Major Energy Users Inc.

Australian Energy Markets Commission

Power of choice - giving consumers options in the way they use electricity

Comments on the Issues Paper

Submission by

The Major Energy Users Inc

August 2011

Assistance in preparing this submission by the Major Energy Users Inc (MEU) was provided by Headberry Partners Pty Ltd and Bob Lim & Co Pty Ltd.

This project was part funded by the Consumer Advocacy Panel (www.advocacypanel.com.au) as part of its grants process for consumer advocacy and research projects for the benefit of consumers of electricity and natural gas.

The views expressed in this document do not necessarily reflect the views of the Consumer Advocacy Panel or the Australian Energy Market Commission. The content and conclusions reached in this submission are entirely the work of the MEU and its consultants.

TABLE OF CONTENTS

Executive Summary

The Major Energy Users Inc (MEU) supports the AEMC`s most recent efforts at reviewing options for demand side participation (DSP) in the electricity market, and especially from its viewpoint of empowering consumers with choices and options in the way electricity is used. This empowering of consumer choices provides much and is a refreshing perspective in its approach to DSP as other previous approaches have not been successful because of a failure to adequately reflect consumer perspectives.

The MEU considers that the starting point to this review should be a clear understanding of the electricity market as it currently is, with rapidly escalating electricity prices caused by:

- Increasing concentration with a few dominant businesses now controlling key elements,
- The re-aggregation of generators and retailers,
- The increasing volatility and riskiness of the wholesale market due to the increasing "peakiness" of regional load profiles and the easy ability of some generators to exercise market power even in the absence of scarcity of supply
- The over-incentivisation of network investments by unbalanced rules
- Large increases in network access charges from other causes such as excessively high returns, propose/respond model, minimal ability to control opex setting and conservative approaches to forecast usage and performance settings
- Massive interventions by all levels of government in the electricity market
- The myriad renewable energy and energy efficiency schemes.

As strongly advocated by the MEU, the key challenge for the AEMC in seeking to increase active participation in the electricity market by consumers, is to make it attractive and rewarding to do so, that is by incentivising behavioural change, just as has been done in the case of the electricity supply side of the market.

In this submission the MEU identifies various impediments that should be removed and provides responses to the specific questions raised in the AEMC Issues Paper

In addition, this submission carries an attachment which reviews a wide range of reports addressing DSP in many jurisdictions. This attachment includes valid conclusions considered useful for the AEMC's consideration.

1. Introduction

The Major Energy Users Inc (MEU) welcomes the opportunity to provide views on the AEMC's Issues Paper "Power of choice - giving consumers options in the way they use electricity".

1.1 A general overview of the electricity market

In looking at the specific issues raised in the Issues Paper, it is pertinent to look at the reasons for the changes in the structure of the electricity supply industry over the past decade or so.

The original concepts behind the NEM (as propounded by Professor Hilmer) were that disaggregation of the vertically integrated government owned electricity providers would result in increased efficiencies, prevent the extraction of monopoly rents in sectors that are natural monopolies, and through robust competition in contestable sectors, deliver efficient services, when coupled with efficient economic regulation. In the monopoly sector, the disaggregation was intended to allow consumers to be more involved in managing their demand for electricity supplies and to minimise their costs through greater transparency.

Despite the initial moves in the electricity market to foster robust competition by diversifying ownership, the Australian electricity industry has, in fact, become more concentrated, along with re-aggregation between retailers and generators[1]. During the 'reform period', this process of concentration has resulted in fewer retailers and three dominant vertically integrated "gentailer" businesses dealing in multi-fuels, including wind, solar and other renewable energy sources. Investments in new generation have largely been undertaken by these vertically integrated businesses who have also procured many generation assets made available for sale[2]. There has been little interest by merchant/independent generators building new generation assets since the early period in the development of the NEM.

These outcomes (ie fewer independent generators and a very few very large energy retailers which are also the major providers of new generation) would suggest that the barriers to entry are higher now in both retail and generator sectors since the disaggregation process.

The MEU has analysed the degree of competition in the NEM based on calculations of the Herfindahl Hirschman Index (HHI), which an indicator used to provide a helicopter view of market competition. The revealed trends are not encouraging.

---

[1] For example, it is interesting to note that Origin Energy and AGL Energy are now larger businesses than any of the state owned entities that were the initial focus of the disaggregation
[2] These include the "gentrader" assets sold recently in NSW

For example, the HHI for retail in the NEM (now that EnergyAustralia, Integral Energy and Country Energy retail functions have been acquired by Origin Energy and TRUenergy) indicates that the electricity retail market is classified as "highly concentrated".

Generation is classified as "moderately concentrated" on a NEM wide basis, but in each region of the NEM, generation is "highly concentrated" in all regions but Victoria, where it is classed as "moderately concentrated".

Of interest is that the HHI for generation in the NEM states prior to disaggregation indicates that generation only just reached the classification of "highly concentrated", and the market concentration of retail was of a similar order. This indicates that whilst the process for disaggregation of generation has achieved some small reduction in generation market concentration, the outcome for retail shows that there has been an increase in market concentration on a NEM wide basis.

Quantitative analysis, such as this, clearly reinforces the intuitive views that the NEM has achieved only small gains in generation competition (although there are marked regional differences) but retail concentration has increased markedly in recent years. Yet, despite such quantitative analysis demonstrating the reverse, there has been a curious mantra perpetuated by some; that competition has increased as a result of the disaggregation of the government owned vertically integrated supply businesses.

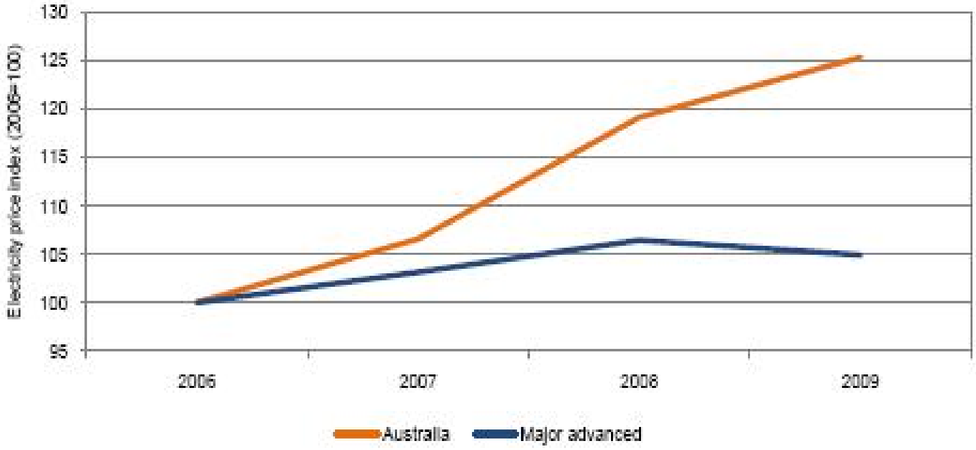
Such minimal reductions in generation competition with reduced retail competition provides, prima facie, a view that there are significant barriers to entry of new generation and even more so for new entrant retailers.

The NEM design is based on providing strong incentives for the supply side to provide a vibrant and responsive electricity supply. But in delivering a reliable electricity market, the incentives provided to supply side participants have resulted in a number of detrimental outcomes, including:

- The sharply increasing cost of electricity as identified by Garnaut[3] in his update #8 in both relative (figure 1) and actual (figure 2) terms[4]

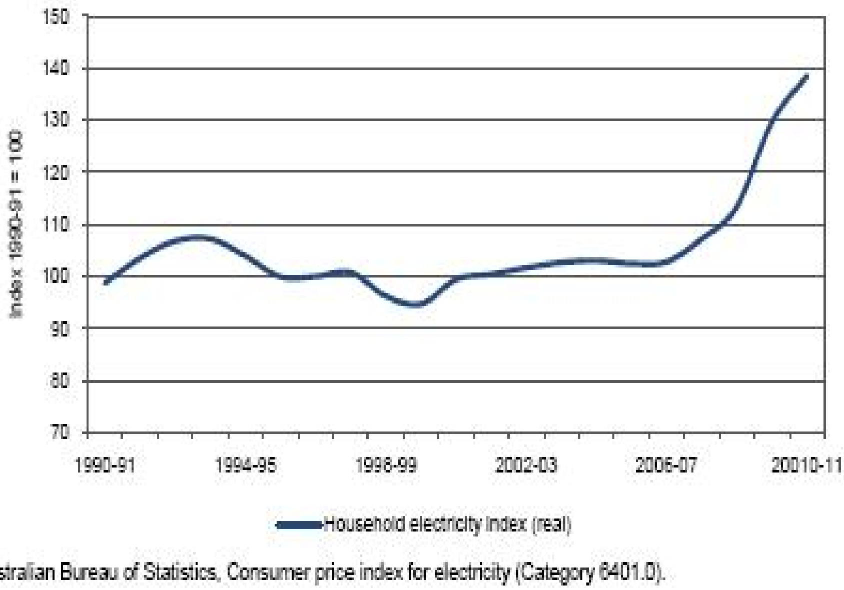
[3] Garnaut: Climate Change Review Update 2011 Transforming the electricity sector
[4] ibid pages 7 and 8

Figure 1: Real electricity prices in Australia and the seven major advanced economies, 2006 to 2009, index in US dollars



Source: IEA 2009, OECD 2010.

Figure 2: Real household electricity price movements
(constant 100 would mean electricity prices rising at same rate as other prices)



Source: Australian Bureau of Statistics, Consumer price index for electricity (Category 6401.0).

- Electricity consumption in recent years has flattened to the extent in some regions electricity consumption is falling such as in NSW. This fall in NSW might be a result of the massively increasing costs of electricity in that region.
- The apparent use by state governments to use their electricity assets to extract indirect taxation from electricity consumers through ever increasing dividends
- The separation of the setting of network reliability performance standards (set by governments) from the costs involved (set by the regulator)

- Increased consumer costs caused by the continually increasing:
    - Volatility and risks in the market resulting in increased costs for consumers
    - Transaction and prudential costs
- The loss of the benefits of competition by concentration and raising of barriers to new entrants by:
    - A reducing number of participants due to amalgamation and sale of government owned entities to existing market participants
    - The re-aggregation of generation and retailing and the emergence of the "gentailer" model of market participant
    - The ability of generators to exercise market power

Overall, whilst the supply side incentives have delivered a reliable electricity supply system, there have been some significant negative outcomes to the approach taken.

1.2 Encouraging demand side participation

The key challenge for the AEMC in attempting to increase the active participation by consumers in the electricity market is to make it attractive and rewarding to do so. The electricity market designers have actively provided incentives to supply side participants to encourage behavioural change in the market but have failed to recognise that incentives are just as necessary for demand side participants. As a result there has been minimal involvement in the electricity market by consumers. Analysis of the way the market operates now and feedback from end users of electricity highlights a number of areas that need to be addressed in order to encourage greater demand side participation.

1.2.1 Electricity cost price signals

- Retailers prefer to sell electricity as they get a margin on the sales they make. Therefore, there is an inbuilt disincentive on retailers to offer DSP products to end users. Those retailers that do offer to assist in demand side responsiveness, seek to have the lion's share of any benefit that is achieved, reducing the incentive on end users to get involved because the reward does not offset the costs they incur nor the risks the end user would need to carry.
- The spot market offers an opportunity for an end user to reduce demand when the spot price is high. The costs to set up to operate as a spot user of electricity are large, and to do so requires considerable management attention and a reduction in production when spot prices are high. The barriers to smaller users of electricity to operate in the spot market are high and the rewards are variable. Few end users (by number) of any size operate in the spot market for this reason, although those that do tend to be larger users of electricity.
- The impact on the market of any one large consumer ceasing to use electricity when spot prices are high is modest when compared to the

output of a generator. This means that multiple end users have to shed load to offset the relative market power of the large generators. Not all consumers will be able to shed load on call (they may have critical needs, they may already be off line, etc) so aggregation of those prepared to shed load at call is needed.

- There is a need for aggregators of DSP (not locked into retailing) to be able to operate in the market but the current structure does not make this viable. For example, end users must have retail contracts (or be market participants) so the benefits of shedding load at high price times would go to the retailer (unless the end user has spot market exposure) and not the aggregator.

1.2.2 Self (embedded) generation

- The costs of self generation suffer from loss of scale, meaning self generation of electricity is more expensive on a per unit basis than large scale generation
- Network signals are required to price demand at non peak demand times to send a signal to load shift. Such an approach would incentivise consumers with the ability to self generate to ensure their generation plant is operating at peak demand times.
- Network pricing actively acts to prevent self generation as the network requires the same payment for use of the network regardless of the frequency or timing of its use. Network pricing for demand at low demand times is necessary.
- The behaviour of network businesses often results in unreasonably impeding requests for connection agreements with end users` embedded generation.

1.2.3 Networks and network pricing

- Price caps for electricity networks incentivise network owners to increase the use of electricity so there is an active incentive for networks to want increases in demand[5]
- Network pricing is structured to favour low consumption, high demand for electricity. This stops at the point where demand is sufficiently high to warrant the utilisation of demand tariffs.
- Demand tariffs are generally applied to larger users of electricity in order to limit their demand. Demand tariffs are not applied to smaller users[6].

---

[5] For example, one network owner in Victoria in the early years of the NEM provided a cash bonus consumers that installed a refrigerative air conditioner

[6] The addition of demand limiting switches in meter boxes of small consumers could be used to provide a signal to residential and small business with the cost of their demand, eg end users could “buy” the demand they want and by doing so would receive a signal (ie power shut off) if they exceeded this demand. Such an approach provides a non-interval meter approach to manage network peak demand.

- Within the demand tariffs, there are no incentives to limit demand, even at high network demand times creating a major barrier to the provision of demand management when it is most needed.
- High spot prices and high network usage do not necessarily coincide. So how to send a signal to end users when the network usage is high and there are benefits of shedding load to the networks. To provide network support requires the network to contract with a large end user but for a large end user to be able to shed load on demand can be difficult (eg may have critical activities, may not be using power at the time)
- The chapter 6 and 6A rules need to be structured so that there is an incentive on consumers to provide a demand side response. Currently the rules are structured to incentivise network investment and do not provide for strong price signals to incentivise demand side
- Networks have an incentive to prevent demand side responses as a demand side response increases their operational and interfacing costs but concurrently reduces the revenue they get

1.2.4 Other general observations

- There is an assumption made that consumers will address electricity as an input to their cost structure. To some extent this is true (especially for very larger users of electricity), but in reality, most consumers (especially smaller users) have limited time and resources to devote to the input costs and of necessity they focus on the large cost items (which in most cases electricity is not) and those where the effort will give the best outcome. This means that if electricity is a relatively small component of the overall input costs, it may not receive the resources and time needed to provide the outcome desired by the electricity market. This reinforces the underlying reality that the incentive has to be significant and the likelihood of receiving the incentive very high.
- The model being proposed by the electricity market is based on an indirect method to get the desired outcome by pricing signals. Price signals requires the presence of the end user to be aware of what the market is doing at all times and to be physically present to take the action desired by the price signal. More direct methods of limiting demand are more likely to get the desired result.
- Large users of electricity get their load profile from their retailer or NSP. They use their load profile to get the best price available from a retailer. There is a concern that small users of electricity will not be able to access their load profile and even if they do, whether retailers will provide them with any load shape benefit due to the large number of profiles that retailers would have to process.
- Market rules are written for the supply side which are large entities focusing on electricity matters. The same rules are applied to the demand side entities but there is no attempt to reflect in the requirements the relativities between the costs involved and the benefits that might flow.

- There is a disconnect between reliability/licensing conditions and the costs involved and these costs are imposed regardless of the consumer's actual requirements for reliability
- A holistic approach is required to the issue eg better designed housing, better energy efficient consumer products and relating their use to the market. Eg refrigeration is an essential use of electricity but using power for plasma TVs and refrigerative air conditioners is more discretionary. Pricing signals should reflect this difference to drive the desired outcome
- Consumer driven energy efficiency (which is not a direct issue for the electricity market) has the potential to reduce system load factor by reducing consumption but not demand thereby increasing unit costs for power supply

Attached to this submission is a report carried out for the Essential Services Commission of SA which reviews a wide range of reports addressing demand side participation. While this survey was carried out in 2004, the conclusions are still valid and replicate the observations made above.

2. The AEMC approach to the review

This section addresses elements of the review following the AEMC structure of the Issues Paper

2.1 The framework of the review

In chapter 3 of the Issues Paper, the AEMC observes;

> "Theoretically, consumers will be able to interact efficiently in the market when they:
> 1. face the price that reflects the underlying value of resources;
> 2. are able to adjust their consumption in response to that price; and
> 3. see value in responding (taking into account transaction costs).
>
> That is, in order to participate in the market, consumers must have an incentive, ability and willingness to adjust their consumption pattern."

The MEU would agree that these are necessary precedents for initiating demand side participation, but they are not complete. Three of the major aspects of DSP that the surveys detailed in Appendix A show that in addition to the above three aspects above, the demand side entity must be able to:

- Quantify the benefit (ie see that the benefit they will receive is a known outcome) for the action they propose to take
- Know ahead of time what action will be required to receive the benefit
- Be present at the time to take the action that will realise the benefit.

It was apparent from the various trials that have been carried out that it was insufficient to expect that price signals alone will provide the hoped for outcome.

It is also pertinent to note that, although the AEMC framework is predicated on consumers

> "...always mak[ing] the best decision from their viewpoint, based on the prices they face, the technology and equipment they have access to, the information they have and their individual transaction costs...",

there is clear evidence from the surveys of decisions consumers have made[7] in relation to electricity supplies, that consumers will not always make rational decisions. With this in mind, it is clear that rather than relying on signals to

[7] Including those from the various energy ombudsman schemes in the NEM and overseas indicating that a large proportion of electricity consumers when able to switch retailer providers, they have gone to a retailer which charges a <u>higher</u> price

generate the desired behaviour, a more direct methodology is more likely to produce the desired outcome.

2.2 Consumer Participation

In Chapter 4, the AEMC addresses the extent of likely consumer participation in DSP. It highlights that rising power costs will drive consumers towards DSP and to some extent this is borne out as power costs have risen dramatically in the last 2-3 years and there has been a small but noticeable fall in consumption across the NEM, although peak demand has continued to rise.

This might indicate that rising prices have caused this but care is needed in this assessment as the impact of the global financial crisis, the high $A, the extensive floods in the eastern states during 2010/11 and the myriad State based solar feed in tariff schemes will have also caused a downturn in consumption. The probability is that all have contributed but the proportions of each are uncertain. The MEU cautions the AEMC against drawing the conclusion that price alone has been the major cause of this downturn.

The MEU also points out that historically domestic use of electricity falls when prices rise quickly, but over time, the impact of the higher prices tends to lessen as consumers revert to their earlier usage patterns, which are driven predominantly by convenience. It is also probable that industry will revert to fuller production when the impact of the GFC reduces and a lower $A eventuates.

As noted above, a small number of large companies have moved to buying their electricity on the spot market and load shedding when spot prices are high. As the AEMC notes, the ability to do this effectively involves significant cost and management time. The reason this approach is successful for these companies is that they get the full value from the market for their load shedding. However, when these costs are shared with retailers, the benefit to a company prepared to load shed falls away very quickly. In practice, the introduction of an intermediary into the DSP process quickly reduces the benefits to the party providing the DSP to such an extent where the benefits are quickly lost. In this, the retailer has stronger bargaining power than the end user offering DSP, whilst a vertically integrated (gentailer) business may not have the incentive to encourage DSP.

Peak demand shifting can be effectively driven by strong pricing signals, but these will be of most use in relation to network charges. This is because the price signals from the wholesale market do not necessary relate to periods of high demand, nor do they necessarily coincide with network peak demands. This means there is a disconnect between the current pricing signals indicating high demand and the peak demands indicating a need for network augmentation.

2.3 Market conditions needed for efficient DSP

As noted above, there is more to getting DSP (whether efficient or not) than just creating an environment where consumers might take action – a more direct approach is needed to ensure that consumers actually implement the DSP that results in increasing efficiency of the electricity market, as noted in section 2.1 above.

In addition, there has to be an approach that will overcome the inertia for change that is sustained and not transient as has been seen in the past when there has been a price shock.

Further, although DSP is seen as “a good thing” there must be clarity of what is the intended impact of the DSP on the electricity market. The second reading speeches for the introduction of the new electricity laws in 2005 and 2007 were quite explicit – the electricity market is not intended to be the vehicle for social goals to be achieved such as carbon emission reduction, efficient use of energy by consumers, to improve energy conservation or to provide relief to any class of consumer (such as disadvantaged consumers). This means that the electricity market can only be changed to encourage better efficiency *in the electricity market* which will provide a long term benefit to consumers.

The Issues Paper tends to confuse what is considered to be “a good thing to do” as well as what changes are required in the electricity market to allow achievement of aspects which are more related to social goals.

2.3.1 Pricing

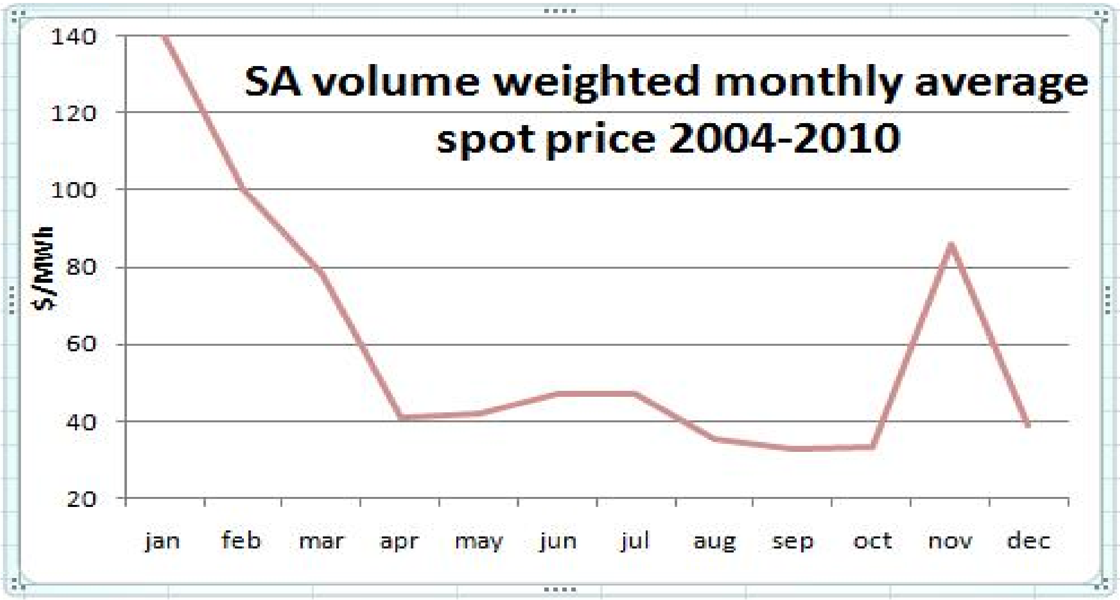
The current pricing approaches for electricity supplies are based on a number of inputs – the wholesale price of electricity, the cost of network provision, the cost of risk management as well as retail margin. How the retailer bundles all this is its call, but there are some constraints on how this is done but the retailer tends to develop its pricing for the electricity supply and pass through the network and other costs. This means the retailer has little control as to how the NSP structures it’s pricing and it would be a courageous retailer that took a risk on repricing the network costs and so exposing itself to mismatches.

To a degree this assists in identifying where DSP can be focused, although such an approach tends to lose the benefits of aggregating the benefits of all areas where DSP provides value.

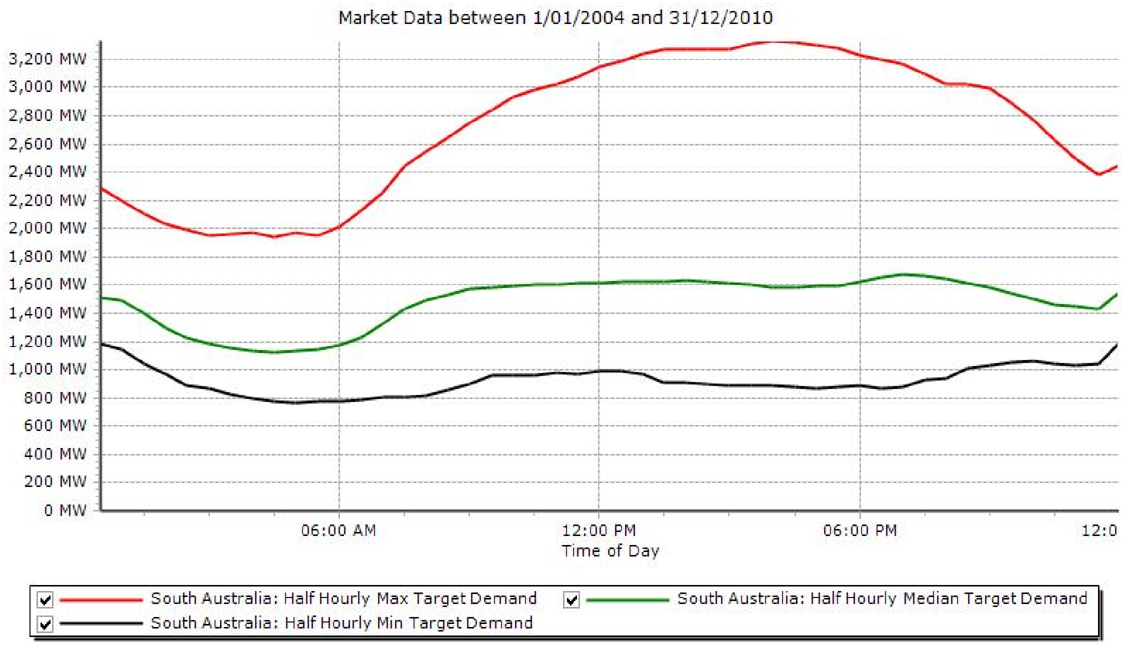
In the area of retail pricing in the early years of the NEM, retailers offered multi-part pricing based on peak, shoulder and off peak times, coupled to winter, summer and mid season periods. Such multi-part offers were seldom accepted and this led to a trend to retail pricing on peak, shoulder and off peak times which reflected the same timeframes as network pricing. Such an approach returned to the pricing used by the vertically integrated government owned electricity providers due to the inherent simplicity of comparison and management of costs. The main drawback of the two/three part tariff of peak/shoulder and offpeak pricing is that the times used to delineate these periods are quite wide and for most consumers, do not lend themselves to easily implement DSP.

It is apparent that consumers prefer simple electricity tariffs but this militates against being able to provide a benefit from various forms of DSP such as load shifting, self generation, conservation and selling power back.

Limiting the provision of electricity to a two part tariff does not reflect the actual movement of wholesale prices over a day as the following figure shows



Source: NEMReview, AEMO data



Source: NEMReview

The first of these figures shows that there is considerable variation of electricity price month on month with the summer months showing a large variation between them as well as to the mid season months; the winter months exhibit a small premium over the mid season. This variation is difficult to accommodate in a simple two/three part tariff for electricity supply and the averaging removes any DSP incentive.

The second figure shows that the greatest peak demands occur in the afternoon and early evening, yet tariffs are based on a peak period of 7 am to 10-11 pm on workdays.

Analysis of network pricing structures shows that NSPs do not provide any drivers for DSP. The simplistic tariffs provided are mainly based on peak/offpeak pricing and demand based tariff elements are set on peak demand recorded in a year.

Overall, there is little benefit from retail or network tariffs to end users from any form of DSP[8]. This prevents strategic load shedding to reduce network demands, and those consumers load shedding on the hot summer afternoons (unless they take spot price risk) receive no benefits.

Those consumers looking to self generate are still charged a network demand tariff which is related to the peak demand recorded in a year, even though this occurs infrequently and may occur in a low system demand period.

---

[8] This even a greater problem when it is realised that under price cap regulation, NSPs are incentivised to increase usage rather than encourage DSP

There is an allegation in the Issues Paper that retail price caps act to prevent DSP. The MEU considers that it is the pricing structures of networks and retailers that prevent DSP rather than retail price caps. The Issues Paper observes that the retail price cap prevents residential and small business users from seeing the impact of price variation with time. This is a distortion of the truth. Network costs comprise more than 50% of the delivered cost of electricity and network tariffs are essentially two part tariffs[9] (peak/offpeak).

Retail tariffs offered are mainly two/three part tariffs and make no attempt to accommodate the relative short periods of very high prices that occur in the spot market. This is understandable as retailers generally have a portfolio of generation pricing for their supplies, and these tend to average out variations in the spot market. The MEU has seen no evidence at all that retail price caps act to prevent DSP.

The Issues Paper seems to present the view that increased flexibility of pricing will lead to a greater ability to engage in DSP. In fact, observation of the retail market indicates that the large majority of consumers do not want increased complexity, but seek simplicity. To send pricing signals as part of everyday tariffs will increase complexity significantly and as consumers have a preference for simplicity, use of everyday tariffs to send signals is probably unlikely to achieve the aims of DSP, although some refinement of tariff setting might result in more cost reflective tariffs.

With this in mind, the MEU considers that the tariff pricing approaches need to reflect real attempts by consumers to provide DSP. Such approaches might reflect actual proposals by consumers:

- Self generation proposals might receive a demand tariff that reflects the peak usage at peak network demand times rather than the actual peak recorded in a year. The incentive is to ensure the self generator is operating at key times and is scheduled for outage when system demands are low.
- Tariff structures could provide cost reduction incentives for reduction in load during known specified high demand periods other than the general "peak" period
- When a consumers requests, a retailer could offer a price reduction in charges for reducing demand at times of high spot pricing
- A consumer might agree to limit its demand on the network. The network would then set a special tariff based on agreed demands. Rather than monitoring actual demand via a smart meter, the agreed demand could be enforced by the inclusion of a demand switch in the meter box set at the agreed level

[9] SP Ausnet in Victoria proposed a summer peak tariff arrangement in it recent revenue reset proposal but this was not approved by the AER, but so far this is the only example of a network proposing a summer peak tariff.

- If a consumer seeks to limit its demand at particular times (eg during the summer period) networks and retailers could provide tariffs based on consumption used at these times rather than averaging across a year.

This listing is not exhaustive but provides a guide as to views provided to the MEU by its members and other end users. What is a common feature is that, as regards the actual benefit for providing DSP, the pricing is sought in a form so that the benefit can be clearly quantified.

2.3.2 Information

There is probably adequate information available in most cases for consumers to identify the value of a DSP option, but such information is not provided in a form which allows a convenient conversion to a cash benefit of implementing the option.

Where such readily available data allows benefit quantification and where the benefit is significant, the DSP option is often implemented. An example of this has been the rapid take up of solar panels. In that case the benefits are quantified and firm and, with this data, a clear cost/benefit analysis can be made. This highlights that actual savings from DSP must be able to be quantified and not just be implied.

Data needs to be in a form that readily allows conversion to the benefit that arises from its use. For example rating an appliance by efficiency stars does not allow a ready conversion to value. What would be useful is for the actual consumption on a daily basis under standard conditions to be identified and with this the benefit can be then be valued using the price for electricity shown on a recent bill.

2.3.3 Pricing Options

The MEU agrees with the approach in the Issues Paper in regard to pricing options, products and consumer incentives, but there is a need to address other issues such as consumer inertia, and incentives against DSP by supply side entities such as retailers getting a better return for selling more electricity and NSPs under a price cap being incentivised to sell more electricity, generators wanting less competition, etc.

The MEU is concerned that there are too many negative elements against DSP (discussed above) embedded in the market and too little of the benefit making its way to consumers, for there to be a strong incentive for consumers to become more active. That there has been so little DSP implemented in the market supports this view.

2.3.4 Consumer investment

The Issues Paper provides a view that there is a need to invest in order to provide DSP, and where the incentive is misaligned, this does prevent DSP being implemented.

From a consumer aspect, they will invest in DSP if the rewards from the investment exceed the costs of not doing so. As a general rule, such investment would be classed as discretionary, where there is no imperative to invest, but where there rewards from doing so will exceed to costs when measured over a period of time. The MEU has been advised by its members that discretionary investment would require a return in 2 years or less, and this would only occur if there was capital available after imperative investments (ie those where the viability of the business is impacted) have been provided for.

It is possible that in a residential environment, this payback period might be even shorter.

From a supply side view, they have to invest sufficiently to ensure they can measure the benefit of the DSP. If there are incentives not to implement DSP, the supply side entity will attempt to demonstrate that the investment they need to make will not provide an adequate return on the DSP. This is an area where a regulator (in the case of an NSP) needs to devote significant attention.

2.3.5 Technology and system capability

The MEU has no additional comments to add to the discussion provided in the Issues Paper.

What the MEU is aware of is that “smart meters” have been in use by large and medium sized businesses for over a decade, during this time, retail tariffs have essentially shrunk to two/three part tariff offerings as the use of multipart tariffs has not been generally been taken up. Further, businesses have not been seen to utilise many of the so-called benefits identified by governments and regulators from smart meter roll outs. Few companies have moved to spot market exposure (which is enabled by smart meters).

At a residential level, there are a number of preconditions that must prevail before smart meters deliver a benefit to consumers. Such preconditions include the knowledge of the cash benefit they will accrue from taking action at any point in time, combined with an ability to take action at that time. Whether this is by knowing the actual cost of electricity at the time, or a benefit for taking action in the future (such as a day ahead warning), this cash benefit needs to be weighed against the impact on the consumer. For example, the consumer would weigh the cost of running an air conditioner when it is hot against the comfort they will achieve. The hotter it is the less likely load shedding would be a real option is a concern that has to be addressed.

What the MEU draws from this, is that great care is needed to ensure that benefits from introducing new technology must be carefully assessed and not based on a “wish list” of possible outcomes.

2.4 Market and regulatory arrangements

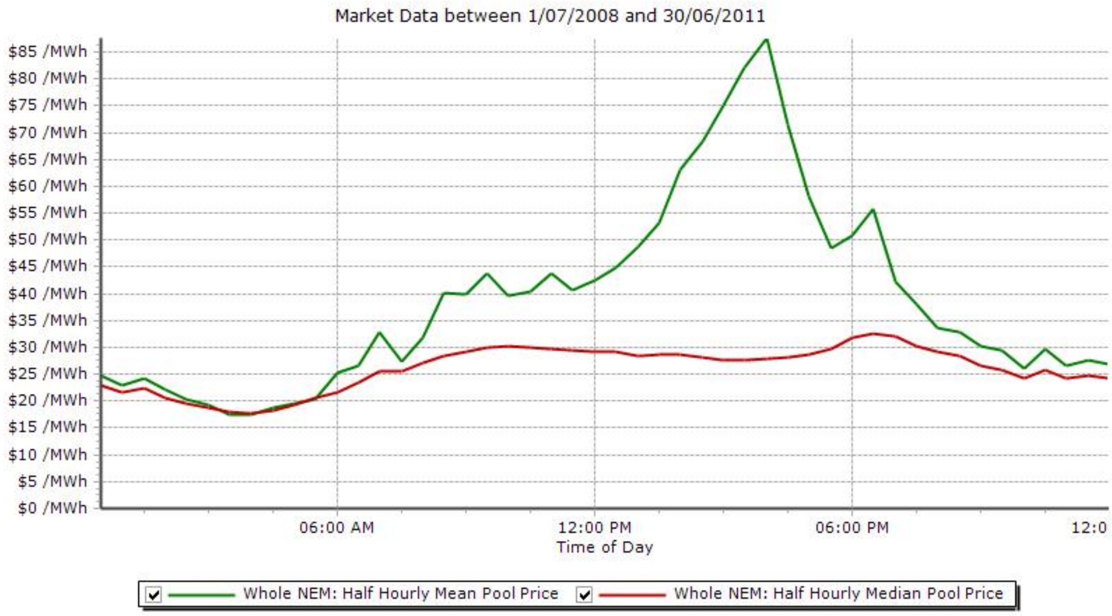
As discussed above, it is important to understand the way prices by retailers and networks are developed, and what the incentives each has to act in the way that might cause them not to support DSP.

A retailer builds up its “book” of power pricing based on its view of the way its portfolio of consumers will use electricity in the future. They will buy a mix of firm hedges from generators (including generators it owns) for different amounts of base, intermediate and peak offers, adding to the mix futures pricing and other derivatives. It might also include a firm offer from particular consumers to shed load on request. Once its “book” is developed, it has little ability to change its cost structure in the short term (such as a day ahead), although in the longer term it can change its book. Whilst a retailer might tailor its price offering for a large consumer, there is doubt that this occurs for small consumers. Most retailers impose a limited range over which the contract price is valid for large consumers (commonly +/- 20% although there is variation between retailers) and if the range is exceeded, a new price is imposed. This means that retailers have some risk in their contracting with consumers and this tends to result in some averaging of pricing – this averaging implies retailers have less ability to reward consumers (especially small consumers) for any load changes that result from DSP.

A network has its revenue set by the regulator every 5 years. Under a price cap approach (which applies to most DNSPs) the network takes the risk on the amount of electricity transported on the network. Under-runs in transport results in decreased revenue and over-runs provide increased revenue. Whilst the NER calls for network pricing to be cost reflective, subject to the NSP providing the AER with a methodology for cost allocation and for price setting, the price setting approach is determined by the network. Small users of electricity are charged on a $/MWh (consumption) tariff and large users on a combined $/MW and $/MWh (demand plus consumption) tariff. Demand is set on the maximum demand used in a year and usually does not reflect the time of the year when this occurs. There is no flexibility provided by networks to accommodate DSP and where a price cap is involved, a network is incentivised not to encourage reductions in consumption from DSP.

Using the example of load shifting in the Issues Paper to exemplify the constraints, unless the load shift is from the network’s peak period to offpeak period (a peak period is usually 7am to 10-11pm weekdays) there is no benefit for load shifting. To load shift from day and afternoon shifts to the night shift is difficult and expensive as a night shift premium is significant. From a domestic viewpoint, to operate household appliances outside the peak period is challenging.

What makes calculating load shifting more challenging is that the peak wholesale prices do not cover same period as the network peak periods. For example the "Whole of NEM" spot price averaged over the past 3 years is shown in the following figure.



Source: NEMReview

This provides some interesting features:

1. The fact that the median curve is so flat implies that for most days the spot market price does not vary significantly
2. That the mean price shows some movement away from the median, indicates that there are a relatively few very large prices that have a major bearing on the mean prices
3. Despite there being a few very high prices, these generally occur between noon and 6 pm – a six hour time window. This is quite different from the times when networks set their peak tariffs.

Load shifting to avoid the high wholesale prices (ie for a retailer) would appear to allow a shift to earlier in the day (in relation to the mean spot price) but as the median spot price variation is quite modest over a day there is no easy ability to define which specific days require load shifting so that there is an ability to generate a DSP benefit.

Thus, in the case of incentives for networks to encourage DSP, the current structures do not reflect the benefits DSP could provide nor do they provide a benefit if DSP is provided. This is a direct outcome of the pricing structures used by networks. To enable DSP, network pricing structures have to be significantly modified and monitored by the AER to ensure that there is no drift away by the networks.

In the case of retailers, whilst there is an ability to identify when a high spot price is likely 1-3 days ahead, to be certain about high prices any further out than that time period is almost impossible. As noted above, for a retailer to offer a benefit they need more time than just a few days ahead and the ability to identify if the DSP was provided when it was needed. For consumers to be certain of the benefit they get can be quantified so they can make an informed decision requires the retailer to be definite as to the value of the DSP. In the attached report, it was identified that DSP could be quantified for the next day and consumers would offer DSP on this basis. This works for a relatively few consumers but has difficulties in widening the scope due to logistics.

Retailers have offered large consumers a discounted retail price based on the consumer being required to load shed an agreed amount of power “at call” but the definition of the “at call” timing is not adequate for the consumer to assess the costs of providing the DSP.

2.5 Energy Efficiency measures

The MEU is concerned with the implication drawn from the Issues Paper, that the market Rules might be changed to encourage energy efficiency. The MEU accepts that energy efficiency should be supported, but it does not consider the role of the NER is to encourage the integration of social policies.

Energy efficiency results in less energy being used and, other than it resulting in perhaps a lesser requirement for investment in generation and networks, it does not impact introduce greater efficiency in the provision of electricity services. In fact the outcome of energy efficiency measures might make the electricity supply chain less efficient thereby acting against the NEO.

The Issues Paper advises that it intends to provide analysis of the cost effectiveness of various energy efficiency schemes established by various governments. The MEU considers that this should not be an activity of the AEMC if the analysis is intended to result in recommendations to change the NER; such changes would be related to the achievement of social policies and not of the NEO.

The Issues Paper considers that an outcome of energy efficiency programs might result in effective DSP. The MEU sees that this is the wrong way to look at DSP. If effective DSP (developed in its own right) results in an enhancement of energy efficiency, then this is a benefit that needs to be quantified in terms of the DSP initiative.

For example, it is energy efficient to replace incandescent lighting with compact fluorescent of LED lighting. The decision to use these by consumers should be based on the cost benefit analysis for the different lighting approaches. There may be an impact on the network by the large take up of fluorescent or LED lighting (eg in terms of reactive power supplies). This cost impact on the network should be seen as a result of the energy efficiency program. It would be inappropriate to use the NER to force a change to one form of lighting over another, other than to advise the cost impact of the change.

It is recognised that energy efficiency is a form of DSP but its implementation does not make the NEM more efficient. Other forms of DSP (such as load shifting, self generation) all have the capability to increase the efficiency of the NEM and therefore should be incentivised. Energy efficiency should not be incentivised in the NEM rules

3. Responses to AEMC questions

Chapter	#	AEMC question	MEU response
3	**1**	Chapter 3 outlines our approach to identifying "market and regulatory arrangements that enable the participation of both supply and demand side options in achieving an economically efficient demand/supply balance in the electricity market." Do you agree with our approach?	The MEU generally agrees with the approach but draws attention to the points made in section 1 (especially subsections 1.2 and 1.3)
	2	How should the benefits of DSP be measured? Can they be accurately quantified?	As the signals are to be provided in cash terms, then the benefits need to reflect this and be measured in cash terms. Some of the benefits might be in other than cash (eg the "feeling of doing the right thing" in terms of reducing energy demand). Some of the detriments might be in non-cash terms (eg loss of convenience). Benefits and detriments need to be converted into cash terms so that comparisons can be made.
	3	What are appropriate discount rates to apply to DSP investments for the various parties across the supply chain?	Most firms look at discretional investment in terms of a return in 1-3 years. Residential consumers would expect to see similar returns, Such high rates of return are appropriate for users where electricity is a relatively small element of their total costs.
	4	Are there other issues which we should consider in our assessment process and criteria?	See comments in sections 1.2 and 2.1 and in appendix A
4	**5**	What are considered the drivers behind why consumers may choose to change their	Price is a consideration as a driver of change, but there are a number of other factors that must be considered. In particular, whilst

		electricity consumption patterns? Please provide examples or evidence where appropriate.	price might be a driver initially for change, convenience, comfort, focus on other issues, inertia, reversion are all militating factors that will act against increasing demand side participation
	6	Chapter 4 lists some plausible DSP options that are currently used or could be used by consumers. Are there any other plausible DSP options currently used by consumers that have not been identified? Please provide description of measures and examples, where available.	The three basic approaches used by industry to reduce energy costs are – reduce the price by addressing all elements of the supply chain, using less energy for the same output or changing the way the energy is provided (eg heat and motive power are required but gas/coal and electricity are what is purchased so the effort is put to see how better alternative ways to source the heat and motive power actually required). There are many variations on delivering the three basic approaches but all come back to one of the three. The MEU agrees with the listing provided in box 4.1 although it does see that by addressing the energy supply chains in more detail, consumers can influence how the energy supply chain might be improved.
	7	Are there any DSP options that are currently available to consumers, but are not commonly used? If so, what are they, and why are they not commonly used (i.e. what are the barriers to their uptake)? Please provide examples and evidence if available.	The MEU has observed that many end users do not take an aggressive approach to their energy costs. To a degree this is a hangover from the time when vertically integrated state owned or controlled utilities provided energy and the approach by them was “take it or leave it” and there was no ability to finesse the supply chain or its prices. This attitude is still wide spread and the majority of end users, by number, still consider that tendering by retailers is all that is needed to get the best deal that is available. This means that the overall, the approaches listed in the AEMC while apparently straight forward could not be classed as “common” in that they are not used by the majority of energy users. The MEU recommends that until there is widespread take up of these “basic”

			approaches, to identify and implement facility to use more options is probably not efficient.
	8	Are there other DSP options that are not currently available to consumers, but could be available if currently available technologies, processes or information were employed (or employed more effectively) in the electricity (or a related) market?	There are technologies that might improve the implementation of DSP but the costs to use these and possibly the risk of being "first user" of using these, militate against the new technologies. However, if the structures are in place that would result in end users gaining benefits by their use, then it is possible that the new technology take up would result.
5	**9**	What are considered the relevant market conditions to facilitate and promote consumer take up of cost effective DSP?	In addition to the market conditions identified in the Issues Paper, the market environment has to reflect the ne4ed that positive action is needed to get most consumers to provide DSP. This will overcome the inertia that is prevalent. An example of this inertia is that most changes in retailer by consumers ("churn") are made as a response to retailer selling (door-to-door, telemarketing) rather than consumers initiating a change. This implies that even though the market structure allows change, the actuality of change does not result from consumer initiative.
	10	Are there any specific market conditions which may need to be in place to enable third parties to facilitate consumer decision making and capture the value of flexible demand? Please provide examples and evidence as appropriate	See responses to questions 9 and 11.
	11	What market conditions (technologies,	As noted in section 2.3 above, there are positive actions that are

		processes, tariff structures, information etc) are needed, that are not currently employed in the electricity market, to make other DSP options available to consumers?	needed from consumers to improve the efficiency of the electricity market. Just providing an environment where consumers might take action to assist in making the electricity market more efficient might not be sufficient (as noted in section 2.1 above). The MEU considers that there will be some consumers who will be utilising the structure of the market to provide DSP (eg such as already occurs in load shedding when there are high spot prices), this is unlikely to provide sufficient response to achieve significant improvement in the efficiency in the electricity market. With this in mind, the MEU considers that to get the outcome sought, there might have to be direct actions taken. An example of such direct action would be an agreement with a number of consumers (for a declared cost saving) to allow the local NSP to cycle their air conditioners to flatten demand in the network. Another might be to provide consumers with direct price reductions in electricity supplies, to limit demand on the next day when high temperatures are forecast.
Pricing	**12**	Do you consider retail tariffs currently reflect the costs to a retailer of supplying consumers with electricity	No. See comments in section 2.3.1
	13	Are any changes needed to retail price regulation to facilitate and promote take up of DSP?	No. As discussed in section 2.3.1 retail price caps are not the main problem, whereas non-cost reflective network tariffs and the desire for simplicity in pricing structures are a major problem.
	14	Do the charges to retailers for use of transmission networks reflect the value of that use?	Distribution networks pay the transmission charges and then repackage this cost within their own network tariffs. In doing this, cost reflectivity is lost and benefits the TNSP might get from DSP are effectively lost.

			Commonly retailers offer energy pricing only plus a pass through of NSP pricing to all consumers but residential and small business consumers. For the small users, retailers do repackage network charges so these are not immediately obvious to the small consumer. This makes sense as it reduces complexity for the small consumer. Equally this repackaging provides a means to prevent benefits to networks being passed through to the consumer that provides the benefit and shares the benefit to all of the retailer's customers. To overcome this, retailers could be required to include in their retail price offerings, a statement as to the pass through cost of the network charges (similar to the way the amount of GST charged is required to be shown on an invoice). In this way consumers would have the regulated costs defined and changes in these could be seen by the DSP provider.
	15	Do the charges to retailers for use of distribution networks reflect the value of that use?	See comments above
	16	Do all consumer groups, including vulnerable consumers benefit from having cost reflective prices in place? If not, are any special provisions required to protect certain classes of consumers?	Cost reflective pricing is not intended to provide a benefit to any class of consumer, but to provide an accurate share of the costs of providing the service to each customer or customer class. Without cost reflective pricing, providing an accurate value for DSP becomes impossible. Pricing in the electricity market is not intended to provide social goals.
Inform-ation	**17**	To what extent do consumers understand the how they can reduce their electricity bill? What information do consumers need	There is adequate information available for any consumer to find out how to reduce their electricity bill, but it requires time and effort to do so. The issue for getting DSP is to overcome the inertia of

		in order to increase their understanding of how they can reduce and manage their electricity consumption and hence bills?	consumers to take action. As noted in section 2.3 and in the answer to question 9, the large majority of consumers do not take positive action with regard to getting the best price for their electricity, let alone taking positive action with regard to DSP. To a large degree it is not lack of information to enable development of DSP, but the inability of the current market structure to provide firm values of the benefits that accrue from the DSP.
	18	What issues are associated with provision of existing information in the market? Are there arrangements that could improve delivery of such information? If so, how and by whom?	As noted in the answer to the previous question, the value of the benefit must be clear and unequivocal. This means that benefit from a specific action must be made available by retailers and networks. Further this benefit must reflect the full value that is received. As noted in section 1.2.1, retailers currently seek to take a large share of the benefit from consumers load shedding in response to high system prices but take little of the risk. DSP requires the full value of the benefit to flow to the provider of the DSP.
	19	Could better information be provided to consumers regarding the actual consumption of individual appliances and pieces of equipment? If so, what information could be provided and in what form?	Such information is useful, and consumers need to understand that the nameplate rating of an appliance might not be the actual consumption figure. Data needs to be in a form that readily allows conversion to the benefit that arises from its use. For example rating an appliance by efficiency stars does not allow a ready conversion to value. What is useful is for the actual consumption on a daily basis under standard conditions to be identified which can be then be valued against a price for electricity.
Pricing Options	**20**	Are retailer and distributor business models supportive of DSP?	No. Firstly the benefits of DSP are partly recovered by NSPs and some are recovered by retailers. It is important to find a way to provide consumers with the combined benefits from both retail and

			networks. Secondly, the incentives that retailers and networks have by not encouraging DSP are too great compared to the marginal benefits to them of implementing DSP.
	21	What incentives are likely to encourage research and development of other parties to promote efficient DSP?	The more other parties are encouraged to share in the benefits of DSP, the less will flow to the consumers that carry the risks for providing DSP. This reduces the incentives to consumers to balance the costs of DSP against the reducing benefits to consumers.
	22	Are there any regulatory, cultural or organisational barriers that affect take up of DSP opportunities?	Yes. These are discussed throughout this submission.
	23	What forms of commercial contracts/clauses are required for facilitating and promoting efficient DSP?	There is no doubt that the contractual arrangements provided by NSPs and retailers on consumers who want to implement DSP, are onerous. At the most simplistic, the penalties that applied to consumers for failing to provide DSP have in a number of cases prevented the DSP project proceeding. It is understandable that the retailer or NSP must be sure that the DSP benefit will occur as they also have made arrangements based on the DSP occurring, but if the consumer is prevented from providing the DSP in a specific instance, then the penalties to all might be too large to warrant the risk. To overcome this, there is a need to strengthen the rewards to consumers and/or to look at alternatives to ensure the DSP occurs, such as by aggregating a number of potential DSP providers to increase the likelihood the DSP will occur at the time it is required.
Incen-tives	**24**	Are there specific issues associated with investment in infrastructure needed for	See comments in section 2.3.4

		consumers to take up DSP opportunities?	
	25	Do you consider that the issue of split or misaligned incentives has prevented efficient investment in DSP from taking place?	The more the benefit of DSP is shared with others or where the risks become too great, the less likely a consumer will implement DSP. For example, the MEU is aware of: • A number of embedded generation projects have not proceeded because the costs of using the network occasionally as a backup (when the self generator is out of service) have prevented there being an overall benefit or the payback period being too long. • Many larger consumers not being prepared to shed load when the spot price is high because the retailer wants too great a proportion of the benefit, or has required too onerous load shedding requirements.
	26	What are potential measures for addressing any issues associated with split or misaligned incentives?	The Rules have to be modified so that: • The disparate benefits of DSP (eg to retail and networks) can be combined. • The onerous requirements imposed by retail and networks on consumers for providing DSP can be alleviated
	27	Are there specific issues concerning ease of access to capital for consumers and other parties?	As noted in section 2.3.4 and in answers to earlier questions, investment in DSP is seen as discretionary investment by consumers, and this comes after imperative investment and competes with other discretionary projects. Therefore DSP must provide a high rate of return from a consumer viewpoint. From a network viewpoint, they would receive a regulated return. Retailers would expect a return less than consumers but more than networks.

Tech-nology	**28**	What are the significant energy market challenges in optimising the value of technology and system capability to facilitate an efficient level of DSP?	The MEU considers that there is a tendency to overstate the benefits of DSP arising from new technology – this has been seen in relation to "smart meters". The MEU considers that supposed benefits need to be tested by real people and businesses to ensure that the benefits are really there and that there will be a take up of the new technology and its benefits. This means that it is insufficient just to take an economic view in isolation.
	29	Do current technology, metering and control devices support DSP? If not, why not, and what are considered some of the issues?	Smart meters do provide the ability to measure the DSP that has been implemented so that the costs and benefits can be appropriately calculated. The mere presence of a smart meter does not mean that DSP will occur. The MEU considers that when a DSP project is implemented, then the necessary technology to allow it to be measured needs to be implemented. That is, the new technology *follows* the DSP rather than leading it.
	30	How can issues relating to weak and/or split incentives be addressed to ensure that the benefits of smart grid technologies are aligned and felt across the electricity supply chain, including by consumers?	The MEU has no comment on this.
	31	How can pricing signals/tariff arrangements be made complementary with smart grid technologies to facilitate efficient DSP in the NEM?	As discussed above, the pricing signals are needed to encourage DSP. New technology follows its take up.
	32	In maximising the value of technologies,	The power usage by each consumer, its timing and quantity, is

		such as smart grids for DSP, what are the issues relating to consumer protection and privacy?	commercially sensitive information to each business, as is whether it has implemented DSP or not and what sort of DSP has been used. While a business may elect to make such information available it must not be divulged by a supply side entity unless by prior agreement.
6	**33**	To what extent do parties have appropriate incentives to put in place the systems, technologies, information flows etc that facilitate efficient DSP?	To a large extent networks have incentives not to seek DSP and this is discussed in section 2.4 and elsewhere in this submission. From a consumer viewpoint network pricing provides a barrier to DSP. There is more scope with retailers to provide DSP (eg load shedding "at call" but this provides difficulties for consumers being able to quantify the costs and the benefits. Overall the MEU considers that the current rules provide barriers to the provision of DSP
	34	Are there aspects of the NEL or the Rules which prevent parties taking actions that would otherwise allow for more efficient levels of DSP?	Yes. These are discussed in section 2.4 and elsewhere, and particularly apply in the case of networks.
	35	Are there market failures which mean regulation is needed in some areas to ensure appropriate market conditions are in place?	Yes. In particular, network pricing provides a barrier to DSP. This is discussed in section 2.4 and elsewhere in the submission. The way a retailer has to build its "book" of generation hedges makes it more difficult for a retailer to be able to act quickly in response to an actual need for DSP, such as a high price forecast for the next day.
7	**36**	What energy efficiency policies and schemes should be considered as part of this Review, i.e. as impacting on, or seeking	None. The effectiveness (or otherwise) of energy efficiency programs should not be used to push changes in the NER as energy efficiency has little ability to make the NEM more efficient whereas

		to integrate with the NEM?	other forms of DSP can increase NEM efficiency. The NEO is written in terms of the efficiency of the NEM, not increasing energy efficiency which is a social policy. The NER should not be structured to prevent the uptake of energy efficiency, but neither should the NER push energy efficiency as an outcome
	37	To what extent can energy efficiency policies and schemes be adopted as options for enhancing the efficiency of DSP in the NEM? What are the strengths and limitations of energy efficiency policies as a DSP option compared to other options?	Implementing energy efficiency is a form of DSP as it will reduce the amount of energy needed in the NEM. The NER should not impose barriers to any form of DSP, but as an increase in energy efficiency does not increase the efficiency of the NEM, it should not be a driver of change.
	38	To what extent do existing retailer obligation schemes facilitate efficient choices by consumers in their electricity use? Are there aspects of those schemes that facilitate efficient consumption choices more than others? If so, please explain.	The MEU has no comment on this.

Review of the ETSA Utilities Revenue for 2005-2010

A report to

The Consumers Advisory Council
Working Group

of

the Essential Services Commission of South Australia

Survey of documents relating to metering, demand side participation and embedded generation

By Headberry Partners P/L

June 2004

Headberry Partners P/L
Energy, Management and Procurement Services
ABN 75 011 240 472

73 Longview Road
North Balwyn
VIC 3104

Phone: 61 3 9859 9138
Fax: 61 3 9859 2301
Mob: 0417 397 056
Email: davidheadberry@bigpond.com

THE ISSUE

The demand for electricity in South Australia is one of the most “peaky” in the National Electricity Market. This results in the need to provide electricity generation and network assets which are used for relatively short periods of time. It is estimated that some 30% of the capacity in the SA electricity system is required for less than 3% of the time. Notwithstanding the fact that the peakiness is caused by consumers of electricity, this demand situation is seen as undesirable as it adds costs to consumers of electricity in SA. However these costs need to be seen in relation to the total cost of supplying and delivering electricity to consumers and we are fortunate to be the beneficiaries of having relative low cost electricity compared to consumers in most overseas jurisdictions. This fact has significant implications for governments and regulators.

Whilst a business owning a vertically integrated electricity supply system has the ability to provide a system wide approach to addressing this “peakiness”, with the disaggregation of electricity supply into its constituent parts, this creates the challenge of attempting to address a system wide problem through a series of disparate decisions. In particular the disaggregation between retail and distribution creates unique challenges as the competing needs of the two elements are not necessarily coincident, resulting in the need for separate and sometimes competing drivers for change.

The development of the NEM as applied in SA has all of the constituent parts operated and controlled by private enterprise, severely limiting the ability of Government to effect any direction over the supply of electricity. The generation and the retail functions operate in a competitive environment. The transmission network is overseen by the national regulator (ACCC), and the distribution network is overseen by the state based regulator (ESCoSA). The oversight of the NEM as a whole is now provided on a national basis through the national Ministerial Council on Energy (MCE).

Thus the challenge facing the Essential Services Commission of SA in its review for the 2005-2010 revenue to be awarded to ETSA Utilities (EU) is to attempt to provide appropriate signals within its Decision to encourage appropriate actions by EU to offset the need for additional capital to ensure electricity supply is maintained to all consumers, by instituting demand side responses and embedded generation. In this regard it is required that to reduce the need for capital investment in the network requires demand side action to be focused where the network is constrained, or close to constraint.

DOCUMENT SURVEY

The purpose of this paper is to summarise the views from a variety of sources regarding

- pricing signals
- the impact of metering with regard to demand side participation

- other demand side approaches to encourage reduction in demand
- the use of embedded generation

The documents studied were:

1. Essential Services Commission of SA
    a. Consumer issues with Prepayment meters, May 2004
    b. Embedded generation, working conclusions, May 2004
    c. Memo to CAC-WG "Demand management/Interval metering – The European and American experience", Jun 2004
    d. Combined report with EU, "Metering and demand side management in Europe and USA" May 2004
    e. Info paper #4, "Small generator connections: technical and financial issues" Feb 2001
2. Independent Pricing and Regulatory Tribunal (NSW)
    a. Final Decision on Distribution Pricing Review, Jun 2004 (Ch 11 and 13)
    b. Report on Final Decision on Distribution Review , Jun 2004 (Ch 8)
    c. Final report on DSM, Oct 2002
3. Final Report, SA Demand side management taskforce, Jun 2002
4. Draft report, "Joint jurisdictional review of metrology procedures" Dec 2003
5. KPMG Final Report "Consumer issues with prepayment meters" Apr 2004
6. ESCoV Draft Decision, "Mandatory roll out of Interval meters for electricity customers" Mar 2004
7. MCE SCO Discussion paper "Improving user participation in the Australian energy market", Mar 2004 and responses to it
8. CRA preliminary draft report "Assessment of demand management and metering strategy options" May 2004
9. CRA discussion paper "Peak demand on the ETSA Utilities system" Feb 2004
10. Energetics "Electricity pricing structures for customers with interval meters" Mar 2003
11. ETSA Utilities "Expenditure submission 05/06-09/10" Jun 2004
12. Consumer advocate submissions to ESCoV regarding interval metering
    a. Pareto Associates "Profiling or interval metering – the customer perspective" March 2001, and "Smart meters for smart competition", March 2003
    b. Headberry Partners "Interval metering of electricity supplies to domestic consumers", January 2004

The appendix 1 to this report includes a brief synopsis of the key elements of these reports *as they apply to the issues being reviewed* by the CACWG. At the end of each section a brief assessment is provided of each document as it applies to the issues being considered.

Appendix 2 reviews some more documents additional to those listed above.

There is a wealth of information available regarding the encouragement of demand side participation in an electricity market, and of the tools considered necessary to achieve the desired outcome. In order to bring focus to the research, it required a consistent reiteration that whatever was to be examined and reviewed has to have relevance to the pricing review of EU network distribution business being currently undertaken.

This required that demand side participation issues which involve consumers and generators currently connected to the transmission network should be discarded. Where possible, issues which fall within the province of Government policy were only noted, unless such could be incorporated as an element into the pricing review.

THE OUTCOME OF THE DOCUMENT SURVEY

The findings from the document survey

- It is apparent that **if** domestic consumers stopped using their air conditioners, the summer peakiness of the electricity market would reduce dramatically, and the asymmetric time loading of the networks would also reduce dramatically. There appears no dispute about this finding.

- It is widely assumed that the cost of providing the infrastructure to provide for the current peaks in demand is an unnecessary expenditure and therefore unwarranted. Countering this, there is no evidence to suggest that this view is correct. In fact with the relatively low cost of energy supplies as a proportion of the average take-home-pay, many consumers *might* prefer to pay more for convenience and comfort. Whilst some consumers might find the impost of increased charges too great, is there a more cost effective way of managing this specific concern, and at the same time allowing all other consumers the right to pay for the additional infrastructure which they consider acceptable?

- There are a number of solutions proposed to overcome the cost premium of increased generation and network infrastructure to accommodate system and local peaks. Many rely on activities not related to regulating distribution networks. IPART provides good guidance to those which could be incorporated into a pricing review, and has included these in its recently completed review.

- Where incentives have been provided to consumers to change their usage pattern, there has been seen some load shifting. The time allocated to these programs has not been long enough in duration to demonstrate a lasting commitment to new usage pattern. Anecdotal evidence indicates that domestic consumers tend to revert to earlier practice after the expiration of the “crisis” or the incentive program. After all, why have an air conditioner and not use it when it is hot?

- An alternative to using financial incentives to drive load shifting is the ability of the network operator to remotely cycle air conditioners on and off, recognising that the thermal inertia of the cooled space can permit such an approach with minimal impact on users. This approach provides the necessary certainty of demand reduction which pricing mechanisms alone cannot provide. The cost/benefit of this approach needs to be demonstrated and it is noted that EU is actively considering a trial.

- There is insufficient evidence to demonstrate that reasonable pricing signals alone will achieve the targeted goals without mandating actions. In fact there is evidence that consumers prefer simplicity of tariffs to receiving price signals. An alternative therefore is that draconian pricing signals might be necessary to get the outcomes sought.

- Economic philosophy indicates that consumers will respond to price signals, and many of the documents reviewed take this philosophy as a given. However there is significant countering evidence that if consumers have adequate funds then price signals may come behind other drivers when making a decision (ie if there are sufficient funds available, is comfort – being cool – more important than cost?).

- There is almost no discussion in the documents about whether wholesale price signals closely correlate with system demands, and therefore demonstrate that this tool really will assist in impacting on network loading. In fact there is countering evidence that high system prices and high system demands <u>have at best a low to medium correlation, weakening this tool as a driver of change.</u>

- A number of the documents imply that with the averaging approach used to develop tariffs (both retail and distribution) there is a cross subsidy from those users without air conditioning to those with air conditioning. The implication in the documents for resolving this cross subsidy issue is that interval meters are essential to provide for a fair allocation of costs. There is little examination of alternative ways (eg having small user distribution tariffs based on demand rather than usage[10], or using a block tariff approach[11]) to reduce any perceived cross subsidy. [Retail pricing cross subsidies are not an issue for this pricing review.]

- There are competing views as to legitimacy of the cost benefit analyses carried out to support the argument for interval meter roll out. An example of this is where NSW Treasury is clearly not entirely in accord with ESCoV as to the costs and benefits ESCoV has used in its development of the mandating of interval metering roll out.

- The need for capex in the network is driven in part by local demand increases (eg where a specific substation needs to be augmented) and in part by network refurbishment. However the demand side responses which might occur from network tariff drivers are likely to be located elsewhere in

[10] Such an approach permits the ability of the network to introduce a “progressive” demand tariff, which increases the tariff rate with increased demand eg 0-3 kW at a low base rate, 4-6 kW at twice the base rate, 7-10 kW at four times the base rate.
[11] A block tariff approach has the first amount of usage at a low rate, with subsequent blocks of usage at increasingly higher rates

the network. Thus the ultimate outcome will be a reducing of demand throughout the network to secure a reduction at a specific point – what could be seen as a blunt instrument approach rather than a focussed response. This broad brush approach will result in reduced revenue to both retailers and network owners as both are rewarded by increasing sales of energy (retailers through a margin on sales and network owners by the price cap approach).

- Demand side responses have to be evaluated against deferral capital. Thus at the end of the deferral period, the augmentation will proceed making the demand side response redundant. Thus any capital invested by the demand side provider has to be recovered in a very short period. This militates against any demand side response requiring capital for its implementation.

- Local demand side responsiveness can be encouraged by tariffs related to the local constraint. Whilst economically sound in practice this will cause local price spikes which are not unacceptable from a policy viewpoint (the EPO requires postage stamp charging and so clearly precludes this approach), and would also be unattractive from the local consumer viewpoint.

- The economics of embedded generation demonstrate that this form of demand side response faces a viability issue if there is no financial support provided from the transmission and distribution networks. The document review supports this view but goes no further than recommending that embedded generation should receive the full value of the pass through of avoided TUoS[12].

CONCLUSIONS

The documentation survey raises as many questions as it answers.

Whether universal interval metering is required is not demonstrated or proven one way or the other, and the recommendation of the regulators' "Joint jurisdictional review of the metrology proceedings" and the standing committee of officials for the Ministerial Council of Energy "Improving user participation in the Australian energy market" both handball the decision to each jurisdiction, suggesting that each should carry out its own cost benefit analysis. What is absent is any examination of alternatives.

The best guidance for practical solutions to encouraging demand side responsiveness in networks comes from the work by IPART in its "Inquiry into the role of demand management and other options in the provision of energy services" and the approach to network pricing included in the report attached to the Final

[12] Headberry Partners has been involved in trying to establish a number of embedded generation projects in Victoria, NSW and SA. This observation is made based on this direct experience and does not come from the review of the documentation.

Determination for the distribution businesses, June 2004. It is recommended that these documents be examined more fully and the issues and solutions “teased out” more fully than this document review permits. The attached appendix sections 10 and 13 provide some details as to the IPART approach.

Embedded generation needs more support – financial rather than moral – if this form of demand side response is to be encouraged. Transferring the avoided TUoS (even if it can be calculated) is probably not sufficient to provide sufficient financial support and the benefits of the embedded generation provided to the distribution network need to be recognised and included in the financial incentive.

Appendix 1

Review of various documents having relevance to metering, demand side responses and embedded generation

1. Draft report "Joint jurisdictional review of the metrology proceedings" prepared by the regulators of Victoria, South Australia, ACT, New South Wales, Tasmania and Queensland, in December 2003

In the report it is stated that there is a feature of the competitive market which requires the active participation of the demand side and without this, competition is blunted and the potential benefits of competition may not be fully realized. This review is concerned with the mechanisms (particularly with regard to who will provide the metering services) by which the market can provide different pricing offers to customers and so provide customers with a choice and be able to respond to pricing signals.

There is a stated concern that unless there is consistent metrology between the jurisdictions this can create a barrier to full retail competition. As a result of their review the regulators have published a **draft report** that states the following points. However it must be stressed that this is a draft report and the Final Report may vary from these draft views.

- Economic efficiency, practicality and equity must be the key drivers in assessing efficient metering solutions
- There should be a single metrology procedure manager (NEMMCo is recommended for this role) which covers technical issues. However Jurisdictions should continue to have responsibility for policy and consumer protection
- Metering solutions for large customers should have flexibility of provider but for small consumers it is considered more appropriate for the local distribution business to provide the services, although unbundling of metering services from DUoS charges should occur
- Regulated distribution and retail tariffs do not provide any incentive for adoption of economically efficient metering solutions, and a policy direction is required to realign tariffs to be more cost reflective
- There is a threshold between whether an interval meter should be used as an interval meter or whether it may be used as an accumulation meter – this threshold is to be established by each jurisdiction
- NEMMCo should
  - decide on the requirements for storing and accessing data,
  - should monitor developments of metering and
  - assess whether the code should be amended as part of developing a single national metrology procedure

- A roll-out of interval meters to all customers requires an assessment of the costs and benefits to be carried out by each jurisdiction prior to proceeding. Because of this a load profiling methodology is still required

Assessment

The review appears to indicate that for small consumers it is a jurisdictional decision as to whether there should be a roll-out of interval metering, and before any mandating of roll out, there is to be a detailed cost-benefit assessment made. In addition they concluded there should be a national metrology procedure and process managed by NEMMCo.

2 Energetics report "Electricity pricing structures for customers with the interval meters", March 2003 (available ESCoSA website)

This report was to identify whether electricity price structures requested by consumers made use of the perceived value of being able to measure usage of electricity on a half-hourly basis. Interval metering has been available in Australia for nearly a decade and in some overseas jurisdictions for even longer. It is recognised that if interval metering does in fact provide a mechanism useful to consumers, then this would be reflected in the tariff structure requested by consumers and/or offered by retailers.

Energetics found that overwhelmingly (97 per cent) consumers with interval metering operated with a two or three part tariff. This clearly identifies that consumers prefer simplicity to complexity in their tariff arrangements. [It should also be noted that anecdotal evidence exists implying that retailers prefer simplicity of tariffs as well. Ease of billing alone would support this view!]

Given that in the National Electricity Market there are 48 price periods per day, a distinct difference in pricing between work days and non-work days and an acceptance that there is different pricing between summer, winter and mid-season, for consumers to move to a simple tariff structure clearly militates against the ability to use variability in the electricity market to reduce the cost of electricity supplies.

The clear implication of simplicity in tariffs is that consumers either do not recognise the benefits provided by interval metering, or do not consider the detriments sufficiently outweigh the potential savings. This observation was supported by investigation of some electricity pricing programs used overseas.

Energetics also observed that whilst interval metering provided a vital role enabling a retailer to price against profiles for customers with large demands, it was not identified that having real-time data for small customers assisted retailers in providing an enhanced tariff structure for this class of consumer.

Assessment

The Energetics report provides clear evidence that most consumers want simplicity in their electricity tariffs, and that those consumers with interval metering by and large do not fully utilise the perceived benefits of interval metering.

3. Two competing views from recognized consumer advocates regarding interval metering. http://www.esc.vic.gov.au/electricity614.html (for the Pareto papers)

Pareto Associates has published two papers on interval metering – the first “Profiling or interval metering - the customer perspective” in March 2001 and “Smart meters for smart competition?” in March 2003.

Pareto makes the point that interval metering can be provided at a low cost if it is done on a large scale. It states that this has been done in three overseas jurisdictions, but it was carried out at the instigation of the distribution company with costs included in the regulatory revenue. However Pareto observes that they found no examples of roll-out of interval meters in any jurisdiction which relied on competition and consumer choice to initiate the installation. Pareto also makes the comment that it is essential for the market to operate in an open fashion for the benefits of interval metering to be garnered. They point to market power abuse by generators, which if remains unfettered will render meaningless voluntary load management.

Pareto observes that interval metering has the potential to greatly increase willingness of consumers to respond to price signals and makes the point that those users without air conditioning are cross-subsidising those with air-conditioning. This inequality Pareto states will be readily overcome by the use of interval metering, although there is no attempt to identify if there are any alternatives mechanisms which might achieve the same goal.

Headberry Partners published “Interval metering of electricity suppliers to domestic consumers”, January 2004, which offers the view that domestic consumers will have minimal ability to utilise interval meters to manage their usage, that there is little readily available information to identify price trends in the market place which the domestic consumer can access to give the power to minimise domestic power bills. The Headberry Partners report supports the Pareto view regarding the negative effect of unfettered generator market power creating a disincentive to gain consumer responsiveness to price signals. [It should be noted that re-aggregation of generation and retailing either directly (as in the AGL partial acquisition of Loy Yang) or indirectly (as in NSW with the ETEF scheme) eliminates some of the risks faced separately by retailers and generators, but has the potential detriment of muting pricing signals.]

The Headberry Partners report implies that the costs for a consumer to adequately benefit from having better knowledge of usage is much wider than the cost just to install and read an interval meter. Such hidden and indirect costs include installing an appropriate energy management system, new switching for appliances with associated hard wiring back to the energy management system, rewiring downstream of the new meter, installation of computers with continuous on-line facility to an electricity price source, the purchase costs for new "smart" appliances, self-education to understand how to fully utilise the electricity market price signals, and the time commitment required to gain the benefits costs

Assessment

There is some divergence between consumer advocates as to the efficacy of interval metering.

4. Draft decision by the ESC of Victoria mandatory roll-out of interval meters for electricity customers March 2004
http://www.esc.vic.gov.au/electricity204.html#DftDecMandatoryRollout

The draft decision sets out the ESC of Victoria decision to mandate the roll-out of interval meters. The ESCoV has concluded the roll-out of interval meters will improve the competitiveness and efficiency of the electricity market in Victoria, and thereby contribute to future economic benefits to electricity consumers and to the economy generally.

The ESCoV considers the price signals that reflect the cost of consumers' electricity use patterns are a prerequisite for the full realisation of the potential benefits of the reforms that have occurred in the electricity industry. It considers (see page 3)

> "The benefits … are based on the demand management efficiency gains that arise from avoided generation, transmission and distribution capacity costs. These efficiency gains have been estimated **on the basis of customers responding to interval meter based price signals**, primarily during the system peak in summer. The results demonstrate that the benefit of installing interval meters exceeds the small incremental cost of these meters over the cost of standard accumulation meters." (my emphasis)

This implies that ESCoV considers that interval meters will invoke responses such as load profile modification, improving efficiency of the market, improve the balance between supply and demand, and lower the cost of energy by delaying investments in new infrastructure.

The draft decision indicates that the cost benefit of interval metering for large consumers is readily demonstrated although the cost benefit for small consumers is less so in favour of roll-out. However as the draft decision includes only the benefit of avoided network capital expenditure (and excludes quantification of all other benefits which the ESC considers are significant) their view is that the modest benefit to small and domestic consumers will be larger in reality.

The “results” noted in the above quotation in the draft decision refer primarily to some US experiences which show examples where very large increases in costs to residential consumers have changed their electricity usage habits. It is interesting to note that the studies refer only to supply of electricity in a high cost supply environment (such as the “California crisis”) rather than to examples where there might be allocations of the cost of constraints in distribution networks.

The ESCoV has not carried out any quantitative examination of Victorian consumer reaction to time of use pricing and potential load shifting. For example the ESCoV does not refer to the work of Energetics which examines consumer reactions.

Interestingly the draft decision notes that the benefits of interval meters to network efficiencies are likely to depend more on the ability to record customer peak demand levels than on the provision of pricing signals to achieve efficiency benefits. This statement would seem to militate against using interval meters to reduce network constraints, which was the fundamental focus of the value placed on the benefit of interval meters.

Assessment

The work underpinning the ESC of Victoria draft decision addresses the issue of interval metering in a global fashion whereas the benefits to a network are perforce calculated at a local level.

The ESCoV decision appears based on a philosophy underpinning economics – that every action by a consumer is predominantly driven by financial drivers. It cites the reactions of consumers in certain jurisdictions where demand appeared to be reduced by pricing pressures and financial incentives.

There is no discussion whether any other drivers might have contributed to the observed outcome. For example the consumer reaction in California could also be considered to have been driven by a community desire to contribute to community well being under a crisis condition rather than (or perhaps in addition to) any driver to gain financial benefit.

As ESCoV calculations of the benefits and costs of interval metering roll out for domestic consumers indicate that the cost/benefit balance is apparently only slightly in favour of roll out, this is accepted as sufficient basis to mandate the roll out – if the costs equal the conservative benefits assessed, then the roll out is justified. As the only benefit is assumed to come from network savings, if these savings do not eventuate, then the basis of the roll out decision is flawed.

What is absent from the ESCoV analysis is any discussion as to the likelihood of consumers absorbing cost increases in order to maintaining comfort levels – if sufficient consumers have sufficient ability to absorb cost increases, then the desired outcomes of network savings will not result.

With regard to the ESCoSA pricing review, the main concern is that network constraints must be addressed, and the ESCoV draft decision does not supply sufficient supporting data at the local level in the network to indicate that the necessary demand reduction would occur at the locations in the network needed to relieve constraints. It would seem that the key assumption made is that a network wide approach to demand modification will include the necessary demand reduction at the points of constraint as well, although there can be no guarantee this will be the case. There was no examination by ESCoV of any alternative methods to achieve the desired result.

5. Final report from KPMG “Consumer issues with pre-payment meters”, April 2004, and the associated ESCOSA summary “Consumer issues with Prepayment meters”, May 2004 (available on ESCoSA website)

The report is an excellent articulation of the issues and how they might be resolved either by regulation or technology. Essentially pre-payment meters are seen as a tool to overcome payment difficulties. The overseas experiences included do not record the effectiveness their use in demand management and load shifting. Experience in Tasmania and SA was based on limited (and incentivised) time of use tariffs.

It analyses a range of consumer issues in relation to the use of pre-payment meters for electricity supply. It identifies a number of potential consumer benefits for such metering but observes that many of these benefits are not necessarily exclusive just to pre-payment meters. Therefore alternative mechanisms could be used to achieve the same goals. At the same time it highlights that there are a number of negative attributes associated with pre-payment meters.

In relation to the distribution pricing review the increased usage of pre-payment meters would have some mixed results. On the one hand the pre-payment meter (particularly if a time of use meter and variable tariffs are used) can provide a very clear signal to vary the time electricity is used and of the cash benefits associated with that this feature. On the other hand the use of pre-payment meters with its fixed tariffs tends to dampen any price signals that may be associated with time of use indicators, and perhaps more telling, can be a barrier to consumers benefiting from retail contestability.

A pre-payment meter has a major benefit over interval meters in that the pre-payment meter may provide implied cost information whereas the interval meter provides only usage information.

Assessment

Prepayment meters can provide some benefit to consumers, but have a number of detriments. As network constraints are local (or move as demand varies and as the constraints are relieved, the cost and implications of using prepayment meters to assist managing network augmentation militates against their use for this purpose.

6. Report by ETSA and ESCoSA “Metering and demand side management in Europe and USA”, May 2004, and related memo from B Burgstad to CACWG “Demand management/Interval metering – the European and American experience” June 2004

Representatives from ETSA and ESCoSA visited a number of electricity utilities in Europe and the USA to evaluate the latest trends in metering systems and demand side management systems. Visits were targeted to those utilities actually involved with smart metering and DSM initiatives.

The reasons for trialing smart metering were varied but mainly driven by customer service needs. Based on price drivers there were some demand side responses, but there is a view that consumer apathy would resurface if positive incentives were removed. The ability to control certain loads (eg domestic air conditioning) has been introduced but this was driven by regulation rather than by an initiating entity. All of the utilities visited had combined retail and distribution functions, and therefore this needs to be taken into consideration when comparing achievable and available benefits for the disaggregated retail and distribution structure in South Australia.

The report observes that actual financial justification was difficult to assess due to the presence of mandatory requirements. Drivers for the installation were usually policy driven.

It was seen that the technology was available to carryout automatic reading and remotely controlled load shedding and/or cycling. A trial is suggested to identify if using the latest technology can deliver the targeted response from consumers.

The separate memo from ESCoSA builds on the report highlighting the need to have any demand reduction “firm” to permit the avoidance of augmentation. As the profit drivers and operational goals of retail and distribution functions are different. Due to the disaggregation of these functions in SA, it is not easy to ensure the aggregation of benefits will be coincident. As the results overseas were based on incentives (either cash or customer service) if pricing alone is used to encourage changes in consumer habits, then the price drivers will have to be significant.

Assessment

As the utilities visited had other drivers for the roll out of interval metering, it is difficult to identify whether “acceptable” levels of price signaling alone will be sufficient on which to base avoidance of augmentation. Certainty of load reduction is essential on which to base deferral of augmentation. A trial is one way to assess the efficacy of the approach and of the benefits that might accrue.

To ensure legitimacy of a South Australian trial it must be based on a typical mix of consumers and not have any incentives other than the tariff price drivers. If incentives are provided, then this can lead to a biased outcome.

7. Reports by Charles River Associates “Peak demand on the ETSA Utilities system” February 2004, (available ESCoSA website) **and “Assessment a of demand management and metering strategy options” May 2004 (incomplete report)**

The first report identifies the customer types and the end users that contribute to peak demands on the distribution network.

Not surprisingly the report identifies that the peak demand on the network occurs on a hot summer’s day following a sequence of hot days. The main contributors to the peak demand early in the afternoon were large business and domestic users. Whilst the demand from large business and small business declined towards the evening the demand from domestic consumers increased noticeably. When these trends were compared to a milder day, it became obvious that the main driver of the peak demand was the air conditioning load experienced in South Australia, with domestic consumers the dominating contributor.

The first report also highlighted that low-income households tended to use their air conditioning later in the afternoon than the average residential customer. The conclusion drawn was that this class of customer might commonly operate their air conditioners manually and wait longer to turn them on than do customers with higher levels of disposable income.

The second report is to examine mechanisms to provide sufficient spare capacity in the ETSA network to meet peak demand periods. The study aims to assess the scope for utilising technology of interval meters and demand side management programs to cost-effectively defer the construction of additional distribution capacity to meet the distribution system demand peaks.

Assessment

Residential air-conditioning load would appear to drive the system spikes. As augmentation of the network occurs in step amounts, the network goes quickly from being constrained to having large spare capacity. Demand side responses required initially to relieve network constraints, will be of a short duration and therefore the capital required by the consumer to respond to the network constraint will have to be recovered in this short period.

[Observation: As augmentation provides a large step increase in capacity, what was a constraint in the network will be relieved. As the price cap approach encourages distribution businesses to increase usage, there will be endeavors to increase the demand at that location to maximise revenue. The demand side responses then put in place earlier would no longer be required and therefore have no commercial value to the network.]

8. Discussion paper "Improving user participation in the Australian Energy Market" by MCE standing committee of officials, March 2004

http://www.industry.gov.au/content/itrinternet/cmscontent.cfm?objectID=1C92DAAD-8F2B-4BFD-8D06513B424C83B8

This discussion paper addresses three major concern areas:- demand side response, interval meters and retail pricing. Whilst raising and discussing issues, the paper is designed to receive responses from interested parties.

The aspect of demand side response was particularly focused at the principle of "pay as bid" in the supply side sector which would assist in establishing rules which may permit readily aggregation of demand side responses.

Regarding the aspect of interval metering, the discussion paper notes that there is economic efficiency and equity arising from time of use tariffs. It notes that properly implemented, interval metering can be used to settle the wholesale market more efficiently than load profiling. On the other hand it observes that roll-out of interval metering may be premature and that appropriate analysis has not been carried out in most jurisdictions. It notes that other measurement technology may be just as cost-effective in delivering the same outcomes for small consumer classes.

With regard to retail pricing the discussion paper primarily concentrates on the issue of establishing a set of policy principles to ensure transparent decision-making on retail price regulation.

Assessment

The discussion paper implies that aggregation of demand side responses should be further investigated but there is some doubt as to the efficacy of universal roll-out of interval metering.

9. Final report by the (SA) Electricity Demand Side Measures Taskforce, June 2002

http://www.sustainable.energy.sa.gov.au/pages/programs/dsm/elec_dsm/outputs/outputs.htm:sectID=108&tempID=62

The report notes that the business sector consumes 65 per cent of the state electricity usage but contributes 57 per cent of peak demand. Conversely the residential sector consumes 35 per cent of the state electricity but contributes 43 per cent of the state peak demand. These statistics support other investigations carried out, implying the demand spike is primarily driven by residential air conditioning needs.

The report notes that demand side responses have been limited in the past due to

- a lack of awareness,
- a distrust of some information,
- the relatively very low energy prices,
- the demand peak being only a recent phenomenon,
- accumulation metering not sending price signals,
- a cost barrier to energy efficiency investments,
- the dichotomy of aims between the tenants and landlords, and
- the energy price not recognising environmental costs.

It notes as a summary that energy management and efficiency does not have a high priority with consumers.

The report again tends to take a high level view of demand side responsiveness. In particular it notes the need to deliver consumer responses through price signals, which implies the need for time of use tariffs and appropriate metering. It also proposes the establishment of a retailer DSM scheme fund which would be used to encourage demand management within the small consumer sector. In addition to these two activities the task force recommends raising the profile of sustainable energy programs and initiatives.

Assessment

The report proposes a number of sound strategies for addressing the issues they were asked to address. However the report does not provide guidance in relation to addressing the specific issues relating to the need for augmentation of the distribution network and how this might be mitigated by the use of interval metering and demand side measures.

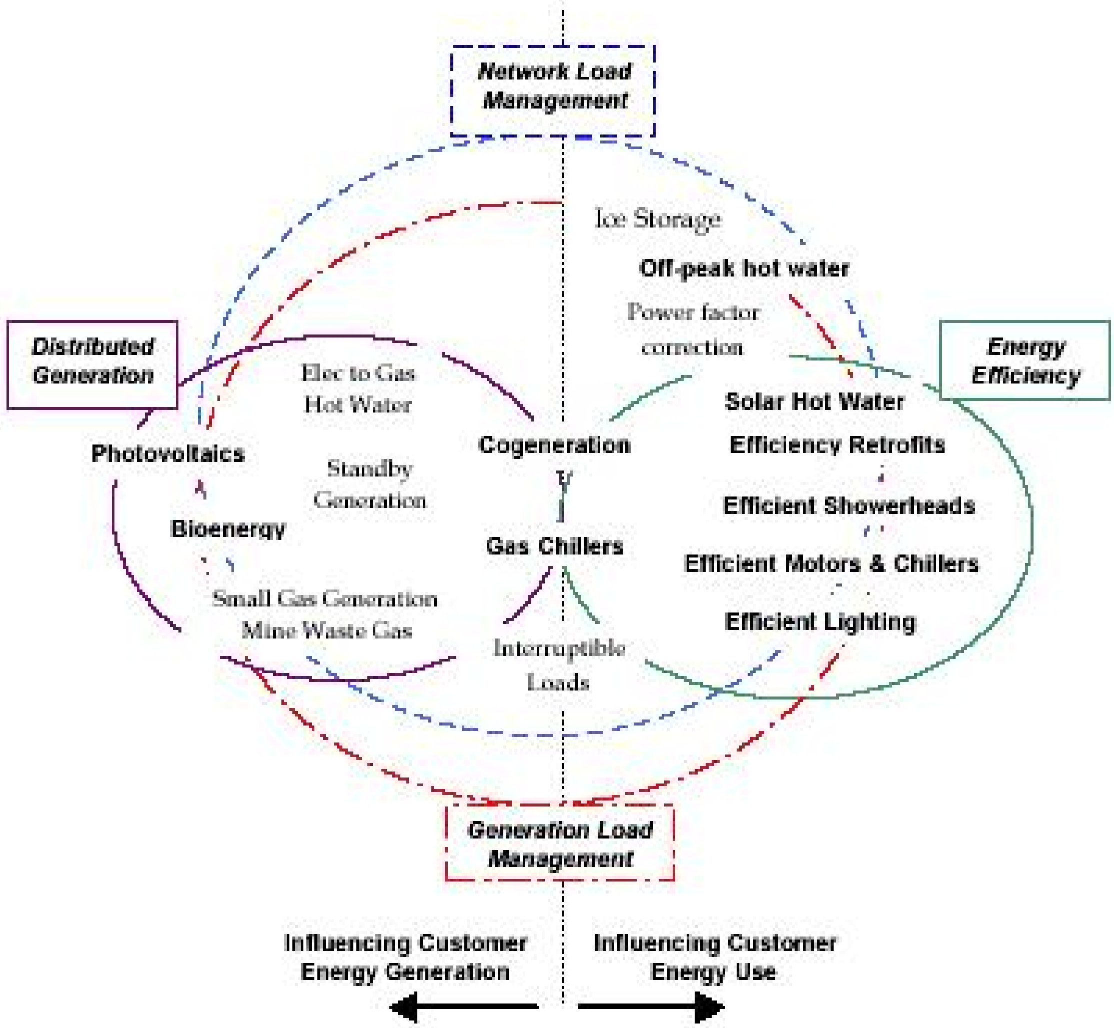
10. Final report by IPART "Inquiry into the role of demand management and other options in the provision of energy services", October 2002

http://www.ipart.nsw.gov.au/

The purpose of this report arose from the concern about potential and substantial increases in capital expenditure in networks and a worsening utilisation of network assets, leading to adverse cost implications faced by consumers in New South Wales. The report observes that the extent of expenditure required to meet demand growth highlights the importance of getting demand management right. However despite noting that demand side options can provide a benefit in the distribution network there still seems to be more attention devoted to electricity price issues rather than a focus on network options.

In this report IPART produces a very useful diagram relating to technologies used to achieve demand management. This highlights the inter-relationship of technologies between energy efficiency, network load management, distributed generation and generation load management.

Figure A2.1 Technologies used to achieve Demand Management



Specific matters raised in the report include

- Instituting a “coarse screen” to help networks identify where it may be useful to send stronger price signals to the market place
- A view that demand side management can improve short-term reliability but that these types of responses will not improve long-term system performance

- An observation that extraordinary circumstances (eg the California crisis) can obtain a demand side response that can and will reduce demand, but that such approaches might not be sufficient in the longer term
- Programs (such as “Cash for Kilowatts”) can be successful, but as there is no penalty for non-performance reliance on them by a network is dubious
- Identification and critical analysis of the barriers to entry of demand management. One such barrier noted is “end user preference for simplicity, convenience, reliability, ‘luxury’ …”
- Encouragement of environmentally driven demand management (such as efficiency) and retail market demand management (such as interruptible supplies)
- The use of the usually unused standby generators to be called on by retailers and networks to assist in relieving short term power shortages, although network constraints might be relieved by the use of such equipment.
- Roll out of interval meters to send better sending price signals
- Aggregation of demand side responses

IPART notes that there are three fundamental demand side response aspects. These are those which are

- environmentally driven,
- network driven and
- retail market driven.

The network driven response focuses on solving network capacity constraints in ways that are more cost-effective than by network augmentation. Such include technologies which drive load shape changes such as distributed generation, power factor correction and fuel switching.

The report implies reference to the issue of “global overview versus local needs” in that it comments the analysis only provides a broad indication of delivered costs *because the cost effectiveness of demand side technologies tends to be very site-specific*.

IPART makes 13 recommendations in its report. Specific to “network driven responses” are

- the establishment of a demand management fund,
- ensuring that distribution examines non network solutions as well as augmentation (the regulatory test approach),
- localised congestion pricing,
- pass through of avoided TUoS,
- review of the ability to offer avoided DUoS charges,
- development of standard guidelines for embedded generation and examining the costs faced by embedded generators for connection, and

- a Government review of the roll-out of interval meters, and if appropriate, to accelerate their availability to provide better price signals.

It is probably the section of the report on encouraging network driven demand management that is most appropriate to the current pricing review. The report notes an example of an approach by Integral Energy where in 1999/2000 IE reportedly deferred nearly $29 million of capital investment for a demand side cost of $1.2 million. Initiatives used by IE included contracts with large customers for load reduction at times of network constraint, fuel substitution programs and the management of off-peak load.

IPART notes that the regulatory environment itself militates against demand side management. In particular uniform network tariffs throughout the distribution area do not provide pricing signals to consumers related to specific locational issues. In addition a lack of clarity as to whether recovery of capex on demand side measures will be permitted further clouds the issue. [It should be noted that the SA Electricity Pricing Order requires distribution pricing to be postage stamped, preventing such an option to be considered by ESCoSA.]

Assessment

The report provides an in-depth analysis of the issues. It proposes a number of sensible approaches which if applied in an integrated way could encourage demand side responses to reduce network capex needs and/or provide a sensible approach to deferral of capital expenditure.

11. Working conclusions by ESCoSA "Embedded generation", May 2004, and Information Paper No. 4 "Small generator connections: technical and financial issues", February 2001 (available ESCoSA website)

The need for the working conclusions arose because of a concern that only some 170 megawatts of embedded generation has been installed in South Australia and therefore there is needed some clear guidelines as to connection and network augmentation costs associated with the provision of these new generation assets. It is stated that the encouragement of embedded generation should see a reduction of network losses, deferral of network augmentation, an enhancement of network reliability and provision of an ability to manage peak demands. Taken together these would result in reduced costs for consumers.

The working conclusions can be summarized as follows:-

- The Distribution Code should incorporate a methodology for calculating embedded generation network connection and augmentation charges, and that there is a distinction between large and small generation arbitrarily split at 20 K V A

- The ESC does not support stipulating network support payments in that any benefits of an embedded generator to the network must be negotiated with ETSA. The ESC will provide guidelines for these negotiations.
- The ESC will develop the guidelines for the technical issues relating to connection of large embedded generators and the terms of a standard offer for small embedded generators. It will also prepare a standard reporting pro-forma for licensed generators
- Whilst it was noted that other than perhaps avoided TUoS charges, there are limited options available for identifying a cash benefit to a distribution company from embedded generation. The ESC will examine incorporating incentives (including avoided TUoS) in the new embedded generation guideline.
- The ESC does not have the power to set electricity buy-back rates, and it decided that the use of bi-directional meters remains an appropriate tool for all embedded generation. However the ESC will provide information on the principles behind buy-back rates.
- There is a need for publicly available standard requirements covering embedded generators incorporated into the network. The ESC will develop these for ETSA to publish.

Assessment

It is obvious that there is a great deal of difficulty in identifying a cash benefit that a distribution company can grant to do an embedded generator, other than perhaps avoided TUoS charges. At best it would seem the regulator can establish a framework that can provide a calculation for avoided TUoS and so facilitate negotiations between an embedded generator and the distribution business. It should be noted that even the calculation of avoided TUoS is extremely difficult.

12. IPART Final Determination for New South Wales electricity distribution pricing, June 2004 http://www.ipart.nsw.gov.au/

The final determination includes some references to demand side management. However the bulk of the supporting documentation is included in a separate report on the final determination.

The actual determination includes for a methodology such that demand management approaches used in the normal activities of the distribution business can be rewarded. This is carried out through formal demand management reporting and by the setting of “D” factors which provide for a mechanism to adjust network pricing to accommodate demand side activities.

The final determination also includes for the pass through of a demand management levy if such is imposed on any distribution network business.

Assessment

The final determination provides a “road map” for the distribution businesses as to how they will develop their approach to pricing. The report on the determination provides the detailed discussion of the issues.

13. **IPART report on the NSW electricity distribution pricing determination, June 2004** http://www.ipart.nsw.gov.au/

The determination sets a series of price caps which arise out of the evaluation of needed revenue and expected demand. Therefore there is an expectation that the distribution business has at some risk to its revenue if the expected demand does not reach the expected levels. The implications of this are that the network will

- Tend to underestimate demand levels for the pricing review, and
- Then endeavor to maximise utilisation of the network during the regulatory period to maximise their revenue.

Both of these issues have the tendency to drive the network businesses to only seek demand side responses where there is an actual constraint in the network.

IPART noted that some 10% of the EnergyAustralia network capacity is used for less than 1% of the time. This has resulted in substantial increases in capex to accommodate the peak demands and therefore reduced their asset utilisation. Despite the finding in its 2002 inquiry into demand management that demand management options can be more cost-effective to relieve network constraints, IPART identified that the distribution businesses have undertaken few demand management activities in the current regulatory period. It went on to note that whilst its determination is an important step in promoting demand management, the determination *will not overcome all the barriers preventing demand side responses*.

The determination report notes a number of issues raised by respondents to its various inquiries, specifically

- Distribution businesses should be able to recover “learning by doing” or R& D type expenditure
- A demand management framework should not be restricted to non-tariff measures
- Recovery of demand management costs are uncertain towards the end of the regulatory period
- The framework should span more than one regulatory period
- The approach to calculating forgone revenue needs to be made clear

- Price increases resulting from demand management should be outside the price limits on network tariffs
- The outcomes for customers need to be explained
- There has not been enough support and encouragement in demand management

As a result of this review a feature of the determination is that another factor being added into the weighted average price cap control formula (the “D” factor) which allows for

- recovery of approved non-tariff-based demand management implementation costs up to a maximum value equivalent to the avoid distribution cost,
- the inclusion of certain approved tariff-based demand management implementation costs and
- approved revenue forgone as a result of non-tariff-based demand management activities.

Another feature of the determination is the ability for the distribution business to recover avoided TUoS payments expected to be paid to embedded generators.

The determination also requires the establishment of three working groups to examine distribution network planning processes, the development of methods for assessing the economic prudency of energy loss management investment, and calculation of distribution revenue foregone as a result of demand management activities.

IPART places the onus on the distribution businesses to ensure that their tariff structures provide proper signals to customers as to the impact of their consumption on network costs. In this way it supports the view that appropriately structured pricing signals to reflect network capacity constraints should be trialed. It goes on to say that although empirical evidence is that consumers’ consumption does not vary greatly in response to price changes, some overseas experience indicates that price signals with non-price measures can be successful limiting demand.

The determination states that the pricing principles require signaling of the impact of additional usage on future investment costs, discouragement of uneconomic bypass, and to allow negotiations to better reflect economic value of embedded generation and other options.

IPART is of the view that its decision to allow distribution businesses to pass through demand management implementation costs is likely to have only a modest impact on consumers.

Assessment

The report provides some useful indicators on how the key findings of earlier report on demand management might be included into a pricing review of distribution network businesses.

14. ETSA Utilities expenditure submission 2005/06-2009/2010, June 2004 (available ESCoSA website)

This submission details the extent to which ETSA considers it requires approval for additional capital expenditure necessary to support the continued reliability of electricity supplies to new and existing consumers. This submission is being reviewed for legitimacy by consultants retained by ESCoSA.

Assessment

Understandably, the submission effectively assumes that increasing demand for electricity will serviced by augmentation of the network.

Appendix 2

Addendum to

Review of various documents having relevance to metering, demand side responses and embedded generation

15. McGregor Tan Research "Air Conditioning Survey" for ESCoSA, June 2004

Residential refrigerant air conditioning is identified as the single largest cause of the electricity system spike in electricity demand. There is a view that residential air conditioning is mainly focused in the upper income groups and which leads to a perception that low income groups are cross subsidizing larger power users through the use of flat tariffs.

The purpose of the research was to identify the extent to which low income people have residential air conditioning compared to the general public, and whether there are significant differences between usage patterns. The research was carried out by telephone survey of randomly selected 405 adults in the Adelaide metropolitan area to provide a "general public" response, and a sample of 400 low income earning adults in the Adelaide metropolitan area to provide a "low income" response.

The survey found that the penetration of air conditioning in Adelaide is very high, with ~60% residences using refrigeration as the cooling medium, ~30% using evaporation as the cooling medium and ~10% not having any air conditioning. Generally there is little difference between the two groups, except that

a. The low income group tends to have older air conditioners
b. The low income group uses a greater proportion of wall and window mounted units
c. Low income groups indicated a more likely need for cooling due to illness, disability, age or other reasons
d. Intriguingly however there is a higher proportion (>5% more) of the general population using non-refrigerant type or no air conditioners than the low income group.

The survey also confirms the recorded electricity consumption data, in that greater use is made of air conditioning when the ambient temperature is high, and there is an increasing usage in the later days of a hot spell as it extends in time.

Assessment

The survey provides a sound quantitative analysis of the usage patterns of consumers regarding air conditioners, which would appear to support previous qualitative assessments made on this issue.

The survey confirms that by and large there is little difference between the general population and low income groups regarding the penetration of air conditioners and usage of air conditioning. However the type of air conditioner more likely to be used by low income residents would indicate that they would be rated at a lower power requirement, but being older they are likely to be less efficient, militating against the lower power rating.

The survey results indicate that a great deal of care needs to be taken in establishing any tariff regime which imposes price premiums for increased demand on critical days. Such an approach is likely to have a relatively greater financial impact on those with illness, disability or age who are identified as being a higher proportion of the low income group.

16. Rosenfeld, Jaske and Borenstein "Dynamic pricing, advanced metering, and demand response in electricity markets" California 2002

Researchers Rosenfeld, Jaske and Borenstein prepared a detailed theoretical analysis[13] of what demand side involvement should provide under a regime of dynamic retail pricing where prices faced by end use customers can be adjusted frequently and at short notice to reflect changes in wholesale prices and in the supply/demand balance. The work was prepared in response to the "California crisis" where they noted the spike in demand for electricity was driven largely by air-conditioning for commercial use (>20% of the peak load), although residential air conditioning (at ~14% of peak load) was seen as a significant factor

The principles they develop have at their basis, the assumption that consumers will modify their usage pattern of electricity in response to pricing signals, providing these signals are strong enough and consumers have sufficient notice in order to respond. The theme developed by Rosenfeld is that electricity prices, particularly at times of high demand and/or price, should be varied by retailers to provide consumers with strong pricing signals to modify their demand. Reference is made to two basic approaches – real time pricing varying with time (hourly or half hourly) and critical peak pricing where the retailer declares an unusually high price for a limited period. They believe that the use of either (or both in combination) of these approaches can be accommodated within the needs of consumers for "bill stability" and meeting retailer revenue requirements, and that it can be a voluntary program. They explain that their "dynamic pricing program" is best targeted at large

[13] Rosenfeld, Jaske and Borenstein, "Dynamic Pricing, Advanced Metering and Demand Response in Electricity Markets", October 2002, for The Energy Foundation. This work is one of a series of papers examining the California energy crisis and potential solutions for the future

consumers, who are able to reduce their exposure to these real time prices by entering into forward contracts. [This seems to be a contradiction – if price signals are to be provided when high prices apply, to have forward contracts which dampen these signals will reduce the impact of the high prices!]

Two fundamental requirements of this model are that the dynamic prices must be signaled ahead of time (one day is suggested as a typical period of forward notice) and all consumers involved in the program must have time-of-use or interval metering. Rosenfeld notes that as the size of the demand for each customer reduces the costs for interval metering increases proportionately, making their approach less commercially attractive to impose at small user levels, but more attractive to impose on large users. [With Australia's "gross pool" model and its inability to determine and fix the wholesale electricity prices by the day preceding (needed to give consumers foreknowledge of the ensuing electricity price), the approach developed would appear to have marginal application in the NEM.]

What Rosenfeld observes is the trend for technology enhancements to increasingly provide mechanisms to readily institute energy management, even by the small consumer. Using these technology advances permits remote management of loads, with the system operator being responsible for sending forward price signals, and for consumers to have installed energy management systems to make use of these forward price signals. The real issue then becomes one of identifying the cost/benefit trade off point between savings from implementing such mechanisms against the cost of implementation.

Assessment

Understandably (as this work was mainly to address the issue of the "California crisis) the approach proposed by Rosenfeld et al is primarily targeted at managing the overall supply of power rather than establishing a demand side response for managing network constraints.

For the Rosenfeld approach to result in relieving network constraints, network needs must be coincident with system peak pricing, as well as system demand peaks. The Rosenfeld work builds on a model which assumes that price increase with demand, and there are a number of significant aspects regarding this assumption that need to be noted.

a. The peak ISO demand in California during June 2000 of 45,000 MW was 50% greater than the current peak of 30,000 MW in the NEM.

b. The ratio of peak demand to average is much lower in California to that applying in South Australia

c. The maximum prices in June 2000 reached in California were at most 10-12 times of the average price – in South Australia the peak price reached is some 270 times the average price[14]. This is a direct result of the lower system price cap (VoLL) applying in California than in Australia.

d. Peak prices in California during June 2000 occurred between 30% of average demand and 80% of average demand, implying there is not a firm correlation between price and demand.

Effectively what Rosenfeld proposes is a transfer of volatility from the wholesale market (in which the professional market participants operate) to the retail market where much less well informed consumers have to operate. Countering this, to mitigate the increase risk to consumers, Rosenfeld proposes that consumers (and retailers) can buy forward contracts which have a natural dampening of the short term price volatility related to critical peak demands.

17. Charles River Associates, "Assessment of Demand Management and Metering Strategy Options" July 2004

Charles River Associates (CRA) was retained by the ESCoSA to assess the net benefit-cost of using demand side management initiatives and/or pricing signals in combination with interval metering, to defer augmentation of constrained network elements on ETSA Utilities' distribution system. This additional report is a continuation of the task referred to in item 7 earlier in this review of documentation relevant to demand side responses and interval metering.

As deferral of investment has its major benefit when the need to augment a specific asset is required in a short to medium time frame, CRA focussed on three locations in the ETSA Utilities network soon to require augmentation. They examined both the realistic availability of demand side responses by examining availability of existing installed standby generation, power factor correction, transfer of work shifts to another time period, transfer of air conditioning and refrigeration loads out of peak periods, voluntary load reduction, and direct load reduction by cycling and/or interruption. As an alternative they carried out modelling a pricing initiative using a critical peak price (CPP) of 5 times[15] a base rate.

CRA notes that "firm" reductions in demand would only result from the direct load reduction approach and by utilisation of standby generation and power factor correction. Other approaches are seen as "non-firm".

CRA makes a number of useful points which give an indication of issues which need to be considered when examining a pricing pressure approach, or a voluntary demand reduction program.

---

[14] Reached on 8 March 2004

[15] The executive summary notes that 6 times the base rate was used. The base rate is not quantified in the report.

- Advice of forward pricing is noted as being needed to be provided ahead of the time the peak price is identified
- Assessment of consumer response to CPP is based on results identified in other studies in the US and France. They note that for a 100% increase in base rates, the likely system demand reduction is 2.5% for residential consumers and 0.4% for small business consumers
- Interval metering is required to be installed to verify the load reduction provided by each consumer. This needs to be compared to the normal operation to demonstrate if the reduction was in fact provided

They also noted that

- Fuel substitution as a demand side measure ultimately leads to loss of that demand, effectively permanently reducing the revenue to the utility from that source. [This implies that if ETSA Utilities contributes funding to this option, then they are funding a loss of revenue]
- Energy efficiency leads to a permanent loss of part of the demand, again reducing the revenue to the utility

The expected demand reductions calculated from using the two different approaches at the three locations examined are

% of needed load reduction achieved by each approach	DSM	CPP
North Adelaide	**697%**	96%
Findon-Fulham Gardens	86%	48%
Modbury	19%	42%

The study indicates that even with an aggressive critical peak pricing approach using 5 times base rates for price signalling the expectation of a sufficient response to defer augmentation does not provide the needed reduction. [For two of the sites, the CPP would need to be 10-12 times the base rate to achieve the demand reduction]

From their analysis, CRA concludes that the CPP approach does not provide sufficient load reduction to warrant any detailed cost/benefit analysis, nor that it warrants pursuing detailed analyses of the DSM approach for either Findon-Fulham or Modbury.

CRA prepared an indication of the cost per kVA to source the different demand side measures that could be obtained for North Adelaide substation. These need to be assessed in context of the capital cost to provide a network solution estimated by CRA at $260/kVA as the present value of the deferred investment.

Cost of demand side measures to ETSA $/kVA	North Adelaide
Implementing PF correction	73

Accessing standby generation	184
Direct load control	251
Curtailable load	345
Voluntary load reduction	1,084

Assessment

As an overall statement the CRA study indicates that to get a sufficient demand side response to defer network augmentation is quite difficult, and is heavily influenced by the location in the network, and type of customers connected. Of the three locations selected for study only one of the three appeared to have the potential to be able to defer network augmentation resulting from demand side measures. Investigations for Findon-Fulham Gardens and Modbury showed that there was insufficient DSM or CPP driven responses sufficient to provide deferral of augmentation of the network. For North Adelaide the present value of the cost of the program totals $190k and the present value of the avoided costs is $260k, a saving of some 25% of the costs.

It must be stressed that the commerciality of the alternatives to augmentation were only assessed against the benefits to the network, and did not cost or allow for any other benefits which might occur in the regional.

The study indicates that even with an aggressive critical peak pricing approach using 5 times base rates for price signalling the expectation of a sufficient response to defer augmentation does not appear to provide a viable option. To increase the critical peak pricing to the levels required, may present significant equity and political challenges.

The most cost effective demand side measures would appear to be implementing power factor correction, accessing standby generation, and direct load management. The added advantage of each of these is that they provide “firm” load reductions, and except for direct load management, do not impact of the revenue stream to the network.

The CRA review would imply that overall the ability of demand side measures to provide sufficient demand reduction would appear to be over-rated. Investigations for Findon-Fulham Gardens and Modbury showed that there was insufficient DSM or CPP driven responses sufficient to provide deferral of augmentation of the network. For North Adelaide the present value of the cost of the DSM program totals $190k and the present value of the avoided network costs is $260k, a saving of some 25% of the costs.

18. Final decision by the ESC of Victoria mandatory roll-out of interval meters for electricity customers July 2004

In July 2004, the ESCoV released its Final Decision on interval metering and this decision mandates the universal roll out of interval meters in Victoria[16]. The Final Decision effectively replicates the outworkings of the Draft Decision, although weight is added to the conclusions by the preliminary results of some pilot studies in the US (these are discussed in more detail in the next section of this review).

The commentary provided in the earlier review of documents is essentially unchanged as a result of the ESCoV Final Decision on interval metering. However there is one major change of emphasis in the Final Decision which needs to be noted.

As stated in the assessment of the ESCoV Draft Decision, the work by the ESCoV is predicated on the principle that financial pressures alone will encourage a demand shift and so deliver the benefits of a reduced system peak demand. Of real concern is that the assumption that consumers will shift their demand as a result of these pricing pressures might not be proven in actuality, and that demand increases may still result, with consumers electing to pay any financial premiums rather than accept the inconvenience of not using power when they wish.

Therefore it is difficult to assume a deferral of network augmentation will be a firm outcome of the ESCoV decision, even though the savings for this comprise the bulk of the benefit calculated by the ESCoV. The ESCoV does not necessarily even accept that demand side responses will occur as a result of its decision, as it states that the distribution businesses will have to institute their own programs to ensure the network savings from demand management, as interval metering is not seen as providing this guaranteed service.

> "The [ESCoV] has not considered all the options by which demand reductions may occur and it expects that retailers and distributors are best placed to consider innovative market developments. …Low cost approaches may be available for remotely controlling certain loads or indicating to customers that demand should be reduced, for example. The [ESCoV] considers that all these approaches will benefit from interval meters … That is, the interval meter does not replace these [other] technologies, but it enables them to provide price signals to retailers and also to customers." [17]

---

[16] The Final Decision of ESCoV regarding this issue can be accessed at http://www.esc.vic.gov.au/electricity819.html

[17] Page 39 ESCoV Final Decision on Interval Metering Roll Out

Assessment

There is a subtle shift in the view of the ESCoV regarding interval meter roll out. Initially the implication of the roll out was seen as providing the desired outcomes. Now it is seen as being an element needed for the implementation of other actions which will provide the desired outcomes.

19. Reports on some trials carried out in Florida, California and Illinois

a. Florida

As a specific assessment of an approach used overseas, officers of ETSA Utilities and the Commission observed the approach being taken by Florida Light and Power to encourage demand side involvement in the electricity market. Florida Light and Power, at the behest of the Florida Energy Commission in order to reduce the growth of generation and for environmental reasons, has implemented a successful program to reduce peak demand.

The core of the program is to have direct control of widespread loads from residential and small business consumers and the power authority has the ability to control certain load types and to cycle on/off certain other load types, with the ultimate ability to turn off agreed loads for some hours under emergency conditions. For providing this service consumers are paid to be part of this voluntary system. Capital costs for installing the consumer load management systems were borne by the power authority.

One observation regarding the success of the program was that the strong response observed was that the "middle class consumer" tended to be more responsive when made aware of its ability to provide support for a positive outcome for the environment. [This can also be seen in Australia by the extent of the take-up of domestic consumers' actively purchasing "green electricity".]

Florida Light and Power is a vertically integrated power supplier, and has addressed demand management essentially for managing system supply. Their approach has proven successful in achieving this goal, but there is no clear identification of the benefits the program has in limiting network augmentation as this has not been the focus of their approach.

b. California

In its review of interval metering the ESCoV highlighted the results of the Statewide Pricing Pilot trial carried out in California during 2003 and 2004, included in the interim report provided in June 2004[18] by Charles River Associates.

[18] Charles River Associates "California's Statewide Pricing Pilot Summer 2003", Impact Evaluation by Ahmad Faruqui and Stephen S. George, reported June 2004

This trial is built around the principle espoused in the theoretical (Rosenfeld) report referred to in section 16 above, and attempts to implement the principles of dynamic pricing which is at the core of that report, and to assess the reality of the theory espoused. The principles of the critical peak pricing (CPP) used overlaid a complex five tier increasing block structure[19]. The CPP allows for demand reduction on 15 days per year with 12-18 hours notice of the need of a demand reduction plus additional demand reduction which can be called at 4 hours notice for the critical period of 2pm to 7 pm. Involvement in the program is voluntary.

Of particular note is that customers are given a “pre-warning” of the prices to follow the next day and are therefore able to take informed action. The price penalties for using power when a CPP applied were three times the price of peak power, and five times the average power price.

The preliminary results show that while consumers are responding to a CPP approach and provide significant and sufficient demand reduction to warrant furthering the trial, it is also noted that consumers showed little response to the standard time-of-use pricing measures. Although at first view the response to the CPP measures can be seen positive reinforcement for the theoretical principles of price elasticity, the observed result could have benefited significantly by the direct advice provided prior to expect high priced events and of high demands expected in the ensuing period.

c. Illinois

As with the California pilot, this study was an attempt to assess the responses from residential customers exposed to real time pricing, based on a day ahead market based prices. The program was not revenue neutral as participants were offered a 10% saving due to the transfer of risk from retailer to customer.

The expectation was a 10% reduction in electricity costs would result compared to pricing based on historical tariffs. The program was voluntary and included 750 customers. Each customer was provided day ahead hourly prices by access a website or calling a toll free number. Participants were notified by email or phone if there was to be a high price the next day. A price cap of $500/MWh applied and each participant was personally briefed on the program and energy management.

Review indicates a high initial response but this tapered off over time. Low income and multi-family respondents were particularly responsive to the program. Whilst nearly 50% of respondents reduced air conditioner use during high price periods about half of these transferred some of the demand to an earlier for pre-cooling. Washing machine and dryer usage pattern changed.

[19] Most time-of-use block structures are two part (peak and off peak) pricing, or three part (peak, shoulder and off peak) pricing

Participants noted the cash savings and bill control as the main feature of the program but also cited environmental benefits and getting a better understanding of energy as benefits of the program.

The program has only run for one year (2003) of three years, and the 2003 summer was reported as quite mild, with only 30 days where pricing went above $100/MWh

Assessment

The three studies are primarily focused on obtaining a system wide reduction in electricity demand. There is no clear evidence that such a program will directly result in a reduction in a need for network augmentation, and the downsides to achieving this network outcome from a system wide approach still remain.

It appears that the success of the California and Illinois programs rely heavily on the day ahead prices being readily available to participants, together with the direct advise of extreme price events about to occur. With this foreknowledge and incentives to participate it would appear that this approach is an essential element of a successful trial. Whilst such an approach might be possible for a pilot, there is concern about how such an approach could operate on a statewide basis.

It should also be noted that all of the programs reviewed were based on voluntary involvement. Therefore some of the success may be attributable to the fact that the volunteers already had an interest in demand management and therefore have a strong interest in seeing the program successful.