Australian Energy Market Commission

DRAFT REPORT

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

6 September 2012

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About the AEMC

The Council of Australian Governments (COAG), through its then Ministerial Council on Energy (MCE), established the Australian Energy Market Commission (AEMC) in July 2005. In June 2011, COAG established the Standing Council on Energy and Resources (SCER) to replace the MCE. The AEMC has two principal functions. We make and amend the national electricity, gas and energy retail rules, and we conduct independent reviews of the energy markets for the SCER.

Executive summary

Efficient markets are characterised by effective participation of both the supply and demand side.

The supply side of the market provides a product or service at a price, and the demand side responds to the price/value of the product or service being offered. While there is some evidence of uptake of demand side participation (DSP) in the NEM over recent years, the efficiency of the electricity market can be improved by effective use of the demand side. Making this happen will require changes to some aspects of how the supply side of the electricity market operates and through greater empowerment of consumers.

The power of choice review is identifying opportunities for consumers to make informed choices about the way they use electricity. Consumers require information, education, incentives and technology to make efficient choices. The review is also addressing the incentives needed for network operators, retailers and other parties to maximise the potential of efficient DSP and respond to the consumers' choices, in a manner that minimises the total cost of electricity services.

The draft report

This report sets out our draft recommendations for supporting the market conditions necessary to facilitate efficient DSP. We propose changes to the existing market and regulatory arrangements that will enable the market to use the demand side to meet consumer needs as efficiently as possible.

The draft recommendations form a package of integrated reforms. These reforms act to facilitate efficient DSP in two ways:

- Enabling consumers to see and access the value of taking up demand side options; and

- Enabling the market to support consumer choice through better incentives to capture the value of DSP options and through decreasing transaction costs and information barriers.

These draft recommendations will make it easier for consumers to make informed decisions in managing their electricity use. In turn, consumers will have greater ability to control their bills through choosing demand-side products and services that may better suit their needs. The draft recommendations will also help market participants (retailers, networks, and other third party intermediaries) to use more flexible demand to reduce capital and operating costs. In the longer term, all consumers will benefit through reduced prices.

The way in which consumers engage and participate in the electricity market is a key factor in realising the benefits and full potential of efficient DSP. Effective communication and education strategies will be needed to build consumer confidence so that consumers utilise the potential of DSP products and services offered by the market.

We propose these outcomes can be achieved through:

- **Rewarding DSP in the wholesale market:** Establishing a new demand response mechanism that allows consumers or third parties on consumers' behalf to directly participate in the wholesale market and to receive the spot price for the change in demand.

- **Gradually phasing in time varying network tariffs:** The transition to better price signals in the NEM should be done in a gradual phased approach. We propose that this can be achieved through:

  - Focusing only on introducing time varying prices for the network tariff component of consumer bills. Retailers would be free to decide how to include the relevant network tariff into their retail offers; and

  - Segmenting residential and small business consumers into three different consumption bands and applying time varying network tariffs in different ways. Large residential and small business consumers would be required to have a time varying network tariff as part of their retail price.

  We have selected this approach as we consider that large consumers are likely to have the greatest impact on system costs for a marginal change in consumption, and also the potential to change their consumption.

- **Protecting vulnerable consumers:** Some types of consumers may have limited capacity to respond and change their consumption over the day and therefore may face increased financial difficulties if they were moved to a time varying tariff. We have proposed arrangements for these consumers to remain on a retail tariff which has a flat network component.

- **Separating DSP actions from the sale and supply of electricity:** Providing arrangements to allow consumers to sell their DSP to parties other than their electricity retailer by introducing a new category of market participant. We have also proposed changes to the technical arrangements for metering which we outlined in our electric vehicles and natural gas vehicles review. These include enabling consumers to separate and source their consumption from different suppliers. In addition, those consumers who have distributed generation will be able to sell their electricity to parties other than their existing retailer.

- **Enhancing consumers' ability to access consumption information:** Enabling consumers to have better access to their consumption data and information about their electricity use. We also propose that there are transparent arrangements for how parties directly engage with consumers to offer DSP products and services.

- **Enabling technology:** Establishing the overarching framework to encourage commercial investment in better metering and promote consumer choice in how their meter can provide additional functions to provide DSP products.

- **Distribution network incentives:** Building a framework that will provide a commercially sound and sustainable basis for making DSP part of the network planning and investing process; and improve the framework for how distribution determining network businesses tariffs.

- **Establishing formal consultation when setting network tariffs:** We propose that distribution network businesses engage in a formal consultation process with retailers and consumers when setting network their tariffs.

- **Energy efficiency measures and polices:** We consider that there should be greater coordination between DSP and energy efficiency government policies so that the consumer can be rewarded for the full value of their DSP action.

In the draft report we outline a number of other minor rule changes. The key draft recommendations as outlined above are set out in Table 1.

Trends in electricity production and consumption

The context in which electricity is produced and consumed has changed markedly over the past 15 years. Some of the most important changes include the following:

- The strong economy Australia enjoyed from the mid-nineties through the middle of this decade resulted in a very significant increase in the percentage of homes using air conditioning and in the size of new homes being built. The combination of these factors significantly increased the amount of electricity generation and network capacity needed to meet customers' demand for electricity, particularly during extended periods of hot weather.

- Over the same period, households purchased more electrical appliances and many Australian businesses have introduced business processes that rely on electrical systems. These changes to businesses systems have made even momentary supply faults more apparent and more inconvenient and costly. In response, some governments have tightened the reliability standards of the electricity network businesses within their jurisdictions, which has resulted in the need for additional capital investment.

- More recently, several network businesses have embarked on major asset replacement programs because the poles and wires that were installed in the 1950s and 1960s need to be replaced for their continued reliable and safe operation. This has required capital investment and has resulted in increases in electricity prices for consumers.

- Concern about the environment and particularly greenhouse gas emissions has driven a series of policy initiatives aimed at reducing carbon emissions and encouraging renewable energy generation.[1] All of these initiatives have tended to reduce average electricity consumption to a greater extent than reducing peak demand. The cost of renewable electricity has generally been higher than the cost of the conventional electricity it has replaced, resulting in increased electricity costs for consumers.

- The global financial crisis occurred at about the same time these asset replacement and network expansion programs began. The slowdown in Australia's economy has made consumers much more aware and reactive to price increases. As a consequence, the amount of electricity used on a year on year basis has declined– the first time this has happened in the history of the industry in Australia. At the same time, peak demand has continued to grow, although at a slower rate than previously, meaning that investments in additional generation and network capacity to meet this demand continue to be made. This is ultimately reflected in an increase in consumer electricity prices. There are significant technology changes afoot. Smart grid technology, offers the potential to improve electricity supply reliability and market system processes. Such technologies also allow for the integration of decentralised technologies like co- and tri-generation, electric vehicles, solar photovoltaic and mini-wind generation systems. This will also require capital investment.

These changes have posed challenges to the electricity supply industry and, more importantly, have changed the nature of electricity supply and consumption. In this new operating context, better integration of the potential of the demand side into supply side investment decisions is required. The electricity market will require further enhancements to accommodate these changes, and provide a framework in which supply and demand resources are coordinated to interact more easily and deliver mutual benefits.

Our proposed recommendations provide a policy pathway for achieving efficient demand side participation in the NEM. The recommendations act on the supply side to improve its ability to better value and coordinate demand side resources, as well as providing recommendations that will allow all types of consumers –both household and business - to respond to the changing environment. They aim to ensure the market remains robust, flexible and is able to adapt to the changing environment, irrespective of what pattern of demand emerges.

Impact of proposed changes for the market

The recommendations will help to ensure that over time, increases in electricity costs will be lower than they otherwise would have been. In other words, the lowest cost combination of DSP and supply options is used to meet consumers' demand for

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1 These included the decision in a number of jurisdictions to discourage or prohibit new and replacement applications of off-peak electric water heating, the encouragement of solar photovoltaic and other renewable energy systems by end users. In addition to the requirement that electricity retailers source a specified percentage of the electricity required by their customers from renewable energy.

electricity services (i.e. the appropriate balance between affordable and reliable energy supply).

DSP provides a tool for consumers to actively participate in the market, by offering a suite of options for them to manage their electricity consumption and, in turn, their bills. It includes actions such as energy efficiency, peak demand shifting, fuel substitution, and consumers generating their own electricity.

For example, in the short term, analyses that has been undertaken for the review, suggests that an average consumer who simply moves from a retail flat tariff to more flexible time varying tariffs could potentially save up to around $100 per year. This could increase to as much as $200 per year if the consumer also changes their consumption pattern. These figures could increase if DSP results in long term savings to supply costs.[2]

DSP also reduces the costs incurred by the electricity supply chain in meeting consumers' electricity needs in aggregate. This can exert downward pressure on electricity prices. Industry analysis indicates that the combined economic value of DSP measures (such as dynamic pricing, direct load control, electric vehicle to grid technology, energy efficiency measures and small scale solar generation) may be in the range of $1.5 billion to $4.6 billion over the next nine years.[3]

While DSP opportunities provide benefits, there will also be costs in taking up DSP options by consumers and other parties. These include the upfront costs to install technology and any costs associated with operating that technology, including any payments made to consumers when certain DSP options are undertaken. Those costs need to be weighed against the benefits that DSP provides.

We are undertaking further work to understand the costs and likely benefits of implementing the reforms proposed. We will present these findings in our final report.

Draft package of reforms

Every consumer sector can provide and benefit from DSP. Large industrial and commercial consumers can alter their consumption in ways which will save them money by responding to price signals or demand side program offers. These types of consumers typically have access to more accurate information regarding their electricity use from metering and other services available to them. This is mainly due to the fact that for some of these consumers electricity is a substantial part of their business costs.

Household and business consumers have a different capacity to participate in the market by responding to price signals and accessing demand side programs. As more information on DSP options becomes available and consumer knowledge increases,

2 Frontier Economics, *Retail Tariff Model, A report prepared for the AEMC*, September 2012, available on the AEMC's Power of choice webpage.

3 Deloitte, *Analysis of initiatives to lower peak demand: Final Report*, prepared for the Energy Supply Association of Australia, April 2012.

there will be greater potential and opportunity for these consumers to participate in the market. The reforms we have proposed are designed to enable residential and small business consumers to better manage and control their bills.

The key themes that have emerged from the review and that our recommendations seek to build upon are as follows:

- There is no 'best' form of DSP. The right form of DSP will vary between different consumers and different types of consumers and may also vary in different locations and at different times. It is important to have a framework that allows and facilitates consumers and industry to find the solutions that work for all parties.

- We are not pre-judging consumer decisions on how, when and how much they should be consuming at a given price level. Consumers, given the right information and tools, will be in the best position to decide what course of action is appropriate for them.

- Currently, consumers' understanding of energy use and what they need to know for making smart energy consumption decisions is limited. A more strategic and coordinated approach is required to build consumers' energy literacy, taking into account the different capacities and preferences across and within consumer sectors. To this end, partnerships will need to be formed between all parties across the supply chain. Governments will also have a role to play. Better access to their metering data and consumption patterns will enable consumers to quantify their consumption decisions.

- The way in which network and retail tariffs are currently structured means that individual consumers are not always faced with final prices which accurately reflect the actual costs of supply and delivery of their electricity. The current pricing structures limit the ability for consumers to take up DSP options. Experience elsewhere suggests that greater choice in pricing options helps consumers reduce their costs. However, some consumers may have very little, if any, ability to change their consumption patterns, and other consumers – particularly vulnerable consumers – cannot afford to pay any more than they already do. For these consumers there needs to be pricing options and support mechanisms to ensure reliable and affordable energy supplies.

- While over the short term, exposure to time varying pricing will impact consumers in different ways, over the longer term more cost reflective pricing should lower energy bills for all consumers due to lower system costs. Hence it is important that the arrangements for managing bill changes (the first round effects) do not undermine the ability to capture the benefits of better asset utilisation and lower system costs (second round effects).

- Better metering – and particularly interval metering – can play a very important role in helping consumers understand their energy use. Moreover it can help identify – or enlist the help of consumers' retailer or third parties in identifying –

actions that they can take to reduce their energy costs, with no, or at least an acceptable, reduction in their comfort and convenience. Interval meters can also support innovative pricing options. These options can give consumers more information about the cost of supplying energy and a reason to undertake actions to reduce their bills in the near term. This can help reduce the costs that the electricity supply industry will need to incur in the future to meet consumer needs and, in turn, reduce upward pressure on electricity prices to all consumers.

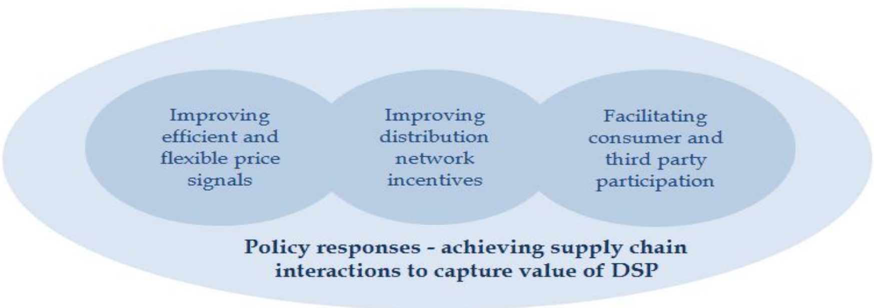
- Retailers and distributors also need to be assured that undertaking DSP will not interfere with their ability to meet their responsibilities in providing safe and reliable power to consumers. The market needs an agreed approach for assessing the value of DSP. The commercial and regulatory arrangements of the market also need to ensure that retailers and distributors do not face undue commercial risks in pursuing DSP. These should enable such businesses to enjoy commercial rewards no less than they would have from pursuing traditional supply side options.

- There is a role for specialist third parties to help consumers understand and manage their electricity usage. Regulatory and commercial arrangements need to be structured in such a way that makes it possible to harness the expertise and innovation of specialist sector businesses. At the same time, these arrangements need to ensure that consumers have access to appropriate technical and commercial protections.

- Distributed generation from rooftop PV systems, co- and tri-generation systems, mini-wind turbines, electric vehicles and other such technologies can provide cleaner sources of power, reduce line losses, and defer the need for more network infrastructure. Market arrangements regarding the ownership, connection and operation of these resources should not constrain their use.

- It is important that each part of the supply chain sees the costs and benefits of DSP options and aligns the commercial interests of different participants for an efficient market outcome. How our proposed reforms promote co-ordination across the supply chain is shown in Figure 1.

Figure 1 Policy responses to support coordination across the electricity market supply chain.



How these reforms will be implemented

This review was undertaken in response to a request from the former Ministerial Council on Energy, now the Standing Council on Energy and Resources (SCER) in March 2011.

We have considered a wide range of issues in the review. In undertaking our work, we have been informed by the National Electricity Objective (NEO) which is our overarching guiding criteria for the review. The reforms we have proposed seek to target the priority areas important in the context of the review.

Stakeholder engagement for the review has been ongoing and the response has been extensive and positive to date. We have aimed for our assessments to be based on issues raised by stakeholders, submissions to the review and evidence gathered through supporting reports. We have also taken into account input from the Stakeholder Reference Group we established for the review.

We have not attached detailed rule changes to this report. In the final report we will outline how the draft recommendations can be implemented, including by whom and by when. Primarily, the proposed recommendations are for the SCER to consider, and if agreed, to be implemented where appropriate through rule changes and other regulatory mechanisms.

Making a submission

We encourage stakeholders to consider the issues raised in this report when preparing their submissions. We will be holding a public forum on 3 October for stakeholders to present their views and provide the AEMC with feedback on proposed reforms. Submissions close on 11 October 2012.

Table 1 Summary of key recommendations

Action area	Review draft recommendations
Improving consumer participation	
DSP in wholesale markets	**We recommend that:** • A demand response mechanism that pays changes in demand via the wholesale electricity market is introduced. Under this mechanism, consumers participating in this mechanism can either make the decision to continue consuming, or reduce their consumption by a certain amount for which they would be paid the prevailing spot price. • The National Electricity Rules (NER) is amended to clarify the Australian Energy Market Operator (AEMO) role in developing both long and short term demand forecasts. This includes estimating DSP, for the purpose of providing accurate price signals to the market over various time frames including pre-dispatch. • Creating a new category of market participant in the NER that will allow for the unbundling of non-energy services (e.g., ancillary services) from the sale and supply of electricity.
Efficient and flexible pricing options	**To manage the impacts on vulnerable consumers, we recommend that:** • Arrangements are put in place for consumers, which may a limited capacity to respond, to remain on a retail tariff which has a flat network component. These consumers would have the option to choose a time varying tariff. • Government programs target advice and assistance to these consumers to help manage their

Action area	Review draft recommendations
	consumption. • Governments review their energy concession schemes so that they are appropriately targeted.
	The transition to more efficient and flexible price options in the NEM should be done in a gradual phased approach. We recommend: • Focusing only on introducing time varying prices for the network tariff component of consumer bills. Retailers would be free to decide how to include the relevant network tariff into their retail offers; and • Segmenting residential and small business consumers into three different consumption bands and applying time varying network tariffs in different ways: - For large consumers (band 1), the relevant network tariff component of the retail price must be time varying. This would require these consumers to have a meter that can be read on an interval basis. - Medium to large consumers (band 2) with an interval meter would transition to a retail price which includes a time varying network tariff component. These consumers would have the option of a flat network tariff. - Small to medium consumers (band 3) would remain on a flat network tariff. These consumers would have the option to select a retail offer which includes a time varying network tariff, if they so choose.

Action area	Review draft recommendations
	• Better education and information on the impacts of transitioning to more time varying retail prices. • Each year, distribution network businesses will be required to consult with consumer groups and retailers on their proposed tariff structures. • Amendments to the distribution pricing principles in the NER economic regulation framework are made to better support the introduction of time varying network tariffs.
	In regards to retailers, we recommend that: • Once a residential consumer has a meter which measures on an interval basis (ie every 30 mins), that consumption should be settled in the wholesale market using the interval data and not the net system load profile. This will be the case irrespective of whether the consumer has a flat retail tariff.
Enabling technology (metering)	**We recommend that:** • A minimum functionality specification is included into the NER for all future new meters installed for residential and small businesses consumers. That specification should include, interval read capability and remote communications. • The installation of meters consistent with the proposed minimum functionality specification to be required in certain situations (eg refurbishment, new connections, replacements). Such metering must also be installed on an accelerated basis for large residential and small business consumers (band 1) whose annual consumption is above the proposed defined threshold.

Action area	Review draft recommendations
	• Reforms to the current metering arrangements are necessary to promote investment in better metering technology and consumer choice. We have put forward a model where metering services are open to competition and can be provided to residential and small business consumers by any approved metering service provider.
Facilitating consumer access to electricity consumption information	**We recommend changes are made to:** • Chapter 7.7 (a) of the NER to clarify the requirements on a retailer when consumers request access to their energy and metering data. This would include provisions relating to the format and structure of data to be provided; the timeframes for delivery; and fees that can be charged. • Chapter 7 of the NER to require, at a minimum, a retailer to provide residential and small businesses consumers with information about their electricity consumption load profile. There may be a need to amend the National Energy Customer Framework (NECF) to ensure consistency of arrangements. • Chapter 7.7 (a) of the NER to enable agents, acting on behalf of consumers, to access consumers' energy and metering data directly from a retailer. This would include requirements on a retailer to provide consumers' energy and metering data to an authorised consumer's agent (third party), following explicit informed consent. • The NER to require AEMO to publish market information on representative consumer sector load profiles.
Role of parties to engage with consumers	**We recommend that the:** • NECF is clarified to make it clear what arrangements apply to third parties providing "DSP energy

Action area	Review draft recommendations
	services". This should involve establishing criteria either in the NECF or the Australian Energy Regulator (AER) guidelines on retail exemptions. The criteria could include the circumstances where accreditation (or exemptions) of parties is required and the relevant provisions of the NECF that would apply (ie marketing rules, and the relevant enforcement and monitoring provisions). • The NER and NECF are clarified to outline the conditions when a distribution network business can engage directly with consumers to offer DSP network management services. This may involve establishing appropriate guidelines/process for the AER to apply and outlining which elements of the NECF apply.
Distribution network incentives and distributed generation	
	We recommend that: • The AER consider reforming the application of the current demand management and embedded generation connection incentive scheme to provide an appropriate return for DSP projects which deliver a net cost saving to consumers. We have put forward principles and two mechanisms for how this could be achieved. • A two-part approach is adopted to address the issue of business profits being dependent upon actual volumes. This includes improvements to the pricing principles to guide network tariff structures and secondly, to include an allowance for foregone revenue under the DSP incentive scheme. • A number of minor changes are made to the rules to provide clarity and flexibility for how the AER treats networks' DSP expenditure.

Action area	Review draft recommendations
Energy efficiency measures and policies	
	We recommend that: • There is better coordination of energy efficiency and DSP policy and measures. • Any regulatory schemes relating to energy efficiency need to address the secondary impacts that they are likely to have on the electricity market and its participants. • There is better reporting and more publicly available data on the load shape impacts of energy efficiency measures on both peak and average electricity demand.

Contents

1 Background

1.1 Introduction

The Australian energy sector is going through a period of change and faces a number of major challenges. Structural readjustments have resulted in an overall reduction in the energy intensity of the Australian economy, while increases in household wealth and adoption of new technologies are altering the way that we use electricity in the home. Delivering the investment necessary to meet the objectives of climate change policy is also placing a range of new demands on the National Electricity Market (NEM).

Meeting these challenges efficiently requires the NEM to make use of all available resources. This means using both the demand and supply sides of the market to ensure that community demand for electricity continues to be met, while at the same time minimising costs to the system. However, this can only happen when all opportunities for efficient demand side participation (DSP) are identified and captured.

The Ministerial Council on Energy (now the Standing Council on Energy and Resources (SCER)) commissioned the Australian Energy Market Commission (AEMC) to undertake a review of the market and regulatory arrangements needed across the electricity supply chain to facilitate efficient investment in, operation and use of DSP in the NEM.

This review is to recommend possible changes so that efficient DSP options are considered and correctly valued in the planning and operation of the NEM. It examines how consumers can make informed choices about the way they use electricity through the provision of appropriate information, education programs, incentives and technology. It also considers how network operators, retailers and other parties can be incentivised to facilitate and respond to consumer choices in a manner that results in minimising total costs of energy services.

The AEMC's recommendations are assessed in the context of the likely costs and benefits they confer on the market and against the National Electricity Objective (NEO).

This chapter provides an overview of the general trends in Australian electricity consumption. These trends reflect how Australian consumers use electricity and help us identify how consumers can be empowered to make informed choices. It also provides an overview of some of the potential benefits associated with DSP and concludes with a summary of the AEMC's analytical framework and work program.

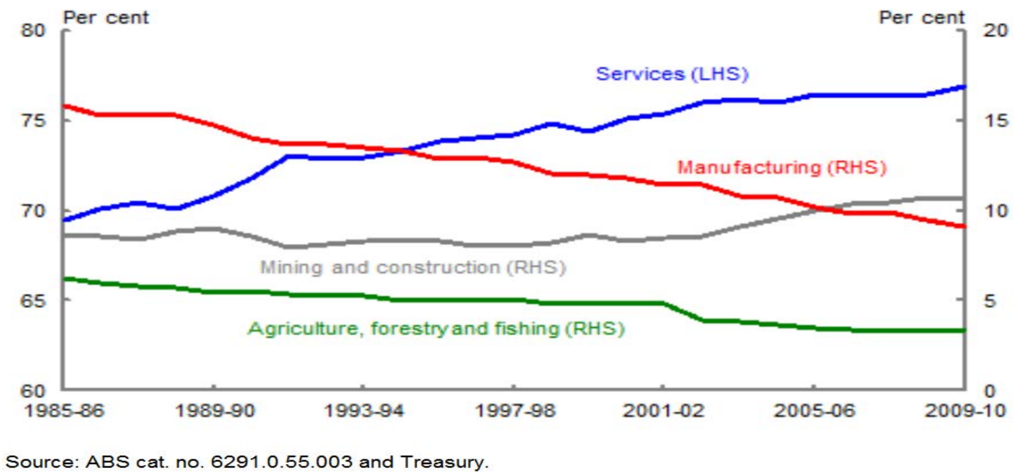
1.2 Demand in the NEM: the context for DSP

1.2.1 Trends in energy consumption

Sectoral shifts in the economy are a major driver of Australian energy consumption patterns. Key shifts include growth in the services sector and more recently the mining sector, coupled with a decrease in manufacturing. Each of these sectors uses energy in different ways and, as their relative contributions to the Australian economy have changed, so too has the economy's overall energy intensity.[4]

Over the longer term, services have been the fastest growing sector of the Australian economy and today represent around 70 per cent of Australian gross domestic product.[5] The manufacturing sector has experienced a relative decline over the longer term and currently contributes around 10 per cent of GDP.[6] This trend is shown in terms of relative employment shares, by sector, in Figure 1.1

Figure 1.1 Employment share by history



Source: D Gruen, Economic Roundup Issue 2, 2011, Australian Government Department of the Treasury website, viewed at 20 August 2012[7].

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4 Energy intensity, is the ratio of total final energy consumption to gross value added GDP. Another indicator of energy intensity is composite energy intensity, which describes economy wide energy intensity, by aggregating energy intensities of individual sectors. For further discussion on energy intensity measures, see: BREE, *Economic analysis of end-use energy intensity in Australia*, Bureau of Resource and Energy Economics, Canberra, May 2012; BREE, Australian Energy Statistics – Energy Update 2011 Table F, Bureau of Resource and Energy Economics. Viewed at 20 August 2012. www.bree.gov.au

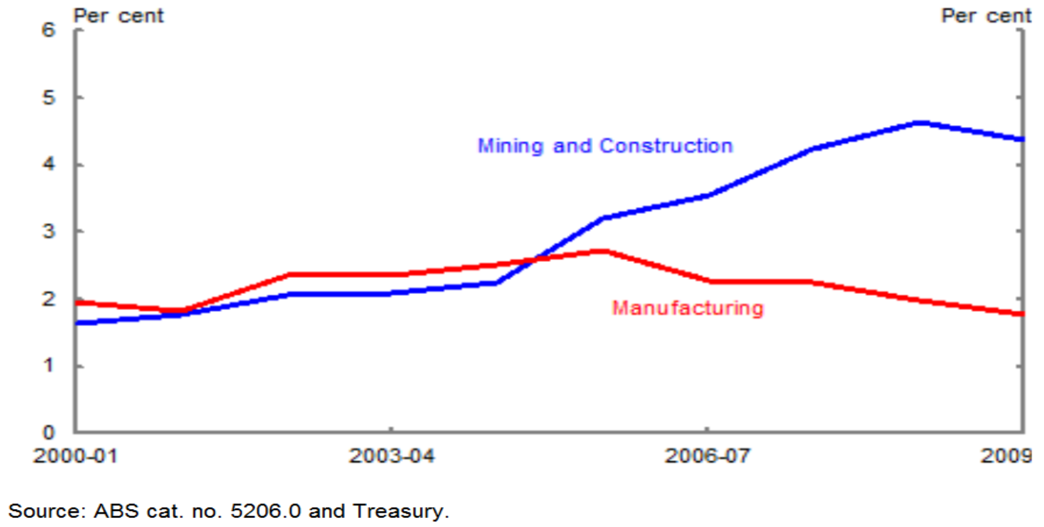
5 Department of Foreign Affairs and Trade, 'The importance of services trade to Australia'. Viewed at 20 August 2012. www.dfat.gov.au

6 ABS, Year Book Australia 2012, cat.no.1301.0. Viewed 20 August 2012.www.abs.gov.au/ausstats

7 http://www.treasury.gov.au/PublicationsAndMedia/Publications/2011/Economic-Roundup-Issue-2/Report/The-resources-boom-and-structural-change-in-the-Australian-economy

The other key sectoral trend is the growth of the mining and construction sector over the previous decade, as Australian commodity production and capacity has grown to meet demand. This growth is shown in Figure 1.2, which also highlights the divergence in investment trends between mining and manufacturing.

Figure 1.2 Investment as share of GDP



Source: D Gruen, Economic Roundup Issue 2, 2011, Australian Government Department of the Treasury website, viewed at 20 August 2012[8].

There are a number of factors driving these sectoral changes in Australia. For example, the combination of high resource prices and a strong Australian dollar are attracting labour and capital out of the non-resource sector (including some, but not all, parts of the manufacturing sector) and into mining and construction. Similarly, increased direct competition from developing economies in non-resource sectors, such as manufacturing, is impacting on employment in those sectors in Australia.[9] The global financial crisis has also played a major role in the most recent downturn in the manufacturing sector, with total manufacturing output declining by an estimated 4.2 per cent in 2008/09, one of the steepest declines in output since the early 1980s.[10]

These sectoral trends are reflected in the changing electricity consumption patterns of the Australian economy, which is illustrated in Figure 1.3. The relatively energy intensive Australian manufacturing sector has shown a steady increase in total electricity consumed over the long term. However, there has been a marked downturn in energy consumption in recent years, reflecting the trends described above (in particular the impacts of the GFC. In contrast, the commercial and public services sectors, while substantially less energy intensive than manufacturing, have shown a steady increase in total consumption over the long term.

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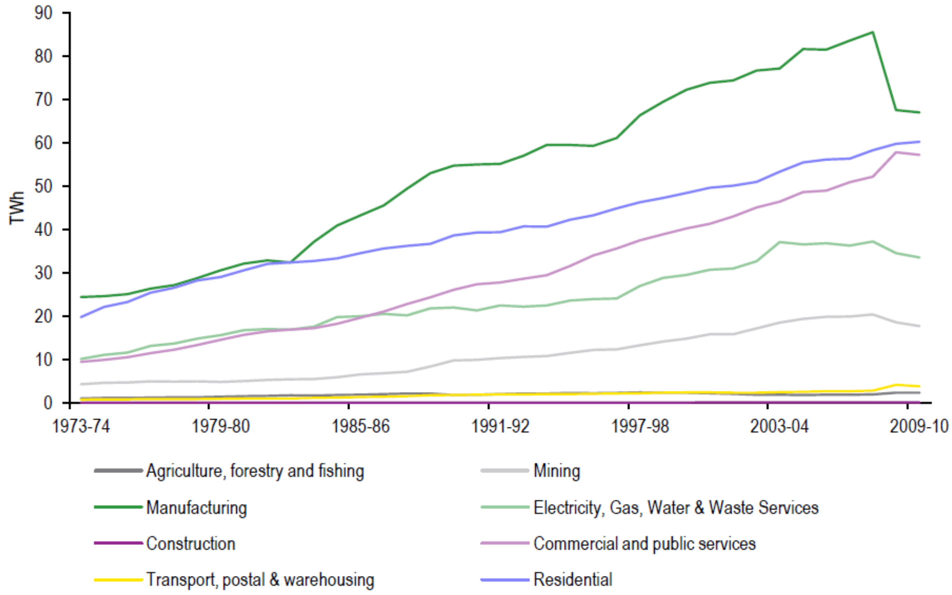
8 http://www.bree.gov.au/documents/publications/energy/Energy_intensity.pdf

9 D Gruen, *Economic Roundup Issue 2*, 2011, Australian Government Treasury website, viewed at 20 August 2012.www.treasury.gov.au

10 DIISR, *Manufacturing sector overview of structural change: Industry brief 2008/09*, Department of Innovation, Industry, Science and Research, July 2010, p.1.

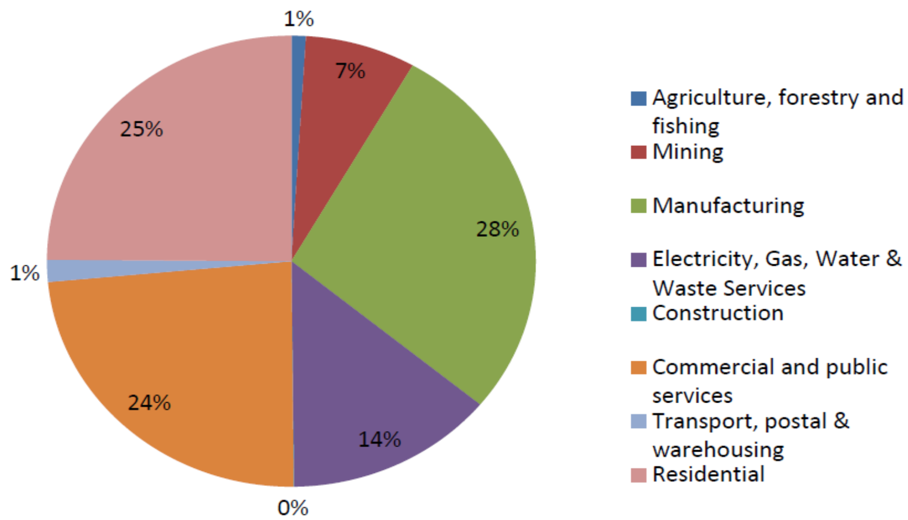
Figure 1.3 Electricity consumption in Australia



Source: Ernst and Young, *Rationale and drivers for DSP in the electricity market – demand and supply of electricity*, 20 December 2011, p.13. Data sourced from BREE, Australian Energy Statistics – Energy Update 2011.

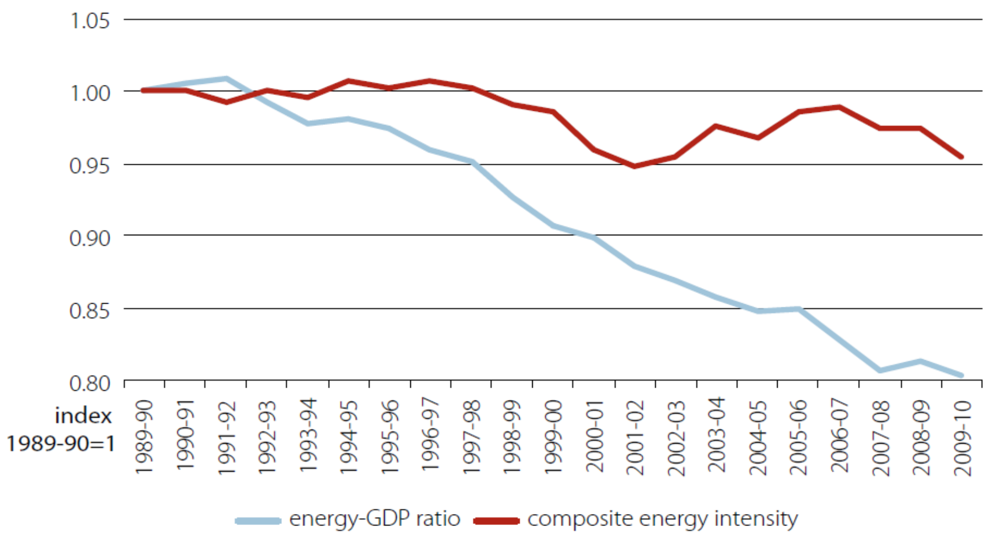
While there has been a steady increase in Australia's electricity consumption, the sectoral trends described above have resulted in a steady decrease in the energy intensity of the economy. This trend is illustrated in Figure 1.5 below, which shows the continuing trend of a decreasing ratio of energy used per unit of GDP in Australia.

Figure 1.4 Australian energy consumption by sector - 2011



Source: Ernst and Young, *Rationale and drivers for DSP in the electricity market – demand and supply of electricity*, 20 December 2011, p.15. Data sourced from BREE, Australian Energy Statistics – Energy Update 2011.

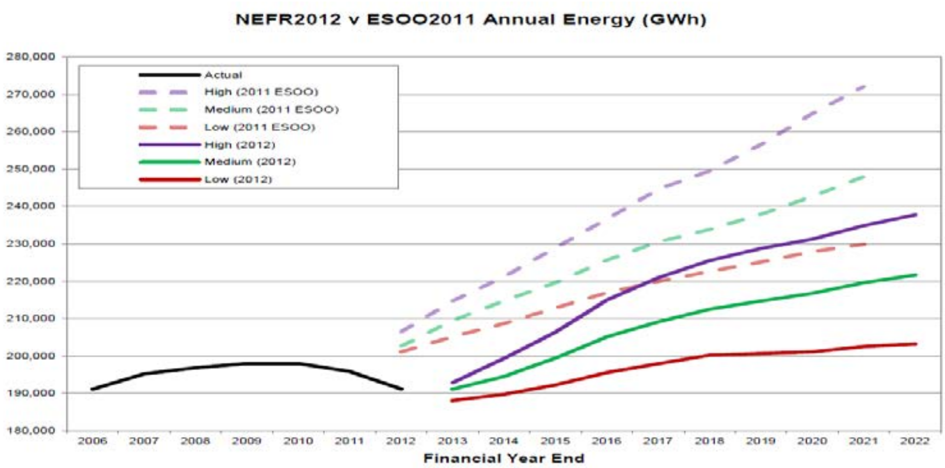
Figure 1.5 Trends in energy GDP ratio



Source: BREE., *Economic analysis of end-use energy intensity in Australia* Bureau of Resource and Energy Economics, Canberra, May 2012.

Forecasts of Australian energy consumption have also changed in recent years. As shown in Figure 1.6, the Australian Energy Market Operator (AEMO) has revised its 10 year forecasts of electricity downwards, as expected growth in average and peak demand has not occurred as rapidly as previously predicted. The potential causes of this are numerous and include the effects of sectoral change, global economic trends and improved energy efficiency in the Australian economy. AEMO has also stated that increased entry of small scale, residential level solar photovoltaic (PV) generation may also be contributing to these forecast decreases, as are other forms of direct commercial and residential consumer response to rising electricity costs.[11]

Figure 1.6 Forecast total energy 2011 vs. 2012



Source: AEMO, *Media Release: Inaugural energy use forecasts signal new demand and investment outlook*, Australian Energy Market Operator, June 2012

11 AEMO, *National electricity forecasting report*, Australian Energy Market Operator, June 2012.

1.2.2 Price of electricity

Electricity prices have increased in recent years. As shown in Figure 1.7 below, the cost of distribution networks is forecast to contribute approximately 34 per cent of future electricity retail price increases out to 2013/14, while the wholesale cost of electricity is forecast to contribute a further 40 per cent.[12]

Several factors are driving these forecasted increases. Network price increases are primarily due to replacement of ageing assets, the impacts of increasing peak demand , rising costs of finance following the GFC, input cost changes (such as the cost of steel, copper, labour etc), increased reliability standards, and connection of renewable generation. Wholesale price increases are being driven by the price on carbon as well as input and fuel cost increases.

Increases in electricity prices may not appear to align with the general reductions in total demand seen over recent years. However, it is important to note that prices include the cost of large capital investments, such as network augmentations, which have been made to ensure continued reliability of supply. Once these large network investments are made, their cost is recovered from consumers, regardless of how much electricity is actually used. This can result in increased prices for energy consumed by end users. Where average demand is slowing down but costs continue to increase, the prices faced by consumers will also increase.

Figure 1.7 National residential electricity price increases out to 2013/14

Total price comparison:			**Contribution of each component to price increases:**	
2010/11 price (c/kWh)		22.41	**Transmission**	6.0%
2013/14 price (c/kWh)		30.75	**Distribution**	33.6%
Total c/kWh increase		8.34	**Wholesale**	40.2%
Total nominal % increase (2010/11 to 2013/14)		37.2%	**Retail**	12.1%
			Feed-in tariff	2.8%
Carbon impact:	**c/kWh**	**Percentage**	**LRET**	3.8%
2012/13	1.64	5.6%	**SRES**	-0.8%
2013/14	1.74	5.7%	**Other state based schemes**	2.3%

Source: AEMC, Possible Future Retail Electricity Price Movements: 1 July 2011 to 30 June 2014, Final Report, 25 November 2011, Sydney

DSP may help consumers deal with the impacts of electricity price rises. Contracting to provide DSP, or responding to new tariff structures, may offer the opportunity to households or businesses to shift a proportion of their electricity usage to cheaper, off peak times, saving money on final bills. Of course, this is dependent on the development of more flexible tariff arrangements and availability of necessary technology. In conjunction with this paper, we have released a tariff model from

12 AEMC, *Possible Future Retail Electricity Price Movements: 1 July 2011 to 30 June 2014*, Final Report, 25 November 2011, Sydney

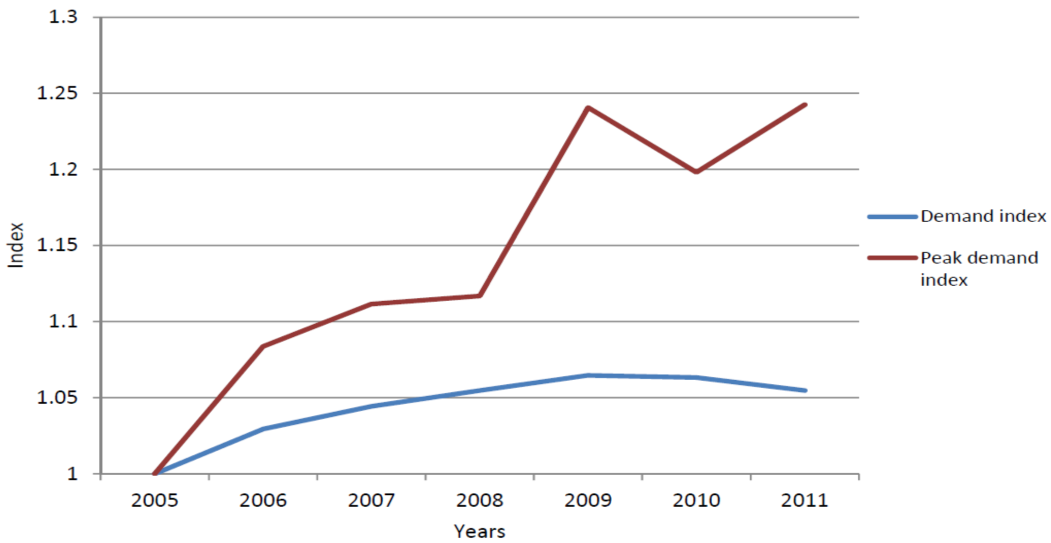
Frontier economics which helps to explain the impacts of different tariff arrangements on consumers' bills. This is discussed in chapter six.

DSP options such as peak demand reduction may also offset the need for new network investment. Such reductions in total levels of investment may help manage the extent of future price increases for consumers. We explore the concept of peak demand and DSP options to facilitate peak demand reduction in further detail below.

1.2.3 Peak demand growth: drivers and impacts

A key aspect of Australian energy consumption patterns has been the rapid growth of peak demand relative to average demand.[13] Between 2005 and 2011, peak demand increased at a rate of approximately 1.8 per cent a year, while total energy grew at 0.5 per cent a year.[14] Figure 1.8 shows the relative growth of peak and average demand in the NEM over the previous six years. Recently, AEMO has published detailed forecasts out to 2021/22 which show peak demand continuing to grow at a faster rate than average demand in all states except for Queensland and New South Wales (NSW).[15]

Figure 1.8 Peak versus average demand growth



Source: Energy Networks Association, Consultation Paper submission, Economic regulation of networks Rule change. Data sourced from AEMO 2011 ESOO.

For the directions paper, we commissioned Ernst and Young (EY) to analyse peak demand trends in the NEM. EY identified that various sectors of the economy are making different contributions, with growth in peak demand for the commercial sector

13 Peak demand, sometimes expressed as maximum demand, is the largest volume of electricity demanded within a specific timeframe. Average demand, also expressed as total energy, is the total volume of electricity demanded across a specific timeframe.

14 AEMO, *2011 Electricity Statement of Opportunities*, Australian Energy Market Operator, August 2011.

15 AEMO, *National Electricity Forecasting Report* , Australian Energy Market Operator, June 2012

expected to outpace growth in peak demand for the industrial sector in most jurisdictions.[16] This is consistent with the likely continued sectoral shift towards the commercial and public services sectors. As the electricity consumption of these sectors continues to grow, the opportunities for efficient DSP in these sectors will also increase.

We found that residential consumption is another key driver of peak demand growth in the NEM. While the residential sector consumes around 25 per cent of total energy (as seen in Figure 1.4), various studies have shown that the residential contribution to peak demand can be as high as 35 per cent to 45 per cent on peak demand days.[17] Residential customers have relatively peaky demand profiles that reflect usage of household appliances at peak times, the prime example being the use of air conditioners on hot days.[18]

Higher levels of peak demand relative to average demand can result in the power system being used inefficiently. This occurs because generation and network assets built to meet a few short periods of peak demand, may be underused in other periods.

A decreasing load factor (the ratio of average demand to peak demand) is indicative of this situation. The cost of developing new generation and network infrastructure to meet such incremental demand is increasing.[19] These costs are ultimately passed on to consumers and can contribute to substantial increases in end user bills.

DSP options which target peak demand growth may provide significant cost savings. The commercial and industrial (C&I) sector may have a role to play in developing these options. This sector accounts for around 75 per cent of total energy demand in the NEM. Thus reducing their consumption during peak periods may have a significant impact on total power system costs. These larger consumers tend to display relatively "flat" or predictable demand profiles and may have greater discretion to modify their electricity use during peak periods.

The residential sector can also play a role in addressing peak demand. DSP options for the residential sector can include technologies that directly reduce consumption at certain times or tariff based DSP. For example, direct load control or time-sensitive

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16 Except in Queensland, most likely due to the significant levels of industrial activity in support of the state's growing resources sector.

17 These figures extracted from various reports prepared for the Essential Services Commission of South Australia (ESCOSA), Energex and Ergon Energy. including: CRA, *Assessment of Demand Management and Metering Strategy Options*, Charles River Associates, prepared for ESCOSA, August 2004; CRA, *Queensland Network Demand Management Framework*, Charles River Associates, prepared for Ergon Energy and Energex, October 2006.

18 Ernst and Young, *Rationale and drivers for DSP in the electricity market – demand and supply of electricity*, 20 December 2011, p.41

19 The costs of meeting increments of demand are linked to the costs of inputs needed for investment in networks and generation stock, such as finance, labour and raw materials. This also includes operational costs, such as fuel. As the cost of these input costs increases, so too does the cost of meeting further increments of demand. This may be particularly the case if the price of gas increases, as gas is likely to fuel an increasing portion of the NEM generation stock in the future.

tariffs such as critical peak pricing may help provide consumers with price signals that more clearly reflect the extent of their impact on power system costs.[20]

While peak demand growth is likely to continue to be an issue in the NEM, the variance between peak demand and average demand growth has reduced between AEMO's 2011 and 2012 forecasts. Stakeholders including the Consumer Action Law Centre have noted the general decrease in forecasts of average and peak demand growth, and caution against the inefficient adoption of DSP solutions in response to "yesterday's problem".[21]

We note that recent levels of demand and forecast demand growth have deviated from previous trends. As identified by AEMO, there are a number of factors likely to be contributing to these changes, including the effect of cooler weather, worldwide economic conditions and the rollout of solar PV technology.[22] However, it is important to remember that patterns of demand are cyclical and the decrease in demand seen in recent years does not necessarily mean that a new long term trend has arrived. The recommendations in this report seek to improve the efficiency of the market to minimise the cost of supply irrespective of what pattern of demand emerges.

1.3 Efficient DSP

The trends described above highlight the kinds of challenges likely to be faced by the NEM over the coming years. Meeting these challenges at the lowest possible total system cost requires that both the demand and supply sides of the market are fully and efficiently used. By effectively using DSP, we can help ensure that demand for electricity is met with the most efficient mix of demand and supply side options.

While DSP may provide a range of benefits, it is not without its own costs. It is therefore important to weigh these costs against all benefits so that a DSP action is efficient.

1.3.1 What is efficient DSP?

We have identified efficient DSP as an action taken by consumers (either independently or via an intermediary) to manage or reduce their electricity consumption so they deliver a net benefit to the wider market (such as lower costs of supply), that is more than the loss in value or the costs incurred by the consumer.

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20 The extent of these costs can be substantial. As recently highlighted by the Department of Resources, Energy and Tourism in the *Draft Energy White Paper*, while it costs around $1500 to purchase and install a 2 kilowatt air conditioner, such a unit can impose costs on the energy system of around $7000 when adding to peak demand.

21 Consumer Action Law Centre, directions paper submission, p.3

22 Total installed solar PV capacity in the NEM has grown to around 1450MW as of February 2012 and is forecast to grow to 5100 MW by 2021/22, supplying around 3.4% of annual energy. AEMO, *National Electricity Forecasting Report*, Australian Energy Market Operator, June 2012; AEMO, *Rooftop PV information paper*, Australian Energy Market Commission, 2012, p.iii.

At an individual consumer level, efficient DSP is about striking a balance between the value that consumers place on their electricity consumption and the benefits that result if they were to reduce or otherwise change their consumption. For the market, efficient DSP occurs when the cost of doing DSP is less than the system cost savings and benefits.

DSP may take a number of forms. Generally, DSP options fall into two broad types: contracted DSP (such as network support agreements or direct load control) and uncontracted DSP (such as changes in electricity use based on price, including time sensitive retail tariffs).[23] Different market conditions and participant preferences will determine which options are selected. An overview of the various kinds of DSP options available is provided in Chapter three in the review's directions paper.

As an example, a DSP option could include a direct load control arrangement between a Distribution Network Service Provider (DNSP) and a residential consumer, where the former installs equipment that allows the DNSP to manage an electric appliance owned by the consumer for a specified amount of time, in return for a payment to that consumer. Other examples of DSP have already been adopted by DNSPs, for example the installation of off peak hot water systems. The net benefit to the market may include reductions in the cost of supply, through more efficient use of the electricity system and deferral of network augmentation.[24] This option will be efficient where these net market benefits outweigh any loss in value faced by the customer.

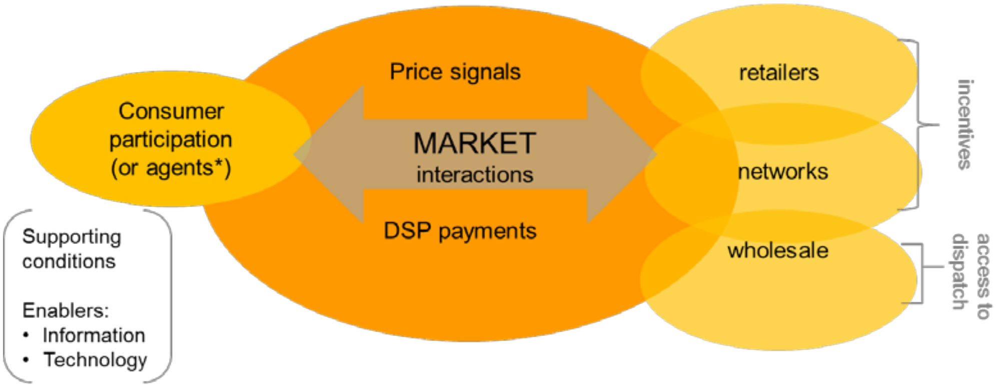
From an overall market perspective, the optimal use of resources occurs where the lowest cost combination of DSP and traditional supply side options are used to meet total demand. This will occur when all opportunities for efficient DSP are captured. In the directions paper, we identified a number of key conditions necessary for efficient DSP to be realised:

- Consumers (or their agents) need to be able to compare the value they place on electricity services with the costs incurred in providing those services; and to understand the benefits and costs associated with DSP
- Market participants (such as retailers, networks, energy service companies (ESCOs) and aggregators) need to be able to identify opportunities for efficient DSP and to facilitate and encourage the appropriate action. Participants must also have clear incentives to offer these services
- The incentives influencing the consumer in deciding upon a DSP option need to be aligned with the wider impacts on the electricity market.

23 There is also passive DSP, which differs from all the other DSP options as it is a by-product of an end-use technology which requires no interaction from anyone (either the end user or the supply chain) once the technology is installed. This could be as simple as the effect of a high efficiency air conditioner, which will alter the consumer's load profile and the system load duration curve.

24 A range of other benefits may accrue from this action. For further detail of the potential benefits of DSP actions, see chapter 2 of the directions paper.

Figure 1.9 Market conditions for efficient DSP



Note that agents may include energy service companies (ie ESCOs and aggregators)

1.3.2 Consumer engagement and participation

The way in which consumers engage and participate in the electricity market is a key factor in realising the benefits and full potential of efficient DSP. Engaged consumers allow market participants to capture the value of flexible demand and offer different and innovative services and products.

Traditionally, consumers have been relatively passive participants in the electricity market. This situation has changed in recent times, with consumers becoming increasingly interested in managing their electricity usage and costs.

DSP provides a tool for consumers to actively participate in the market, by offering a suite of options for them to manage their electricity consumption and, in turn, their exposure to prices. It includes actions such as energy efficiency, peak demand shifting, fuel substitution, and consumers generating their own electricity.

Electricity is a derived demand. This means that its value is directly related to the goods or services it is used to produce. Different consumers will place different values on these goods and services, which will in turn shape their willingness to engage in DSP.

The nature of this value depends on a number of variables. For example, during periods of extreme temperature, some consumers may attach a high value to the use of appliances such as heaters or air conditioners, which will influence their willingness to change their consumption and to engage in DSP. Similarly, consumers may attach higher values to different kinds of appliances, depending on whether the consumer considers that the appliance delivers an essential or discretionary service, as well as the cost of the appliance.

Individual behaviours, attitudes and opinions also influence consumer engagement in DSP. Perceptions and values are shaped by a variety of factors including: the ability to process information; prices; knowledge of the issues (eg energy costs); time limitations; access to finances; and general appetite/commitment to change.

Consumer habits and heuristics will also influence consumption behaviours and levels of engagement in DSP. Consumers may use electricity in particular ways not solely due to its monetary cost or perceived value, but also because of learned behaviours or social norms.

Physical characteristics and limitations are also important in shaping consumer engagement. At the residential level, physical housing characteristics will influence how much energy a household consumes, which may in turn influence the capability of the household to engage in DSP.[25] For larger C&I consumers, minimum operating levels of industrial equipment or external contractual arrangements may also constrain the ability to engage in DSP.

Other consumers may face particular limitations on their capability to engage in DSP. For example, elderly, people with disabilities or low income consumers may face particular constraints on their capacity to reduce or change their consumption patterns.[26] Such households may also be limited in their capacity to buy equipment necessary to undertake particular forms of DSP.

We consider that individual consumers are capable of determining the value they place on the use of electricity, based on their own considerations. This means that, provided with the right information and tools, consumers will be in the best position to decide how they use electricity and to choose whether or not to engage in DSP activities. We are not presupposing consumer decisions on how, when and how much they should be consuming at a given price level.

1.3.3 Delivery of DSP by the market

While informed and active consumers are important for efficient market participation, the market must respond to consumer demand and deliver new products and services. Adequately incentivised market participants can address the search and transaction costs associated with developing DSP and may also help capture the total value of DSP along the supply chain.

Third parties will play a role in facilitating the development of DSP options, particularly for smaller consumers. Smaller consumers may not have the capacity or desire to directly engage with electricity markets, and their small disaggregated nature can create substantial transaction costs for any potential buyer of DSP.

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25 The NSW Independent Pricing and Regulatory Tribunal (IPART) has identified relationships between particular household characteristics and appliance usage and increased levels of consumption. IPART, *Determinants of residential energy and water consumption in Sydney and surrounds: Regression analysis of the 2008 and 2010 IPART Household Survey data*, Independent Pricing and Regulatory Tribunal, December 2011, Sydney.

26 The AEMC considers that while the cost of electricity may be a relatively small proportion of expenditure for many households, this is not the case for everyone. Such households may be particularly impacted by increases in energy costs, particularly if they do not receive government assistance. Consideration of these households is a component of the Commission's assessment of DSP.

Third parties, such as DSP aggregators or ESCOs, may act as an intermediary for small consumers and, in doing so, may address the transaction costs issue. This action can help to capture and coordinate the value of small customer DSP by creating a product which can be sold to another party. The role of third parties is discussed in chapters three, five and eight of this report.

1.4 DSP in the NEM: what are the benefits for consumers?

DSP has the potential to provide consumers with a number of benefits. Individual consumers may see cost savings through using less energy generally, or using less energy at certain times, and may also receive explicit payments for participating in DSP programs. At the market level, DSP may deliver more efficient outcomes through reducing variability of supply costs in the short term and reducing the need to build new infrastructure in the longer term, which can deliver savings to all consumers as a result.[27]

It is challenging to provide a quantitative measurement of the kinds of benefits likely to flow from efficient DSP, as the value can vary significantly depending upon the location and time of day. We are considering approaches to quantifying benefits at the individual consumer level and are hoping to include this in our final report. Various stakeholders have provided measures of the potential dollar value benefits:

- AGL has examined the impact of peak demand and how improvements in load factors may contribute to reduced end costs for consumers. It found that improving system load factors by around 11 per cent could reduce an average annual consumer bill by around 12 per cent, or $245.[28]

- The Energy Supply Association of Australia engaged Deloitte to assess the potential benefits of lowering peak demand. Deloitte considered DSP options such as dynamic pricing, direct load control, electric vehicle to grid technology, energy efficiency measures and small scale solar generation. They found that the combined economic value of these measures may range between $1.5 billion and $4.6 billion by 2021.[29]

- The AEMC engaged Ernst and Young (EY) to assess DSP programs that could reduce peak demand; EY found that by removing the top one per cent of peak demand periods between 2011 and 2030, DSP could provide an indicative value of between $3.3 billion and $11.1 billion in network cost savings across the NEM.[30]

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27 Chapter 2 of the directions paper provides a detailed overview of the kinds of benefits available.

28 AGL, *Dynamic Pricing and the Peak Load Problem*, presentation by Professor Paul Simshauser to Power of choice public forum, Sydney, 19 April 2012. Available at www.aemc.gov.au.

29 Deloitte, *Analysis of initiatives to lower peak demand: Final Report*, prepared for the Energy Supply Association of Australia, April 2012.

30 It should be noted that this potential benefit of avoided network cost does not take into account the costs associated with implementing DSP measures. See chapter four of Ernst & Young, *Rationale and drivers for DSP in the electricity market - demand and supply of electricity*, 20 December 2011.

- Ausgrid estimates that for each additional megawatt (MW) delivered by the electricity system, around $3.3 million worth of investment in assets is required. This comprises distribution costs of $1.5 million, transmission costs of $0.8 million and generation costs of $1 million.[31] Similarly, Energex estimates a total cost per MW of $3.5 million, comprising distribution costs of $2 million transmission costs of $0.7 million and generation costs of $0.8 million.[32] These figures provide an indication of the incremental value associated with using DSP to reduce the volumes of investment needed to meet peak demand.

1.5 The AEMC's analytical framework

1.5.1 NEO assessment and key topic areas

In conducting its assessment of DSP in the NEM, the AEMC is required to have regard to the National Electricity Objective (NEO). The NEO is defined in section seven of the National Electricity Law (NEL) and states:

> "The objective of this Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to: (a) price, quality, safety, reliability and security of supply of electricity; and (b) the reliability, safety and security of the national electricity system."

The NEO informs the assessment framework we use to evaluate potential changes to market and regulatory arrangements. This includes identifying and assessing the ability of such changes to promote efficient DSP.

This promotion of efficient DSP requires us to consider the total range of relevant costs and benefits. DSP has the potential to provide consumers with benefits, either at the individual level or through improving the efficiency of electricity markets. However, these benefits must be robustly examined in light of their potential costs, so that the net outcome is in consumers' long term interests.

1.5.2 Consideration of vulnerable consumers

In acknowledging the varying capacity of consumers to engage with the electricity market, we will take into account those whose capacity to engage may be reduced through a particular reliance on electricity, such as people with disabilities or the elderly.

We also note the variability between different households in terms of the proportion of their income spent on electricity bills. While average expenditure on electricity bills is generally a relatively low proportion of average weekly household earnings, there are

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31 Ausgrid, directions paper submission, p.1.

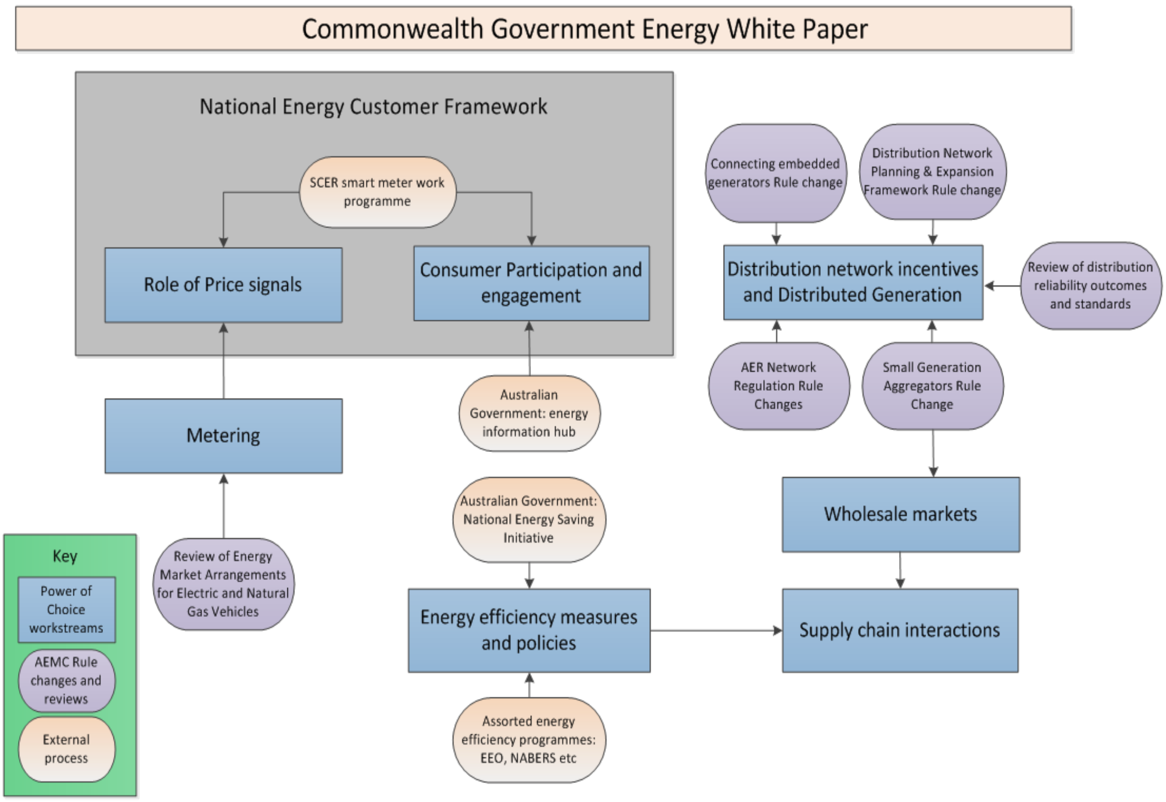
32 DEEDI, *Queensland Energy Management Plan*, Queensland Government Department of Employment, Economic Development and Innovation, May 2011, p.4.

also likely to be households who do not fit this description.[33] Such households may be especially impacted through any changes to electricity pricing arrangements, particularly where there are increases in other unrelated costs such as mortgage repayments and rental prices. The consequences of changes to electricity market arrangements should be carefully considered in the context of the impacts on these households.

1.5.3 Other processes relevant to the Commission's consideration

There are a number of other projects currently underway, both internal and external to the AEMC, which have informed our considerations in this report. In particular, we note the various work streams being progressed by the Standing Council on Energy and Resources and the Australian Government related to smart metering, consumer protections, consumer information provision and energy efficiency.

Figure 1.10 Interactions with other projects



33 Some studies have shown that Australian household expenditure on electricity is around 2per cent of average weekly earnings. However, others argue that this overall figure may contain differences between household groups, finding that lower income households may spend over 5 per cent of disposable income on electricity costs. P Simshauser, D Downer, 'Limited-form dynamic pricing: applying shock therapy to peak demand growth', *AGL Applied Economic and Policy Research, Working Paper 24 – Dynamic Pricing*, February 2011, p.3; L. Chester, A. Morris, 'A new form of energy poverty is the hallmark of liberalised electricity sectors', *Australian Journal of Social Issues*, Vol.46 No.4, 2011.

1.5.4 Structure of the Draft Report

The AEMC's assessment of efficient DSP focuses on several key areas. These are:

- **Consumer participation**: Information, how the market offers products and services and avenues for engagement, consumer (and third party) access to wholesale market and investment in, and use of, metering technology.

- **Efficient and flexible price signals**: Arrangements for the market to provide prices that better reflect the costs of supply and delivery of electricity services; potential for improving price signals to promote consumer uptake of DSP; and the arrangements for vulnerable consumers, where required.

- **Distribution network incentives and distributed generation**: Distribution network profit incentives and ability to manage risks of DSP projects. Incentives on distribution network businesses to engage with and facilitate the uptake of distributed generation.

- **Supply chain interactions**: Coordination and alignment of commercial interests of parties across the supply chain to capture the value of DSP.

- **Energy efficiency**: Consideration of energy efficiency regulatory measures and policies and interaction of energy efficiency and DSP.

There are a wide range of issues associated with how market arrangements facilitate efficient DSP. For this review, we have focused on those areas where we consider we can add the most value to facilitating uptake of efficient DSP. Some of the issues we have not examined in detail are being explored in other processes and rule changes as indicated in Figure 1.10.

1.5.5 Project dates and submissions

Table 1.1 Review consultation papers and timelines

Document	Date of Publication	Submissions received
Issues Paper	15 July 2012	45
Directions Paper	23 March 2012	47
Draft Report	6 September 2012	
Public Forum	3 October 2012	
Final Report	November 2012	

We have received a number of submissions to earlier stages of the report which have informed our considerations. A summary of the key points made in these submissions is included in Appendix D. Given the large number of submissions received, this summary is necessarily at a high level and may not address every point made by stakeholders.

1.5.6 Making a submission

We welcome stakeholder feedback to our draft report through written submissions, bilateral meetings and other forums. We particularly welcome any evidence that can be provided which may assist us in further developing the options for change included in this document.

We will be holding a public forum for stakeholders to present their views and provide the AEMC with feedback on the recommendations made in this report. The public forum will be on 3 October 2012, in Melbourne.

Submissions to the draft report paper close on 11 October 2012.

2 Facilitating consumer access to electricity consumption information

Summary

Helping consumers to get access to information about how much electricity they use and costs is likely to:

- increase awareness of their energy consumption patterns;
- enable consumers to make more informed choices about taking up products and services that better suit their circumstances and needs; and
- promote more efficient retail electricity markets through improved products and services offered to consumers.

We recommend changes be made to the existing National Electricity Rules (NER) to provide a consistent and transparent approach for consumers to access their energy and metering data[34] and receive relevant and sufficient information about their electricity consumption use, patterns and related cost impacts.

Our recommendations reflect the overarching principle that all consumers have a right to access, and control the sharing of, their energy and metering data (in accordance with privacy, security and other consumer protections arrangements).

We recommend that:

- Changes to the NER to clarify the requirements on a retailer to respond to a consumer's request for access to their energy and metering data.
- New provisions the NER and NECF that require, at a minimum, a retailer is to provide residential and small businesses consumers with information about their electricity consumption load profile (ie timing of use over a period).
- A new rule that would require AEMO to publish market information on representative consumer sector load profiles. Broader market information would assist parties to develop products and services and improve the efficiency of the energy services they offer to consumers.

These provisions would not limit consumers from accessing their data from a distribution business (or a metering data provider), or limit third parties from providing information to consumers about their electricity consumption.

Arrangements and guidelines for ensuring the privacy, security and confidentiality of consumers' information and data already exist. The SCER

34 Energy and metering data refers to the information recorded and retrieved from a consumer's meter, validated through NEM processes and systems (i.e. for settlement and billing purposes).

Smart Meter, Consumer Protection and Safety program is reviewing these arrangements in the context of greater penetration of smart meters in the market.

We propose that supporting guidelines to inform the provisions of the rules (ie standardised form and structure of data, timeframes, fees etc) be developed by the AEMC in consultation with industry, consumer and market institutions (AER and AEMO), during the rule change process. Any changes to the rules would take into account the work by SCER.

2.1 Market conditions for uptake of efficient DSP

To facilitate the uptake of DSP, consumers must be sufficiently informed and have the necessary tools to adjust their consumption and behaviour patterns. Moreover, to help them understand how much, and when electricity is used, compare retail tariff offers and evaluate products and services to fully realise benefits and manage costs[35], it is essential that they have timely access to their consumption information. Part of this involves consumers being able to quantify the impacts of their decisions (ie costs of using appliances/equipment) and converting prices into costs. There is room for improving this information to consumers as well as third parties.

There is no doubt that, particularly in light of recent price rises, consumers want more information about how they use their electricity to determine how they can save money. This interest in consumption is also being driven by smarter technology (ie interval/smart meters) that provides better information about actual consumption[36]

This chapter focuses on our proposed improvements to market and regulatory arrangements to facilitate consumers' access to their energy and metering data and other information on electricity use patterns. The type of energy/metering data available will depend on the metering technology, including whether it is "live or real time" or it is post consumption data that is verified by AEMO for billing purposes.

We refer to energy and metering data which is that recorded by a consumer's meter, and retrieved for validation purposes through NEM processes and systems for market settlement and billing. We have not considered "live or real-time" data which may be available from a smart meter as those consumers who have such meters are able to access their consumption information using the relevant communication devices that are available in the market.

We note that there are other studies under way that are considering issues associated with consumers having timely access to electricity consumption information. These

35 For example, engage energy management services to provide energy audits and plans, enter into a contract for direct load control services.

36 The Clean Energy Council (CEC) indicated in their issues paper submission that their Auspoll research found that 73 per cent of consumers surveyed wanted more information about how to manage electricity costs. Futura Consulting, *Investigation of demand side participation in the electricity market*, report for the Australian Energy Market Commission, 8 December 2011.

include the SCER work program to review the national smart meter, consumer protections and safety arrangements[37] and the Australian Government scoping study on the need for establishing an energy information hub.[38]

2.2 Issues identified

The directions paper identified that there is an opportunity to improve the NER to facilitate consumers' and their agents' access to their energy and metering data. This is to make it easier for consumers to access their data and to afford better understanding and awareness of their energy use.

As highlighted in the directions paper, consumers or their agents indicated that they face practical issues when they seek to access their validated energy and metering data under the current arrangements. Specifically, when they request billing or metering data from retailers, they experience no response, time delays, or the data provided is too difficult to interpret or use. It was also noted that the existing provisions under the NER are unclear about whether distribution network businesses or Meter Data Providers (MDPs) are able to provide metering data directly to consumers. Overall, there was concern that these issues are making it difficult for consumers or their agents to obtain data, and therefore to understand consumption patterns, and take up appropriate DSP offers or packages.[39]

Consumers can obtain information about their electricity consumption from a number of sources. They can refer to their retail electricity bills, or, in the case of large consumers, their invoices, or alternatively, they can request access to their energy and metering data (historical or current) from their retailer. Those consumers who have smart meters may be able to have instant access to energy data through communication devices such as home area networks (HAN), and an in-home displays (IHD).[40]

Each of the above provides consumers with different levels of information. Retail electricity bills can provide them with average historical consumption for a specified period (ie three months). Metering data can provide them with better information and, in some cases, more accurate information. For example, interval data provides information on the time the energy was used. It is important to recognise that a consumers' energy and metering data will differ depending on whether an

37 http://www.scer.gov.au/workstreams/energy-market-reform/demand-side-participation/smart-meters/

38 http://www.ret.gov.au/Department/Documents/clean-energy-future/ELECTRICITY-PRICES-FACTSHEET.pdf

39 AEMC, *Power of choice review – giving consumers options in the way they use electricity*, directions paper, March 2012, p. 46-47.

40 Futura Consulting, *Investigation of demand side participation in the electricity market*, report for the Australian Energy Market Commission, 8 December 2011, p. 16-17.

accumulation,[41] interval or smart meter is installed in the home or business (see Box 2.1).

Box 2.1: Types of meters and electricity consumption data recorded

Accumulation meters – records accumulated consumption data on a periodic basis (typically three month periods to match billing cycle). This data provides consumers with their total historical consumption; however does not provide timing of energy use (either both how much and when electricity is used).[42] The data is retrieved manually from the meter at a consumer's premises.

Basic interval meters – records consumption on a near real time interval basis (ie half hourly consumption). This information provides consumers with the timing of their current consumption data for a time period. The data may be retrieved manually at the premises or may be read remotely via communication technology (ie without having to visit the consumer premises).

Smart meters/data – records consumption on a near real time interval basis (ie half hourly consumption). However, smart meters have communication technology that enables data to be retrieved remotely, provides other smart services (ie network support (faults/problems on network, load management), and can link to devices (ie through HAN and IHD) that enable instant access to electricity use profile.

The existing rules give consumers the right to access and receive their energy and/or metering data. Specifically, clause 7.7 (a) 7 requires a financially responsible market participant (FRMP) to provide, upon request from consumers, their energy or metering data. In most cases this is a consumer's retailer. There are also other provisions regarding the ability of consumers to electronically access their energy data in metering installation.[43] An overview of existing arrangements and flow of data to relevant parties under the NER is provided in Figure 2.1.

There are other national and jurisdictional arrangements which also require that residential and small businesses consumers are provided with energy consumption information. Specifically, under the National Energy Customer Framework (NECF)[44]

41 Where accumulation data is used, the average consumption profile of their distribution areas (or net system load profile) is applied to represent the timing of energy use consumption of each consumer and calculate the costs of supplying and delivering electricity to those individual consumers.

42 We note that some accumulation meters may accumulate energy use in periods such as peak and off peak.

43 clause 7.7 (b).

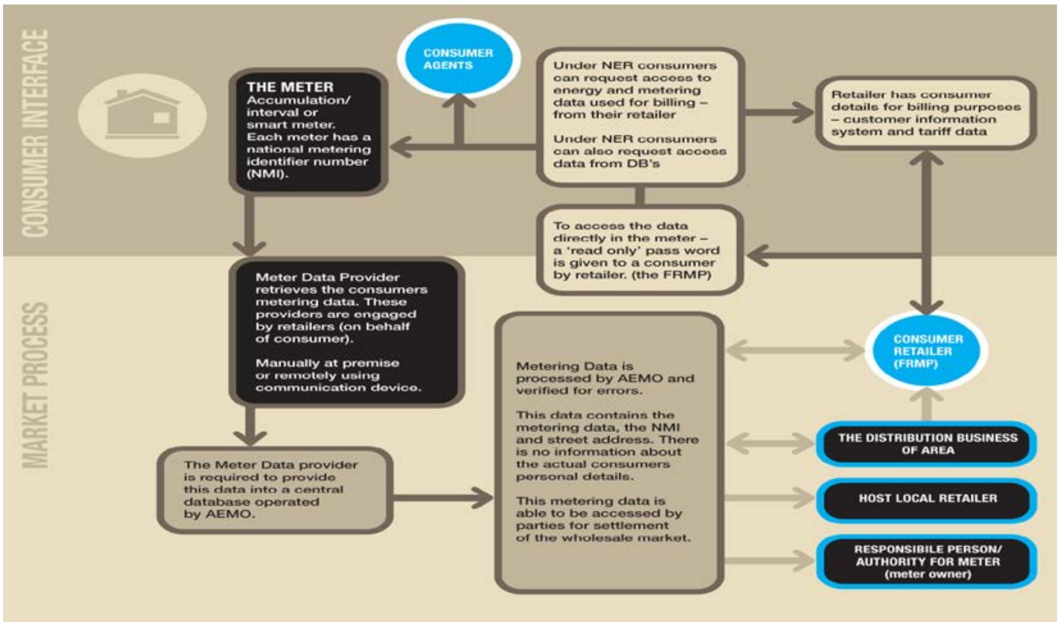
44 http://www.scer.gov.au/workstreams/energy-market-reform/national-energy-customer-framework/

retailers are required to provide -- upon request from consumers-- their historical data (up to two years) at no cost.[45] In addition, distributors are required (on request by consumers, or consumers' retailers) to provide information about a consumers' energy consumption.[46] There are also other provisions relating to information that should be provided by retailers on consumers' bills.[47]

Supplying energy and metering data to consumers must be in accordance with confidentiality, security and privacy arrangements under the NEL, NECF[48] and other Australian and jurisdictional regulatory instruments.

As noted, the SCER Energy Market Reform Working Group is currently reviewing the existing customer protection arrangements under the NECF, including the need for additional arrangements in the context of smart meters and associated services in the market.[49]

Figure 2.1 Overview of existing arrangements – flow of metering data to parties and the consumer



45 National Energy Retail Rules (NERR) clause 28.

46 NERR clause 86.

47 NERR clause 25.

48 The NECF establishes the national framework for regulating the sale and supply of energy to retail consumers and covers a range of matters, including but not limited to; retailer and consumer relationships, associated rights, obligations, and consumer protection measures, which include informed consent, security and privacy provisions

49 See Department of Resources, Energy and Tourism for further information on these programs: http://www.ret.gov.au/Documents/mce/emr/smart_meters/default.html.

There are a range of DSP actions available. Some DSP actions do not necessarily depend on consumers receiving information about their specific energy consumption (ie, the purchase and installation of energy efficient appliances). However, if all consumers are able to easily access – and understand – their energy consumption and relationship to costs, this is likely to build awareness of the potential opportunities that could be taken up to manage, use and realise the value of cost effective DSP.

We confirm our position that improvements should be made to the existing rules to clarify and provide guidance on the current framework for the provision of energy and metering data to all consumers. Improvements to the rules would provide certainty to consumers that they are able to access their data, engage with third parties and undertake appropriate investment decisions that reflect their individual circumstances. Providing a transparent and consistent approach would also assist market participants and third parties to develop more innovative DSP products and services to consumers.

Generally, there is consensus across the industry that consumers have a right to their electricity consumption data, and better information should be available to improve awareness of energy use. This was made clear by the submissions to the directions paper, most of which supported this position.[50] In recent times, there has been a move to supply electricity consumption information to consumers through online channels.[51] Some other market participants (eg distributors) have also introduced, or are looking to provide, more accessible information to consumers about their electricity consumption.[52]

These and other developments will improve information flow to consumers over time.[53] Notwithstanding this, many stakeholders considered that existing regulatory frameworks need to be improved to provide clarity and transparency on existing policy and arrangements.

Stakeholders who wanted the rules amended, also proposed that specific changes be made to enable data to be transferred directly to consumers' agents, along with explicit informed consent arrangements.[54] Some stakeholders reiterated that the rules governing the provision of data by distribution businesses (or MDPs) to consumers (or their agents) need to be clarified.[55] Finally, EnerNOC commented on the need to

50 Refer to Appendix D – Stakeholder submissions summary to directions paper.

51 Origin Energy "Origin smart" consumer access portal, released in June 2012 http://www.originenergy.com.au/originsmart/

52 On 15 June, Jemena launched a free web portal for consumers living in Jemena Electricity Network area across the north-western suburbs of Melbourne (https://electricityoutlook.jemena.com.au); SPAusNet home energy management trial; Ausgrid Smart city, Smart grid trial.

53 For example, Randwick City Council promoting installation of Efergy meter for their residents to track energy use http://www.randwick.nsw.gov.au/Your_Council/Whats_happening/News/Save_on_your_power_bills/indexdl_14747.aspx

54 Refer to Appendix D – stakeholder submissions summary to Power of choice review directions paper.

55 United Energy directions paper submission, p.5; MEU directions paper submission, p.32; Ausgrid directions paper submission, p.6; AER directions paper submission, p.4; Powercor Citipower

clarify the arrangements that apply when third parties have explicit informed consent to retrieve consumers' data from meter data providers, but consumers then decide to change retailers. At present, all arrangements are terminated, and the third parties are required to once again verify explicit informed consent from the consumer to that retailer.[56]

Some retailers and the Energy Retailers Association of Australia (ERAA) considered that the existing arrangements for accessing data are adequate and do not need to be changed. Their view was that the NECF provides sufficient scope for consumers to access their data and for information to be provided to third parties (assuming informed consent has been granted). Overall, they felt that expanding existing arrangements may cause consumer confusion.[57]

Broader concerns were also raised about general market information on consumer energy and consumption data. This included information about consumer sector load profiles and the ability to access data independently of a retailer.[58] It was noted that the lack of arrangements enabling the authorised transfer of energy data to third parties may be impeding innovation, choice for consumers, and delivery of energy services.

2.3 Considerations

Consumers' ability to make informed decisions will depend on a variety of factors, including the way in which data is provided. Consumers generally want information that is easy to understand, convenient, cost effective to access, and provided in a timely manner.

We note that the ability of different consumer to access data will differ, as will the type of information required.[59] For instance, residential and small business consumers probably do not know they can ask retailers for their data nor have access to their electricity consumption information on a regular basis. Generally, these consumers are likely to want basic information that enables them to compare usage against different pricing tariff options, costs or to invest in energy efficient appliances.

Industrial or commercial consumers may require more detailed information to be able to participate in DSP activities or to make operating investment decisions. This may include access to raw data that shows consumption recorded every half hour.

directions paper submission, p.4; ETSA Utilities directions paper submission, p.4; ENA directions paper submission, p.8.

56 EnerNoc directions paper submission, p.9.

57 ERAA directions paper submission, p.4, Origin Energy directions paper submission, p.6. AGL directions paper submission, p.3.

58 SACOSS directions paper submission, p.11; Ausgrid directions paper submission, p.7; Energex directions paper submission, p.7.

59 AEMC, *Power of choice review – giving consumers options in the way they use electricity*, directions paper, March 2012, p. 41-42.

The overarching principle for any changes to the rules should be that consumers have the right to access and share their electricity and metering data. Consumers should know the data exists and be able to get it. They also should know how it will be used, in accordance with explicit informed consent, privacy and confidentiality provisions.[60]

2.3.1 Timely and accessible energy and metering data to consumers

DRAFT RECOMMENDATIONS

We propose that changes are made to:

- **Chapter 7.7 (a) of the NER to clarify the requirements on a retailer when consumers request access to their energy and metering data. This would include provisions relating to the format and structure of data to be provided; the timeframes for delivery; and fees that can be charged.**
- **Chapter 7 of the NER to require, at a minimum, a retailer to provide residential and small businesses consumers with information about their electricity consumption load profile. There may be a need to amend the NECF to ensure consistency of arrangements.**

Form of data and timeframes for delivery

All consumers should be able to access and receive their raw historical and current energy and metering data that is validated through AEMO processes for market settlement. As discussed, the level of data available to consumers will depend on the type of meter they have. Consumers with accumulation meters will have access to their historical consumption data, while those with interval and smart meters will have access to current consumption profiles.

A key principle is that the information is given to consumers in a format that enables them to see how their consumption use varies across different time periods (ie peak, off peak, shoulder). This is important because it enables consumers to consider the impacts of their consumption, how potential changes to that consumption relates to costs, and to choose pricing offers that may reduce their electricity bill.

When consumers have requested their energy or metering data, this has been traditionally provided by retailers in a variety of ways: raw data on bills, printed invoices or excel files sent via email or post. The availability of technology, such as web-based portals and smart phone applications is improving the channels through which consumers are able to access, view and use their data.[61]

60 For example, NECF provisions, Australian Consumer Law and National Privacy Law.

61 For this review, we are not commenting on the different channels that information can be provided or made available, as consumers will typically likely to drive preferences for the market.

At present, there are arrangements for the exchange of energy and metering data between market participants to facilitate wholesale market settlement.[62] This includes the standard format for information to be provided between parties. No such standard approach exists for how data is given to consumers or their agents by retailers.

Many stakeholder submissions to the directions paper considered that there remains a need for the rules to provide for a standardised framework to govern the form and structure of data provided to consumers or their agents. Some pointed out that the lack of a standardised approach translates into significant time and effort to process the variety of formats currently provided by retailers or responsible parties.[63]

We propose that Chapter 7.7 (a) of the rules is amended to include arrangements for the exchange of data from retailers to consumers. This includes the minimum standard format of information that retailers would need to provide to consumers and the timing of delivery of that data.

We consider the minimum requirements regarding the form of data should include provision of both raw data and aggregated data that shows consumers' consumption profiles. At a minimum, the aggregated data should include peak, off-peak and shoulder profiles, or average versus peak consumption information. It is recognised that the level of aggregated data needed may differ between residential and industrial/commercial consumers.

The level and timing of energy and metering data available to consumers will depend on their metering installation. As noted, where accumulation and interval meters are manually read at a premises, data availability will be limited by the date of the most recent meter read and AEMO's validation processes (quarterly meter reads are typically six weeks in arrears). That said, it is important for the framework in the rules to include the timeframes for retailers to respond to consumers' request (eg. within 10 business days).[64] Any changes would need to consider AEMO's current validation processes and protocols.

We recognise that residential and small businesses consumers are unlikely to actively seek out their information in the short term, particularly given the current level of understanding about energy use.

Thus, we propose that a new provision is included in the rules (and NECF) that requires, at minimum, consumers to be provided with their consumption load profiles. This information could be provided by retailers or distributors. For those consumers on accumulation meters, their actual consumption profiles will not be available due to type of metering technology. We therefore recommend that these consumers are provided with the net system load profile of their distribution area. The costs to market

62 For example, the standard format for data exchange between parties is provided in the NEM12 and aseXML standards (http://www.aemo.com.au/en/Electricity/Retail-and-Metering/aseXML-Standards)

63 Refer to Appendix D – Stakeholder submissions summary to directions paper.

64 We note that there are some jurisdictional arrangements which impose requirements on retailers to provide data within certain time limits (ie Victorian Retail Code).

participants of providing such information would need to be taken into account, as would the appropriate channel through which the information is provided (eg., bill, flyer or via web portal).[65]

We note some stakeholders' views regarding consumers' ability to access data from a distribution business or MDP. We do not consider that these requirements limit the ability of consumers to access their data from these parties, particularly in the circumstances of larger industrial and commercial consumers who currently have direct relationships with those businesses. The requirements, should also not limit the delivery of more detailed information to consumers by retailers or other third parties.

We are seeking stakeholder views on the arrangements for the exchange of data between retailers and consumers, including the minimum requirements for the format of data. In considering the minimum requirements, the costs of different approaches will be taken into account.

Fees payable by a consumer (or agent)

In most cases, residential and small business consumers are provided their energy consumption information at no additional cost. This is expected to continue with the rollout of web portals, since the systems for storing and managing historical consumption data are already in place. In addition, data provision is generally considered inexpensive and part of existing metering services. There are circumstances where third parties or larger industrial consumers have been charged fees for accessing their raw metering data. This is typically where the retailer has supplied more sophisticated profiles or when a third party deals directly with the MDP and is charged a fee for the service by the MDP for forwarding the data.[66]

The NECF requires that historical metering data is provided to residential and small business consumers at no cost. Under the NER, a retailer may charge a consumer for the cost of providing the metering data.[67] Although such provisions exist, it is unclear in what circumstances the consumer is liable.

A number of stakeholder submissions to the review raised concerns regarding the ambiguity of current rules relating to the fees that retailers are able to charge consumers, specifically industrial and commercial businesses. Some third parties have noted that they have been charged significant fees to retrieve a consumer's data.[68]

Consumers should be able to access their consumption data at no cost. This is consistent with the existing principles applied under the NECF and current practice by

65 Sapere Research Group, Scoping study for a consumer energy data access system, report for the Australian government , August 2012.

66 Clause 7.11.2 (b) 1 provides that a MDP may provide metering data at the request of the FRMP but based on cost recovery to the MDP.

67 Clause 7.7 (a) and 7.3A (d).

68 EnerNoc directions paper submission, p.9; AEMC, Power of choice review – giving consumers options in the way they use electricity, directions paper, March 2012, p. 41-42.

retailers. There will, however, be circumstances where fees may apply, particularly where specialised services are offered.

We consider the rules should be clarified to reflect where:

- Standardised format data is supplied to consumers; this should be at no cost to the consumer;
- Additional data services are provided by retailer or responsible party; a reasonable fee should apply; and
- Consumers (or their agents) request information more than once per billing period over a twelve month period; a retailer (responsible party) should be able to charge a reasonable fee. This is consistent with existing NECF provisions.

Such changes would provide clarity to existing participants and transparency on when retailers (or responsible party) are able to charge fees for service.

Questions

1. What should be the minimum standard form and structure of energy and metering data supplied to consumers (or their agents)? Should these arrangements differentiate between consumer sectors (ie industrial/ commercial and residential)
2. When do you think it is appropriate for a retailer (or responsible party) to charge a fee for supplying energy and metering data to consumers or their agents?

2.3.2 Transfer of energy and metering data to authorised consumer agents

DRAFT RECOMMENDATIONS

- **We propose that changes are made to Chapter 7.7 (a) of the NER to enable agents, acting on behalf of consumers, to access consumers' energy and metering data directly from a retailer. This would include requirements on a retailer to provide consumers' energy and metering data to an authorised consumer's agent (third party), following explicit informed consent.**

Most residential and small business consumers do not want to spend time trying to decipher raw energy or metering data and available options to manage energy use. For this reason, some may engage third parties to help them understand their consumption patterns, provide information on options to manage that consumption and advise them on the kinds of investments that can be made to improve energy efficiency.

To facilitate decision making, consumers will likely want to authorise these third parties (agents) to access information, including energy and metering data, directly on their behalf. In accordance with existing rules, consumers have to contact their retailers' call centre and request their energy and metering data. They then have to forward data to their agents (refer to Figure 2.1). Some third parties acting on behalf of industrial or commercial businesses have sought data directly from the retailer. However in these cases the third parties are required to forward a letter of authority from the consumer.[69]

In submissions to the directions paper, stakeholders indicated that these cumbersome arrangements limit the ability of consumers to engage third parties and may well be responsible for less than efficient market outcomes. These stakeholders considered that the rules framework should include arrangements for the transfer of data from retailers to consumers' agents, similar to that which is agreed practice for consumers switching retailers, and/or transfer of consumer information in the banking and telecommunication industries.[70] A few stakeholders noted that obligations could be placed on the responsible person or MDP to provide data directly to a consumer's agent without necessarily going through a retailer.[71]

Clarifying the framework for exchange of data to consumers and their agents is likely to reduce the existing complexity around accessing and receiving consumption information. It will also make the delivery of energy services more efficient. We do not anticipate that the proposed changes will place additional costs on retailers, or responsible parties; rather they will provide clarity to the market on how the current arrangements should be applied.

Retailers are currently responsible for obtaining informed consent from consumers and are also subject to provisions under the NECF and jurisdictional codes regarding consumer protection and support. Some stakeholders have indicated that it would be useful to clarify who is responsible for obtaining informed consent from consumers (ie retailer or third party). Some also expressed the need for third party accreditations/registrations where these parties may use data to offer energy management services. For the final report, we will take this issue into account, noting that similar issues are being considered by the SCER Smart Meter, Consumer Protection and Safety work. We address the provision of energy services by third parties more broadly in Chapter three.

69 EnerNoc directions paper submission, p.9.

70 Refer to Appendix D – Stakeholder submissions summary to Power of choice review directions paper.

71 Ausgrid directions paper submission, p.7.

2.3.3 Market information to develop DSP products and services

DRAFT RECOMMENDATION

- **We propose that changes are made to the NER to require AEMO to publish market information on representative consumer sector load profiles.**

Smarter technology will significantly improve the quality of information. This will, in turn, encourage the release of more innovative products and energy services to help consumers manage and control their energy use. Better metering data will also enhance and improve existing market processes and systems. We further discuss metering and load profiling by AEMO in Chapter four.

A key condition for developing more innovative products and energy services is to provide information about different consumer sectors' consumption patterns and representative load profiles. As shown in Figure 2.1, retailers are entitled to access consumption profiles for their consumers. Distributors also have access to similar information. While these parties are able to access the information, other third party providers (ie ESCOs, aggregators and other retailers) seeking to develop general non-specific DSP products can only access detailed information about consumption profiles following informed consent from each and every consumer.

Concerns have been raised in submissions to the directions paper about the information disadvantage these energy service providers suffer, and also how this is limiting the ability of consumers to use these parties' energy services.[72]

We note that the Australian Government, as part of its 2011 Clean Energy Future Package is currently undertaking a scoping study to determine the need for an energy information hub to improve energy information disclosure. This would provide consumers with easier access to their energy information currently held by retailers and distributors.[73] The study is specifically considering how third parties generally can access consumer information and how that data can be efficiently transferred to these and other parties (ie business to businesses/accreditations).[74]

Currently, there is a divergence of stakeholder views on the need for a central repository for consumers and on exchange protocols for third parties to access energy data. Some note web portals that are in place or under development and a central repository may duplicate existing systems and place additional costs on retailers and other market participants. These costs may in turn be imposed on consumers.[75] Others

72 Clean Energy Council, directions paper submission, p.3;

73 http://www.ret.gov.au/Department/Documents/clean-energy-future/ELECTRICITY-PRICES-FACTSHEET.pdf

74 Sapere Research Group, Scoping study for a consumer energy data access system, report for the Australian Government, August 2012.

75 See Appendix D – Stakeholder submissions summary to directions paper for detail comments.

consider a single repository may limit future consumer confusion regarding which entity they should approach to access their data.[76]

The proposed changes to the rules are likely to address some of the concerns raised by stakeholders. However, given concerns about information asymmetries between parties, we consider that there may be merit in publishing broader market information about consumer load profiles. Such information could be used to help parties develop and offer potential DSP products, promote general consumer awareness of energy use, and improve information for policy development.

AEMO holds mass market metering data for market settlement purposes. The rules could be changed to require AEMO to use this information, and, where available, publish standard market information on average consumer sector load profiles (representative load curves). This would enhance existing information published by AEMO on the Net System Load profile (NSLP) for each of the distribution network areas.

We are seeking stakeholder views on whether such information would be useful and whether AEMO is the appropriate body to publish such information.

Questions

3. Do you agree that general market information should be published on consumer segment load profiles to inform the development of DSP products and services to consumers?

4. Is AEMO the appropriate body to publish such information, or should each DNSP be required to provide such information particularly where data will be at the feeder level where accumulation meters are installed?

76 Smart Grid Australia, directions paper submission, p.2; Listening post, directions paper submission, p.2.

3 Engaging with consumers to provide DSP products and services

Summary

Robust market arrangements that allow for good engagement between market participants and consumers can help build consumer confidence to take up, and realise the value of, DSP products. Such arrangements should also support and protect the interests of those who are unable to vary their consumption. Building consumer confidence in this way is also likely to promote competition and encourage the introduction of new energy services in the retail energy market.

Advances in technology and better metering information are encouraging the development of a variety of energy management products and services. These new energy management services are not necessarily directly related to the sale of electricity. It is important that the NECF is clarified to make it clear what arrangements apply to third parties providing "DSP energy services". We propose that, either, the NECF or the Australian Energy Regulator (AER) guidelines on exemptions include criteria that outlines the circumstances where accreditation (or exemptions) of parties is required and the relevant provisions of the NECF to apply (ie marketing rules, and the relevant enforcement and monitoring provisions).

We also recommend that arrangements are put in place to clarify the circumstances in which distribution businesses are able to directly engage with residential and small consumers to provide DSP network management services. We seek stakeholder views on the following:

- Where the AER has approved DSP network management services as "regulated network support services", that network business should seek to engage with a retailer or third party to offer those services to consumers. In certain circumstances, the network business should be able to offer DSP network services directly to consumers.
- Appropriate arrangements should be placed on retailers to ensure consumers are provided with appropriate information and offers on the DSP products and services which may be available to them.

As noted, the SCER Smart Meter, Consumer Protection and Safety program is also considering similar issues in the context of its work on smart meters. The results of this work will inform our final recommendations for the review.

3.1 Market conditions for uptake of efficient DSP

Market arrangements will influence the development of DSP options and products, and how these are taken up by consumers. To encourage consumers to participate and realise the benefits of DSP, such arrangements should support consumer decision making and should not introduce, nor lead to, increased complexity. It is also important that sufficient consumer protection and other support mechanisms are in place.

The draft report considers the role that parties need to play across the supply chain to facilitate efficient DSP. It proposes changes to the market and regulatory arrangements to ensure there are appropriate incentives to facilitate consumer choices in a way that results in the delivery of energy services at the lowest cost.

This chapter specifically considers the provision of DSP products and services by a variety of parties (ie third parties, distributors and retailers) seeking to have direct contact with consumers, and how existing arrangements to protect consumers apply.

It focuses on residential and small business consumers.[77] The industrial and commercial sector has had access to DSP products for some time. Generally there are arrangements in place to support industrial and commercial consumers to engage with a range of parties in the market.[78]

3.2 Issues identified

In the directions paper, we explained that we would further consider the respective roles of network businesses, retailers and other parties in providing DSP products and services, and how dialogue with the consumer could take place in a transparent manner.[79]

As discussed previously, the energy retail market is changing. Smart appliances and smart meters will provide opportunities for consumers to better control and manage their electricity use. This will also enable the commercial development of new DSP products and services that can extend beyond the meter.[80]

These include the provision of energy market information that assists consumers to better manage and understand the cost drivers of their consumption[81]; energy

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77 As defined under the National Energy Retail Law and supporting regulations (ie a residential customer who purchases energy principally for personal, household or domestic use at premises and business customer who consumes energy at a business premise below the upper consumption threshold of 100MWh per year).

78 AEMC, *Power of choice review – giving consumers options in the way they use electricity*, directions paper, March 2012, p.41-42.

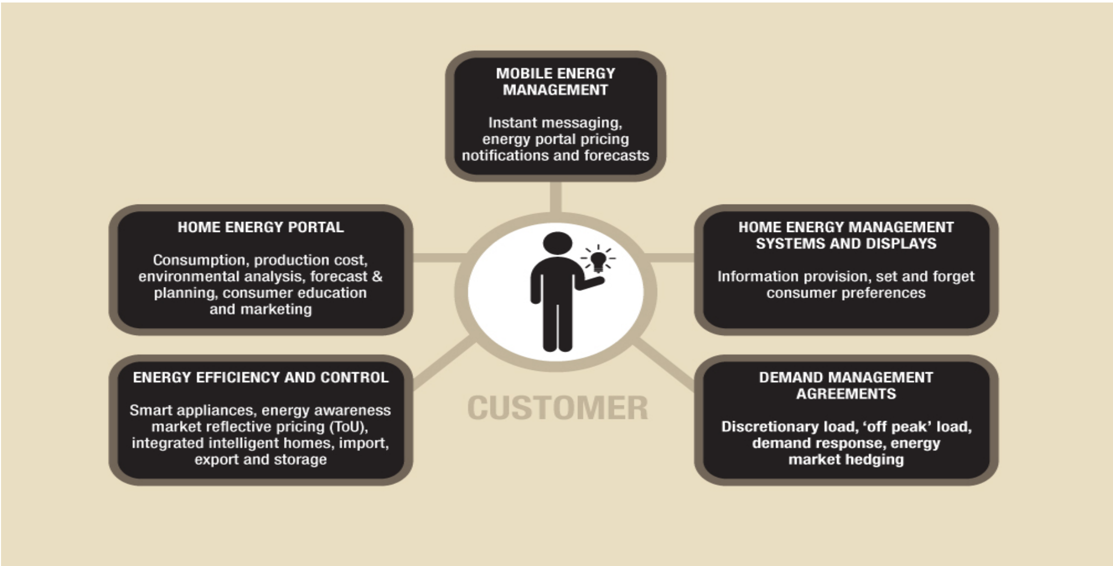
79 AEMC, *Power of choice review – giving consumers options in the way they use electricity*, directions paper, March 2012

80 KEMA, *Services enabled by smart grid technology*, a report for the AEMC, November 2010.

81 For example, price comparison web sites, smart phone applications – see Telstra project smart home trial, http://www.brw.com.au/p/technology/telstra_plans_home_of_the_future_QQdNer2gzY46RsBT13V6WO

efficiency services that seek to improve efficiency of use[82] and uptake of distributed generation (ie storage and solar PV systems, and demand management services for network support and control) The range of players seeking to offer these energy services include retailers and distribution businesses, as well as non-traditional market participants such as energy service companies, information service providers and DSP aggregators (collectively known as third parties).

Figure 3.1 Emerging energy services to consumers



Retailers and some other stakeholders have raised concerns about the governance of new energy management services and how they will be delivered to the market. Specifically, they wanted to know how these services, as opposed to traditional retail energy services under the NECF, will be treated. They considered that:

- Retail energy services now extend beyond simply the essential service of sale and supply of electricity. Retail energy services are evolving to include the supply of information, energy and network management services.
- There is a need to review third-party responsibilities to consumers and these parties can be brought under the NECF efficiently and effectively. It is considered that consumer law is not adequate to protect consumers from activities provided by the third parties. It was noted that that this may potentially create consumer confusion, given that these parties potentially have different business models and arrangements for communicating with consumers than electricity retailers.[83]

82 For example, ESCO's working with industrial and commercial businesses under the Australian Government Energy Efficiency Opportunities program.

83 Simply Energy directions paper submission,p1-3, Alinta Energy directions paper submission, p.4; Origin Energy directions paper submission, p. 12; AGL directions paper submission, p.5; TRU Energy directions paper submission, p.3; ENA directions paper submission supporting evidence, p.1. ERAA directions paper submission, p.11.

Current arrangements

A range of consumer protection obligations and support mechanisms are in place. These include national and state arrangements such as the NECF,[84] jurisdictional safety and concession regimes, and the Australian Consumer Law (ACL) which provides contractual and market conduct requirements to engage with consumers.[85]

The NECF (and supporting regulations[86]) establishes the energy specific consumer protection obligations and arrangements for regulating the sale and supply of electricity and gas to consumers. It covers a range of matters, including, but not limited to, retailer and consumer relationships (contractual arrangements), associated rights, obligations, and consumer protection measures (marketing, informed consent, security and privacy provisions). There are also provisions that relate to the relationship between distribution businesses and consumers, specifically for customer connection services.[87]

The SCER Smart Meter, Consumer Protection and Safety program is currently considering the circumstances under which NECF arrangements should apply and the need for additional arrangements in light of services enabled by smart meters. We have taken this work into account in considering the issues raised in this review.

Given the SCER work, we have not attempted to address all the issues associated with the introduction of DSP energy services. We have however considered the broad issues relating to DSP energy services and the relationship of these services to the sale of supply of electricity in the context of the NECF. We also discuss the role of retailers and distribution network business to directly engage with residential consumers regarding DSP products.

3.3 Considerations

3.3.1 Energy services to residential and small business consumers

DRAFT RECOMMENDATION

- **We recommend that the NECF is clarified to make it clear what arrangements apply to third parties providing "DSP energy services". This should involve establishing criteria either in the NECF or the AER guidelines on retail exemptions. The criteria could include the circumstances where accreditation (or exemptions) of parties is required and the relevant provisions of the NECF that**

84 The NECF commenced on 1 July 2012 for participating jurisdictions and will, when adopted by all jurisdictions harmonise most jurisdictional consumer protection arrangements.

85 http://www.consumerlaw.gov.au/content/Content.aspx?doc=home.htm

86 Supporting legislation and regulations include National Energy Retail Law, National Energy Retail (South Australia act 2011 (the Act); National Energy Retail Regulations (the regulations); and National Energy Retail Rules (the Rules).

87 http://www.aemc.gov.au/Media/docs/Binder1-84bb7f5b-d82f-4484-851b-5e3c662c5f84-1.PDF

would apply (ie marketing rules, and the relevant enforcement and monitoring provisions).

The NECF relates to the sale and supply of electricity or gas to consumers.[88] The sale of electricity to consumers is prohibited unless the seller holds a current retailer authorisation and is a registered participant, buying electricity directly through a wholesale exchange as required by the NEL. There are, however, some provisions which allow the seller to be exempt from the requirement to hold a retailer authorisation.[89]

New energy service providers are entering the market providing a wide range of energy services to consumers and play an important role in the market. While there are mechanisms in place, such as ACL, the NECF does not generally apply to the services provided by these businesses. As such, obligations relating to consumer protection and support do not apply to them.

There is current disagreement within the industry about the market arrangements that should apply to third parties who are seeking to provide energy management services to residential and small businesses consumers.[90] Issues raised by stakeholders include:

- It is essential that these new entrants are subject to the same regulatory obligations that apply to retailers, to have a level playing field and to adequately protect consumers.
- At a minimum, all parties offering DSP services directly to consumers should have to obtain explicit informed consent and comply with the NECF's and ACL's marketing obligations.[91]
- There should be a broad review of what constitutes the sale of electricity and what elements of the NECF should be amended to provide specific authorisations for certain energy management service providers.[92]

The provision of energy management services by third parties and the applicability of the NECF will depend on a number of factors. These include the type of product and sale conditions which are offered to consumers. For instance, price comparator websites as opposed to a service offering a contract for load management control

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88 National Energy Retail (South Australian) Act, s 16.

89 The AER is able to, as applicable, exempt a person from the requirement to hold a retailer authorisation or retailer licence, subject to certain conditions (National Energy retail (South Australian) Act, ss2 and 88).

90 http://www.scer.gov.au/files/2011/12/National-Smart-Meter-Customer-Protections-EMRWG-FINAL.pdf

91 AGL directions paper submission, p.6.

92 Simply Energy directions paper submission, p. 1-3; Origin Energy directions paper submission, p. 12.

(otherwise referred to as direct load control). The classification of energy services by third parties will also depend on whether the primary purpose of the service is to supply electricity or whether the supply of electricity has been combined or bundled with other goods and services. For example, when a consumer buys an energy efficient air conditioner with a contract for direct load control capability. Generally, where third parties are providing energy management services directly to consumers, the specific circumstances would need to be considered to determine the regulatory arrangements to apply.

As noted, the NECF's primary objective relates to the sale and supply of electricity and gas. In regards to electricity, we do not consider that the test under the NERL for retail licensing or authorisations should be amended to include the "sale of energy services".

Broadly, a clear distinction can be made between services that affect the consumer's ability to get a reliable supply of electricity (ie services that include potential for disconnection) and those services that provide information on how to manage consumption.

We seek stakeholder views on whether the NECF or AER guidelines should include criteria outlining the circumstances in which NECF obligations may apply to third parties that offer DSP products and services.

Questions

5. What specific criteria could be used to determine whether elements of the NECF (ie marketing code) apply to third parties providing DSP energy services to consumers? That is, beyond Australian Consumer Law?
6. What requirements should be in place for these third parties? For example, what should be the form of authorisations/accreditations?

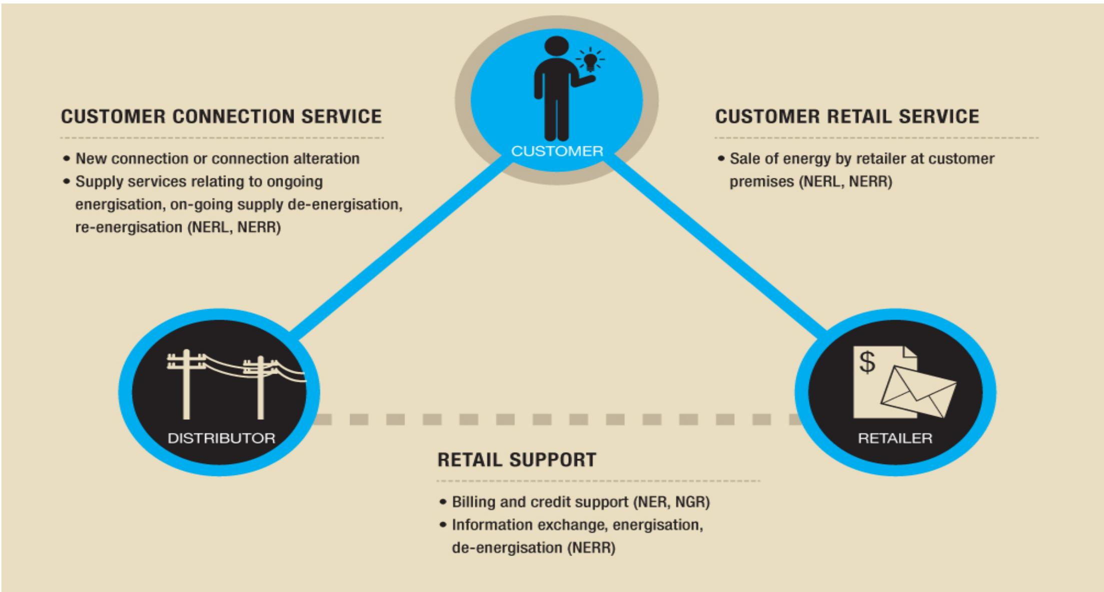
3.3.2 Role of retailers and distribution network businesses - engaging with consumers

DRAFT RECOMMENDATIONS

– **We recommend that the NER and NECF are clarified to outline the conditions when a distribution network business can engage directly with consumers to offer DSP network management services. This may involve establishing appropriate guidelines/process for the AER to apply and outlining which elements of the NECF apply.**

The NECF establishes a triangular relationship between consumer, retailer and distribution businesses as shown in Figure 3.2 below.

Figure 3.2 NECF arrangements – retailer, distribution and consumer relationship



As the key interface between consumers and the rest of the supply chain, the retailers' contracts with consumers can offer both the means for the latter to participate in DSP, and a route by which consumers can be compensated for those DSP actions (for example through the price structure and conditions of the contract, or side payments for specified actions).[93] Retailers' behaviour in facilitating DSP will be driven by commercial incentives which, in turn, are influenced by competition in the market. If they face effective competition, retailers should be in a position to support the deployment of DSP options that are more efficient than buying and transporting additional electricity. This is discussed in more detail in Chapter six.

93 See the AEMC website at http://www.aemc.gov.au/Media/docs/Futura%20Consulting-508587ea-32b3-42b1-9e8b-014c62231aff-0.PDF

Network businesses also play an important role in facilitating efficient DSP. They pursue efficient projects and support consumer participation in DSP through, for example, tariff-based options, planning information and other non-tariff based contractual arrangements. Network businesses have traditionally undertaken or contracted DSP in specified areas of their network to defer network capital expenditure and reduce the risk of not being able to supply consumers. In some cases, the network businesses have also used broader DSP options across the wider network, for network support (eg., off-peak hot water).[94]

In recent times, network businesses have explored DSP solutions and innovative products through pilots and trials.[95] For instance they have engaged directly with residential, commercial and industrial consumers, providing rebates to install energy management devices for load control or entering into load curtailment contracts with large customers. They have also worked in partnership with third party providers to develop network support arrangements with large customers. This has been driven by a number of factors, including network cost increases, advances in technology and the trend of decreasing asset utilisation.

Generally, views between retailers and distribution business are split. Some retailers[96] and the ERAA consider:

- That where distribution network businesses are providing contestable energy services, these should be ring-fenced and that they should have the same obligations imposed on them as are imposed on retailers (ie marketing code under NECF).
- Allowing distributors to offer new contestable services, such as DSP, may be inconsistent with the Competition Principles Agreement's objectives and could create risks for the National Energy Retail Law (NERL). This is of particular concern where distributors provide direct information to consumers about specific products related to energy use such as direct load control, in-home displays, smart appliances and home area networks.
- Distribution network businesses will subsidise their activities in the retail market with regulated revenue (irrespective of current ring fencing provisions). As such, when a distributor does engage in activities that are considered to be contestable services, it should be subject to the appropriate regulatory conditions imposed on retailers and there should be appropriate ring fencing in the business.[97]

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94 Example – Energex peak demand program. Refer to: http://www.energex.com.au/__data/assets/pdf_file/0020/26705/ENERGEX_s_Regulatory_Proposal_2010-2015.pdf

95 Futura Consulting, *Investigation of demand side participation in the electricity market*, report for the Australian Energy Market Commission, 8 December 2011, p. 16-17.

96 Origin Energy, AGL, Simply Energy, Alinta Energy, TRU Energy, International Power, GDF SUEZ,

97 ERAA directions paper submission, p. 29

Contrary to this view, distribution businesses consider that:

- They are well-placed to play a greater role in building consumers' knowledge, helping them manage their energy use and delivering DSP products.[98]

- While local DSP initiatives can be effective, networks have a role to play in raising awareness about the impact of current consumption patterns on network costs and what consumers can do to reduce the upward pressure on network investment.

- It is important that they are able to engage and communicate with their consumers as a mechanism for consumers and network businesses to realise the benefits from DSP.

- It is impractical for them to have no contact with consumers as this is not consistent with the arrangements under the NECF and commercial practice on the ground.

Consumers and other third-party stakeholders considered that retailers and network businesses ultimately have a responsibility to support consumers, and should be incentivised to provide appropriate, meaningful and useful information about DSP.[99]

Proposed approach

Retailers sell electricity to consumers. As such, they are more than likely to remain the first point of contact for consumers on energy and energy-related purchases in the medium to long term.

It is important that the regulatory arrangements in place, such as the NECF and NER, facilitate consumer choice to allow for the benefits of DSP to be realised. They should not create greater complexity for the consumer, particularly in the current climate where consumers' knowledge and awareness of their electricity use remains relatively limited.

Network businesses generally undertake DSP as part of their regulated network services as approved by the AER. These can be price-based DSP (ie tariffs) or contracted DSP (ie contract with third party provider).

Generally, network services tariffs are recovered via the retailer, and not directly by consumers. Where network businesses undertake activities that are performed by a competitive market, they are required to do so through a separately ring-fenced entity, and under the guidelines established by the AER.[100] This aims to ensure that monopoly network businesses do not have priority access, information or cheaper

98 Ausgrid directions paper submission p.18, Energex directions paper submission, p.22; United Energy directions paper submission, p.19.

99 MEU directions paper submission, p.40; EnerNoc directions paper submission, p. 22. Submission responses to SCER working group paper, no.2.

100 http://www.aer.gov.au/node/12493

prices to any competitive business that it has (if any). Ring-fencing is also in place so that revenues earned from a competitive activity are not cross-subsidised from regulated activities.

Distribution businesses have stated that they prefer to facilitate the delivery of DSP by contracting with other parties such as retailers and third parties.[101] However, there will be circumstances when DSP options provide distribution businesses with cost effective options to address specific and localised constraints on the network and deferral of network investment. In these situations, it would be appropriate for network businesses to directly engage with residential and small consumers to deliver their DSP network management services/programs. One example that currently is utilised in this manner is direct load control (DLC).

We are seeking stakeholder views on arrangements that should apply to DNSPs for these circumstances. We consider that the existing rules and guidelines applied by the AER could be enhanced to clearly outline the circumstances when distribution businesses are able to deliver DSP network management services/programs, and what NECF provisions should apply to network businesses (ie marketing code).

Finally, appropriate arrangements should be placed on retailers to ensure that consumers are appropriately informed of the DSP options available to them. This could be achieved through changes to the NECF, and relevant jurisdictional arrangements.

Question

7. Do you agree that existing rules and guidelines should be amended to clearly outline the circumstances when distribution businesses are able to directly contract with residential and small consumers to deliver DSP network management services/programs?

101 ENA directions paper submission, p. 7.

4 Enabling technologies for DSP

Summary

The uptake of efficient DSP can be assisted by enabling technologies. There is a wide range of enabling technology available for consumers and market participants, including metering, automated control systems, and energy management services.

We have focused our assessment on the market arrangements to facilitate commercial investment in metering technology to support DSP, including whether the current arrangements adequately facilitate consumers' choice should they wish to upgrade their meters.

Our recommendations are :

- A minimum functionality specification is included into the NER for all future new meters installed for residential and small businesses consumers. This specification should include interval read capability and remote communications.
- The installation of metering consistent with this minimum functionality must occur in certain situations. eg. refurbishment, new connections, replacement of old meters.
- In addition, such metering capability must also be installed on an accelerated basis for large residential and small business consumers with annual consumption above a defined threshold.

The benefits of these arrangements through facilitating efficient DSP are expected to exceed the costs involved to consumers who install the meters and the market as a whole.

There are multiple reasons why the current arrangements are inhibiting the ability of consumers and market participants to invest in metering technology which supports DSP. To overcome these barriers, a series of reforms is necessary and a policy decision required on how meters are provided for residential and small business consumers.

The choice is between opening up the provision of metering services to any approved provider or making the local network distribution businesses the exclusive provider. We have put forward a possible model for stakeholder comment where the retailer is mainly responsibility for metering services, and can contract with any approved metering provider. The exemption to this is where the consumer has actively decided to contract directly with a metering provider. Also we consider that the network business should continue to have the ability to do a targeted roll out of smart meters in its territory, as part of its DSP programs.

4.1 Market conditions for uptake of efficient DSP

Technology can assist consumers' ability to adjust their electricity consumption and, importantly, capture the value of doing so. This value can be captured can be through a variety of means, such as through providing more real time information or facilitating automated responses. It is important that market arrangements provide market participants and consumers with the confidence and certainty to make investments in such technology. To do so, the arrangements should provide prospective investors with:

- access to information and face minimal transaction costs;
- access to capital;
- certainty about future conditions and potential returns;
- clear rules on the DSP technology usage and how it interacts with the energy and network systems; and
- the ability to accrue the value of the benefits that the technology brings to the market.

4.2 Issues identified

Advances in control systems and communications technologies have significantly increased the functionality of smart metering and demand response technologies. At the same time, the costs of such technologies have fallen significantly over the past ten years. Technologies currently available (typically referred to as "enabling technologies"), can help consumers manage their electricity consumption in response to time-varying price signals. For instance, devices such as programmable communicating thermostats can receive a signal during a critical peak pricing event and automatically reduce residential customers' air-conditioning usage to a level that they have specified. This ability to "set it and forget it" reduces the need to manually respond to high-priced events.[102]

This concept could be extended to control other end-uses and appliances through a home area network. For larger commercial and industrial consumers, automated demand response (or "Auto-DR") technology works in a similar fashion, allowing them to automate electricity consumption reductions in a range of processes and load sources by integrating with the building's energy management system.

102 Enabling technologies can also help customers manage their electricity consumption by providing new information about energy use that the customers otherwise would not have access to. For example, in-home displays can give customers information such as the amount of electricity that they are using, what this is costing them, how that translates into their carbon footprint, how close they are to energy savings goals, and other such data. The information could be provided through a smartphone, website, plugin device, or other means.

Given these developments, the SCER asked the AEMC to assess energy market frameworks that would maximise the economic value to consumers of services enabled by smart meter/smart grid technologies, including load control technologies. In the directions paper, we identified a number of issues:

- Clarification on the ownership and usage rights of consumers and other market participants with respect to DSP technology and the ability of the consumer to capture all full value of DSP technology.
- Factors that impede efficient investment decisions (ie short payback periods, behaviour, time and effort required for consumers to make investment decisions).
- How current arrangements encourage investment in metering capability which supports DSP.

We also recommended that there should be open standards and a gateway to make it possible for:

1. Consumers to purchase in-home control and information devices that would automatically communicate with their meter and that, in turn, would help automate or otherwise increase their demand response; and
2. Market participants to communicate with consumers' meters and appliances.

Open standards might also reduce costs by encouraging competition among technology providers. Regarding this, privacy and security are important matters that need to be managed. Given that the federal and state governments are progressing this issue, we have not developed advice on open standards.

In the directions paper, we recognised the role of energy service companies to help consumers make decisions about investing in DSP technology. The role of these companies and how the market arrangements facilitate that role is discussed in Chapters five and eight. In the future, networks may increase their investments in DSP technology (ie direct load control). How the current market arrangements support network investment in DSP is discussed in Chapter seven.

The SCER is currently applying a staged approach to facilitating a national roll-out of smart metering technology in areas where the benefits outweigh the costs. It has provided for mandated smart meter roll-outs to be exclusively performed by distribution businesses. SCER considered that the potential benefits of a roll-out are split between various parties in such a way that individual parties are unlikely to independently establish a positive business case for investing in a roll-out.

To facilitate this, amendments have been made to the NEL to enable Energy Ministers in participating jurisdictions to make a determination to require distribution businesses (operating predominately in their jurisdiction) to roll-out smart metering services to consumers within their jurisdiction.

There are no current plans for a government-mandated roll-out in jurisdictions that have not previously committed. We have focused our assessment on the market arrangements to facilitate commercial and consumer investment in metering technology which supports DSP. By commercial investment we are referring to the following situations:

- Where the consumer wishes to upgrade their meter;
- Where the retailer (or third party provider) wishes to install a meter at a consumer premise as part of its service product (i.e. time varying tariff); and
- Where the distribution business wishes to initiate a roll out of smart meters in parts of its territory.

We also consider that there should be situations where it is required that a meter with interval read capability is installed (e.g. refurbishment, new connections, replacement of old meters and residential and small business consumers above a defined consumption threshold). Our rationale for this is explained is section 4.3.2. The arrangements for supporting commercial investment must also support these requirements.

We have identified are a number of issues with the current arrangements that are preventing such commercial investment occurring. Our analysis and recommendations are focussed on residential and small business consumers (see Box 5. for jurisdictional definitions). We consider that the current arrangements are adequate for medium to large commercial and industrial consumers.

While there are potential benefits from the installation of AMI, the majority of residential and small businesses consumers only have an accumulation meter, except in Victoria. Where a consumer wants to switch to a time varying retail tariff and/or install DSP enabling appliances, the market must support that choice. Installation of the appropriate metering technology is fundamental to enable consumers to capture the full value of these decisions.

We have published a separate supplementary paper setting out the issues and a summary of our advice on the issues is set out in the next section.[103] We have organised our assessment on the following issues:

1. What should the NER require on the functional specification of the meters to facilitate DSP?
2. Arrangements for when DSP enabling meters should be installed in the residential and small business sectors
3. Arrangements for supporting commercial investment, including which party should be responsible for facilitating consumer choice in metering and providing metering provision and data services.

[103] AEMC, Principles for metering arrangements in the NEM to promote installation of DSP metering Technology, supplementary paper to the Power of choice review draft report, 6 September 2012.

Our proposals for encouraging commercial investment are not required where there is a mandatory roll out such as in Victoria. We note that some of our proposals for how metering arrangements should operate could apply to Victoria following the end of the period where distributors have exclusivity over meter provision.

Box 4.2: Defining residential and small business consumers

The recommendations for meter installation and transitioning to time varying prices outlined in this draft report relate to residential and small business consumers. For the purpose of our analysis we have considered both the definition used under the NECF and also jurisdictional energy consumption thresholds that are used to define small consumers. These jurisdictional thresholds apply both to consumer protection measures and also derogation arrangements for type 5 and type 6 meters. These can differ within a jurisdiction.

We have outlined the current definitions/energy consumption thresholds in the table below.

Table 7.1 Energy consumption thresholds

Jurisdiction	Consumption threshold
NECF	A small consumer is defined as a residential consumer that uses electricity for the purpose of personal, household or domestic use, or a business consumer with an upper consumption threshold of 100MWh per annum.
Victoria	Domestic consumers are defined as those whose aggregate annual consumption is less than 20MWh. Small business consumers are those with less than 40MWh of electricity per year All Victorian consumers under 160MWh will have a smart meter installed by end 2013.
South Australia	Small consumers defined by an annual consumption threshold of 160MWh per annum. This applies to both consumer protections and metering.
Australian Capital Territory	Transitioned to NECF. Residential and small business consumers are defined as equal to or below 100 MWh.
New South Wales	A small retail consumer is defined as a consumer whose electricity consumption is no more than 160MWh per annum. For metering the threshold is 100MWh
Queensland	For both consumer protection and metering, the residential and small business threshold is defined as those where their annual consumption is, or will be, less than 100MWh per annum.
Tasmania	Transitioned to NECF. Interval meters are required for all large contestable customers, ie business customers consuming at least 150MWh per annum.

4.3 Metering considerations

4.3.1 Functional Specification of meters in the NER

DRAFT RECOMMENDATION

- **We recommend that a new minimum functionality specification is included into the NER for all future new meters installed for residential and small businesses consumers. That specification should include, interval read capability and remote communications.**

Residential and small business consumers will either have an accumulation meter, an interval meter (which may be remotely read or manually read at the consumer site) or a smart meter. As explained before, the consumer would need to upgrade an accumulation meter to either an interval meter or a smart meter to enable it to take advantage of time varying prices and other DSP products.

Advances in technology have the potential to significantly expand the range of functions that traditional meters can provide, thereby enabling new products, services, and markets. Questions to consider are:

- what should the NER specify as a minimum functional specification of meters which enable DSP?, and hence
- do the existing minimum standards (in Chapter 7 of the NER) for meters need to be changed?

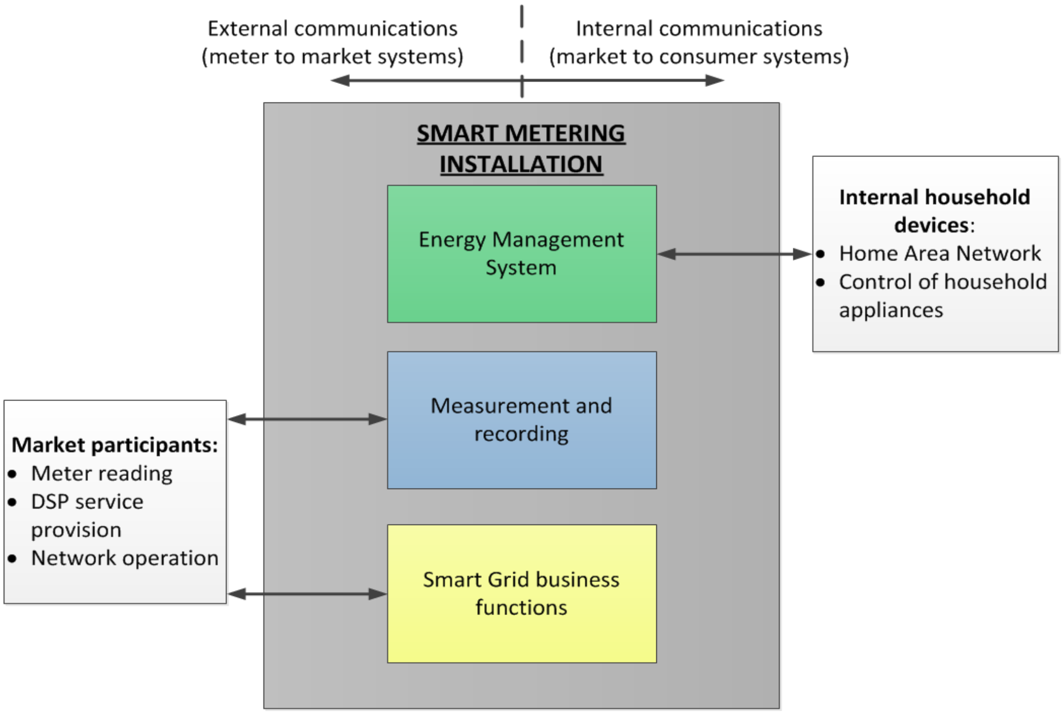
There are potential up to three components to a smart metering installation (see diagram 4.1. These are:

1. The measuring element (or multiple elements) which measures and records the energy consumption.

2. Energy management system functions which could send messages into the consumer premise and communicate with its appliances (ie for load control, home area networks).

3. Smart Grid business functions, which enable market participants to communicate with the meter, to both receive information and send messages/instructions to the metering installation. These could support such functions as supply capacity control, loss of supply detection, energisation/de-energisation etc.

Diagram 4.1: Potential Functionality of Advanced Metering Infrastructure



SCER has already endorsed a minimum functionality specification for smart meters (SMI Minimum Functionality Specification) – which is available to jurisdictional Ministers should they wish to evoke a mandatory rollout of smart meters. This functionality specification covers aspects of all three of the components listed above. The Victorian Government rollout of smart meters commenced prior to the development of the SCER decision on SMI Minimum Functionality Specification and therefore has its own minimum functionality.

There are two differing approaches regarding the functionality and architecture of the meters. One view is that all smart meter functions (i.e. the second and third components) are delivered through the meter and are part of the required metering installation functionality. The alternative approach is that the meter performs all the required measurement (metrology) services and the delivery of other energy management and business function is left open to competition and consumer choice. Under this alternative approach there is a question of whether some of the smart network and retail services should be included in the functions performed by the meter (i.e. outage detection, remote energisation).

For the purpose of facilitating the consumer's ability to capture the value of changing its consumption patterns, it is essential that the meter has the ability to record consumption on an interval basis. Also the remote electronic communications to the meter will also facilitate greater range of DSP products (and also the smart grid business functions. Our initial view is that the minimum functionality to be included in the NER should be a meter which has, amongst other features, the ability to record interval consumption and have remote communication. We have referred to this specification as advanced metering infrastructure and Appendices B and C of the supporting paper provides more detail on the proposed minimum functionality and the minimum standard for the communications.[104]

This means that the consumer has the choice to influence the characteristics of its metering installation and decide whether it is appropriate to include additional functions above this minimum functionality. This would enable the consumer to pay for the meter which best meets its ability and preference to do DSP, at the lowest costs. When additional functionality is to be installed, in addition to the above payment choices, the Service Provider offering the additional functionality may determine that there are benefits accruing to that Service Provider (and often only recognisable by that Service Provider) that allow that party to offer a discount to the consumer.

We note that SCER took a system wide view of the role and functions of the smart meter and developed its minimum functionality which best captures all the potential benefits of smart grids. Given that, there may be merit to also expand the proposed minimum functionality to include some of the smart grid business functions. We appreciate stakeholder views on this.

Question

7. Should the minimum functionality specification for meters be limited to only those functions required to record interval consumption and have remote communication? Alternatively, should the minimum functionality include some, or all, of the additional functions specified in the SMI Minimum Functionality Specification?

4.3.2 When should metering infrastructure be installed

DRAFT RECOMMENDATION

We recommend that:

- **the installation of meters consistent with the proposed minimum functionality specification to be required in certain situations (eg refurbishment, new connections, replacements).**

- **Such metering must also be installed on an accelerated basis for large residential and small business consumers whose annual consumption a defined threshold.**

We understand that at least two distribution businesses routinely install accumulation meters in new construction and refurbishments where for which a new meter is

104 Further information on AMI and metering is provided in an information sheet published with the power of choice draft report

required. While they have made this decision on a straight business case basis, it is clear to us that this is a lost opportunity to take advantage of current technology.

We consider that there is substantial merit in applying rules to require the installation of appropriate metering technology when the opportunity arises. This refers to the following situations:

- all new construction;
- all refurbishments of existing buildings where the electrical installation is being ungraded; and
- where the existing meter is going to be replaced because it is broken or at the end of its useful life.

We also recommend that meters with interval reading capability must also be installed on an accelerated basis for residential and small business consumers with annual consumption above a defined threshold. More analysis is required as to the appropriate threshold level and whether it should vary by jurisdiction. We envisage the threshold to be materially more than average consumption as it is intended is to capture residential consumers who place most demand onto the electricity system. We discuss the application of the threshold more in the Chapter six on efficient and flexible pricing options. We consider that this threshold can be used in a phased transition towards more efficient pricing signals in the market.

Such meters should be consistent with the proposed minimum functionality specifications set out above. These specifications will include requiring that meters are capable of being read on interval basis and have remote two-way communications. In these situations, the consumer's retailer will be required to install the required meter and the costs would be charge to the consumer (as set out in the next section).

As explained in the national cost benefit analysis, there are significant cost savings to be had from installing meters with remote communications, largely attributable to the avoidance of meter reading costs and enhanced operational efficiencies.[105] As well, these meters, provide improved data capture capabilities and have the potential to provide significant other benefits to the consumer and network operations in the future.

According to metering industry sources the cost that of an interval meter with remote communications functionality is approximately between $250 and $400, depending upon the number of measuring elements it contains. Installation costs could be around $200 on average, depending upon jurisdictional requirements.[106] Hence the average total cost for meter installation is estimated to be between $350 and $600. This

105 MCE, Smart meter cost benefit analysis, 2008

106 There may be an additional costs associated with meter and communications software, which the metering provider may incur.

compares to the AER decision on a cost of replacing an accumulation meter on a like for like basis of $170 (for both the meter and installation).[107]

Consumers receiving the new meters will pay for them as part of their bills, just as all consumers currently pay for their existing meters. Because these meters are similar in price to conventional meters, consumers' bills may not change significantly. These costs would be incurred over the life of the meter, which tends to be around 15 years, hence the annual cost could be relatively small compared to the consumers total energy bill.

Consumers receiving interval meters with remote communications will be better informed about how much electricity they're consuming over the course of each day and how that varies in different seasons. This information will help them determine how they can save money by undertaking particular DSP actions. It may also allow them to have the choice to use new communications and control technologies that take information from the meter and adjust the use of electrical equipment within the home. This can generally be done in a way that maintains the comfort and convenience the household wants, but saves money by reducing the use of electricity that is not needed or making sure that certain equipment can't run when the price is above a certain level.

The information from the meter will also allow these consumers to get electricity price offers from retailers that reflect their individual usage. This will help them to pay a fair price for the amount of electricity they use.

We recognise that the use of a threshold to determine which households and businesses are required to have a minimum specification meter and which ones do not can raise problems. But there are a number of other reasons, over and above those stated that make the installation of these meters important in the environment we face. Interval meters are the most effective way to integrate rooftop solar electricity systems into the use of the home and to allow the consumer to capture the value of the electricity exported back into the grid. They will also be critical for ensuring that the use of large appliances, such as air-conditioners and electric vehicles, does not impose unfair costs on other consumers.

In our review on electric vehicles and natural gas vehicles, we found that if electric vehicles users did not face appropriate prices to encourage them to charge their vehicles at off-peak times, it could result in the need for about $1,000 per year in additional generation and network infrastructure costs per electric vehicle. Obviously this will have an impact on all consumers' bills. The use of an interval meter and time varying tariffs will provide a proper price signal to electric vehicle users to encourage them to charge their vehicles off peak – or pay the fair price for doing so at other times.

107 AER final distribution determination on ETSA Utilities, table 17.8, page 267.

4.3.3 Arrangements to support commercial investment in metering technology

DRAFT RECOMMENDATION

- **Reforms to the current metering arrangements are necessary to promote investment in better metering technology and promote consumer choice. We put forward a model where metering services are open to competition and can be provided to residential and small business consumers by any approved metering service provider.**
- **If new arrangements are implemented, then we advise that governments should consider removing the possibility of a mandated roll-out of smart meters.**

There are multiple reasons why the current arrangements are inhibiting the ability of consumers and market participants to invest in metering technology which supports DSP. To overcome these barriers, a policy decision is required to determine how meters should be provided for residential and small business consumers.

The choice is between either making the provision of meter competitive and open to any approved metering service provider (this is refer to the contestable model) or making the local network distribution businesses the exclusive provider (which we refer to as monopoly model).

We have put forward a proposed model for stakeholder comment where the retailer is mainly responsibility for metering provision and data services, except where the consumer has actively decided to contract directly with a separate metering provider. Also within proposed approach we consider that the network business should continue to have the option to roll out smart meters in its area as part of a DSP program (i.e., to defer network augmentation. The incremental costs of the smart meter could be funded through its regulated revenue).

Issues with the current arrangements

While there are potential benefits from the installation of Advanced Metering Infrastructure (AMI) the majority of consumers currently only have an accumulation meter. There are many reasons for this lack of investment in AMI but the main reasons relate to three areas:

- the current regulatory practice of making retailers responsible for remotely read interval meters while the local distribution business is responsible for the regulated provision of manually read interval and accumulation meters;
- uncertainty in relation to government policy, especially on the regulatory treatment of smart meter services; and
- some misalignments between the party who pays for the costs of the metering installation and the party who benefits.

There are a number of risks facing market participants if they invest in installing advanced metering infrastructure. These risks include:

- The risk that metering installation may be replaced if consumers change retailers;
- The risk that consumers would revert to a flat tariff, while the retailer wholesale energy costs would be determine using the consumer's interval data;
- Uncertainty of consumer protection arrangements for smart meters as these are still being developed;
- The risk that government mandated smart meter roll out would strand metering investments; and
- The uncertainty over who has rights to use the non-metering control functions included in the meter.

In some jurisdiction retailers and consumers also face strong disincentives to investing in AMI. In Queensland, New South Wales, Tasmania and the ACT metering costs are not unbundled from Distribution Use Of System (DUOS) charges. This means consumers with AMI would end paying twice for their metering. Also, except for South Australia, there is not a clearly defined exit fee when a consumer upgrades its meter to an interval meter. Instead the retailer and distribution business is required to negotiate in good faith on the appropriate value of the accumulation meter being replaced.

Distribution businesses also have a strong incentive to invest in manually read meters, since under the NER retailers are responsible for providing remotely read interval meters, unless they devolve this responsibility to the associated distribution business. In addition distribution businesses can only seek regulatory approval for metering expenditure and metering charges for invest in manually read interval meters, given that the NER classified remotely read interval meters as a contestable service.

Principles to support commercial investment in metering

We have done some initial analysis on what changes to the current metering arrangements would be required to promote a greater uptake of AMI, in the absence of a government mandated roll out. We consider this roll out should facilitate an efficient level of demand side participation with a greater level of consumer choice in the metering services available.

The key principles we have adopted are:

- The metering choices should be simple and practicable from the consumer's perspective.
- Metering provision should be contestable where sufficient competition is expected.
- The aim should be to facilitate efficient levels of investment with a view to:

- maximising overall market efficiency by reducing the investment risks and assigning costs to the likely beneficiaries of the investment; and
- promoting innovation in the metering services being provided in a framework that is expected to be robust in the long term.

Possible amendments to support commercial investment in metering

To consider the issues and principles above we have investigated possible AMI roll out under a contestable model and a monopoly model.

For the contestable model, the retailer will be responsible for managing the metering arrangements at a premise, on behalf of the consumer. The consumer will have the ability to contract directly with metering service providers, if it so wishes.

Under the possible contestable model we would propose the provision of metering services be separated from retail energy contracts. This would allow the metering service providers to recover their costs over a longer period thus helping manage meter churn risk. Allowing any entity that is accredited with AEMO to provide metering services would be expected to provide additional competition for the provision of these services and remove the incentive on distribution businesses to install manually read meters.

Under the contestable model, we consider that it would be necessary for metering costs to be unbundled from DUOS and that there is a standard exit fee for when a network accumulation meter is upgraded. Having a standard exit fee will remove the need for negotiation between the parties on the loss of value to the network business. The supporting paper proposes that the standard fee should be 30 per cent of the cost of the replaced meter. This is based upon a simple assumption that on average, the remaining life of accumulation meters could be roughly one –third of the total life of the meter. However we are open for the industry to propose alternative amounts. What is important is that there is a standard fee and no requirement for the parties to negotiation on a case by case basis.[108]

Under the monopoly metering roll out model, metering services for small consumers would be exclusively provided by the local distribution business. In this case the AER would need to regulate the provision of these metering services. Consumers can still choose its type of meter and any additional functionality.

Further analysis and stakeholder discussion is required before a recommendation can be made between these models. But there are some specific recommendations that should be applied irrespective of which AMI roll out model is adopted. These recommendations are to:

- Unbundle metering costs from DUOS charges.

108 This standard fee would need to be complemented by arrangements for any remaining residual value to the networks being recovered from all consumers through DUOS.

- Recover the stranded distribution business metering investments with a 30 per cent exit fee (with any residual being recovered from all consumers through DUOS).

- Remove the distinction between the provision of different types of meters based on LNSP exclusivity (the difference in arrangements for type 4 meters compared to type 5&6 meters).

- Make provision of the non-metering functions available in smart meters contestable.

To further promote discussion on amendments to the arrangements to encourage the roll out of AMI, we are putting forward a possible model for consultation. Under this model the provision of metering services would be contestable but a network businesses would also be able to roll out AMI in its geographic area, as part of its expenditure program.

In this situation, the network can contract directly with the consumer or via the retailer of its decision to install a smart meter and will be responsible for providing the meter and data services at that consumer site. The network metering fees may be regulated by the AER in this situation. The retailer would still be responsible for managing the services provided by the network business on behalf of the consumer.

The proposed model would work as follows:

- Small consumers have the right to upgrade their metering installation.

- Small consumers have the right to contract with any accredited provider for the provision of metering services. The retailer at the consumer site will be required to facilitate any contracts between the consumer and metering provider.

- In most cases we envisage that consumers will not actively exercise this option, in such circumstances the retailer is responsible for ensuring the metering installation reflects the consumers' needs.

- If consumers change retailers for the supply of electricity they would not be required to change their meters.

- Consumers' current retailer will be responsible for the costs of metering and managing metering services providers on their behalf.

- Consumers will be liable for the costs of the metering and associated services over the life of the metering contract.

- Network businesses can offer a discount on DUOS or fees to those consumers who also install meters with additional functionality that delivers network operational benefits.

- Any non-metering services relating to the meter (ie energy management services and smart grid business functions) will be contestable and can be provided by any third party provider. Our recommendations regarding metering data access will support this.

We favour a contestable approach because meter provision does not have the characteristics of a monopoly service and we consider it will drive innovation and metering services at a lower cost. A number of third parties have indicated to us their keenness to enter this market and provide efficient solutions to consumers. Work is needed on the detail and practicalities of this approach and we are keen to work with all stakeholders to develop these issues further.

In situations where it is required that an interval meter should be installed (eg consumers above the consumption threshold), we consider the current retailer should be responsible for ensuring that such meters are installed in a timely manner. We need to assess whether this is can work in practice (eg for new developments there may not be an existing retailer) and whether there are benefits to assigning this responsible to the local network business.

If our proposed arrangements are implemented, then the governments should consider removing the possibility of a mandated roll-out of smart meters. The approach of mandating roll-out of smart meters may no longer be required and this would facilitate commercial participants entering into the market and providing metering services. We are concerned that the risks created by the possibility of a government-mandated roll-out occurring in the future could be forestalling commercial investment.

Questions

8. Does the separation of the provision of metering services from retail energy contracts remove the need for meter churn when a consumer changes retailer? Does this cause any unforeseen difficulties or create any material risk? Are there any alternative approaches to reducing the need for meter churn?

9. Are there sufficient potential metering services providers to facilitate a contestable roll out of AMI? Does the proposed model mitigate all the material risks of a contestable roll out? If not, should a monopoly roll out be adopted?

10. What should the exit fee when a consumer upgrades it meter from one provided by the local distribution business? Is the proposed fixed 30% of the cost of a replaced meter appropriate?

11. Does the option of a government mandating an AMI roll out within its jurisdiction act as a strong disincentive to a commercial roll out? Should the ability for these governments to mandate an AMI roll out removed from the NEL?

5 Demand side participation in wholesale electricity and ancillary services markets

Summary

Under the current arrangements consumers are limited in their ability to respond to changes in the wholesale electricity spot price. While they are able to physically reduce their consumption in response to the spot price under specific contractual arrangements such as interruptible tariffs, spot pass-through and scheduled demand, these involve a degree of risk that cannot be efficiently managed for most commercial and industrial users. In response, we have developed a set of recommendations to enhance participation by consumers in the wholesale electricity and ancillary services markets. We have also recommended ways to preserve accurate demand forecasts as increasing levels of DSP enter the NEM in the future.

The recommendations to achieve this are as follows.

- A demand response mechanism that rewards changes in demand via the wholesale market. Under this mechanism demand resources would be treated in a manner analogous to generation and be paid the wholesale electricity spot price for reducing demand. Further consideration needs to be given as to how to include scheduled demand resources in AEMO's dispatch process, and how to calculate a consumer's baseline consumption that determines the amount of payment.

- Amending the rules to clarify AEMO's role in developing both long and short term demand forecasts, including estimating price responsive DSP. We also recommend the existing rules associated with specific reporting obligations are rationalised to remove any ambiguity regarding AEMO's information gathering powers.

- A new category of market participant to unbundle the sale and supply of electricity from non-energy services, such as ancillary services.

These recommendations should result in enhancing consumers' ability to respond to the wholesale electricity spot prices, and consequently change consumption behaviour so that consumers shift the timing of their consumption, or reduce it at times of high spot prices where they stand to benefit.

5.1 Market conditions for uptake of efficient DSP

An efficiently operating electricity market should incorporate both dynamic supply and demand resources. When this condition is satisfied participants can adjust their consumption or production over time, leading to an efficient market outcome. Currently in the wholesale market, generation resources can effectively respond to the wholesale electricity spot price and adjust their production in response to market conditions.

At present demand resources can physically respond to the spot price in the short term by reducing consumption. However, commercial practices combined with current rules tend to inhibit consumers from participating directly in the wholesale spot market. Arrangements such as interruptible tariffs, spot pass-through and scheduled demand are feasible, but not attractive, meaning there is a relatively low level of demand side participation. These arrangements lead to an outcome where the efficient level of consumption in the wholesale electricity market is not achieved.

5.2 Issues identified

In the directions paper we considered the different ways in which consumers could currently access the wholesale electricity and ancillary services market and noted that the current regulatory arrangements could be improved to facilitate better access. We also considered that aggregators are likely to play an important role in coordinating consumers' demand resources into wholesale electricity and ancillary services markets.

Stakeholder submissions were generally supportive of improving demand resources' ability to access the wholesale electricity and ancillary services markets. Stakeholders identified a number of key issues including the risks of being exposed to the spot price and the costs of participation relative to the benefits.[109] Stakeholders also noted that current arrangements prevented demand response opportunities being unbundled from the sale and supply of electricity provided through a retailer.[110]

This chapter sets out a number of recommendations to address these issues. The first section, 5.3 onwards, discusses amendments to the NEM settlements to enable a demand response in the wholesale electricity market to explicitly be compensated at the wholesale electricity price. We also consider a range of additional changes that would be required to support this recommendation.

Section 5.6 onwards recommends amendments to AEMO's role in developing both long and short term forecasts, including the price responsiveness of DSP, for the purpose of forecasting more accurate price information to the market over various time frames including pre-dispatch. This is an important measure given the potential and likely increase in the level of DSP in the market.

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109 EUAA, directions paper submission, page 6; MEU, directions paper submission, p. 38

110 Energy Efficiency Council, directions paper submission, p. 19

The last section, from section 5.7 onwards, recommends creating a new category of market participant to unbundle non-energy services from the sale and supply of electricity. We discuss how this is likely to result in third parties, such as aggregators, being able to coordinate a consumer's ancillary services independently of that consumer's retailer and the supply of electricity.

5.3 Demand response mechanism

DRAFT RECOMMENDATION

- **We recommend a demand response mechanism that pays demand resources via the wholesale electricity market is introduced. Under this mechanism, consumers participating in the wholesale market can make the decision to continue consumption, or reduce their consumption by a certain amount for which they would be paid the prevailing spot price.**

The key principle for the operation of this mechanism is that demand resources are treated in an analogous manner to generation, such that demand resources are remunerated at the wholesale electricity spot price. The spot price would continue to be calculated as currently, on the basis of the marginal scheduled bands of generation, or any scheduled demand resource. The demand resource is paid according to the amount of 'demand response' delivered to the market. This is calculated as the difference between consumers' actual metered consumption and their calculated "baseline consumption" for the demand response interval. The baseline consumption is an estimate of consumers' consumption had they not changed their consumption.

Under this mechanism it is necessary for consumers to continue paying their retailer for electricity according to their estimated baseline consumption. Similarly, consumers' retailers are required to pay the wholesale market spot price according to their estimated baseline consumption. This arrangement allows for AEMO to recover enough funds to pay consumers[111] for their demand response at the wholesale price. The total net benefit to consumers of providing the demand response under this mechanism is the spot price minus energy component of the retail price (this excludes the opportunity cost of not consuming).

The following points outline how the mechanism will work, including the role of each of the three key participants: AEMO, consumers and retailers.

Contractual arrangements and the consumer's estimated consumption

- Consumers providing a demand response must have a retail contract in place with a registered Market Customer[112] (i.e. a retailer).

111 We note that in practice, the registered person receiving funds would be an aggregator on behalf of the consumer (otherwise referred to as the "end-use" consumer).

112 The rules define a Market Customer as "a customer who has classified any of its loads as a market load and who is also registered by AEMO as a Market Customer under Chapter 2". Typically,

- The retailer will be settled in the wholesale market based on the consumer's estimated baseline consumption.
- Consumers would be expected to pay their retailers according to their estimated consumption at the retail tariff.
- Consumers register their participation under the demand response mechanism with AEMO.
- Consumers can choose to have their demand resources participate on a scheduled or non-scheduled basis, subject to any threshold requirements.
- The quantity of demand response consumers deliver to the wholesale electricity market during the demand response interval is calculated as the difference between their estimated consumption and the actual metered consumption at their site.
- A method would need to be developed for calculating consumers' estimated consumption.

Market operation, scheduling arrangements and the impact on the spot price

- Subject to threshold requirements consumers should be required to notify their retailers and AEMO of their intention of beginning a demand response interval by the start of the interval, and similarly at the end of the demand response interval.
- The operation of the dispatch does not change and the calculation of the spot price would continue as it does now where the marginal scheduled bands of generation or demand resource would be the basis for the spot price.
- *Non-scheduled demand resources.* If the demand resource is non-scheduled then the reduced demand may indirectly lead to a spot price that is lower or unchanged. Non-scheduled demand resource participating under this mechanism would be exposed to the same price risk as a demand resource on tariff which is dynamic and changes with the spot price.
- *Scheduled demand resources.* If the demand resource is scheduled it would appear in AEMO's dispatch process in the same way as scheduled demand does now and would be dispatched in accordance to its bid. This could result in the partial dispatch and price being set by the demand resource bid.

Settlement and the impacts on retailers and consumers

- AEMO pays consumers for the quantity of demand response delivered to the market during the trading interval at the spot price. As a result, consumers participating in the mechanism pocket the difference between the spot price and the retail price (energy component).

Market Customers are retailers and the primary interface between end-use consumers and the wholesale market and ancillary services market.

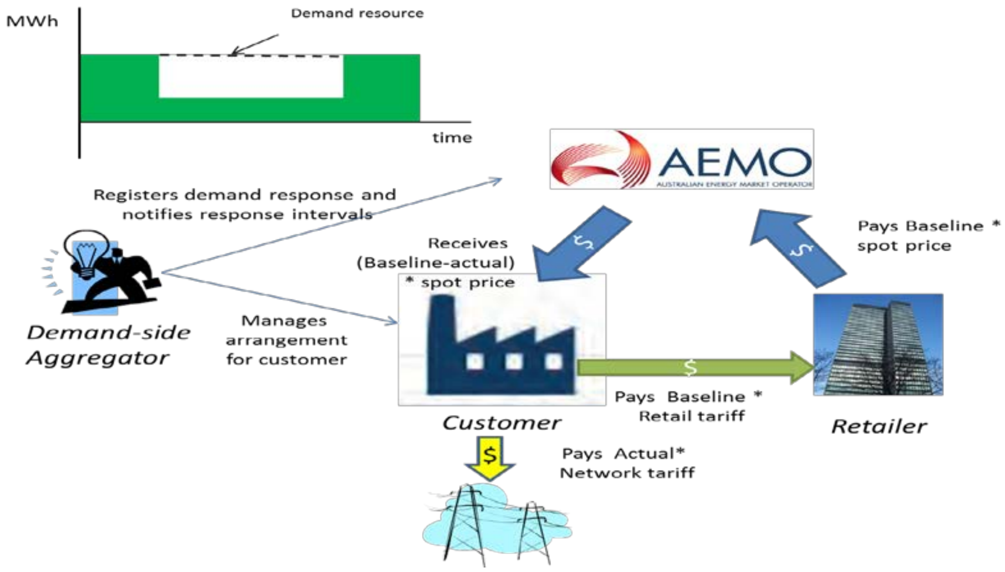
- A verification or auditing process may be required to confirm the amount of demand response delivered to the wholesale market by the consumer.

- Subject to detail on the accuracy of the consumer's estimated consumption, the retailer would be cost neutral to the arrangements. The consumer providing the demand resource would benefit from difference between the retail tariff and the prevailing spot price net of any lost production.

- Consumers pay the network use of system charges based upon their actual consumption volume, not their estimated consumption.

Figure 5.1 outlines the general design and economic relationships that would exist under the proposed demand response mechanism.

Figure 5.1 General design of demand response mechanism



The proposed mechanism would mainly assist large electricity users, such as C&I users that prefer to have an energy retailer manage spot price risk when consuming, but wish to offer their demand response to the wholesale electricity market directly or via a specialist intermediary, such as an aggregator. In the future this mechanism could be adapted by aggregators to include demand responses from residential consumers who have advanced metering technology in place.

The mechanism for paying consumers for their demand response via the wholesale electricity market is in addition to current arrangements whereby large C&I users can register as scheduled load and be included in AEMO's central dispatch process. Similarly, this mechanism does not replace the ability for consumers to enter into a spot price pass through contract with a retailer.

To implement the demand response mechanism we expect that the following rule changes would be required:

- Changes to the settlement process to allow retailers to pay AEMO according to their consumers' estimated baseline consumption, and for AEMO to pay consumers for their demand response.
- Agreed method for calculating consumers' estimated baseline consumption including minimum metering standards.
- Arrangements that allow consumers to provide a demand response under this mechanism on either a scheduled or non-scheduled basis.
- A new sub-category of market generator is proposed as the demand resource units will have an entitlement to receive the spot price in the same way as generation. A sub-category would be more compatible with existing rules, for example, around prudential obligations.
- Changes so that network charges can be separated from energy only costs by retailers. This may also require a change to a retailers' billing systems, although some of their systems may already have this capability in place.

5.4 Rationale

We consider that this mechanism should deliver long term benefits to consumers by facilitating greater participation of price response demand, lowering generation and network costs and increasing competition in the energy market. This will, in turn, lower spot prices and network charges.

In total, we expect the costs of administering this mechanism to be less than the market benefits and consider that implementing this mechanism will be relatively straight forward as a number of procedures needed for it to operate already exist.

Over the mid-term we estimate the demand response mechanism has the potential to capture between 2,100- 2,800MW of demand response from C&I users.[113] The estimate is based on the potential for achievable demand response in the NEM of between six to eight per cent for the total 35,000MW of peak demand and is based upon existing available studies and international experiences.[114] Appendix A provides a summary of the literature used to estimate the potential demand response from C&I users.

The most economically efficient outcome for the market results when consumers face the true costs of supply (see Box 5.1). In the absence of full cost-reflective pricing the proposed demand response mechanism may create a similar set of incentives and

113 See EnerNOC presentation for the Fourth SRG meeting held on 28 May 2012. Presentations and outcomes from the meeting are available on the AEMC's Power of choice webpage www.aemc.gov.au

114 In the near term C&I users market would be likely to account for almost all of demand response, and up to 80% on the mid-term. We understand that already 280MW of demand response is available from C&I users in the NEM during summer periods. Therefore the demand mechanism is likely to build on this amount in the mid-term. See the AEMC website for Futura report, *Investigation of demand side participation in the electricity market*, pg. 9, 8 December 2011.

behaviours with respect to efficient consumption during wholesale electricity market peak and non-peak times. Under this proposal a consumer would provide a demand response when the difference between the spot price and the retail energy price is more than the opportunity cost of not consuming.

Box 5.1 What is an efficient demand response in the wholesale market?

An efficient demand response will occur when the costs to the consumer of supply (including both energy and network costs) is more than the costs of not consuming, i.e. the "opportunity cost" of not consuming.

If a retail contract accurately reflects the cost of supply, including energy and network costs, consumers will change their consumption behaviour in response to market signals. In this situation consumers will decide whether the value of consumption is worth the cost incurred in the supply of electricity. This type of effect can be seen with spot price pass through contracts. Under this type of arrangement, faced with a high spot price, consumers will choose to either reduce their consumption to an efficient level or shift their consumption to a different time period when the cost of supply is cheaper.

Inefficient consumption is likely to arise if a consumer does not face the real costs of supply and instead responds to price signals under a relatively flat retail contract. In this scenario, a consumer is likely to over consume during periods of high spot prices, and under consumer during periods of low spot prices.

A key benefit of this mechanism is that it could potentially lead to downward pressure on spot prices. The spot price is expected to be lower where the incremental cost of participation is less than the price a peaking generator will need to offer to cover its fixed and variable costs from the wholesale market. While an aggregator will need to recover set up and operating costs, the basic infrastructure needed to establish the demand resource, such as connections, is a sunk cost and overall lower than the fixed costs of generation. An assurance of payment at the spot price will also facilitate demand resources selling hedge contracts to both customers and generators.

Under this mechanism retailers should remain indifferent to a consumer's decision to enter into a demand response interval and should not see any change to consumption volume. This is because consumers continue to pay retailers according to their estimated baseline consumption. More generally, retailers could benefit under this mechanism as retail hedging costs are reduced where spot prices and spot price volatility decrease.

In a competitive retail market retailers should pass the cost savings on to consumers. The benefit of reduced wholesale electricity costs is not just limited to consumers who participate in the wholesale market, but should extend to all retail customers including residential consumers.

Sustained and predictable demand responses should lead to downward pressure on network investment costs. Over time, as the predictability of demand responses improves, distribution businesses should be able to use this information to better forecast peak load on their networks as part of the planning and investment process.

Sustained demand responses are also likely to lead to improvements in the level of unserved energy, by way of allocating curtailment opportunities to consumers who are willing to respond to the spot price.[115] Not all consumers face the same opportunity cost of not consuming. However, where consumers value the supply of electricity less than others, a demand response mechanism provides an opportunity for some customers to respond, thereby lessening the potential for a rolling blackout, which affects all consumers. As NERA note in their submission to the directions paper, "effectively load is reduced in the order of value to consumers".[116]

In turn, we would expect that over the longer term, once the mechanism is established to be reliable, the market should move to a new equilibrium and market settings could be reconfigured to limit involuntary load shedding from a new base.

Facilitating greater participation of demand resources can have positive spill-over effects, which can, in turn, provide additional revenue and reinforce the commercial case for DSP. For example, once consumers are participants under this mechanism, possibly through aggregators, they are more likely to participate in arrangements to manage network flows/contingencies as operational management barriers will have been addressed and there will be little or no additional costs. The positive spill over effects potentially offer additional revenue streams for consumers as their demand response can be valued during system peaks as well as network peaks.[117]

Generator behaviour in the wholesale market is predictable and reliable, which contributes to efficient dispatch volume and pricing. We consider that consumers providing demand resources are likely to have sufficiently strong incentives to be reliable, especially where they enter via aggregators who will need to establish infrastructure to coordinate their operations – and even more so if the full potential is realised and the interruptible feature is used as the basis of a financial instrument or a network contract. For C&I users any additional revenue stream would likely be incorporated into longer term business planning, further strengthening the predictability of demand response.

The proposed demand response mechanism will incur some costs to the market. Most of these would be administrative costs as many of the provisions needed to operationalise the mechanism are already in place. Some administrative changes will be required to establish new procedures and guidelines for registering demand resources, as well as changes to the settlement process to account for the recovery of

115 Unserved energy requirements should not exceed 0.002 per cent of the total energy consumption in a NEM region in one year.

116 NERA, directions paper submission, p 10.

117 These new revenue streams are in conjunction with possible payments under the Reliability and Emergency Reserve Trader emergency resource management tool that is in place until 2016.

funds. There may also be additional administrative costs for a monitoring and reporting program during the initial years of operation. No major changes are required to metering procedures which may otherwise represent a material cost.

The demand response mechanism proposed in this is different to other mechanisms previously considered. For example, uplift charges to fund DSP payments have previously been considered (Parer Review, Demand Side Participation stage 2 review). In each of these reviews it has been decided not to introduce an uplift payment in the spot market settlement in light of the economic implications and complexity of design and compliance requirements. This demand response mechanism provides payments to demand resources for their reduction in consumption but avoids the need to introduce complex regulatory instruments such as uplift payments. Also it treats demand resources in the same manner as generation.

5.5 Considerations

There are a number of important considerations in developing the demand response mechanism:

1. Calculating consumers’ baseline consumption is an important component of determining the amount of compensation they receive for their demand response delivered to the market.

2. The extent to which participation in the wholesale market by consumers is on a scheduled or non-scheduled basis. A material increase in the levels of non-scheduled demand resources may have implications for efficient dispatch volume and pricing.

3. How to facilitate demand resources participating in the wholesale market and whether a new category of market participant is required to do so.

We also note that advances in technology are likely to facilitate greater C&I users' participation in the wholesale market, potentially including residential users in the longer term. Technical standards and the interoperability of systems may therefore, become increasingly important. For example, it should be feasible for any aggregator to provide a demand response to consumers who already have infrastructure in place to accommodate a demand response.[118]

Appendix A of this report includes a more detailed description of the how the demand response mechanism works, including two examples, greater detail on calculating a consumer’s baseline consumption, and information regarding the potential demand response from C&I users.

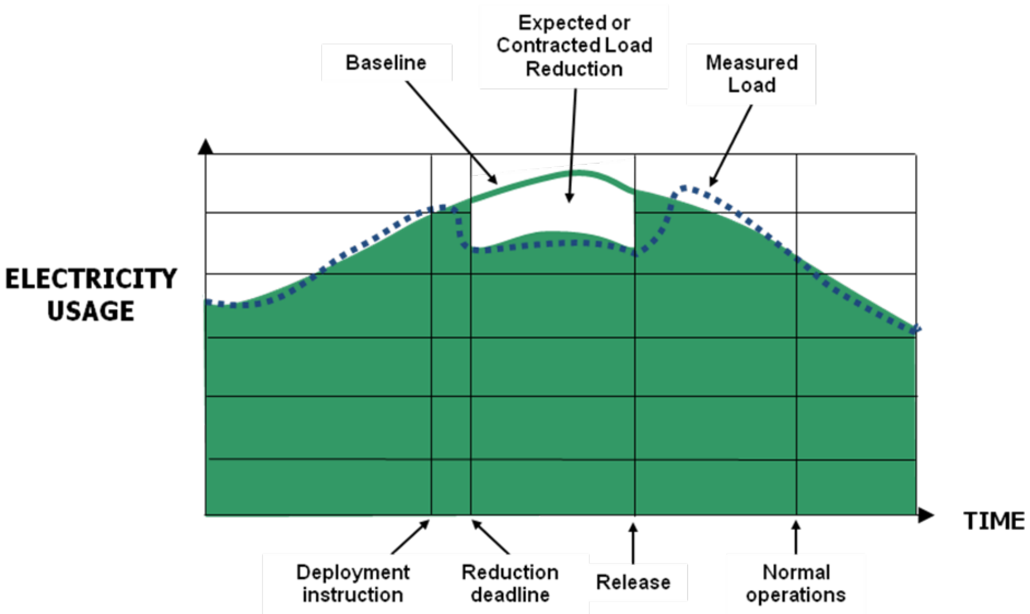
118 In the United States an industry lead process is underway to develop minimum technology standards for demand response programs called the “Open ADR Alliance”. The alliance is comprised of industry stakeholders interested in fostering the deployment of low-cost price and reliability based demand response communication protocol by facilitating and accelerating the development and adoption of open standards and compliance with those standards. More information is available on their website: www.openadr.org

Calculating baseline consumption

This demand response mechanism will require a monitoring and verification (M&V) system to calculate the amount of demand response that is being delivered to the market. The main objective of an M&V system is to confirm the amount of demand response delivered to the market by a consumer for the purposes of receiving the spot price. Typically, this amount is calculated as the difference between consumers' actual metered consumption during the demand response interval and their theoretical consumption had they not changed their consumption.

Determining consumers' theoretical consumption – otherwise referred to as their baseline consumption – is a key design element of a demand response mechanism that pays consumers for their demand response. An accurate baseline consumption should mirror as closely as possible the likely behaviour of consumers had they not been dispatched during the demand response interval. This principle is demonstrated in Figure 5.2.[119]

Figure 5.2 Calculating baseline consumption



A variety of methods can be used to calculate a consumer's baseline consumption. In most cases the calculation is made up of two components. The first component with the greatest weight relates to the consumer's consumption over a period of days or weeks and represents the consumer's 'baseline consumption' in the longer term. The second component considers the consumer's consumption immediately prior to the demand response event and is called a 'baseline adjustment'. The weighting of each of these

119 See Recommendation to the NAESB Executive Committee, *Review and develop business practice standards to support DR and DSM – EE programs*, Proposed standards, October 3, 2008. We note that the diagram represents arrangements for scheduled demand resources, and does not represent arrangements for non-scheduled demand resources, or reflect 5 minute intervals that are used in the NEM.

components may vary for each approach, depending on which delivers the best estimate of the consumer's baseline consumption.

Table 5.1 below sets out the key components that are required to calculate a consumer's baseline consumption. Appendix A provides a more detailed description of the various baseline calculation methodologies.

Table 5.1 Components of a baseline consumption methodology

Component	Approaches
Baseline consumption	This can be calculated according to the consumer's average load profile, or may be static in nature. The former is used more frequently in North American demand response programs.
Baseline adjustment	The baseline consumption can be adjusted to take into account conditions immediately prior to the demand response event. Changes to the baseline consumption, using the baseline adjustment, can move either upwards or downwards (or both) and may be capped as a percentage or MW amount of the baseline consumption. Weather and calendar data can also be used to inform or adjust the baseline consumption.
Meter data	In most cases, meter data is used to calculate the baseline consumption. Meter data can be used in the weeks, days, or even hours leading up to the demand response event to calculate the baseline consumption.
Metering requirements	Demand response programs may require that an individual meter is used for each demand response site. Baseline consumption may be derived for a group of consumers for large scale residential programs where the cost of installing metering equipment does not outweigh the benefits.

Box 5.2 illustrates how baseline consumption is calculated for the demand response program in operation in the Pennsylvania New Jersey and Maryland (PJM) electricity market.

It is important that a baseline consumption method minimises opportunities for consumers to overestimate their consumption, otherwise they may be overpaid for the demand response they delivered to the market. These types of opportunities can arise in two ways: when there is minimal opportunity to refresh the consumer's baseline consumption with actual metered data, or where the method doesn't suit the load characteristics.

To limit these distortions we recommend the following principles should be adopted when developing baseline consumption methods:

- *Clear rules for refreshing metered consumption data.* This means that there should be frequent opportunities to refresh a consumer's baseline consumption profile with actual metered data. Consideration needs to be given as to how to refresh the baseline if the load is deployed over a sustained number of days resulting in out-of-date metered data being used to calculate baseline consumption.

- *Accuracy is paramount.* The baseline consumption should accurately reflect what the consumer's consumption would have been if the demand response event did not take place. Developing a suitable method, taking into account the components described in table 5.1 is paramount in achieving this. To arrange that a suitable approach has been selected, the baseline consumption method should be subject to review during the first few years of its implementation, and periodically thereafter.[120]
- *Metering requirements.* The use of separate metering should be encouraged when it is easy and efficient to do so. Using baseline consumption methods should not be viewed as an adequate substitute for metering. Metering equipment can be the metering equipment used for a consumer's retail electricity supply, or customer owned metering equipment, or metering equipment acquired by a third party for the customer.

We propose that market institutions form a working group to develop a suitable method for calculating baseline consumption, taking into account the objectives of the demand response mechanism, load characteristics and NEM market arrangements. The working group should also more closely consider the necessary minimum metering and settlement standards and protocols. The group would be guided by, and have expert input provided by, industry participants.

Box 5.2 Demand response in the Pennsylvania, New Jersey and Maryland (PJM) electricity market

The PJM electricity market has a demand response program in place which enables retail electricity consumers to earn revenue for reducing electricity consumption when either electricity prices are high, or the reliability of the electricity grid is threatened. Demand responses are classified as either Economic or Emergency Demand Response.

For Emergency Demand Response, consumer revenue for reducing consumption is largely driven by participation in PJM's capacity market. Economic Demand Response is compensated at the locational marginal price when the benefits of providing the demand response are outweighed by the costs of providing the demand response. The Federal Energy Regulatory Commission's (FERC) final rule outlines that demand resources are compensated at the locational marginal price when the following conditions are met:

- the demand resource has the capability to balance supply and demand; and

120 We note that the approach adopted for estimating a consumer's baseline consumption can act as an incentive for consumer's to install above specification metering devices. For example, to keep confidence that a retailer is kept whole, where baseline uncertainty exists, a conservative approach (i.e. an under-estimate bias) could be used to calculate the volume of interruption, which would provide an incentive for the customer to install above specification metering.

- payment of locational marginal price to the demand resource is cost effective.

The framework used to calculate a consumer's baseline consumption is based on a "Baseline type I" model – specifically, a high 4 of 5 averages with symmetric additive adjustment.

Under this method, the five ***most recent*** "non-event" days are selected for calculation, which should also exclude public holidays, weekends and "event" days. For each of the five days selected, the average daily event period usage and average event period usage level is calculated. If any day's average daily event period usage is less than 25 per cent of the average, then this day is excluded from the calculation, and replaced with the next eligible non-event day. At the conclusion of this process, the day with the lowest average daily event period usage is eliminated from the top five days to achieve the high 4 of 5 averages.

The calculation also includes a symmetric additive adjustment to adjust the consumer's baseline consumption to load conditions prior to the load reduction event. This calculation works by skipping one hour prior to the start of the event, and counting back, averaging the next three hours to obtain a 'basic average'. The basic average is then compared to the high 4 of 5 averages. The difference between the two averages is used to ratchet the consumer baseline value either up or down.

Incorporating demand response into central dispatch processes

Consideration needs to be given as to how demand resources participating under the mechanism can be accounted for in AEMO's central dispatch process. Accounting for this in AEMO's process is an important function because AEMO uses data received through the centralised dispatch process to operate systems. This includes accurately forecasting demand that leads to efficient dispatch volume and pricing.

We consider that the current arrangements should continue to apply to any consumer providing a demand resource delivered under this mechanism. That is, the consumer can either participate as scheduled or non-scheduled basis, subject to threshold requirements.[121] In order to develop a suitable framework for the participation of scheduled and non-scheduled demand resources under this mechanism we need to:

121 The current arrangements for market generation may provide some guidance as to how to the thresholds for categorising whether a demand resource is required to participate in the central dispatch process. Under the rules generating systems with an aggregate nameplate rating of 30MW or greater are required to be classified as a scheduled or semi-scheduled generation unit; less than 30MW can be classified as non-scheduled market generation unit. There are some exemptions to generating systems greater than 30MW being classified as non-scheduled, such as if the generation is used locally, or it is not practical for the generating unit to participate in central dispatch.

- review the current scheduling requirements and assess their adaptability for the type of consumers likely to participate under this mechanism; and
- consider reporting and monitoring arrangements for non-scheduled demand resources delivered under the mechanism.

Currently, to be included as part of AEMO's central dispatch processes consumers must register their market load as scheduled load. This requires meeting a range of technical and prudential requirements primarily designed for large C&I users participating in the wholesale market. Such requirements include telemetry and communication standards to enable response to dispatch instructions in five minute intervals.

For smaller C&I users, who are likely to arise as participants under the proposed mechanism, these requirements may impose substantial costs. As noted by many stakeholders, the costs of participation as scheduled load can be material and outweigh any expected benefits.[122] We intend to review the current requirements in conjunction with AEMO for the purpose of assessing whether amendments are appropriate to facilitate the participation of scheduled demand resources under the proposed mechanism.

Onerous scheduling requirements for smaller C&I users may result in them preferring to participate as non-scheduled load under the mechanism. An increase in the level of non-scheduled load is likely to impact AEMO's ability to accurately forecast demand, leading to inefficient dispatch volume and pricing. Non-scheduled demand resources would be able to select the times at which they interrupt load, independent of the dispatch process which enables that resources are efficiently deployed.

Performance and reporting program

Given the uncertainty on the level and rate of uptake of the potential new form of demand resource under the mechanism, there is merit in including a performance and reporting program during the initial years of operation. This program is different to the M&V system discussed earlier. Specifically, this program would monitor the impacts of demand responses on dispatch volumes and pricing. In this regard, the program could act to forewarn the market that additional information triggers may be required if substantial volumes of non-scheduled demand resources becomes unpredictable.

In the event non-scheduled demand response adversely impacts AEMO's ability to forecast short term demand, it may be necessary to place some reporting requirements on demand resources participating on a non-scheduled basis to maintain accurate demand forecasts for efficient dispatch volume and pricing. Reporting requirements may include non-binding standing advice of an expected demand response. Any additional notification details should be consistent with AEMO's ability to develop an accurate pre-dispatch. Consumers providing a demand response in the wholesale market should also be required to notify their retailer and AEMO of their intention to

122 ATA, directions paper submission, p 12; EUAA, directions paper submission, p 6.

enter and conclude a demand response interval before the start and end of the interval. The anticipated volume of response would also be advised.

New sub-category of market participant

We consider that consumers providing demand resources should be categorised as a sub-category of market generator. Forming a sub-category of market generator is reasonable given that demand resources are expected to participate in the wholesale market in an analogous manner to generation, and receive the spot price for the demand response delivered to the market. Demand resources also face a similar set of prudential risks to generators, as they do not incur substantial liabilities to the market and are not involved in the sale and supply of electricity. Rather, the market incurs liabilities to the generator, or in this case the consumer providing the demand resource.

There are enough differences in the method of participation between a generator and a demand resource that a sub-category of market generator may be required. For instance, consumers providing a demand response may have their demand resource characterised in a manner that is specific to the mechanism. Similarly, there may be different telemetry and communication requirements, as well as finer details regarding settlement procedures and metering (including endorsement of baseline consumption methods). The extent to whether this issue can be resolved through AEMO's consultation and procedures, or through the rules, will be addressed in the next stage of the review.

In their submission EnerNOC noted that a key barrier to participation in the wholesale market was that to sell a consumer's demand response, an entity would have to be registered as the only financially responsible participant for a consumer's load. This problem should be overcome by allowing an entity to effectively participate as a generator to coordinate a consumer's demand response into the wholesale market.

Entities registered under this sub-category would have the option to present to market on an aggregated basis. The ability for aggregators to coordinate demand responses and act on a consumer's behalf was viewed by stakeholders as being critical to the success of demand side participation in the wholesale market.[123] Aggregators can reduce transactions costs for demand resources by monitoring the spot price and therefore removing the need for demand resources to be classified as a retailer.

Day a head market

We have previously recognised that uncertainty in the spot price may act to hinder DSP action in the wholesale market. For instance, an instantaneous spot market can create uncertainty about whether there are benefits from incurring the costs to prepare to respond, particularly when these costs may need to be incurred 24 hours in advance of a demand response action. In this regard, a day-ahead market could overcome the uncertainty problem for DSP.

123 MEU, directions paper submission, p 38; United Energy, directions paper submission, p 19.

In the demand side participation stage 2 review, the AEMC considered that overcoming spot price uncertainty could be achieved in the short term financial contracts market. We considered this issue again in the directions paper by asking stakeholders how effective current financial markets were at providing a hedge against price risk for DSP options. In response, EnerNOC noted that: "quite apart from the Financial Services Licensing issues which prevent most consumers from dealing with derivatives, the financial contracts that are traded do not provide anything similar to a day-ahead market: they span whole calendar quarters, rather than the shorter intervals over which a day-ahead market would usefully give certainty".[124]

The proposed demand response mechanism puts demand response in the same position as a generator that may need to make commitment a day ahead, for example, to alter production schedules. This mechanism allows demand resources to enter into financial instruments that hedge the spot price. However, as discussed earlier, a significant potential benefit from demand resources arises if supply costs can be reduced. Supply costs will be reduced only if the demand response is reliable, that is, there is an assurance that demand will be reduced, or prices hedged, over at least peak months of the year. An individual demand resource unit may not be able to make such a lengthy commitment, but this could be achieved by way of the aggregator's portfolio of different consumers.

As a result, the proposed mechanism should mean the reason for a day ahead market is overcome because the demand response will receive a spot price payment, which removes uncertainty about payment (albeit with the same risk as a generator).[125]

Questions

12. Participation in the wholesale market:

    (a) Do stakeholders agree that the proposed demand response mechanism is likely to result in efficient consumption decisions by end-users? If not, are there any changes you recommend to the mechanism to facilitate this?

    (b) On balance, is a new sub-category of market generator required for consumers providing a demand that enables aggregation? What types of issues should be considered when developing the registration process?

13. Consumer baseline consumption:

    (a) What factors should be taken into consideration when developing a

124 EnerNOC, directions paper submission, p 20.

125 A demand resource seeking a firm commitment for payment at a specified level of demand response would in all circumstances need to find a purchaser prepared to pay regardless of the outcome. This would be the case under any form of contract. Accordingly, a day ahead market does not offer additional benefit or facilitate short term demand response deployment that is reliable, and therefore delivering the desired deferment of network investment.

baseline consumption method?

(b) Have we identified the correct three key principles for developing a baseline consumption method (data refresh, accuracy, metering)?

(c) Are there any substantial changes to metering and settlement arrangements required for this mechanism to be implemented? Can these issues be resolved through AEMO's consultation process and procedures or are broader amendments to the rules required?

14. Incorporating demand response into central dispatch:

(a) Do you agree that similar arrangements for generation should apply to demand resources in terms of thresholds for registering as scheduled or non-scheduled basis?

(b) What are the ways in which the regulatory arrangements can be adapted to facilitate the participation of scheduled and non-scheduled load in AEMO's central dispatch process? Are there any specific changes to reporting, telemetry and communication requirements?

(c) Should both market and non-market loads above a certain size be required to provide information to AEMO regarding their controllable (and therefore interruptible) load blocks?

(d) Should there be a trigger in the monitoring and reporting framework that requires consumers to provide greater detail regarding their demand resource to AEMO or affected DNSPs?

5.6 Reporting requirements for demand forecasting

Accurate demand forecasts are an important feature of an efficiently operating electricity market. Demand forecasts contribute to a broad range of decision making processes, such as volume dispatch and pricing decisions by AEMO, long term system planning and potential investment decisions, and as inputs into the Australian Energy Regulator's distribution and transmission determination process. Demand forecasts also provide AEMO with important information regarding their procurement decisions, such as the ancillary services market, network support control ancillary services, frequency control ancillary services and the Reliability and Emergency Reserve Trader.

Market and regulatory arrangements aimed at promoting the uptake of efficient DSP may impact on AEMO's ability to accurately forecast demand as more non-scheduled and price responsive DSP enters the market. As being scheduled is a voluntary arrangement for demand, non-scheduled action represents the greatest majority of demand side response, for which there is poor visibility of the volume of this response to AEMO, and therefore the market. AEMO noted in its submission to the directions paper that forecasting load growth will become increasingly difficult with the entry of large volumes of DSP in the NEM, particularly for non-scheduled DSP.[126]

The need to improve demand forecasting was generally supported by stakeholders. AEMO considered that there is a need for a load forecasting framework that incorporated data from demand resources not included in the central dispatch process (i.e. non-scheduled DSP).[127]

Distribution businesses generally supported measures to improve expected demand forecasting, but noted that in some instances, access to information may not improve as the DSP is undertaken by a competitive process, or by consumers on their own behalf.[128]

Retailers did not consider that additional reporting obligations are required as this role was already fulfilled as "the obligations that they would owe in their roles as intermediaries under the rules would be sufficient".[129] Origin noted that additional information should only be required where DSP contracts exceeded a predetermined threshold.[130]

6.6.1 Demand forecasting

DRAFT RECOMMENDATION

- **We recommend that the NER is amended to clarify AEMO's role in developing both long and short term demand forecasts, including estimating DSP, for the purpose of providing accurate price signals to the market over various time frames including pre-dispatch.**

- **To achieve clarity in this regard, the existing rules associated with specific reporting obligations may need to be rationalised to remove any ambiguity regarding their information gathering powers.**[131]

We consider that the rules should provide a high level clause outlining that in its pre-dispatch, Projected Assessment of System Adequacy (PASA) reports, and Electricity Statement of Opportunities (ESOO) processes, AEMO must report on and attempt to represent managed non-scheduled demand and non-scheduled generation in relation to:

126 Australian Energy Market Operator, directions paper submission, p. 5-6.

127 Ibid

128 Essential Energy, directions paper submission, p 12; United Energy, directions paper submission, p 18; Ausgrid, directions paper submission, p.15.

129 AGL, directions paper submission, p. 7

130 Origin, directions paper submission, p.18

131 For the various clauses relating to AEMO's demand forecasting responsibilities, see rules: 3.7.1; 3.7.3; 3.7 c; 3.8.1; 3.8.4; 3.8.7; 3.8.9; 3.8.20; 3.13.4; 4.25; 4.3.4; 4.9.1; 4.9.3 and schedule 5.7.

- elasticity to retail prices, including spot prices;
- response to time variable network tariffs; and
- response to mechanism by which the network companies directly manage network loading.[132]

To provide transparency to these processes, we also recommend that AEMO should develop a set of procedures, in consultation with stakeholders, relating to its collection of information and representation of non-scheduled demand and non-scheduled generation. This may also include the ability for AEMO to assess the compliance of market participants in providing information in comparison to ex-post analysis of a consumer's behaviour.

An overarching obligation should be placed on AEMO to require it to update its expectations regarding DSP capabilities in the NEM on a regular basis. We are seeking stakeholder feedback as to how frequently an information gathering and reporting process would need to be undertaken.

To further support AEMO's role in this regard, we also recommend that a general obligation should be placed on all market participants to provide data, on request, to AEMO to enable it to effectively perform this function.

5.6.2 Rationale

Currently, the rules provide AEMO with guidance on very specific reporting obligations relating to pre-dispatch, Short Term PASA[133], (ST PASA), Medium Tern PASA[134], (MT PASA) and the ESOO.[135] The extent to which these provisions could be interpreted as providing AEMO with broader information gathering powers beyond these specific reporting obligations is not clear.

Further, it appears that the rules do not contemplate a role for AEMO in developing demand forecasts for non-scheduled load and non-scheduled generation. In this regard it may be difficult for AEMO to forecast for price-responsive DSP, which is likely to impact on accurate demand forecasts in the context of increasing levels of DSP in the NEM in the future.

Given the relatively discrete approach from guiding AEMO's demand forecasting responsibilities, including the absence of developing forecasts for non-scheduled load and non-scheduled generation, we recommend the rules are amended to provide high

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132 Note this may be expanded to include retailer-led direct load control for managing system load.

133 The short term PASA (ST PASA) process is run every two hours and provides reserve forecast information for every half-hour over the next seven days.

134 The MT PASA process is run at least once per week and provides a reserve forecast for the next two years.

135 The ESOO provides a broad analysis of opportunities for generation and demand-side investment in the NEM. The ESOO also provides information about demand projections, generation capacities, and NEM supply adequacy for the next 10 years.

level authority in this regard. Rationalising obligations that already exist in the rules may help to further clarify AEMO's responsibilities in demand forecasting, and complements the proposed high level clause.

Given the potential and likely increase in the level of DSP in the market, there are a number of significant immediate and longer term market benefits to improving the accuracy of demand forecasts. These relate to efficient investment, the regulatory process for network determinations and market signals for demand resources for pre-dispatch.

AEMO's demand forecasts are incorporated into a number of its system planning reports, including ESOO (10 year forecast), the MT PASA (two year forecast), and the ST PASA (seven days from the current dispatch). Improving reporting requirements used to make efficient investment decisions should lead to improved asset utilisation (deferring both generation and network investments) as well as system planning.

Improved accuracy in demand forecasts developed by AEMO should also assist the AER in its network determination process.[136] Expected load on a distribution network is used as an input to determine the amount of allowable capital expenditure for network businesses over a five year period. If demand forecasts do not accurately reflect DSP capabilities within a region, the amount of capital expenditure required to meet reliability standards may be overestimated, leading to additional electricity price increases that will impact on consumer bills. Better DSP information could also be useful for the AER in assessing the performance of demand-side incentives schemes.

Forecasting demand is particularly important during pre-dispatch timeframes, as price responsive demand side resources use this information to ascertain the potential value of providing a demand response. Accurate forecasts are required for C&I users to make economic decisions regarding their demand response and plant operation in the event of increased level of non-scheduled demand response.

This issue is particularly important given our draft proposal to introduce a demand response mechanism that pays demand resources via the wholesale electricity market. Should they decide to provide a demand response, economic decisions regarding plant operation levels need to be made. The risks involved in making such decisions are reduced when pre-dispatch price signals closely reflect actual dispatch.

There may be administrative costs to market participants and the AEMO as a result of increased reporting obligations. However, we consider that these additional obligations on retailers and distribution businesses should be minimal, as they are already likely to have the required information on DSP capabilities. The market benefits are likely to outweigh the costs of increased reporting obligations.

136 Given that demand forecasts are used for a variety of reasons, there may be merit in requiring AEMO to develop demand forecasts on a state-wide basis, and also according to distribution areas. The latter is likely to better assist the AER for their network determination processes.

5.6.3 Considerations

We have previously considered the efficacy of AEMO's process for gathering information on the levels of DSP present in the market in both the Climate Change Review (2007), and DSP2 (2009).[137] In the former we recommended that AEMO's ability to forecast reserve shortfalls should be enhanced by strengthening the quality of demand side capability information available to it through improved reporting. In response, AEMO undertook a consultative process to improve its annual DSP survey.

In the DSP2 review we recommended that the current arrangements should be strengthened under the rules to give clarity to AEMO's ability to gather information regarding the level of DSP present in the market, and by requiring AEMO to use such information in a more sophisticated, probabilistic manner to allow for different degrees of "firmness" of DSP. In this regard, we re-assert our initial view that AEMO should endeavour to enhance its survey questions and for the NER to be amended to clarify AEMO's role in demand forecasting. A possible approach would be for AEMO to try to identify the demand elasticity/demand curve of response. Presently AEMO only asks for interruption that would occur in Market Price Cap[138] conditions, which is useful for AEMO in forecasting reliability, but has limited value for the market.

We consider that AEMO's survey on DSP capability should form part of AEMO's regular information gathering practices and could be performed on at least a twice yearly basis. Information gathering on a regular basis should reveal clearer information on the intended use of DSP capabilities against actual use through ex-post review. As this exercise is repeated AEMO should develop a clearer view as to the actual DSP capabilities available in the NEM.

Potentially, AEMO could use the best available information on active and price responsive DSP to improve pricing signals for pre-dispatch timeframes, or to supplement its existing pre-dispatch sensitivity modelling. Improving the accuracy of pre-dispatch price signals is likely to benefit C&I users by allowing them to better estimate the potential value of their demand response at least 24 hours in advance of needing to make operational decisions.

Box 5.3 describes how improved demand forecasting could potentially be used by AEMO to develop a pre-dispatch schedule for non-scheduled demand response.

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137 See AEMC, *Review of Demand-Side Participation in the National Electricity Market,* final report, 27 November 2009, Sydney and AEMC, *Review of Energy Market Frameworks in light of Climate Change Policies*, final report, 30 September 2009

138 The Rules set a maximum spot price, also known as a Market Price Cap, of $12,500 per megawatt hour (MWh). This is the maximum price at which generators can bid into the market and is the price automatically triggered when AEMO directs network service providers to interrupt customer supply in order to keep supply and demand in the system in balance.

Box 5.3 Representing non-scheduled response in pre-dispatch

AEMO's existing information collations of non-scheduled response are used only in longer-term forecasts, such as PASA. These are useful for assessing supply/demand in extreme, peak load conditions, and attempt to represent the response that would emerge during very high spot prices.

There is however no attempt to capture non-scheduled response in the pre-dispatch horizon, up to 40 hours in advance. This is a critical period for generators and demand response, who ready their operations according to pre-dispatch price forecasts. But those prices are in turn derived from AEMO's static demand forecast. There is no attempt to predict the price impact of non-scheduled price response, resulting in inefficient operational decisions by all participants.

One possible solution is for AEMO to introduce an estimate of demand elasticity into the pre-dispatch forecast. In its surveys, AEMO could seek information as to the price at which response is likely to occur. These loads could be represented in pre-dispatch as dummy bids, as if they were scheduled loads.

Questions

15. How should AEMO's powers be expanded to improve demand forecasting? Should retailers and other market participants be obliged to provide information regarding DSP capabilities? Will non-obligatory requirements achieve the desired accuracy in reporting requirements?

16. In what ways can AEMO improve its survey questions regarding DSP capabilities? How often should AEMO be required to update its expectations on DSP capabilities in the NEM?

17. Would a pre-dispatch that includes active and price-responsive DSP improve decision making processes for C&I users and aggregators? If not, do you have any other suggestions for improving the ability for AEMO to accurately forecast demand?

5.7 New category of market participant for non-energy services

Currently third parties wishing to participate in the ancillary services market must register as a Market Customer[139] and meet requirements effectively designed to manage the risks associated with the sale and purchase of electricity from the wholesale market. In addition, only a single financially responsible market participant at a connection point can provide energy and non-energy services. In effect, the provision of "non-energy" services[140] cannot be easily unbundled from the sale and supply of electricity.

A retailer's incentive to provide these services may not always align with the interests of consumers. For instance, the contractual arrangements between a consumer and a retailer may be primarily designed to manage exposure to high electricity spot prices, including provisions for demand reduction by the consumer. The incentive for a retailer to provide competitive ancillary services into the ancillary services market on behalf of the consumer is less clear, which means that the ancillary services market may not be efficiently used.

Further, retailers may be reluctant to arrange for market load to be classified as ancillary services load if the appropriate system to participate is not in place, or the associated demand response may have negative financial implications. Submissions on this noted that third parties, such as aggregators, may wish to provide ancillary services from loads, but are limited from doing so because of the registration provisions of the rules effectively precluding them from doing so unless they become retailers in their own right.[141]

The AEMC held an industry workshop on this issue in April 2012. Presentations and outcomes from the workshop can be found on the power of choice website.

5.7.1 Creating new category of market participant

DRAFT RECOMMENDATION

- **We recommend creating a new category of market participant in the NER that will allow for the unbundling of all non-energy services from the sale and supply of electricity.**

There seems to be no fundamental reason that the provision of ancillary services should be bundled with either the consumption or supply of electricity, as is the case

139 We note that Market Generators can also provide ancillary services.

140 We have defined 'non-energy services' as those services not related to the sale and supply of electricity for the purposes of consumption. Types of non-energy services may include, but are not limited to, the provision of market ancillary services, reactive power, and network control support ancillary services.

141 See AEMC's Power of choice webpage for information sheet on the current arrangements and barriers for third parties providing ancillary services on behalf of load.

under the current rules. This recommendation should result in third parties, such as aggregators, being able to coordinate a consumer's ancillary services independently of that consumer's retailer and the supply of electricity. Entities registered under this category would have the option to present to the market on an aggregated basis within a region.

Although the provision would formally apply to generators, the impact should be purely administrative with incumbent and new generators able to register as both the electricity supplier and ancillary service provider in one application, as would apply to the current situation of registering a generator and classifying it as an ancillary service unit.[142]

Market participants already registered as a market generator or market customer would be exempt from having to register in this category. They would still be required however, to apply to AEMO to have their generation units or load registered as an ancillary service, and meet the technical requirements it sets out.

The rules currently assign AEMO with responsibility for establishing the technical and procedural requirements for registering as an ancillary service unit. We consider that in establishing a new category of market participant these responsibilities should remain with AEMO.

5.7.2 Considerations

For the next stage of the review we will develop greater detail on the proposed new category of market participant which should cover the following issues:

- *Eligibility requirements.* Registration in this category of market participant alone would not permit an entity to sell and purchase electricity from the wholesale market. Financial liabilities incurred by entities registered under this category are likely to be minimal. However, they should be required to demonstrate at least some business capacity similar to that outlined in rule 3.3.1.[143]

- *Metering and procedural requirements*. For ancillary services these are currently determined by AEMO and we would expect it to continue to provide this function under the proposed arrangements

- *Obligations and liabilities.* Clear obligation and liabilities should be specified for each financial responsible market participant associated with a consumer's load, to minimise power system and security risks. The rules should set out clear

142 This would also avoid the impractical situation where coordinated electricity and ancillary service bids would be required within the operating trapezium for scheduled generators.

143 Rule 3.3.1 sets out a threshold for participation in the market including requirements relating to the Corporations Act, Australian residency and so forth.

obligation on each party to notify relevant parties of changes to their availability of service, or any power security issues that may arise.[144]

- *Exemptions for registration.* Already registered market participants should not be required to register in this category if they wish to provide ancillary services. Instead current provisions should continue to apply.
- *Metering and settlement.* Responsibility for this should remain largely unchanged from the current arrangements as ancillary services are already metered and settled separately to the wholesale market.

Interaction with other rule changes and recommendations

Questions remain as to how the arrangements proposed in this draft report could operate in conjunction with the small generator aggregator rule change currently under consideration by the AEMC. In this draft report we are proposing:

1. A new category for market participant for the provision of non-energy services; and
2. Potentially a new sub-category of market generator to accommodate demand resources participating under the proposed demand mechanism.

It is feasible that the small generator aggregator rule change currently in draft rule form could be used to accommodate demand resources participating under the proposed demand mechanism. We are interested in the views of stakeholders on this issue, and the feasibility of this option, noting that any new category of market participant would need to accommodate scheduled and non-scheduled demand resources.

Questions

15. Do you agree that a new category of market participant should be established for the provision of non-energy services?
16. What types of issues should be considered when developing the registration process, such as eligibility, obligations and liabilities?
17. What metering arrangements need to change to implement this mechanism?

144 This issue is imperative under the scenario where, for example, load is interrupted as a demand response but the commensurate changes to bids in the ancillary services market does not occur. Under this scenario it would be expected that the market participant would be responsible for any activities associated with the ancillary services market, even though this scenario arises due to a disruption of energy related services.

6 Efficient and flexible pricing options

Summary

We consider there are a range of issues that currently prevent efficient and flexible pricing from being offered to residential and small business consumers in the NEM. These include both the lack of metering capability and the low level of consumer understanding of the relationship between usage and costs.

Addressing these issues will require a balance between managing consumer impacts and addressing the needs of consumers who could face increased financial difficulties under new pricing structures, and strengthening the arrangements for retailers and distributors to set cost reflective pricing.

The transition to better price signals in the NEM should be done in a gradual phased approach. We propose that this can be achieved through:

a) Focusing only on introducing time varying prices for the network tariff component of consumer bills. Retailers would be free to decide how to include the relevant network tariff into their retail offers; and

b) Segmenting residential and small business consumers into three different consumption bands and applying time varying network tariffs in different ways:

   - For large consumers (band 1), the relevant network tariff component of the retail price must be time varying. This would require these consumers to have a meter that can be read on an interval basis.

   - Medium to large consumers (band 2) with an interval meter would transition to a retail price which includes a time varying network tariff component. These consumers would have the option of a flat network tariff.

   - Small to medium consumers (band 3) would remain on a flat network tariff. These consumers would have the option to select a retail offer which includes a time varying network tariff, if they so choose.

- In addition, for vulnerable consumers, we recommend that:
  - government programs target advice and assistance such consumers to help manage their electricity use. (ie as applied in the South Australian Residential Energy Efficiency Scheme); and
  - governments review their energy concession schemes.
- Better education and information on the impacts of transitioning to more time varying prices.
- Distribution pricing rules are amended so that distributors have sufficient guidance in setting efficient and flexible pricing, and to adequately

recognise consumer impacts.

- Distribution network businesses are required to consult with consumer groups and retailers on their proposed tariff structures.
- Where consumers have an interval meter their wholesale energy costs should be settled using their interval meter data irrespective of their choice of tariff.

6.1 Market conditions for uptake of efficient DSP

Electricity retail prices that accurately reflect network and supply costs are a key component in promoting the uptake of efficient DSP in the electricity market. Such prices disseminate information about the value of reducing or shifting consumption at different times. This helps to encourage behaviour that reduces impacts customers' demands on network and electricity supply infrastructure.

Currently most residential and small business consumers do not face time varying prices for their consumption. As we identified in the directions paper, consumers generally face flat[145] or inclining block tariffs[146], which bears little relationship to the actual time varying impacts they impose on network and electricity supply costs. This chapter considers the improvements that can be made to market and regulatory arrangements to better facilitate cost reflective pricing for residential consumers.

Improving the degree to which the costs of supplying and delivering electricity are communicated to consumers will also allow them to participate more effectively in the NEM through better managing their electricity bills and contributing to lowering the costs of electricity supply over time.

What is meant by cost reflective prices?

As we set out in the directions paper, cost reflective prices are those which signal the costs of supplying and transporting electricity at different times of the day and/or year to consumers in different locations. Retail prices developed on a cost reflective basis will tend to vary by time of day and possibly by geographical location.

A retail tariff reflecting these characteristics would include the following key components:[147]

- A variable component that recovers efficient wholesale energy costs. Wholesale costs refer to the costs retailers incur when acquiring electricity in the wholesale

145 A flat tariff is a tariff structure which has no time element incorporated and could include a block structure.

146 Inclining block tariffs see the marginal price for a unit of electricity increasing as a certain consumption threshold during a particular period is crossed. They are not based on time of day or the time of year.

147 Price Waterhouse Coopers, *Investigation of the efficient operation of Price Signals in the NEM*, Report prepared for the Australian Energy Market Commission, December 2011, page 16.

market to supply the needs of their customers. Wholesale spot prices vary every five minutes but are averaged on a half hourly basis for settlement purposes. Most retailers hedge their wholesale spot purchases with derivative contracts and/or through their own generation capacity.

- A variable component that varies by both time and location to recover transmission and distribution network costs in a manner that signals the cost of future augmentations to meet peak demand in different parts of the network. Network costs vary much less than wholesale costs, as network costs are primarily driven by system peak demands occurring only a few times a year.

- A fixed dollar component that recovers fixed network and retail costs and does not vary by time.

In practice there are limitations on achieving complete cost reflectivity for consumers, even with interval metering technology in place. This is due to the difficulty of designing associated tariffs, the transactions costs involved and need to develop prices that consumers understand and accept. These reasons are greater for the residential sector than for commercial and industrial consumers. For example, full half hourly pass through of the wholesale price is unlikely to be viable or desirable for most residential consumers; and designing network tariffs for every consumer that reflect the true locational variation of network costs would be far too complex. Network and retail prices will inevitably reflect a balance between the need for efficient signalling of costs and more practical considerations.[148]

For this reason when we refer to cost reflective prices in the context of this review we do not mean prices that are perfectly cost reflective from a theoretical stand point, but rather are likely to provide a more efficient price signal to consumers compared with those that currently exist. This may involve prices varying by both time and location.

There is a wide range of tariff options, either currently available or in their trial stages, that provide varying degrees of cost reflectivity above existing flat tariffs. These include time of use (TOU) and variations of TOU such as seasonal TOU, full wholesale price pass through (real time pricing or RTP); critical peak pricing (CPP); variable peak pricing (VPP), peak time rebates/incentives and new forms of network charges that attempt to capture the cost of peak demand (such as capacity based charging).

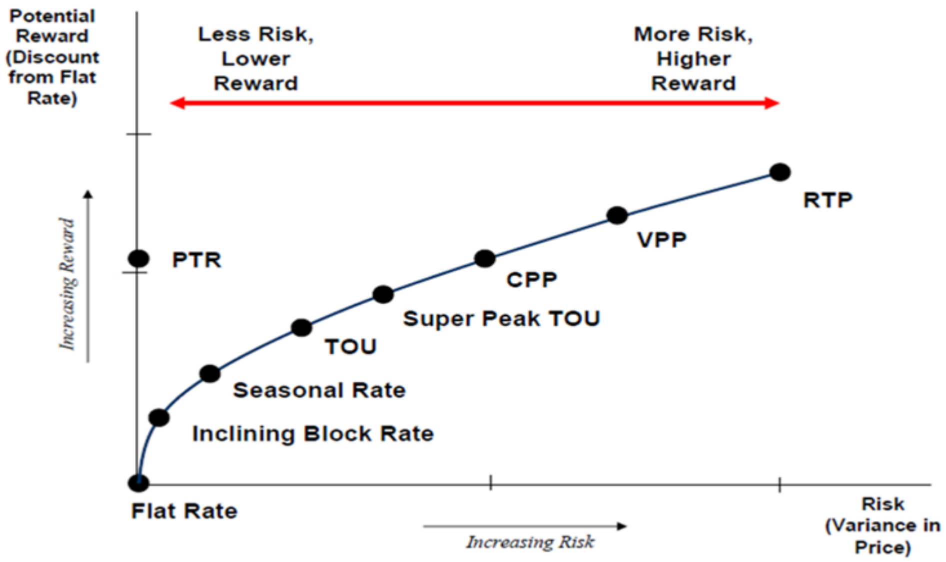
These rates can also be mixed and matched in various ways. For example a basic TOU structure could be matched with a CPP of some form. Some options can be applied to residential and small business consumers, while others may be more appropriately applied to large industrial facilities given their business operations. At the core of all these options is a price that varies over time to capture the impact of consumption on the costs of electricity supply at different times.[149]

148 There is a supporting factsheet on the AEMC website that explains the different components of the electricity price.

149 Appendix B describes some of the key time varying pricing options.

We describe these options in detail in Appendix B, and illustrate in Figure 6.1 below that they imply different levels of risk versus reward for consumers.

Figure 6.1 Types of tariffs for cost reflective pricing[150]



It is important to recognise that time varying prices are not a new concept. In fact, this approach to pricing is already used in many other industries. Airlines, hotels, and car rental companies are some of the most common examples of industries that dynamically vary prices in response to fluctuations in demand. We recognise that the supply of electricity is an essential service and the introduction of more cost reflective prices should not undermine the ability of consumers to access an affordable, reliable supply of electricity.

Why introduce time varying prices?

A rationale for implementing cost reflective pricing is that by exposing consumers to the costs they impose on network and generation, they can respond in ways to reduce these costs over time. This in turn will reduce energy bills for all consumers in the long run.

We recognise that prices are only one factor influencing consumers' decisions on when and how much to consume. Other factors that affect consumer behaviour, such as convenience, awareness and understanding, also have a role in influencing how consumers respond to prices. Evidence suggests, however, that prices play a key role.

Work we commissioned from Futura Consulting for the directions paper demonstrates the potential for more cost reflective prices to drive reductions in network costs over time.[151] Its survey of domestic and international trials showed that where consumers

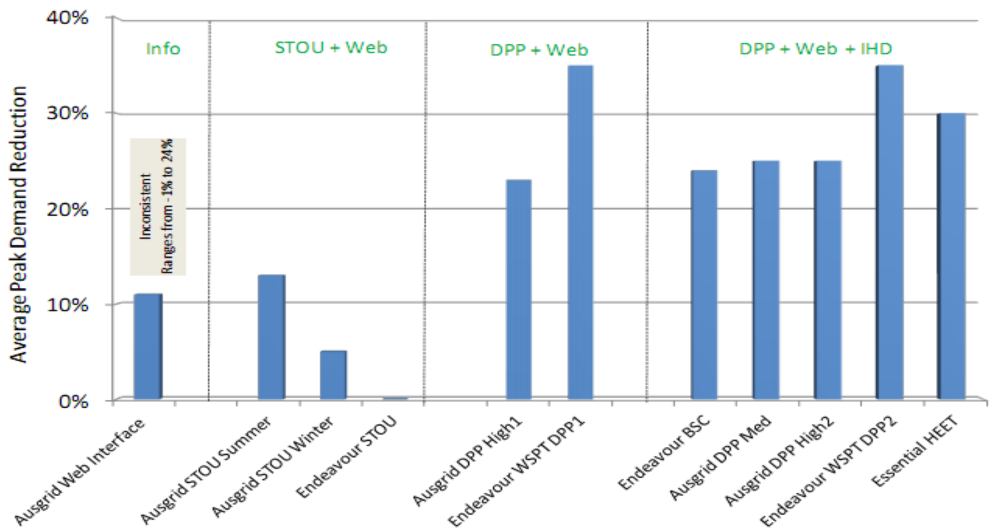
150 Source: The Brattle Group, *Shaping our Energy Future through Dynamic Pricing*, Ahmad Faruqui, PhD, 21 August 2012

151 See Futura Consulting, *Investigation of existing and plausible future demand side participation in the electricity market,* Final report for the Australian Energy Market Commission, 16 December 2011

are exposed to time varying prices, peak demand reductions of up to 30 or 40 per cent could be achieved.[152] This indicates that expanding the scope of cost reflective pricing in the NEM could drive significant longer term reductions in system costs, which would benefit all consumers in the form of lower electricity prices than would otherwise have been.

Figure 6.2 shows a summary of peak demand reduction results of seasonal time of use (STOU) and dynamic peak pricing (CPP in this case) trials recently conducted by Ausgrid, Endeavour and Essential Energy. It shows that potential impact on peak demand of applying more time varying tariffs in the NEM. It also shows that the impact can be greater where the tariffs are supported through better communication channels (for example, webpages or in home displays (IHDs).

Figure 6.2 Summary of peak demand reduction results from DSP trials in Australia[153]



Box 7.1 is a case study of SPAusNet's distribution network CPP for C&I users in Victoria. The case study shows that CPP results in an estimated 88MW system wide peak load reduction on their distribution network.

Time varying prices improve the economic attractiveness of certain types of distributed resources such as rooftop solar with energy storage, which allow owners to avoid consuming electricity during higher priced peak hours.

Time varying prices may also be a way to encourage more efficient charging of electric vehicles. In the AEMC's Electric Vehicles and Natural Gas Vehicles Review, we found that if users of these vehicles users didn't face appropriate signals to charge their vehicles at off-peak times, significant costs as a result of extra network and generation supply would be added to all consumer bills.

152 Ibid, page 24

153 Source: Futura Consulting, *Investigation of existing and plausible future demand side participation in the electricity market*, pp. 88, December 2011

Box 7.1 Case study: SP AusNet Distribution network critical peak tariff

In 2011 SP AusNet replaced its anytime demand tariff with a critical peak demand tariff. The voluntary new tariff applied to C&I users on its distribution network in Victoria who consumed above 160MWh per year. Roughly 1,800 consumers elected to move to the new critical peak tariff.

The tariff's purpose is to reduce peak demand on the electricity network, thereby reducing the costs of investment needed to guarantee supply during periods of high demand. The tariff also provides C&I users with the opportunity to minimise peak period electricity use, and to more flexibly choose ways to reduce electricity costs.

It comprises four different components, one of which is a **variable demand charge**. The demand charge is based on the average of a consumer's maximum kVA recorded on the five nominated peak demand weekdays during a **defined critical peak demand period. This** is defined as:

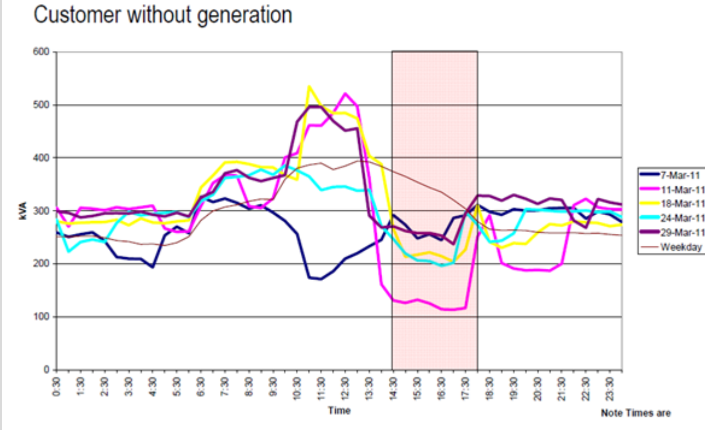
- Summer days that are nominated and communicated to consumers at least one day in advance. SP AusNet uses both SMS and email to notify its consumers of the intended critical peak period.
- The period is only ever between 2pm – 6pm on the nominated day.
- The five maximums are averaged and used as the basis for the demand charge for the next 12 months.

For the summer period of 2011/12 SP AusNet declared critical peak demand periods from mid-February through to the end of March 2012.

SP AusNet's analysis of the first year of the program's implementation revealed a marked response to the critical peak tariff. Of the 1,800 C&I users on the tariff, the following demand reductions were observed:

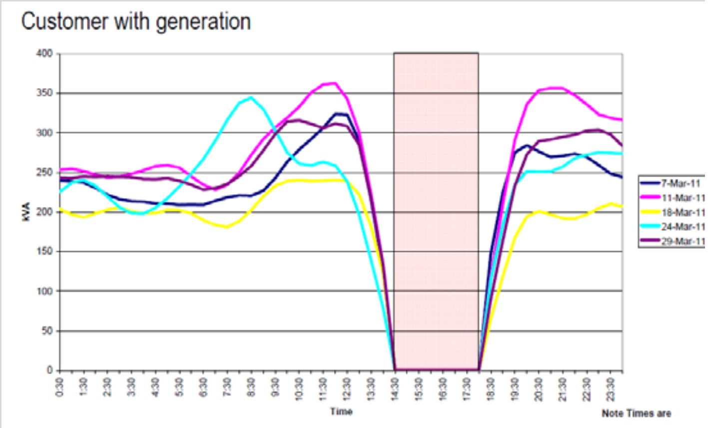
- Two thirds of all consumers responded by reducing demand; and
- Over 300 reduced peak demand by more than 50 per cent. Of these, 75 reduced peak demand by more than 90 per cent.

SP AusNet estimated an 88MW system wide peak load reduction was achieved on its distribution network. However, SP AusNet cautioned that the 2011 Victorian summer was mild so care must be taken before inferring that all the observed reduction was due just to the new tariff.



Source: SP AusNet (Futura report)

In addition to the observed peak demand reductions, SP AusNet also observed that the tariff had created considerable activity in the market from retailers and third parties who recognised the commercial opportunities in offering products and services to assist consumer in maximising cost savings under the new tariff.



Source: SP AusNet (Futura report)
See: Futura Consulting, Draft report for the Australian Energy Market Commission, 8 December 2011. Available on the AEMC's Power of choice webpage; SP AusNet website, and SP AusNet presentation to AEMC Power of choice public forum held on 19 April 2012.

While achieving longer term reductions in system costs is one reason to transition to more cost reflective pricing, another is to provide consumers with the information and tools necessary to realise more immediate gains on an individual basis.

Under existing retail pricing, the share of network and wholesale costs for each consumer is determined on the basis of an average consumption profile applied to all consumers (due to the lack of interval meters individual half hourly consumption profiles are not available). This means that consumers wishing to reduce their energy bill by adjusting their consumption pattern will not realise the full benefits of doing so; rather these benefits are shared with all consumers. Interval meter data combined with better price signals will increase consumers' awareness of their own consumption patterns and better link costs to cause. This in turn will allow consumers to make more informed choices with respect to implementing measures and strategies to help reduce their energy bills.

Time varying prices will impose two types of direct costs on consumers. The first is the incremental metering costs associated with upgrading a consumer's own meter to support time varying pricing. We discuss this potential cost in Chapter 4. The second cost might be the loss in value from having to change consumption patterns, for example, either by reducing consumption during a high price period or shifting consumption to a lower cost period.

There has been a range of empirical work undertaken on estimating the potential benefits of residential consumers moving to time varying pricing. Analysis by Ausgrid of 32,000 household electricity accounts that are already on time-of-use billing found families were saving on average $64 a year compared to standard flat pricing, with 69 per cent of consumers better off under time varying pricing. They also found that on average families were using 78 per cent of power outside peak times.[154]

In another study, AGL found that over 37 per cent of consumers would be significantly better off under time varying prices, and approximately 31 per cent would be overall worse off, while the remainder would be indifferent.[155] This however, assumes no change in the consumer's consumption patterns. One of the key findings of time varying pricing pilots both in Australia and elsewhere around the world is that most consumers do adjust their consumption patterns when exposed to higher prices, and achieve significant benefits in doing so.[156]

Time varying pricing also has an important role to play in signalling the value of demand side management opportunities across the supply chain. However there are transactions costs in realising the benefits that mean while time varying prices are necessary, they are not a sufficient condition on their own to facilitate efficient DSP.

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154 See Energy Australia, *Network Pricing proposal (Revised)*, May 2009, p 10

155 Paul Simshauser and Downer, D., *Limited form dynamic pricing: applying shock therapy to peak demand growth*, p 14

156 Future Consulting report in Note 145, and see also Ahmad Faruqui and Sanem Sergici, *Household response to Dynamic pricing of electricity – A survey of the experimental evidence*, January 10, 2009

They may need to be supplemented with additional arrangements to capture the full benefits of DSP.

Are time varying prices necessary for DSP?

An issue to consider is whether the benefits of cost reflective pricing could be delivered through other means. A number of alternatives have been put forward.

Currently some retailers have implemented inclining block tariffs for consumers on accumulation meters. Such tariffs provide some signalling by increasing the level of the charge once a particular consumption threshold has been reached. But they do not reflect the actual costs consumers are imposing on the network and are unlikely to be effective.

When consumers face such tariffs, they have an incentive to reduce consumption at times convenient to them. This is not during very hot critical peak weather events – the events that drive additional network investment. On the contrary, inclining block tariffs may lead to deterioration in the system load profile by reducing the share of demand in non-peak times. Another issue with inclining block tariffs is that it's difficult for consumers to actually monitor their consumption levels against the consumption bands and be able to identify the consumption point where the inclining block tariff increases.

During this review, some stakeholders have advocated the merits of non-price based DSP options (e.g., direct load control) as a cheaper, more effective alternative, given that such options could avoid the costs of installing meters for residential consumers. Under these DSP options, consumers would agree to alter their electricity use under certain defined circumstances in return for an explicit monetary reward.

We recognise the effectiveness of these types of DSP options and consider that the market must offer and capture the full value of all forms of DSP. However, such forms of DSP do not obviate the need for cost reflective pricing. There is an important interaction between the availability of time varying prices and these non-tariff based DSP options. The size of the reward necessary to get the consumer to participate in these non-tariff DSP options is dependent upon the consumer's retail tariff. If consumers are on a flat tariff, the business would need to offer a larger reward to compensate them for alternating their consumption patterns. In addition, in the absence of interval metering consumers who participate in these non-tariff DSP options can only capture the reward offered by the counter-party. For example, if the direct load control is offered by the network business, then consumers will be unable to capture the wholesale market value of their decisions to change consumption.

Two additional approaches were also considered:

- Introducing a range of net system load profiles (NSLP) for non-interval meter residential consumers; and
- A more limited implementation of cost reflective network tariff set at points within the distribution system (ie at the sub-station level).

The first approach seeks to segment the current net settlement system load profile, on which retailers of accumulation metered consumers are settled, into a number of different load profiles that better capture the impacts of different groups of consumers. This approach was used in the UK in the mid-1990s. The South Australian Council of Social Services (SACOSS) submitted a proposal recommending the creation of a separate load profile for residents of public housing.[157]

We have published a paper from Oakley Greenwood which assessed the viability of this option.[158] We concluded that segmenting the NSLP into different load profiles based on the characteristics of difference consumers would add significant complexity to settlement in the NEM.

The second approach is based on a more limited application of time varying pricing. There would be a meter and an associated time varying network tariff set at substation connection points. The time varying charge would be applied to all retailers downstream of that substation point. These retailers who would then have the option of passing it through to their consumers whom would not necessarily have interval meters.

Under this approach retailers, in principle, would have an incentive to encourage consumers to install interval meters so the retailers could better manage the risk of being exposed to a time varying network charge.

This is an approach which has been applied in New Zealand where Orion has introduced demand based charging at an aggregated level and we consulted in the directions paper on the merits of such an approach.

Stakeholders doubted the effectiveness of such an approach in Australia. Ausgrid commented that this approach is more suitable to markets where the problem is system wide coincident demand not locational network peak demand growth and noted that in New Zealand 30 per cent of consumer bills are transmission costs. While the MEU agreed that network tariff should be more related to demand than consumption, it stated that using averaging at the aggregated level will still prevent the benefits of DSP being garnered by those providing the DSP.

The problem with both of these approaches is that they do not reward individual behaviour and hence there is no extra incentive on the individual consumer to improve its load profile. The main benefit in adopting such alternative approaches is that it could result in more equitable distribution of costs – which in turn may drive the consumer to want to install an interval meter. We consider that the full benefits of DSP are unlikely to be achieved without deployment of interval meters and cost reflective pricing for consumers.

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157 See South Australian Council of Social Services, directions paper submission, p 3

158 See Oakley Greenwood, *The potential for a revised approach to profiling to encourage greater levels of DSP among non-interval read residential consumers*, August 2012

6.2 Issues identified

There are a number of issues that are contributing to the current lack of time varying pricing in the market for residential consumers. There are two core themes: a lack of consumer engagement with time varying pricing and weak incentives for retailers and network businesses to install the necessary meters and implement such pricing arrangements. We briefly discuss these issues below before we set out our recommendations to address them.

The arrangements for metering investment and pricing need to be complementary and implemented together. We envisage that service providers will want to offer consumers a time varying package which include both upgrading their meter and introducing an appropriate time varying tariff. Our recommendations for supporting investment in better metering technology are set out in Chapter four.

Time varying pricing will expose consumers to a range of new and potentially complex tariff structures. Retailers may be reluctant to implement interval meters or time varying pricing if there is a lack of interest or acceptance for them to do so. Eliciting consumer engagement is a critical aspect of realising the benefits of cost reflective pricing and this will depend on how the transition is managed.

In this regard it is important to note that not all consumers will benefit from time varying pricing. Those who consume most of their energy at peak times and are unable to adjust their consumption patterns may be worse off. For some consumers on low incomes this could lead to financial distress, affecting their ability to pay their electricity bills. We consider that unless the needs of these consumers are specifically addressed, it is unlikely that such pricing changes will attract broad public acceptance.

Also important is the extent to which retailers and network businesses themselves have an incentive to implement time varying pricing. A lack of metering capability may not be the only factor. It will also depend upon the extent to which time varying pricing impacts profits and/or costs for retailers and network businesses; as well as the extent to which it creates new risks that will need to be managed. Hence an important factor will be how network businesses and retailers perceive time varying pricing affecting their profits. There may also be jurisdictional provisions that will influence how time varying prices are offered to residential consumers.

To address these issues we consider an integrated strategy is required that strengthens incentives for retailers and network businesses to implement time varying pricing, while at the same time garnering sufficient consumer confidence in the process. The approach we are recommending comprises the following key components:

1. Arrangements that support investment in metering technology.
2. Building consumer confidence and engagement, by:
   (a) educating and informing consumers;
   (b) addressing the needs of vulnerable consumers; and

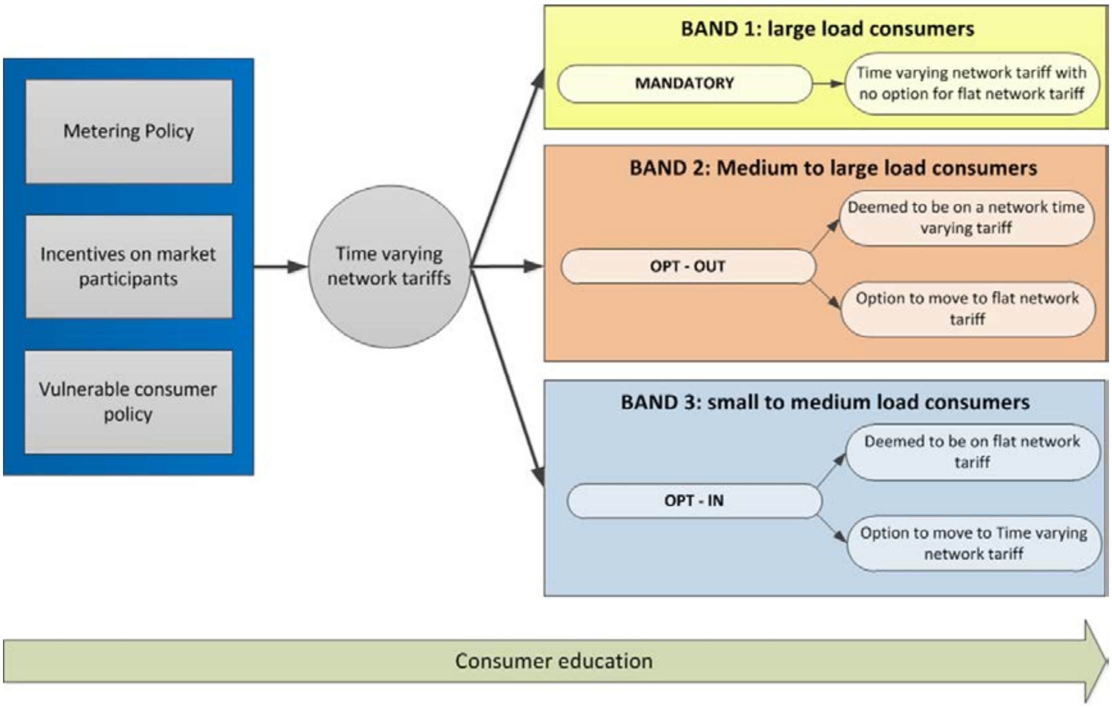
(c) phasing in network time varying prices in a way that manages consumer impacts (we propose a gradual process beginning with large consumers).

3. Reviewing the rules so that network businesses have the appropriate obligations and flexibility to implement time varying prices.

4. Clarifying the wholesale settlement arrangements for consumers who have meters with interval read capability.

We set out our proposed approach diagrammatically below. Detail on phasing in network time varying prices in discussed from section 6.3.5 onwards.

Figure 6.3 Proposed strategy for implementing cost reflective pricing



While over the short term, exposure to time varying pricing will impact consumers in different ways, over the longer term more cost reflective pricing should lower energy bills for all consumers due to lower system costs. Hence it is important that the arrangements for managing bill changes (the first round effects) do not undermine the ability to capture the benefits of better asset utilisation and lower system costs (second round effects).

We also note that the SCER Smart Meter, Consumer Protection and Safety program is considering a range of issues associated with services, including price based DSP products enabled by smart metering technology. It is also considering how NECF arrangements might apply under such services. On this basis, we have not attempted to address all of the issues associated with the introduction of these types of services.

6.3 Considerations

6.3.1 Impacts of time varying prices on consumers

Understanding the impacts of moving towards more cost reflective pricing for small consumers is necessary so that such pricing options are implemented in a manner that provides both:

- an opportunity for the individual consumer to understand and respond to those impacts; and
- protections for those consumers who have difficulty in managing such impacts and which affects the consumer's financial ability to pay their electricity bills.

How the current retail prices allocate system costs across consumers, and the extent to which introducing cost reflective pricing changes that allocation, will be a key factor behind consumer impacts.

For the vast majority of residential and small business consumers, energy and network costs are spread equally across all consumers, resulting in each consumer paying an average share of total costs. This is because for most residential consumers their energy costs are calculated in accordance with an average system load profile, and not the individual consumer's consumption pattern.[159] Also, distribution network businesses tend to set the same network price for all residential consumers in their supply areas. Overall, this results in cross-subsidisation across residential consumers, with those who have a relatively flat consumption pattern contributing to the costs of serving those with peaky load profiles.

Facilitating the installation of better metering technology and moving to more cost reflective pricing will reduce this averaging effect. It will enable prices to be based upon a consumer's individual consumption pattern. Therefore, consumers who use more electricity in the peak hours than the average consumer would see higher bills, while consumers who use less electricity in the peak hours than the average consumer would see lower bills.

While this reflects a more appropriate allocation of system costs, some consumers will face a level of 'price shock' as their overall bills increase. There will be a need for an education strategy to help such consumers understand these impacts and let them assess whether, and how, they can change their behaviour.

In addition to developing a clear and effective educational message that resonates with consumers, there are other ways to help them understand and benefit from time varying prices. One is to provide temporary bill protection, meaning that a consumer's bill on a time varying tariff could be no higher than it would have been otherwise under the applicable tariff. This would give consumers a chance to become familiar

[159] This is due to such consumers not having meters which record consumption on an interval basis.

with the tariff and experiment with approaches to energy conservation and load shifting before being exposed to the risk of a bill increase.

We have published a paper from The Brattle Group which describes such bill protection pricing products.

Overall, the impact on an individual consumer's energy bill of moving from a flat tariff to a time varying tariff will depend upon:

- the consumer's load profile pattern relative to the average net system load profile used in settlement;
- any resulting change in consumption which in turn, depends on the ability of the consumer to shift or reduce consumption (which is referred to as level of discretionary consumption);
- the design of the new pricing structure relative to existing tariffs; and
- the energy efficiency of the household.

To assist consumer understanding of the impacts, we commissioned Frontier Economics to develop a user friendly model that assesses the impact of alternate tariff structures and consumption patterns on consumer bills.[160] The model is available on the AEMC's website and allows stakeholders to assess how time varying pricing options could be implemented and how these might affect bills.

Even where consumers are not subject to time varying prices, their bills could also be affected by the adoption of time varying tariffs by other small consumers. This is because a greater penetration of time varying pricing will change the current distribution of system costs across the residential consumer base and therefore will impact all consumers. There are three impacts to consider in transitioning to cost reflective pricing:

- Even under voluntary arrangements those that remain on the regulated flat retail tariff may over time see higher bills. These tariffs are currently determined on the basis of the NSLP. Those consumers who voluntarily seek out time varying prices will likely be those with the better load profiles (as they have most to gain) while those with peakier profiles are likely to remain on the regulated flat retail tariff. Hence, the cost of serving these remaining consumers will likely rise, placing upward pricing pressure on the regulated flat retail tariff.
- The above effect may be reinforced because the administrative costs associated with accumulation meters (i.e., manual meter reading) will be spread over a smaller number of consumers who remain on accumulation meters. Therefore the cost per consumer will be higher.

160 See Frontier Economics, *Retail Tariff Model, A report prepared for the AEMC*, September 2012, available on the AEMC's Power of choice webpage.

- Network businesses and retailers may lose revenue from consumers who respond to higher prices by reducing their consumption. To avoid this they may try to recover such revenues from those consumers who remain on flat tariffs (because they may be less likely to respond by adjusting their consumption).

The extent of such impacts will depend on the number of consumers subject to time varying prices and how time varying prices are calculated. In the long term, cost reflective pricing could lead to lower system costs and hence lower bills for consumers.

6.3.2 Building consumer confidence through education

DRAFT RECOMMENDATION

- **We recommend that governments and industry work together to educate consumers and provide them with the information they need to understand both the system wide benefits and potential individual gains from time varying tariffs.**

Understanding of the likely impacts is important to develop consumer confidence towards changing the way electricity is priced. Some consumers may equate time varying prices with higher price volatility, or simply equate it with higher bills. Any transition to more cost reflective pricing needs to be supported with an intensive education and information campaign. This will help consumers to understand the benefits and opportunities of such pricing.

Additionally, consumers could be provided with enhanced information about their energy use and potential to shift peak load, whether through a detailed bill insert, a web portal, or by some other means. This information would advance their understanding of their energy consumption patterns and help them identify ways to reduce their energy bills. The recommendations set out in Chapter two will support these developments.

As noted, some retailers and distributors (notably, Origin and Jemena) are already providing information on their websites about time varying pricing. However, engendering broad consumer confidence will require governments and industry working together to educate and provide the information necessary to help consumers understand both the system wide benefits and potential individual gains from cost reflective pricing.

6.3.3 Managing the impacts on vulnerable consumers

DRAFT RECOMMENDATION

To manage the impacts on vulnerable consumers we recommend that:

- **Arrangements are put in place for consumers, which may a limited capacity to respond, to remain on a retail tariff which has a flat network component, and would have the option to choose a time varying tariff.**

- **Government programs target advice and assistance to these consumers to help manage their consumption.**

- **Governments review their energy concession schemes so that they are appropriately targeted.**

Not all consumers may have the ability to manage and respond to time varying pricing by adjusting their consumption levels. This could lead to significant financial stress for these consumers, affecting their ability to pay their energy bills. We recognise that such consumers might be at risk from suffering increased hardship under a move towards cost reflective pricing.[161] Consumers who may be in this situation include those at home during the day, such as the elderly, those with chronic medical conditions, shift workers, the unemployed and parents with young children.

Concern over the impact of time varying pricing on these types of consumers was a theme in submissions from consumer groups to the directions paper. The Consumer Action Law Centre did not support time varying pricing for this reason. On the other hand, the SACOSS observed that many public housing tenants did not have scope for installing air conditioning and so were likely to have relatively flat load profiles and would benefit from time varying pricing.[162]

This outcome is reflected in trials in international markets and demonstrates that many low income consumers could in fact benefit from time varying pricing given their consumption patterns. However this will not apply to all low income consumers, as some could have quite peaky profiles.

There are currently two sets of arrangements to assist certain types of consumers to manage their energy bills. These are government energy concession payments and hardship provisions in the NECF.

Some sections of the community currently qualify for government support towards meeting their energy bills. This income support takes the form of community services obligations (CSOs) and Appendix C provides details on the design of these schemes

161 Consumer Action Law Centre, directions paper submission, p. 9.

162 South Australian Council of Social Services, directions paper submission, pp. 1-2

and eligibility criteria. It is important that any move to more cost reflective pricing does not dilute the impact of current government support for such consumers.

The eligibility criteria for such schemes provide a basis for considering the types of consumers who could be vulnerable to time varying pricing. However not all consumers who qualify for income support will be worse off under time varying pricing because, as explained above, the impact depends upon the consumer load profile pattern relative to the average system load profile.

In addition, there will be other categories of consumers who do not qualify for such schemes but for whom cost reflective pricing may lead to a significant deterioration in their ability to pay their bills. For example, the eligibility criteria will not capture those low to medium income households (approximately $40,000 - $80,000) who face a bill increase (due to their load profile) and have difficulty paying for this.

We note, however, that the NECF hardship provisions could apply to these consumers. Key aspects of this framework include the requirement by retailers to implement hardship policies for consumers and for the AER to develop specific hardship indicators.

6.3.4 Strategy for vulnerable consumers

How to implement an appropriate transition to cost reflective pricing, which includes managing the potential impacts on all sectors of the community, are central considerations in this review. The lack of a comprehensive strategy to deal with such impacts, especially for vulnerable sections of the community, is seen as a barrier to community acceptance for more cost reflective pricing.

We recommend the following series of measures to help manage the impacts on these consumers:

- Implementing network time varying prices in a gradual phased process that focusses on large residential and small business consumers. This means that most, if not all consumers who may not have the ability to respond to time varying tariff will have the ability to choose of a flat retail tariff;

- Government programs target advice and assistance to vulnerable consumers to provide a mechanism for them improve their consumption patterns, and hence make them less affected by time varying tariffs. The South Australian REES has as an explicit focus on low income households.

- Access to appropriate education and information on the impacts of time varying pricing.

We also advise that state governments could review the structure of their energy concession schemes in light of the move to time varying pricing. There appears to be scope to improve targeting and to improve flexibility in the payments. In particular, energy rebates tend not to take account of household size and composition (or overall consumption). A low income person may receive the same energy rebate regardless of whether he or she was single with no dependents, or formed part of a larger family cohort. Energy rebates may need to be reviewed to ensure they are appropriately targeted and provide a sufficient quantum of financial support in a changing energy market environment for certain types of consumers.

Also we note that while the existing energy concession schemes and the NECF provide a useful basis to identify the types of consumers who may face financial difficulties under the impacts of cost reflective pricing, there is scope for better reporting and identification measures. This would help to develop better targeted, cost-effective policies in the long term. Also we suggest that the NECF hardship indicators are extended to include how hardship consumers are managing the transition to time varying pricing.

Consumers who don't move to time varying pricing may also be affected. A greater penetration of time varying tariffs by customers currently settled on the net system load profile will change the current allocation of system costs across the residential consumer base and therefore will impact on all consumers. The impact on flat tariff consumers will depend on:

- In the short term – whether customers exiting the net system load profile and adopting time varying tariffs have peakier or flatter load profiles than the average:
  - If peakier, remaining customers will be better off on average
  - If flatter (as would be expected), remaining customers will be worse off on average

- In the long term – whether customers facing time varying tariffs reduce their peak consumption by enough to reduce system costs sufficiently to offset the higher bills that may be payable by those remaining on flat tariffs.

There is another possible arrangement that could provide some protection for certain types of consumers in this situation. As noted below, SACOSS submitted a proposal to the directions paper that recommended the creation of a separate load profile for residents of public housing.

The rationale for this is that these consumers tend to have a flatter load profile as they have less capacity to generate cooling demand than the average household. This is due to these dwellings having smaller than average floor areas, lower penetration of air-conditioning and small air conditioners when they do have them. SACOSS considers that if South Australian public housing consumers are settled on their own load profile and not the net system load profile, they could benefit from electricity bill savings of 10 to 20 per cent. This proposal in discussed in the Oakley Greenwood paper.

6.3.5 Phasing in time varying pricing

DRAFT RECOMMENDATION

The transition to better price signals in the NEM should be done in a gradual phased approach. We propose that this can be achieved through:

- **Focusing only on introducing time varying prices for the network tariff component of consumer bills. Retailers would be free to decide how to include the relevant network tariff into their retail offers; and**
- **Segmenting residential and small business consumers into three different consumption bands and applying time varying network tariffs in different ways. This would work as:**
  - **For large consumers (band 1), the relevant network tariff component of the retail price must be time varying. This would require these consumers to have a meter that can be read on an interval basis.**
  - **Medium to large consumers (band 2) with an interval meter would transition to a retail price which includes a time varying network tariff component. These consumers would have the option of a flat network tariff.**
  - **Small to medium consumers (band 3) would remain on a flat network tariff. These consumers would have the option to select a retail offer which includes a time varying network tariff, if they so choose.**

Time varying pricing can generally be offered in three different ways. The first is “opt-in” deployment, in which consumers would have to proactively select to leave their current flat retail tariff and sign up for the new time varying network tariff. The second method of deployment is “opt-out” recruitment. Consumers would automatically be enrolled in the new time varying network tariff, but would have the option not to accept the new tariff and thus revert to a flat tariff. The third option is mandatory deployment, in which consumers are given only one rate choice and that is the new time varying network tariff.

Moving the market to cost reflective pricing will mean that the majority of residential consumers will for the first time be exposed to a new way of pricing electricity. As we discuss above, this will require a process of adjustment and adaptation. Forcing consumers onto time varying pricing immediately with insufficient opportunity for learning or adjustment may create consumer confusion and resistance.

It is therefore essential for any transition to cost reflective pricing to happen in an orderly and coordinated way. Consumers will need to be well informed of the impacts of time varying prices and have the appropriate knowledge and tools in place so that they can effectively manage the impacts. It will take time to build this knowledge in the residential and small businesses consumer base, and for community confidence to transition to cost reflective pricing to grow.

For this reason we propose that a mix of the above approaches is used to introduce cost reflective pricing. Each different approach is predicated on the level of consumption of residential and small business consumers.

Our draft recommendations are solely focused on introducing more cost reflective pricing through the network component to consumer bills. We consider that in a competitive market, the retailer should have the choice to decide how to recover their efficient costs of supply from consumers and will offer products that reflect consumers' preferences. Where competition is not effective, state legislation provides arrangements for retail price regulation. Hence where we make recommendation regarding time varying network tariffs, the retailer will have the option to either package that time varying network tariff up into a flat retail offer or decide to pass through that network tariff to the consumer.

Therefore, we are not making any recommendations regarding the structure of retail pricing offers. We envisage that where the network business offers the choice of time varying tariff or a flat tariff for a class of consumer, retailers will reflect that choice in its range of pricing options.

Our approach begins with segmenting residential and small business consumers into three bands of consumptions for the purpose of applying time varying prices. The three consumption bands for residential and small business consumers are as follows:

- **Band 1:** Large consumers above a defined consumption threshold (the same threshold as raised in the Chapter four regarding meter installations);
- **Band 2:** Medium to large consumers that range between a lower and upper defined consumption threshold;
- **Band 3:** Small to medium consumers that fall below the lower consumption threshold for medium to large consumers.

This approach to applying time varying network prices for the most part only applies to consumers that have an interval capability meter in place, and not the general residential and small business consumer base. It complements our recommendations for requiring the installation of meters in defined situations as set out in Chapter four.

We have not defined the thresholds for each of the consumption bands and note that the thresholds could vary by jurisdiction and change over time. For large consumers (band 1) we consider that the consumption threshold should be substantially above the average consumption, and at a level that captures those consumers with multiple heavy load appliances such as electric vehicles, or large air-conditioning systems.

The transition to time varying prices should focus on large residential and small business consumers. The reason for this is two-fold. First, while larger consumers are not necessarily peakier than lower consumption consumers their higher consumption volume means any adjustments they make at the margin will have a greater incremental impact on system costs. Second, consumers on lower incomes, and other consumer groups who may not have the ability to respond to time varying prices, are likely to be below the defined threshold for large consumers and they can avoid time varying prices.

This approach would require interval meters to be installed at the premises of consumers above the defined threshold (as per our metering policy recommendations in Chapter four).

We recommend that consumers above this threshold are required to be charged a price which includes a time varying network tariff. This does not necessarily mean that these consumers will be required to face a time varying retail tariff, as retailers may decide to package the time varying network tariff into a flat retail rate, which may include an appropriate risk premium. Competition in the retail sector will promote consumer choice in this regard. It may also mean that such consumers may not be able to access the regulated standing offer, if that is expressed as a flat retail tariff.

This recommendation is a limited form of mandatory deployment of time varying prices at the network level. It will provide large users with a better signal of the costs of electricity supply involved in meeting their consumption requirements.

We note that there are likely to be consumers below this threshold who have meters with interval reading capability or will have such metering technology installed over time. Some of these consumers will already be on time varying rates (i.e. simple time of use tariffs). We have also considered the appropriate pricing arrangements for these consumers.

For all other consumers below the band 1 threshold, we consider that an alternative approach should be adopted that gives these consumers the option of time varying prices.[163] We recommend medium to large consumers with interval meters should have a time varying network tariff as the default option but have the choice to opt-out to a flat retail tariff (based on a flat network tariff) if they so prefer. A retailer would have the right to a flat network tariff if their consumer opts out to the flat retail tariff.

We consider that this approach for medium to large consumers will ultimately result in a more effective adoption of time varying pricing in the longer term.

It has been found that the deployment plan for a specific rate has a significant effect on its ultimate adoption. As a result, consumer participation rates can vary widely. Evidence from international experience with time varying pricing is that participation in an opt-out approach could be as high as 80 per cent of the eligible population, while participation in an opt-in approach might be closer to 20 per cent.[164]

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163 We note that there are likely to be consumers below the large consumer threshold (band 1) who already have meters with interval reading capability or who will have such metering technology installed over time. Some of these consumers will already be on time varying tariffs (ie simple time of use tariffs). For the purpose of our recommendations and describing the deployment of time varying network tariffs we have excluded discussion on these consumers.

164 See *Time- Varying and Dynamic Rate Design*, Global Power Best Practice Series, The Brattle Group, RAP, July 2012.

While the potential gains or costs for consumers are the same for either approach, the significant variation in participation rates reflect the tendency for consumer bias; in particular a bias toward sticking with the status quo; or to be more concerned over losses than gains when it comes to changing their behaviour.[165]

For this reason, we recommend consumers in the medium to large band should transition to being on time varying network rate – but have the option to revert back to a flat network tariff. This will be a gradual opt-out deployment method and should be dependent upon such consumers being educated prior to any changes to their retail prices.

We consider that a different approach is necessary for small to medium load consumers. Given the nature of their consumption and electricity use, such consumers may have a limited ability to respond to time varying tariff through shifting their consumption to different times of the day. This threshold approach is likely to capture most, if not all, those types of consumers who could be negatively affected.[166] Consumers with interval meters should have a flat network tariff as the default option – but have the choice to "opt – in" to retail tariff which includes a time varying network tariff if they prefer. This reflects the recommended approach of gradually introducing cost reflective prices, focusing on large consumers in the short to medium term. It avoids the costs and disruption of moving a large proportion of residential consumers onto time varying network tariffs.

Determining time varying and flat network tariffs

We recognise that more analysis is required on the design of the time varying network tariff. The impact on these consumers will depend upon the design of the new pricing structure relative to existing tariffs. There might be merit in gradually increasing the degree of cost-reflectivity in the time varying network tariff over time. We discuss this in next section in our coverage of the distribution pricing principles. Further work is required on how the flat network tariff should be calculated.

Bill protection products

We consider consumers below the band 1 consumption threshold for large consumers could benefit from being offered appropriate bill protection products to allow them to experiment with moving to time varying rates. Such products are explained in detail in the report by The Brattle Group. Their key benefit relative to a flat tariff is that they would offer a level of protection for a core volume of consumption, while still providing incentives at the margin for consumers to engage in DSP. We discuss the basics of such an approach in Box 6.2 below.

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165 See Ofgem discussion paper, *What can behavioural economics say about GB energy consumers?*, 21 March 2011, page 6

166 IPART analysis shows that on average, low income households consume less electricity than high income households, although there are large consumption households that are also low income. See IPART, *Residential energy and water use in Sydney*, Blue Mountains and Illawara, 2008

Box 6.2 The consumer baseline and real time price approach

A consumer baseline (CBL) approach locks in an agreed profile of consumption at a fixed price (reflecting a weighted average of the off peak and real time price). Any electricity usage above this volume is exposed to a real time price (RTP), or a critical peak price (CPP).

The most common CBL is historical hourly load data since this means that consumers' bills remain unchanged if their usage remains unchanged. However, any baseline is theoretically possible. We expect where such options are provided in the competitive market consumers will able to choose their own baselines.

The key advantage of the CBL + RTP approach is that it still creates incentives for consumers to manage their consumption, but it eliminates much of the bill risk they are exposed to compared with purer forms of time varying pricing. If consumers maintain the same usage as their historic baseline, then their electricity bills will remain unchanged from the flat rate. However, since any changes from this CBL are charged at the market price (or CPP), consumers now have an incentive to shift consumption from expensive peak periods to cheaper off-peak periods. This can reduce their bills and increase economic efficiency. There is minimal revenue risk for utilities, since all new marginal electricity usage is at the real-time or close to real time price.

Two potential issues to note is that a CBL that varies by person may be difficult for consumers to understand, therefore requiring extra education, and there may be some administrative costs in setting up and running the CBL.

These proposed arrangements should not impede consumer choice. A key aspect of the approach is that any consumer who wants to move to a time varying tariff should have the choice to do so, irrespective of his or her consumption level. These recommendations are illustrated in Figure 6.4 below (using information for NSW consumers) and the summary box. We have not attempted to define the thresholds for each consumption band.

Figure 6.4 Applying time varying prices to consumption thresholds

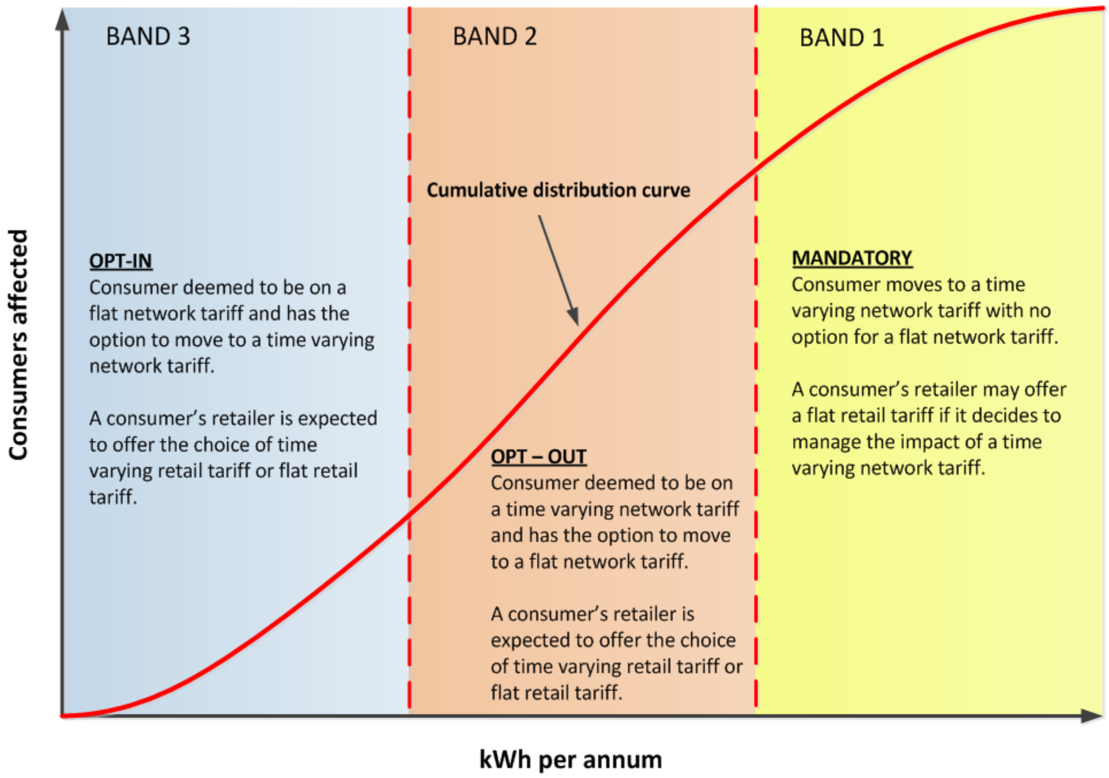

Table 6.2 describes the network and retail tariff arrangements that would apply to each consumption band under our proposed approach for phasing in cost-reflective pricing.

Table 6.2 Network and retail tariff arrangements

	Network tariff arrangements	Retail tariff arrangements
Band 1: Large residential and small business consumers	Consumer moves to a time varying network tariff with no option for a flat network tariff.	Retailer may offer a flat retail tariff if it decides to manage the impact of a time varying network tariff.
Band 2: Medium to large residential and small business consumers	Consumer deemed to be on a time varying network tariff and has the option to move to a flat network tariff.	A consumer's retailer is expected to offer the choice of time varying retail tariff or flat retail tariff.
Band 3: Small to medium residential and small business consumers	Consumer deemed to be on a flat network tariff and has the option to move to a time varying network tariff.	A consumer's retailer is expected to offer the choice of time varying retail tariff or flat retail tariff.

We consider that these recommendations provide the appropriate mix of consumer protection and incentives to transition to more cost-reflective pricing. They include appropriate consumer protections, especially for consumers who may not have the ability to respond, but at the same time provide an appropriate signal to large to incentivise their consumption behaviour. We note that there could be a small possibility that some consumers who are vulnerable could be captured by the large consumption threshold. However the arrangements set out in the previous section will help to manage the impacts on these consumers (ie through targeted DSP programs under government energy efficiency schemes).

More analysis is required on these recommendations and we appreciate stakeholder views.

Questions

18. Do stakeholders agree with our approach for phasing in cost-reflective pricing? If not, how can the policy be improved to transition to cost-reflective pricing?

19. Have we identified the main issues with transitioning to cost reflective pricing? If not, what other issues need to be considered?

20. How should consumption thresholds be determined?

6.3.6 Strengthening arrangements for network tariffs

DRAFT RECOMMENDATIONS

We recommend that:

- **The distribution network pricing rules in the NER are amended so that distribution network businesses have sufficient guidance to set efficient and flexible network tariff structures that support DSP.**

- **A new provision is included in the rules which require distribution network businesses to consult with consumer groups and retailers on their proposed tariff structures each year.**

In the directions paper we noted that the marginal costs of the network vary by time and location and that to recover these costs efficiently would require a price or charge that also varies by time and location. A time varying network tariff that reflects the marginal costs of network use is therefore an important component of a retail tariff. However, to date network businesses have not set prices that reflect costs in this way.

We consider there to be a number of contributing factors:

- Interval meters are a necessary prerequisite for cost reflective pricing, but to date their implementation has been limited. In submissions to the directions paper many network businesses suggested that regulatory impediments to implementing interval meters was the key deterrent to them setting more cost reflective prices.

- Costs of a network business are dominated by large fixed and sunk cost; that is, costs which have already been incurred or do not vary greatly with consumption in the short term. Recovery of such costs lends itself to pricing structures that are stable, simple and do not deter utilisation.

- The incentive on network businesses to price at marginal costs may be complicated by how costs are treated under the regulatory arrangements. For example, outcomes with respect to how the cost of capital is set, the allowance for depreciation, and the degree to which forecast volumes vary from actual volumes, can have a considerable impact on incentives for network businesses to set time varying network tariffs.

For these reasons network businesses may have only limited incentives to set time varying tariffs. We discuss these factors in Chapter 7 in more detail in our exploration of incentives on distribution business to pursue efficient DSP.

In light of this, we consider that the rules under which businesses set network tariffs may need to be strengthened. We therefore propose that the distribution pricing principles in Chapter 6 of the NER are reviewed to assess whether more guidance or prescription is needed as to how distribution businesses set their networks tariffs. An important aspect of this review is that as networks move towards more cost reflective pricing they have proper regard to the impacts on consumers and provide appropriate arrangements to help consumers manage those impacts, as discussed in the previous section.

Pricing principles

The way distribution businesses set their network charges is governed by pricing principles, as outlined in Chapter 6 of the NER. While these pricing principles have been implemented to encourage efficient recovery of network costs, for example by requiring network businesses to take into account the long run marginal cost of the network, in practice the principles provide significant discretion for how tariff structures might be set to reflect these principles.

This can be interpreted in many ways by network businesses and there is no explicit requirement within the distribution rules to set network tariffs in a way that reduces peak demand. Network businesses can use their own judgment to balance fixed versus variable components in deciding how to recover their costs, conditioned by the level of complexity, transactions costs and the degree to which they consider consumers will respond to the price they set (see NER clause 6.18.5 (a) (2)).[167]

167 Pricing principles for transmission companies (Chapter 6A of the NER) are more prescriptive and conducive to cost reflective pricing. There is an important requirement under 6A.23.4 (e) for transmission businesses to structure the locational component of their prices based on “demand at times of greatest utilisation of the transmission network”. This concept attempts to capture peak

In light of these issues we consider the pricing principles that underpin the setting of distribution network charges could be refined and strengthened.

We propose that the distribution pricing principles should specify that, where consumers have an interval meter in place the applicable network tariff should reflect our recommendations for the proposed transition to time varying rates. This includes appropriate guidance on calculating time varying network tariffs. This should have regard to:

- the requirement for network tariffs to signal the time varying nature of network costs; and in particular how consumers' demand drives network investment;
- the possibility that drivers for network costs differ to those for wholesale costs and thus a different tariff structure might be appropriate; and
- the range of possible different tariff options which provide a more efficient signal (as explained in Appendix B).

An alternative to setting critical peak pricing is to set a charge based on a consumer's demand during the peak periods over the year. This could be based on a kW, rather than kWh, measurement, during those peaks. However, we recognise that more analysis is needed on how distribution businesses could move from consumption charges to demand charges and how best to manage the resulting impacts on consumers.

Generally providing a locational signal to the residential and small business consumers in the distribution network is likely to be challenging. This is partly because of the absence of the appropriate metering technology, but more significantly, because of the shared nature of many of the assets they use. This makes it difficult to precisely attribute the assets' costs to specific consumers. There are a number of other factors that also currently limit the extent to which prices can reflect locational factors; particularly political preferences with regard to managing cost variations for consumers between city and regional areas.

While we recognise that locational variation will inevitably reflect a compromise between efficiency and these latter considerations, we consider that the pricing principles should provide some flexibility for networks to signal differences in locational costs (for example by implementing a CPP in constrained parts of the distribution network). However caution is advised so that this does not impose a price shock on consumers. This could possibly be limited to:

- either large residential and small business consumers (i.e. above the defined consumption threshold); or

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demand, however, it only applies to half the total costs of the transmission network (the other half of costs is reflected in a postage stamp charge). Transmission businesses also differ with respect to how they implement this provision.

- consumers who have elected to split their load between two financially responsible market participants under the arrangements we propose in our Electric Vehicles and Natural Gas Vehicles Review; or
- in selected constrained areas of the distribution system where the network is permitted to provide an incremental locational signal as a means of avoiding network investment.

Tightening the pricing principles in the manner we set out above should increase prospects for time varying pricing which reflects peak investment drivers on the network. We consider the pricing principles would still afford sufficient flexibility for distributors to craft innovative network tariffs relevant to their own circumstances and preferences. For example, it is important that the pricing principles do not impede the businesses' ability to offer the bill protection type products which we referred to earlier and covered in The Brattle Group paper.

One key issue to address is the potential effect clause NER 6.18.5 (a) (2) could have under a policy of requiring networks to implement time varying pricing to recover their costs. This is because under this clause network businesses are allowed to shift costs from responsive to unresponsive consumers.[168] Those consumers on flat retail tariffs could therefore see significant increases in their tariffs. If the market is to efficiently transition to cost reflective pricing, this clause needs to be reviewed.

In its submission to the directions paper the AER noted that improving the network pricing principles to provide greater flexibility could help to promote cost reflective tariffs.[169] One aspect of this could be the price constraints regarding the degree to which network prices can change on an annual basis. While the effect of pricing side constraints is to limit the variability in price changes to which consumers are exposed, they could restrict the ability of network businesses to move consumers to time varying network tariffs over time. This issue should also be part of the review into distribution pricing principles.

Our focus at this stage is on distribution pricing, where the effects of peak demand are most significant, but greater consistency could also be introduced into transmission pricing principles. We are considering the transmission pricing arrangement as part of the Inter-Regional TUOS rule change currently underway.

168 Ramsey pricing is a second best pricing rule applicable to natural monopolies such as networks. First best pricing is marginal cost pricing, but this would lead to a revenue loss for monopolies, because the total costs of the firm would not be recovered. Ramsey pricing proposes that prices are increased above marginal cost in a way that is inversely proportional to the elasticity of demand. This keeps demand and volume as consistent as possible with what would have occurred under marginal cost pricing, minimising the efficiency loss from above marginal cost pricing. In the current context this would mean prices are raised higher at times when consumers are least likely to reduce their consumption, or for consumers who are least likely to respond to such price increases. The latter may be considered to breach equity principles however.

169 AER, directions paper submission, p.6.

Consultation with retailers and consumers

It is also appropriate that retailers and consumer groups have a role in reviewing such network tariffs. Retailers have greater experience and expertise with respect to the types of tariffs that will suit consumers. While currently distributors often voluntarily share information on their network prices with retailers, we consider there is value in creating a more formal review role for retailers, and consumer groups, in the network tariff setting process.

Distribution network businesses are required to submit pricing proposals for annual review by the AER. We consider this process should allow a period of consultation with external stakeholders on the structure of network tariffs. In addition, the AER should monitor distribution network businesses so that they actively develop and improve their tariffs structures to meet the revised principles as best as possible at all times. This will require changes to the current annual tariff setting process to give the AER sufficient time to undertake this role.

Question

21. We seek stakeholder comments on appropriate pricing principles for distribution businesses and the appropriate time period for stakeholder consultation on distribution network pricing proposals.

6.3.7 Addressing risks for retailers under cost reflective pricing

DRAFT RECOMMENDATION

- **We recommend that once a residential and small business consumer has a meter with interval read capability, that consumer's consumption should be settled in the wholesale market using the interval data and not the net system load profile. This will be the case irrespective of whether the consumer has reverted to a flat retail tariff.**

Retailers buy energy in the wholesale market, pay for transport costs and package these costs in the form of retail tariffs. This includes passing through a risk premium for managing the risks of fluctuating wholesale and (potentially) network prices. Currently, most residential consumers pay the same price for every unit of electricity they consume regardless of what time of the day or time of year it is consumed. A focus of this review is to identify what restrictions, if any, retailers currently face that prevent them from offering more innovative pricing options that better reflect consumers' actual consumption profiles.

Retailers operate in a competitive market so they should, in principle, have incentives to offer time varying tariffs and interval meters to consumers where there is a commercial benefit in doing so. As explained earlier, consumers with a flatter than average profile would be expected to save money by moving from a flat retail tariff priced on the costs of serving the NSLP, to a time varying tariff priced on the basis of that consumer's actual wholesale energy costs.

Retailers would benefit by offering time varying pricing options to these consumers by sharing in the cost savings. In addition, interval meters would allow retailers to offer a range of innovative tariffs (for example critical peak pricing) that would allow it to better share wholesale market risks with consumers (depending on the latter's risk preferences). In practice neither interval meters nor more innovative tariffs have been implemented by retailers to date.

One potential disincentive for retailers implementing time varying pricing is that this may expose them to revenue risk due to more volatile pricing and consumption volumes that may arise as a consequence of demand response. We do not consider this to be a significant issue. While this might create some uncertainty for retailers around volume to begin with, this risk will reduce as retailers get better at predicting their consumers' reactions to peak pricing over time. In general we consider that prospects for reduced volumes at peak times are unlikely to be a disincentive for retailers to offer time varying tariffs. If anything, demand side participation by consumers could reduce retailers' costs and their need to hedge their expected wholesale price exposures.[170]

Submissions to the directions paper identified three other issues that may be contributing to a lack of cost reflective pricing at the retail level: risks associated with recovering costs of installing interval meters; perceived regulatory risks associated with retail price regulation; and risk associated with a policy of reversion between the different types of tariffs. We consider metering issues in Chapter four. The remaining issues are considered below.

Price regulation

A potential obstacle to retailers offering innovative tariff structures is if they primarily base their market offers on existing standard offer prices or first tier default retailer rates[171] that are not time varying. To determine whether standing offers are likely to present such obstacles, it is worth examining how second tier retailers (new retailers within a distribution area) typically set their market offers. If they usually reference their tariffs to standing offer tariffs – such as offering a percentage discount on standing offer tariffs published by the default retailers – then this could discourage more innovative tariff structures.

170 The exception to this may be retailers who also own generation assets. We also note that it could be of value to retailers if the demand side response is reliable. Retailers may be able to use it in the same way they use a cap or generation.

171 A first tier retailer is a retailer who under the previously fully regulated energy market was responsible for supply electricity to consumers within a particular distribution area.

Second-tier retailers, appear however to be publishing their own tariffs without reference to the standing offers of first-tier retailers.[172] Many retailers offer discounts on their gazetted rates for direct debit/prompt payment.[173] In other words, second-tier retailers do not appear to be defining their offers as a percentage discount off the first-tier standing offer tariff in the consumer area. This suggests that the structure of standing offers by first-tier retailers should not in itself deter new entrant retailers from developing and offering innovative tariff structures.

In the directions paper, we asked if specific aspects of the state based retail prices regulation were deterring retailers from offering innovative tariffs and products. No stakeholder raised any specific problems with how price regulation is set across the states. Most of the points raised by retailers are general concerns about retail price regulation.

While we do not agree that retail price regulation should discourage retailers from introducing innovative time varying tariffs, we do consider that price regulation adds compliance costs and reduces flexibility for retailers. Variations in regulation across states can limit the development of nationwide retail products and make it difficult for new retailers to enter into the market. In this regard we consider there to be merit in removing or amending price regulation not only where competition is already effective, but also as a means of stimulating competition in retail markets.

The AEMC has responsibility for reviewing retail competition periodically in each of the states and territories of the NEM. It is important that the regulated retail pricing framework promotes efficient and flexible pricing options.

Reversion risk

As discussed above, one measure to assist the market transitioning to time varying tariffs is to allow consumers to revert between time varying tariffs and the regulated flat retail tariff. The purpose would be to allow consumers to test the benefits of innovative time varying tariffs while facing limited exposure to the cost impacts thereby encouraging and improving consumer confidence in cost reflective pricing.

However retailers have noted that they could face risks when their consumers revert from time varying tariffs to regulated flat retail tariffs. There are two types of risk:

- If the retailer continues to be charged a time varying network tariff by distributors in respect of their consumer's consumption; and
- If the consumer is settled on the interval data and doesn't revert back to being settled on the net system load profile.

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172 In Victoria, all retailers have to publish all their tariffs in the Government Gazette – they cannot simply set tariffs referenced to other retailers' tariffs.

173 In NSW, second-tier retailers like AGL and Red Energy typically publish their own tariffs for single rate, controlled load and time of use structures for each distribution area.

We have addressed the first of these potential risks through our recommendations for introducing time varying tariffs. For consumers below a defined threshold, the network business will be obliged to offer a flat network tariff.

Regarding the second potential risk, we note that this depends upon the method employed by the state regulators and whether the standard flat retail tariff continues to be calculated on basis of the NSLP profile.

We consider it inappropriate to reinstate an estimated average consumption profile in the wholesale market, for a particular consumer once an actual consumption profile can be established for that consumer on the basis of individual interval meter data. The interval meter data should be used to improve accuracy of wholesale settlement. The difference between the NSLP and actual profile of the reverting consumer will provide the retailer with either a windfall gain or loss depending on whether that consumer is more or less peaky relative to the average consumer profile encapsulated in the NSLP. We advise that the state regulators have regard to this potential issue when determining what method to use to set the regulated flat retail tariff.

7 Distribution networks and distributed generation

Summary

Distribution network businesses play an important role in developing the demand side of the market. They do this through directly undertaking DSP projects as an efficient alternative to capital infrastructure investment. They also facilitate the delivery of DSP by other parties, such as aggregators, through cost reflective network tariffs and publishing planning information.

The current arrangements do not adequately support this role. There are a number of reasons for this, ranging from how financial incentives are applied, to how network tariffs are set. As a result, network businesses are not developing the best solutions for consumers and are not spending consumers' money to deliver the most efficient outcomes. To address this, we recommend that:

- The AER considers reforming the application of the current demand management incentive scheme to provide appropriate reward for DSP projects which deliver a net cost saving to consumers. We put forward two mechanisms and guiding principles for how this could be achieved.
- A two-part approach is adopted to address the issue of business profits being dependent upon actual volumes. Firstly, improvements to the pricing principles to guide network tariff structures and secondly, include allowance for foregone revenue under the DSP incentive scheme.
- Changes are made to the rules to provide clarity and flexibility for how the AER treats networks' DSP expenditure. This is to reflect the different nature of DSP related expenditure as opposed to normal capital investment.

DSP must make financial sense for both consumers and networks businesses alike. These reforms will help to capture the potential of DSP as an efficient alternative to investing in infrastructure such as poles and wires. Distributed generation (DG) will also play an increasing role in the demand side of the market. We propose a series of reforms which will allow the owners of DG units to sell the value of their demand response to parties other than their existing retailer. We also recommend that government feed in tariff structures should be designed to recognise that the value of DG will differ over the course of the day and to encourage owners of DG units to maximise their export during peak demand periods.

Other reforms, and our suggested changes to the demand management incentive scheme, will support networks role to assist efficient installation of DG units and export of power from these units.

7.1 Market conditions for uptake of efficient DSP

The regulatory framework uses incentives and obligations to encourage network businesses to generate outcomes that consumers and the community need, want and are willing to pay for, and to do so efficiently. With respect to DSP, the regulatory framework should be ensuring that network businesses pursue and develop DSP projects where such projects are more efficient than capital investment.

The regulatory framework will not be consistent with this condition if it leads to a business choosing a solution or strategy to resolve a network issue when a better one for consumers and the market exists. This relates to the arrangement governing the way in which distribution businesses get approval to recover their expenditure and how they determine network tariffs.

Evidence suggests that the application of the current regulatory framework, in combination with other influences, may mean that network businesses are not reacting to the incentives in the way intended with respect to pursuing efficient DSP projects. The directions paper identified a number of issues as to why this could be the case.

7.2 Issues identified

7.2.1 Network incentives

Investment by network businesses is generally driven by the need to build sufficient network capacity to meet peak demand and any reliability standards (with an acceptable level of redundancy for unexpected contingencies). In certain circumstances, demand management programs can mitigate the need for capital investment by dampening the peak. To do so, the network business can either purchase a DSP service from a third party provider or develop its own DSP products.

As explained in Chapter one, investment in network infrastructure has grown significantly in recent years. During the same period, distribution businesses have been, to varying degrees, trialling and implementing new cost reflective pricing and incentive based DSP initiatives. However the scope of these initiatives has been small and the potential for DSP to provide a credible, efficient alternative to network investment remains largely untapped. We highlighted in the directions paper that moving from this current pilot and trial stage to mass deployment of DSP is a pertinent issue for network businesses and this review.

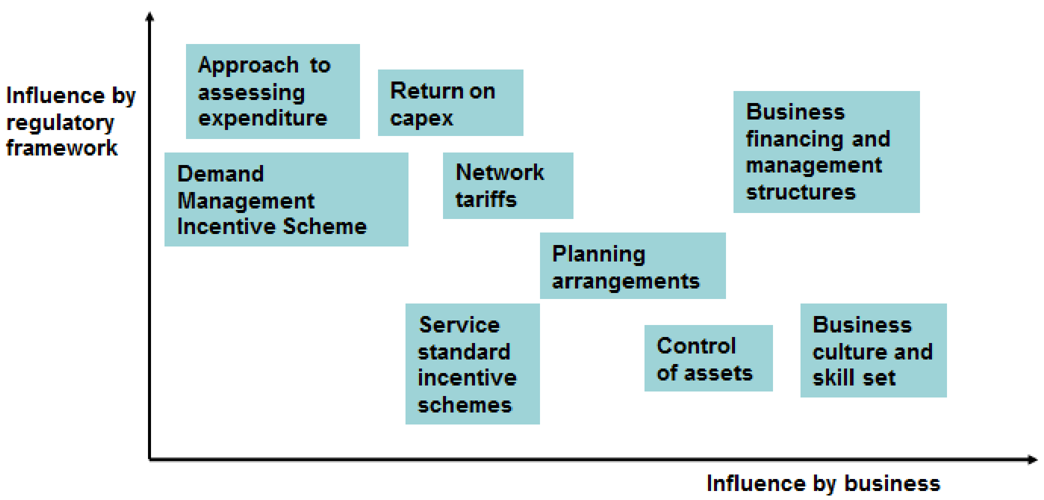
In the directions paper we found that the current arrangements could be discouraging distribution businesses from pursuing efficient DSP projects. Stakeholders – and the businesses themselves – generally agreed with this finding. According to the businesses, under the current arrangements there is insufficient potential to adequately fund DSP projects to motivate them to do DSP. The result is a preference towards network capital investment – which consumers pay for over the long term – and under-development of the potential of the demand side.

The factors contributing to this preference for capital investment within the business' planning and investment decision making framework include:

- The regulatory framework for assessing and approving operating (opex) and capital expenditure (capex) and the potential profit associated with DSP projects;
- Differing incentive strengths of opex and capex (the regulatory framework has a powerful influence on this);
- The ability of the businesses' planning process and procedures to generate network solutions;
- The businesses' understanding and approach to risk management and decision making at all levels within the organisation;
- The way in which network businesses recover their allowed costs through their tariff structure; and
- The way in which the businesses' planning and investment frameworks supports them in managing the risks and uncertainty associated with DSP projects, especially given that the DSP market is in the early stages of development and the technology is constantly evolving.

Since this is not one problem, but rather a series of problems, any solution may have difficulty in adequately addressing all the issues. Also it is important to note that some of the incentives that the businesses face may not be the direct consequence of the regulatory framework. Favouring capital investment solutions can relate to engineering preferences. Network employees' experience and expertise could influence the solutions that they develop and the decisions they take. The ability to address these issues will be under the influence of both the regulatory framework and the business itself, as illustrated in Figure 7.1.

Figure 7.1 Ability to influence the issues relating to networks motivation to do DSP



We recognise the danger in making general statements about network investment. Each investment decision will depend upon its unique circumstances. However, the current arrangements may be failing to motivate distribution business to consider and implement DSP as an efficient alternative to network capital investment and to provide cost reflective network pricing.

We have assessed a series of options to amend the current regulatory framework to address these issues. The options cut across the main areas of Chapter six of the NER and include:

- How forecast expenditure is treated at the start of the regulatory period and also how actual expenditure is treated at the end of the regulatory period;
- The framework for how the AER makes decisions on efficient expenditure;
- The application of the current incentive scheme for demand management (known as the demand management and embedded generation connection incentive scheme (DMEGCIS);
- How network tariffs are set; and
- How network tariffs can be adjusted through the regulated period.

The AEMC is currently progressing a number of rule changes on the regulatory framework for network businesses.[174] These address, among other issues, how the current arrangements provide incentives for efficient capital expenditure and determine the allowed rate of return. As such, they relate to the issues being addressed in this chapter. We took into account the draft determination on these rule changes when developing our recommendations on these issues.

7.2.2 Distributed Generation

In the directions paper, we canvassed a range of issues that influence the development of the distributed generation sector under the current arrangements. We indicated that a number of these issues are being addressed in other processes and rule changes.[175] For this report, we have focused on two issues relating to distributed generation. These are the ability of networks to own and operate distributed generation and whether the current arrangements provide the right incentives for networks to engage with, and connect, DG installations in an efficient and timely manner. We also highlight the value of more time varying tariffs and payments to better reflect the value of DG exports to the system.

Another issue relating to distributed generation covered in the directions paper is the ability of DG installations (as well other forms of DSP) to sell their demand response to parties other than existing retailers. This has been addressed through:

174 Australian Energy Market Commission, Economic Regulation of Network Service Providers Rule change, draft determination, AEMC, 23 August 2012.

(a) our proposed recommendations for having two financially responsible market participants at the same consumer site, as set out in the electric vehicles and natural gas review draft report[176]; and

(b) our proposal for a different classification of market participant to facilitate the unbundling of DSP products from the energy component of the retail contract. This is discussed in section 5.7.1.

Network businesses have a role to play in facilitating DSP, even though the DSP services may not provide any direct benefit to the business in terms of deferring network investment. This could be through providing cost reflective tariffs, publishing information to assist potential DSP projects or how they engage with potential DSP providers. There needs to be a mix of appropriate obligations and incentives for network businesses to support this role.

How network businesses include DSP alternatives within their planning and project assessment process is also important. As noted above, the AEMC is currently finalising a rule change to implement national distribution planning arrangements.[177] These include requiring the distribution businesses to have greater regard to DSP potential, and publishing more information and engaging with DSP related businesses. Such proposals represent a positive step forward and should complement appropriate financial incentives.

Box 7.1 provides a series of case studies that indicate network businesses are exploring various approaches to network-initiated DSP. In some instances, networks are engaging directly with residential, commercial and industrial consumers for the provision of DSP, for example rebates to install energy management devices for load control, or large customer load curtailment contracts. In other instances, they are working in partnership with other DSP providers to develop network support arrangements with large customers.

Box 7.1: Case studies of current network DSP initiatives

In the summer of 2009/2010, NSW distributor Ausgrid launched a local project to cut demand by 6.3 MVA at the Willoughby sub-transmission substation so that it could defer building a new substation, but still ensure reliable supply to local customers. The target reduction was achieved through a mix of network support agreements with large customers, a gas-fired cogeneration site (through an aggregator), and the installation of power factor correction equipment.

175 See Distributed Generation information sheet on Power of choice webpage.

176 AEMC, Electric Vehicles and Natural Gas Review Draft Report, 29 August 2012.

177 The Distribution Network Planning and Expansion Framework rule change is assessing the appropriate range of information which DNSPs must publish in an annual planning report and the development of a Regulatory Investment Test for Distribution (RIT-D) for assessing various options to address system limitations. The proposed framework also provides a requirement for the businesses to develop a Demand Side Engagement Strategy.

Customers benefitted from the project through capital expenditure deferral savings and a 58 per cent reduction in the risk of non-supply.

Ergon Energy has a local DSP project underway in Moronbah, Queensland which aims to reduce demand by 3 MVA and defer the need for a new substation and transformers until the end of 2014, and a new 11kV feeder until 2016. Ergon has forecast that, in the absence of this project, demand on the existing substation would exceed its capacity by summer 2012/13. Ergon would not have been able to complete a network solution by this time; hence the use of DSP allows Ergon to maintain a reliable supply.

South Australian distributor ETSA is undertaking a trial of demand response enabling devices (DREDs) in air conditioners with the aim of quantifying the potential demand reduction benefits that such measures could deliver. Customers will be given an incentive payment in return for giving ETSA authority to limit the power consumption of their air-conditioners at certain times during the summer.

Queensland distributor Energex is running broad-based demand management trials to reduce forecast demand across its network by 144 MVA by 2015. These trials include:

- Offering residential consumers an incentive payment in return for installing an energy management device in pool pumps, air conditioners and hot water units, which allows Energex to limit peak power consumption during critical times;
- Offering commercial and industrial consumers an incentive payment in return for installing energy management solutions such as power factor correction equipment and upgrades to lighting, heating, ventilation and cooling systems; and
- Encouraging customers, through reward based tariffs, to reduce their energy consumption during peak periods.

In summer 2011, Victorian distributor SP AusNet restructured its commercial and industrial network tariffs to better reflect the network's costs and to target reductions in demand during peak times on critical peak days. This was achieved by introducing a two part charge with a critical peak component (based on the customer's maximum demand on five notified days during a defined critical peak demand period) and a capacity component. The critical peak demand tariff resulted in a significant customer response, with a reduction of 88MW in summer peak demand.

7.3 Considerations

We have assessed all the options put forward by stakeholders and organised our recommendations into five areas:

- Potential return for network businesses implementing DSP projects;
- Network tariff structure influencing incentive to do DSP;
- Potential bias towards capital investment instead of operating expenditure;
- Target obligation on network businesses; and
- Providing clarity and flexibility for DSP related expenditure.

The next sections steps through each of the above areas and presents the reasoning behind our proposed recommendations. Our assessment covers only distribution networks, as the AEMC Transmission Frameworks Review is investigating incentives for transmission businesses.

We are examining whether the current arrangements provide the right motivation for distribution network businesses to use the potential of DSP projects as an efficient alternative to network capital investment. If the current arrangements fail to deliver this outcome, then network businesses will meet the growth in peak demand by investing more in supply side infrastructure. The cost of this investment will go into allowed expenditure and be charged on consumers over the asset life of the capital investment.

Stakeholders have different opinions on the best way to address this matter. The network businesses themselves state that there is insufficient profit potential from implementing DSP projects and suggest that they be allowed to keep a share of the market benefits associated with DSP projects. The AER proposed that the solution was to amend existing arrangements to provide it with the ability to develop better capex incentive mechanisms. Consumer/environment groups want to impose targets on network businesses to require them to spend more on DSP (and DG) solutions. EnerNoc stated that networks must be incentivised to use DSP when it is the most efficient solution. All mostly agree on the need for some incremental rule changes to provide clarity on the treatment of DSP costs.

7.3.1 Potential return for network businesses implementing DSP projects

DRAFT RECOMMENDATION

- **We recommend that the AER considers reforming the application of the current demand management and embedded generation connection incentive scheme to provide an appropriate return for DSP projects which deliver a net cost saving to**

consumers. We have put forward principles and two mechanisms for how this could be achieved.

The previous section looked at the relative treatment of capital expenditure compared to operating expenditure under the regulatory framework. This section looks at the potential return a business could earn if it pursues DSP options and assesses whether the current arrangements provide a sufficient profit opportunity. This opportunity should be sufficient to motivate businesses to use the potential of DSP as an efficient alternative to capital infrastructure.

The NEL states that the allowed expenditure for the provision of a network service should allow for a return commensurate with the regulatory and commercial risks involved in providing the relevant direct control network service.[178] However, we recognise that given the market for DSP options is developing and the technology still emerging, there are additional uncertainties and risks associated with DSP, compared with traditional capital investment.

How the regulatory framework allocates risks between the businesses and consumers is an important influence on the business' decision making processes. To date, the current framework has dealt with the risks associated with traditional capital investment. Different risks are associated with DSP and a business is unlikely to implement a DSP project if it faces insufficient rewards for these risks. For DSP projects, the extra risk is in the uncertainty of the expenditure forecasts to cover actual costs and in the ability of the DSP project to deliver the required needs.

When a business is faced with a choice between network investment and a DSP project and both have the same potential for earned returns, the business is likely to go with the "easier" network investment option. We recognise that factors such as the extra investigation and scoping time required, hassle costs, going against operational planning culture, uncertainty about the impacts of DSP projects and having to develop a DSP project for a large number of residential consumers, could cause genuine extra costs and raise risks for which the business may need to be compensated. However, the extent of this will vary according to the nature of each specific project.

A related issue is how the regulatory framework rewards businesses for achieving cost savings for any type of expenditure. Effectively, the current arrangements allow businesses to keep the value of any cost savings until the end of the five year regulatory period. This can encourage businesses to pursue cost efficiencies that can be immediately realised, but may not be effective in motivating them to develop products that have long term benefits.

As such, the current arrangements may not be suitable for DSP projects where the benefits take time to materialise but could be quite substantial in terms of long term network capex savings. As a result, DSP activities that do not deliver a current period benefit (by deferring capital expenditure or maintaining reliability), are not proceeding

178 Section 7A (5) of the Revenue and Pricing Principles, National Electricity Law.

because the business is unable to make a positive business case due to insufficient returns.

The current arrangements already recognise these issues and allow the AER to develop and apply a separate incentive scheme for demand management, referred to as the DMEGCIS.[179] To date, this scheme has been applied in a very limited manner, to provide limited innovation allowances, as well as cost recovery and revenue foregone for a small number of approved DSP projects. This means the scheme is not a "true" incentive scheme; i.e. a scheme which allows a business to earn extra rewards where it has delivered defined goals. We also note that both the AER and network businesses have raised concerns about the administrative burden and costs of the current scheme.

We consider that there are two factors that need to be addressed in developing an incentive scheme with a wider scope and which provides the opportunity for appropriate returns to businesses:

1. The scheme should not be applied in a way that prevents DSP from becoming part of a network business' standard planning and business practices, but should complement the normal expenditure determination process; and

2. It should not reward a network business for doing DSP, without corresponding net benefits to consumers.

The first factor can be addressed by ensuring that any expenditure associated with projects approved under this scheme is treated in the same manner as all other operating and capital expenditure. This is in relation to how the AER approves costs and assesses the efficiency of that expenditure. The scheme would work by giving an adjustment to the determined allowed expenditure for the DSP projects which qualify for returns under the scheme.

As for the second factor, we consider that there are two possible mechanisms for an incentive scheme that would align the extra reward opportunity and consumers net benefit:

- Where the DSP project delivers sufficient wider market benefits (ie, additional to avoided network costs) when implementing a DSP project. Distribution businesses could be allowed to earn a share of any additional market benefits; and

- Where the DSP project delays or defers the need for capital investment. Distribution businesses could be allowed to retain the value of capex savings for a sufficient number of years (e.g., a specific efficiency benefit sharing scheme for capex allowance which is deferred as a result of DSP investment).

179 The demand management and embedded generation connection incentive scheme, (DMEGCIS), is described in clause 6.6.3 of the NER. This clause allows the AER to develop a scheme (or schemes) to provide incentives to DNSPs to implement efficient non-network alternatives, to manage expected demand standard control services or to efficiently connect embedded generators.

The first mechanism would provide a positive incentive payment that reflects a deemed share of the actual and future benefits of the DSP activity to the wider electricity supply chain and consumers. Network businesses have argued that the current incentive scheme does not provide sufficient reward for pursuing DSP that, in turn, generate wider social benefits.[180] Under this mechanism, consumers would be better off because businesses will be motivated to implement projects which deliver lower overall system costs. This would also help to overcome some of the issues relating to the supply chain coordination discussed in Chapter eight, by motivating network businesses to consider and implement DSP projects which deliver market benefits across the supply chain.

The second suggested mechanism works in a slightly different way, as the incentive payment would be linked to the value of savings in capital infrastructure. The value of these savings, which are retained by the network business, depends upon the number of years the business keeps the savings before passing them through to consumers. In the absence of an efficiency benefit saving scheme for capex, this will depend upon the number of years remaining in the five year regulatory period. As the number of years remaining decreases, the profit to the network also declines. The smaller the value of its share of the savings, the less motivated a business will be to pursue efficient DSP alternatives.

To date, the AER has decided against applying such an efficiency benefit saving scheme for capital expenditure because of concerns that it would encourage inefficient deferral of capex into future regulatory periods. The draft determination on network regulation rule changes provides more explanation on this matter.[181]

However, in situations where the capex has been deferred because alternative DSP projects have been implemented, such concerns are not warranted. In fact, the deferral of capex is a positive sign of the effectiveness of DSP. Given this, we consider that there would be merit in including the ability for a specific efficiency benefit sharing scheme for DSP alternative projects under the incentive scheme. Under this mechanism, the business would be permitted to retain the value of the capex savings for a defined period, where a DSP alternative removed the need for capital investment and the approved cost of the capital investment can be identified by the AER.[182] Obviously the AER assessment of whether to apply this second mechanism will depend upon what the general capex incentive scheme is being applied to the business.

An incentive payment scheme is only effective if it changes the business' behaviour and should only be permitted where such change in behaviour results in a net gain to consumers. We consider that there are appropriate ways to reform the current incentive scheme so that it can be applied in a more effective, broad based manner. We

180 Ausgrid directions paper submission; ETSA directions paper submission.

181 Australian Energy Market Commission, Economic Regulation of Network Service Providers Rule change, draft determination, AEMC, 23 August 2012.

182 Having a separate DSP scheme could also give flexibility to add a stronger incentive for the business to use DSP projects to defer or replace approved capital augmentation projects by increasing the number of years the savings is retained by the business.

have put forward two mechanisms which would capture situations where both consumers and network businesses win. Reforming the scheme in such a manner would help to level the playing field between capital investment and DSP projects.

We note that the NER already contains rules that provide the AER with the power and discretion to put these types of mechanism in place for distribution business. However, it might be beneficial to clarify this in the rules and we seek stakeholder views on this.

The next section will highlight the importance of maintaining a network business' ability to recover lost revenues under any reformed incentive scheme. If this does not occur, the business may end up intentionally investing in ineffective programs which are rewarded under the scheme but don't reduce demand.

How should the reformed incentive scheme be applied?

In the draft determination on the AER network regulation rule changes, the AEMC's approach has been to give the AER appropriate discretion to deal with the issues. In doing so, the AER would be required to take into account an objective and set of principles to guide how it exercises that discretion. The same approach could be applied to the recommendations put forward in this chapter, including any reforms to the DMEGCIS. This would allow the AER the discretion to decide on a case by case basis the best way forward for a particular business, depending on its particular circumstances.

Regarding the application of a reformed scheme, we consider that the AER should be guided by the following principles:

- DSP projects assessed as being efficient only quantify for the return offered under this scheme (with reference to market rates for DSP services);
- Payment of reward should reflect the timing of benefits in order to smooth the bill impact on consumers;
- Costs associated with the value that would have occurred if customers had used the electricity at that time (lost consumer benefit), must also be included in the assessment. If not, the consumer cost of DSP projects will be underestimated;
- The value of the share of market benefits should be capped. We note that for similar schemes applied in the US, the average maximum incentive that can be earned by the business is approximately 11 per cent of net benefits;[183]
- The rewards should be calibrated with regard to the value of the non-network benefits which can be passed through to consumers;
- The longer term value of DSP activities, beyond the regulatory period in which the activities are undertaken, should be recognised;

183 American Council for an Energy-Efficient Economy, 'Carrots for Utilities, Providing financial returns for utility investments in energy efficiency', Report number U111, January 2011, p.11.

- Have regard to other incentive schemes being applied to the business;
- Projects approved under this scheme should undergo the same cost approval process as all capital or operating expenditure; and
- An underlying network issue is being addressed by the DSP project.

We also consider that there should be some performance indicators applied to measure the "success" of this scheme so that consumers get a net benefit from its application. Incentives should be designed to reward exceptional performance, not business-as-usual. This could be accomplished by using stretch goals for performance. While some reward may be allowed as performance nears the goal, the business should not be rewarded for achieving what is easily (or already) accomplished. Therefore performance indicators are important. For the final report we intend doing more work on the design of these performance indicators for the final report and appreciate any stakeholder views on what indicators may be appropriate.

We believe the specific application of the scheme should be developed through consultation between the AER and the network businesses. There may be merit in allowing the business to propose how it thinks the incentive scheme should be applied. The AER would approve or adapt the application based upon the set of principles, and possibly an overall objective. The AER may also consider that this type of incentive scheme is only justified in the short term as the market transitions to more cost reflective pricing.

Question

22. Would it be beneficial to include reference to the suggested mechanisms and provide more guidance and an overall objective in the Rules governing the demand management incentive scheme?

Possible standard methods to valuing DSP costs and benefits

Such reforms to the incentive scheme may need to be supported by consistent methods that govern how the businesses and the AER value the market benefits of DSP projects. Ausgrid recognised that to apply the incentive scheme for non-network benefits would require the calculation of a deemed value of DSP benefits across the supply chain.[184] ENA commented that to ensure consistency and some certainty, the reformed scheme could include a defined method or deemed value for the benefits of DSP projects that:[185]

- accrue outside the NSP boundary (i.e. to another network level and generation);
- are not directly assessable (e.g. NSP benefits to LV or MV feeder levels); and

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184 Ausgrid, directions paper submission, p.3.

185 Energy Networks Association, directions paper submission, p.15.

- would accrue beyond the current planning horizon (where DSP effects are persistent).

Stakeholders' views differ about the need for a standardised approach to valuing DSP. Essential Energy, Energex, United Energy, ETSA Utilities, ERAA and the ENA have all called for a standardised approach to the valuation of DSP to account for the total benefits of DSP that accrue across the supply chain. ETSA utilities and the ENA suggested that this standardised approach to DSP valuation could be included in the DMIS (or DMEGCIS). Ausgrid suggested that the AEMC may be best placed to calculate standardised values related to peak demand reductions in the generation and transmission sectors.[186]

Other stakeholders suggested alternative approaches. AGL felt that since the value of DSP will vary depending on the perspective of individual market participants, that these values can be effectively determined in the market.[187] EnerNOC took the view that the value of DSP (in this case, demand response) may be difficult to quantify in a traditional sense and suggested that a spatially and/or temporally smoothed value could overcome this issue.[188] The MEU suggested that DSP options will have a different benefit for each element of the supply chain and that valuation of DSP should recognise these impacts.[189]

There could be merit in having standard, consistent methods for valuing the costs and benefits of DSP to the market. Such methods could improve the transparency of the network planning process and the application of the incentive scheme. Plus they may also reduce AER administrative costs.

We consider that the question of having standard methods is a matter for the AER. This would be consistent with the proposed responsibility for the AER to develop guidelines for the new Regulatory Investment Test-Distribution (RIT-D) process. We note that the work on defining the baseline consumptions for the proposed demand response mechanism raised in Chapter five could assist any standard methods.

Innovation Allowance

The demand management innovation allowance (DMIA) aspect of the current scheme addresses the need for network businesses to access funding to experiment and trial innovative DSP schemes which they would otherwise have been unable to fund through their normal expenditure allowance. Facilitating such testing and learning should lead to more cost effective investment in the future. To date the DMIA allowance is small, totalling no more than $1million a year for each DNSP.

186 For a summary of the issues raised by stakeholders in submissions to the directions paper, see Appendix D.

187 AGL, directions paper submission, p.7.

188 EnerNOC, directions paper submission, p.17.

189 MEU, directions paper submission, p.37.

Given our proposed recommendations regarding the incentive scheme, we invite comment on whether there is merit in separating out the arrangements for the innovation allowance. We note the allowance serves a different purpose from an incentive scheme, and that there has been some misperception of the application of the incentive scheme when the innovation allowance remains part of that scheme.

Furthermore, given the research and development nature of the projects covered by this allowance, it is unlikely that these projects will attract the extra funding available under the suggested reforms to the demand management incentive scheme. As well, there may be good reasons to treat these projects differently compared to normal expenditure. For example, the AER may want to apply a use or lose provision to such allowances.

With respect to the design of the innovation allowance we consider that a framework which gives the AER discretion to apply the allowance, subject to certain principles, remains appropriate. However we note that a cost recovery mechanism may not sufficiently incentivise innovation as network businesses are not able to capture a share of any associated long term benefits.

We also note that there are other sources of funding being offered for investment in clean energy technology of one sort or another, mainly by governments, in particular the Commonwealth Government (e.g. Smart Grids, Smart Cities, etc). It is important that an innovation allowance for distribution network businesses does not create a duplication of these arrangements.

Question

23. Should separate provisions for an innovation allowance be included into the rules? Given that the costs of the allowance would be borne by electricity consumers, is it more appropriate for such innovation to be funded through government programs?

Possible application to the transmission network business

To achieve consistency in the arrangements for transmission and distribution, ENA has recommended the NER be amended to contain similar demand management incentive scheme provisions for transmission businesses. While the Transmission Frameworks Review is looking at the issue of transmission incentives generally, we would appreciate stakeholder views on whether including the provisions for an incentive scheme for demand side participation in the rules for transmission businesses is appropriate.

Question

24. Should the provisions for a demand management incentive scheme be included in the regulatory framework for transmission businesses?

7.3.2 Network tariff structure influencing incentive to do DSP

DRAFT RECOMMENDATION

- **We recommend a combination of two approaches to mitigate the problem of network profits being linked to actual volume. Firstly, the pricing principles in Chapter 6 of the NER need to be amended to provide greater guidance on how network businesses should set their tariffs to reflect their costs. Secondly, we recommend that the AER considers expanding the current application of the foregone revenue component of the demand management incentive scheme to cover DSP tariff based projects as well.**

In the directions paper we stated that when a network business develops tariffs which are based on consumption volumes, its profits could depend upon the level of actual volumes. Under such a tariff structure, the business would have no incentive to pursue any form of DSP project (or energy efficiency project) which decreases volumes.

In summary, the extent of this disincentive will depend upon three factors:[190]

- the form of regulatory control applying to the business;[191]
- the relationship between volume, and the business' costs; and
- whether the network tariffs are equal to efficient costs.

Typically it has been assumed that distribution network businesses have an incentive to set cost-efficient tariffs. The NER's pricing principles have been based upon this assumption.[192] It was considered that, as additional consumption at peak times can create additional costs, a network business would set prices higher at peak times as a means of discouraging consumption, and, in turn, avoiding additional costs. If prices reflect the efficient cost of extra consumption, then the business profit would not be dependent upon actual volumes.

It now appears that this assumption may not hold in practice. There are two main reasons for this:

190 Further explanation is provided in our supplementary paper to the power of choice directions paper on profit incentives for distribution businesses.

191 The form of regulatory control differs across DNSPs largely due to the AER's decision to continue with previous forms of control set by jurisdictional regulators. Distribution businesses in Queensland are subject to the revenue cap form of regulation, while in NSW, Victoria and South Australia, distributors are subject to the price cap form of regulation. Under a revenue cap, there is no link between allowed revenue and actual volume as prices are allowed to be re-adjusted each year to account for any deviations in allowed revenue caused by differences in actual and forecast volumes. Under a price cap, a business bears all the volume risk and therefore deviations between actual and forecast volumes will affect the businesses total revenue and hence potentially profit.

192 *Distribution Pricing Rule Framework,* NERA report to the Network Policy Working Group, December 2006, p.12.

a) the technical and policy restrictions on networks to price at cost reflective levels, and

b) the fact that the link between volumes at peak times, higher costs and lower profits is not straightforward for a network business. This is as a result of the treatment of costs under the regulatory framework.

   Basically, the additional consumption at peak times will only lead to a profit loss to the businesses if firstly, the costs were not foreseen at the start of the regulatory period and secondly, the costs cannot be deferred to the next regulatory period. The link between pricing at efficient cost and networks' profitability is not as strong as would be the case in other competitive market situations.

For these reasons, there is currently a misalignment between the drivers of network costs and the structure of network tariffs. Where the form of regulation is price cap regulation (which applies to all distribution businesses except Ergon and Energex), this can result in an incentive to increase consumption above the forecast approved in the regulatory determination and a preference to prevent projects that lead to decreased volumes.[193] That said the degree of this incentive will differ by network business and situation.

The AER has done some analysis of the potential extra revenue earned by businesses if actual volumes are more than the forecast volumes used to set the allowed price caps. It has found that there is the potential for substantial over recovery of revenue. In the Victorian 2006–10 regulatory control period, the AER asserted there was over recovery of revenue of $568 million (in 2010 values) above the adjusted forecast. This represents an over recovery of revenue of 8.28 per cent annually for each distribution business.[194]

The AER has questioned whether, where interval meters are available, distribution businesses will set a network tariff that which reflects efficient costs.[195] It considers that the theoretical incentives for efficient pricing provided by price cap regulation have resulted in little practical benefit in distribution businesses' pricing. The AER has considered the pricing approaches of Essential Energy, Endeavour Energy and the Victorian DNSPs and compared these to Ausgrid's tariff structure. The AER considers that apart from Ausgrid's pricing, pricing efficiency in relation to other DNSPs has not materially improved since the introduction of price caps in the previous regulatory period.

We note that the majority of existing time of use network tariffs have a lengthy peak period of over 14 hours, but with a relatively small difference between the peak tariff compared to the off peak tariff (where the peak tariff is around three times the off peak

193 This is being driven because a proportion of the fixed costs are being recovered in the variable charge.

194 AER, *Preliminary positions, Framework and Approach Paper for NSW Distribution businesses*, June 2012, p.55

195 AER, *Preliminary positions, Framework and Approach Paper for NSW Distribution businesses*, June 2012, p.47

tariff). The design of the Ausgrid time of use tariff for residential consumers is different. The peak period only lasts for six hours and the peak tariff is around 10 times the off peak tariff.

As explained above, if network businesses are not setting tariffs which are equal to efficient cost of extra augmentation, their profits are likely to become linked to actual volumes. We consider that a combination of two approaches is required to address this issue. Firstly, it will be necessary to review the pricing principles in Chapter 6 of the rules, in order to assess whether greater guidance is needed on how network businesses should set their tariffs to reflect their costs. We have already discussed this issue in the pricing chapter when we assessed the profit impact on networks of introducing more cost reflective tariff structures. In that chapter we set out our recommendations that the distribution pricing principles needed to be reviewed for that network businesses face the right obligations and to ensure that consumer impacts of moving to cost reflective prices are properly managed.

The aim of any revisions to the existing pricing principles should be to specify the appropriate objectives and principles for charging, in order to allow the businesses some discretion to develop tariffs which are consistent with these defined principles. In addition, the AER should be checking and encouraging distribution businesses to actively develop and improve their tariff structures to meet the defined principles. This will require changes to the current annual tariff setting process to give the AER sufficient time to undertake this role. As discussed in chapter six on pricing, we are recommending that there is formal consultation on proposed network tariffs with retailers and consumers.

Given the practical limitations and transaction costs of offering more accurate cost reflective network tariffs, an additional mechanism is required which decouples the link between network profit and volumes. Four approaches to decoupling are well established. These include:

1. Moving to a revenue cap regulation;

2. Selective compensation for the loss of allowed revenues due to their DSP programs;

3. Setting a high fixed charge; and

4. Establishing a comprehensive DSP incentive mechanism which, while not expressly designed to recover lost revenues, can nonetheless mitigate financial attrition and remove disincentives if well designed.

All these approaches are permitted under the current arrangements, either at the discretion of the AER or within the decision of the network business. The current incentive scheme contains a form of the second approach in its recovery of foregone revenue component.[196]

Our preliminary view is that changing the form of regulation from price cap to revenue cap may not be the appropriate answer. Under a revenue cap, businesses will most likely be motivated to collect revenues in a manner that generates the least amount of customer resistance and as total revenue is fixed, they will maximise profit by minimising costs.

Under a revenue cap a network business loses very little from not setting its tariff price at a good estimate of its underlying costs. To the extent that pricing at efficient cost involves significant complexity and/ or raises challenging stakeholder issues, then the business may adopt other approaches. For these reasons, any move towards revenue cap regulation would need to be supported by introducing more prescriptive detail prescription in the rules on how distribution network business sets their network tariffs.[197] While we have found that the incentive to set tariffs at efficient cost under a price cap regulation is weaker than what was assumed, it will still be considerably better than under revenue cap regulation.

We also recommend that the AER considers expanding the current application of the foregone revenue component of the demand management incentive scheme to also cover DSP tariff based projects. This relates to the second of the four approaches listed above.

If DSP projects are not included in the foregone revenue component of the scheme, this may lead network businesses to design tariff based DSP projects which minimises the impacts on their revenue (i.e., revenue neutral). Market arrangements should be ensuring that networks evaluate tariff based and non-tariff DSP projects on their efficiency and effectiveness, rather than in regard to the relative risk posed by these projects to their revenues.

We also note that some DSP projects might see capital savings through load management rather than load reduction. While total volumes may not change, the network business may face increased revenue risk as it is required to forecast how consumers will shift their load between peak and off peak times. Hence a high variable time of use tariff structure will expose the networks to greater risk from demand fluctuations. We therefore point to the possible merit of including such tariff based DSP projects into the foregone revenue component of the incentive scheme.

The AER would need to consider the application of the demand management incentive scheme so that there is no duplication of compensation. If the suggested changes to the incentive scheme are implemented, this issue may become less material, as the return

196 This allows a distributor to recover revenue foregone in a regulatory control period resulting from a reduction in the quantity of energy sold due to a project approved under demand management innovation allowance part of the DMEGCIS. This applies to businesses with a price cap and only covers non-tariff based schemes.

197 Also under a revenue cap, a DNSP will not be incentivised to meet additional demand if that additional demand delivers increases costs (even if it increases profit).

provided to the business under the reformed incentive scheme may be sufficient to off-set the risk of foregone revenue.

Question

25. What amendments are required to the current distribution pricing principles as set out in clause 6.18.4 of the national electricity rules?

7.3.3 Bias towards capital investment instead of operating expenditure

DSP projects can either be treated as opex or capex under the regulatory arrangements. Most DSP has tended to be contractual payments to third parties and treated as operating expenditure. However network businesses could invest in DSP enabling technology, such as smart meters, which would be classified as capital expenditure.

A capex bias occurs where capital expenditure options are chosen inappropriately over operating expenditure. The regulatory framework could create or contribute to a capex bias if it meant that a network business could gain more financially from spending on capex rather than opex.

We stated in the directions paper that there could be a bias towards capital expenditure against operating expenditure under the current arrangements, for the following reasons:

- When the business achieves a savings in its costs, it is able to keep a larger proportion of those savings for capex than for opex. This means that businesses are rewarded more for savings on capital expenditure compared to savings in operating expenditure. This leads to them wanting to increase the proportion of allowed expenditure allocated to capital expenditure; and
- The current rules provide a greater guarantee of recovery of actual capex rather than opex based projects;
- Capex allowances are subject to a financial rate of return – referred to as the weighted average cost of capital (WACC). This gives the business the opportunity of earning additional profits if it is are able to finance their capital investments at a lower rate than the allowed WACC. This opportunity does not exist for opex. Again this could give the businesses the preference to increase the proportion of allowed expenditure allocated to capex. [198]

We have also noted that an internal bias towards engineering solutions will also contribute to a capex bias in business planning and delivery. Networks businesses may

198 The fact that capex is remunerated through the regulatory asset base and earns a return while opex is remunerated on a current basis, earning no such return, should not be a problem if the allowed return were to equal the cost of capital –an investor should then be indifferent to the form of remuneration. But the incentives to achieve financing efficiencies and regulatory asset base (RAB) growth are having an important influence in both business planning and delivery.

perceive that having direct control of assets will increase their ability to service their assets, potentially creating a preference for capex.[199] As well as not spending consumers' money to deliver the right outcomes, a potential bias towards capex within network businesses may limit the ability of third party service providers to develop a DSP market and engage with consumers.

We are not recommending introducing any new mechanisms into the rules on this matter. We recognise that this is a complex matter and that different degrees of bias potentially exist under different circumstances. It is not correct to make a general statement that distribution business will always prefer capex over opex projects. There will be situations were opex projects make more financial sense for the business.[200] We note that the relative differences in proportion of cost savings retained by the business between opex and capex may not be that material to result in a change of projects.

The rules regarding recovery of actual capex and also the weighted average cost of capital are, among other issues, are subject to change as part of the network regulation rule changes. The proposed amendments set out in the draft determination on network regulation will influence business behaviour toward capital expenditure and there could be less incentive to spend capex generally (for example through introducing the possibility of an efficiency review on past capex). Under these proposed amendments, the AER will have access to a range of tools and the discretion to apply those tools that can be tailored to meet the specific circumstances of each network business.

7.3.4 Target obligation on network businesses

Legislation and regulations have been implemented in a number of jurisdictions in Australia and elsewhere around the world requiring electricity retail and/or distribution businesses to achieve an annual target of energy savings. In many cases, these programs have used tradeable certificates, and have therefore been referred to as 'white certificate' schemes.

In most cases, these requirements have been put in place to reduce greenhouse gas emissions. In Australia, a desire to assist consumers in reducing their bills has also informed the implementation of these policies. Because network cost increases have contributed significantly to recent electricity price increases, and are expected to continue to put upward pressure on electricity prices over the next several years, some of the consumer and environment groups have raised the idea that putting a target on distribution business to reduce peak demand.[201]

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199 The separation of opex and capex in business structures and decision-making is another issue. Additionally, while it may be easier to do opex benchmarking, there may be some difficulty associated with identifying external benchmarks for reductions in capital costs. This may mean that the level of regulatory scrutiny differs between these two types of expenditure.

200 For example, where capital markets are tight or the distribution business is approaching its debt limits, it may not want to incur capital expenditure.

201 Alternative Technology Association, directions paper submission; Energy Efficiency Council directions paper submission.

There are several different approaches, under this option, in which a peak demand reduction target could be set for distribution businesses:

1. ***Expenditure on DSP –*** This approach would simply set a target for the amount of money to be spent by the distribution business on DSP. The target could be set with regard to factors such as capability building or the development of specific resources, or with regard to the distribution business's total or augmentation capex budget. The target could be set with direct reference to one or another measure of the distribution system's augmentation activities. That is, the target could be based on the capex to be spent on network augmentation, the amount of MW of augmentation forecast, or the number of augmentation projects to be undertaken

2. ***Forecast peak demand*** – A target could be set with regard to the level of peak demand forecast by the network. Such an approach would create a link between the forecast growth in peak demand (and therefore potentially augmentation capex) and the amount of peak demand reduction the distribution business would be expected to achieve.

3. ***Measured, weather corrected global peak demand*** – The target could be set with regard to measured, weather-corrected global peak demand within the distribution service territory. Setting the target would need to take into account the current weather-corrected peak demand within the distribution service area, and other factors such as forecast growth in customer numbers.

4. ***Weather-corrected top-end system load factor*** – Such a target would focus on the load factor of the 100 to 200 hours of highest peak demand. The objective would be to avoid the very sharpest needle peaks that require augmentation that is used for extremely short periods of time. To be as useful as possible, the number of hours to be used to define the top-end period would need to be distribution system specific, based on the distribution system's current load duration curve.

These approaches could incorporate both incentives and penalties around the target, if desired.

Augmentation of the network is undertaken on an area-specific basis, with its timing and magnitude dependent on the level of capacity, and the current level and growth rate of peak demand within the area. The possible approaches are linked to the aggregate peak demand across the distribution business's entire service area. Given this, such targets might not defer any network capex in the short term.[202] As a result, they would be less likely to reduce upward pressure on electricity costs in the short term. In fact, they could very well increase upward pressure on price in the short term.

202 In general, in order for a specific augmentation project to be deferred, DSP equal to the annual growth rate within the local area needs to be arranged prior to the time at which a commitment would need to be made to the construction of the supply-side augmentation project. In addition, that peak demand reduction needs to be available every time it would be needed over the deferral period (that is, whenever conditions of supply and demand at the local service area would otherwise require network support or load shedding)

It is important that achieving the target is largely (if not wholly) within the control of the distribution business subject to it. Of the approaches discussed above, some can be controlled relatively by the distribution business, while others cannot. Conversely, achievement of the target should not be able to be gamed.

Reducing peak demand at the distribution network level is clearly beneficial. However, setting a target on distribution businesses to achieve these benefits is not entirely straightforward. Based on consideration of several different ways to set a target that seeks to reduce upward pressure on electricity price, it would appear that there is no perfect solution; that is, no option for setting a target appears to maximise the potential for achieving its aim without running the risk of being gamed, being ineffectual or actually increasing costs, at least in the near term. Network businesses could over invest in DSP through doing DSP for the sake of making the target, without any consideration of the efficiency of the project or its impacts on consumers. For these reasons, we do not consider placing a target on distribution businesses to be appropriate.

7.3.5 Providing clarity and flexibility for DSP related expenditure

We are seeking stakeholder views on the following series of amendments to the rules, the purpose of which is to better reflect the different characteristics and costs of DSP related expenditure compared to expenditure on capital infrastructure. These amendments will:

- Clarify that the AER can consider market benefits when assessing the efficiency of network expenditure allowances;
- Include flexibility to address any extra volatility in DSP expenditure;
- Provide more certainty on how unforeseen DSP costs are treated and allowed for at the next regulatory determination re-set; and
- Provide for a temporary exemption from the Service Performance Target Incentive Scheme in certain circumstances.

A description of these amendments and the reasoning behind them is set out below.

a) Inclusion of market benefits into the AER regulatory expenditure reset assessment.

DRAFT RECOMMENDATION

- **We recommend that the NER is clarified to enable the AER to consider potential non-network benefits when assessing the efficiency of network expenditure allowances.**

The expenditure criteria in the rules determine those projects for which network businesses may obtain funding. [203] It is unclear whether the AER can approve an expenditure allowance which includes projects that deliver wider market benefits, in addition to the distribution cost savings. This is because the expenditure criteria only refer to the need for projects which relate to network performance, network reliability and meeting local network demand. However, it is possible that DSP projects implemented by networks may also provide non-distribution network benefits, such as wholesale price savings, savings in transmission network costs and improved system reliability.

Under the proposed new RIT-D, businesses will be required to consider the potential for market benefits. The purpose of this recommendation, therefore, is to align the arrangements for approval of network expenditure with the objectives of the new distribution planning framework.

This amendment would work by clarifying that when considering how a businesses' proposed expenditure meets the operational and capital expenditure criteria, the AER can have regard to the potential for the network businesses expenditure to deliver market benefits. The term market benefit should be defined with reference to the RIT-D. This would clarify the businesses' ability to seek extra funding for DSP activities that deliver wider market benefits. This may also help to overcome some of the supply chain interaction issues raised in Chapter 8 and would support the suggested reforms to the demand management incentive scheme mentioned in section 8.3.2.[204]

In their submissions to the direction paper, the AER and network businesses requested that the rules are amended to clarify the range of benefits associated with DSP projects that can be considered as part of the AER regulatory expenditure reset assessment.

This allowance will be additive, in the sense that there must be an underlying network issue being addressed. It is not appropriate for the business to recover regulated expenditure for non-network projects which may only provide non-network benefits, such as a peaking generator.

b) Managing volatility in DSP expenditure

DRAFT RECOMMENDATION

- **We recommend that the NER is amended to include the ability for distribution network businesses to have extra flexibility in their annual tariff setting process to reflect changing DSP costs.**

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203 Clauses 6.5.6 (a) to (c) and 6.5.7(a) to (c).

204 This amendment is required irrespective of whether the demand management incentive scheme is reformed in the manner suggested in section 8.3.2.

Under current arrangements, network investment plans are assessed by the AER every five years, with allowed expenditure levels being set for the next five years. This works to incentivise a business to seek cost savings, since it is able to retain a proportion of any savings on the allowed expenditure. However, a business is also exposed to potential losses if it over-spends its allowed expenditure. The level of certainty that the business has in the allowed expenditure level to cover its true costs will influence its investment decisions.[205]

The cost profile of a DSP project can differ significantly compared with capital infrastructure. With capital infrastructure, most of the costs are upfront and a business manages the expenditure risk during the construction phase. However, for certain types of DSP projects, the cost profile can be quite varied over a five-year period, particularly the DSP is dependent on network and weather conditions. As a result, the costs associated with DSP may be difficult to forecast. For example, if the DSP program involves a peak time rebate, a network business would have to forecast the number of times such rebates will be triggered over the period. This could involve estimating the number of days where the temperature reaches 35 degrees over a five year period.

We note that such additional uncertainty will be the case for all DSP expenditure. Some DSP projects, such as distributed generation unit performing a network support function, can also be capital intensive. Requiring the distribution businesses to manage the expenditure risk associated with certain DSP projects could put these projects at a comparative disadvantage compared with capital infrastructure projects. To address this risk, we recommend that additional provisions are added to the annual tariff process. This would provide the required flexibility to adapt the existing allowed expenditure levels, so that network businesses could better manage the extra volatility in DSP related expenditure.

For the final report, we will work with the businesses and the AER on the appropriate design of such provisions and how they should be applied. We recognise that if the network tariffs become too unpredictable it will become hard for retailers to offer fixed price products over reasonable periods of time; accordingly, options that are only based on adjusting network prices for material pass-throughs, and with clear signalling in advance, should be considered. For example, these arrangements could be limited to actual payments to consumers under agreed rebates/rewards based DSP projects. We also appreciate any stakeholder views on the matter.

205 We also note that there are provisions within the current arrangements to adjust the allowed expenditure level during the five year periods due to defined cost pass through events.

c) Clarifying treatment of DSP operating expenditure at regulatory resets

DRAFT RECOMMENDATION

- **We propose that a new rule is introduced in the NER that provides distribution network businesses with more certainty on how DSP expenditure incurred in a regulatory period (but which is not included in the approved allowance) will be treated in future regulatory determinations.**

The costs of a DSP project could straddle multiple regulatory periods. This would lead to situations where the AER is required to assess the costs of an on-going DSP project at a regulatory reset which the business has already implemented. Current arrangements could be discouraging DNSPs from funding long term operating cost DSP projects through their capital expenditure allowances, if they are unclear how the AER will treat the expenditure on such DSP projects in future regulatory determinations.

A network business' payments for network support (for example, for embedded generation) include two elements: an availability payment and a performance payment if the option is called on. There is uncertainty about whether network businesses will be able to recover payments under an ongoing network support agreement (operating expenses) in future regulatory periods. This is because when the AER considers payments under an ongoing network support agreement, it considers those payments made in the previous period. However, this may not be an accurate reflection of costs in subsequent periods because a network support option may not have been called upon in the initial period. This could be a potential barrier to entering into a network support agreement.

The AEMC has made a rule relating to the AER's treatment of non-network expenditure incurred by transmission businesses (e.g. demand management activities) in future revenue determinations.[206] The result is that clause 6A.6.6 of the rules guarantees that the remaining costs of a network support agreement must be accepted as allowed operating expenditure. However, no such provision exists for distribution and such a lack of certainty may create some additional risks for the DNSP. We recommend that a similar clause is included in the distribution rules.

d) Temporary exemption from the Service Target Performance Incentive Scheme

DRAFT RECOMMENDATION

- **We propose that the NER is changed to permit the AER to grant temporary exemption from reliability service standards for specific DSP pilots/trials.**

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206 AEMC, *Economic regulation of network service providers, draft determination*, Australian Energy Market Commission, 23 August 2012.

The presence of minimum standards and penalties could drive risk-averse behaviour. The directions paper stated that the current incentive schemes for service standards, which reward or penalise varying levels of service performance, can impact on the amount of revenue earned by network businesses. In that paper, we raised the option of having a limited exemption for certain DSP projects.

Distribution business replied that DSP projects are currently typically less reliable than network options and not within the DNSPs control. They stated that businesses should not suffer liability and hence a penalty payment under the service target performance incentive scheme for non-performance in the initial period of a DSP project.[207]

The risk of a financial penalty under the service standards scheme could discourage a network business from deploying a non-network option given the extra level of uncertainty associated with that option. It may also lead the business to take a conservative view towards DSP assessments. This could, in turn, prevent the network business moving from the phase of doing limited pilots and trials of DSP projects to a wider deployment of DSP across its network. In addition, it could also limit the ability for the DSP market to foster and encourage DSP service providers to enter the market and develop products.

That said, the design of any exemption should not lead to any perverse incentives or remove any consideration of the relative reliability and quality of supply impacts of DSP projects. Furthermore, as these businesses develop more experience and expertise in DSP, they will gain a better understanding of the likely response from DSP options.

The AER supports a possible temporary and specific exemption from the reliability service standards for DSP pilots/trials. For any exemption, the potential reliability impact of the exempted pilots/trials would need to be identifiable to properly allow them to be removed from the service target performance incentive scheme. However, an unqualified exemption for all DSP projects would be inappropriate as consumers cannot manage the extra risk of unserved energy. The application of any exemption should not affect consumer's entitlement to guaranteed service level compensation payments.[208]

Given this, we recommend that the rules are amended to permit the AER to grant temporary exemption from the reliability service standards for specific DSP pilots/trials, where it considers this to be appropriate.

207 Related comments were made by Powercor Citpower, Energex, ETSA Utilities, SP Ausnet, United Energy, Essential Energy.

208 AER, directions paper submission, p.10.

7.4 Distributed Generation

7.4.1 Market conditions for uptake of efficient DSP

DG is generation on the consumer's side of the meter. As a DSP option, DG has the potential to address peak demand and thus reduce the reliance on large scale generation and network investment to meet peak demand. It may also provide reliability benefits and reduce network losses, in addition to managing consumers' demand for electricity. Therefore a necessary market condition is for the arrangements to facilitate the installation and export of power from DG, where, from the market's perspective, it can be efficiently undertaken.

7.4.2 Issues identified

Distribution networks have a key role to play in facilitating the connection and export of power from DG. This section examines:

- The incentives faced by distribution businesses to facilitate the connection and export of power from DG;
- Issues surrounding distribution business ownership and operation of DG units; and
- The benefits associated with time varying feed in tariffs and payments to DG proponents to better reflect the value of DG exports to the system.

7.4.3 Considerations

a) DNSP incentives regarding DG

As we identified in the directions paper, distribution businesses may not have strong incentives to engage with DG proponents or to facilitate connection and export of power from DG. Given this, we consulted on how DNSPs so be incentivised to facilitate both the efficient connection of DG projects and the export of their energy output. We also pointed to an explicit incentive payment mechanism introduced in Great Britain by the Office of Gas and Electricity Markets (Ofgem) which seeks to deliver these outcomes.

There are a number of factors which may reduce the willingness of DNSPs to facilitate the connection and export of power from DG. Key amongst these are:

- Existing regulatory arrangements may not provide sufficient expenditure allowances or an effective incentive mechanism to encourage DNSPs to assist DG proponents in the development of a connection application.
- Connection of large volumes of DG to distribution networks may have implications for power system security and how DNSPs plan networks. DNSPs

may try to address these risks by imposing relatively stringent conditions on DG proponents when negotiating connection agreements.

- Uncertainty in forecasting the number of DG projects likely to connect during a regulatory period can have implications for DNSP revenue. As total allowed revenue includes a forecast of investment necessary to connect an expected number of future DG projects, a larger than expected number of connections will affect DNSP revenues.

- Whether or not a DNSP is incentivised to connect DG is likely to reflect the extent to which connection of the DG unit will provide the DNSP with a clear benefit (such as a deferral of network augmentation), or whether the benefit is likely to manifest in other parts of the supply chain.

In their submissions to the directions paper, stakeholders including Powercor, Ausgrid, SP AusNet and EnerNOC all supported some form of DNSP incentive mechanism to drive DNSP connection of DG. SP AusNet stated that this could take the form of a $ per kW incentive rate.[209]

We have assessed the merits of introducing a specific mechanism to address these issues. In particular, we have examined the design and application of the Ofgem model (see Box. 7.2). This model includes a specific "$ per kW" approach, where the distribution business is given a specified payment for volumes of DG connected to its network.

Box 7.2: Explanation of the Ofgem model for distributed generation incentives

In Great Britain, Ofgem introduced the Framework for Distributed Generation incentive mechanism (the framework) as part of its 2004 Electricity Distribution Price Control Review. The framework was in turn developed in relation to a UK Government policy commitment to source 10GW of energy from combined heat and power (CHP) sources by 2010.

The framework is a "hybrid" incentive scheme which consists of two components:

- An 80% pass through rate for network investment caused by connection of DG. This pass through element is recovered over an assumed asset life of 15 years on an annuity basis from generators connecting to the distribution network after 1 April 2005. The pass through mechanism is designed to reduce the risk faced by DNSPs in regards to uncertain volumes of DG seeking connection to the network.

- An incentive rate of £1.50/kW/year (adjusted in 2009 to £1.00/kW/year) per kW of installed DG capacity, based on an additional rate of return above the cost of capital.

209 For a summary of stakeholder submissions, refer to Appendix D.

The framework also contains a mechanism to facilitate ongoing network access for DG units that have been connected by the DNSP. This incentive is set at a rate of £0.002/kWh and is paid by the DNSP to the DG in the event that the DNSP fails to provide the DG with access to the network. This mechanism is designed to provide DG proponents with some certainty as to levels of access to the network and may be adjusted or otherwise negotiated by either the DG proponent or the DNSP.

In 2009, Ofgem reviewed the framework as part of the next DNSP regulatory reset. Ofgem did not provide a detailed economic assessment of project benefits. However, the project was extended into the next regulatory period with some minor amendments.

The introduction of any form of incentive mechanism must be assessed against the NEO. Any requirement for market participants to fund a specific incentive mechanism must be considered in light of the materiality of the issues it has been designed to address, and whether this will provide a net benefit that is in the long term interests of consumers.

We consider that the appropriate approach to addressing these issues is through the design and application of the existing demand management incentive mechanism. In section 7.3.1, we recommend the introduction of a broader mechanism to incentivise DNSP uptake of efficient DSP, through amendments to the design of the demand management and embedded generation connection incentive scheme. This mechanism will allow for the most efficient form of DSP (potentially including DG) to be selected, rather than focusing on any particular form of DSP technology.

Additionally, we consider that provision of incentive payments to DNSPs for connection of DG will not necessarily translate into additional benefits for the market. In circumstances where a DNSP faces sufficient incentive to engage a third party DG proponent as an alternative to network augmentation, any further subsidy or payment is excess to needs. In this circumstance, there is also a risk that the DG proponent may increase the fee it charges the DNSP for provision of services by an amount that reflects the value of the incentive payment. In this situation, the additional payment is unnecessary and represents an inefficient wealth transfer from market participants to DNSPs or DG proponents.

For these reasons, it is considered that there is no need for the introduction of a specific incentive payment mechanism – like the Ofgem model - to incentivise distribution businesses to facilitate the connection and export of power from DG.

We have also considered the way businesses work with DG proponents to develop connection inquiries and applications. Assistance during this stage of a DG project may be central to its viability, particularly if DG proponents do not have experience in market operation. However, distribution businesses may have limited incentives, available resources or expertise to provide this support.

Stakeholders have suggested that a fee for service model may be used to address this issue. Submissions to the directions paper from the Total Environment Centre, Energex, and EnerNOC supported the introduction of a fee for service model.[210]

Assessment of a potential fee for service model is part of our consideration of the *Connecting Embedded Generation* rule change, which was submitted to the AEMC by ClimateWorks Australia, Seed Advisory and the Property Council of Australia. At this stage, the AEMC is scheduled to publish a draft determination on this rule change by December 2012. We are also making a determination on *Small Generation Aggregator Framework* rule change. Given that this work is under way, we will not undertake any further consideration of a fee for service model in this review.

b) Ability of DNSPs to own and operate DG

DRAFT RECOMMENDATION

We recommend that the AER should give consideration to the benefits of allowing distribution network businesses to own and operate DG assets when developing the national consistent ring fencing guidelines for these businesses

As we identified in the directions paper, some distribution businesses have stated that existing processes make it difficult for them to own DG assets or to sell energy generated by a DG back into the market. We consider that there may be a number of benefits associated with allowing distribution businesses to own DG assets and to export power from these assets into the wholesale market. However, these benefits must be considered in the context of competition impacts and overall efficiency.

A factor affecting the ability of distribution businesses to own DG assets and export power from these assets is the various jurisdictional ring fencing arrangements. The purpose of these arrangements is to separate the operation of the regulated and non-regulated arms of vertically integrated businesses, in order to limit the capability of a regulated monopoly business from discriminating against upstream or downstream competitors. Each jurisdiction of the NEM has its own set of ring fencing arrangements; the AER is currently examining these with the intention of developing a standardised set of ring fencing arrangements to apply across the NEM.[211]

Along with other restrictions, the jurisdictional ring fencing arrangements may place limitations on the ability of DNSPs to own DG units and to offer electricity from these units into the wholesale market. The extent of these limitations varies between jurisdictions. The AER has highlighted that distribution businesses are actively prohibited from engaging in generation activities in Queensland and the ACT while specific limitations are placed on DNSPs in other jurisdictions. For example, in South Australia, DNSPs are only permitted to own generation for the purpose of providing

210 Total Environment Centre, directions paper submission, p.3; Energex, directions paper submission, p.11; EnerNOC, directions paper submission, p.24.

211 AER, *Electricity Distribution Ring-Fencing Guidelines Review: Discussion Paper*, AER, December 2011.

network support, meaning that South Australian DNSPs are prohibited from obtaining revenue from selling energy.[212]

Stakeholders had differing perspectives on this issue. Network businesses including ENA, ETSA Utilities and SP AusNet stated that ring fencing arrangements should not prevent DNSPs from participating in the provision of non-regulated services. In particular, ETSA Utilities argued that DNSPs should be able to bid generation into the NEM, where the primary purpose of that generation was network support. Retailers, including the ERAA, AGL and Origin all called for a nationally consistent set of ring fencing guidelines to be applied and for a clear separation of monopoly and competitive elements competing in the same market.[213]

We consider that DNSPs should be allowed to own DG assets, where the primary purpose is to provide network support. Secondly, we also consider that there are likely to be substantial benefits associated with allowing DNSPs to export power from these assets to the wholesale market. However, we acknowledge that both of these outcomes must be considered in the context of their impacts on competition in non-regulated markets.

Construction of a DG asset may represent the most efficient option for augmentation of a distribution network. By developing a non-network solution, DNSPs may be able to reduce total system costs, ultimately helping to minimise price increases for consumers. However, there is a risk that DNSPs may favour construction of their own DG assets in order to increase their RAB, rather than necessarily seeking the lowest cost option through open tender. There is also a risk that a DG unit constructed by a DNSP to provide a regulated service may be used to generate revenue in non-regulated sectors, potentially resulting in cross subsidisation.

We consider that these risks are addressed through a number of existing processes. The introduction of the RIT-D and the requirement for DNSPs to publish an annual planning report will provide the market with a degree of clarity as to the opportunities for non-network solutions and how DNSPs go about acquiring these solutions. This should go some way to addressing concerns that DNSPs will favour building their own non-network solutions, or favouring related parties.

More generally, the nature of economic regulation suggests that DNSPs should have an incentive to seek the lowest cost option to address an identified network constraint, in as much as they are able to retain the resultant capex cost saving. This means that DNSPs may have some incentive to select the lowest cost non-network option, as obtained through open tender. However, we acknowledge that in making this decision, the DNSP will weigh the potential cost saving against the total return on capex it would receive if it constructed the asset itself and included this asset in the RAB.

In regards to potential cross subsidisation between regulated and non-regulated services, we note that the *Economic Regulation of Network Service Providers* Rule change

212 AER, directions paper submission, p.11.

213 For a summary of stakeholder submissions, refer to Appendix D

draft determination involves a mechanism to enable the AER to reduce the cost of DG assets included in the RAB, to reflect the profit earned through the use of DG assets in competitive markets. The AER has also indicated in its ring fencing guidelines discussion paper that DNSP generation services will not form part of standard control services and that any unregulated services will be appropriately ring fenced. Clear separation of the forms of regulatory control applied to different services should help address the risk of cross subsidisation.

We consider that there are likely to be significant benefits associated with allowing distribution businesses to export power from DG assets into the wholesale market. For example, DNSP owned DG assets which are primarily used to provide regulated network support services could also be used to provide power during wholesale market peaks. This has the potential to reduce the total cost of supply and minimise price increases for consumers.

These benefits may not be realised if ring fencing arrangements place overly stringent restrictions on the ability of DNSPs to provide generation services. However, we also acknowledge stakeholder concerns regarding the need for clear separation between the regulated and competitive sectors of the NEM.

In developing a set of nationally consistent ring fencing guidelines, we consider that the AER is best placed to determine the appropriate nature of this separation. In making its decision, we recommend that the AER consider the substantial benefits associated with ensuring the full utilisation of DG assets owned by distribution businesses.

c) Feed in tariffs and value of export from DG units

DRAFT RECOMMENDATION

- **We consider that SCER should, in developing a national approach to feed in tariffs, take into account the value of time varying feed in tariffs to encourage owners of DG to maximise the export of their energy during peak demand periods**

In the directions paper, we noted that the value to the system of energy from DG units may vary according to market and power system conditions. For example, the value of energy from DG units will generally be greater during periods of network or wholesale market peak demand. We identified that it would be beneficial to encourage DG unit owners to maximise their export at peak times, through the use of specifically designed feed in tariffs, side payments or time varying tariffs.

A number of stakeholders commented on this issue. Ceramic Fuel Cells, Powercor and AGL called for the development of standardised feed in tariff rates, with a range of different designs. Other stakeholders suggested that such tariffs could be designed to deliver specific outcomes and to send signals to DG proponents reflecting the value of their energy at different times. For example, Powercor advocated the introduction of a market based gross feed in tariff, while United Energy described a range of different types of feed in tariffs which could encourage different kinds of DG behaviour, including export of power at peak times.[214]

We note that the SCER is currently developing guidelines for a consistent national approach to feed in tariffs. We recommend that in developing these guidelines, SCER considers how different feed in tariff structures, including time based charges, might be used to encourage owners of DG to maximise export of energy at times when it is of most value to the market, especially if the feed in tariff is a net tariff.[215]

214 For a summary of stakeholder submissions, refer to Appendix D.

215 We recognise that this would require the installation of interval read meters at the DG site. We understand that in most PV solar installations this has been the case, except in South Australia where bi-directional accumulation meters have been installed.

8 Supply chain interactions

Summary

Effective coordination and interaction across the electricity market supply chain should support the deployment and take up of efficient DSP opportunities by all parties.

In this review, we have considered each of the individual elements of the supply chain and the conditions needed for the parties to take up efficient DSP. As outlined in each of the chapters, we have recommended a range of reforms to current market and regulatory arrangements across these areas.

We consider that the suite of reforms identified will decrease the transaction costs for consumers and other parties by allowing them to access and capture the value of DSP. This should promote better coordination amongst parties to package up a “product” that consumers see value in and take up.

The market should be given time to adjust and transition to this new environment. Consequently, we do not consider that additional regulatory mechanisms beyond those in this report are needed at this time. It is important that there is ongoing monitoring and evaluation of the market so that the desired outcomes are being achieved.

8.1 Market conditions for uptake of efficient DSP

Efficient DSP will create different costs and benefits for different parts of the supply chain, from the wholesale market to the retail sector. Where a DSP option creates multiple specific impacts in the NEM, each market participant will decide whether to facilitate or impede that DSP option, based upon its own commercial position.

An important condition for uptake of efficient DSP is that each part of the supply chain recognises the costs and benefits of DSP options, acts in a collective and coordinated manner and aligns the commercial interests of the participants to support the deployment of efficient DSP to consumers.

We have proposed a package of reforms that are considered to promote better coordination between parties. We discuss a number of alternative regulatory policy approaches that have been raised and how our proposed reforms are likely to address issues.

8.2 Issues identified

DSP can essentially be considered as a transaction. That is, consumers willing to offer a service for changing their electricity consumption pattern, in return for some form of reward as compensation for the loss of value. Efficient DSP should occur when the compensation offered to consumers for their DSP reflects all the costs and benefits for the market from that DSP option.

In the directions paper, we looked at how existing arrangements currently treat DSP options and value their benefits - and the extent to which those arrangements promote the right coordination between parts of the supply chain.

We concluded that there are a number of factors that may be limiting efficient coordination and the formation of contracts between parts of the supply chain. These include:

- The existence of substantial transaction costs and information asymmetries.
- The absence of efficient and flexible prices that give consumers accurate signals on the costs of supplying and delivering electricity.
- The benefits accruing to some parties from taking up a DSP option without them being required to pay a share of the costs (free-riders).
- Differences in interests between participants and consumers to make efficient investments in DSP (split incentives).

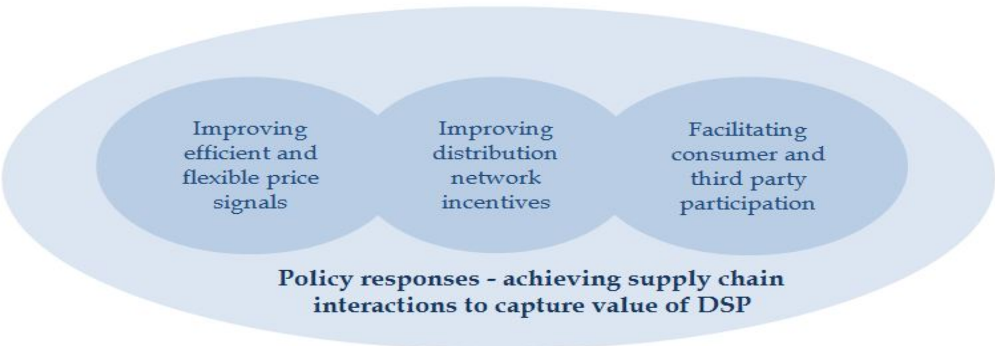
8.3 Considerations

Figure 8.1 shows the mix of arrangements we have proposed. Among other things, these include:

- providing for more efficient and flexible price signals;
- improving distribution network incentives; and
- facilitating consumer and third party (eg ESCOs and aggregators) participation.

In the following sections we provide a discussion of the extent to which price signals are likely to promote coordination across the supply chain. We then turn to the additional policy responses that have been raised.

Figure 8.1 Proposed policy responses in draft report



Use of price signals to facilitate efficient DSP

The efficiency of price signals is important for promoting consumer participation and for determining how the benefits and costs of DSP are shared across parties. Chapter six discusses in detail the role of efficient and flexible prices and recommends ways to improve existing pricing options for residential and small business consumers.

In the directions paper, we noted that if all consumers received fully cost reflective prices, the value of DSP would be clear and transparent, noting that prices are not the only factor influencing consumer decision making (ie preferences, habits etc). Greater use of price signals could improve both allocative and productive efficiency.

- The NEM is characterised by 'needle' demand and price spikes. While these spikes are driven by a number of factors, a primary factor is the air-conditioning load used in the event of consecutively hot days. Currently, such consumption decisions do not take account of the very high costs of serving these demand spikes. Allocative efficiency would improve if consumers were better exposed to the costs of their consumption and consider their consumption in light of costs.

- More effective price signals could also improve productive efficiency through altering consumer decisions on the type of distributed generation to install (and so its firmness at peak) and the possible use of storage. Distributed generation issues are discussed in Chapter seven.

As we have put forward in Chapter six, there is undoubtedly room for price signals which better reflect the costs and supply of electricity. In addition, if retailers are more exposed to the costs of their customers' decision on time of use, then they will have incentives to use low cost methods to influence those decisions. We consider that our recommendations set out in Chapter six provide the appropriate framework for the NEM to transition to better price signals.

Limitations to use price signals

There are a number of reasons why price signals alone may not provide an efficient level of DSP. These are discussed below.

Currently, the effectiveness of price signals varies amongst energy markets, networks and consumer classes.

- The wholesale market has half-hourly regional pricing and very sharp signals on time of use in comparison with most other energy markets around the world.[216] These arrangements therefore mean that the marginal costs in the wholesale market vary significantly by time of use and location. Therefore, we consider that in the NEM, energy charges are reasonably cost reflective.

216 While it has a lower degree of locational pricing than New Zealand or some US markets, the regional pricing in the NEM reflects the location of major constraints and provides stronger locational signals than in most European markets or the single price zone in Great Britain.

- For most industrial and commercial consumers, the marginal costs of supplying and delivering electricity are partially reflected in their pricing structures. As evidence suggests, these consumers generally do respond to such price signals -- adjusting their consumption in short periods in response to high wholesale prices.[217] These larger consumers may also adjust consumption to avoid peak transmission flows in jurisdictions where a high share of the charges is based on use of network services during peak periods.

- In contrast, residential and small business consumers currently have relatively blunt price signals, with limited time varying prices. As we have discussed in Chapter six, there are a range of changes needed to improve price signals, these include technology, pricing principles for distribution network businesses and also improvements to market system processes.

The impediments to relying solely on price signals relates to the:

- Direct costs of implementing the measures necessary to expose consumers to price signals.

- Implications of exposing customers to the very high volatility of the wholesale market.

Generally, retailers protect consumers against the volatility and are well placed to provide this service through their knowledge of the market, their ability to pool risk and – where relevant – their vertical integration.

- In the NEM, prices can infrequently rise well above their average level. This is an inevitable consequence of the market design. If prices always reflected the marginal cost of energy there would be a “missing money” problem, since the revenues would not be sufficient to cover the fixed costs of capacity. As these fixed costs are reflected in energy prices during infrequent periods of high demand, the price distribution is inevitably skewed.

- Peak prices in the NEM wholesale market can be around 300 times average prices.[218] It is unrealistic to expect customers to monitor real time prices and real time consumption and adjust consumption accordingly. This would expose customers to an infrequent risk of spikes in their bills comparable to the price spikes in the wholesale energy market.

A possible issue with an increasing the time varying nature of retail tariffs is that it could increase the uncertainty surrounding the potential pay-offs for consumers who choose to participate in DSP. If there is uncertainty about future electricity tariffs,

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217 AER directions paper submission, p. 13.

218 This high level of price volatility should in theory create strong incentives for DSP. In practice retailers hedge these price risks through contracts which cap the risk. These contracts are typically supported by peak generation capacity and could in theory be supported by DSP. As a result the existence of central contracts (in a capacity mechanism) or contracts held by retailers (in an energy only market) can both support DSP.

consumers may hesitate to support new investment in long-lived, capital intensive DSP. Hence, this could reduce the pool of consumers wanting to participate in the DSP option, to those consumers who can manage such risk. We consider that proposal for the demand management mechanism in the wholesale market will help to address this risk.

Noting the absence of fully accurate price signals, consumers will not have full information to optimise the use of DSP. The above and other factors such as concerns about consumer protection, consumer behaviour and preferences, will also mean that there is likely to be significant practical limitations on moving to fully cost reflective pricing. Therefore for consumers to access the value of DSP, it does make it harder for consumers or their agents to manage DSP related transactions. Consequently, there is going to be a need for another way that consumers can obtain the DSP value or some party is incentivised to seek out the highest value of DSP.

There are significant benefits of DSP in reducing peak load and deferring network investments. However, the limitation for relying on price signals to realise these benefits are much greater for networks than in the energy market. That is, the marginal cost of distribution services is less straightforward to define or measure and to then convert into a price which the consumer understands and accepts.

DSP provides joint benefits by potentially reducing both energy and network costs. Fully cost reflective price signals could reveal the marginal benefit of DSP for both uses. However, in practice, these price signals are likely to be only partly cost reflective and there would be remaining risks of misallocation. The joint benefits can create challenges in coordination between networks and retailers for the optimum investment in fixed costs such as metering, remote load control or other upfront fixed costs.

There are differing drivers between network and energy companies. Network companies are incentivised to use DSP to reduce peak network flows for fairly short periods. Peak transmission and distribution flows are partially but not fully coincident. Energy companies are incentivised to minimise energy charges by shifting demand from peak to off-peak periods throughout the year, although these incentives are greater during short-lived spikes in wholesale prices including to shifting it to lower price periods.

While these are different drivers, it would be less of a problem if they coincided. For example, as the share of intermittent generation increases, peak energy prices will be driven by demand net of wind, while peak energy flows will be driven by demand. This could lead to a very significant divergence in the value of DSP for network and energy companies, further increasing the challenge of coordination.

8.3.1 Alternative approaches to facilitate efficient DSP

DRAFT RECOMMENDATION

- **The recommendations are a package of integrated reforms for the market. If implemented, the market should have time to adjust and transition to the new environment. There should be ongoing monitoring and evaluation of the market for the desired outcomes to be achieved. We therefore do not consider that additional regulatory mechanisms beyond those recommended in this report are needed for the market at this time.**

This section discusses additional policy responses that could be made to achieve greater coordination across the supply chain. We discuss:

- establishing a framework for multilateral arrangements;
- arrangements for energy service companies; and
- establishing a virtual DSP exchange.

We note that other mechanisms have been raised such as a regulatory peak demand incentive scheme on market participants (i.e. specifically network businesses). We consider this issue in both Chapters seven and nine.

Framework for multilateral agreements

We have noted in this review that it is currently difficult for a DSP provider to negotiate with multiple potential users of the DSP – in particular retailers and network businesses. In the directions paper, we raised the possibility of moving from the current bilateral state of DSP contracts to multilateral arrangements.

Currently, the commercial frameworks for DSP are based on bilateral agreements between DSP providers (ie consumers or third parties) and energy retailers or network businesses. Currently, bilateral agreements differ a good deal between DSP which is used to reduce energy costs and DSP which is used to reduce network costs. There are a number of issues for bilateral contracts. These include:

1. Appropriate supply of DSP.

   - When DSP is contracted for network uses it is likely to be called at periods of peak network flows. This will also provide an energy benefit since (a) expensive peak costs will be reduced but (b) revenues will not be correspondingly reduced since consumer tariffs do not fully reflect peak costs.

- Where DSP is contracted for energy businesses (for example through agreements for remote load control) it is likely to be called at periods of peak wholesale prices. This may also provide a network benefit since these periods may overlap to some extent with periods of peak network flows.

A bilateral framework is unlikely to fully reflect these benefits. If the agreement is between the DSP provider and the distributor/retailer, then the agreement will not reflect the benefits to the retailer/distributor. As a result the DSP provider will not be fully rewarded for the benefits being provided and the supply may be inefficiently low.

2. An inefficient use of DSP

    - Consumers cannot judge the value of their DSP actions on the basis of prices that they face for energy or for network services. Energy businesses and network businesses are also poorly informed on the alternative uses of DSP and so the opportunity cost. Both aspects create a risk that consumers may become locked in to supply DSP to one user when value from another user would have been higher.

3. Incentives on the parties

    - Retailers have incentives to sell energy – but may pursue DSP when the marginal revenues are below their marginal costs in the wholesale market. Network businesses have incentives to provide sufficient network capacity to meet performance targets – but may pursue DSP rather than network expansion when it is lower cost.

    - Although both suppliers and network businesses can be incentivised to use DSP, they may suffer if another party calls that DSP. Suppliers will face a (small) reduction in sales volumes if network businesses use DSP to defer network investment. Similarly network businesses will face a reduction in volumes if suppliers use DSP to protect against price spikes.

The issues identified only apply if DSP for both energy and network benefits is contracted. If DSP providers are exposed to cost reflective tariffs for peak energy consumption and for peak network flows then both network and energy benefits will be realised through the pricing signals. Any reduction in consumption will save costs equivalent to the wholesale and network benefits.

It is possible that energy and transmission benefits could be realised for large C&I consumers on an un-contracted basis through their exposure to cost reflective charges. It is not credible that this would be fully achieved for residential and small business consumers. Distribution charges will not fully reflect marginal costs for either major C&I users or for smaller consumers.

Issues can arise however when consumers are party to contractual approaches to DSP.

- Under a network support contract with a distribution business contracted loads need to be reduced by an agreed volume or kept below an agreed volume. This needs to be a firm reduction (ie available) to allow confidence that peak load can be constrained and enable a decision to defer investment in new distribution capacity.

- Under a contract with an energy business load reduction needs to be sufficiently firm so that the business can reduce exposure to peak energy prices and avoid the costs of hedging through some other means.

In both cases the contract needs to be firm. A network business cannot defer investment on the basis of an agreement that an end user might reduce load. Similarly an energy business cannot reduce its hedging if consumers may cut consumption during high price periods -- but may not. It is impossible for those contracts to be fully firm for both purposes. The contract will either be firm for the distribution business and available for the energy business subject to the needs of the first contract, or vice versa.

Limitations of multilateral agreements

A difficulty in realising the benefits of multilateral agreements is that the value of the 'non-firm' (ie price responsive) component is likely to be above zero but hard to fully value. Firm DSP (ie contracted DSP) can be compared with other firm responses. For example, for a distribution business, firm DSP can be compared with the costs of network augmentation and for an energy business, firm DSP can be compared with the costs of hedging.

The most effective approach will be affected by the nature of the 'residual' benefits, that is, the benefits from the non-firm supply of DSP. It is noted however, the value of aggregated DSP may be greater than the value of DSP negotiated at an individual level through the impact of diversity on firmness.

Three principal options for a multilateral framework could be considered. These are given below.

- Option 1. Consumers could enter a firm contract with the end user of their choice and then seek to negotiate additional revenues from other energy businesses. Currently there is nothing preventing consumers from seeking to do this. Enabling a standard multilateral arrangement managed by individual consumers is unlikely to be effective for mass market consumers. The transaction costs of negotiating individual agreements are likely to be high. In addition such an arrangement would not realise the benefits of increased firmness from aggregation. Noting this, there may be a need to have additional measures to promote such agreements, such as standard contract forms, obligations on other parties to engage in negotiations and so on.

- Option 2. Consumers who were seeking to realise wider benefits from DSP could appoint an agent to manage their DSP. This option would reduce the difficulties of dealing with incumbent networks, since an informed agent would conduct any negotiations on their behalf. It would also realise greater value from aggregation. Mandating that all agreements have to be mediated through third parties, may delay progress on simpler mechanisms or models. As with option 1 there is nothing presently to prevent these negotiations however there could be an argument for the existing rules to be enhanced to assist and facilitate it.

- Option 3. This would be in the form of an obligation in the NER on the contract parties to seek additional value from other businesses. For example, if distribution businesses enter firm DSP contracts for network support they would be obliged to also contact the customer's energy supplier to seek to negotiate any additional benefits from the energy savings when the DSP was called. Similarly, if the consumer entered a contract enabling remote load control managed by the supplier then an obligation would be placed on the supplier to contract the distribution business and seek to obtain additional value for the consumer, for example through a reduction in network charges.

  This option would see either the supplier or the network business negotiating on behalf of the consumer to realise additional benefits from the use of their DSP. This approach would have lower transaction costs and is more likely to realise the benefits from aggregation. However it does not resolve of the issue of whether the energy or network benefits should be treated as residual.

Preferred approach

Overall, it would be possible to realise additional value through any of these routes. Taking this into account, we consider that it is not necessary to mandate a single mechanism for implementing multilateral frameworks at this stage. As we have recommended, the preferred approach would be to better support for the role of third parties in negotiating such agreements, and to seek to reduce the transaction costs of the different mechanisms.

We believe that this can be achieved through the proposed recommendations put forward for DSP in the wholesale market, and modifications to the demand management incentive scheme, that includes allowing DNSPs a share of non-network benefits associated with DSP. In addition, these could be supported by standard methods for valuing DSP costs and benefits.

Arrangements for energy services companies

We have identified in the review that third parties can play in coordinating the actions of parties along the supply chain to capture the value of DSP.

Opportunities for a consumer to capture the benefits from a DSP option are based mostly on negotiations with a market participant. Hence the expertise and commercial bargaining skills of consumers, or a third parties on their behalf, will determine whether the DSP option receives the appropriate price for its benefits.

We have identified that a range of market conditions are needed to enable the effective participation of ESCOs in the energy market. These include:

- Access to consumer data to develop attractive products for end-use consumers;
- Supply chain incentives needing to be aligned to create incentives for DSP activities; and
- Some industry-specific consumer protections.

In this report we outline a number of ways of increasing the provision of information directly to consumers, and to entities such as ESCOs. For example, while it is possible for an energy company to access consumers' consumption data with their consent, this may not be sufficient for them to develop products for the broader residential consumer market. On this basis, we are proposing changes to the rules to allow AEMO to publish market information on representative consumer sector load profiles. We have considered that broader market information would assist third parties to develop DSP products and services and improve efficiency of energy services to consumers.

We note that the Prime Minister's Task Group on Energy Efficiency closely considered the role of ESCOs in the Australian market, albeit in relation to energy efficiency. The task group identified several issues associated with the development of an effective ESCO market to facilitate the uptake of energy efficiency measures, including low awareness of ESCO activities, the transaction costs and risks, low demand and limited capacity and capability. On that basis, the task group recommended a set of actions. These included establishing a financing mechanism to support energy efficiency improvements across community facilities, improving energy efficiency of government buildings and self-regulation of the ESCO sector to increase confidence in the quality of ESCO products and services.

We considered in more detail the transaction costs and risks of ESCO activities. Typically, financial institutions may perceive the risk of energy efficiency or DSP related project to be high, which results in higher lending costs. In turn, this affects the feasibility of projects and the timeframes for cost recovery. For example, for the size of the funds being borrowed a financial institution may expect to recover the funds over a five year period, but the project may require a ten year period for the recovery of funds.

Many governments, internationally and in Australia, have introduced various forms of public partnerships to overcome the ESCO funding issues. In Australia, these mainly relate to energy efficiency programs and have been created at various levels of government, including local government.[219] Some of the schemes may involve direct government funding, or a government backed guarantee to reduce the effective costs of funding the activity. For the most part, these types of programs are aimed at improving energy efficiency measures for both large commercial buildings and the residential sector.

Preferred approach

219 For example, Green Building Fund, Melbourne City Council 1200 Buildings initiative.

In conjunction with the recommendations set out in this draft report, we consider that the market conditions necessary to enable ESCOs to operate effectively in the energy market can be addressed. It is expected that the market for ESCO activity will develop appropriately as the levels of DSP increase in the market, and DSP is viewed as an acceptable means of managing energy consumption.

In order to improve ESCO capability in this area, and to develop the market for ESCO activities, there is also potential for government schemes aimed at improving energy efficiency measures to also include DSP actions in their eligibility requirements. This would improve existing interaction between EE and DSP policies and actions.

Establishing a virtual DSP market/exchange

An alternative mechanism to all of the above which could be established is a virtual DSP/market exchange, similar perhaps to the gas bulletin board. We outline the form this might take and the practical issues in developing a solution of this kind.

Form of market or exchange

There are several options that could be considered for a DSP market. These include:

- *A contact network or bulletin board*. This could be used for DSP providers to give their contact details and some information on location, load, DSP availability etc. This would reduce the transaction cost for DSP users in finding DSP providers. It would leave a significant negotiation to be undertaken once contact had been established. A contact network could also increase competition for some types of DSP and so increase the share of economic rent likely to go to DSP providers. This is credible where multiple DSP users could realise similar value from the DSP.

- *An indicative offer network*. This could establish greater rigour around the information required by DSP providers. The bulletin board might require offers to be in a particular form specifying the location and size of load, the frequency with which DSP could be called, the duration when called, the firmness and other characteristics. An network would presumably include information on the price at which DSP is offered.[220]

- A further measure might be a scheduling network where DSP providers make offers which are callable by DSP users – network businesses, energy businesses or others. This would add on a substantial increase in the rigor attached to offers. Pricing rules would be needed. Prudential and settlement

220 This would provide potential suppliers of DSP with more information on the private value attached to DSP by other providers and so might lead to price convergence over time. The additional information on nature and price of DSP would reduce the transaction costs for DSP users but would increase the transaction costs for DSP providers. This might act as a deterrent and so reduce the level of participation. It might also encourage the growth of intermediaries (such as aggregators).

requirements would be a major issue if these were handled through the exchange rather than bilaterally.

These options all assume that the form of the auction is one with a single seller (the DSP provider) and multiple buyers (potential users of DSP). An alternative would be a market where there is a single buyer and multiple sellers. For example, a distribution network might seek DSP at particularly strategic locations in the network and might auction the opportunity to provide this DSP. The requirement would presumably be DSP that is firm and callable at particular locations and during short periods of peak network flows. The distribution business would take offers up to the capacity required or the limit price set by the cost of network expansion.

More limited markets such as this may be less attractive – since they provide less benefit in terms of overall efficiency gains. However they may be a good deal simpler to organise.

Considerations

In selecting between these and other choices it is useful to consider the nature of the problem, including information asymmetries, transaction costs and potentially market power:

- Information asymmetry arises because DSP users do not know a consumer's willingness to provide DSP. Similarly consumers do not know the private value of other potential DSP providers or the value to the retail/network business of any DSP they might provide. Consumers also do not know the sensitivity of that value to key characteristics – for example, would the value go up a lot if they could offer longer DSP, shorter notice periods etc.

- Transaction costs arise because it is currently costly for parties to overcome these information asymmetries. There may also be further transaction costs in operating DSP once the barriers to an initial agreement have been overcome – such as monitoring and verification costs.

- Market power arises because – for some DSP uses – there is only one DSP user. This means that DSP providers cannot establish the value to the network business through competitive processes or test it through consulting other potential users. The problem is greater because the value to network businesses of short periods of DSP at the right time and location are potentially very high.

Preferred approach

The extent of the problems varies between potential DSP uses. Some uses provide an energy value by shifting consumption from periods of high wholesale prices to periods of low prices or by reducing consumption during high price periods.

There is a clear and transparent basis for valuing energy benefits. There is a large and liquid energy market with published half-hourly prices which are very similar within regions. This is supported by the contract market which provides similar value to retailers by hedging them against high wholesale prices.

These characteristics are very different from the relatively opaque arrangements in the gas sector – and the initial rationale for establishing the gas market bulletin board. By comparison the electricity market has a very large volume of published information. The gross pool arrangements in the NEM support this. As a result the missing information in the DSP market is much more granular than it was in the gas market – the value of DSP at particular locations and the private value of potential providers.

Finally there is a competitive retail market and established processes for customer transfer. These features make it easier to value the energy benefits and it is more likely that a larger share of the economic rent will be realised by consumers.

Some uses provide a network value. The value may be from shifting consumption from periods of peak network flow to lower flow periods or by reducing consumption during peak flows. There may also be other values which are less developed.[221]

This draft report outlines a number of recommendations that, if implemented, would establish the appropriate institutional framework to enable market- led solutions for valuing DSP. Foremost, efficient and cost-reflective price signals for a variety of consumers, from large C&I users to residential and small business consumers, is the one of the most effective ways of capturing the value of DSP actions.

We have also recommended actions to more effectively involve third parties in the energy market to better capture the value of DSP options by alleviating some existing information asymmetries. This includes better information provision to consumers on their consumption activities and more detailed profiles of different segments of the consumers.

In addition to this, we have recommended ways to improve the regulatory arrangements to enable network businesses to better incorporate DSP options into their network planning process.

The range of recommendations in this report provides a sound basis for encouraging the uptake of efficient DSP. We consider that developing the appropriate regulatory and market arrangements for the efficient uptake of DSP is an ongoing issue as the market adapts and evolves as increased awareness and new technologies shape the breadth of DSP opportunities. In this regard, the effectiveness of our recommendations will need to be continually monitored, with possible future additional refinements made to the market and regulatory arrangements.

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221 The Capacity to Customers project in ENW's distribution network in the UK suggests that significant value can be realised through using DSR very infrequently – perhaps only once every few years – to assist with fault response and reduce network redundancy for this purpose. Further details at http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=153&refer=Networks/ElecDist/lcnf/stlcn

9 Energy Efficiency measures and policies

Summary

Energy efficiency (EE) can help consumers manage their electricity use and their bills.

In accordance with the terms of reference for this review, we assessed the regulatory programs that impose a direct obligation or incentive on NEM participants to promote efficient DSP in the NEM. The measures we looked at therefore included the New South Wales, Victorian and South Australian regulatory energy efficiency schemes, and the Commonwealth Energy Efficiency Opportunities (EEO) program.

In light of our assessment of these schemes, we consider that:

- The electricity market should provide the right signals for uptake of DSP and EE on a sustainable basis. As such, the issues of peak demand and facilitating efficient DSP outcomes should be addressed within the market and not external to its regulatory arrangements.
- Any regulatory schemes relating to energy efficiency need to address the secondary impacts that they are likely to have on the electricity market and its participants. It is important that these schemes do not impose unintended impacts on the market, for example, upward pressure on electricity prices.
- The existing schemes do not consider the full range of DSP options (ie those that have peak demand reduction potential) available to consumers, hence the right information on total DSP options and rewards may not be provided.
- Better coordination of EE and DSP policy and measures is required to drive new and competitive electricity services and take up of DSP. This may help bring about cost efficiencies and a more rational allocation of resources for both program providers and consumers. This coordination could help consumers, as it may provide a packaged approach to managing their energy usage.
- Improving the measurement of, and level of publicly available data on the load shape impacts of EE measures on electricity demand (average and peak) should be undertaken. Consideration should also be given to making use of available market mechanisms, regulatory arrangements and/or program design and requirements to develop and disseminate data.
- Existing or future EE regulatory scheme could be used to focus on, and help, low income households manage their electricity use and impacts of electricity prices (noting that the associated costs of implementation would need to be considered).

We have had regard to the work of the Australian government who is scoping the need for a national energy savings initiative as part of its Clean Energy Future package. Our analysis aims to inform that process.

9.1 Market conditions for uptake of efficient DSP

For this review, we have characterised energy efficiency opportunities as a form of DSP. Energy efficiency involves using less energy to produce the same level of output, or using the same amount of energy to deliver a higher level of output.[222] Energy efficiency opportunities can be those offered under the suite of regulatory programs in place or energy efficiency actions taken up by consumers independently.[223]

There are a number of policies and regulatory measures introduced by state and federal governments to encourage improvements in energy efficiency. These measures include education and information programs; obligations for minimum standards on appliances, products or buildings; direct financial assistance, such as grants or rebates; and market based schemes (ie. white certificate schemes).[224]

This chapter focuses on our analysis of the regulatory energy efficiency programs that directly impact or seek to integrate with the NEM. We also consider the extent to which energy efficiency measures and policies promote the efficient use of, and investment in, DSP in the electricity market.

The Australian government is considering the need for a National Energy Savings Initiative (NESI) as part of its Clean Energy Future package. Council of Australian Governments (COAG) has also established a taskforce to determine how to fast track and rationalise policy and programs that are not complementary to a carbon price, or are ineffective, inefficient or impose duplicative reporting requirements on businesses.[225] We have had regard to this work in the review.

9.2 Issues identified

The SCER has specifically requested that the AEMC assess the potential for energy efficiency measures and policies to promote the efficient use of, and investment in, DSP in the stationary energy sector. As part of this work, we were required to undertake a stocktake and analysis of regulatory arrangements for energy efficiency measures and policies that impact on, or seek to integrate with, the NEM, for example, retailer

222 Prime Minister's Task Group on Energy Efficiency, Final Report 2010, p.27.

223 Actions can include installing more efficient appliances and/or equipment or engaging a third party to provide energy audits/assessments of household or business operations.

224 Further discussion and description of these various policy and regulatory measures is presented on pages 11 through 14 of OGW's Stage 1 Report.

225 http://www.coag.gov.au/node/431#Progress on Seamless National Economy Reforms

obligation schemes.[226] As previously indicated, given the number of regulatory energy efficiency measures or programs in place, we have limited our assessment to only those existing regulatory policies and measures that impose a direct obligation or incentive on NEM participants (ie retailers).

In the directions paper, we highlighted that we would be undertaking our work in two stages. The first stage focused on identifying those programs that would be part of the stocktake and analysis, with commentary on other domestic and international programs in place. The consultant report by Oakley Greenwood (OGW) report was published with our directions paper in March 2012.[227]

The second stage and focus of this chapter, involved assessing the effectiveness and cost-efficiency of those regulatory measures and policies identified and consideration of the areas outlined in the section 9.2.1. This work was undertaken by OGW and their final report is provided on the AEMC power of choice webpage.[228]

OGW adopted two different approaches for the analysis – both static analysis and market modelling. The use of these approaches allowed for the following to be considered:

- The longer term economic value of the regulatory policies and measures to the electricity supply chain as a whole, participating consumers in the program and all electricity consumers; and
- The impact of the regulatory policies and measures on the actual operation and costs of the wholesale market of the NEM.

The static analysis

- Every unit (MWh) of energy saved and every unit of reduction in system-coincident peak demand[229] that results from implementing specific energy efficiency technologies incentivised by the program provides a benefit; and
- Values those benefits at the avoided cost of the marginal fuel used for generation and the avoidable cost of infrastructure used to generate and transport electricity.

226 http://www.aemc.gov.au/Media/docs/MCE%20Terms%20of%20Reference-35e6904a-e39d-4348-8ad5-1a7970af354d-0.pdf

227 http://www.aemc.gov.au/Media/docs/Stage-1-Report---Stocktake-of-EE-Policies-and-Measures-that-impact-or-seek-to-integrate-with-the-NEM-497bcc08-9233-4ca6-8dc4-3a4ffd446336-0.PDF

228 http://www.aemc.gov.au/market-reviews/open/stage-3-demand-side-participation-review-facilitating-consumer-choices-and-energy-efficiency.html

229 System coincident peak demand refers to the demand that a specific end-use, facility, or customer segment places on the electricity supply system at the time the system experiences its maximum demand for the year.

These assumptions make the static approach relatively straightforward to calculate. This approach enables valuation of the network benefits (and particularly distribution system benefits) of energy efficiency that may accrue over an extended period of time and whose geographic location is not precisely known.

It is important to note that the static approach can over-simplify the value of the impacts of energy efficiency programs. This over-simplification results from the very aspects of the static approach that make it easy to use. These aspects include:

- Assuming that the technology measures under the programs always reduce the use of a specific fuel used in generation (ie marginal cost of generation). In practice, energy reductions that occur at different times will reduce the use of different fuels.

- Assuming that every reduction in peak demand will reduce the need for capital investment in generation and network capacity. In actual practice, no reduction in capital investment will actually be experienced in the generation sector until such time as additional capacity is needed. Capital investment in network infrastructure (and particularly the distribution network) is driven by local rather than whole of network considerations.[230] Generally, this cannot be projected with accuracy for more than about five to seven years, and can only be deferred if demand reduction equal to approximately a year's worth of local peak demand growth is achieved by the time the capacity augmentation would need to be committed to.[231]

Market modelling

A wholesale market simulation model was used in the analysis. The model optimises electricity market investment and operation over a number of years, taking into account the physical realities of the electrical power system.

In particular, it allows assessment of the longer term implications of the energy efficiency programs investigated on the timing, amount and type of new capacity market entry, and the use of different types of plant (fuel types) for generating the amount of electricity required. In combination these data allow estimation of the impact of the programs on the cost of electricity at the wholesale level.

However, the market modelling could only address the impacts of the energy efficiency programs on the wholesale market. A similar level of modelling was not possible at the network level due to both the amount of data that would be required (the capacity augmentation needs of each distribution business would need to be assessed at that local area level) and the relatively short timeframe over which such

230 Most importantly the current headroom between installed capacity and current peak demand, and the rate of growth in peak demand.

231 A smaller quantum of demand reduction can still have value – by either reducing the amount of load at risk prior to augmentation and/or potentially deferring the next capacity augmentation within that local area. However, these values are unlikely to be as large as the value of the deferral of the initial augmentation.

capacity requirements are generally assessed within the networks (generally five to seven years as compared to the 20 year timeframe used in the wholesale market modelling).[232]

Comparison of the two approaches and other modelling considerations

The static analysis gives a more holistic - if simplified and approximate – assessment of the economic value of the energy efficiency programs across the electricity supply chain, as compared to the more fine-grained estimate of the likely financial impact of the programs on the generation market. There are some important considerations that need to be taken into account in the context of the analysis. These are:

- In all cases, the analysis assessed only the impacts of the energy efficiency measures that had been installed in the 2009 and 2010 calendar years (in the case of the three state-based retailer obligation programs, these were the first two years of the programs' operation).
- This was done in recognition of the fact that:
  - the impacts of these programs on the electricity supply chain are entirely dependent upon the types, number and relative proportions of energy efficiency measures installed under the programs, and
  - the types of measures and their absolute and relative implementation over time was likely to change.
- Therefore, it was considered more realistic to assess the impacts of what measures had been installed rather than to try to forecast the types of measures that might be included in the programs in the future, as well as the relative proportions in which they would be taken up.

Consequently, the analysis should not be seen as comprising an evaluation of these programs or even a complete assessment of their likely impacts on the electricity supply chain. Rather, they should be seen as a reflection of the types of impacts that these programs can have. Importantly, since the studies were undertaken, each of the programs has changed since those first two years. There is every indication that they are likely to continue to evolve, including with regard to the specific measures that are installed.

9.3 Considerations

This section discusses our findings from the analysis undertaken for the programs included in the stocktake and also provides our considerations with respect to the interaction of EE and DSP more broadly. Our assessment specifically considered, in

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232 http://www.climatechange.gov.au/government/initiatives/energy-savings-initiative/progress-report.aspx

accordance with the MCE terms of reference, the extent to which the policies/measures:

- facilitate efficient consumer DSP and electricity use decisions;
- recognise or reward efficient consumer DSP actions;
- invest directly in energy efficiency opportunities;
- enhance the level and transparency of information identifying DSP opportunities; and
- enhance the potential for NEM infrastructure and systems (i.e. market settlement systems, smart metering, smart grid technologies) to support efficient use of, and investment in, DSP.

9.3.1 Outcomes of analysis of regulatory EE schemes

For the Stage 2 analysis we considered the following programs:

- The Commonwealth Government Energy Efficiency Opportunities (EEO) program. This places an obligation on very large companies to assess their energy use and report publicly on the results of the assessment, including all measures that exhibit a payback of four years or less. While there is no requirement that companies adopt any of the identified opportunities, they are required to disclose which energy efficiency opportunities they plan to take up.[233]
- The three state-based programs that put an obligation on electricity (and in some cases gas retailers) to achieve a targeted level of energy efficiency with end-use consumers eligible within the program. These three programs are:
  - The South Australian Residential Energy Efficiency Scheme (REES),
  - The Victorian Energy Efficiency Target (VEET), and
  - The New South Wales Energy Saving Scheme (ESS).

The above programs were selected from the much larger number of government initiated measures aimed at improving end-use energy efficiency because they impose an obligation of one sort or another on either an electricity market participant, or the consumer.

The OGW Stage 2 final report provides a detailed discussion of the analysis undertaken. The key findings from the study relating to the impacts of the programs on the electricity supply chain are as follows:

233 http://www.ret.gov.au/energy/efficiency/eeo/extension/Pages/EEOElectricityGas.aspx

- At the time they were studied the three state-based retailer obligation programs were quite small, but were found to have had a modest downward pressure on average price in the wholesale electricity market.
- The economic cost/benefit tests that have been undertaken in the static analysis suggest that the programs produce:
  - Significant benefits for those consumers who participate in the programs:
    - The energy efficiency technologies incentivised are widely recognised as being effective in reducing the energy consumption of the specific end-use to which they apply.
    - In most cases, the programs have resulted in incremental take-up of these technologies as compared to business as usual (there were some instances in the early years of some of the programs, where the technologies being incentivised that had already achieved a significant level of take-up in the market without incentivisation).
    - The consumers targeted by these programs in large, have accumulation meters, meaning that only energy savings (as compared to load shape changes) would provide benefits. There is very little reliable information on the load shape changes engendered by the energy efficiency technologies targeted by the programs.
  - Material benefits in terms of avoided or deferred economic costs for fuel and capacity that exceed the sum of the costs incurred by all parties
  - The likelihood of upward pressure on the unit price of network charges, which could have inequitable or regressive distributional effects. At least one of the programs – South Australia's REES - enables such impacts to be mitigated by having a target for low-income participation within the overall program target. Appendix A provides an overview of the SA approach.

It must be noted, that these impacts are entirely a function of the change that the energy efficiency measures installed under them engender in the electricity supply load profile. This load shape change is a function of the specific mix and proportion of the energy efficiency measures taken up, and the results in analysis reflect only those measures taken up in the first two years of these programs.

Since that time, different measures have become eligible for incentives under the programs, and this is likely to continue as: the various measures within each program reach market saturation levels; are removed from eligibility; as other measures become attractive due to price changes or program target levels; or the programs are expanded to additional market sectors.

Generally stakeholders who commented on the issues relating to EE considered that:

- There was a need for a nationally co-ordinated focus on improving energy efficiency, particularly in the context of a carbon price, including amalgamating the state EE schemes with a national scheme as being considered by the Australian Government.

- Approaches to EE should be cost-effective, evidence based and complementary to existing market frameworks and economic regulations.[234]

- Harmonisation of the existing state schemes or transition to a national scheme will alleviate jurisdictional differences and assist to facilitate the role of aggregators in the market.[235]

- A national energy efficiency scheme may help to ameliorate some of the potential negative impacts of DSP measures on energy affordability, provided that efforts are directed at low-income households with high consumption patterns.

The large user groups however noted that many of the energy efficiency programs are inefficient and require cross subsidisation to provide the funds for them. They noted that levying consumers with the cost of these programs and then giving them something "free" does not drive consumers to be involved with DSP. Rather, it was their view that DSP should be about consumers implementing actions on their own behalf because they see a benefit rather than being forced to do something. If consumers can see a clear benefit, then they are most likely to take action. For these parties, this means that the focus of these policies must be on enabling consumers to take action with the rewards covering the costs and providing the incentive.[236]

The analysis undertaken by OGW outlines a number of considerations which governments should be have regard to when aiming to establish or developing energy efficiency measures and policies. We present these in Box 9.1.

Box 9.1 Recommendations for designing EE policies and regulatory schemes - electricity market perspective

- A more integrated approach to EE and DSP policies is needed. Currently, the existing programs are disparate and there are differences in how they are delivered, measured and offered to consumers.

- Regulatory EE scheme could be utilised to:

  - address information and behavioural barriers by enhancing consumer education about how electricity consumption impacts their bills (ie cost impacts of using different appliances/equipment).

234 Refer to Appendix D - Stakeholder submission summary to the power of choice review directions paper.

235 Clean Energy council, directions paper submission, p.6.

236 MEU directions paper submission, p.42.

- reduce the costs of using appliances, provide rebates and low interest finance to invest in more efficient appliances.
- help low income households manage consumption and the impact of electricity price rises.

- Best practice design principles for EE schemes have been established by COAG. In theory, appropriate considerations of the interactions of the energy market will be included. In practice, it depends on how government departments adhere to these principles.
- Policy and design of scheme/measures should ultimately aim to consider:
  - Objectives of scheme/s: – to date state EE schemes that have one or more objectives can have undesirable outcomes. The secondary/unintended impacts must be considered (ie load shape changes of these programs and the impact of those changes on wholesale and network prices).
  - Measures to be included: – the full suite and potential of DSP options have typically not been considered. These should be made available, where appropriate. It is likely that this will improve coordination of EE and DSP to some extent.
  - Compliance – better reporting of impacts on peak demand and load factor of electricity supply system (AEMO forecasting) and use of metering or settlement systems to support measurement of impacts. Our proposals regarding metering and use of data should help improve such processes.
  - Engagement with energy market institutions when developing policy and undertaking market modelling.[237]

9.3.2 Improving the coordination of EE and DSP – considerations for a national energy savings initiative

It is important to recognise there are differences in how DSP and EE actions are perceived in the market and mind-sets of policy makers. Because most demand response programs in effect today are event driven, consumers tend to assume that demand response events occur for limited periods that are called by either the network or system operator. Energy efficiency is seen as leading to a gradual, permanent adjustment to energy consumption growth in the long term. Hence, there are significant differences in how energy efficiency and demand response are measured,

237 We note that the AEMC, AEMO and the AER have been involved in the Australian government's work on considering a NESI.

what organisations offer them, how they are delivered to consumers and how they are rewarded in the market.

Greater coordination of energy efficiency and demand response programs could bring about cost efficiencies and a more rational allocation of resources for both program providers and consumers. This coordination could help consumers by providing a packaged approach to managing their energy usage. In turn, increase demand response market penetration, allowing energy savings to be captured and consumer bill-reduction opportunities that might otherwise be lost.

Over the long term, smart grid investments in communications, monitoring, analytics, and control technologies will reduce many of the distinctions between energy efficiency and demand response and will help realise the benefits of this integration. A number of Australian examples of integrated EE and DSP trials were outlined the Futura report commissioned for the AEMC.[238] In box 9.2 we present some other examples of where EE and DSP can interact and have helped to deliver savings to parties.[239]

Box 9.2 Example of United States programs serving both EE and DSP

- Austin Energy, Kansas City Power & Light, Long Island Power Authority, and others offer residential "smart" thermostat programs that provide customers with communicating programmable thermostats in return for participation in a demand response program that curtails load during a limited number of summer hours. This is achieved by raising the thermostat's set point. When properly used, programmable thermostats can also provide daily energy savings.

- Sacramento Municipal Utility District (SMUD) implemented the Small Business Summer Solutions Research Pilot in summer 2008 targeted to small commercial customers with peak demands less than 20 kilowatts (kW). Building on an energy efficiency audit and conservation and efficiency options, the demand response component gives consumers critical peak rates, options to install communicating programmable thermostats, and a variety of pre-cooling and conventional control strategies. This integrated approach led to a 23 per cent reduction in weather-adjusted energy use and a 20 per cent average peak load reduction on critical peak event days.

- The New York State Energy Research & Development Authority offers incentives for prequalified measures and performance-based incentives to customers and ESCOs for electric and gas efficiency, as well as incentives

238 Futura Consulting, *Investigation of demand side participation in the electricity market*, report for the Australian Energy Market Commission, 8 December 2011.

239 Ernest Orlando Lawrence Berkley National Laboratory, *Coordination of Energy Efficiency and Demand Response*, Report for the United States Department of Energy, January 2010

that offset the cost of demand response-enabling equipment, such as load-shedding controls and automation equipment.

Stakeholders reiterated their views on the importance of coordinating EE and DSP, and that energy efficiency measures and DSP are potentially poorly linked. There was support for better consumer education in relation to the difference between energy efficiency policies and schemes as distinct from policies and incentives focused directly on peak network demand.

Generally, there was a view that there is a risk that the promotion of energy efficiency without appropriate information and incentives around peak demand management will result in less efficient overall network usage with little or no reduction in peak demand. That is, some energy efficiency measures can reduce average demand, but have little impact on peak demand. By reducing distribution network utilisation, such initiatives can increase the unit (per kWh) cost of distribution prices, as the total cost of distributing energy remaining largely unchanged, but the number of units materially reduces.

Stakeholders also raised concern on utilising EE measures and policies to address peak demand, including:

- EE schemes should be overcoming barriers to allocative efficiency and hence EE schemes should not be utilised to specifically target peak demand. EE schemes should be implemented in conjunction with information, education on peak demand and suitable time-of-use pricing regimes. A reduction in peak demand would then be an outcome of improved energy efficiency - complementary to DSP measures.[240]

- EE schemes should sit outside the economic regulatory framework for distribution network services. Such schemes generally lack flexibility in locational and timing signals to deliver the most cost effective DSP responses, which are targeted towards the constrained areas of networks at the right time to appropriately capture network infrastructure cost savings benefits.[241] This is because they were typically designed to achieve carbon reductions, rather than focus on reducing peak demand.

External to the AEMC process, the Australian government, under its Clean Energy Future package, is assessing how to:

> *"expedite the development of a national energy savings initiative (ESI) and . . . examine further how such a scheme may assist households and businesses to adjust to rising energy costs,"*[242]

240 AGL directions paper submission, p.10; Origin Energy directions paper submission, p.25, International Power, directions paper submission, p.10; Powercor Citipower directions paper submission, p.13, United Energy directions paper submission, p.24; ERAA directions paper submission, p.32.

241 Powercor Citipower directions paper submission, p.13.

242 Australian Government, Report of the Prime Minister's Task Group on Energy Efficiency, Canberra, July 2010, p. 81.

The package further stated that the ESI itself would:

> *"have broad coverage (that is residential, commercial and industrial sectors); and create an incentive or a requirement to create certificates in both low income homes and in ways that reduce peak electricity demand".*[243]

In accordance with that commitment, the Australian government has undertaken a study to consider how incentives to reduce peak demand could be integrated with the approach(es) being considered for either the harmonisation of the existing state-based retailer obligation schemes or their replacement with a national scheme.

The AEMC has been involved in this assessment (which is still in progress). We have stressed the importance of policy mechanisms to promote energy efficiency, greenhouse gas emissions reductions, or indeed any other objectives that may affect the electricity market, explicitly consider those effects in the program's design and the assessment of its benefits and costs.

In particular, the inclusion of mechanisms to incentivise efficient DSP – or at least take into consideration the impacts of EE measures and policies on the electricity market – in programs such as a NESI can assist in:

- Providing signals to customers regarding the impact of when they use electricity – in addition to how much electricity they use – on the electricity supply system and indeed their own electricity costs.
- Building awareness of and capability regarding DSP within the private sector firms that are delivering the existing and potentially expanded energy efficiency programs implemented by governments.
- Protecting the benefit realisation of the ESI and other EE programs by reducing unanticipated deleterious impacts of those programs on both program participants and non-participants.

Based on the work undertaken in Stage 2 of the stocktake and assessment by OGW and taking on board the comments received from stakeholders to the directions paper, we consider that the processes and mechanisms available within the electricity market and associated regulatory framework are the best avenues for providing pricing and other signals regarding the value of peak demand reductions to end-use consumers and private sector firms (including electricity retailers and distributors).

It is unlikely that any single program or policy setting will be able to maximise both energy efficiency and peak demand outcomes simultaneously. Energy efficiency is a very good way for electricity consumers to reduce the energy portion of their electricity bills. It can also contribute to environmental outcomes. However, the impact of energy efficiency on either bills or greenhouse gas emissions is not entirely straightforward. In the case of electricity bills, energy efficiency will reduce the amount incurred for

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243 Australian Government, Securing a Clean Energy Future – The Australian Government's climate change plan, Canberra, July 2011, p.

electricity itself, but may increase pressure on infrastructure requirements throughout the value chain, thereby increasing supply chain costs and putting upward pressure on unit electricity costs. The impact of energy efficiency on greenhouse gas reductions will depend on the marginal generation fuel at the time at which electricity consumption is reduced.

To the extent that energy efficiency is a response to the fact that electricity is priced relatively similarly regardless of when it is consumed, a price signal that incorporates the time differentiated cost of supplying electricity along with the environmental costs of its emissions content would appear to provide a better basis for engendering the development of innovative products and services on the part of the electricity supply chain and third parties, and the use of those products and services by consumers.

However, it is also important for governments initiating policy or program measures that target changes in end-use electricity use to both consider the impact of the policy or program on the electricity supply chain (and consequent impacts on the cost to serve end-use customers) and to include mechanisms within those programs and policies that can mitigate to the extent possible any such deleterious impacts.

Abbreviations

ACL	Australian Consumer Law
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
AEMO	Australian Energy Market Operator
AMI	Advanced metering infrastructure
CEC	Clean Energy Council
COAG	Council of Australian Governments
CPP	Critical peak pricing
DAPR	Distribution Annual Planning Report
DEEDI	Department of Employment, Economic Development and Innovation
DG	Distributed generation
DIISR	Department of Innovation, Industry, Science and Research
DMIA	Demand Management Innovation Allowance
DMIEGS	Demand Management Incentive Embedded Generation Scheme
DMIS	Demand Management Incentive Scheme
DNSP	Distribution Network Service Provider
DSP	Demand side participation
EE	Energy efficiency
EEO	Energy Efficiency Opportunities
ESCO	Energy service companies
ESCOSA	Essential Services Commission of South Australia
ESOO	Electricity Statement of Opportunities

ESS	Energy Saving Scheme
EV	Electric vehicle
EY	Ernst and Young
FRMP	Financially Responsible Market Participant
GFC	Global financial crisis
HAN	Home area networks
IHD	In-home displays
IPART	Independent Pricing and Regulatory Tribunal
IR-TUOS	Inter Regional - Transmission Use of System
LNSP	Local Network Service Provider
LV	Low voltage
MCE	Ministerial Council on Energy
MDP	Meter Data Providers
MV	Medium voltage
NECF	National Energy Customer Framework
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
NERR	National Energy Retail Rules
NESI	National Energy Savings Initiative
NSLP	Net System Load profile
NSP	Network Service Provider
PASA	Projected Assessment of System Adequacy
PJM	Pennsylvania New Jersey and Maryland

PTR	Peak time rebate
PV	Photovoltaic
RAB	Regulatory Asset Base
REES	Residential Energy Efficiency Scheme
RIT-D	Regulatory Investment Test for Distribution
RTP	Real time pricing
SCER	Standing Council on Energy and Resources
ST PASA	Short term PASA
STOU	Seasonal time of use
TOU	Time of use
VEET	Victorian Energy Efficiency Target
WACC	Weighted Average Cost of Capital