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Mr John Pierce
Chairman
Australian Energy Market Commission
Via email: submissions@aemc.gov.au

Dear ~~Mr Pierce~~ John

I am pleased to make this submission responding to the Australian Energy Market Commission's Discussion Paper on Strategic Priorities for Energy Market Development.

Firstly, I wish to commend the Commission for initiating a public discussion on priorities for market design in the Australian energy market. I believe that it will provide valuable information for helping to structure the AEMC's future work program.

This submission is largely aimed at providing Ausgrid's perspective on Strategic Priority 2: "Building the capability and capturing the value of flexible demand". Ausgrid feels that the emphasis on flexible demand is particularly important for improving efficiency in the national electricity market. In particular, there is growing opportunity to manage the costs of peak demand growth through a range of actions, in particular through new pricing regimes – assisted by new technology.

However, current regulatory arrangements are not facilitating significant peak demand management by distributors. To address this, we propose consideration of new, long-term incentive mechanisms to encourage more peak demand management. The attached submission provides a discussion of such proposed incentive mechanisms.

If you wish to discuss any aspect of this submission please do not hesitate to contact me or Mr Peter Birk, Executive General Manager – System Planning & Regulation on 02 9269 2611.

Yours sincerely

George Maltabarow

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Managing Director

Enclosed

Ausgrid

AEMC review of strategic priorities for Energy Market Development

20 May 2011

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Executive Summary

The AEMC has asked for responses to its first Discussion Paper on Strategic Priorities for Energy Market Development. Ausgrid is pleased to respond to this discussion paper and supports the priorities the AEMC has proposed.

Ausgrid strongly supports a focus on flexible demand and peak demand growth as an important strategic priority for the Australian electricity industry. The AEMC's second strategic priority focuses on building the capability and capturing the value of flexible demand and peak demand reductions.

Peak demand growth drives system augmentation costs across the whole electricity supply chain over the long term. Peak demand has been growing faster than energy use in the NEM and this means that the average $/kWh cost to meet the peak is increasing. Small customers (typically residential) are driving peak demand growth and a deteriorating load factor in Ausgrid's network area. The consumption decisions of these customers are made in the absence of price signals that show the true costs of their consumption decisions.

There is an opportunity to manage the costs of peak demand growth through a range of demand management actions. Reducing peak demand growth provides an opportunity to increase the efficiency of the production and transport of electricity. Over the long term this can reduce the costs associated with expanding all parts of the supply chain. While more work needs to be done to quantify the possible benefits of reducing the growth of peak demand, our initial estimates suggest that the opportunity could be around $2.6 – 4.5 million per megawatt of avoided peak demand growth across the supply chain. The sources of potential value from peak demand management vary by sector within the electricity industry.

There is a range of actions which are available to reduce the growth in peak demand including more cost reflective pricing, curtailable/controllable load, energy storage, alternative sources of energy and energy efficiency and conservation. These actions have been trialed and implemented to differing degrees in Australia and overseas. Pricing options in particular have the potential to reduce the growth of peak demand as they send a signal to electricity consumers about the cost of their consumption at a particular time. Pricing trials in Australia and overseas have shown that technology assisted pricing regimes have the largest effect on peak demand. Most pricing trials have focused on residential customers, but there may be greater potential for larger reductions in peak demand at critical times from industrial and commercial customers.

There are challenges and barriers which are impeding the implementation of significant peak demand in the NEM. The vertically disaggregated nature of the Australian energy market means that the incentives for peak demand management are split between different parts of the supply chain: no one entity can capture all the benefits of peak demand management. There are regulatory challenges for distribution and transmission entities to pursue large scale demand management, some technical barriers to demand management and market-based barriers.

The structure of the distribution regulatory regime provides little incentive for the implementation of demand management. Risk management considerations and 'business culture' mean that distributors prefer network augmentation solutions to demand management solutions. The D-factor is available to distributors in NSW only, and provides an incentive for demand management solutions to respond to short-term network constraints. While the D-factor has been a very valuable learning tool and has facilitated numerous demand management initiatives since it was introduced in 2004, it does have a number of shortcomings. In particular, it does not promote broad-based, longer term demand management, does not generally take account of the value chain benefits of demand management and is very complex to implement.

Ausgrid proposes that a new, explicit incentive mechanism should be developed to provide distributors with a positive incentive to implement broad-based, longer term peak demand management. There is a strong argument that distributors are the appropriate part of the supply chain to be given an additional demand management incentive. Distributors are regulated entities and so can be given new incentives more easily than other parts of the value chain. They also have access to each customer in an area.

Ausgrid has begun developing options for possible new incentive mechanisms for the distribution sector. Any new incentive should specifically target peak demand growth over the long-term and should allow for broad-based demand management initiatives including more cost reflective pricing. Incentive payments should allocate most of the benefit of avoided peak demand growth to customers but should be sufficient enough to overcome the risks and other business culture impediments to implementing peak demand management, particularly in terms of supporting the use of new technology. Ausgrid considers that a new incentive mechanism with these characteristics would overcome the shortcomings of existing incentives and barriers to demand management and could reduce system augmentation costs over the long term. Ausgrid is continuing to develop these options for new incentive mechanisms and looks forward to participating in the AEMC's Stage 3 Review of Demand Side Participation in the NEM.

While the focus of Ausgrid's submission is on strategic priority 2, we also offer brief comments on the other two proposed strategic priorities.

Introduction

The AEMC has asked for responses to its first Discussion Paper on Strategic Priorities for Energy Market Development. Ausgrid is pleased to participate in this review and supports the priorities the AEMC has proposed.

Building the capability and capturing the value of flexible demand has been identified as the AEMC's second proposed strategic priority. Ausgrid recommends that investigation and promotion of peak demand management should be a high priority in the further development of the Australian energy market. Section 1 of this document addresses this proposed strategic priority in detail, and forms the core of Ausgrid's submission.

The AEMC has identified the development of a regulatory and market environment that rewards economically efficient investment as its first proposed strategic priority. Ausgrid supports the achievement of economic efficiency throughout the electricity supply chain and considers this strategic priority is appropriate. Section 2 of this document presents Ausgrid's views on this proposed strategic priority.

In the third strategic priority the AEMC seeks views on is whether the current framework for the provision of transmission services facilitates making efficient use of the existing network and delivers efficient and timely investment in new transmission. A continuing discussion of the economic regulation framework for transmission and distribution network service providers is of value, although Ausgrid believes that the current framework is in general working well. Incentive regulation requires a reasonable time frame to allow incentive schemes to work as businesses take time to understand and respond to these schemes. Section 3 of this document outlines Ausgrid's views on this proposed strategic priority.

All three of the proposed strategic priorities refer to efficiency. The AEMC points out in its discussion paper that economic efficiency can be considered in three ways: allocative efficiency, productive efficiency and dynamic efficiency.[1]

Allocative efficiency means allocating resources to the consumers who value them most. Ausgrid already has in place differentiated pricing aimed at shifting load and resource allocation. We are considering the possibilities associated with changing pricing structures to introduce more cost reflective pricing, including capacity based pricing. This has the potential to further improve the allocative efficiency of distribution network use in particular.

Productive efficiency means minimising the costs of producing outputs. Overall, energy efficiency initiatives can improve the productive efficiency for consumers of energy by allowing them to produce more with less energy. Flexible demand and non-network solutions that are more cost effective than capital investment have the potential to improve productive efficiency. Demand management initiatives which reduce the growth in peak demand have the potential to minimise system augmentation costs over the medium to long-term. This would improve productive efficiency of electricity infrastructure across the whole supply chain.

Dynamic efficiency refers to the promotion of innovation and technological change to facilitate more productive use of resources, including discovering new resources of different uses for existing resources. New technologies such as the smart grid, smart meters, renewable energy technologies and energy storage devices will likely change the electricity sector dramatically. Peak demand management and energy efficiency can encourage dynamic efficiency where they create the scope and incentives for future change. Enhanced regulatory incentives for peak demand management will form part of the regulatory change needed for the potential of new technologies to be realised.

Ausgrid suggest that a focus on peak demand growth and peak demand management has the potential to improve all three of these aspects.

The next section sets out our perspective on strategic priority 2.

[1] Strategic Priorities for Energy Efficiency, Discussion Paper, AEMC 2011, p. 13

1 Building the capability and capturing the value of flexible demand

The AEMC's second strategic priority focuses on building the capability and capturing the value of flexible demand and peak demand reductions. The AEMC notes that cost effective demand side participation in the electricity market can help reduce the need for more generation and network investment to meet forecast increases in peak demand. Ausgrid strongly supports a focus on flexible demand and peak demand growth as an important strategic priority for the Australian electricity industry.

This section:

- **Presents the problems** caused by growing peak demand, quantifies peak demand and energy growth across the NEM and in Ausgrid's network area, and identifies drivers of this peak demand growth (Section 1.1)
- **Estimates the size of the opportunity** peak demand management presents to improve the efficiency of the electricity system and minimise future system augmentation costs and outlines types of demand management actions that are available (Section 1.2)
- **Describes the challenges** to implementing peak demand and capturing the potential value in terms of regulatory, technical and market based challenges (Section 1.3)
- **Proposes options for a new demand management** incentive for distributors to overcome existing barriers to implementing demand management (Section 1.4)
- **Suggests next steps** to continue the work on promoting improvements to demand management (Section 1.5).

Terms such as demand management, demand response, peak demand reduction, energy efficiency, energy conservation and non-network alternatives are sometimes used interchangeably in public discourse. It is important to be clear about the distinctions between them and Appendix 1 provides detailed descriptions and definitions of the all commonly used terms in this area. This submission uses the term peak demand management to refer to measures which reduce the growth of peak demand.

1.1 Background: Peak demand growth drives costs over the long term

Over the long term, peak demand growth drives system augmentation costs across the whole electricity supply chain and will drive cost increases in meeting electricity demand. The cost of meeting peak demand is generation and network capacity that is used infrequently. The growth of peak demand is driven by consumption choices made by customers in the absence of price signals that show the true cost of their choices.

1.1.1 Peak demand is growing faster than energy use across the NEM

As the AEMC has noted, peak demand has been and is forecast to continue to grow faster than average energy use in the NEM. This is of concern because over the long term, peak demand growth drives system augmentation across the whole electricity supply chain. Faster growth in peak demand than energy use means that the average $/kWh cost to supply customers is increasing.

Across the NEM peak demand has grown by 3.5% per annum since 2005 while energy use grew by 1.2% per annum. Peak demand is forecast to grow by 2.6% per annum to 2020 while energy use is forecast to grow by 2.1% per annum.

These NEM-wide averages mask significant regional variation in peak demand and energy growth rates. Queensland is forecast to have the highest peak demand and energy growth rates to 2020 (4.2% and 3.9% per annum respectively).[2] By contrast, Victoria is forecast to have lower peak demand and energy growth (1.9% and 1.0% per annum respectively) but the greatest difference between those growth rates.

Within Ausgrid's area, weather corrected peak demand grew by 1.5% per annum from 2005 to 2010 while energy use grew by just 0.5% per annum. Energy use is forecast to ***decline*** by 1.4% per annum to 2019 while peak demand is forecast to continue to grow at 1.6% per annum.

This divergence in energy and peak demand growth rates means that system load factors are trending downwards (that is, worsening) across the NEM and in most states, and are forecast to continue to do so. Deteriorating load factors lead to less efficient use of installed capacity, particularly for transmission and distribution networks.

[2] AEMO: Electricity Statement of Opportunities, 2010.

Again, there is considerable regional variation in load factor. South Australia and Victoria have the lowest (worst) summer load factors in the NEM. South Australia's FY09 summer load factor was 45% and Victoria's was 52%.[3] At the same time Tasmania's load factor was significantly higher (better) at 85%.

Ausgrid's weather corrected 2011 load factor was 55.4%, down from 61.3% in 2001. Ausgrid's load factor is forecast to continue to deteriorate to 43.5% by 2019.

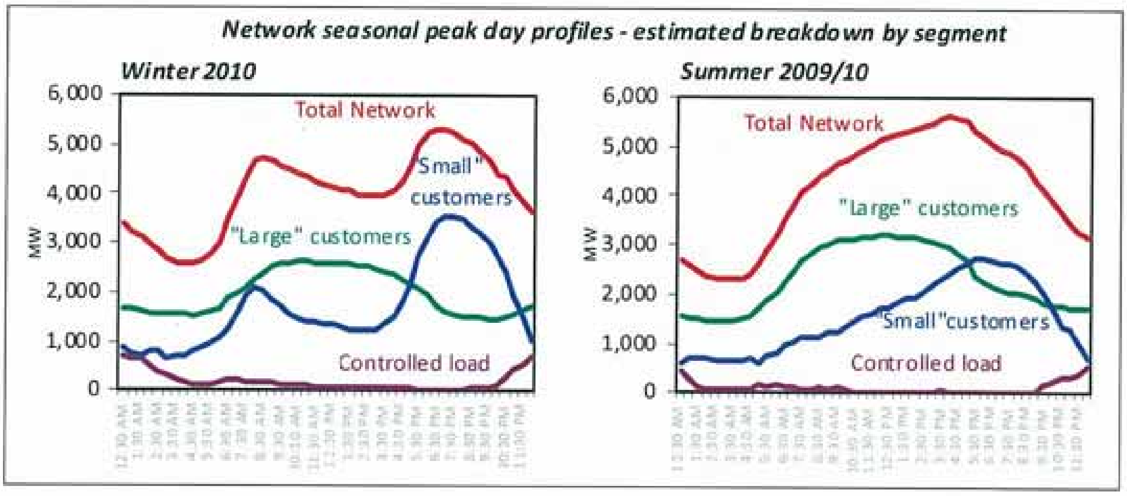
1.1.2 Small customers drive peak demand growth and deteriorating load factor

Commercial and industrial customers represent approximately 70% of demand and residential customers approximately 30%. Residential customers tend to have the greatest sensitivity to weather and therefore display significant variation in their peak demands on a daily and seasonal basis. Figure 1 shows that in Ausgrid's network area, "small" customers[4] contribute most to the peakiness of the load in both summer and winter. Small customers contribute 64% of the winter peak demand. In contrast, large customers have relatively flatter loads and do not contribute as much to the evening peaks in particular.

The peakiness of the small customer load is caused by individual customer choices about the use of energy. These choices are driven by lifestyle, such as, returning home from work to cook dinner, or using an installed air-conditioner on hot days. Customers should be able to make choices about when and why they use energy. The problem is that customers are currently making these choices in the absence of appropriate price signals.

Deteriorating load factors are caused by increases in peak demand and reductions in energy use during off-peak and shoulder periods. This reduction during off-peak and shoulder periods again reflects customers' life styles (i.e. people tend to sleep after 10:30pm) but may be magnified by individual energy conservation measures and/or improvements in the energy efficiency of appliances such as fridges.

Figure 1: Ausgrid network seasonal peak day profiles



1.1.3 Peak demand is one driver of retail price increases

As noted by the AEMC, retail energy prices have increased by up to 30% over the last 3-4 years. Retail prices have been driven largely by increases in network costs and the cost of green programs such as the Commonwealth Renewable Energy Target (RET) and jurisdictional feed-in tariff schemes. Network cost increases are caused by asset replacement and renewal programs, changes to reliability standards and the growth of peak demand.

It is also likely that delivered energy costs will continue to increase over the next 5-10 years at the retail level to reflect the movement of gas and coal price increases towards export parity price levels and to pass through the costs of the much anticipated carbon price in Australia.[5]

While the retail price of delivered energy is increasing, it is important to remember that retail bills are influenced by both increasing prices of the supply chain and the amount of energy consumed. Average

[3] AEMO: Electricity Statement of Opportunities, 2010, Ausgrid analysis.
[4] Small customers include residential and non-residential customers who use less than 40MWh per annum.
[5] Edwin O'Young, Port Jackson Partners Limited, 'Not just a carbon hit on electricity prices' August 2009, available: www.pjpl.com.au

household electricity use has increased almost fourfold since 1955[6], but in recent years some customers have begun to use less electricity. Energy efficiency measures mean that customers are getting the same or better amenity with less energy use. An unexpected consequence of this increased energy efficiency has been to contribute to deteriorating load factors. This has added to increasing network unit costs ($/kWh) overall. While it is true that customers can pay less if they consume less, the costs per unit are rising at a more significant rate than the reduction in energy use, resulting in most customers paying higher energy bills. The reason that customer behaviour is not resulting in reduced prices is because customers are reacting to their overall bills and decreasing energy use overall, rather than reacting to price signals from networks that reflect the costs of network congestion at times of peak.

Network pricing has an important role to play in signaling true costs to customers. Pricing approaches based on parameters that better reflect congestion rather than $/kWh-is likely to lead to more efficient consumption outcomes and better utilised networks. Pricing regimes are considered in more detail in Section 1.2.2.

1.2 The opportunity: There is an opportunity to manage the costs of peak demand growth through a range of actions

Reducing the growth in peak demand provides a long-term opportunity to improve the efficiency of the electricity system and to reduce the costs associated with expanding all parts of the electricity supply chain. Over the long term the total cost of supply could be lowered through demand management measures. These measures can either reduce peak period demand so that energy use during that period is avoided completely or shift the timing of that demand to a different, non-peak time. It is possible to estimate the size of the opportunity presented by peak demand management.

There is a series of demand management actions which are available to reduce the growth in peak demand. These actions include more efficient pricing, curtailable load, energy storage, alternative sources of energy and energy efficiency measures. If implemented, these options are likely to dampen the growth of peak demand and thereby work to reduce future costs.

1.2.1 The size and nature of the peak demand management opportunity varies across sectors

Our initial estimates suggest that the value of the peak demand management opportunity could be around $2.6 - 4.5 million per megawatt of avoided peak demand growth across the supply chain.

One published source which attempts to quantify the value of improving the productivity of installed electricity come from Simshauser and Downer.[7] They recently estimated that if the load factor of households in Queensland was able to be improved from 38.5% to 50%, residential energy costs could decline by $32.67/MWh or 12%. They apply this to all households in Queensland, New South Wales, Victoria and South Australia and estimate avoided costs of $1.67 billion per annum in the household sector alone. They modelled gains from:

- Reductions in unit fuel costs for generation due to increased use of base plant and reduced use of peaking plant
- Reduced capacity costs for generation because the capital costs were spread across a greater unit of output
- Reduced transmission and distribution charges due to enhance loading of the power system
- Retail and GST costs also decline in line with the revised costs.

While Simshauser and Downer modeled improved use of existing capital, it is plausible that improving load factors by reducing future growth of peak demand could have a similar effect.

The potential value from demand management measures varies by sector within the electricity industry. The distribution sector can capture the value of peak demand locally, so demand management initiatives must be focused on local areas. Transmission is regionally (state) based, so the transmission sector can aggregate demand management initiatives that are undertaken across the region. Generation is based at the most aggregated point in the supply chain and demand management initiatives can have an effect no matter where they are located (within interconnector constraints). Each sector is discussed in more detail below.

[6] The Hon Martin Ferguson, Speech to CEDA: 'Australia's Energy Future'. May 2011.
[7] Simshauser, P. & Downer, D., 2011, 'Limited-form dynamic pricing: applying shock therapy to peak demand growth', AGL Applied Economic and Policy Research, Working Paper No. 24.

Distribution

Our estimates of growth related capex and peak demand growth for the distribution sector show that the costs of growth related capex are $1.2 - 4.0 million per megawatt depending on state and region within state. On average, typical expansion capital costs associated with peak demand are around $2.0 million per megawatt. Peak demand management that avoids the need for this additional capacity could save these costs.

Network infrastructure must be sized to meet peak demand and pre-determined reliability standards. This means that some capacity will be used very infrequently. For distributors, peak demand is both local and seasonal. Individual areas within the network may be summer or winter peaking and may have different proportions of residential versus commercial and industrial loads, leading to different peak demand profiles. This presents both opportunities and challenges. The opportunities are that it may be easier to target a particular area with demand management measures. By contrast, it may be hard to use broad-based measures which are offered to all customers to get enough response in a particular area to have any effect on capital spending.

A limit on the availability of demand management initiatives is that different distribution companies are at different stages of the investment cycle. Distributors which are currently investing heavily in replacement capital (e.g. Ausgrid) are able to invest in low marginal cost capacity, which will provide growth capacity to address identified constraints. For these distributors investments solely driven by peak demand in the short to medium term represent a smaller proportion of investment that distributors whose capital programs are predominantly driven by growth. Distribution investment can also be driven by changes in reliability requirements, which also gives little flexibility to pursue savings due to reducing peak demand growth. Distributors which have high proportions of growth driven capital are more likely to be able to capture savings in the shorter term if they can influence the growth of peak demand.

Over the long term, however, peak demand is typically a principal driver of the quantity and cost of network infrastructure. The flatter the load shape, the less amount of infrastructure is required to be built to deliver the same amount of energy. A flatter load shape makes more intensive use of the same amount of infrastructure at little or no additional cost (short run marginal costs are limited to losses alone).

Transmission

Estimates of the cost of growth related capex in the transmission sector may be made by comparing actual total growth related capex and peak demand growth. Our estimates show that the costs of growth related capex are $0.4 - 1.1 million per megawatt, with considerable state-based variation. Peak demand management that avoids the need for this additional capacity could save these costs. The larger catchment areas of transmission compared to distribution mean that peak demand management initiatives need not be focussed in small geographic areas but could be aggregated to have an effect on transmission expansion costs[8].

High voltage transmission infrastructure connecting generation to load has a number of distinguishing characteristics, such as:

- Fixed infrastructure with high capital costs but low marginal cost of usage
- Highly location-specific, particularly by reference to generation investment decisions
- Investment in new capacity typically occurs in large-scale, lumpy profiles, with the sizing of such capacity augmentations typically driven by the need to satisfy peak demand
- Strong economies of scale in terms of the capacity of new transmission lines, e.g. a 1500 MVA line costs much less than two 750 MVA lines.

These characteristics give rise to potential economic value arising from demand management through either:

- Avoiding or deferring large new transmission augmentations, by reducing peak demand, such as through contracts for demand response in the form of embedded generation or flexible load;
- Reducing the risk of not meeting construction schedules or maintaining prescribed reliability standards, particularly when these are likely to be breached for only a small number of hours in the year.

Generation

In the generation sector, avoided peak demand growth can defer the need for new generation and reduce the use of peaking generation. The economic value arises from the reduced need for peaking generation capacity

[8] Note that TNSPs only have direct relationships with a few large customers which limits their ability to contract for demand management.

in an optimal portfolio, or reduced need for additional peaking generation capacity in the system. Peaking generation typically costs $0.75 - 1.5 million per megawatt to install. Peak demand management that avoids the need for this additional capacity could save these costs as well as the fuel costs associated with running this capacity.

The Western Australian electricity market requires retailers to enter into firm contracts (either supply side or demand side) to cover the peak demand of their retail customers, or pay a penalty price. The penalty is set at $186,000 per megawatt per annum. This penalty price provides an estimate of the value of peak demand in that market. The WA market has about 450MW of demand management under contract (approximately 12%) of the total system compared to approximately 3.5% in the NEM. The example from Western Australia shows the potential for demand side participation when the industry is given a price incentive.

Retailing

Energy retailing is a 'risk management' function that intermediates between the large scale transactions and risks arising in the wholesale energy market and the needs of individual end users, such as smaller scale transactions and generally lower risk appetite. Retailing also involves the procurement of network services, generally on a 'pass through' basis.

The potential economic value from demand management initiatives at the retail level arises from the reduced costs of the risk management function where the underlying risks themselves have reduced. This might arise where:

- the total energy demand is lower than it otherwise would be - the less energy consumed, the less risk there is to manage
- the volatility in energy demand at peak is reduced, thereby reducing the magnitude of the wholesale market risks that need to be managed and thus causing a reduction in the cost of hedging even if the total energy consumed remains the same.

One option open to retailers for managing wholesale market risks is to engage in demand side management initiatives of their own. Retailers can and do enter into contracts with the demand side. Typically, a major energy user will agree to provide a specified reduction in demand, as and when called for by the retailer.

1.2.2 There are many possible tools available to manage peak demand growth

There is a series of peak demand management actions which are available and which have been trialed and implemented to differing degrees within the NEM. These demand management actions are tools that may flatten the growth of peak demand. These demand management actions fall into five broad categories: pricing options, curtailable/controllable load options, energy storage mechanisms, alternative sources of energy and energy efficiency/conservation measures. Each of these types of measures is outlined below. Appendix 2 provides a more detailed summary of the types of demand management that can be used and the parties that can typically implement them.

Pricing options

There are a number of pricing strategies that could be used to reduce peak demand. Well designed efficient pricing strategies send a signal to energy consumers about the true cost of consuming energy at a particular time.

The simplest time-based pricing option is **time-of-use pricing**, which has different prices at different times of day representing the changing levels of network congestion throughout the day. It is necessary for customers to have interval meters for this pricing option to be offered effectively. Ausgrid has analysed customer energy use for customers on time-of-use tariffs and those on inclining block tariffs and found that the average reduction in coincident maximum demand is 4%.[9]

Time-of-use pricing can also be applied to represent the changes in network congestion by season as well as by time of day. In 2010, SPAusnet in Victoria proposed distribution tariffs which were higher in summer and winter than other times of year as well as varying by time of day. Ausgrid has run preliminary trials with seasonal time-of-use tariffs and found that residential customers reduced their peak demand by 13% in summer and 5% in winter during the top 20 network demand days.

Dynamic or critical peak pricing is another form of time varying pricing which can be used to target specific times of the day or year when network congestion or high wholesale prices are expected to occur. Ausgrid has completed trials of critical peak pricing and found that customers reduced peak demand use by 25% on average on days when critical peak events were called.[10] An alternative form of this pricing strategy could

[9] Impact of TOU pricing on EnergyAustralia customers – Final report, December 2009.
[10] Strategic Pricing Study Report, EnergyAustralia, April 2010.

involve critical peak rebates, where customers are paid a rebate for reducing peak demand use during specified periods rather than being charged a higher tariff.

Another pricing strategy is a move to **capacity based pricing**, where customers are charged based on their maximum demand (kVA or KW). The strength of the capacity price signal is increased where the capacity charge is calculated over a specified period (say 10 peak days, or over a month) and held for a period (say a month, several months or a year) before it is reset. Capacity based pricing most closely reflects the costs faced by distributors in providing network capacity, as networks do not supply energy per se, they supply network capacity. Ausgrid applies capacity charges to all customers above 40MWh within its network area. The capacity charge is a strong signal to business customers that their demand drives network costs. While Ausgrid has made significant progress in implementing capacity charges to the business sector, residential and small business customers who typically have the peakiest loads do not yet face this prices signal.

There have been a number of overseas trials looking at different pricing strategies that signal the true cost of peak demand. Faruqui has published a number of papers[11] which review up to 70 trials of various pricing regimes. The results are consistent with Ausgrid's own internal studies.

Technology can play a central role in communicating price signals to customers. However, it is not simply the price impact that customers want to see. Trials show that customers respond to price signals better when they can see the impact of their consumption behaviour. Feedback technologies facilitated by technology such as interval meters or smart meters (AMI) together with home area networks (HAN) can communicate to networks how and when customers use energy. This same data can be fed back to customers via in-home displays (IHDs) or web-based interfaces (portals) and display the nature of energy usage and its price/bill consequence. Customers faced with feedback about their own energy use are better placed to make informed decisions about their energy consumption patterns and can more effectively weigh up the costs and benefits of consuming energy at certain times.

Results of studies both here and overseas confirm that technology assistance greatly increases the response made by customers to all types of pricing strategies. Technology assisted critical peak pricing has been shown to have the largest effect on peak demand, with an average reduction in peak demand of 34% across those trials. Technology assistance included options such as cycling switches, 'kill switches' to turn all appliances to standby mode, In-Home Displays and others. Table 1 summarises the results of those trials.

Table 1: Results of dynamic pricing trials[12]

Average peak demand reduction (range of outcomes)

	Without technology	**With technology assistance**
TOU pricing	4.7% (2-11%)	17.8% (2-32%)
TOU and peak time rebate	13.6% (5-23%)	22.1% (7-33%)
TOU and Critical peak pricing	20.7% (10-50%)	34.1% (15-54%)
Real time pricing	10% (5-15%)	-

Many of these technologies are being trialed under the Smart Grid Smart City program that Ausgrid and a number of retail and technology partners are conducting in the Newcastle and Hunter regions with the generous assistance of the Commonwealth Government. Appendix 4 contains further detail of the SGSC trials.

Evidence to date suggests that variable tariffs that reflect the costs of network congestion can have a significant effect on consumption behaviour, particularly in the residential sector, and has the potential to positively impact growth of peak demand in future particularly if facilitating technologies and feedback is provided.

[11] E.g. Faruqui, A., 2010, 'The Ethics of Dynamic Pricing', The Electricity Journal, Vol. 23, Issue 6; Faruqui, A., Hledik, R. & Sergici, S., 2010, 'Rethinking Prices', Public Utilities Fortnightly, January 2010; Faruqui, A. & Sergici, S., 2010, 'Household response to pricing of dynamic pricing of electricity: a survey of 15 experiments', Journal of Regulatory Economics, Vol. 38, no. 2.

[12] Recently cited and summarised in Simshauser, P. & Downer, D., 'Limited-form dynamic pricing: applying shock therapy to peak demand growth', AGL Applied Economic and Policy Research, Working Paper No. 24, February 2011.

While the SGSC trial represents the future direction of pricing strategy for Ausgrid, our roll out of interval meters that has facilitated implementation of time-of-use pricing has already reached 334,000 customers in Ausgrid's area. However, Ausgrid still has 1.25 million customers with an accumulation meter installed. This demonstrates that while significant progress has been made on pricing reform, the majority of residential customers still have an accumulation meter installed that does not facilitate time-varying or more sophisticated tariffs that are required to reflect network costs. This is a major challenge for Ausgrid and other networks.

Most of the pricing trials undertaken to date have focused on residential demand. As noted in section 1.1.2 above, it is important to remember that approximately70% of demand is from industrial and commercial customers and just 30% from residential customers. While residential customers do tend to have the greatest variation in their peak, commercial and industrial customers have bigger loads and are fewer in number, which makes them easier to target for demand management. In addition, there is likely to be more potential for large reductions in peak demand from industrial and commercial customers.

Distributors or retailers can and do offer tariffs that contain cost reflective pricing signals to non-residential customers. Where distributors establish these pricing regimes, it is important that the price signals are passed through to customers via retailers to ensure that customers are exposed to the pricing signals and have the opportunity to alter their energy use in response. This is true also of pricing signals sent to residential customers.

1.2.3 Curtailable and controllable loads

Curtailable/interruptible loads are loads that do not need to operate continuously and can be contracted to turn off. They are generally subject to limitations regarding the length of time they are asked to be off, how often they are likely to be asked to be off, and the number of consecutive days they may be likely to be asked to be switched off.

These loads tend to be discretionary loads and tend to be found in larger commercial and industrial facilities. The switching may be manual or automated, and is generally at the customer end, but in some cases the customer may allow the utility to have control of the switch. Commercial and industrial customers can provide large increments of peak demand reduction with few transactions for the distributor to manage.

Controllable loads are loads within a customer's facility that are controlled remotely by the utility. These are most often in smaller customers' facilities. Examples include:

- Controlled off-peak hot water
- Controlled pool pumps
- Cycling of air-conditioning
- Possibly electric car batteries in the longer term

Any other controlled circuit arrangements whereby connected (and generally hard-wired) end use equipment can only operate during times determined by the utility.

The biggest single demand management measure currently available is controllable off-peak hot water loads which are managed via ripple control systems. Air conditioning trials in South Australia and Queensland indicate that reductions in peak demand are possible using this strategy.

Residential based controllable load is necessarily based on a large number of individual transactions, which adds complexity and transaction costs. Residential based controllable load also requires consistent appliance standards and communications, or Demand Response Enabling Devices (DREDs).

As with pricing options, there is potential for commercial curtailable load contracts to provide reductions in peak demand at critical times and in local areas. Commercial and industrial customers could provide larger increments of peak demand reduction in specific areas with fewer transactions.

While current curtailable load trials have focused on air conditioners as the driver of peak demand it is equally possible to reduce peak demand by reducing other, baseload, energy use. While customers may not be willing to stop using air conditioners on peak demand days (typically hot days), they may be willing to reduce their peak demand by choosing not to run the dishwasher or other appliances simultaneously. There is potential for peak demand reduction without reducing customer comfort levels.

1.2.4 Energy Storage

Commercial scale batteries have the potential to have multiple benefits for the energy system. They could be used for network management (peak demand management) to smooth out peaks and potentially assist in the utilisation of the smart grid. They could also provide emergency back-up if installed in buildings and can provide back-up supply to improve reliability.

The increasing use of renewables in the generation sector means that there will be increasing value in flexible demand, not just peak demand management. Batteries have the potential to smooth energy supply variability associated with wind and solar energy. Batteries could also be used for spot market trading if they are able to sell energy to the market at times of high prices.

NaS (sodium sulfur) and flow batteries are currently being examined for utility scale grid support roles in Japan, the US and Europe and could be a future source of demand management. The Smart Grid Smart City program is also trialing the use of distributed flow batteries.

Electric car batteries could also be used for peak demand management in the future if large-scale deployment occurs.

Thermal storage systems use the ability of various substances to store heat (or cool) as a means for 'storing' electricity. The heat (or cool) is generated at times when electricity is less expensive and then used at times when it is more expensive. The most common application of thermal storage in Australia is off-peak water heating. Other examples include systems that freeze or chill water when electricity is relatively less costly and store it in insulated containers for use in air conditioning or other processes that require a chilled input at times of higher prices. Key parameters for this type of demand management action are the existence of time-differentiated prices, adequate space for the storage, and the rate at which the stored thermal energy is lost.

1.2.5 Alternative sources of energy

Alternative sources of energy such as embedded generation (cogeneration or tri-generation) in individual buildings or precincts could also be used to reduce the growth in peak demand for networks.

Embedded generation is the use of an electricity generation system that is located on the customer side of the meter. Some forms of small-scale renewable energy utilisation (e.g., rooftop PV arrays – but not solar water heaters) are forms of embedded generation. Embedded generation can also include the use of gas- or diesel- fired standby generators that are located within a customer's facility.

Dual fuel is the ability to use an alternative input energy to power a particular end use. This could involve two different pieces of end use equipment, or more commonly a specific piece of end–use equipment that can use more than one input fuel. The use of a gas-fuelled engine as an alternative to an electric motor (often used in critical water pumping applications), or the use of electric back-up for solar water heating systems (often with the electric element fixed to only operate off-peak).

Fuel substitution involves switching from one energy source to another. Solar water heaters, PV arrays, mini-wind generators and small-scale methane generators are all examples of renewable energy sources substituting for centrally generated and grid-supplied electricity.

1.2.6 Energy efficiency/energy conservation measures

Energy efficiency includes the replacement or retrofitting of any end use equipment that allows the equipment to produce the same level of work, output or amenity with less input energy. Examples include the replacement of existing lighting with more efficient (or more effective[13]) lighting equipment, the replacement of motors with more efficient ones, and improvements in building envelope characteristics, such as the replacement of single-glazed windows with double glazing. Almost every end use can be made more efficient, generally through more than one approach.

Energy efficiency measures can reduce peak demand if they are applied when local peak demand occurs. If appliances which operate at all times such as fridges, or appliances which operate at times of peak demand such as heaters are made more energy efficient then peak demand will be reduced. If appliances which are not in use at times of peak demand (e.g. light bulbs, televisions,) are made more energy efficient, however, energy efficiency measures can exacerbate load factor deterioration.

Other examples of energy efficiency measures include smart building controls and smart process control which can be used to manage and optimise electricity use in buildings and commercial and industrial processes.

Standards also have a role in improving energy efficiency. Standards can include building standards, building design, siting and orientation and appliance standards. There is clearly a role for government in setting appropriate standards in these sectors. Appendix 2 has more detail about these measures.

[13] Where more effective lighting is installed fewer fixtures may be needed and the lighting end use becomes more efficient (because the overall lighting task is accomplished with less total energy, even if the individual fixtures are no more efficient than those they replaced).

1.3 Challenges: Current systems and incentives do not facilitate significant demand management

Current incentives for promoting peak demand management and demand side participation are not leading to significant implementation of peak demand management in the NEM. It is therefore important that the AEMC's proposed Strategic Priority 2 is pursued to consider what else can be done to promote efficient demand management.

The challenges and barriers to implementing peak demand management in the NEM can be categorised as regulatory-based, technical and market-based challenges. The regulatory challenges are those associated with the underlying and explicit incentives for distributors and transmission service providers to undertake demand management. The technical challenges are to do with the lack of modern metrology and remote load control technologies in place with existing networks. The market challenges exist due to the characteristics of the market structure itself, but also include limited incentives for retailers and generators to seek demand management options, particularly where they are integrated entities.

1.3.1 Regulatory challenge: disaggregated market structure

The vertically disaggregated nature of the Australian energy market means that the incentives for peak demand management are split between different parts of the supply chain. The benefits of managing the growth of peak demand cannot be captured by any one entity and peak demand management is therefore currently not a primary focus of generators, retailers, transmission providers or distributors. In addition, the existing explicit peak demand management incentive schemes for distributors, such as the D-factor, tend to ignore "cross value chain" opportunities and focus on benefits for the distribution network on its own.

Ausgrid is a leader in implementing peak demand management initiatives within the distribution sector. Over the six years to 2009-10, Ausgrid has undertaken a demand management investigation process for each augmentation project with an estimated cost of more than $1 million. Of the 207 screening tests undertaken, 27 demand management projects have been undertaken. Around $443 million of growth related capex has been avoided or deferred by non-network alternatives and around $30 million of benefit has been captured from these initiatives. While Ausgrid has undertaken significant demand management, this value is relatively small compared to the overall capital program of $4.1 billion over the same period.

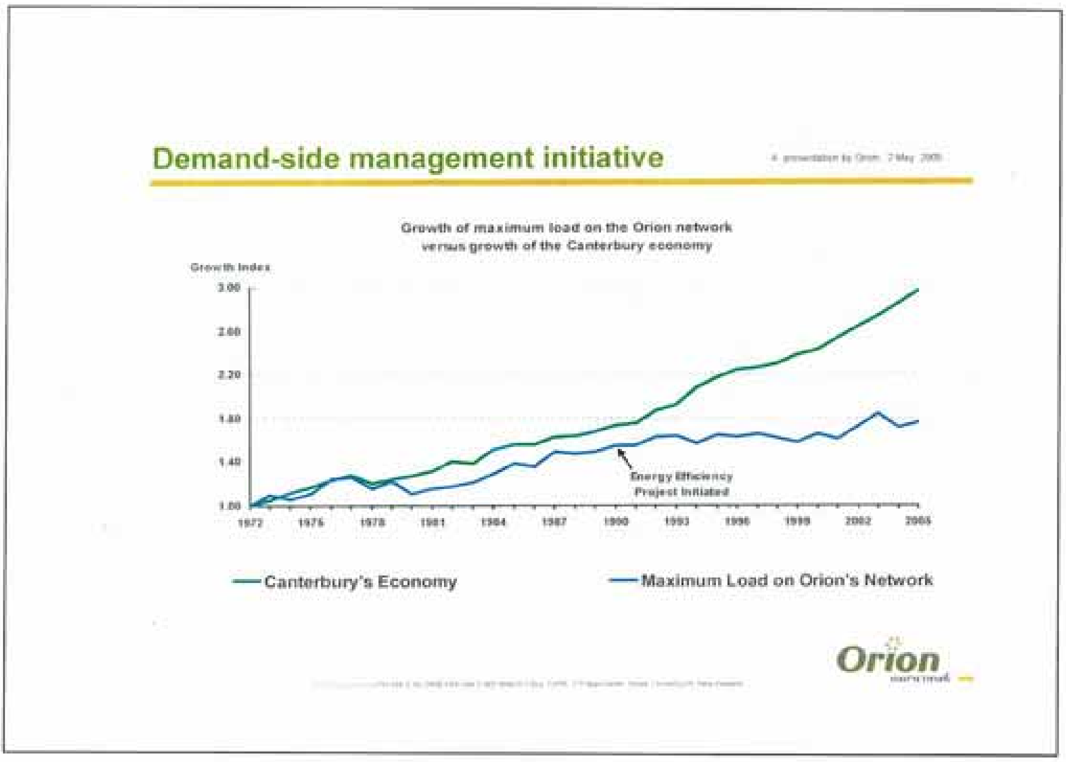
The limited role of demand response in the Australian market is also highlighted in the 2008 Smart Meter cost-benefit analysis[14]. The cost-benefit analysis ascribes $250-$738 million in net present value to the benefits of demand response over 20 years, Australia wide. This benefit is based on an assumed 260-700MW of peak demand reduction by 2020, or 1% peak demand reduction. Of these savings, $207-379 million are assumed to come from deferral of network augmentation and $163-$391 million from market benefits. The remainder is from greenhouse benefits and transfers. It is possible that more demand response benefit may be available if additional incentives were applied and benefits across the value chain were able to be captured.

Some overseas energy and network providers appear to have implemented more peak demand management initiatives than have been undertaken in Australia. For example, in New York, there is 2,200MW of demand that can be turned off on request in the context of a 37,400MW system (around 6%). Between August 2006 and July 2010 energy consumption grew by 7.8% while peak demand reduced by 1.4%.

In New Zealand, significant reductions in peak demand growth were achieved through pricing initiatives, particularly capacity pricing which was extended to all business customers and eventually residential customers. Importantly, the slower rate of peak demand growth did not dampen economic growth as can be seen in Figure 2 below.

[14] Cost benefit analysis of smart metering and direct load control, Final Executive Summary, 23 May 2008

Figure 2: Growth of maximum load on the Orion Energy compared to economic growth of surrounding district.[15]



Not all international precedents are directly applicable to Australia as they operate under different structural and regulatory frameworks. However, it is still relevant to note that other countries are able to call large volumes of peak demand management. It also highlights the potential peak demand management that may be achievable if policy settings and incentives are designed to promote it. Appendix 3 has more detail of relevant international examples.

1.3.2 Regulatory challenge: distributor incentives for peak demand management

Underlying incentives

The structure of the distribution regulatory regime provides little incentive for the implementation of demand management. Under the existing framework distributors earn a return on capital that is added to the regulated asset base (RAB) but receive no long-term benefit for avoiding or deferring capital.[16]

In addition risk management considerations and 'business culture' mean that distributors find network augmentation solutions preferable to demand management solutions. There are many reasons why supply-side or network investment solutions are favoured by distributors including:

- Network augmentation solutions are aligned with the professional expertise and experience of most technical staff
- Network augmentation infrastructure generally involves technology which is known to be reliable
- Network augmentation is installed in large increments thus transaction (administrative) costs are minimal
- It is easy to procure network augmentation solutions quickly. There is a mature market of suppliers, products and constructors of supply-side solutions to standard business needs
- There is an established track record of being able to deliver supply-side solutions on time and on budget.

[15] Joint paper by OakleyGreenwood and NERA commissioned by Ausgrid 2011, *Demand Management – Incentives, Constraints and Options for Reform.*

[16] The framework includes a short term benefit for networks where the costs avoided through capital deferral during the period are kept by the business during the five year regulatory period. This lower actual capital expenditure in rolled forward into the regulatory asset base in the next regulatory period – to the benefit of customers...

By contrast, demand side responses tend to be harder for distributors to implement:

- Demand management solutions are not available as 'off-the-shelf' solutions, but must be sought out on an individual basis. This can be time and resource intensive.
- Many employees do not have the technical expertise to pursue demand side solutions
- Demand management solutions are seen as less reliable than network augmentation solutions, which creates a bias against them
- There may be liability issues if contracted providers of demand management fail to perform as required by the distributor
- Demand management solutions often involve aggregating many small increments, which involves high transaction costs and can be much slower to achieve than network augmentation solutions
- Demand management solutions have had a variable track record of deliverability with some solutions being highly effective and others having failed to materialise.
- There is uncertainty about regulatory treatment of costs allocated to demand management initiatives.

While underlying economic incentives and business drivers can bias against demand management, the structure of the regulatory regime does provide a short-term (within regulatory period) incentive to defer capital through demand management or other capital efficiency measures. This is because the framework allows the network to keep the capital costs avoided via capital deferral during the period. This incentive promotes deferral of capital in the short-term from the start of the period towards the end of the period, if this can be done efficiently within the capital works program. It should be noted that for this incentive to be effective the costs of the demand management must be less than the present value of the capital deferral or around 10% of the capital deferred for two years. The longer the capital is deferred, the more demand management costs can be accommodated.

The AEMC has previously stated that "where [demand side participation] DSP is the more efficient option, network businesses are likely to earn systematically higher profits by purchasing DSP compared to augmenting the network" and added that "this result holds in the absence of schemes to promote DSP explicitly".[17] The AEMC acknowledges that incentive schemes may, however be "justified as a stimulus to change, if there is a perceived bias against DSP in established cultures of business and their management practices".

Explicit incentives and programs

In addition to the incentives inherent in the structure of the regulatory regime, distributors in all NEM states have the Demand Management Innovation Allowance (DMIA) and distributors in New South Wales also have the "D-factor" incentive scheme. The DMIA is a small allowance of additional revenue which may be spent on demand management related projects. It is not an incentive payment as it is not linked to demand management outcomes, but is none the less a valuable way for distributors to experiment with new approaches to demand management. The small size of the DMIA, limits the scale of the trials that may be undertaken under this scheme. For Ausgrid the DMIA is worth $5 million over 5 years which represents 0.06% of the capital program.

The NSW D-factor scheme is an explicit scheme to reduce the regulatory barriers to demand management. It has multiple components. First, it is described as trying to overcome the barriers associated with the weighted average price cap form of regulation, which may indirectly provide DNSPs with disincentives to undertake demand management[18]. Second, it was introduced to mitigate the risks associated with implementing demand management compared to network solutions and also to provide a positive incentive to promote demand management. Third, it was designed to provide certainty of financial outcomes for distributors implementing demand management initiatives. The financial outcomes are based on expectations at the time of implementation, and there is no look back which could alter the financial outcome after the event.

The D-factor was introduced by IPART and was continued by the AER for the current regulatory determination. No other state has an equivalent scheme incorporated in the most recent regulatory determinations, and there is some uncertainty as to whether the D-factor will be renewed for the next regulatory period in NSW.

The D-factor allows DNSPs to recover approved foregone revenue as a result of non-tariff-based demand management activities. It also provides a positive incentive payment equal to:

- Approved non-tariff based demand management implementation costs, up to a maximum value equivalent to the expected avoided distribution costs, or
- Approved tariff-based demand management implementation costs.

[17] AEMC Final Report on Review of Demand-Side Participation in the National Electricity Market, November 2009, p. 18.
[18] AER NSW 2009-2014 Regulatory Determination

Existing peak demand management programs such as those implemented by Ausgrid have responded to the incentives available and have focused on deferring specific increments of capital for short periods of time (12-18 months). Distributors have not typically focused on broad-based peak demand management with longer-term payoffs.[19]

Distributors in other states, which do not have the D-factor available to them, have undertaken demand management programs which are not incentive based. As an example, Energex has an extensive demand management program as part of its current regulatory determination. This spending program was agreed to by the AER as part of the investment plan, unlike incentive schemes such as the D-factor which must be claimed ex-post. This demand management program is not linked explicitly to reducing peak demand or reducing capital expenditure. ETSA's Peak Breaker program involved extensive trials of new technology to control air conditioning remotely. These trials have apparently been discontinued in the current determination which allowed lower levels of DMIA funding.

Shortcomings of existing incentives and programs

The D-factor has been a very valuable learning tool and has facilitated demand management initiatives in the seven years since its introduction. The existing explicit and implicit incentive mechanisms for demand management do, however, have a number of shortcomings. They are inadequate to promote broad-based, longer-term demand management, and the D-factor has some flaws for promoting targeted demand management. The D-factor also has a problem with 'missed opportunities', that is, the D-factor can only be claimed for a demand side solution to solve a current supply side constraint. The D-factor does not allow for demand management initiatives to be taken in anticipation of a future supply-side constraint. Finally, the D-factor is also complex to implement with the price cap formula, and can undermine its financial value when implementation mistakes are made.[20]

Under the D-factor there is limited incentive for distributors to undertake "broad-based" or "generalised" demand management with longer term benefits such as implementing new pricing regimes. The D-factor generally only allows cost recovery where an identifiable increment of capital has been deferred. Demand management initiatives undertaken therefore typically defer small amounts of capital for a short period of time because longer term benefits are harder to capture and quantify. Current demand management initiatives may be seen as playing round at the margins, rather than substantially changing the use of assets to reduce capital expenditure in the long term.

Under the D-factor recovery of foregone revenue tariff-based demand management such as time-of-use or dynamic peak pricing is not allowed. There is no positive incentive for implementing, for example, time-of-use pricing under a revenue cap. There is a disincentive under a price (WAPC) cap, as any effect the time-of-use pricing has on customers' use of energy reduces the revenue a distributor will earn (where that fall in volumes has not been incorporated into the forecasts underpinning the price path). In a previous submission to the AEMC[21], Ausgrid (then EnergyAustralia) noted that our own trials had demonstrated the effectiveness of dynamic peak pricing signals in reducing peak demand use, but that we had decided not to proceed to implement this form of pricing, due in part to the operation of the WAPC. This is because there is a significant proportion of revenue that is typically earned at peak times which would be at risk of not being recovered from customers with a dynamic peak tariff. While reducing peak demand via these sorts of measures could have an effect on capital expenditure in the longer term, such pricing strategies will not be implemented mid-period due to revenue considerations. The D-factor, though successful in localised capital deferral is limited in value and scope in a broader context.

The D-factor also generally does not take account of the benefits provided to other parts of the value chain through efforts undertaken by the distributor. Such benefits cannot be harnessed in order to make the case for more expensive or extensive demand management projects.

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[19] This is particularly true of distributors that operate under a price cap where forecast energy volumes form the basis of the price cap. Any broad based peak demand management investment that has an impact on energy volumes that was not explicitly taken into account in the forecast underpinning the price path could lead to lower revenues. The price cap form of regulation when combined with energy based pricing can be a disincentive to demand management and promotion of energy conservation.

[20] In its regulatory determination for Ausgrid, the AER made a mistake in the formula for calculating the incremental D-factor to apply to prices. The AER has not agreed to amend its determination to correct for this error. As a result, Ausgrid will receive a lower revenue than it should have been allowed during this period despite undertaking legitimate and beneficial demand management

[21] EnergyAustralia, Submission to the AEMC Review of Demand Side Participation in the NEM, 12 June 2009.

There are several other limitations on the D-factor arising from the regulatory structure. In particular, if a distributor has unspent capital at the regulatory reset then the return on that capital is lost until the capital is spent. This can occur if the capital is deferred several years into the next regulatory period. Further, if demand management is incorporated into the capital plan at the planning stage the distributor has a lower forecast asset base and hence lower returns on its investment than otherwise would be the case. This provides a perverse incentive for network businesses to identify demand management after the capital program has been approved.

Finally, the D-factor is relatively complex to understand and implement. Both distributors and regulators have, at times, had trouble in interpreting how the D-factor is to be applied, particularly during the transition from one regulatory period to another.

1.3.3 Regulatory challenge: transmission obligations for peak demand management

The regulatory investment test for transmission (RIT-T) establishes a comprehensive process for undertaking an economic evaluation of all significant transmission augmentation decisions. The RIT-T is designed to ensure that the full potential economic value of demand side management options are identified and evaluated prior to making transmission augmentation decisions. The RIT-T obliges transmission service providers to consider the total market costs and benefits of both demand side and augmentation solutions when planning for any new transmission project. TNSPs are also required to undertake a consultation process designed to elicit possible proponents of demand side solutions.

There is a perception that the RIT-T and previous versions of the transmission planning process has not been effective in providing much demand management in practice.

The demand management considered by TNSPs under the RIT-T is directed to manage an immediate or short-term constraint. The RIT-T focuses on ensuring transparent decision are made about managing immediate constraints. It does not necessarily encourage efficient or optimal augmentation strategies for the long term.

In the most recent regulatory determination TransGrid was given a demand management allowance of $1 million per annum to develop and investigate demand management solutions to network constraints. Like the DMIA for distributors, this is not an incentive payment as it is not linked to demand management outcomes. It is a valuable way for TNSPs to experiment with new approaches to demand management. The small size of this allowance will, however, limit the scale of the trials that may be undertaken.

1.3.4 Technical challenge

As mentioned in section 1.2.2 above, some demand management initiatives can be facilitated by technology. Interval meters or smart meters (AMI) can enable measurement of the extent to which customers vary energy use in response to incentives and enables customers to be rewarded appropriately. Facilitating technology for customers such as home area networks (HANs), in home displays (IHD) or web-based interfaces (portals) can provide feedback about energy use.

The technology to deliver feedback to customers is available but its application within networks within Australia is limited. The process of integrating separate retail and network billing information on a real time basis for customers to see is a significant challenge and requires significant investment in back end systems and operating protocols. The devices themselves also vary in price and scope from simple and relatively cheap IHDs to expensive customer wired HANs and load cycling equipment.

Neither smart meters nor customer feedback technology are widespread and the costs of their deployment is significant. Both these factors represent a barrier to more effective demand management. Large scale investment in new facilitating technologies in an environment where all sectors of the supply chain are experiencing upward cost pressures is difficult, particularly given the current level of unease from some sectors of the community about recent and future increases in household energy costs.

As mentioned above, the only widespread load control technology is ripple-controlled hot water. While effective, much of the load control equipment is old and in poor condition and requires significant investment to remain effective. Other load control technologies could facilitate additional demand management in a more effective manner but the switch of technologies brings additional costs of back end systems and system integration. This represents an ongoing challenge for network businesses as they move from electromechanical and analogue technologies to digital capabilities.

1.3.5 Consumer protection challenge

The cost of a roll-out of facilitating technology is largely prohibitive without strong government backing. However, even in jurisdictions where strong government support for technology has been present (i.e. the smart meter roll-out in Victoria) the politics associated with higher living costs and the fear of the unknown impact of time-varying prices for residential customers energy bills has led to a freeze on the implementation of time-of-use pricing – the very object the technology was supposed to facilitate. This unfortunate state of affairs could have been avoided if consumer protection issues were addressed more appropriately at the time the decision was made.

Customer benefits and costs is a key consideration for market participants and governments investing in smart technology. Technology comes at a cost that will ultimately be borne by customers through their energy bills. The case for consumer benefits only stacks up where the costs of this facilitating technology can be fully paid for by avoiding costs of future investment in greater network and generation capacity. Unfortunately, for today's market and its customers, the benefits of demand management in avoiding future costs can only be forecast not proven which makes the pay back for customers tenuous. This remains as a continuing challenge to investment. It is hoped that the Smart Grid Smart City trials will go some way to providing comprehensive Australian data to support investment decisions.

1.3.6 Market challenge

As noted in the AEMC's Discussion Paper, although retailers do enter into demand response arrangements with their customers (generally, larger industrial and commercial customers[22]) the volume of these contracts appears to be relatively small. AEMO estimates there was 177 MW of load that is very likely to reduce consumption in Summer 2010-2011 in response to high prices, and 423 MW that had an even chance of reducing consumption[23]. This total of 600 MW represents about 1.3% of the installed capacity of the NEM[24]. The extent of demand response capability in the NEM appears to much smaller than in Western Australia where there is 12.5% of peak system demand that is contracted by way of demand response in the wholesale electricity market (500 MW contracted in a system of approximately 4,000 MW).

The small volume of contracted demand response in the NEM is likely due to the limited incentives that retailers, 'gentailers' and generators have to pursue demand management. Retailers have some incentive to pursue demand management to the extent that it can substitute for the financial hedging contracts or physical generation capacity required to support retail loads. Demand management is clearly seen as a less attractive option than controlling peaking generation or entering into financial contracts as there is less evidence of the existence of demand management within the market compared to the integrated investment in peaking plant or availability of contracts. Demand management involves many small transactions and can be seen as less certain than physical or financial hedges, which again explains its relatively small uptake in the market to date.

Generators have limited incentive to pursue demand management directly, as demand management and generation may be seen as substitutes. The only incentive they may have to pursue demand management is to increase the proportion of their generating capacity they are willing to contract. Generators typically contract not more than (N-1) of their generating units to limit exposure if a unit is unable to generate. Demand management contracts with large customers may allow generators to contract more of their generating capacity. There is limited evidence that generators do in fact pursue demand management.

1.4 The solution: a new incentive for distributors can promote more demand management

The AEMC has asked what incentives and information will create cost effective demand side response. Ausgrid proposes that a new, explicit, long-term incentive for distributors to pursue demand management would be desirable and that such an incentive would allow significant economic value to be released in the form of lower future costs for customers. This section defines the characteristics that a new incentive mechanism should have and then suggests the form a possible new peak demand management incentive may take.

1.4.1 Characteristics of new peak demand management incentive mechanism

An incentive-based approach is more suitable to economic regulation than 'command-and-control' based regulation. Incentives achieve better outcomes than prescriptive approaches and better reflect competitive market forces than prescriptive and externally set requirements.

The characteristics that any peak demand management incentive should incorporate include:

[22] These customers have been preferred because of the larger amount of demand response that they can generally provide and the lower transaction costs required (on a per-unit basis of demand response contracted). Retailer-dispatched demand response in small volume customers is limited by the lack of interval metering because settlement via the net system load profile essentially spreads the impact of the demand response to all customers (and hence all retailers). The retailer and customers that dispatched the demand response will only benefit by this spread impact – exactly the same benefit to be delivered to all other small customers and their retailers.

[23] AEMC Strategic Priorities for Energy Market Development, Discussion Paper, pp. 40-41.

[24] Installed capacity of the NEM is ~45,000MW while peak demand is ~34,000MW

- **Simplicity** – The scheme should be simple to understand and implement so that its chances of success are maximised. It should be structured in such a way that a broad range of participants in the energy sector and within individual organisations can understand the mechanism itself and understand how their actions can contribute to peak demand reduction
- **Supply chain benefits** – The scheme should recognise the split incentive problem by considering the 'whole of value chain' benefits of any peak demand management initiatives, not just the value able to be captured by one entity
- **Customer benefits** - Ensure that the majority of the benefits are allocated to customers
- **Target** – the scheme must be proven to target the problem identified, be designed to avoid perverse incentives and ensure benefits flow from actions promoted by the scheme. There should not be penalties for outcomes outside of the entity's control.
- **Appropriate scope** - Promote broad-based, longer-term (longer than five years) peak demand management, as well as short-term, easily quantifiable specific demand management actions. Longer term peak demand management avoids the 'lost opportunity' trap by allowing demand management initiatives to be undertaken in advance of known network or wider system constraints
- **Broad based** - Have the ability to promote different types of demand management, including new pricing regimes
- **Promote innovation** - Have the flexibility to promote innovation and new technologies as they become available (new technologies may include the smart grid, smart meters, renewable energy technologies, energy storage devices and others)
- **Account for interaction of other schemes** - Recognise and address the potential short-term revenue consequences for distributors in particular which are effective at promoting peak demand management.

There is a strong argument that distributors are the appropriate part of the supply chain to be given a better and more material demand management incentive. Distributors represent one of two parts of the energy supply chain that are regulated and like transmission businesses, are already subject to an incentive based form of price/revenue regulation. The addition of another incentive component to the existing regime would be relatively easy compared to the application of a demand management incentive scheme to an unregulated sector of the market.

Unlike transmission businesses, distributors have a direct relationship with each customer in their franchise area through their connection and typically, for small customers at least, own the meter. This means distributors are uniquely placed to aggregate peak demand management both at a localised level and within a region. This also means that network facilitated demand management could support demand management requirements of both networks and retailers.

Ausgrid considers that distributors are in a position to implement demand management measures that could flow through to benefits in the electricity system. As previously discussed, distributors face regulatory and technical challenges that provide little incentive to implement demand management. Given the challenges, some form of explicit incentive mechanism is required to overcome these challenges.

The following section sets out a high level discussion of possible approaches to explicit incentive mechanisms to facilitate distributor driven demand management.

1.4.2 Possible new incentive mechanism for distributors

Peak demand focused incentive

Ausgrid has begun developing possible options for a new incentive mechanism for the distribution sector. While these options are not fully developed, Ausgrid feels it is appropriate to put forward a possible direction of a new scheme to promote peak demand management to engage other networks and policy makers in considering this type of addition to the existing regulatory framework.

First, the incentive should specifically target the problem which Ausgrid defines as the driver of cost of network expansion - that is, peak demand growth. There are two possible targets for the incentive:

- Load factor: Incentive payments could be based on achieving a measureable improvement to load factor through time. The scheme would need to be designed to focus on the problem area of the load duration curve (i.e. the top end) to avoid perverse behaviour of promoting energy use at times when the network is not congested which would do nothing to address the problem itself. By targeting the top end of the load duration curve, for example, the top 300 hours each year would provide an incentive to improve the load factor of new loads as well as that of existing loads. It also recognises and rewards the value of adding load at higher than average (i.e. better) load factors.

- Peak demand based: Incentive payments could be based on achieving measurable reductions in peak demand growth. That is, taking verifiable actions that reduces peak demand growth to be lower than it otherwise would have been, at the time of peak demand for a particular area (i.e. winter or summer). For example, implementing a pricing regime which demonstrably has an effect on the growth of peak demand for an existing group of customers could be eligible for incentive payments. Focusing on peak demand growth would specifically target the long-term driver of electricity system augmentation costs.

It is important that the basis on which incentive payments are made reflect factors that distributors can influence. The corollary is that distributors must not be penalised for outcomes beyond their control. If incentive payments are made with reference to outcomes against a target, for example, it would be necessary for the target to take account of factors including weather, economic growth and the increase in customer numbers.

Second, incentive payments to the distributor should be based on a proportion of the value of avoided peak demand growth across the whole supply chain. While the majority of the benefit should be captured by customers, the incentive payment would need to be sufficient to overcome the risks and other barriers that networks already face in implementing demand management.

Third, the design should be consistent with the timeframe over which the results of peak demand management are sought. For example, the D-factor focuses on short (within regulatory period) timeframes. In Ausgrid's view, the D-factor is a valuable mechanism and should be retained. However, we consider a new incentive scheme should focus on the effect of demand management initiatives based on timeframes that are longer than five years.

In Ausgrid's experience, there is a lag of approximately five years between actions taken to reduce peak demand growth and any material effect on the capital program. This is because the capital program is largely locked in four to five years in advance due to the long lead times of major capital investments. Beyond five years it is possible to alter the capital plan to take account of changes in peak demand growth trajectories.

Furthermore, the design of a demand management incentive mechanism must encourage efficient network pricing. The response to efficient prices takes time to manifest as there is typically a gap between energy use and when customers receive their bills (the typical bill cycle is quarterly). Customers take time to understand the implications of new tariff structures (i.e. time-of-use pricing or capacity charges), and then respond to the signals particularly when their response involves capital decisions such as investment in additional insulation or solar hot water systems. In our experience, there is a lag between the implementation of a pricing signals and customer response.

Given the lag between action and response, it would be necessary that any incentive scheme were in place over multiple regulatory periods to ensure the benefits of the scheme had a high likelihood of being captured, and to ensure businesses had ongoing incentives to try new methods of achieving demand management outcomes. This is particularly important where new technologies will be used as there is significant time invested up front in making technologies work before they are implemented.

In addition, any new scheme should be designed to avoid perverse outcomes in its interaction with other existing incentive schemes, such as the Efficiency Benefit Sharing Scheme (EBSS) and the Service Target Performance Incentive Scheme (STPIS) and the existing D-factor. This is consistent with the current operation of the D-factor, where any operating costs associated with an approved D-factor project are removed from the operating costs used for calculation of the EBSS. A similar mechanism would need to be incorporated as it is very likely that new demand management activities would incorporate additional operating costs.

Any scheme should also be designed without the need for ex-post review, consistent with the current regulatory approach. This is an important design factor in that the scheme should not require a subjective 'look-back' at what demand may have been in the absence of the project. This type of subjective review has the potential to lead to unnecessary complications and debate in the implementation of the scheme which could undermine its overall effectiveness. A good scheme design would be one that uses existing processes to measure effectiveness of the incentive mechanism, and is calculated in a manner with little discretion i.e. via established formula using actual rather than forecasts. A scheme based on load factor would lend itself well to this type of design.

One example that might fit the criteria and characteristics listed above is a load flattening incentive mechanism based on the top end load factor. This could be defined as the annual change in load factor for the top several hundred hours of the year (amount to be determined) where the load factor during this portion of the load duration curve is defined as average demand divided by peak demand.

The focus on load factor reflects a desire to increase efficient utilisation of network capital assets and would:

- Ensure the metric addressed capital expenditure for peak
- Minimise the potential use of perverse incentives such as 'valley-filling' strategies to achieve better load factor overall and therefore gain the value of the incentive mechanism
- Recognise and reward the value of adding load at higher than average load factors
- Recognise that a focus on reducing peak demand on its own would (a) penalise distributors experiencing high load growth, and (b) provide no incentive to improve the load factor of new loads
- Avoid the need for new forecast information and thereby remove the complexity associated with forecast error or gaming of forecasts

Of the two suggested targets for an incentive mechanism proposed above, the design of an incentive mechanism that encouraged improvement in load factor is probably the better of the two. Such an incentive could leverage off the design of existing incentive schemes such as STPIS and D-factor. Incentive payments could be made on the basis of actual improvements in top end load factor. While this is likely to require weather corrected data, any incentive payments could be made on the basis of a formulaic calculation of actual improvements in load factor ex-post and would therefore remove the need to rely on estimates of the beneficial impacts of individual projects.

Like the D-factor, the load factor incentive could be available to businesses to claim but not required to be claimed if no projects were implemented, or no improvement was seen during the course of a year. This asymmetry is important to ensure that businesses are not penalised if load factor does not improve due to factors outside of the business's control.

The size of the payment itself might be based on a proportion of the avoided cost of network capital expansion. Given that any successful reduction in load factor at the top end of the load duration curve is likely to avoid additional network investment, it is also likely to flow through to other parts of the supply chain such as transmission and generation in the form of avoided investment. So while incentive payments might be based on some portion of the avoided cost of distribution investment, the benefits to customers of this avoided investment would include the remaining portion of avoided costs for distribution, plus the avoided costs throughout the supply chain.

The costs borne by businesses in pursuit of incentive payments under such a scheme would need to be treated in a manner to ensure that the business did not face an unintended disincentive to invest. For example, operating costs spent in delivering projects to improve load factor would need to be removed from the operating costs upon which the EBSS is calculated. This is similar to the current treatment of operating costs spent under the D-factor in NSW. Costs are removed before the penalty or reward for opex is calculated. Similarly, any capital costs spent in pursuit of this incentive would also need to be recognised within the asset base to ensure that businesses were provided with an incentive sufficiently material to counterbalance the bias to invest in supply side solutions.

The scheme described above is clearly in very early stages of development and will require significant analysis including worked examples to ensure that it works and does not have unintended consequences. Clearly, any such scheme would benefit from extensive consultation with industry and with regulators to test its validity prior to it being introduced. It does, however, represent an exciting new option to be considered that may, more effectively, promote demand response within the NEM.

Ausgrid is continuing to develop this incentive scheme and explore the potential for other variations. A demand management incentive scheme could be explored and refined as part of the upcoming Stage 3 Review of Demand Side Participation in the NEM.

1.4.3 Greater support for existing solutions

This section has focused on a new incentive scheme. However, there are several options for promoting demand management that already exist but would benefit from greater encouragement and regulatory support.

Network Pricing Reform

There are varying degrees of sophistication in network pricing in the NEM today, linked largely to the metrology available to network operators. Regardless of the starting point for network businesses, the economically ideal distribution tariff is one that gives substantial emphasis to a customer's energy demand (kW) during time of system-wide (or localised) peak demand. The intent of such a tariff would be to provide cost-reflective price signals that would either induce customers to alter their consumption in such a way as to provide economic benefits to the network, or to ensure that customers paid for the costs their consumption patterns actually impose on the network.

Such a tariff arrangement would:

- Recover the appropriate proportion of the distributor's revenue requirement by means of a charge that was 'fixed' be reference to each class of customer's use of system at those peak times;
- Be dynamic, in that there would be some form of communication to end customers (and/or retailers) as to when and where system peaks were expected to occur, in sufficient time for them to take responding demand-side action;
- Reflect the different infrastructure need that arise for connections at different voltage levels (i.e. different peak charges would arise for customers connected at different voltage levels: and
- Involve a relatively low variable (delivered energy) component.

Clearly the current limitation of metrology slows the progress towards these ideals, but in areas where this can be overcome, regulatory support is key to ensure the successful implementation of more cost reflective pricing.

A key issue is ensuring that network pricing signals are transmitted to customers through retailer pricing. The ability of network prices to alter demand is largely dependent on the extent to which retailers pass on cost reflective network prices to customers. While retailers clearly have their own costs to factor in and have a role to package the network service and energy products, the potential for network signals to get lost within the bundled price is of concern. Consideration by policy makers of ways to ensure that network pricing signals are passed through to customers would be beneficial. For instance, this may be achieved through mandating requirements to publish information on real time costs of customer's consumption so that customers can compare their bundled price to the costs they would bear under a more cost reflective arrangement. While care must be taken not to intrude on the competitive workings of the retail market, the lack of price information in the market can be considered a market failure from a society's perspective and therefore may require explicit regulatory attention.

Expanded Demand Management Innovation Allowance (DMIA)

The DMIA exists in all NEM jurisdictions. However, the size of the DMIA limits its usefulness. Ausgrid considers that it would be valuable to provide a more substantial DMIA which would facilitate more research and development as well as assist with implementation of demand management initiatives. The DMIA could be expanded with criteria to specify what type of demand management is to be undertaken. Guidelines would provide more certainty about what may be proposed in a program. This is more along the lines of the South Australian Peak Breaker trial funding and the Energex Demand Management package included in its most recent determination.

1.4.4 Customer protections must be maintained in parallel with any new incentive mechanism

It is important to understand that peak demand management programs provide opportunities for customers to vary their energy use. They do not place people under an obligation to reduce load. [25]

> *"Under dynamic pricing [or other demand management programs], customers do not have to pull the plug on major end uses, live in the dark, or eliminate all peak usage in order to benefit. They simply have to reduce peak usage by some discretionary amount that does not compromise their lifestyle, threaten their well-being or endanger their health. Clearly, the more they reduce, the more they will save. But the choice is up to them."*

Customer protections must be maintained as any new incentive mechanisms are implemented, particularly ones that promote new pricing regimes. It is important that customers see the price signal, so they have an incentive to alter their energy consumption. At the same time, it is necessary that any income effects are ameliorated without removing the pricing signals. This could take the form of explicit government rebates to customers in need. This approach is similar to the proposed compensation mechanisms associated with the introduction of a carbon price.

1.5 Where to from here?

The AEMC's Stage 3 Review of Demand Side Participation in the National Electricity Market will provide the next forum for promoting the role of peak demand management. Ausgrid notes that the Ministerial Council on Energy (MCE) has issued the terms of reference for this review and we look forward to participating.

[25] Faruqui, A. 2010, "The Ethics of Dynamic Pricing", The Electricity Journal, Vol. 23, Issue 6, p.16.
[27] AEMC, Strategic Priorities for Energy Market Development, Discussion Paper, April 2011, page 42.

The AEMC has identified that there is potential for technology to monitor and control individual load in real time.[27] We agree with the AEMC that there needs to be a clear commercial and regulatory framework through which interested parties can contract. A clear policy on the commercial and regulatory framework for load control and monitoring technology will provide greater certainty in the electricity sector. There are a range of complex issues that need to be addressed in order to achieve a clear framework.

The AEMC has identified a series of preliminary issues to be addressed including questions of property rights for load control; privacy protection of personal information; role of regulated networks in smart meter technology; the design of economic regulation applying to smart meter technology; and the boundary between regulated and competitive industries. These issues are relevant in developing a clear framework and Ausgrid is considering its position on these questions.

We note that the issues identified by the AEMC are, to a large extent, consistent with the MCE's terms of reference for the Stage 3 Demand Side Participation Review (DSPR). In particular, the AEMC has been asked to assess the market frameworks that would be necessary to maximise the economic value to consumers of services enabled by technologies.[28] It would be appropriate for the AEMC to raise the above issues as part of the Stage 3 DSPR.

Ausgrid is at the forefront of these types of technology advances and is currently undertaking 'Smart Grid Smart City' trials. It will be important for the Australian energy industry and community to learn from these trials. These trials include looking at customer responses to different types of pricing signals, using advanced metering infrastructure to give more control over energy use to customers, retailers and distributors, trialling new technologies such as utility scale batteries, and many other technology-related solutions. Learning from these trials will inform the current debate on demand side participation and peak demand management. The trials may also help us to develop a better understanding of the requirements for achieving a clear commercial and regulatory framework for load control and monitoring technology.

Ausgrid is continuing to develop ideas about potential regulatory change to promote peak demand management. We would be pleased to work with the AEMC as these proposals are developed.

[28] Ministerial Council on Energy, Direction to the AEMC, letter dated 29 March 2011, page 4.

2 Section 2: A predictable regulatory and market environment for rewarding economically efficient investment

The AEMC's first suggested priority is focused on the development of a regulatory and market environment that rewards economically efficient investment in generation. This priority is intended to respond to the challenges identified by the AEMC including minimising policy uncertainty in the electricity sector in ways that minimise costs for consumers. The AEMC notes a challenge for generators is meeting the expected growth in demand, particularly peak demand. Policy uncertainty about pricing for carbon emissions is currently affecting incentives to invest in generation capacity to meet the expected increase in demand.

Efficient investment in generation is an important issue for the Australian electricity market and Ausgrid sees significant linkages between efficient investment in generation and the efficient use of demand management (addressed in detail in the previous section).. Distributors sit in the middle of the supply chain between generators and customers and our actions in undertaking peak demand management can contribute to the market environment in which generators invest.

This section comments specifically on:

- The uncertainty and inconsistency of government policy settings for greenhouse abatement leading to price increases which are not well recognised by customers or across the industry.
- The implications of intermittent generation capacity on the wholesale market structure and how demand management and flexible demand could contribute to managing this intermittent supply.
- Barriers to demand management affecting the efficiency of investment in generation.

Uncertainty about government policy settings

The AEMC has noted that changes in the policy environment including the expanded Renewable Energy Target (RET), the announcement of a proposed framework to introduce a carbon price and the range of national and state-based schemes promoting energy efficiency and carbon abatement create significant uncertainty for investors in the generation market. Ausgrid supports work by the AEMC in this area, and agrees that policy uncertainty may be leading to poor investment outcomes in the generation sector.

Ausgrid is also concerned that the lack of certainty on carbon pricing has resulted in a plethora of government schemes aimed at reducing greenhouse gas emissions and encouraging renewable energy sources. The cost of all these schemes is having an impact on the affordability of electricity for consumers. These various environment-related schemes are leading to price increases for customers which may not be well recognised. For example, retail prices for regulated customers in Ausgrid's network area are expected to increase by 17.9% on 1 July 2011, and 6 percentge points (one third) of this increase is due to additional costs arising from changes to the RET.[29]

It is also of concern that the various State and Federal carbon abatement schemes do not work together and drive a very high cost per tonne of carbon abated. Ausgrid estimates that the average customer in our network area will pay $128 per annum for Federal ($82) and State ($46) green schemes. This represents a cost of $55/tonne of carbon abated, which is much higher than the expected range of a carbon price ($20-40/tonne).

Energy conservation schemes can also add to unit ($/kWh) costs because they typically promote reducing energy use during off-peak and shoulder periods but not necessarily during peak periods. Greenhouse-related schemes which focus on energy conservation can inadvertently lead to further deterioration of network load factor and can exacerbate the disjoint between rising peak demand and slowing (or declining) energy use which is partly responsible for rising average prices for customers. Green schemes can add complexity to initiatives focused on peak demand management.

The effect of intermittent generation on the wholesale market structure

Greenhouse related schemes including the RET and the Solar Bonus Scheme affect the generation market directly. One of the future trends in generation investment is the increased use of renewables, including intermittent wind and solar generation.

The AEMC's discussion paper suggests that increased intermittent generation could lead to higher spot price volatility and the need for additional back-up capacity, likely gas-fired generation. Ausgrid suggests that there is an opportunity to explore how flexible demand could be used to match intermittent supply. Flexible demand could enable better matching of load to intermittent generation capacity. This could reduce the need for

[29] IPART: Changes in regulated electricity retail prices from 1 July 2011, Draft Report, April 2011.

conventional generation to back up intermittent renewable sources which may be a more efficient outcome. For example, if there were flexible demand available at call (such as hot water load), it could be turned on to use energy when wind generators are producing energy.

The potential for flexible demand to assist in efficient investment in the generation sector is a valuable use of demand management that should be pursued to ensure customers are paying for the most efficient chain of supply for their energy consumption needs.

Barriers to demand management affect the efficiency of investment in generation

Demand management initiatives can contribute to achieving more efficient outcomes by reducing volatility in the wholesale market and changing long term investment requirements. A key issue for achieving efficient generation investment is to address barriers to efficient demand management that exist in the competitive market and in the design of the regulatory framework.

Some barriers to demand management in the competitive market are the lack of retail price signals and, potentially, the emergence of internally hedged retail businesses ('gentailers').

Lack of cost reflective retail pricing

The lack of cost reflective retail pricing means customers do not see the true costs of their energy consumption decisions. Price signals to customers that reflect their impact on the demand for capacity in the electricity market are the most effective measure for achieving allocative and dynamic efficiency. Prices that reflect the costs of providing capacity are not a current feature of the electricity industry.

As discussed in detail in section 1, this lack of cost reflective pricing can be barrier to economically efficient investment in network capacity but it will also impact the efficient investment in generation. Pricing reform to create more cost reflective pricing could alleviate this.

Emergence of gentailers

The electricity market structure is changing with the emergence of 'gentailers' (internally hedged retail businesses) as a dominant force. The AEMC points out that this can have a negative effect on the liquidity of the derivatives market. In addition, the emergence of gentailers is leading to a possible reduction of the commercial need for demand management.

Retailers that have invested in peaking generation make returns on their plant when it is despatched at times of high demand or price. Peaking generation is guaranteed, available and represents an existing capability for these businesses to manage their exposure to the volatile spot market.

While commercially sound at the individual business level, these commercial investments may not represent the most efficient way for society to ensure electricity supply meets demand. It is possible that these investments may lead to more peaking generation capacity than is economically efficient. The presence of gentailers may remove the need for retailers to contract with customers for flexible demand. This removes the signals that may otherwise encourage customers to moderate their own behaviour to ensure overall costs of energy supply are reduced.

3 Section 3: Ensuring the transmission framework delivers efficient and timely investment (including a look at economic regulation for distribution)

The AEMC's third priority focuses on the transmission framework and whether the current arrangements are making efficient use of the network and delivering efficient and timely investment. The AEMC comments that the transmission framework review will help to address this strategic priority. However, we note that the AEMC will not be looking at economic regulation of transmission networks as part of the transmission framework review.

We are currently preparing our submission to the AEMC and will reserve our comments on the transmission framework until then.

The main issue we wish to comment on in this submission is the AEMC's reference to the economic regulation of networks. We are concerned about the AEMC comments that the design and operation of the Rules is "evolving" and that it is important for the Rules to be kept under review. The AEMC mentions its review into total factor productivity as an example.

While keeping things under review can work to ensure they remain relevant, we caution that constant change or the 'threat' of change is not consistent with the principle of predictability espoused by the AEMC. Nor is it consistent with the principles of incentive regulation.

Principles underlying economic regulation of networks

The design and operation of economic regulation applied to transmission and distribution networks underwent significant reforms in 2006 and 2007. The reforms were the result of extensive consultation undertaken by the AEMC for transmission and the Ministerial Council on Energy for distribution. These reforms were initiated following the findings of the Council of Australian Governments' Independent Review of Energy Market Directions (*Towards a Truly National and Efficient Energy Market, 2002*).

The principles underlying the economic regulation of network business are set out in the National Electricity Law and include providing network service providers with a reasonable opportunity to recover at least the efficient costs incurred in providing regulated services and complying with regulatory obligations. Further, the network service provider should be provided with effective incentives to promote economic efficiency in investment, and in the provision and use of regulated services. Prices or revenues should allow for a return commensurate with the regulatory and commercial risk of the service provided.

The regulatory framework is intended to provide network service providers with incentives to achieve efficient outcomes by establishing the efficient level of costs. The ex ante incentive framework provides network service providers with an incentive to outperform these forecasts and deliver outcomes for less.

As the AEMC knows, economic regulation of monopoly electricity networks attempts to emulate the competitive market by providing regulated entities with incentives to continually look for ways to reduce operating and capital costs. The efficiency benefits achieved under incentive regulation are shared between the customers and regulated networks.

An important principle underlying incentive regulation is that the incentives need a reasonable time frame to work in practice. The AER's Efficiency Benefit Sharing Scheme (EBSS) and Service Target Performance Incentive Scheme (STPIS) together with the capital expenditure incentives factored into the Rules are aimed at ensuring that network prices reflect efficient costs while encouraging improvements in service standards. The existing capital incentive operates over a relatively short time frame (i.e. within a regulatory period), but the EBSS and STPIS incentive schemes have a medium term focus as they operate over more than one regulatory period.

The regulatory determination for NSW came into effect on 1 July 2009 and the incentive mechanisms will take a number of years to take effect. Network service providers, like all businesses, require a predictable regulatory environment for rewarding economically efficient investment.

The recent reforms of the regulatory framework were aimed at achieving transparency and certainty for the industry and consumers. The current framework is an improvement over the previous framework (under the National Electricity Code) which was characterised by opaque decision making processes and a low level of regulatory accountability. The framework that is set out in the Rules has improved the level of regulatory certainty to network service providers and consumers relative to previous arrangements.

In its discussion paper the AEMC states that:[31]

> *"Minimising policy uncertainty is an essential pre-requisite for efficient investment to meet the investment challenge in the energy sector in ways that minimise costs for consumers".*

We consider that the networks have the same requirements for certainty as other sections of the electricity industry.

The current framework is relatively new and the operations and processes within Ausgrid are responding to the incentives set out in the schemes. Ausgrid is less than two years into the 2009- 2014 regulatory determination and we consider that calls for reviews of the framework not only create uncertainty and weaken the incentive framework itself, but come too early in the life of the framework to judge its success.

There is no compelling evidence to suggest that the economic regulatory framework under the Rules is not resulting in efficient results for the long term interests of consumers. On the contrary, Ausgrid views the current framework as having delivered sustainable and repeatable decision making from the regulator with a long term strategic focus after having weighed the balance of business and consumer interests and risks.

If there are concerns about the regulatory framework under the Rules, the National Electricity Law provides an avenue for the AEMC to consider and determine on a Rule change proposal. We note from the AEMC's paper that the AER may be considering submitting a Rule change request regarding aspects of the regulatory framework. We support a proper process with full consultation being conducted to ensure that Rule makers are able to make high quality and well informed decisions.

Strengthening incentives and certainty for demand management

Following on from our discussion on Strategic Priority 2 at the start of this document, we consider that there is scope for strengthening the incentives for distribution networks to initiate demand management and non-network solutions. We believe that these incentives should be designed to operate within the current regulatory framework.

We consider that there may be scope to create an explicit incentive mechanism that is targeted specifically at influencing peak demand growth. As previously discussed we have started developing possible options for this type of incentive mechanism for the distribution sector. Our intention is to ensure that these options have a medium to long term focus aligned with elements of the existing EBSS and the STPIS. The options being developed are intended to work as an explicit incentive mechanism within the existing regulatory framework.

We intend to provide further information on a possible scheme as part of the upcoming Stage 3 Review of Demand Side Participation in the NEM.

[31] AEMC page 6

Appendix 1: Taxonomy of Demand Management

The terms demand-side management, demand response, peak demand reduction, energy efficiency, energy savings (or conservation), greenhouse gas reduction, renewable energy utilisation, embedded generation, and distributed generation have all passed into relatively common parlance, and are sometimes used as if they are almost the same thing – or at least accomplish the same thing. In fact, they do not accomplish the same things, and important distinctions are lost when their precise meanings – and differences – are not maintained.

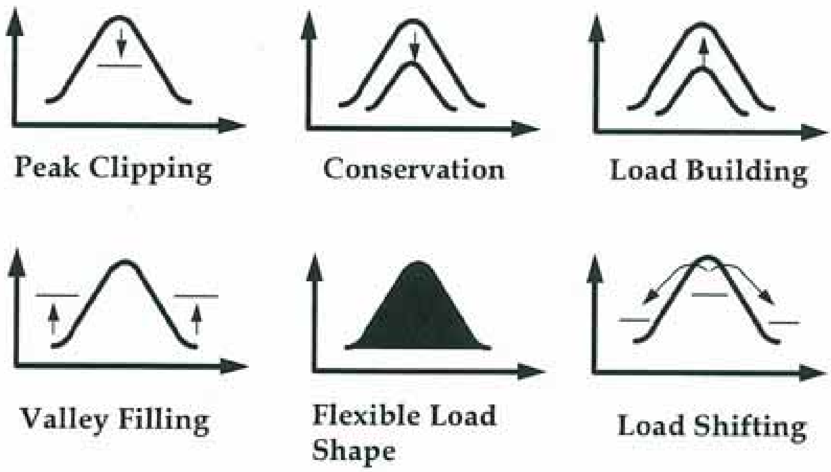
The purpose of this appendix is to provide a set of succinct and accurate definitions of the various forms of demand-side (and related) activities in order to provide a precise vocabulary with which to address the specific questions raised in the AEMC's Discussion Paper and to further consider what arrangements within the NEM will be needed to "build the capability and capture the value of flexible demand".

The term demand-side management (DSM) was created in the early 1980's in work undertaken by and for the Electric Power Research Institute (EPRI) of the USA. The term refers to actions undertaken on the customer side of the utility meter that are encouraged by the electricity utility because those actions will provide benefits to both the electricity system and the customer.

As such, demand-side activities were characterised with regard to their impacts on utility load shape. In undertaking a demand-side program the utility would identify the change that it wanted to engender in its load shape, and select specific end-use technology (and in some cases behavioural) changes that would produce those changes. The utility would then use a variety of mechanisms to encourage customers who could take up the targeted end-use technology or behavioural changes. These mechanisms included any or any combination of the following: education, innovative tariff design, technical assistance and/or financial incentives.

The specific loadshape impacts included within DSM in EPRI's original conceptualisation of the field are shown in the figure below.

Figure 1: EPRI's loadshape objectives of DSM



These loadshape objectives (discussed below in order of their relative impact on peak demand as compared to other portions of the loadshape) were defined at the time as follows:

- provision of a more **flexible utility load shape** — the ability for the customer to alter his/her end-use consumption on an as-needed basis upon request from the utility;
- **peak clipping** — the reduction of utility load primarily during periods of peak demand;
- **load shifting** — the reduction of utility loads during periods of peak demand by shifting that demand to off-peak periods[32];
- **conservation** — the reduction of utility loads, more or less equally, during all or most hours of the day, or those hours during which a particular end-use is in operation;

[32] While load shifting generally does not alter total electricity consumption substantially, where it does change consumption it generally results in an increase, often due to standby losses.

- **valley-filling** — the improvement of system load factor by building load in off-peak periods; and
- **load building** — the increase of utility loads, more or less equally, during all or most hours of the day to better utilise available infrastructure capacity.

The key aspects of the original concept of DSM that should be kept in mind in the present discussion are that:

- DSM was intended to be an addition to the utility's traditional planning and development activities. At its core, it was simply a realisation that customer demand could be considered, within limits, a malleable quantity, rather than an exogenous factor entirely outside the control of the utility that the utility simply had to cater for.
- DSM was originally intended to be an umbrella term for actions that might have quite divergent loadshape objectives; however, the motivation for using DSM was almost always to improve the utility's load factor or system utilisation.
- The loadshape objectives were to be addressed through activities undertaken on the customer side of the meter. Under that definition, the use of renewable energy systems or other generation sources deployed on the customer side of the meter (e.g., rooftop PV systems and standby generators) would be considered DSM. By contrast, standalone generators deployed to provide network support or to inject energy into the grid for the wholesale market (e.g., wind farms) would not be considered DSM initiatives.
- DSM originated within the vertically integrated utility structure of the US, in which the benefits of any loadshape change could be assessed from the perspective of all functional elements of the electricity supply chain. Even so, the issues of foregone revenue (or at least foregone margin) had to be addressed before DSM gained significant traction.

A number of these factors do not apply to the present discussion. The structure of the electricity market and the electricity industry in eastern Australian is fundamentally different from that of the US of the 1980s. The NEM is an energy-only market, it is vertically disaggregated, and it is subject to a more light-handed regulatory regime. There have also been other significant changes relevant to demand-side activities including the availability of cost-effective advanced metering and control technologies, and the increasing importance of climate change in community perception and behaviour, and government policy.

The AEMC Discussion Paper makes several statements regarding the demand-side objectives it is trying to address within today's NEM. They are as follows:

> *Cost-effective demand-side participation in the electricity market can help reduce the need for more generation and network investment to meet forecast increases in peak demand. (page 39)*
>
> *This strategic priority has the potential to mitigate the impact of rising prices, and to increase market resilience, particularly if more demand side participation is available at times of high demand. (page 39)*
>
> *The AEMC wants to ensure that there are no unnecessary barriers to cost effective demand side participation and development of energy efficiency measures. (page 44)*

Based on this, it is clear that the AEMC's primary focus will be on the loadshape objectives of flexible loadshape, peak clipping, and peak shifting, as well as energy efficiency, particularly where the specific end uses that are made more energy efficient also have an impact at the time of system peak demand. The use of renewable energy systems (i.e., fuel substitution) are also likely to be of interest where such systems can meet peak demand more cost-effectively than traditional electricity infrastructure, particularly as these plants provide the added benefit of greenhouse gas reduction. By contrast, valley filling and load building – although legitimate demand-side loadshape objectives – do not effectively address the AEMC's issues (and probably do not fit into today's popular conception of DSM).

With this in mind, the following definitions are offered for the popular terms listed in the first paragraph of this section:

- **Demand response** – the ability of the customer to alter his/her consumption from the electricity supply system upon request, generally (but not necessarily only) at times of peak demand.
- **Peak demand management** – measures which reduce the growth of peak demand.
- **Peak demand reduction** – a permanent reduction in the customer's peak demand on the electricity supply system.

- **Energy efficiency** – the ability to produce the same level of work, output or amenity with less input energy. For the purpose of this report, demand-side energy efficiency is defined as a characteristic of end-use technology to distinguish it from energy conservation (see below)33.

- **Energy conservation** – the elimination on the customer side of the meter of wasteful energy use and/or the willingness to accept a reduction in amenity or output in return for reduced cost or other benefits.

- **Greenhouse gas reduction** – any action on the customer side of the meter that reduces the amount of greenhouse gas released into the atmosphere due (for present purposes) to the use of electricity that is generated by fossil fuels. Renewable energy utilisation (fuel substitution), energy conservation, energy efficiency, peak demand reductions and demand response can all reduce greenhouse gas emissions, but the magnitude of their effect will depend on the greenhouse gas intensity of the electricity being generated at the time the demand-side action affects the customer's consumption34. It should be noted that greenhouse gas reduction is a by-product of one of the other types of loadshape modification rather than being a loadshape modification objective in and of itself.

- **Renewable energy utilisation** – the use of any renewable energy source (including solar, wind, biomass, and hydro) to generate electricity or substitute for the use of grid-supplied electricity. For renewable energy utilisation to be classified as a demand-side measure the technology must be deployed on the customer side of the meter. This would include the following small-scale renewable energy systems: mini-wind systems, rooftop PV arrays, solar water heaters, on-farm biomass systems, etc). By contrast, large-scale renewable energy systems (wind farms, large-scale standalone PV arrays, solar towers, etc) are not demand-side measures and are better classified as distributed generation (see below).

- **Embedded generation** – for the present purpose, embedded generation will be defined as the use of an electricity generation system that is located on the customer side of the meter. As such, some forms of small-scale renewable energy utilisation (e.g., rooftop PV arrays – but not solar water heaters) are forms of embedded generation, but embedded generation can also include the use of gas- or diesel- fired standby generators that are located within a customer's facility.

- **Distributed generation** – to maintain the distinction from embedded generation, distributed generation is defined as generation that is located within the distribution network, but not located on the customer side of a meter. Distributed generation is generally larger in installed capacity than embedded generation but smaller than the generation plants connected to the transmission grid.

- **Non-network solutions** – this term is used to describe arrangements made to reduce or defer (and in some rare cases permanently substitute for) the need for augmentation of the distribution system. As such, non-network solutions can include any form of DSM (as defined above) as well as distributed generation (including distributed renewable energy electricity generation systems).

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33 It should be noted that energy efficiency strategies can also be applied to electricity supply-side technology.

34 It is generally the case at present in the NEM that greenhouse gas intensity is highest during off-peak periods and lowest at times of peak. This may change as the mix of electricity generation sources changes, including most importantly the amount of electricity generated by large- and small-scale renewable energy sources.

4 Appendix 2: Types of demand management that can be undertaken

Type of DM action	Applicable types of DM	Parties most typically involved	Arrangements most frequently used
Interruptible load	Demand response	Network Retailer	Network - Special tariff, standing offers, bids Retail – Pool price arbitrage
Controlled load (various end uses)	Demand response Peak demand reduction	Network Retailer	Network – special tariff Retail – pool price arbitrage, special tariff
Building standards	Energy efficiency Greenhouse gas reduction Peak demand reduction Renewable energy utilisation	Government	Regulation
Building design, siting and orientation	Energy efficiency Greenhouse gas reduction Peak demand reduction Renewable energy utilisation	Government Market intermediaries	Regulation Demonstration projects Market intermediaries / professional education
Appliance standards	Energy efficiency Greenhouse gas reduction Peak demand reduction	Government	Regulation
Embedded generation	Demand response Peak demand reduction Renewable energy utilisation	Network Retailer	Network – network support contracting, standing offer
Energy efficiency (lighting, insulation, appliance trade-outs, maintenance and upgrades, green plugs for standby, motors – standalone and OEM)	Energy efficiency Greenhouse gas reduction Peak demand reduction	Government Private sector equipment providers Private sector consultants	Customer education Price and environmentally motivated demand response State-based incentives and certificate schemes Audits and action plans
Smart building controls (programmable thermostats, load shed prioritisation against peak price, BEMS, controls based on occupancy or open doors)	Energy efficiency Peak demand reduction Greenhouse gas reduction Demand response	Government Private sector equipment providers	Price and environmentally motivated demand response State-based incentives and certificate schemes Private sector equipment providers Customer education
Smart process control (industrial process control)	Energy efficiency Peak demand reduction Greenhouse gas reduction Demand response	Government Private sector equipment providers	Price motivated demand response Better process control and productivity State-based incentives and certificate schemes Private sector equipment providers Customer education

Type of DM action	Applicable types of DM	Parties most typically involved	Arrangements most frequently used
Thermal storage (ice storage, under-floor heating, heat banks, loads with thermal lag)	Peak demand reduction (impact on greenhouse gas not straightforward)	Private sector equipment providers	Price motivated demand response
Dual fuel	Demand response Possible greenhouse gas reduction	Network Private sector equipment providers	Network support contract or standing offer
Fuel substitution (gas, renewables)	Peak demand reduction Greenhouse gas reduction	Government Private sector equipment providers	State- and Commonwealth incentive programs Price and environmentally motivated demand response

Appendix 3: International examples of DM arrangements

This appendix provides a number of case studies of DM initiatives that have been pursued in other jurisdictions and, when possible, the effects that those initiatives have had in the relevant market.

4.1 Orion New Zealand Limited

Orion New Zealand Limited (Orion)[35] is the electricity distribution network supplying Christchurch and the Canterbury region in New Zealand. It has run a dynamic pricing strategy targeted at increasing its system load factor for some 18 years, and achieved conspicuous success.

In 1993/94, Orion could see that peak demand growth would trigger a major upgrade in transmission capacity down the South Island for very little initial return for customers. It was also apparent that the very poor load factor of that demand growth (weather sensitive) was driving substantial future investment in distribution capital.

At the time, Orion was not subject to industry-specific economic regulation. Rather, it was subject to general competition law and to the 'threat' of regulation if it was seen to be abusing its market power. In short, Orion had few regulatory constraints. However, it was (and continues to be) owned by two major municipal councils and there was:

- significant competition for the provision of capital by these groups and ongoing pressure to ensure a decent return;
- an expectation of high system reliability during peak (cold) seasons; and
- ongoing pressure to limit the economic impact on local industry of electricity prices.

This prompted Orion to investigate the potential application of more cost reflective pricing.[36] This led it to develop and implement dynamic pricing – initially to the major customers in the region but later to all customers. This meant ultimately that more than 50 per cent of the electricity price that large customers paid was based on the costs associated with meeting peak network demand. This pricing was transparent to these customers, since they had separate connection agreements at the time.[37]

This pricing was then developed for all voltage levels and was charged to retailers directly using grid exit point settlement data (as is effectively the case in Australia for NEM settlement). The use of the net system load profiles with dynamic pricing (charged monthly not instantaneously) has since prompted retailers to install interval meters due to both the increased pricing risks posed by cost reflective distribution tariffs, and for associated competitive purposes.

Eighteen years later, the dynamic peak demand price continues to be based on the LRAIC of adding demand at peak.

The development of dynamic, more cost-reflective prices was complemented with an extensive demand side support program aimed at assisting customers to make the transition to the new regime. The program was very successful in stemming peak demand growth even though economic growth continued to be very healthy throughout the region. It also enabled the upgrade of the transmission system to be deferred by at least 15 years. Orion is also now running this peak demand reduction strategy across the north island on behalf of other networks to continue to reduce the overall costs of transmission.

The following charts show the very significant effects of this program, ie:

- it has significantly improved the load factor of the network;
- it has deferred substantial capital expenditure;
- it has seen the development of highly innovative demand control systems and peak reduction strategies; and
- it has significantly benefited local industry and consumers.

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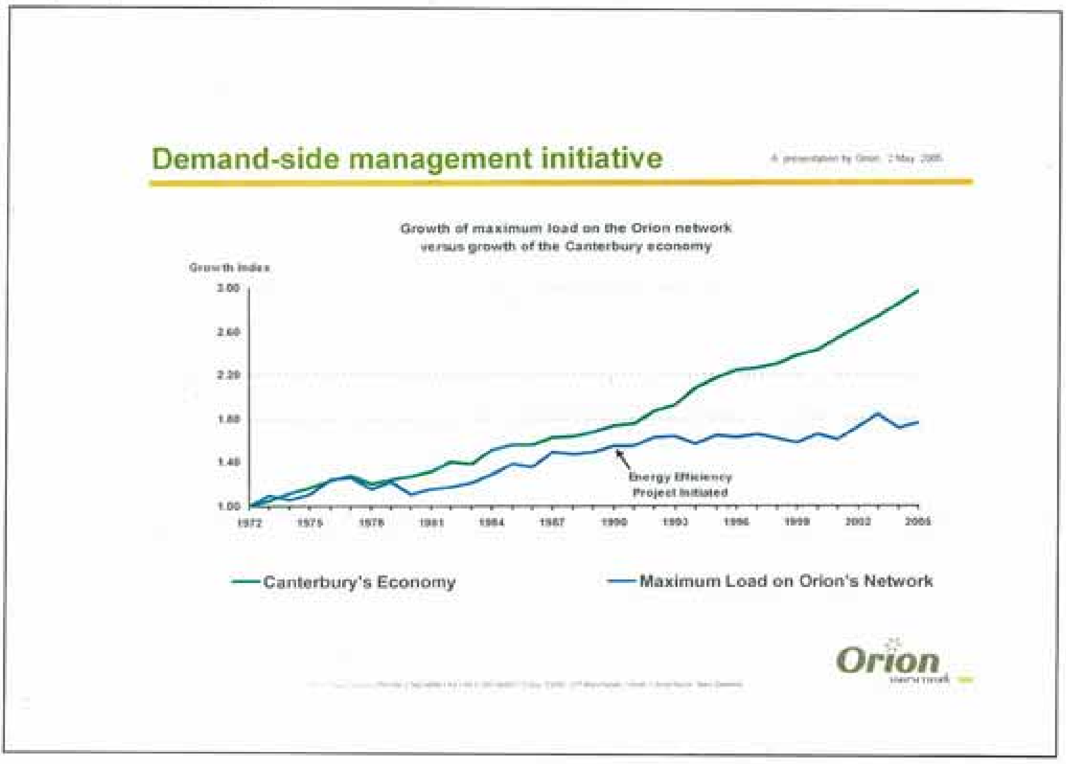
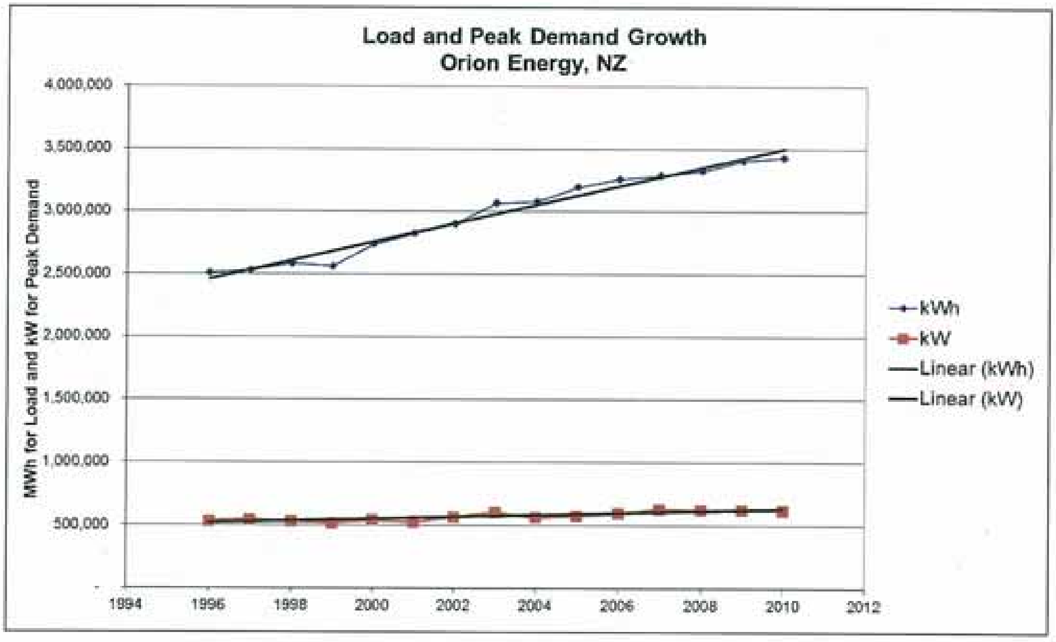
35 Formerly Southpower.

36 J Snow assisted with this process, developed the LRAIC and developed and implemented the demand-side response program.

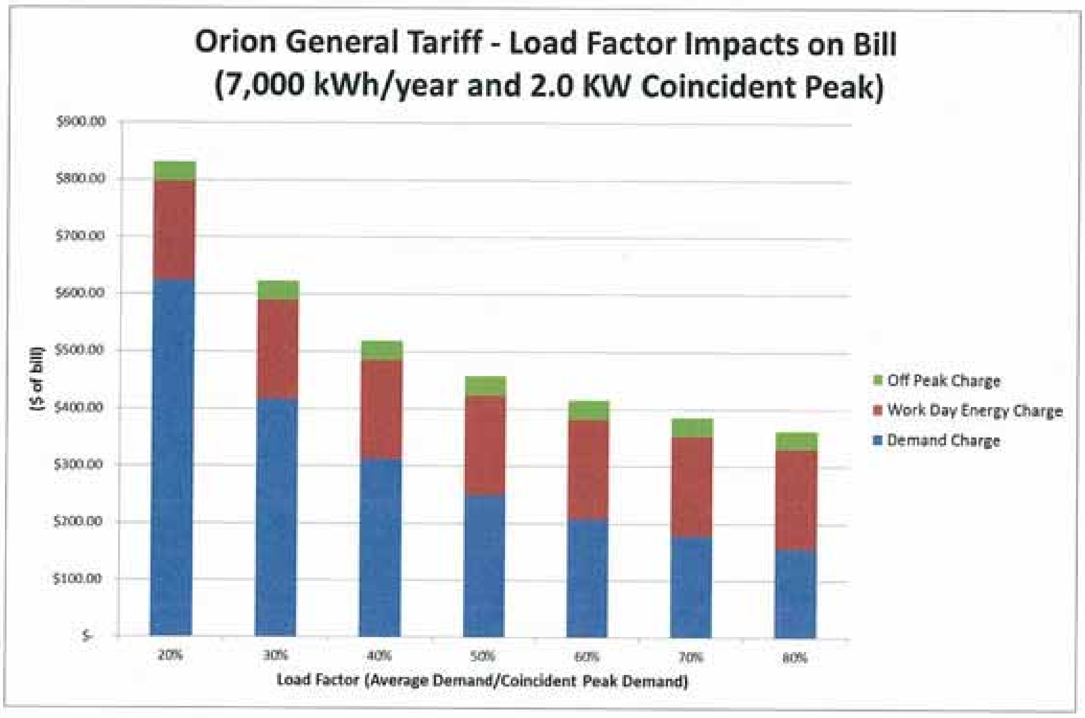
37 Orion was the main retailer in the region at the time, but has since ceased this function

The upstream impacts – including the transmission network benefits – have also been effectively passed through to customers for no additional cost. Importantly, Orion has also activated the demand side and retail markets to participate in the program. Put simply, it has become the normal order of business with the program spreading to adjacent areas and further.





The following chart demonstrates the impact on the general supply group – low voltage supply customers. The network costs escalate in response to individual load factors. Actual peak demand use is determined dynamically for each retailer's load but charged on a monthly basis (annually ex-post calculations) to avoid cash flow issues.



The Orion experience therefore serves as an informative case study of the types of benefits that can potentially be delivered throughout the supply chain through the adoption of relatively straightforward reforms.

4.2 California

4.2.1 Market Structure

The electricity industry in California is dominated by the state's three large, investor-owned and vertically integrated utilities, Pacific Gas & Electric, Southern California Edison and San Diego Gas and Electric, each of whom operate in franchise transmission/distribution areas. Between them they serve 11.5 million electricity accounts and 5.2 million gas accounts[38].

The state also includes municipal utilities, which are generally only distribution and retail companies, though some also own generation facilities, and Community Choice Aggregators (CCAs), which are generally operated by municipal or county level governments.

Customers can also exercise choice of their retail providers. These retailers are called Electricity Service Providers (ESPs), though the vast majority of the customers continue to buy their electricity from the incumbent retailers.

4.2.2 Policy and Regulation

Electricity and broader energy policy is set by the California Energy Commission (CEC), working in concert with state government. The California Public Utilities Commission (CPUC) is the state-based regulatory body, and has jurisdiction of most licensing, regulatory and tariff-setting. Some matters are regulated at the federal level, by the Federal Energy Regulatory Commission. There is also an independent system operator, CAISO.

Regulation is undertaken on a revenue cap basis, which de-couples revenue from throughput. Fuel costs for utility's own power plants plus any power purchase arrangements are treated as pass through costs, and the remainder to the utilities costs, once approved by the regulator, plus a return on invested capital, are then recovered through tariffs. The tariff-setting approach removes revenue risk due to the volume of electricity sold to customers, though the utility is exposed to risk in managing its capital and operational expenses[39].

California has a long history in energy efficiency and demand management, and has included aggressive appliance and building standards. The state's first Energy Action Plan, developed jointly by the CPUC, CEC and the California Consumer Power and Conservation Financing Authority (Power Authority) in 2003 established a preferred "loading order" for the resources to be used in meeting the state's demand for

[38] Company websites
[39] PG&E Corporation and Pacific Gas and Electric Company, *2010 Annual Report*, p 10.

electricity. The order of preference for the development of resources was as follows: energy efficiency, demand response, renewables, and distributed generation.

The stated intent of the loading order was to develop and operate California's electricity system in the best, long-term interest of consumers, ratepayers, and taxpayers. Subsequent policy papers identified the barriers that must be overcome to integrate energy efficiency, demand response, renewables, and distributed generation into California's electricity system, and suggested policy options and regulatory instruments to address these barriers.

Two instruments that evolved from the loading order and Energy Action Plan that have played significant roles in developing the involvement of the state's electricity utilities in energy efficiency and demand response – and that are relevant to the issues raised by the AEMC are the Resource Adequacy Requirement Program and Energy Efficiency Risk/Reward Mechanism.

Under the Energy Efficiency Risk/Reward Mechanism, each of the three investor-owned electricity utilities are assigned a target energy efficiency goal, which is expressed in an annual reduction in average customer consumption. They are also provided with an incentive for achieving a specified percentage of the target. Originally, only technology-based efficiency programs were eligible to be included in utility programs to meet the target. However, in 2010, the Commission decided that the verified results of behaviour-based energy efficiency programs should also be allowed to be counted toward the utilities' targets based on the experience of a number of pilots in California and other regions that showed that these programs can produce significant and measurable energy savings.

As an example of the size of these programs in financial terms, in the years 2006 -2008, PG&E (the state's largest utility) spent approximately USD 915 million and received USD 104 million in incentive payments – equivalent to a return on investment of 11.3%. Subsequently, the CPUC authorised PG&E to collect $1.3 billion in its tariffs to fund its 2010 through 2012 programs, a 42% increase over the amount authorised for its 2006 through 2008 programs. However, the regulator also proposed to set a cap on the total amount of incentive payments to be made to the three companies in aggregate in order to increase the proportion of the benefit provided by the increased energy efficiency to customers.[40]

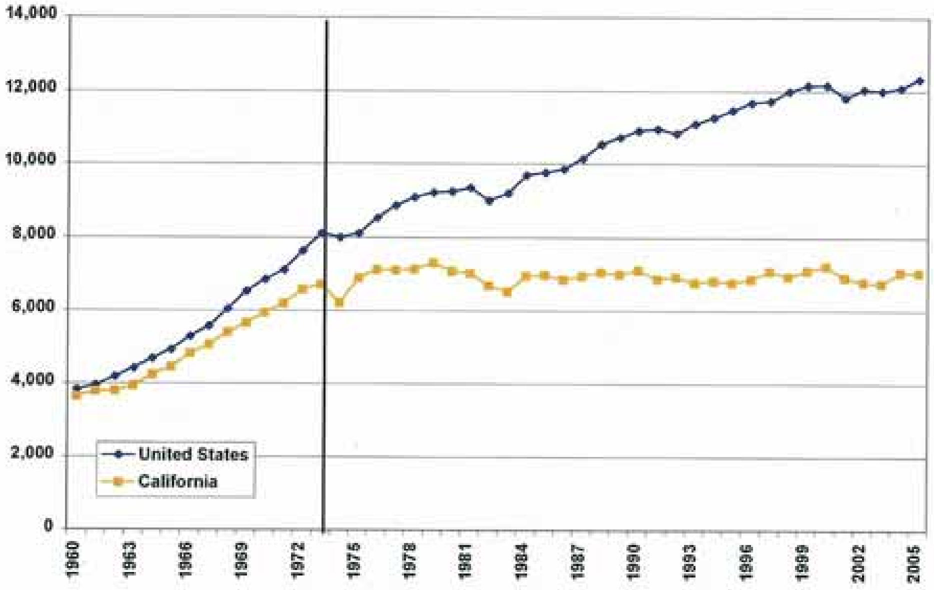
Under the Resource Adequacy provisions, each electricity supplier is required to procure (and to file with the CPUC) evidence demonstrating that it has procured sufficient capacity resources including reserves needed to serve its 115% of its aggregate system load on a monthly basis. In addition, the procurement must be adequate to provide the specified level of capacity for its load within each transmission-constrained local area in which the utility has customers. The motivation behind this requirement was to ensure that sufficient capacity would be available to the CAISO to meet demand when and where needed[41].

4.2.3 Results

California has achieved remarkable results as compared to the rest of the US in terms of average consumption per household, as shown in the figure below.

[40] PG&E Corporation and Pacific Gas and Electric Company, *2010 Annual Report*, p 32.
[41] http://www.cpuc.ca.gov/PUC/energy/Procurement/RA/

U.S. v. California Per Capita Electricity Sales



Source: California Energy Commission, *2008 Energy Action Plan Update*, Figure3, p 6.

While the energy efficiency programs that the utilities are mandated and incentivised to undertake do not account for all of this effect, they have certainly contributed materially to it.

As shown in the two tables below, the utilities have also met their demand response targets, and demand response is now certainly an integral part of the state's capacity mix.

Investor utility demand response goals and results (MW)

Goals				
Year	***PG&E***	***SCE***	***SDG&E***	***Total***
2003	150	150	30	330
2004	343	141	47	531
2005	450	628	125	1,203
Results 2005				
Price responsive programs	371	150	35	556
Reliability programs	335	1,145	76	1,556
Total	706	1,295	111	1,212

Source: California Energy Commission, *Implementing California's Loading Order for Electricity Resources*, Table E-2, p E-7, and Table E-3, p E-8.

2011 California Summer Supply and Demand Outlook (MW)

	June	July	August	September
Net generation capacity	74,566	74,393	74,135	73,943
Demand response, interruptible and curtailable programs	2,811	3,054	2,946	2,982
Total capacity	77,377	77,447	77,081	76,925
DR as percent of net generation capacity	3.8%	4.1%	4.0%	4.0%
50 POE demand	53,123	57,343	59,571	54,220
DR as percent of 50 POE demand	5.3%	5.3%	4.9%	5.5%
10POE demand	57,579	62,163	64,527	58,800
DR as percent of 10 POE demand	4.9%	4.9%	4.6%	5.1%

Source: California Energy Commission, *Summer 2011 Electricity Supply and Demand Outlook*, Table 2, p 5.

4.3 Italy

Italy is an interesting case study because it was the location of the first widespread deployment of smart meters. Specifically, in 2001, the then state-owned, vertically integrated[42] electricity company Enel, decided to replace its Italian customers' traditional electromechanical meters with new, electronic smart meters.[43] This €2 billion[44] investment project was the first of its kind in the world, and made it possible for Enel to take meter readings in real time and manage contractual relationships remotely.

Today, Enel has rolled out advanced metering infrastructure to approximately 32 million Italian customers who are remotely managed and serviced.[45] This number is unmatched on a worldwide basis. The introduction of smart meters enabled Enel to introduce a new tariff system that enabled prices to be levied on an hourly basis. This enables end customers to select supply contracts that are better suited to their individual requirements.[46] Customers are also able to view their energy consumption, the current price and their contractual tariffs on the meter display.[47]

In short, this unprecedented deployment of smart metering infrastructure, coupled with tariff reforms, has provided Enel's customers with much more timely information to which they can then respond by making informed consumption decisions. In other words, the roll-out has provided greater opportunities to facilitate an effective demand-side response from customers. There is some evidence to suggest that customers have responded to those efforts by changing their behaviour in a material way.

Specifically, Enel has estimated that, following the introduction of smart meters, its peak demand declined by around 5 per cent.[48] It attributes this to greater customer awareness and the improved price signals that smart metering has enabled. Enel has also estimated that the roll out of smart metering infrastructure has reduced

42 Enel produces, distributes and sells electricity throughout Italy, the rest of Europe, in North American and in Latin America.

43 Gerwen, Jaarsma, & Wilhite, (2006), *Smart Metering*, July 2006, KEMA, The Netherlands, p.6.

44 European Union Information website, available at: <http://www.euractiv.com/en/climate-environment/enel-italy-reaping-first-mover-benefits-smart-meters>.

45 Enel website, available at: <http://www.enel.com/en-GB/innovation/project_technology/zero_emission_life/smart_networks/smart_meters.aspx?it=0>.

46 Enel website, available at: <http://www.enel.com/en-GB/innovation/project_technology/zero_emission_life/smart_networks/smart_meters.aspx?it=0>.

47 European Union Information website, available at: <http://www.euractiv.com/en/climate-environment/enel-italy-reaping-first-mover-benefits-smart-meters>.

48 European Union Information website, available at: <http://www.euractiv.com/en/food/rising-electricity-bills-smart-meters-help-consumers-news-502921>.

its annual meter management costs by 5 per cent, and almost halved the costs attributable to service interruptions.[49]

4.4 United Kingdom

In the United Kingdom (UK), initiatives specifically designed to entice a demand-side response are presently limited to interruptible contracts for larger business consumers, transmission charges that increase substantially during times of maximum demand and various types of time-of-use (TOU) tariffs for domestic and, to a lesser extent, small business consumers.

4.4.1 TOU tariffs

Currently, the majority of domestic customers in the UK have little or no incentive to shift their consumption away from peak periods, because the prices that they pay for electricity does not depend upon when that consumption occurs.[50] Most customers still pay a flat price for all of the electricity that they have consumed.

Moreover, because advanced interval metering infrastructure has not been widely deployed in the UK, the TOU tariffs that do exist are not dynamic, ie, peak and off-peak periods – and associated TOU prices – are fixed in advance.[51] Nonetheless, all major suppliers offer tariffs under which electricity is cheaper at night and slightly more expensive during the day.[52] Some suppliers also offer tariffs with three different times of use, including a shoulder period.[53]

In addition, around 1 million households that are on TOU tariffs have dynamic teleswitching functionality on their meters. This enables the retailer or the local distribution business to remotely 'switch' the consumer's electricity supply.[54] Specifically, it enables suppliers to vary the times that electric storage heaters are on or off, and allows distributors to manage constraints and prevent overloading.[55]

There are currently a number of trials being conducted to gauge whether a more extensive demand-side response can be elicited from households. In particular, Ofgem is managing the Energy Demand Research Project, in which around 59,000 households are trialling initiatives such as more frequent billing, smart meters and visual display units.56 The results of this trial are expected later this year.

In conjunction, the UK Department of Energy and Climate Change announced in March 2011 the Government's plans for a mandatory national roll-out of smart meters.[57] The intention is to install 53 million smart meters in households and businesses by 2019, with the roll-out expected to commence in 2014.[58] Ofgem has previously estimated that the installation of smart meters may reduce peak demand by around 2.5 per cent and overall demand by 1 per cent.[59]

4.4.2 Interruptible contracts

Large industrial and commercial customers in the UK can provide demand-side management by contracting directly with the transmission or distribution network provider for interruptible load. Although the precise contractual terms may vary, all involve the customers being instructed to limit the amount of energy that they use when the system is tight. In return, the customer receives either reduced transmission system levies and/or a reduced overall electricity bill.60

We are not aware of any quantitative estimates of the extent of interruptible contracts in the UK, or of their effect on system peak demand. However, we understand that some suppliers are currently undertaking trial

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49 European Union Information website, available at: <http://www.euractiv.com/en/climate-environment/enel-italy-reaping-first-mover-benefits-smart-meters>.

50 Ofgem, *Demand Side Response: A Discussion Paper*, 15 July 2010, p.10.

51 Ofgem, *Demand Side Response: A Discussion Paper*, 15 July 2010, p.11.

52 This is a potentially attractive offering for customers who are happy to use appliances overnight and who have night-time electric storage heaters.

53 Ofgem, *Demand Side Response: A Discussion Paper*, 15 July 2010, p.11.

54 *Ibid.*

55 *Ibid.*

56 Ofgem, *Demand Side Response: A Discussion Paper*, 15 July 2010, p.12.

57 Department of Energy and Climate Change Press Release, 30 March 2011, available at: http://www.decc.gov.uk/en/content/cms/news/pn11_032/pn11_032.aspx

58 Department of Energy and Climate Change Press Release, 30 March 2011, available at: http://www.decc.gov.uk/en/content/cms/news/pn11_032/pn11_032.aspx

59 Ofgem, *Domestic Metering Innovation*, February 2006.

60 Ofgem, *Demand Side Response: A Discussion Paper*, 15 July 2010, p.13.

load management services targeted at large energy intensive users with a view to expanding them to less intensive energy users if they are successful.[61]

4.4.3 Triad system

Electricity retailers in the UK must pay the transmission network operator (National Grid) for energy transmission, calculated from their demand in each region at the times of the three highest national half hour peaks. These peak demand times are known as 'triads' and historically have occurred between November and February – typically between 5.00pm and 6.00pm.

The triad charges are passed on to large industrial and commercial customers (but not small customers), based on their own demands at the time of the triads. Customers have the option to be notified by the supplier of when a triad period is *expected* to occur – although there is no way to be completely sure when the three system peaks will occur.[62]

The triad pricing system is a means for National Grid to recover its network costs while imposing an incentive on large customers to minimise their consumption during times of system peak demand. This potentially reduces the need for investment in the system, although, we are not aware of any reliable studies of how much the arrangements have reduced system peak load.

[61] Ofgem, *Demand Side Response: A Discussion Paper*, 15 July 2010, p.14.
[62] *Ibid.*

Appendix 4: Smart Grid Smart City

Overview

Following a successful bid for the Australian Government's Smart Grid Smart City program (SGSC), Ausgrid has commenced working on the project that will keep Australia at the forefront of energy technology and lead to ground breaking changes to the country's energy industry.

The SGSC entails the development of Australia's first commercial-scale smart grid in Newcastle, New South Wales, in a demonstration project that will help identify technical and economic opportunities and challenges in implementing a new generation of innovative electricity distribution technology. Parts of the trial will also be conducted in Newington, Sydney's CBD, Ku-ring-gai and Scone. This initiative will gather robust information about the costs and benefits of smart grids to inform future decisions by government, electricity providers, technology suppliers and consumers across Australia.

A smart grid is a new type of electricity network that uses advanced communication, sensing and metering that more efficiently manages electricity supply and demand. Smart grids give households the ability to better manage their energy use by providing information about how much energy is being used and the estimated costs. Smart Grid, Smart City will also trial distributed storage which can provide extra electricity to the power supply during peak periods.

The Ausgrid consortium testing the smart grid technologies and ensuring their suitability for Australian conditions includes TruEnergy, IBM Australia, GE Energy, AGL, CSIRO, Transgrid, and Newcastle City Council.

Customer Applications

The SGSC program involves a large trial of 'Customer Applications' - technology and tariff related products for residential consumers. The SGSC project is currently planning for commercial deployment of the following categories of Customer Applications from March 2012:

- Information feedback devices (without tariffs)
- Community education programs eg. residential energy audits
- Enhanced Retail Bill Payment options
- Rebates from Networks and/or Retailers to reward demand management activities by consumers i.e. energy saving/shifting efforts
- Engineering solutions such as Air Conditioner cycling
- Innovative tariffs that involve a Network and Retail component. This item is of relevance to Ausgrid's FY12 Pricing Proposal.

In keeping with common practice in the NEM, it is expected that each retail tariff structure described above will be based on the underlying network tariff structure, i.e. have the same general structure. Consequently Ausgrid has been working with the SGSC's participating Retailers to devise innovative tariff structures. Each tariff aims to deliver benefits in at least one of the following categories, with no negative impacts in the others:

- Consumers – through enhanced visibility of their energy use and likely costs, and a wider range of bill savings and payment options
- The Environment – through reduction in energy usage
- Networks – through directing consumer's energy usage away from network peaks
- Retailers – through directing consumers' energy usage away from periods of high wholesale costs

The development of new tariffs is also limited by available technology. For example, while Real Time Pricing (RTP) has theoretical merit, the outcome of discussions with project stakeholders prioritised tariffs which are closer to having the requisite technologies in place.

The SGSC project is mindful of the need to ensure suitable customer protection strategies are in place during the trial. Elements of the trial designed to ensure this are:

- All SGSC tariffs are voluntary and Retail contracts will include without-penalty exit clauses
- Providing a high standard of information to consumers to allow them to choose to become involved in the trial and benefit
- The SGSC program has committed to working with community groups representing the interests of customers who may experience hardship due to current or future energy costs.

Operation of the Pricing Trial

Although the SGSC trial is still being designed, at this stage it is envisaged that:

- Retailers will market innovative Retail tariffs to customers in the trial area. As the innovative tariffs require time-based metering, all customers taking up an offer will have a smart meter installed
- The Retailers will inform Ausgrid as to which customers took up which SGSC Retail tariff product. Ausgrid will from that point charge the corresponding Network Tariff and the Retailer will commence billing the new Retail tariff
- Ausgrid will return each site to a non-SGSC Network Tariff when the customer exits their SGSC Retail tariff at the end of the trial period.

As the relative weighting of tariff and non-tariff Customer Applications is still in progress, an estimate of the number of customers who voluntarily uptake new Retail tariffs that include a new Network tariff is not yet determined. The likely range is between 5,000 and 30,000.

Tariff Design Principles

The design of the draft SGSC network tariffs has been informed by local and international thinking on efficient and cost-reflective tariff structures that have potential to deliver the previously noted benefits to customers, the environment, Networks and Retailers.