demand side options should be considered on the same basis as other network options with risk considerations relating to DM being just part of the business prudence governance.

2.2 The building blocks control setting method may limit incentives for innovation in demand management,

2.2.1 Why might this be a barrier or disincentive to DSP?

Noting that the Australian Energy Regulator (AER) is currently considering making revenue allowance for research and development for distribution network businesses in South Australia we welcome your views on whether the Rules provide sufficient incentives for network businesses to undertake research and development and innovation on DSP initiatives.

ENA Response

Because network DM is in its infancy, one of the key barriers to its wider use is lack of experience and knowledge of both its costs and the predictability of its performance. Incentives that focus entirely on identifiable capital cost avoidance are unlikely to facilitate a rapid improvement in this area. In addition, broad based DM options (for example customer education) may suffer from similar problems.

ENA's position is that the only effective means of addressing this deficiency quickly is through undertaking pilot programs and projects without the pressure of needing to perform or risk the reliability of network services.

Currently there is insufficient policy and regulatory support for research and development. Regulatory incentives in place effectively limit demand management to live situations, where demand management is relied on to defer or avoid network expenditure. ENA believes there is a widespread need for policy and regulatory support for research and development in network demand management to limit the risks and uncertainty faced by network businesses seeking to increase DSP.

Therefore there is a need to provide clear national policies on the treatment of research and development expenditures including pilots and trials relating to DSP. These pilots and trials are an essential prerequisite for DBs to build the experience and manage the risks associated with DSP.

ENA's view is that pilots and trial projects represent an essential 'learning by doing' stage in the process of expanding the role of demand management. This stage enables distributors to build capabilities and experience in demand management off line. It also involves increased research and development into the reliability characteristics of different approaches to improve the scope of packaged DM options to be used in a similar way to network investment options.

ENA' position is that the best way to address the needs of research and development is to enable the AER to recognise the costs of pilots and trials specifically through the building blocks control method determining the revenue required using key cost components.

Your views on what approaches could be adopted to encourage efficient innovation on DSP.

ENA Response

The AEMC and the AER should consider appropriate mechanisms and incentives to support network demand management pilots and trials.

The recent acceptance by AER of a level of funding for demand management innovation is a step in the right direction. Recognition of a wider role for R & D spending to form an explicit component of building block costs would be a positive step.

2.3 The form of price control may not facilitate efficient demand side participation

2.3.1 Why might this be a barrier or disincentive to DSP?

Not linking revenue to demand can create strong incentives for network business to minimise costs through demand-side options as it will not face a revenue penalty for reduced demand.

Based on this, we are seeking your views on the materiality of the impact of these incentives on the pursuit of efficient DSP options while having regard to the positive outcomes each form of price control may encourage.

ENA response

The form of price control should be subject to a much broader consideration than its impact on DSP. However, failure to include incentive structures appropriate to the form of price control can create a material bias against DSP.

Price capping can embody a significant financial disincentive for network owners to undertake many forms of DM activities. Some DM projects that have been implemented under IPART's D-factor regime in NSW have had lost revenue impacts many times larger than the underlying project cost. . Under a revenue cap, the need for revenue loss compensation is reduced, but other issues remain.

Ultimately ENA considers that the choice of price control, be it a price cap, revenue cap or a form of hybrid cap should be considered on the basis of the most appropriate approach for the network in question, rather than the incentive or otherwise that approach may deliver for DSP. We note that the NER does not contain a bias towards one form of control over another, and the ENA would not support such a bias.

In this context it is worth noting that in ENA's experience, irrespective of the form of regulatory control applied we are not seeing the amount of DSP that could occur. What is needed are regulatory incentives that put DSP on the same basis as network augmentation so that an assessment of alternatives can be made by DBs on the basis of their respective merits.

We also note that in the new distribution Rules mechanisms such as a demand-side incentive scheme have been introduced to overcome some of the disincentives. We are seeking your views on the appropriateness of such a scheme for transmission networks and other network businesses that are subject to a revenue cap.

ENA Response

DBs when they are regulated under a price cap, will always face a disincentive to pursue demand management projects that lead to risks that they will under recover allowable revenue. This means that mechanisms to remove this disincentive are a necessary component of the regulatory regime for both price and non-price DSP.

One option is to decouple the link between the amount of electricity passing through the network and network returns such as the application of a revenue rather than a price cap. However, as mentioned in the previous response the form of cap to be applied should be decided only after taking into account all benefits and costs as in many instances price caps may still be the most efficient option.

ENA notes that there will always be instances where a price cap will apply and therefore the use of DM as an alternative to network investment remains a riskier option. Further, there are significant potential impacts from the regulatory reset after each five year period.

ENA therefore supports the inclusion of an incentive mechanism in the Rules that compensates distribution businesses operating under the current regulatory framework. ENA's view is that aspects of a D factor style scheme should be part of any regulatory regime going forward. A key characteristic of the D factor cost recovery mechanism is that its objective is to balance the risk exposure faced by businesses from DSP compared to network investment, by ensuring that a prudent DM project will recover, at least in principle, its costs regardless of whether expected DM efficiencies are achieved. The degree to which such a scheme is effective in providing compensation for revenue foregone would be a matter of design.

The approach adopted needs to meet the reasonable expectation that distribution businesses have that capital expenditure will not be optimised out of the regulatory asset base. Without DM cost pass through in some form, 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 DM projects. Avoiding this extra risk delivers a more balanced regulatory regime.

To deliver broader DM outcomes distributors need regulatory incentive mechanisms to support their investment in signalling and switching capabilities into air conditioners and other high energy use appliances, as well as investing in communications facilities to switch these appliances on a broad scale.

The funding to provide this infrastructure should be considered as an integral part of the building block process. The available capacity (backed by agreements with customers on the use of this capacity) generated by this funding could provide long term benefits in capital deferment and network reliability, without the initial investment in the capacity being targeted at addressing a specific network constraint. A similar capacity currently exists with respect to hot water load control, which is delivering benefits beyond those expected at the time of initial investment in the load control infrastructure.

2.4 The Structure and components of tariffs may not provide customers with efficient signals about electricity use

2.4.1 Why might this be a barrier or disincentive to DSP?

We seek your views on options for improving the signals to consumers to manage their demand. For example, would there be benefits from increasing the locational component of tariffs or requiring more efficient signals about the use of network capacity to be provided to consumers?

ENA Response

Efficient pricing structures

ENA considers there is scope within the current regulatory arrangements to pursue more efficient pricing structures. For example, large customers could be exposed to capacity pricing or time of use tariffs. As for domestic customers, electricity retail prices are regulated in all jurisdictions. In many cases, the regulated retail prices are not cost reflective and there are few locational or temporal price signals. This means that customers that may otherwise be prepared to offer efficient demand management services have no incentive to do so.

However, it must be recognised that price signals are a useful but limited tool in the pursuit of cost effective demand side alternatives to network investments. More cost reflective prices, including time of use and capacity or demand based prices do help by signaling the general underlying factors driving network costs. To be effective in changing purchase or operational behaviour, they need to be understandable and consistent over long periods of time, and this limits their usefulness in a more dynamic location based role. The above remains true even where capacity pricing and seasonal time of use pricing are technically possible, since there will always be a need for a level of simplicity, equity and consistency over time in the practical use of tariffs. For this reason, the application of network sponsored DM projects should also be seen as a critical element of the overall pricing package.

Introduction of the capacity pricing approach would provide more incentives for customers to engage in DM activities such as load control, load cycling and capacity limitation to manage capacity charges. Significant regulatory pricing reform is required to move to this type of pricing approach. Further, while load control, load cycling and capacity limitation can be initiated without the use of advanced metering, advanced metering with time-of-use tariffs would assist in driving customer uptake of these approaches.

Advanced metering

Advanced metering is expected to provide scope for distribution and retail businesses to offer more efficient prices that signal the costs of energy usage and the provision of peak load capacity. In turn, this is expected to encourage customers to respond to time-of-use price signals, leading to a reduction of energy consumption at times of peak prices. However, ENA's position is that price-based demand response may deliver only limited opportunities for demand side participation. There are three reasons for this:

1. The more efficient pricing structures potentially available through advanced metering are unlikely to reflect the highly location-specific and temporal constraints that drive network demand management. Prices are more likely to reflect the longer term marginal costs of supply related to time-of-use, limiting the potential price fluctuations, price shocks and equity issues that may arise from direct marginal cost pricing of network constraints. This will limit the ability of prices to deliver network demand management.

2. Price-based demand response may not be sufficiently firm, and therefore may not be able to be relied upon to defer network expenditure in all possible circumstances (though it may deliver some improvements in net system reliability in some circumstances). Encouragingly, there is some evidence to suggest time-of-use and capacity based pricing signals do assist in providing customers with sufficient incentives to enroll in demand management programs that assist in network demand management

3. The degree to which retailers choose not to pass on price signals.

CHAPTER 3. NETWORK PLANNING

3.1 The Regulatory Test threshold may be limiting the ability for the alternatives to smaller network augmentations to be considered.

3.1.1 Why might this be a barrier or disincentive to DSP?

We are seeking your views about whether the consultation requirements for new small and large distribution network assets provide sufficient opportunity for non network options to be revealed in the planning process (It should also be noted that we are currently considering a Rule change proposal from the Electricity Transmission Network Owners Forum (ETNOF) to, among other things, increase the minimum threshold for the Regulatory Test from $1 million to $5million).

ENA response

One of the critical upcoming issues is achieving a regulation investment test for distributors, which matches the planning horizons and service requirements of DBs. This question is best responded to in the context of getting the incentives right.

The experience of DBs is that practical and cost effective network demand management options do not arise from the Regulatory Test consultation process. Rather, where they have been implemented, they have arisen from an investigation process undertaken well before the proposed investment reaches that stage.

There is a fundamental problem with expecting regulation imposed consultation processes to drive the effective use of DM alternatives. If the use of DM is in the interests of the network owner and they are incentivised through the underlying economic regulations to use these alternatives wherever cost effective, then the network owners will seek to uncover the demand side options proactively, regardless of the regulatory requirements.

Nevertheless, a large volume of information is provided to the public about forecast demands, future investment needs and decision processes. Despite this the vast majority of the useful engagement with customers and providers regarding demand management comes from the processes undertaken when a specific opportunity is identified.

Where the fundamental incentives are correctly aligned, the Regulatory Test process can provide a useful back stop to the internal processes, and a measure of valuable transparency. However, ENA's view is that the $1 million threshold for requiring consultation on augmentation options applied to new small network assets should be higher to better balance the costs and benefits accruing from the dissemination of planning information.

3.2 The planning arrangements may not allow sufficient time for demand side options to integrate into the planning process.

<u>3.2.1 Why might this be a barrier or disincentive to DSP?</u>

We are seeking your views about whether the arrangements in Chapter 5 of the Rules provide potential demand-side proponents with sufficient time to develop alternative proposals when options are being sought. In this context, you may also have views on the nature and extent of any inconsistencies in jurisdictional planning requirements and which jurisdictional arrangements most effectively reveal efficient demand side options in response to a proposed network investment.

ENA response

ENA experience has shown that better, more valuable consultation is facilitated where networks and their customers and intermediaries can focus on particular areas and high value opportunities in a joint development process.

The timeliness of regulatory consultation may not be ideal if it were the only means of market engagement. Because of the multiple stakeholders such public consultation needs to satisfy, it may be difficult to materially improve this situation. However, reflecting on the issues outlined above, a better solution is to ensure that DBs have an incentive to identify, develop and deploy demand side options. Under such a regime they will develop better, more flexible means of identifying options and alternatives.

Overall, ENA supports the provision of information disclosure and planning requirements but at an appropriate level commensurate with the costs and benefits likely to arise, which needs to be carefully considered.

Distribution businesses are required in many jurisdictions to develop and publish information to assist demand management proponents in identifying potential opportunities for demand management, or siting of embedded generators. In some cases, this information requirement
is augmented by requirements to actively seek proponents for particular projects through expressions of interest.

Significant differences occur between jurisdictions over:

- the level of expected investment at which alternative network options must be considered,
- the level of detail of information on upcoming constraints and proposed augmentations that are being considered,
- how the market is informed on these potential projects,
- the planning timeframe over which potential future projects must be considered, and
- whether the distribution business must actively seek demand-side alternatives or is only required to provide information to the market.

These differences can lead to confusion amongst demand management proponents as to the information disclosure and decision making procedures that apply in a particular jurisdiction. There may be a case for streamlining of these different jurisdictional approaches by developing a single national approach for providing planning and demand management information to the market. A nationally consistent approach could simplify processes for proponents and facilitate understanding amongst distributors of the potential for demand management programmes in their network areas.

It is critically important, however, 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.

Further, both too little or too much information provision to the market will lead to less than optimal outcomes. For example, the detailed information disclosure laws in South Australia have not led to the adoption of DSP based projects to defer network augmentation. The outcome results in the imposition of costs associated with no tangible benefit. Therefore it is critically important that information and planning requirements do not impose costs that are disproportionate to the benefits expected to accrue.

ENA believes there may be a case for further work through the MCE processes to streamline jurisdictional approaches to information through the development of a single consistent national approach. To be successful, it is crucial that the information disclosure and planning regime be focused on stakeholder requirements.

3.3 Consultation on augmentation options rather than on the needs of networks may create a bias against demand side options

3.3.1 Why might this be a barrier or disincentive to DSP?

While we recognise the reliability obligations and timing constraints that apply to network businesses in planning and augmenting their networks, we would like your views about whether the current planning arrangements encourage an undue emphasis on network options to the disadvantage of efficient DSP options.

ENA response

ENA's view is that ultimately, supply and demand side options must be compared equally to enable the most cost effective strategy to be determined, so development of both sets of options must proceed in parallel. Without the context of an estimated value, investigation of options is likely to be wide ranging and inefficient. It is unreasonable to ask customers or demand side providers to develop and provide detailed options without some indication of the likelihood of success. An efficient option development and evaluation process is therefore necessarily iterative.

Notwithstanding the above, ENA accepts the premise that the market benefits from some level of planning requirements on network businesses regarding upcoming constraints and proposed augmentations. The ideal time to search for demand side opportunities is when the network need is clearly defined and an initial view of the cost of a supply option is available. The knowledge of the likely savings that would arise from demand side options with certain characteristics is an important contributor to prioritising opportunities and finding those that may prove cost effective. This need not be a fully developed supply option, but a planning estimate.

ENA's view is that a balanced approach which aligns costs with benefits is required. To be successful, it is critically important that the planning regime be focused on stakeholder requirements, and look more broadly at network planning and reporting. Network business information could be provided in a consistent form to assist proponent understanding of possible network opportunities, and be published centrally.

If so, you should identify the causes of any under-consideration of non-network options and measures that might be adopted to improve the efficiency and balance of the planning process. You may also wish to comment on any lessons from the NTP Review that could be applied to distribution networks in this context.

ENA response

DB experience indicates that a number of reasons for under-consideration of non-network options exist beyond those related to any disincentives in the regulatory framework. These include:

- the relative immaturity of the demand management market,
- DM providers limited understanding of the network role and performance obligation,
- DM proponents lack of information about their proposal performance capability, cost and implementation time, and
- risks linked to the willingness of consumers to participate in DM.

To date there is evidence that the customer is reluctant to invest in projects with long pay backs. In contrast network options are off the shelf and characterised by short lead times.

However the policy, social and economic environment is constantly changing. The increasing public profile of energy and environmental issues, the pending introduction of an Australian Emission Trading Scheme (AETS), the revamping of the Mandatory Renewable Energy Target (MRET) and the pending decision on a national smart meter roll out are among the factors bearing on consumer behaviour. Therefore the potential for DSP needs to be continually tested.

Experience gained through demonstration projects and from the application of demand management options to address specific issues will overcome some of the barriers as they enable distributors to understand the inherent reliability characteristics of different approaches. The pace of these developments will be influenced by how rapidly the regulatory framework achieves neutrality in the treatment of network and non-network solutions, the provision of sufficient support for research and development and the extent to which consumers are exposed to cost reflective electricity pricing in the NEM.

CHAPTER 4. NETWORK ACCESS AND CONNECTION ARRANGEMENTS

4.1 Arrangements to avoided TUOS and DUOS may under / over value demand management options.

4.1.1 Why might this be a barrier or disincentive to DSP?

We are seeking your views on whether the existing requirements for avoided TUOS and DUOS in the Rules provide efficient incentives for investment in and location of EG and whether the current rebate arrangements reflect appropriately the network benefits provided by EG. You should also comment on how the efficiency of these arrangements could be improved.

ENA response

ENA considers that avoided TUOS and DUOS arrangements are demonstrably inefficient and flawed in their application. Predetermined rebates for embedded generators risk cross subsidising one segment of the economy with no countervailing benefit and to the exclusion of other, more cost effective demand side options.

Embedded generation, to a DB, is no different to an interruptible load, or a reduction in load. For this reason claims for network support payments by embedded generators should be managed through the same process for sourcing and evaluating DM options that is used for all other options. No generation specific rebate arrangements should exist if they fail to recognise actual avoided costs.

The following issues arise with respect to avoided TUOS requirements:

- TNSP price structures vary (as permitted under the Code) and the usage charge is based on a cost allocation process then converted to a structure, which is not cost reflective. If this component of TUOS price is used to determine avoided TUOS payments, it results in an economically inefficient outcome.
- This is particularly the case with generators such as wind generators, which may not be able to provide transmission network support sufficient to defer any augmentation.
- TNSP revenue is regulated and any notional avoided TUOS charges which are not avoided as charges are simply reallocated and recovered in the following year via common service charges levied on all customers.
- The present arrangement is unstable. Where a connection point supplies load and embedded generation of approximately the same size, the TUOS usage charge (which recovers a demand-related component of the transmission assets) would increase asymptotically. This is the case since during failure of the generator the full capacity of the network would be used and the full associated costs allocated, yet the net metered usage quantities at the transmission connection point diminish.

The above points also apply to avoided DUOS charges. The use of the term “avoided DUOS” is misleading. DUOS can only be avoided where an embedded generator is placed behind a meter within a customer installation that would otherwise pay DUOS charges. In that circumstance all the DUOS that can be is avoided by the host customer. This could also be considered an uneconomic subsidy as no actual costs are being avoided (for example if the embedded generator does not affect peak demands, or if no network investment is avoided).

Therefore ENA’s position is that the Rules should remove the requirement for DBs to make avoided TUOS/DUOS payments to embedded generators or other DSP providers. The Rules should however provide for DBs to make network support payments to DSP providers, where the planning and regulatory test obligations under the Rules establish that such non-network solutions represent the most efficient means of alleviating a network constraint.

4.2 Minimum technical standards for connection to the network may provide a barrier to potential embedded generation

<u>4.2.1 Why might this be a barrier or disincentive to DSP?</u>

We are seeking your views on whether the existing minimum technical standards contained in the Schedules of Chapter 5 of the Rules reflect the minimum requirements for connection. In addition, we are seeking your views about whether the minimum standards for connection are consistent across jurisdictions and reflect appropriate minimum requirements for connection of EG to the network.

ENA response

ENA notes that the existing minimum/automatic/negotiated access standard provisions were included and defined as a relatively recent change to the NER. From ENA's perspective these Chapter 5 technical standards reflect the minimum connection requirements, while providing sufficient flexibility to accommodate any individual proposals.

Notwithstanding the above the minimum technical standards for connection are not currently consistent across jurisdictions. Any review must recognise that the reasonable technical requirements for embedded generators in a distribution network may vary based on the form of connection, operating intentions and the type of generator. While these may form an effective economic barrier to some forms of embedded generation, there may be some cases where this is a legitimate barrier.

ENA is concerned about the matter of national consistency and has initiated work on an issues paper which is expected to be finalised in late 2008. It must be recognised however that safety of people and the network are not negotiable criteria.

4.3 Deep connection costs to networks may be a barrier to potential embedded generation options

4.3.1 Why might this be a barrier or disincentive to DSP?

We welcome your views on what is an appropriate framework to ensure consistency regarding the connection costs of EGs. In addition, noting the different treatment of connection costs across jurisdictions, is there a framework that would better facilitate the efficient connection of EGs.

ENA response

ENA supports a nationally consistent connection arrangement for embedded generation. These arrangements have the potential to significantly reduce the costs faced by both generation proponents and network businesses. However, the scope for national consistency depends on the expected variation in the type of connections. Therefore national consistency with respect to connection arrangements may be limited to small, standard generation units. Despite these limitations there is still scope in the case of larger generators to harmonise and streamline the application and connection process, if not the detailed arrangements themselves.

ENA believes that an appropriate framework to ensure consistent treatment regarding connection costs of embedded generation should provide for full cost recovery encompassing both shallow and deep costs. How this is to be implemented will depend on the size of the generator. ENA is in the process of preparing a position on this matter.

Overall, ENA's view is that substantive provisions with respect to the connection of embedded generation be included in the *National Electricity Rules*, with only limited use of codes and guidelines to set out details relating to substantive obligations in the Rules.

4.4 Contracting arrangements for embedded generation may not reflect the network support benefits that can be provided.

4.4.1 Why might this be a barrier or disincentive to DSP?

Noting that different arrangements apply across jurisdictions, and that the Rules require negotiation in good faith, we are seeking your views on the extent to which EGs are able to negotiate their contractual arrangements in a timely manner, with sufficient information, such that the remuneration they receive is an appropriate reflection of the network support benefits they are providing.

ENA response

The present procedures provide adequate scope for the negotiation of appropriate network support payments. Experience shows that a major concern regarding these payments is a qualified understanding by the embedded generation proponent of the network role and performance requirements, the Rules obligations and the nature and capabilities of their proposed plant. Examples of this can be seen in the perception that all embedded generation is good because it is close to the load and hence reduces losses, improves voltage regulation and reliability when in fact it can significantly worsen these aspects off network performance (depending on the match of capacity and output to the load profile, the type of plant and its control, and the number of machines)

For further comment refer to S4.1.1 about appropriate "remuneration" for network support.

We are seeking your views about the adequacy of the dispute resolution arrangements in this area and whether there would be benefits in clarifying dispute resolution provisions in the Rules. We will also examine whether the treatment of the benefits that aggregators can provide as a package of network benefits is appropriate.

ENA response

Refer to ENA members respective submissions

CHAPTER 5. WHOLESALE MARKETS AND FINANCIAL CONTRACTING

Not applicable to ENA

CHAPTER 6. RELIABILITY

6.1 The use of short term emergency Reserve Trader may not facilitate the development and use of efficient demand side participation for reliability

6.1.1 Why might this be a barrier or disincentive to DSP?

We are seeking your views on whether there would be benefits from increasing the certainty and reducing the costs of the arrangements through a standing reserve.

ENA response

In theory, DSP could be contracted as a standing (negative) reserve. Currently however, most DSP options are relatively small compared with supply side options and are often constrained operationally in ways that generation is not. This does not mean they cannot be used where appropriate. However, compared with supply side options they are likely to be less attractive to the market operator.

6.2 The use of reserves may not allow demand-side participants to obtain a fair market value for their services.

6.2.1 Why might this be a barrier or disincentive to DSP?

Noting that the Reserve Trader is a backstop emergency measure, we are seeking your views on whether the use of reserves is operating to facilitate efficient demand side participation in those arrangements. That is, without the Reserve Trader, or through the use of alternative mechanisms, would the demand-side be able to better participate in providing reserve to the market?

ENA response

As per response to 6.1.1

On the above basis, we are seeking your views on whether there are other alternatives for maintaining reliability of supply without distorting market outcomes and investment signals. We will keep in mind that doing this may require significant market change for an uncertain benefit.

ENA response

One factor would be the relationship between demand (as in MW capacity) and energy (as in the time for which the demand is needed/used). The ability to deliver the needed energy could be the province of the Reserve Trader whilst the ability to transfer it at the needed rate is the responsibility of the relevant DB.

ENA's view is that resolving the issue of reliability is crucial to the successful integration of DSP into the NEM given the priority NEMMCO places on meeting reliability standards. Without a resolution of this issue DSP would be unlikely to achieve its potential irrespective of changes to the market framework. This is because DSP may not attract the further investment needed to allow demonstration of its certainty characteristics.