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Ausgrid’s response to the AEMC’s DSP3 Issues Paper

September 2011

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Executive Summary

There is a prima facie case that, to date, the operation of the National Electricity Market has not brought forward an economically efficient level of demand-side participation. There are potential benefits along the supply chain that are currently not being captured and as a result opportunities to deliver lower energy service costs to consumers are being missed.

Ausgrid considers that the disaggregated nature of the NEM has contributed to the lower than expected level of demand side participation. Vertically integrated utilities in other markets internationally that are able to capture supply chain benefits appear to undertake more demand side initiatives.

In Australia's case, vertical re-integration is not a likely solution, but changes to the market and regulatory mechanisms could be made to help facilitate more demand-side participation. Such a mechanism would enable a single actor in the market to take account of supply chain benefits within their demand management business case and provide access to a revenue stream to pay for the implementation costs of resulting actions. The NEM would be made better off as long as the NEM wide benefits of demand side participation outweighed the costs of its facilitation.

Perfectly cost reflective pricing could be seen as a solution to the apparent lack of demand side participation in the NEM. However it is Ausgrid's view that while the presentation of more cost reflective prices to customers is a necessary background element, it is not practical to fully reflect the complexity and volatility of the real marginal cost drivers for each sector. Further, even if this were possible, the level of complexity and unpredictability would mean that few end-use customers would be in a position to respond.

Because of this limitation, a regulatory response is required to bolster demand-side participation in the NEM. This should be focussed on enabling a suitable party to act on behalf of the consumers and the supply chain to develop, promote and implement demand side initiatives that lead to reductions in peak demand.

Prior to developing such a mechanism, it is important that policy makers understand the barriers to demand-side participation to ensure that any mechanism designed overcomes these barriers. We have outlined a range of factors that contribute to the lack of demand side participation and after an assessment of market players, consider that DNSPs are the most suitable players in the market to be provided with a business incentive to undertake more demand-side management. Our reasoning is that:

- Peak demand is an important driver of a DNSP's short- and long-run costs and there is already a reason for DNSPs to focus on demand side options
- The DNSP has the only enduring relationship with each customer facility within its service territory
- The DNSP has access to customers' meters and meter data as well as load data at all levels of the energy system
- DNSPs are in a position to develop IT systems and applications functionality made possible by smart grid and smart meters, to assist customers in managing their consumption
- The DNSP is best placed to calculate and internalise the benefit of peak demand reductions to network constraints and can do so with the lowest transaction costs. Other

benefits are more visible to the market and could be readily calculated on a generalised basis
- The DNSP is already subject to a regulatory framework that ensures network investments deliver value for money to end-use customers, and efficiency gains are shared.

Taking the guiding principles of economic efficiency (both allocative and dynamic), equity, simplicity and effectiveness, we reviewed a range of current mechanisms, possible modifications to improve their effectiveness and new approaches.

Ausgrid recommends several changes to the regulatory framework that applies to DNSPs and their interactions with demand side measures. Our recommendation is that the AEMC consider the following options to achieve this outcome:

- Establish and recognise a deemed value for the benefits of reduced peak demand in the transmission and generation sectors of the market as a legitimate additional element of justification for DSP spending proposals in the five year revenue determinations for DNSPs
- Design an in-period mechanism to adjust DNSP revenues (similar to the way D and S factors currently operate) that would provide a share of the benefits that accrue to the community for demand management initiatives. This would provide a business incentive to DNSPs to undertake both localised and broad-based demand side measures using a combination of internally determined network benefits and the deemed transmission and generation value
- Expand the DMIA scheme to provide a realistic quantity of funding to enable DNSPs to explore, innovate and develop new and better ways to encourage efficient demand side participation.
- Consider introduction of a peak demand performance incentive to provide an incentive payment to DNSPs based on improvements in an observable, objective factor like peak demand or load factor.

Adoption of these recommendations and consideration of alternative options described will result in a much greater implementation of demand side measures in the National Electricity Market and deliver a more efficient, better balanced energy supply system for the benefit of consumers.

We look forward to working with the AEMC to recognise the value of improved DSP incentives for networks and to assisting in the practical design of an appropriate regulatory mechanism.

1 Introduction

1.1 There is currently less demand side participation in the National Electricity Market than would be economically efficient

Various commentaries and regulatory investigations have suggested that the National Electricity Market is dominated by supply side solutions across each sector of the supply chain - generation, transmission and distribution. Evidence from markets with alternative structures reinforces this view.

For example, in Western Australia, where a capacity market mechanism exists in the wholesale energy market, registered demand response represents about 8% of the installed generation capacity. In contrast, the most generous estimates by AEMO of the equivalent in the NEM represent about 3.5%. Internationally, New Zealand has substantially improved the load factor on its transmission network over a 17 year period using demand side initiatives. Over the same time Australian networks have experienced significant declines in load factor. Similarly in the USA, arrangements to promote the use of demand side alternatives have resulted in significant participation.

The *Issues Paper* identifies the objective of the review as being to:

> *investigate and identify the market and regulatory arrangements needed across the electricity supply chain to facilitate the efficient investment in, operation and use of demand side participation (DSP) in the NEM.*

The need for a review of this nature suggests that the MCE shares the view that current levels of demand side participation are lower than would be expected in an efficient market, and that there is a general belief that improvements in that level will require facilitating changes to regulatory and market arrangements.

In the current environment of community concern regarding material increases in electricity prices it is important not only that all options to reduce energy service costs be fairly considered, but that the community have confidence that this is being done.

1.2 Basis for Ausgrid's response

The approach of the *Issues Paper* focuses on the thesis that the NEM can be approached as a simple two-sided market, with generation, retail, transmission and distribution sectors on the supply side, and customers on the demand side, separated by the customer's meter. The issue is characterised as being one of ensuring that customer prices represent the marginal cost of each unit of consumption, and that this will ensure the optimal level of demand side participation will emerge.

Ausgrid's view is that the market is more complex and while the energy market (generation and retailing) might be viewed as a single market interface, the market for energy distribution services contains many demand and supply 'side' interfaces.

With the emerging role of distributed generation, distributed storage and other innovative energy service options, customers may not be the only point at which 'demand side' participation can emerge.

As will be described in more detail later, price interfaces can only approximate the highly volatile and location dependent value of each unit of energy delivered, and other non-price mechanisms are required to facilitate a more active and effective demand side to the market.

It is important to recognise that the economic system does not stop at the customer interface. The value of energy in the consumer’s hands will always be determined by the use the consumer puts it to, and the value that use creates. A simplistic approach that reduces the cost of energy supplied to the lowest level may not maximise consumer surplus, as energy has a different value at different times and for different customers. Successful deployment of demand side participation will require close cooperation between customers and those who seek to facilitate their involvement.

1.3 Benefits of greater demand side participation

Demand flexibility is the long term goal, as it enables responses to both existing challenges, which primarily revolve around reductions in peak demand and consequent flattening of load profiles, and more complex challenges that are only now emerging. An example would be the ability to matching load to intermittent renewable generation sources. This might mean in future that we would want to ensure that there was enough load present to ‘soak up’ the output of significant quantities of wind generation whenever the wind was blowing. At other times the load might be managed down to avoid the need for costly backup generation sources to cover low wind times. Without this flexibility, there may be significant limits to the amount of renewable generation that can be delivered to the market.

However, the generation mix will be dominated by fuel based generation for the medium term, and the transmission and distribution networks are both capacity driven. Because of this, the objective of demand side participation in the current market continues to be to reduce peak demand and as a result deliver lower energy service costs.

Peak demand at any point in the supply chain drives the long term cost of the infrastructure required. The capacity must be large enough to supply the energy required at those few times of the year when everyone needs energy at once. Typically, this occurs on hot summer afternoons when the demand from businesses is still high at the end of the working day, and residential sector demand is rising as people arrive home and begin to use appliances. On hotter days, higher requirements for air-conditioning in businesses and homes means these will be the peak days. In other areas, peaks occur in winter evenings, again because at around 6:30pm homes are using the most at the same time many businesses are still operating, and colder days lead to more heating.

In most parts of the NEM, the demand in these peak periods is much greater than the average requirement – in the Ausgrid system, the peak is almost twice the average. Importantly, in most sectors of the NEM, the top 10% of load is only present for less than 100 hours in a year. Managing these peaks using demand side measures can be much more cost effective than building supply capability.

There are benefits from reductions in peak demand within each element of the supply chain.

1.3.1 Generation

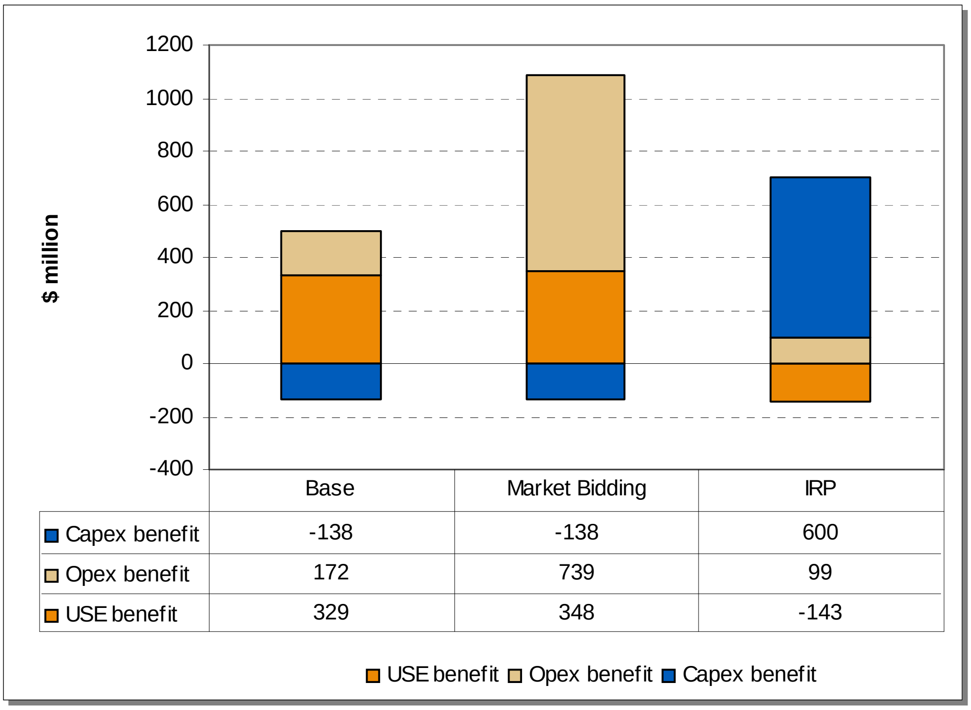
At the generation level, a reduction in peak demand would reduce the requirement for additional investment in peaking plant, increase the utilisation of the existing portfolio and more broadly change the load shape into the future, which can change the number and types of plants needed to meet the forecast load.

The resulting improved load factor would also mean a greater proportional use of more cost effective base load plant. These impacts would result in lower average energy prices. The strategic use of demand flexibility would also dampen volatility in market prices, leading to lower risk management premiums in the retail sector. DSP can also improve system reliability and reduce the amount of unserved energy.

A study conducted by CRA International in 2006 for the International Energy Agency analysed the benefits and costs over a 20 year forecast period of four potential demand response (DR) programs implemented in the NEM on a centralised basis under three different scenarios.[4] The analysis showed meaningful benefits in each of the three scenarios, though their size and composition varied (see graph below).[5]

While this result may not be definitive, it supports the premise that there is value in the wholesale market that could be accessed through appropriate application of DSP.

Figure 1: Composition of total wholesale market DR benefits, by scenario



Source: CRA International 2006

[4] The four programs were (1) interruptible loads and the use of standby generation in larger commercial and industrial facilities; (2) direct load control of residential air conditioners and pool pumps; (3) dynamic pricing (such as critical peak pricing) for residential customers; and (4) voluntary load reductions in smaller commercial and industrial facilities. The three scenarios modelled were (a) a base scenario in which DR is used only to reduce unserved energy (USE), (b) a market bidding scenario in which DR is used to reduce unserved energy and to reduce wholesale market price excursions, and (c) an integrated resource planning (IRP) scenario in which DR is used to minimise total system cost.

[5] CRA International, *Assessing the Value of Demand Response in the NEM*, produced for the International Energy Agency, December 2006.

1.3.2 Transmission Networks

Over the longer term, a key determinant of the cost of the transmission network is peak demand.[6] Appropriately timed reductions in peak demand would enable deferral or avoidance of investments in expansion of network capacity, leading to a lower overall cost of energy supply.

DSP can also be used as a risk mitigation option by reducing the likelihood of load being at risk when portions of the system are subject to episodes of peak demands of very short duration that might otherwise breach reliability standards.

The peak demands faced by transmission networks tend to correlate well with those in the NEM, at least at the regional node level. This is not surprising, because transmission networks aggregate demand from large numbers of customers at a similar level of load aggregation to the generation sector.

The use of DSP for deferral of investments tends to be somewhat episodic in nature, as the most cost effective time to engage DSP is just prior to the need to commit to new investments. Much earlier in the investment decision process the value is lower and less certain, and after an investment is committed, the benefit from DSP in that area drops to near zero until the next constraint begins to appear.

However, the generally long investment lead times and highly averaged demand characteristics of the transmission network tend to provide reasonably consistent benefits for DSP.

1.3.3 Distribution Networks

While there are many similarities between transmission and distribution networks, there are also important differences. Distribution networks are characterised by spatially diverse load profiles that aggregate smaller numbers of customers, often with consistent characteristics in particular locations that are different to those in other locations. Localised weather effects, clustering of residential loads, or local demographics are examples of factors that can mean that peak demands on one element occur at different times of day or different seasons to other elements in the same distribution area.

Distribution investment is also characterized by large numbers of relatively smaller investment decisions. While these approximate a continuous investment process at the macro level, at the level of individual investments, very different DSP strategies may be appropriate.

The episodic nature of benefits from DSP are even more pronounced in this sector, as the benefits tend not only to be sporadic in time, but also specific to limited geographic areas.

Over the longer term, improvements in load factor will reduce the overall cost of the distribution network. While the largest benefits are gained by focusing on near term investment drivers, each reduction in peak demand, if persistent, also provides longer term value by delaying the need for the next increment of growth driven investment.

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[6] Other key determinants of transmission costs include safety, reliability, environmental and asset replacement considerations.

1.3.4 Retail sector

For retailers, DSP can substitute for contract cover, which can be useful at times when the contract market is tight.

The potential economic value to be gained at the retail level from DSP initiatives essentially arises from the reduced costs of the risk management function in circumstances where the underlying risks themselves have declined due to lower or more predictable wholesale market price volatility.

Retailers can and do enter into financially beneficial demand response contracts with their customers. Typically, a major energy user will agree to provide a specified reduction in demand, as and when called for (with specified notice) by the retailer. While these can provide a significant financial benefit, in the short term the majority of this is a wealth transfer. Such arrangements rarely reduce the wholesale price (relative to what it would otherwise have been) in those periods for which demand side response is called. However, over time, such outcomes, if consistent, would reduce price volatility and at least some of the underlying risks that produce it, and therefore would tend to put downward pressure on the cost of the risk management function provided by all retailers[7].

Over the longer term, benefits from retail DSP may accrue within the generation sector as described above.

1.3.5 Overlapping Benefits

There is not perfect overlap between the type of demand responses that result in benefits across the whole chain. For example, a reduction that benefits a part of the distribution network with a winter evening peak may not contribute as much to a summer peaking generation market, or not at all to a summer daytime peaking transmission network. However, even where the time and location of peaks is not coincident, once a demand response capability is established, it can often be used to generate multiple benefits at low marginal cost.[8]

The energy market is constructed so that either competitive pressure or regulation tends to return efficiency gains to customers over time. The same is true for the benefits of DSP. Regardless of how the DSP is motivated or implemented, the benefits of efficient actions will tend to flow to customers as lower energy service costs.

Because there are overlaps (however imperfect) between the characteristics of DSP that would secure benefits in each of the sectors, it is entirely reasonable that actions undertaken in the distribution sector, for example, could result in benefits accruing in the transmission or generation sectors. If the particular DSP activity was designed with this effect in mind, it could be adjusted so that these wider benefits were highly likely to be realised.

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[7] More frequently, however, as discussed in section 2.4 below, the exercise of demand response does not change spot price.

[8] DNSPs consider peak usage on a locational basis as constraints arise in specific locations and drive the need for network expansion. In contrast, peaks in the energy market occur within state markets (a much broader geographical base). There is a weak correlation between locational constraints and energy market peaks. However, the correlation is stronger at a transmission level where locational peak usage is aggregated over a wider geographical area. It is worth noting that peak price events in the wholesale market are often driven by interconnector or transmission congestion not necessarily by peaks in energy consumption.

The result is that DSP should almost always be regarded as having larger economic benefits across the supply chain than those arising in the individual interests of any one actor.

2 Barriers to DSP

Many benefits of DSP are being foregone because there is no consistent mechanism within the market to aggregate and share in the benefits from reductions in peak demand across the energy value chain.

There are several factors that appear to have limited the amount of DSP that has come forward in the NEM, including:

- Disaggregation of DSP benefits due to the vertical unbundling of the electricity industry
- The fact that the wholesale market takes the forecast load duration curve as an inherently exogenous variable
- Vertical re-integration of the retail and generation sectors
- The self-limiting nature of retailer initiated DSP
- Lack of a positive incentive for alternatives to network investment, and
- The particular difficulties and limitations of DSP focussed only on deferring specific distribution network augmentation projects.

2.1 Disaggregation of the economic benefits of DSP across the value chain

As noted above, DSP can offer economic benefits in each part of the electricity value chain. Although at a societal level the benefits of a particular DSP strategy are realised and eventually distributed to all customers, there is currently no single entity that can build a business case based on this entire value chain benefit.

The cost of a particular DSP initiative undertaken by any portion of the value chain will be the same – but the program sponsor will only be able to capture the benefits that accrue to their own business. Obviously, this makes any particular DSP undertaking less economically attractive than it would be if it could obtain the benefits that such response may offer across the value chain. An example is the vertically integrated electricity industries in most of the states of the USA, where demand-side management has a long and comparatively successful track record.

Cooperative DSP activities across sectors are possible, using commercial contracts to share and transfer value between players. However, very little such activity has taken place in the NEM, possibly because of the substantial transaction costs involved.

The notable exception is the exercise of controlled loads by networks, or off-peak tariff arrangements. In this case, the network business establishes a known and predictable switching regime and a lower tariff price for loads connected to these interruptible circuits. Retailers add an energy price, which is also lower than the price for continuously available energy in recognition of the lower cost of purchasing energy out of peak hours. The benefit of lower peak demand results in reduced infrastructure costs for the networks (both distribution and transmission) and reduced generation costs, and the benefits are shared with customers through lower prices. Customers choose to participate by effectively accepting a lower level of availability in exchange for a price discount.

Virtually all controlled load tariffs currently active in the NEM were originally established under a vertically integrated industry model, and continue today because the established arrangement led to low transaction costs. The development of new, more sophisticated versions of load control faces considerable difficulties in coordination and the establishment of agreed arrangements between market players. Failure to properly consider the full chain benefits is likely to significantly delay the emergence of more innovative load control options.

2.2 Exogenous nature of demand for the wholesale market

The wholesale market of the NEM has proven itself to be an exceedingly efficient mechanism for satisfying the forecast load duration curve, as evidenced by the fact that wholesale market prices have remained relatively constant in real terms for over a decade, except for a blip in the 2006 – 2008 period (see Figure 2 below).

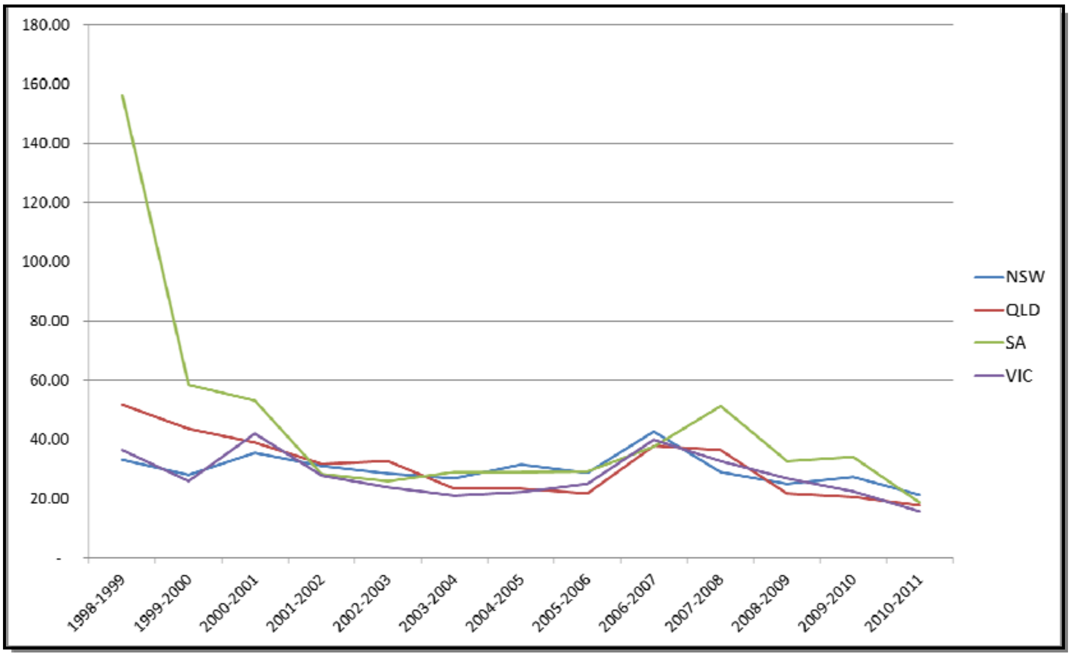

Figure 2: NEM volume weighted average wholesale market prices (CPI adjusted)

However, while the wholesale market is very good at meeting a load duration curve cost-efficiently there is no economic signal to the wholesale market to actively try to change the load duration curve. Indeed, high prices at the top end of the load duration curve, or the threat of those prices provide the signal and economic underpinning for investment in new generation capacity.

No effective mechanism for proponents to capture the benefit of demand side options has been developed in the NEM. Because the underlying spot price is determined after the event, even a direct market participant cannot reduce demand in response to price events without considerable forecasting risk, or by resorting to trading in a derivative market. It is evident that retailers are in a position to take some advantage of these arrangements, but their private benefit (in competitive terms) is maximised when the demand reduction only reduces their volume exposure to high prices, and not the prices themselves. Once the demand reduction achieves a change in the spot price, the benefit is dissipated among all participants.

2.3 Vertical integration of gentailers and access to financial hedges

The three largest retailers in the NEM are also generators, though none have sufficient generation to serve their total retail load. Several of the smaller retailers, by contrast, are owned by generation companies that are much larger than they are. The benefits of owning peaking plant in particular are associated with hedging, use of gas portfolios for low generation operating costs and competitive positioning.

The exercise of the 'natural hedge' provided by demand response may simply represent an exchange of profits between a 'gentailer's' generation and retail arms. It is also possible that contracting for, and exercise of, demand response could remove a competitive advantage associated with the negative financial effect of price volatility on competitors that may not control any or as much peaking plant. In such cases, a strategic business decision might be made to forego the demand-side option in favour of greater profits from the market.

Further, to the extent that a retailer has cap contract hedging arrangements already in place, or has its own natural hedge by way of owning peaking plant, it may not be overly concerned about instances of high pool prices. Although demand response can provide additional arbitrage benefits, that benefit may not be sufficiently material to motivate the retailer to take action, particularly in light of the transaction costs involved in prospecting, contracting, dispatching and settling the demand response.

There is a further restriction in the retail market – which is that demand response can only be 'sold' to the retailer that serves the customer. The reduced throughput is automatically accounted for in that retailer's wholesale market settlement and contract positions. There is no practical and efficient way for the demand response to be used by another party. This serves as a limitation to such demand response being accessible to third parties such as specialist demand-side aggregators who might otherwise assist end-use customers in finding a market for their demand response outside their serving retailer.

2.4 Self-limiting nature of DSP for spot price arbitrage

It is important to note that, except in the case where the retailer is unhedged and deploys demand response to reduce the pool price, the immediate financial value of the exercise of demand response to both the retailer and the customers/aggregators that provide the response is the opportunity to arbitrage the spot price. This introduces a somewhat perverse incentive for these parties to limit their demand response actions so as to avoid reducing the spot price, since any fall in that price will reduce their private benefit. To the extent that demand response only produces such arbitrage benefits (i.e., avoidance of paying pool price obligations, without affecting the pool price itself) it constitutes a wealth transfer from generators to retailers and/or the customers/aggregators that provide demand response. No net economic benefit is produced.

2.5 Lack of a positive incentive for alternatives to network investment

The transmission sector has obligations to consider non-network alternatives, including DSP as an alternative to investments in new transmission assets. However, such a decision leaves the network operator with at best a marginal benefit until the next regulatory reset in exchange for a higher risk profile and more complex business model. It has been argued that the resulting reduction in regulated asset base in the following regulatory period reverses the benefit, resulting in a net negative position for the transmission business. In this environment there is little incentive for such businesses to be innovative, or assiduous in finding and securing DSP.

A similar arrangement exists for most distribution businesses, but the complexity and effort is multiplied by the larger number of diverse and relatively smaller investment decisions that must be made.

In NSW, the application of a "D-factor" incentive has changed this situation and resulted in a positive incentive for the businesses to seek and implement demand management alternatives to network investments. Over the years since its introduction, this has resulted in much more active and effective processes than has resulted in other NEM jurisdictions with identical regulatory obligations but no incentive arrangements.[9]

2.6 The particular difficulties and limitation of DSP focused on deferring specific network augmentation projects

Peak demand at an area-specific level is one of the key drivers of a DNSP's costs, and DNSP DM (demand management) efforts to date have primarily focused on addressing peak demand on this basis. This is entirely rational, as the costs of localised augmentation projects drive the DNSP's peak demand related costs in the short term. Deferral of peak-demand driven augmentation provides a tangible benefit that can be reliably secured. However, there are a number of limitations to area-specific focused DM efforts, including:

- There is generally a relatively short timeframe in which a specific quantity of demand response must be prospected, contracted and commissioned
- The deferral benefit of an augmentation project increases as the need for the augmentation approaches. This, combined with the fact that the demand driver for an augmentation project often changes in magnitude and timing, results in most non-network alternatives being considered when the augmentation requirement is no less than 1 and no more than 3 years into the future
- The process of developing a non-network solution requires substantial involvement in investigation, development and engagement with customers and vendors, and must be carried out in parallel with the development of supply side options. The complexity of this unfamiliar process has been compounded by the lack of any source of funding for capability building, and the process must be repeated for each investment considered.

These factors result in a very constrained solution space for non-network solutions. This is reflected in the relatively few area-specific DM projects that have actually been implemented. Ausgrid's experience over the past three years is a good illustration of this:

Table 1: Consideration of non-network alternatives

	2008-09	2009-10	2010-11
Screening tests	42	26	18
DM investigations	9	6	3
DM projects authorised	5	3	2
Project cost	$3.95m	$2.75m	$1.37m
Projected savings from deferral	$13.4m	$6.46m	$4.17m
% of augmentation capital allowed	3.6%	1.3%	0.7%

[9] DSP activity in WA has been greater than in the NEM. However it should be noted that WA is subject to different regulatory obligations, and DSP activity has been predominantly focussed at a system wide level rather than a distribution level as a result of these requirements.

As can be seen, the potential for area-specific demand response is investigated with regard to a substantial number of network augmentation projects, but relatively few prove feasible and even fewer materialise. An example of the way these benefits are assessed is contained in Appendix A, which includes a typical Demand Management Screening Test of the type undertaken at Ausgrid for all growth driven investments over $1m.

Ausgrid's experience in this regard is not uncommon among DNSPs. In SA, under requirements set out in Guideline 12, ETSA Utilities considers non-network solutions for all proposed network projects over $2m, using a Request for Proposals approach to securing projects. In 2009/2010 ETSA reported that it conducted 7 'reasonableness tests', with only one proceeding to issue of an RFP. According to ETSA's public documents, between 2004 and 2009, ETSA issued 24 RFPs to source non-network alternatives. In almost every case no complying responses were received, and no non-network alternatives have been pursued to implementation in any of these cases.

Even in an area like South Australia, with its acknowledged extremely peaky load profiles, identifying and securing DSP alternatives in response solely to distribution investment drivers is very challenging. There is also a relatively short timeframe in which the demand response will be of value.

Most deferral efforts, where successful, result in supply-side project deferrals of a couple of years at best. The demand response engendered generally has a very limited life. Once the deferral can no longer be maintained, or the load increases beyond the capacity of the network including DM, there ceases to be any economic value in the DM to the network even if it has been captured, and it cannot be supported financially in the longer term.

To the extent the regulatory framework focuses on the deferral of specific capital projects, it does not encourage broader based initiatives that could influence customer's behaviour in the longer term. If a mechanism existed that encouraged networks to undertake broad based initiatives, such capabilities could be leveraged when augmentation projects require deferral and thereby become a very cost effective means of deferring augmentation capital when opportunities arise..The current regulatory framework results in three problems: (1) the relatively short timeframe of the deferral effort seldom justifies material capital investment, so the demand response obtained essentially comprises the lowest hanging fruit, (2) the short-term focus of the program fails to provide an enduring signal for the value of demand response and hence reduces the overall effectiveness of the resources devoted to DM prospecting and contracting , and (3) the inherently time dependent nature of the requirement means that low cost opportunities for demand reductions that arise from customers' installation or refurbishment activity are foregone unless the timing is very fortuitous.

Together these features have limited the overall impact of network DM efforts for both deferring network augmentation and for providing DM capability that could be available for other purposes within the NEM.

It should also be recalled that area-specific peak demand is only one of the drivers of network capital cost, and that the proportion of the capital cost requirement it represents will vary from DNSP to DNSP and for any particular DNSP over time. For example, it is rare that the growth in peak demand among the existing customer base within a given area of a DNSP's service territory will constitute more than 50% of the DNSP's total capital requirement. This is still the case for most DNSPs (and most areas within most DNSPs' service territory) even when growth in peak demand due to new customer connections are included.

In Ausgrid's case, the largest single driver of capital costs at present (and into the medium term future) is replacement of assets in poor condition. These activities are estimated to account for approximately 42% of Ausgrid's capital requirements in the present regulatory period, while growth in peak demand accounts for no more than 29%, and this includes both new connections and the growth-related component of projects primarily driven by replacement needs.

Where asset renewal is a major driver of new investment, the marginal cost of adding network capacity is very low. The incremental cost of the additional capacity required in such a situation is often much lower than a typical localised upgrade of existing assets, thereby requiring exceedingly low-cost DSP alternatives to justify not purchasing that incremental capacity on the supply side.

These comments are not offered to diminish the potential value of location-specific DSP but rather to suggest that the potential for encouraging DSP is significantly limited if the effort is restricted to those areas facing augmentation in the relatively near term.

3 Cost refective pricing is necessary but not sufficient

Pricing in the NEM is not perfectly competitive and inhibits the NEM from operating in a more fully efficient manner. While this is true for the whole market, it is not necessarily true for all sectors of the market. It is therefore useful to separately consider the issue of pricing in the two distinct sectors of the market – the wholesale energy sector and the regulated network sector.

The wholesale energy sector is a reasonably efficient operating market where the price and quantity of energy sold is very flexible and is set to balance supply and demand at five minute intervals. The wholesale market has been designed to facilitate this price flexibility and thereby designed to create efficient energy consumption outcomes. Prices for energy sold at the retail level are the result of the operation of the spot and contract markets and retailers package the inherent volatility of market outcomes in their pricing to customers. There is little in this structure that inhibits the efficient operation of the market.

In contrast, pricing in the regulated network sector is constrained by factors that inhibit appropriate pricing signals being passed through the supply chain to customers, and as a result does not facilitate the efficient use of network services. The largest inhibitor of efficient pricing, particularly in the distribution sector, is the absence of appropriate meter technology. This fact alone means that network prices are highly averaged across customers and despite making up almost 50% of customers' bills, network prices often cannot signal the costs of supplying energy to customers at different times.

Despite its current failing, network pricing has a fundamental role in setting a platform that can influence consumer's energy consumption behaviour in the longer term. While the economic goals of cost reflective pricing have been implemented to a degree in the market, this has occurred predominantly in the context of the largest customers. Most end users face averaged prices that represent a combination of price signals that have been averaged at each part of the supply chain. The price seen by end use customers is therefore highly averaged and not reflective of costs of any single sector of the market.

Costs in each sector of the electricity supply chain vary over time and vary with the level of customer demand for energy. This variation in cost of supply can occur within a single day, vary between seasons or vary over the course of a number of years. The times during which different sectors of the market face cost pressures are not necessarily aligned and it is this additional complexity that also makes efficient price signals (even if they could be signalled by networks) almost impossible to convey in a single price. The cost and pricing complexity is made even worse in a market characterised by large numbers of end use customers who have little understanding of what drives costs in the electricity supply chain.

For example, costs in the wholesale market are largely driven by system wide peaks in energy consumption. This occurs at times of high system load or at times of network (interconnector) congestion and higher wholesale prices can signal the need for further investment in generation capacity.

The transmission sector is also influenced by system wide peak demand, and while there is some alignment between wholesale market peaks and transmission network demand peaks, this does not always occur. The marginal cost for transmission is effectively zero until such time as augmentation is required, when the cost jumps significantly.

In the distribution sector, it is peak demand within localised parts of the network that actually drives augmentation cost. The marginal cost to networks in unconstrained locations is effectively zero, but like transmission, jumps significantly when augmentation is near. The times of localised congestion do not necessarily align with system wide consumption peaks, but rather are driven by the combined behaviour of customers connected to that local network. It should also be noted that augmentation costs are only one of several major cost drivers (and often not the largest of those).

Finally, in the retail sector, costs are driven by wholesale energy costs and the unhedged risk exposure of the retailer's portfolio.

This short summary of augmentation driven costs for each sector of the market demonstrates that the drivers of such cost, the timing of cost pressures and the term over which cost pressures manifest is different for all sectors of the market. Further, this misalignment of costs in terms of timing and scope means that the individual costs cannot meaningfully be built into a single set of cost reflective prices that end-use customers can easily understand and respond to. The complexity and variety of cost drivers means that end-use customers would face significant transaction costs in interpreting the complex price signals even if it were practical to transmit them in pure form. As a result, prices of each sector of the supply chain are averaged and therefore hide the finer details of cost signalling.

It is important to note that the pricing function itself has multiple objectives. From a network business's perspective, the primary task of price setting is to recover allowed revenue. In an environment of declining energy volumes and rising costs to serve, recovery of allowed revenues from a declining base is a challenge. In such an environment, the recovery of revenue is the primary consideration of the pricing function and consideration of other pricing objectives such as influencing customer consumption behaviour which may have a longer term impact on costs becomes a secondary consideration.

Similarly, from a retail perspective, the acquisition and retention of customers is paramount to the retailers' business case and is understandably a fundamental driver of pricing strategy. Responding to customers' desires may be a more much important objective than influencing end-use consumption behaviour.

In a pragmatic sense, the search for a perfectly cost reflective end-user price is not realistic and would probably prove ineffective in the mass market in any case. However, the tariffs customers face can be made more reflective of longer term cost trends and if maintained over the longer term can play an important role in supporting DSP initiatives.

From a network perspective, cost reflective network prices (CRNP) are calculated for the largest customers. These prices are informed by the cost to serve at each connection point and influenced by the usage pattern of the customer himself. It is efficient for CRNP to apply to the largest customers only as in reality, it is the consumption behaviour of these customers that has the largest impact on network costs. In contrast, the majority of smaller network customers face postage-stamp pricing that averages the shared costs of the network. This can also be seen as efficient because due to the diversification of usage patterns and the relatively small contribution of each customers' individual behaviour, meaningful and sizable DSP is less likely to emanate from end use customers in the short term. To the extent that it may take place in the longer term, DSP requires significant investment in technology to facilitate active involvement

Prices to smaller customers are necessarily simplified, but can still be meaningful (i.e. supplying energy during week day afternoons and evenings is more expensive than supplying energy overnight). These simple messages, although highly averaged, can help set the scene for more specific DSP messages to be given to customers to encourage behavioural change specific to their situation.

Of course even these simplified pricing signals require more sophisticated metering technology than many smaller customers currently have. Interval metering, or better smart metering, provides the platform for introducing pricing that enables signalling of different costs at different times. More sophisticated price based products such as dynamic peak pricing or rebates are easier to explain to customers that already have an appreciation that delivered energy costs change over time. New metering technology is essential for these more sophisticated approaches.

In the current market structure, price signals provided by networks may not reach customers because network prices are delivered to retailers who are free to re-package those prices or pass them on directly to the end-use customer. Historically, network price signals have been passed on to larger customers but re-packaged for smaller customers. This is likely to reflect a number of factors including the structure of the network tariffs, the level of risk those tariff structures pose to the retailer and the nature of the metrology in place for different tranches of end-use customers.

While visibility of such a network price to the end-use customer may result in some demand response, this cannot be guaranteed without significant change to the nature of the market structure. Ausgrid does not recommend considering this level of change at this time.

Cost reflective pricing on its own should not be identified as the solution that will promote efficient levels of DSP in the NEM. It is clear that pricing has a role to play in influencing long term behaviour, but other mechanisms must be crafted to encourage DSP in the shorter term.

4 Inability to aggregate benefits is a primary limitation on DSP

The NEM already has a number of mechanisms in place intended to encourage DSP. These mechanisms predominantly exist in the network sector and range from obligations on networks to assess demand-side alternatives when augmenting networks, to incentive mechanisms designed to encourage pursuit of greater non-network opportunities. Despite a suite of mechanisms being in place, the current market and the regulatory framework has proven itself limited in its ability to encourage DSP in a comprehensive and consistent fashion.

The primary limitation of the existing market and regulatory framework surrounding DSP is the inability of any single investor/operator within the market to be able to access value derived by DSP from all parts of the supply chain. Networks can access benefits of network augmentation deferral within their own network, but cannot access potential benefits from deferral in generation capacity. Similarly, retailers can access benefits of managing their own portfolio risk exposure through DSP, but without access to other benefits, DSP is clearly a more expensive or time consuming mechanism than other options available to retailers (i.e. investment in peaking generation). Without access to a wider suite of benefits, the business case for demand side initiatives will always be constrained by the limited scope of benefits that can be captured.

This is true not only in terms of the benefits along the energy supply chain, but over time. Business cases (and regulatory regimes) tend to focus on the short term, highly visible benefits and ignore the longer term benefits that might accrue from persistent changes in demand. For every demand reduction driven investment deferral, there is a knock on effect on the timing of the next investment. These longer term, less certain benefits are generally ignored in current arrangements.

If these benefits were able to be aggregated in some way, a range of demand side options would become much more likely to proceed. These include:

- Arrangements with businesses to reduce their load on call in exchange for a payment
- Expansion of voluntary load control arrangements currently used predominantly for hot water to include a range of other appliances as diverse as airconditioners, pool pumps and clothes dryers
- Distributed generation and eventually battery storage
- Energy efficiency improvement programs with businesses and householders
- Automated energy management in business and homes enabled through smart grid technology

In order to encourage greater DSP within the NEM a mechanism must be designed that allows access to benefits from all sectors of the supply chain and recognises the likely value from longer term benefits.

5 Distribution networks are an appropriate actor to drive DSP

Ausgrid proposes that a new mechanism for support for DSP be focused primarily on the central role and capabilities of the distribution sector.

There are a number of reasons why DNSPs are well suited to facilitating more DSP on behalf of the market through a new or modified DSP mechanism. These include:

- Peak demand is an important driver of a DNSP's short- and long-run costs and there is already a reason for DNSPs to focus on demand side options
- The DNSP has the only enduring relationship with each customer facility within its service territory
- The DNSP has access to customers' meters and meter data as well as load data at all levels of the energy system
- DNSPs are in a position to develop IT systems and applications functionality to assist customers in managing their consumption (i.e. via smart grid and smart meter technology).
- The DNSP is best placed to calculate and internalise the benefit of DM to localised situations and can do so with the lowest transaction costs. Other benefits are more visible to the market and could be readily calculated on a generalised basis
- The DNSP is already subject to a regulatory framework that ensures network investments deliver value for money to end-use customers, and efficiency gains are shared.

5.1 Networks directly experience the impacts of end-use patterns on capital costs and are engaged with the demand side.

As mentioned above, peak demand at an area-specific level is one of the key drivers of a DNSP's costs. Within the current regulatory arrangements, there is a requirement for DNSPs to assess and implement demand side initiatives on a regular basis. To date the focused has been primarily on addressing peak demand on an area-specific basis. However, this has resulted in some DNSPs forming active engagement strategies with customers and DSP providers to explore and develop a range of demand side options.

5.2 Enduring relationship with customers' end-use facilities

A DNSP has an enduring relationship with each end-use facility within its service area, and therefore each customer that inhabits it. This is in contrast to retailers whose relationship with the customer is contestable and in a well functioning market essentially temporary (however much retailers work to encourage loyalty). Because of this enduring relationship, the network has a vested interest in the design and construction of the buildings and industrial processes within its service territory, as well as the operating characteristics and use of the end-use equipment within those buildings. It is involved in the design of the electrical connections to the facility when it is built or modified and continues to be affected by the energy using characteristics of the inhabitants. The DSNP's relationship is necessarily long term and therefore able to take a long view of the impacts and benefits of changes in demand.

Of course, transmission network operators and generators have no direct relationship with any but the very largest of consumers.

We note that the NECF enshrines the triangular relationship between the distributor, the retailer and the customer. Ausgrid believes that explicit recognition and preservation of the relationship between the distributor and the customer is of significant potential value to the NEM as it provides an avenue whereby the only party in the value chain whose costs are directly driven by localized peak demand (and who can be less dependent than other parties on throughput for its revenue) can facilitate DSP with customers. A network's economic perspective of costs, if used in developing long term pricing strategy and more specific short term program offers, can assist end-use customers in modifying their consumption patterns in ways that reduce costs for themselves and the electricity supply chain overall.

5.3 Access to meters, meter data and system demand data

DNSPs provide the meters for the vast majority of the end-use customers and have access to the meter data of all customers. This allows them to function as highly expert, alternative providers of information services for end-use customers. To the extent that the relationship of the DNSP to the customer is qualitatively different from that of the retailer (as discussed above), it may result in the end-use customer seeing the DNSP as capable of providing unbiased expert advice in relation to energy investment, usage choices and usage behaviour. This will become more obvious as networks move away from pricing based on energy volumes and begin to charge customers on the basis of peak demand and therefore have no vested interest in the amount of energy sold to a customer.

Ausgrid believes that the ability to access and interpret the customer's meter data is a fundamental part of its relationship with the customer and recommends that this ability – including the ability to provide information services via portals and in-home devices – be explicitly acknowledged and enabled in the Rules.

In addition, the network has ready access to demand data at all levels of the system – from its own network monitoring up to the transmission connection point and via publicly available data at the NEM level. This enables evaluation and examination of impacts of DSP strategies at all levels of the energy supply chain.

5.4 Ability to leverage information with IT hardware and software system functionality

Beyond the provision of information, the functionality of the DNSP's IT hardware and software systems – particularly its smart metering and smart grid technology – can offer significant benefits to customers interested in responding to DSP initiatives.

One of the key challenges for this next generation of technology is to assemble a compelling business case to make the long term investment in the systems and equipment necessary to enable these smart products. The enduring nature of DNSPs relationship with customers and the ability to leverage smart grid technology platforms for multiple uses makes it more likely that DNSPs could consolidate sufficient benefits to enable these investments to proceed.

Ausgrid's selection to deliver the Commonwealth's Smart Grid, Smart City Program is an explicit recognition of the potential of these synergies. If the ability to bring the wider benefits of DSP to the business case were enabled, it would be more likely that DNSPs could justify the development of smarter systems to support more customer engagement.

5.5 Networks are regulated and already have system of checks and balances in place

Networks are the only (economically) regulated part of the supply chain and therefore already have mechanisms in place under the Rules that ensure that customers receive value for money from network investments. The Rules currently outline a very detailed and prescriptive process that all networks must participate in every five years, whereby an external party, the AER, determines the costs and investment programs that are efficient for each network area. This process already assesses the impact of investment on end use prices likely to be seen by customers and already takes account of efforts networks currently undertake to invest in DM. Importantly it acts to ensure that efficiency gains are fairly shared with consumers over the longer term.

Current arrangements effectively limit DNSPs to consideration of internal business benefits when considering DSP initiatives. If a mechanism were developed to enable DNSPs to consider the value of a DSP initiative across the entire value chain, and to be rewarded with a share of those wider benefits, DSP would be considered economic in many more situations. To the extent the DNSP share was less than the full benefit, part of the benefit would pass to consumers immediately. Existing regulatory arrangements would ensure that the benefits were returned to customers over the longer term.

5.6 DNSP business case is most complex.

Developing a business case for DSP based on the full supply chain value requires an understanding of the benefits in each segment. As previously discussed, achieving this via price transfer mechanisms is complex to the point of impracticality. However, DNSPs are in the best place to undertake analysis of localised benefits of DSP – in fact it is arguable that they are the only entity with this capability in practical terms. This element of the benefit mix is by far the most variable and complex to calculate because costs are specific to local areas; are generally in many small increments; and usually only apply during certain times.

In contrast, the value of DSP in other parts of market is more readily calculated, more consistent over time and much less location dependent. These values could be calculated by an independent party (such as the AEMC or the AER) as the investment cost that would be borne in the absence of DSP. At the transmission level these factors are much more transparent and likely to occur in larger chunks (i.e. investment in a new OCGT plant or an augmentation to a transmission line). This calculated value could be deemed for use in developing business cases for investment in DSP and as the basis for benefit sharing. The internal DNSP benefits would not need to be externally determined as the NSP would be able to internalize both the costs and that portion of the benefits.

6 Guiding Principles

So far, we have established that there is potential value of DSP throughout the sectors of the NEM that appears to be under exploited and identified barriers for greater levels of DSP taking place. We have also established that a further mechanism (or mechanisms) should be designed to actively encourage broader based and longer term DSP on behalf of the NEM and made a case for why we think that this mechanism would most readily be applied to distribution networks.

These are the principles that should be applied in considering and comparing possible options for facilitating greater demand side participation in the NEM:

- Economic efficiency (both allocative and dynamic)
- Equity
- Simplicity
- Effectiveness

These specific criteria have been chosen to provide a sound economic base for the evaluation of options whilst being pragmatic.

6.1 Economic Efficiency

The National Electricity Law and associated Rules have been designed with due regard to principles of allocative and dynamic efficiency. It is therefore implicit that any approach for increasing DSP in the NEM should also be assessed using these parameters.

In its simplest form, allocative efficiency can be thought of as referring to the short term, while dynamic efficiency refers to the longer term. Allocative efficiency is achieved when resources are allocated such that it is not possible to make anyone better off without making someone else worse off. In assessing options for facilitating DSP, allocative efficiency is increased to the extent that the benefits achieved by those who gain from it exceed any costs experienced by others. Several of the classic tests that have been applied to Demand Side Management (DSM) in various jurisdictions concern allocative efficiency. These include the no-losers test, the non-participant test, the all tariff payers test and the total resource cost test, as originally codified in the California *Standard Practice Manual for Economic Analysis of Demand Side Programs and Projects*[10].

Dynamic efficiency, by contrast, focuses on the ability of the market to meet changing needs and wants. Dynamic efficiency is increased to the extent that the change undertaken increases the ability of the market to adapt quickly and at low cost to changed economic conditions and thereby maintain output and productivity performance despite economic shocks. It is often linked to research, development and innovation.

DSM was first put forward as a means for increasing the economic efficiency of the electricity supply chain; that is, as a means for reducing the total cost required to meet the production and amenity needs of consumers. It can increase allocative and dynamic efficiency in several ways:

[10] California Public Utilities Commission, October 2001 and later revisions.

- Demand response at times of high wholesale market pool price can put downward pressure on the market clearing price which reduces costs in the short term, thereby increasing allocative efficiency[11].
- If demand response at times of high wholesale pool price is sufficient and consistent, it can also affect the longer-run investment decisions of the generation sector, an example of increased dynamic efficiency.
- Similarly, reliable availability of demand response in specific quantities at a more localised level can also improve the utilisation of network assets and potentially defer capital expenditure for additional network infrastructure, another example of a shorter term gain in economic efficiency in the form of improved capital allocation.
- However, where the change in demand is persistent[12], it can also change the magnitude and shape of the load duration curve into the future which can change the amount and type of both generation and network infrastructure needed over the longer term, and thereby contribute to dynamic efficiency.

The assessment of various options for facilitating increased DSP should consider the impact of each option on both allocative and dynamic efficiency.

6.2 Equity

Equity is an important consideration in all public policy debates. However, Ausgrid considers that equity considerations should take place after the most efficient policy option from a NEM wide perspective has been identified. A consideration of equity issues prior to selection of an option on efficiency grounds may end in selection of an option that costs the market more overall but benefits some sectors of the market at the expense of others.

Any mechanism that enables DNSPs to promote more DSP could have an impact on costs to networks which must eventually be paid for by customers (although this will be offset by the supply chain benefits over time). It is therefore in all parties' interests that the most efficient option overall is chosen. Once an option is selected, equity should be considered in the design of the mechanism itself in terms of sharing of benefits between networks and customers.

If network prices rise as a result of an incentive payment, this uplift should not represent the total value of the DSP benefit to the market. If it did, it would mean that the total benefits of additional DSP would go directly to the network and those end-use customers who provide the DSP, but the remaining bulk of the customer base would receive no value from these initiatives. While the incentive might act to remove what otherwise might be characterised as a dead weight loss in economic terms, it represents a transfer of this benefit to networks and participating customers at the expense of some of the benefits flowing to customers in general. This is clearly unacceptable. It is important, however, that there is some sharing of the benefits between networks and customers in order to incentivise the former and improve outcomes for the latter, but the relative amount of benefit that flows to networks and customers should be the subject of independent review.

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11 The extent of those costs reductions and the degree to which they result in net cost reductions as compared to transfers between parties may be constrained by several factors as discussed in Section 2.4.

12 That is, where it is the result of a change in the operating characteristics of an end-use technology or the thermal resistance characteristics of a building envelope.

The consideration of outcomes between customers will also be a necessary consideration. However, Ausgrid argues that this matter will be assessed by networks when setting pricing strategy designed to recover revenue including the incremental element that is attributable to new DSP initiatives. While equity considerations can be addressed with transfers after efficient pricing strategies have been set, this can be made easier though considering and understanding equity issues up front. Networks consider the equity implications of revenue recovery at every price change, are experienced in doing so and recognise that these issues are best addressed when detailed proposals are developed. Therefore, we have not specified equity implications in the evaluation of options at this stage.

6.3 Simplicity

Complexity leads to increased administrative and transaction costs and makes any mechanism more difficult to understand. This can have the effect of dulling the effectiveness because customers and market intermediaries find it difficult to understand and respond to rationally. It can also lead to confused messages to industry who, with limited management time may ignore opportunities because of the need to invest too much time and effort in understanding the complexity.

Simplicity is therefore a regulatory virtue that should be maximised. In some cases, more complex but economically sound concepts have been rejected in favour of simpler options based on this concept. Examples include postage stamp pricing and single state based market prices rather than multi node pricing, even though these latter approaches may be used in deriving the final, more smeared result.

On the other hand, the NSW D-factor incentive arguably suffers from being too complex. DNSPs need to deal with differential risk assessments, avoided distribution cost calculations, foregone revenue, exposure to lower future RABs, two year incentive recovery delays, and the peculiar differential application to WAPC calculations. Regulators have found it necessary to subcontract annual reviews to expert consultants, and external reviews by academic institutions have found it impossible to derive an accurate understanding of the results. All this required a substantial investment in developing the necessary knowledge and processes. It is arguable that this is one of the key reasons why some DNSPs have taken less advantage of the incentive than was expected.

Accordingly, options for facilitating DSP should also be examined for how easy they are for market participants and other stakeholders (including end-use consumers and third parties that are likely to be involved in delivering DSP technologies and services) to understand, implement and administer.

6.4 Likely Effectiveness

Effectiveness in this context is seen as the likelihood of the option being able to achieve a material change in the amount of economic DSP available and operating in the market. The amount of DSP activity engendered is an important consideration because, all other things being equal, there will be a preference to keep the number of mechanisms to as few as possible in order to avoid redundant set-up and administration costs, and potential stakeholder confusion.

Effectiveness itself will be determined by the degree to which the mechanism adequately mobilises relevant parties, which in turn requires that:

- the amount and certainty of return to the primary actor (the DNSP in this case), which can be shared with other third parties and participating end-use customers is adequate, and
- benefits are shared in a way that ensures all consumers enjoy a dividend from the wider efficiency gains.

In this regard, the ability for the mechanism to ‘capture’ (i.e., re-aggregate) the benefits that DSP provides to each of the individual portions of the supply chain is likely to be a useful indicator.

7 Options for harnessing the capabilities of DNSPs to deliver demand-side solutions

We have identified a number of options for harnessing the capabilities of the distribution networks to deliver demand-side solutions. We have reviewed a range of current mechanisms and identified several new or adjusted concepts.

7.1 Current mechanisms

There are several mechanisms currently operating in the market that require, permit or encourage DNSPs to undertake activities that promote demand side participation. A detailed review of the theoretical and actual performance of these mechanisms is included as Appendix B.

7.1.1 DSP as an alternative to planned network augmentation as required under the Regulatory Investment Test (RIT)

The Rules require DNSPs to actively and transparently consider non-network alternatives to augmentation projects that are needed to meet growth in peak demand. Funding for the non-network alternatives is expected to be derived from within the DNSP's existing revenue stream due to the offsetting benefit of reduced or delayed capital spending.

This mechanism provides a weak incentive within a regulatory period to the extent that the savings to the DNSP exceed the cost of the alternative measure.

While this appears to be an appropriate mechanism in theory, the outcomes have been poor. To a DNSP it appears primarily as a regulatory obligation rather than an opportunity, and the incentives are usually insufficient to overcome the barriers of unfamiliarity, lack of developed capability and increased risk of reduced revenue.

In the absence of additional incentives, the RIT process alone has resulted in virtually no DSP being brought forth.

7.1.2 The NSW *D-factor*

The D-factor provides additional incentive linked to the RIT process for the NSW DNSPs to engage in demand-side initiatives aimed at deferring area-specific augmentation projects. It provides a mechanism to increase revenues within a regulatory period and provides a level of incentive to overcome the effects of increased risk and revenue loss.

The D-factor enhances the effects of the RIT requirements, and has resulted in increased implementation of demand side options in NSW since its introduction. However, it remains limited in scope and can only be expected to impact a relatively small proportion of customers and locations.

In practice the effect has been small. The actual increase in revenues for Ausgrid for 2010-11 prices arising from the D-factor was only 0.1%. As noted previously, Ausgrid has implemented non-network alternatives in only one in ten of the potential opportunities reviewed over the past three years. Similar (or lower) levels have been evident in the other NSW DNSPs.

The D-factor, as currently configured is very complex (for both DNSPs and the regulator), has very limited reach and has failed to incentivise the development of substantial levels of DSP.

7.1.3 Demand Management Innovation Allowance (DMIA)

In its recent distribution determinations, the AER has generally provided an incentive in the form of an ex ante demand management innovation allowance (DMIA). The DMIA provides a small amount of funding on a use-it-or-lose-it basis to be spent on prescribed types of activities associated with innovative or broad-based demand management. The absolute amount allowed annually is generally very small - $1 million in Ausgrid's case – and insufficient to fund anything beyond early stage trials of new ideas.

This scheme is very simple to apply and very easy to understand. The concept is at least an acknowledgement that capability building is important, and that funding for innovation should be considered as necessary. However, the funding is trivial in size and was never intended to fund significant DSP activity.

7.1.4 Provision for expenditure on DSP within the regulatory determination

Energex, a Queensland DNSP, in its last regulatory proposal incorporated within its operating and capital expenditure building blocks a substantial and comprehensive DM project plan for the 5 year regulatory period. The focus of the projects covered a wide range of initiatives ranging from a short term “summer readiness“ program to long term investments in capability development.

This approach was made under the existing Rules and was highly effective in terms of outcomes as the AER approved both opex and capex allowances to undertake DM during the period. This allowance relating to demand management spending was much higher than anything that had previously been incorporated in a DNSP revenue determination. Importantly, Energex proposed a value of DSP relating to longer-term and upstream market benefits as a basis for the approval of their program and this was accepted by the AER.

By permitting expenditure on the basis of these wider benefits, the regulator implicitly allowed Energex to secure a portion of those benefits. In addition, Energex will still undertake localised demand management initiatives where they arise from RIT processes. Given the significant capability that will be established by the broad-based initiatives, this is also likely to be more effective.

A positive aspect of this approach is the fact that it has a high level of certainty, at least within the given regulatory determination period. Given that the regulator has accepted the existence of longer tem benefits to justify the expenditure, there is a reasonable expectation (providing benefits are delivered) that a future regulator would take a similar view. That said, there remains a risk that the regulator will not approve similar programs at the next regulatory review. This uncertainty will undermine the potential dynamic efficiency of the mechanism.

Energex has significantly increased its resourcing for these activities and is building upon existing successes in the use of distributed generation to manage short term risks and the development of and trialing of residential air-conditioner load control. The plan is wide ranging, but the largest expenditure items include:

- the broad-based rollout of voluntary load control for air-conditioning and pool pumps,

- energy efficiency, curtailable load and distributed generation program for business customers,
- community based energy efficiency and demand management, and
- promotion of conversion hot water systems to existing load control tariffs.

7.2 New or modified mechanisms

The current mechanisms in the market have been in place for some time in various forms. Despite their presence, the amount of DSP that has been brought about through these mechanisms is relatively small and has not generally reached levels that market commentators would consider to be economically efficient, as discussed at the beginning of this submission.

It is clear that there is an opportunity for the existing DSP mechanisms to be modified to reduce the obstacles to DSP, or to introduce an entirely new mechanism to promote more DSP in the market. Ausgrid examines the existing mechanisms and suggests modifications to those mechanisms below.

7.2.1 Market benefits test within RIT-D

Description

The AEMC has put forward a RIT-D similar to the RIT-T that applies in transmission. The RIT-D will explicitly allow DNSPs to include market benefits in the assessment of projects (including non-DM and other network alternatives) and includes within market benefits “changes in the parties’ costs, other than the DNSP’s; … any additional option value (where this value has not already been included in the other classes or market benefits) gained or foregone from implementing the credible option with respect to the likely future investment needs of the market; and changes in electrical energy losses”[13].

The RIT-D would therefore operate in a similar manner to the current regulatory investment test, but would allow distributors explicit access to market benefits to be included in analysis of business cases for DM. However, simply being able to consider the benefits does not enable proponents to access additional funds to cover costs of such projects within the regulatory period. The costs of the DM project still must be paid for through the difference between the value of deferred capital (return on and return off capital) included in the revenue allowance during the period, and the additional operating costs required (in addition to the allowance) to facilitate and operate the project. The business case for a network proposing a DM option is therefore effectively the same under the RIT-D as it is under the current investment test – savings within the framework must be sufficient to pay for the project, otherwise it does not proceed. At no point can a network access a separate funding stream to help pay for the project even though the benefits that may arise from the project may be spread through the market and more than outweigh the costs. The problem remains the same – the inability of DNSPs to access a share of market benefits in financial terms means that investment in DM projects will occur in fewer circumstances than might otherwise be the case (i.e. marginal cases will not be pursued). The inclusion of market benefits in the analysis of the business case does little to actually facilitate (i.e. fund) project implementation.

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[13] AEMC, *Review of National Framework for Electricity Distribution Network Planning and Expansion, Final Report*, 23 September 2009, p 59.

Assessment against principles

The RIT-D has the potential to perform well under dynamic efficiency criteria due to the fact that market benefits can be taken into account. However, the lack of separate funding for projects outside the capex deferral framework means that those benefits are unlikely to actually improve the commercial business case from the DNSP's perspective and therefore may not result in any incremental DSP activity being undertaken.

In simplicity terms, making a business case for a DM project is based on complex analysis and the consideration of market analysis will add a further layer of complexity to the task. However, given that the analysis of the business case is similar to that which currently exists under the building block framework, we think a modified framework would not significantly increase complexity.

In terms of effectiveness, the removal of the requirement that non-network options have a credible proponent and the involvement of other parties in the consultation process could increase the number and quality of DM options considered. However, like the regulatory investment in its current form, the application of this mechanism is limited to specific geographic focus for implementation which will necessarily limit the scale of DSP induced by this mechanism.

7.2.2 Provision for expenditure on DSP within the regulatory determination with deemed external values

The Energex approach of developing a program of demand side investments and incorporating these investments in the building block proposal has led to a significant level of funding being approved to pursue DM in Queensland. One of the most effective aspects of this approach was the value that Energex was able to calculate for upstream benefits that it incorporated into its businesses case analysis used to justify the DM programs to the AER. While this approach was effective, it is likely that distributors that attempt a similar approach in future will face scrutiny of the calculated value of benefits attributed to other sectors of the market.

As discussed in section 5.6, it is possible for a value of upstream benefits from DSP to be calculated independently. Ausgrid considers that an independent valuation of market benefits, particularly in the wholesale energy market would be beneficial to all participants. It would limit the review the AER undertakes to the DNSP business case itself rather than necessitate a debate about the appropriate values of non-DNSP benefits.

Valuation of upstream benefits could be undertaken by an independent party and reviewed periodically in a similar fashion to the way the WACC is reviewed every five years by the AER. This deemed value of upstream DSP benefits would streamline assessment of DM options for networks and regulators alike and not only lead to more DM projects being undertaken, would allow businesses to plan DM projects with confidence that can be included in its regulatory proposal.

A deemed value of benefits and the certainty that costs will be recovered through the building blocks will lead to significantly more DM projects being undertaken in the NEM. However, it should be noted that this mechanism has the potential to provide a one-for-one recovery of funds spent on DM, not an incentive payment per se, and could therefore fall victim to the same issues that faces DM in the market where networks are said to be biased in favour of known, quantifiable and reliable supply-side investment.

A possible modification to the Queensland approach might be a deemed share of the non-DNSP benefits that can be earned by network proponents as an incentive payment that could overcome the inherent biases against DM projects. As long as the benefits to the market are greater than the costs of the project (including the DNSPs share of benefits), the project is efficient and would have overall benefits to the NEM.

Assessment against principles

Estimation and provision of deemed values to be used for upstream benefits of DSP actions would simplify and add certainty to the use of this mechanism, which could be expected to increase its use and therefore its effectiveness. Similarly, inclusion of fixed benefit sharing would also simplify the use of this mechanism and could improve its attractiveness to the DNSP, and thereby its effectiveness. Provision of an appropriate business incentive could also improve the allocative and dynamic efficiency of the mechanism.

7.2.3 A simplified D-factor type mechanism to incorporate deemed value of up-stream benefit

The D-factor mechanism that applies in NSW provides a positive incentive for networks to pursue DM opportunities by providing a mechanism for in-period revenue adjustments that are in addition to the building block deferral benefits, and a mechanism whereby any reduction in energy volumes can be measured and any lost revenue recovered.

However, as mentioned in section 7.2, the NSW D-factor does not currently allow for consideration of upstream benefits of DSP and as a result, is limited in its scope to being focused on network costs and benefits only. It is also very complex and involves significant overheads in calculation and review of cost efficiency and DNSP benefit components for each project.

The proposed mechanism relates to the one discussed above, but provides for a similar deemed value approach to be applied within regulatory periods. Under this arrangement, the regulator would determine a deemed value for the non-DNSP benefits of DSP and a fixed share of those benefits would be claimable by the DNSP for verified DSP projects undertaken. This new D-factor mechanism would be paid under similar recovery provisions as the current approach.

There would be no need for assessment of avoided distribution costs or review of efficiency of project costs, as these would no longer form part of the mechanism. Instead, the incentive component (currently equal to project implementation costs capped by the avoided distribution costs) would be determined according to the deemed values for non-DNSP benefits.

The result would be that where there was an internal benefit to the DNSP, this would be added to the share of external benefits and the greater total benefit would make more DSP cost effective. It would also permit the DNSP to justify the implementation of longer term and more broadly based DSP where the main benefit came from the deemed component and internal benefits were longer term or difficult to quantify.

Again, this would facilitate a greater amount of DM projects to take place, and increase the level of DSP in the market – noting again, that once a capability has been established, it can be called upon multiple times for relatively small incremental cost.

Assessment against principles

The expanded scope made possible by changing the D-factor incentive component to one based on a share of wider supply chain benefits is likely to increase the amount of DSP pursued on behalf of the market and therefore would contribute to allocative efficiency. To the extent that the mechanism is committed to by the regulator, the scheme could contribute to dynamic efficiency over time.

The change to the manner of calculating the incentive component will make the D-factor much simpler, both in administrative terms and in terms of the clarity of the incentive to participate.

Further this forms a very effective complement to the use of a similar approach in the five-yearly determination process by adding the potential to develop projects and programs within the regulatory periods as well as at the commencement.

7.2.4 Extension of scope of DMIA

The final modification that might be contemplated for the existing schemes is a modification to the existing DMIA essentially to increase the amount of money that could be used for innovation, research and development from the relatively small amount of $1m revenue per annum for Ausgrid (less for other networks) to a much more significant fund.

An interesting example of a much larger fund being provided for innovation is the Smart Grid Smart City (SGSC) project that is being undertaken by Ausgrid and other partners on behalf of the Commonwealth Government. The SGSC project is essentially a learn-by-doing project and covers a range of activities including trials of smart grid technology, battery storage, distributed generation, smart meters and associated communications, and innovative pricing trials. The scope of the program is broad and has been set by the Commonwealth who are providing $93m of funding directly to the project. In-kind contributions are also being made by the partners to the project.

The objective of the project is essentially to generate a data set that can be used by market participants to judge the effectiveness of technologies and pricing strategies in managing peak demand, managing the network itself and influencing customer behaviour within their own environments. The scale of the project shows the scale of research that is required in the smart grid space but also demonstrates that good quality research of sufficient scale is expensive and will not occur in the currently regulatory framework in the absence of explicit and targeted innovation funding.

Similarly, in the UK, the regulator Ofgem has introduced an innovation fund where network operators bid for portions of £250m of innovation funding over a regulatory period. This mechanism has been introduced after review of the regulatory framework found that the framework did not support expenditure on innovation and as a consequence may have inhibited innovation taking place that could have benefits to the UK market.

Ausgrid considers that the Australian regulatory framework has also suffered from the same failure to support innovation, and companies that have pursued innovation despite the framework have taken significant regulatory risks in doing so (i.e. risk that regulators will not allow certain funding for projects). We consider that the SGSC initiative demonstrates that there is scope and potential for benefits in making the DMIA a more serious innovation fund than the current very small allowance, and benefits in providing continuity of the arrangements from period to period.

Assessment against principles

Making additional funding available under the DMIA would be expected to increase its dynamic efficiency as more and more innovative approaches to DSP could be investigated, demonstrated and implemented over time. In so doing, the effectiveness of the mechanism would be increased.

There is no reason to expect that expansion of the DMIA would affect either it simplicity or its allocative efficiency.

7.2.5 Peak demand performance incentive

As an alternative to modifications of existing incentive mechanisms, the AEMC might also consider creation of a new performance based incentive mechanism to be added to the regulatory framework.

Description

A performance incentive could be introduced designed to reward DNSP's for improvements in managing peak demand on their networks. The scheme would apply as a factor in the calculation of the weighted average price cap (WAPC) or revenue cap calculation in a similar way to the manner in which the NSW D-factor and STPIS factors apply. It would be indexed to an independently observable factor like peak demand growth or changes in load factor.

Under the scheme, DNSPs would undertake actions to promote demand side participation that leads to the desired outcomes of lower peak demands and improved load factors, and would claim incentives based on the achieved outcomes each year.

At the commencement of the scheme, the regulator would establish the key parameters under the provisions for Demand Management Incentive Schemes. The regulator would need to specify the measurement methodology for the objective index measure, establish the values to apply to the incentive, and develop the required reporting and assessment guidelines. The value of the incentive should be determined based on a percentage of the full range of benefits that reductions in peak demand can deliver, so as to provide a sufficiently large incentive to make it worthwhile for the DNSP, while ensuring that consumers see a net benefit.

Each year, the regulator would be required to review business's incentive claims and supporting documentation and approve the adjustments to revenues or X-factors.

A range of possible index measures have been proposed. These include:

- a comparison of actual, weather corrected peak demand compared to agreed forecast levels
- the level of improvement in annual load factor (again weather adjusted)
- an improvement in the load factor of only the top 50-200 hours of the load duration curve, where the extreme events have their most important effects (also weather adjusted)

It is important that the incentive be asymmetric – penalties for deterioration in a naturally volatile factor like top-end load factor would subject the DNSP to risks that it cannot control (i.e., it may penalise the DNSP for consumer's behaviour).

The decision to seek the incentive would need to be made by the DNSP in its sole discretion, but it would need to explicitly state at the commencement of a regulatory period that it intended to pursue the incentive. This would also protect against the incentive conditions being met due to factors other than the DNSPs efforts, thereby constituting a 'passive win' for the DNSP.

Operating costs would be excluded from calculations under the EBSS. Capital costs would be recognised in the regulated asset base. Where WAPC price control is in place foregone revenue compensation may also be necessary to remove disincentives due to revenue loss.

Assessment against principles

The incentive would perform well against allocative efficiency criteria. Participants would be better off, and the incentive has the potential to make the DNSP better off.

The incentive would perform well against dynamic efficiency also. Monetisation of upstream benefits and the ability to offer a standing price signal into the market should provide a better base for customers to make DSP investment decisions.

This mechanism, although simple in design, may be quite complex in implementation, as it is difficult for the DNSP to accurately predict the impact of DM activities on weather-corrected peak demand or load factor. This uncertainty about outcome is likely to dampen DNSP interest in undertaking the effort of pursuing DM opportunities, particularly if the financial value of the incentive is not material. For example, the DNSP would need to track costs and weather-correct all load data to measure the impact on the load factor at the top end, develop a capability for forecasting the likely impacts of DM projects and normalise for other factors so as to be confident that actions undertaken under such a scheme were rewarded.

The effectiveness of this scheme is difficult to assess and may be strongly influenced by the relative risk DNSPs perceive from their perceived ability to recover costs incurred in pursuing the incentive, the possibility of penalties being imposed (if any), and the likelihood of continuity in application of the mechanism in future periods.

The incentive attached to the performance measure would need to include a share of supply chain benefits to ensure it motivated more than the business as usual level of DSP. The deemed value of upstream benefits could also be applied in this context which would act to simplify this aspect of the mechanism (see section 7.2.2 above).

8 Conclusions and Recommendations

It is clear that there is room for changes to market and regulatory mechanisms to encourage greater demand side participation in the market. There are potential benefits along the supply chain that are currently not being captured and as a result opportunities to deliver lower energy service costs to consumers are being missed.

The presentation of more cost reflective prices to customers is a necessary element in improving this situation but it is not practical to fully reflect the complexity and volatility of the real marginal cost drivers and customers are not in a position to respond to the level of complexity involved.

The key problem is that individual market players are currently only able to focus on the private benefits from any activity to promote changes in demand when establishing a business case for action.

A mechanism that would overcome these issues is necessarily regulatory in nature, and DNSPs are in the best position to act on the community's behalf to implement demand side measures, integrate the full range of benefits and share them with customers.

Providing DNSPs with a business incentive to pursue broad-based demand side participation that is designed to unlock benefits along the entire energy supply chain is the most efficient practical option to expand the use of DSP in the NEM to more efficient levels.

Based on our assessment of the issues and possible remedies, Ausgrid recommends that the AEMC consider the following options to amend the regulatory framework to achieve this outcome:

- Establish and recognise a deemed value for the benefits of reduced peak demand in the transmission and generation sectors of the market as a legitimate additional element of justification for DSP spending proposals in the five year revenue determinations for DNSPs
- Design an in-period mechanism to adjust DNSP revenues (similar to the way D and S factors currently operate) that would provide a share of the benefits that accrue to the community for demand management initiatives. This would provide a business incentive to DNSPs undertake both localised and broad-based demand side measures based on the combination of their internally determined benefits plus the deemed transmission and generation value
- Expand the DMIA scheme to provide a realistic quantity of funding to enable DNSPs to explore, innovate and develop new and better ways to encourage efficient demand side participation.
- Consider introduction of a peak demand performance incentive to provide an incentive payment to DNSPs based on improvements in an observable, objective factor like peak demand or load factor.

We look forward to working with the AEMC to further develop and refine these options as the review proceeds.

APPENDIX A: DEMAND MANAGEMENT SCREENING TEST EXAMPLE

DEMAND MANAGEMENT SCREENING TEST

Establishment of SOPA 132/11kV Zone Substation

Current Supply Arrangements

The Sydney Olympic Park precinct is currently supplied by 11kV feeders from Homebush Bay and Flemington zone substations. Auburn and Lidcombe zone substations are located nearby and load has been transferred from these zones to Flemington and Homebush Bay zones in the past.

Homebush Bay zone substation was designed as a three transformer 132/11kV zone substation, although it is currently equipped with two 50MVA transformers. The licence capacity is 67.8MVA in both summer and winter and is limited by the requirement to not exceed the substation firm rating by more than 88 hours in a year.

The capacity of Flemington zone substation is limited by the incoming underground feeders in summer and the rating of the four transformers in winter. Its licence capacity is currently 114.7MVA in summer and 119.3MVA in winter, based on the requirement to not exceed the substation firm rating by more than 88 hours in a year. Flemington zone substation will have its licence capacity reduced to 77.7MVA in summer and 82.7MVA in winter due to a change in the rating policy for 132/11kV four transformer substations.

Supply Capacity and Demand Forecast

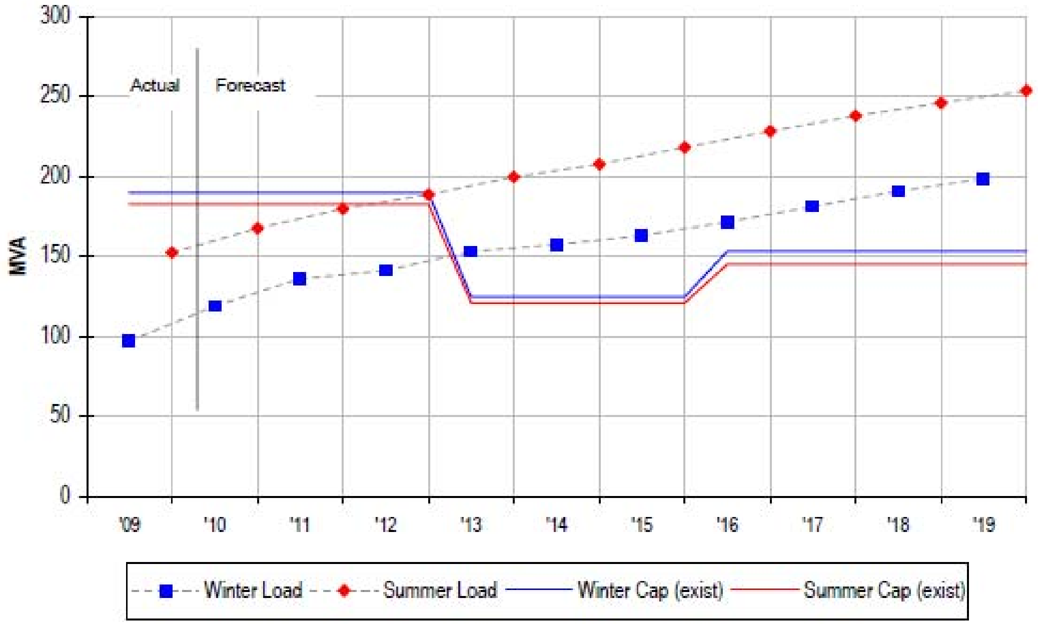
Sydney Olympic Park Authority (SOPA) has existing loads of 15MVA on Flemington and Homebush Bay zones. SOPA has confirmed expected spot load increases of 26MVA, with a further 20MVA proposed. In addition, a proposed multi-purpose development west of Sydney Olympic Park has confirmed an initial requirement for 3MVA, and is expected to ultimately require approximately 30MVA.

Approximately half of the 11kV switchgear at Flemington zone substation is scheduled to be replaced by 2016 due to asset age and condition. This requires a temporary load transfer of approximately 45MVA away from Flemington zone substation between 2013 and 2016 to enable half of the 11kV busbar to be taken out of service. During this time the effective capacity of Flemington zone will be reduced to 53.2MVA in summer and 54MVA in winter.

In the following chart, the capacity is the sum of the licence capacities of Homebush Bay and Flemington zone substations. The load is the diversified sum of the loads at the two zones, and includes an estimate of the most likely scenario for proposed new spot loads in the area.

The load is forecast to exceed the licence capacity in summer 2012/13 by approximately 6.0MVA.

Chart of actual / expected demand vs supply capacity for the combined load on Homebush Bay and Flemington zone substations



Supply Strategy Options

Two supply side options are available to increase the capacity to the area:

- Establish a new 132/11kV SOPA Zone substation with two 50MVA transformers, and a licence capacity of approximately 78MVA. The cost of this project is estimated at $41 million.
- Install a 3rd transformer at Homebush Bay zone substation, resulting in an increase of its licence capacity to approximately 127.1MVA in both summer and winter. The cost of this project is estimated at $5.6 million.

Of these two options, only establishing a new SOPA zone substation will provide sufficient capacity to supply the forecast demand. Accordingly, the preferred supply side solution is to establish a new 132/11kV SOPA zone substation before winter 2013.

In addition, if all anticipated spot load increases occur, the load supplied by the new SOPA zone substation will exceed its licence capacity in summer 2014/15, at which point, installation of the 3rd transformer at Homebush Bay zone substation will also be required.

To meet the required completion date of winter 2013, a decision on this investment must be made by September 2010.

Required Demand Management Characteristics

To defer the need for an investment entirely would require a demand reduction exceeding 70MVA, which represents over a third of the load currently supplied from Flemington and Homebush Bay zone substations. Cost effective demand reductions are unlikely to be available in this magnitude.

Alternatively, if demand could be reduced by 18.3MVA in summer 2013/14, installing the third transformer at Homebush Bay zone substation would provide sufficient capacity to service the demand. SOPA zone substation would then not be required until summer 2014/15.

If, in addition to this, demand could be reduced by 25.8MVA in summer 2014/15, SOPA zone substation would not be required until summer 2015/16.

From summer 2016/17, Flemington zone substation is returned to service in its four transformer configuration following completion of the switchgear replacement project. This will increase the capacity of the system by approximately 25MVA. As a result, if demand could also be reduced by 36.3MVA from summer 2015/16 onwards, SOPA zone substation would not be required until summer 2018/19.

The demand reduction requirements expressed in MVA and as a percentage of the system load are summarised in the following table. These figures assume installation of a third transformer at Homebush Bay zone substation by winter 2013.

Season		Summer 13/14	Summer 14/15	Summer 15/16	Summer 16/17	Summer 17/18
Required demand reduction	(MVA)	18.3	25.8	36.3	21.1	30.9
	% of system load	9%	12%	17%	9%	13%

The savings achieved by deferring SOPA zone substation until 2014/15 is $3.4 million, or $184/kVA, which is moderate. However the required 18.3MVA reduction required to achieve this deferral is high in absolute terms and relative to the system load. The deferral value for each of the scenarios described above are summarised in the following table.

SOPA need in:	Required demand reduction	Total saving (real 2010 dollars)	$/kVA
Summer 14/15	18.3MVA	$3.4 million	184
Summer 15/16	25.8MVA	$5.7 million	220
Summer 18/19	36.3MVA	$11.7 million	322

Given the high demand reduction requirement and moderate savings from deferral, it is not considered reasonable to expect that demand management options could enable implementation of an alternative lower cost supply side solution.

However, it has been identified that there is approximately 6.0MVA of load at risk in summer 2012/13, prior to the expected completion date for the proposed supply side solution. Analysis indicates that the value of reducing this risk completely is approximately $600/kVA, so it is likely that demand management options could cost effectively mitigate all the risk in that season. Given the high uncertainty around demand forecasts for summer 2012/13 at this point in time, it is recommended that this opportunity be re-analysed after the latest summer forecast is released in the second half of 2011.

Recommendation

Based on this analysis it is not considered reasonable to expect that it may be cost-effective to enable an alternative, lower cost supply-side solution by implementing demand management strategies.

However it is likely to be cost effective to implement demand management options to reduce load at risk in summer 2012/13. It is recommended that this opportunity be reviewed when the latest summer demand forecast is released in the second half of 2011.

APPENDIX B - DETAILED REVIEW OF EXISTING MECHANISMS

1.1 DSP as an alternative to planned network augmentation as required under the Regulatory Investment Test (RIT)

Description

The Rules require DNSPs to actively and transparently consider non-network alternatives to augmentation projects that are needed to meet growth in peak demand. The mechanism is in effect an obligation that is used to determine the prudence and efficiency of supply-side projects where they proceed. The assessment of projects and demand side alternatives is administered primarily by the DNSP, but is reviewed in advance by the AER at the time of the regulatory determination. The performance of DNSPs is examined at the subsequent determination and exposed through transparency requirements under the Rules.

The feasibility of demand side options is decided by the DNSP with input from DSP project proponents at the time network augmentation is required. Implementation of a demand-side project can be undertaken directly by the DNSP or in conjunction with project proponents, contractors, and third parties including retailers and aggregators.

The purpose of the RIT is to identify options for resolving limitations in network capacity (including DM and other non-network alternatives) that maximise the present value of net economic benefit from a NEM wide perspective. Funding for DM projects implemented under this mechanism is provided by way of an incentive within the building block framework whereby the capex allowance is largely set on the basis of supply-side options, and DNSPs are encouraged to pursue demand-side options when it is economical to do so. Pursuit of a demand-side option requires assessment of both the capital and operating implications within the regulatory period (the allowances generally are already set with reference to the supply-side option). The DNSP keeps the servicing costs of the capital assumed to be spent (i.e. the capex allowance) for the remainder of the 5 year regulatory period. The benefit of avoided capital investment is received by the network for the remainder of the period, and then shared with customers subsequently as those costs are not added to the RAB and therefore not subsequently paid for by customers through future prices.

Additional opex incurred for non-network projects is spent by the DNSP in addition to the operating allowance. A demand-side project is only economical when the additional opex spent in the period is outweighed by the value of avoided capex in the period (return on and return of capital).

The additional opex is excluded from calculations of the Efficiency Benefit Sharing Scheme (EBSS), thereby removing deleterious interaction with that Scheme. However, to the extent that the non-network project is required to be funded in future periods through contract payments or similar, there is risk as to whether the regulator will continue to fund the required opex in subsequent periods.

This incentive is most likely to generate DM projects that have impacts *within* a regulatory period, and projects likely to occur at the beginning of the period so as to have more years within the period in which to recover the benefits of avoided costs.

Assessment against principles

This incentive performs well under the allocative efficiency criteria but is limited in scope. By definition, the mechanism will increase benefits to the NEM due to reduction in overall costs. No parties should experience higher costs. Participating customers and the DNSP experience benefits during the period initiatives are implemented under the mechanism, and all customers will experience benefits in subsequent regulatory periods. However, the relatively constrained reach of the mechanism means that only a relatively small proportion of customers and total system costs will be affected by this mechanism (i.e. only a finite number of local areas will require augmentation in any regulatory period and in only some of these areas will non-network alternatives be feasible).

This incentive performs adequately under the dynamic efficiency criterion, however, its performance is constrained by its limited scope over time. Benefits are not accessible to investors for more than five years at most, and therefore longer-term benefits are not included in the business case. The fact that the window for planning and implementing demand-side alternatives in each case is relatively short, and is not sustained over the longer term leads to high transaction costs and may reduce the ability of the mechanism to achieve impacts beyond low hanging fruit. Further, the lack of explicit regulatory commitment to honour contracted DM operating costs in future acts to inhibit DM projects towards the end of the regulatory period, particularly those with benefits in a subsequent period.

The incentive is relatively complex and scores poorly in terms of simplicity. The mechanism requires detailed investigations of the feasibility of DM in each application, situation-specific economic criteria, and geographically and time bounded implementation efforts.

The incentive properties of this mechanism are moderate at best in its current form. The inability to capture upstream financial benefits by the DNSP means that projects will be more limited than they might be under another mechanism.

In addition, the regulatory investment test makes no provision for the possible negative revenue impacts of DSP. To the extent that energy consumption (or any other tariff component) falls as a result of DSP, revenues may fall and this may disadvantage the consideration of certain types of DSP options. The regulatory test also enforces the substitution of opex for capex which provides no benefit to the DNSP, and potentially exposes the DNSP to some risks (for example, increased potential for STPIS penalties should DSP prove less reliable than marginally more expensive supply-side options). In summary, the regulatory investment test is more like a requirement than an incentive, and contains some serious unintended consequences for distributors that may make DM options considered under the test difficult to pursue from a business case perspective.

1.1.1 The NSW *D-factor*

Description

The D-factor provides additional incentive for the NSW DNSPs to engage in demand-side initiatives aimed at deferring area-specific augmentation projects. The D-factor works in conjunction with the inherent incentive properties of the building block framework and obligations[20], but is designed to address some of the more obvious flaws in the frameworks' application to

[20] NSW, the only jurisdiction where the *D-factor* has been implemented, has a planning requirement that DNSPs in the state must consider non-network alternatives for all network augmentation projects where it is reasonable to do so.

DNSPs. The D-factor provides explicit compensation for foregone revenue due to the implementation of non-network solutions[21], and operates as an opt-in mechanism from the DNSP's perspective. In its current design, the D-factor does not recognise market benefits.

Under the D-factor the DNSP can recover an incentive equal to the cost of the DM initiative (up to the value of the deferral that the initiative was designed to provide) and the sales revenue that it did not receive due to implementation of the DM measures. These incentives can be pursued outside of the 5-yearly assessment of the capital and operating cost building blocks which allows greater flexibility in its use.[22] Recovery of the incentive takes place two years in arrears via a marginal upward adjustment to the X-factor. The calculation of foregone revenue is quite complex, and the mechanism requires appropriate tracking of projects throughout the period and between periods to ensure that recovery in arrears occurs appropriately.

Through both recovery of both the incentive and foregone revenue, the D-factor provides a positive incentive to pursue DM activities (i.e. DNSPs can actually benefit financially by pursuing DM opportunities compared to the supply-side solution).

The scheme is administered primarily by the DNSP but requires annual reporting of claims by the DNSP and review of such claims by the regulator. The feasibility of projects is decided by the DNSP with input from DSP project proponents. Implementation of a demand-side project can be undertaken directly by the DNSP, or in conjunction with project proponents, contractors, and third parties including retailers and aggregators.

The DNSP has an incentive to use non-network approaches (including DSP) wherever they provide a lower cost than the assumed capex servicing costs allowed in the price determination. Additional opex incurred for non-network projects is excluded from calculations of the EBSS, thereby removing deleterious interaction with that scheme.

Achieving a deferral of network investment at lower costs requires that the total cost incurred by the DNSP for the non-network solution – including any financial incentives paid to end-use customers, or incentives or fees paid to third parties for services or equipment – must be less than the deferral value of the network augmentation. That value is determined by the change in the present value of the augmentation over the period of time it is deferred (similar to the regulatory investment test discussed above).

Assessment against principles

The D-factor performs well under principles of allocative efficiency but is limited in scope. No parties should experience higher costs in the longer term. Participating customers and the DNSP should experience benefits during the period in which initiatives are implemented, and all customers should experience benefits in subsequent periods through avoided capital. However, the relatively constrained reach of the mechanism means that only a relatively small proportion of customers and total system costs will be affected by this mechanism (as only a finite number of

[21] Note that the *D-factor* is currently only available in NSW. If the mechanism were implemented throughout the NEM, compensation for foregone revenue would probably be removed in jurisdictions in which a revenue cap form of regulation is used in order to avoid double compensation.

[22] Without this mechanism, DNSPs that pursue DM would have to have all the DM information to hand to incorporate into their building block proposal. For many distribution projects, the timeframes involved are too far in advance and cannot be realistically accommodated.

local areas will generally be scheduled for augmentation in any regulatory period and in only a portion of these will non-network alternatives be feasible).

The uplift required to provide compensation to the DNSP for costs incurred and foregone revenue imposes costs on all customers, however the impact is spread over the entire customer base, and as a result, the uplift on prices is very small and does not represent a material impact on non-participants' bills.[23] In the longer term, any deferral achieved results in network prices being lower than they otherwise would have been which benefits all network customers.

The mechanism performs adequately with regard to dynamic efficiency, but like the RIT, it represents only a temporary improvement in each case. Despite the fact it is temporary the D-factor does incentivise innovation as the DNSP captures the deferral benefit (i.e. incremental cost reduction) until the next five-year regulatory reset. Following the reset, the benefit is transferred to customers. The balance between provision of benefits to DNSPs and customers is an equity consideration that should be determined by policy makers when assessing the design of the scheme.

The D-factor is similar to the RIT above, but adds a further layer of complexity with regard to recovery of costs. The mechanism requires detailed investigations in each DM application, situation-specific economic criteria, and geographically and time bounded implementation efforts. The calculation of lost revenue is also complex, and the D-factor has suffered from errors when it has been applied to businesses between regulatory periods.

The D-factor's effectiveness has been limited by the relatively constrained timeframe for planning and implementation of DM projects, and its limited geographic scope. However, where applicable, the D-factor has been successful in providing a positive incentive for DM that has acted to defer network capital.

Consideration of supply chain benefits is not a feature of the current D-factor arrangements, but this could be added to the scheme in future to increase the scope of the mechanism.

1.1.2 Demand Management Innovation Allowance (DMIA)

Description

Chapter 6 of the National Electricity Rules (NER) allows the AER to develop and publish a demand management incentive scheme (DMIS) to provide incentives for DNSPs to implement efficient non-network alternatives or to manage the expected demand for standard control services in some other way. To date, the AER has generally provided the incentive contemplated under the DMIS in the form of an ex ante demand management innovation allowance (DMIA). Under the DMIA, the total amount recoverable under the allowance within a regulatory control period is capped at an amount broadly proportionate to the size of the DNSP's average annual revenue requirements in the previous regulatory control period, and distributed evenly across each regulatory year of the regulatory control period. The absolute amount allowed annually is generally not very large - typically $1 million or less.

The DMIA arrangements are different in different jurisdictions based on the regulatory framework in use. In jurisdictions that use a weighted average price cap the DMIA may allow recovery of

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[23] The D-factor that applied to Ausgrid's X factor in FY11 was 0.001.

foregone revenue. This was the case in the 2009-14 determination for NSW and the ACT. By contrast, in jurisdictions in which a revenue cap is used (for example, Queensland), compensation for foregone revenue is not provided.

The DMIA is provided on a use-it-or-lose-it basis, and is in addition to any opex and capex allowances for demand management projects approved in the AER's distribution determination for a DNSP. The amount and details of the DMIA are determined by the AER. The DNSP is free to spend the allowance in ways in which it believes are consistent with the purposes for which the allowance is intended. The DNSP has to report annually to the AER on the specific projects for which DMIA funds were expended and the regulator assesses whether those projects are consistent with the purpose for which the allowance was provided. Expenditure that is not approved by the regulator in this ex post review must be funded from non-DMIA opex allowance. Within the application of the criteria discussed above, the DNSP is free to determine whether, for what purpose, and to what extent to involve third parties in the activities funded under the DMIA.

Funding is provided by the regulator as an explicit category of opex in the DNSPs allowed costs.

The incentive is provided directly to the DNSP for activities that will increase its capabilities in various aspects of DSP planning, implementation, management and evaluation. Due to its focus on capability building and the AER's stated view that it "considers that the primary source of funding for demand management in a regulatory control period should be the forecast operating expenditure (opex) and capital expenditure (capex) approved in the DNSP's distribution determination under chapter 6 of the NER", it is likely that the DMIA is intended to be a temporary mechanism.

Assessment against principles

The mechanism is intended to be (at least) economically neutral because "in developing and implementing a DMIS, the AER must have regard to [among other things] the need to ensure that benefits to consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme for DNSPs"[24]. To the extent that the mechanism incentivises the DNSP to undertake DM activities thought to be efficient, the DMIA should improve allocative efficiency. Over time, the scheme is intended to be significantly positive (i.e. dynamically efficient) as the intention is to build DNSPs' capabilities and experience in identifying, planning and implementing cost-effective DSP.

This scheme is very simple to apply and very easy to understand. It is equivalent to a research and development budget. However, the DMIA is difficult to assess and is relatively small in size relative to DNSPs overall expenditures which limits its effectiveness.

Re-aggregation of benefits is possible within the business case developed for individual initiatives undertaken under the mechanism, but is not explicitly provided for.

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[24] AER, *Demand Management Incentive Scheme, Energex, Ergon Energy and ETSA Utilities 2010 – 15, Final Decision*, October 2008, p 2.

1.1.3 Provision for expenditure on DSP within the regulatory determination

Description

Energex, a Queensland DNSP, in its last regulatory proposal approached the demand management issue in a different manner to that which had previously been taken. Energex incorporated within its operating and capital expenditure building blocks a substantial and comprehensive DM project plan for the 5 year regulatory period. The focus of the projects covered a wide range of initiatives ranging from a short term "summer readiness" program to long term investments in capability development. Energex further identified that within-period substitution of non-network solutions for capital expenditure under the RIT would be additional, but funded within the regulatory allowance.

This approach was made under the existing Rules and was highly effective in terms of outcomes as the AER approved both opex and capex allowances to undertake DM during the period. This allowance was much higher than anything that had previously been incorporated in a DNSP revenue determination. Importantly, Energex proposed a value of DSP relating to longer-term and upstream market benefits as a basis for the approval of their program and this was accepted by the AER.

By permitting expenditure on the basis of these wider benefits, the regulator has implicitly allowed Energex to secure a portion of those benefits. Customers will be required to fund the activities but, as long as the benefits materialise, they will be better off to the extent the benefits exceed the costs.

It is likely that Energex's circumstances of strong growth in peak demand, their strong track record of developing and undertaking DM, and jurisdictional requirements all played a part in convincing the AER that they could deliver outcomes using DM during the period.

Assessment against principles

This approach will improve allocative efficiency where the business case is justified. This is because the consumers will be better off to the extent that the DSP undertakings of the scheme will have produced lower costs than the supply-side options they replaced. The DNSP may also have achieved benefits if a margin on the DSP activities was built in.

To the extent that these conditions are met and that the regulatory approach to these matters remains constant, this approach should have positive impacts on dynamic efficiency as well.

The fact that this mechanism potentially allows incorporation of the full scope of DSP benefits within the NEM will allow more DSP to be captured in terms of its absolute amount, its geographic location and its persistence over time.

Another positive aspect of this approach is the fact that it has a high level of certainty, at least within the given regulatory determination period. Given that the regulator has accepted the existence of longer tem benefits to justify the expenditure, there is a reasonable expectation providing benefits are delivered, that a future regulator would be likely to take a similar view. That said, there remains a risk that the regulator will not approve similar programs at the next regulatory review. This uncertainty will undermine the potential dynamic efficiency of the mechanism.

More problematic in the near term is the fact that this approach requires a relatively high level of capability in DSP in order for it to be undertaken by the DNSP. Only a DNSP with a track record of successful implementation would design an investment program that relied on these outcomes to meet its supply obligations. Developing DSP program plans and offers several years in advance is not something most DNSPs are familiar with or experienced in. It is therefore likely to be some time before DNSPs NEM-wide use this approach as a primary planning tool in their regulatory proposals.