REVIEW

Australian Energy Market Commission

FINAL REPORT

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

30 November 2012

Reference: EPR0022
Final Report

Inquiries

Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

E: aemc@aemc.gov.au
T: (02) 8296 7800
F: (02) 8296 7899

Reference: EPR0022

Citation

AEMC 2012, Power of choice review - giving consumers options in the way they use electricity, Final Report, 30 November 2012, Sydney

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

This final report for the Power of choice review sets out our recommendations for supporting market conditions that facilitate efficient demand side participation (DSP).

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 (ie consumers) responds to the price/value of the product or service being offered.

While there is some evidence of uptake of DSP in the NEM over recent years, the efficiency of the electricity market can be improved by more active participation by the demand side. This will require changes to some aspects of how the supply side of the electricity market operates and interacts with consumers.

The overall objective of this review is to ensure that the community's demand for electricity services is met by the lowest cost combination of demand and supply side options. This objective is best met when consumers are using electricity at the times when the value to them is greater than the cost of supplying that electricity (i.e. the cost of generation and poles and wires).

This report

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 electricity expenditure. It includes actions such as energy efficiency, peak demand shifting, changing consumption patterns, and consumers generating their own electricity.

The recommendations form a package of integrated reforms and 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.

The Power of choice review has identified opportunities for consumers to make more informed choices about the way they use electricity. Consumers require tools - information, education, and technology, and flexible pricing options - to make efficient consumption decisions. Recommendations presented in this report will support these conditions and enable consumers to have more control of their electricity expenditure.

The review has also addressed the market conditions and incentives needed for network operators, retailers and other parties to maximise the potential of efficient DSP and respond to consumers' choices. Our recommendations will also help to support co-ordination along the different parts of the electricity supply chain to support efficient DSP.

Three key reforms can help achieve the efficient demand-supply balance in the market:

1. Rewarding DSP in the wholesale market:

Task AEMO with developing a rule change proposal to establish a new demand response mechanism that allows consumers, or third parties acting on consumers' behalf, to directly participate in the wholesale market and to receive the spot price for the change in demand.

This will enhance consumers' ability to participate in the wholesale electricity market by providing an alternative risk/reward mechanism to a spot price pass through pricing option, thereby lowering consumers' information and transaction costs. The mechanism also provides a way of participating in the wholesale market that is separate from the retail energy contract and hence independent from the retailers' own commercial interests.

2. Providing appropriate consumer protection arrangements and gradually phasing in efficient and flexible pricing options:

We propose that this can be achieved through a phased, targeted approach:

(a) Introducing more efficient and flexible retail energy pricing offers for residential and small business consumers through the introduction of cost reflective electricity distribution network pricing structures. Flexible pricing options would be phased in by segmenting these consumers into three different consumption bands and applying flexible pricing options in different ways. Large residential and small business consumers above a defined threshold will be required to have a cost reflective network tariff as part of their retail pricing offer. We have selected this approach as we consider that such 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 in response to more efficient price signals.

(b) 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 flexible pricing offer (ie time varying tariff). We have proposed arrangements for residential consumers that have low to medium consumption levels to have the option to remain on their existing retail price structure.

(c) Government programs relating to energy efficiency to provide more targeted advice and assistance on managing electricity consumption to consumers that may have limited capacity to respond to flexible pricing options. We also recommend that state governments review their energy concession/rebate schemes so that such schemes are appropriately targeted and can manage the potential transition to more flexible pricing. For such consumers, advice and assistance will be crucial and needs to be provided in advance of rolling out flexible pricing reforms.

(d) Revising the existing distribution pricing arrangements to provide better guidance for setting cost reflective distribution network tariffs. We also propose that distribution network businesses engage in a formal consultation process with retailers and consumers when setting their tariffs. These changes will allow for consumer impacts to be properly taken into account in network tariff structures.

3. **Introduce competition in metering services and develop a framework for smart meters and their services.**

Establishing the regulatory framework to encourage commercial investment in smart meters and associated services to promote consumer choice.

Under our proposed model, the onus will be on the retailer or DSP service provider to elicit consumer consent to a smart meter through offering appropriate retail pricing offers and value added services. This approach will support efficient markets as it promotes innovation, greater DSP options for consumers and efficiency in metering costs. This is preferable to retaining networks as the monopoly provider of metering services to households and small businesses.

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. This will require action by governments, retailers, networks, consumers and community organisations and should occur before the introduction of these reforms. Consumers must be aware of what the reforms and DSP options mean to them and the opportunities available.

In addition to these key reforms, we are also recommending a number of supporting changes to improve the ability of the market to maximise the potential of efficient demand side participation:

- **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 will explore in detail 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 and be able to share their data with approved service providers

- **Establishing a transparent framework for third parties offering demand management services in the National Energy Customer Framework:** We recommend that there are transparent arrangements for how third parties directly engage with consumers to offer DSP products and services.

- **Supporting retail competition through arrangements for retailer switching**: We recommend a review into consumer retailer switching arrangements to improve the ease and time for how consumers switch retailers. This review would assess whether the introduction of a maximum time period rule for processing consumer requests promotes the National Electricity Objective.

- **Introducing a new and replacement smart meter program:** The installation of smart meters to occur in defined situations such as refurbishment, new connections and replacement of old meters. Continued installation of accumulation meters today will lead to increased costs for the consumer and system costs in the long term.

- **Improving demand forecasting for market operations in the NEM:** Clarify provisions in the rules regarding AEMO's ability to forecast demand for its market operational functions.

- **Distribution network incentives:** Building a framework that will provide a commercially sound and sustainable basis for making DSP part of the network planning and investment process.

- **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 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.

We have also assessed a number of issues relating to distributed generation. We consider that in developing a set of national ring fencing guidelines, the AER should consider the value of allowing distribution businesses to own and operate distribution generation assets. We also consider that as part of the review into a national approach to feed in tariffs, consideration be given to the ability of time varying tariffs to encourage owners of distributed generation assets to maximise export of power during peak demand periods.

These recommendations can be implemented via a series of rule changes to the National Electricity Rules and National Energy Retail Rules plus a number of government programs. We have attached an implementation plan with this final report which sets out responsibilities, actions and timeframes.

The recommendations will also help to stimulate more effective retail competition by making switching easier and through the development of a DSP market enabling the demand side to compete with the supply side.

In the short term, consumers who have relatively flat demand and/or can shift their demand to off-peak periods would have most to gain from flexible pricing and other DSP options. Over the medium to longer term however, all consumers should benefit as DSP can reduce costs throughout the electricity system.

Difference between our final and draft recommendations

The Commission published its draft report on 6 September 2012 and received a total 65 submissions. In general, there was overall support for the proposed direction of market development and the need for significant reforms. Some parties questioned specific aspects of the proposed package of reforms.

After considering these submissions, and undertaking further analysis and stakeholder discussions, the Commission has retained the bulk of reforms presented in the draft report, except for the following changes:

- **Consumer access to data:** Remove the proposal for AEMO to publish market information on representative consumer load profiles. There are number of issues with AEMO gathering and publishing such data and we now consider that the data may become available through other sources (i.e. distribution annual planning reports).
- **Consumer engagement:** We are now advising that the NECF is amended to establish a framework for governing third parties (non-retailers) providing energy services to residential and small business consumers.
- **Arrangements for consumer switching retailers:** The final report recommends a review into retailer switching arrangements.
- **Metering:** The final report proposes that the minimum specification for any new smart meter installed should be the National Stakeholder Steering Committee smart meter infrastructure minimum functionality specification which has already been endorsed by SCER. This will facilitate and support a full range of DSP activity and support network operation functions. The final report also clarifies that existing load management capability should be maintained under the new arrangements.
- **Distribution network incentives:** Stakeholders supported the need for more principles and a guiding objective for the demand management incentive scheme. This final report now includes a recommended rule change on this matter. We have also removed some of proposed minor rules on the regulatory treatment of DSP costs.

Impact of proposed changes for the market

The Power of choice review is seeking to give consumers more opportunities to actively participate in the market and capture the value of their consumption decisions. Our recommendations will allow consumers to be in a better position to compare the value of electricity services with the costs incurred through the electricity supply chain.

We engaged Frontier Economics to provide a high level estimate of the potential benefits that could be realised under our recommendations. Ultimately, the realisation of such net benefits will depend upon consumer choice and behaviour.

The value of our recommendations is through giving consumers more opportunities to better manage their expenditure on electricity. The costs associated with our recommendations, on a disaggregated level, will largely be incurred only if a consumer decides to opt for a DSP service or tariff. They will only do so if they consider that the potential benefits will exceed those costs.

Reducing peak demand growth will avoid some future network and generation investment and save generation fuel costs. The extent of the reduction differs by state, Frontier Economics estimated that the reduction in NSW, QLD, and VIC could be between 400 MW to over 1300 MW by 2020. These reductions are estimated using likely consumer behaviour based upon results emerging from tariff trials and other DSP mechanisms.

Frontier Economics estimated that economic cost savings of peak demand reduction in the NEM is likely to be between $4.3 billion to $11.8 billion over the next ten years (net present value, 2013/14 to 2022/23) which equates to between 3 per cent to 9 per cent of total forecast expenditure on the supply side. The majority of these savings occur in the network sector given the current over supply of wholesale generation and relatively conservative view of baseline demand growth. This is based upon an assumption that network expenditure continues at the current rate.

The extent of potential cost savings varies across the NEM. Savings are highest in regions with stronger assumed peak demand growth where savings could be approximately $500 per consumer per annum (in South Australia and Queensland). In NSW, the savings per consumer is expected to be around $350 per annum. Savings are less in Victoria, around $120 per consumer per annum. Frontier Economics also note that there may be additional benefits that accrue to consumers due to flatter load shapes achieved if our recommendations are introduced. Their analysis did not seek to quantify these savings.

In addition, a consumer could also benefit from changing their tariff structure and/or adapting their consumption patterns. A consumer with a relatively flat consumption pattern could save around $50 from just changing its tariff structure to a time varying tariff, without any change in consumption pattern. The same consumer could save an extra $100 a year if they are able to shift around 20 per cent of use from the peak afternoon period (2pm to 8pm) to other times. This could involve changing the time when the dishwasher, tumble dryer or washing machine are in use and would reduce that consumer's annual electricity retail bills by 6 per cent.

Other households which have a high peak time usage pattern can reduce their expenditure by up to $200 a year if they are able to reduce their afternoon peak time consumption by around 15 per cent of original use. This could involve cycling of air-conditioning, installing more energy-efficient appliances or not using certain household appliances at that time.

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. Also some of the savings which an individual consumer can achieve through changing tariffs and adapting their consumption patterns may be passed through to other consumers.

The individual residential consumer who changes their retail price offer may face the incremental costs of the enabling technology (e.g. a smart meter). However under our proposed reforms, it not necessary for every consumer to have an enabling meter installed to achieve the extent of estimated the cost savings. Competition in the provision of metering services to energy service providers will minimise the cost of metering and allow consumers to evaluate the benefits of alternative energy service offerings.

Some of these costs will be incurred by the individual consumer who decides to opt for a DSP service or tariff. However such consumers are only likely to do so if they see a clear financial benefit from using less energy when prices are high, or from shifting usage to lower-priced periods. Other costs will be incurred by market participants and will be passed on to their consumers. The modelling estimates of the value of avoided network and generation costs suggest that the benefits are likely to outweigh such costs in the long run.

The recommendations will help to ensure that over time, increases in electricity service 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 electricity services (ie the appropriate balance between affordable and reliable energy supply).

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 small 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, there will be greater potential and opportunity for these consumers to participate in the market.

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.

- The demand for electricity from consumers is a derived demand. That is, the electricity will be used as an input into providing services or making goods. Consumers are not necessarily concerned with units of electricity per se as it is not required for direct consumption, but rather the amenities that electricity provides (e.g. heat, light, and other goods). The value of electricity to a consumer therefore is a function of the value derived from its end use.

- 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 tariffs and retail pricing offers 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 low income 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 offers the prospect of lower electricity costs for all consumers due to lower total system costs in turn, reduce upward pressure on electricity prices to all consumers. Hence it is important that the arrangements for managing expenditure 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).

- Enabling technology can play a very important role in helping consumers understand their energy use and supporting a range of DSP packages that can be offered to the consumer. Under our recommendations, the consumer is expected to be able to choose a DSP service or tariff offers which they can take to reduce their energy costs, with the outcomes they value. The enabling technology will be packaged as part of their DSP service or tariff.

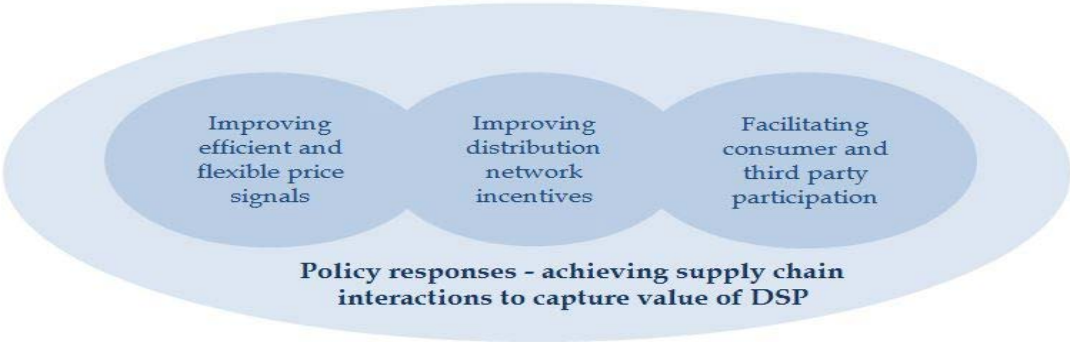
- Retailers and distributors also need to be assured that undertaking DSP will not interfere with their ability to meet their responsibilities in providing safe and reliable power to consumers. The market needs an agreed approach for assessing the value of DSP. The commercial and regulatory arrangements 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 solar systems, co- and tri-generation systems, mini-wind turbines, and other such technologies can provide alternative sources of power, which may 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 consumer choice in this area.

- 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



Changes in technology and consumer consumption patterns 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.

This review has identified a series of recommendations to accommodate these changes, and provide a framework in which supply and demand resources are coordinated to interact more easily and deliver benefits to consumers. These recommendations aim to ensure the market remains robust, flexible and is able to adapt to the changing environment, irrespective of what pattern of demand emerges.

Our approach to this review

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 participation has been extensive and very valuable to the development of the recommendations presented in this final report. We appreciate the advice and evidence provided by various stakeholders including their time and resources committed to the review. The level of consultation during this review has been invaluable in bringing together different interests into a common approach to solving the issues. A consensus has emerged across different stakeholders during this review on the need for significant change.

We have not attached detailed rule changes to this report. Instead we have provided draft specifications of rule change proposals and an implementation plan for all our recommendations. Primarily, the proposed recommendations are for the SCER to consider, and if agreed, to be implemented where appropriate through rule changes and other changes to other regulatory mechanisms.

List of final recommendations for the review

Consumer awareness, education and engagement (Chapter 2)

1. **A comprehensive communication/education strategy is developed to support implementation of the reforms recommended in this review, and to more broadly improve consumer understanding of energy use and relationship to costs. A SCER working group should be established (with participation of stakeholders from consumer organisations and the electricity sector) to develop and manage application of the strategy. This would be supported by the proposed principles in the report for undertaking consumer engagement.**

2. **There is a review of government energy related education and information programs (ie energy efficiency schemes) to ensure an effective and appropriate focus on specific consumer segments.**

3. **There is a review of the existing retailer switching arrangements to better support consumer choice and to make switching retailers more efficient. The review should assess whether a maximum day limit could be introduced in the NEM.**

4. **The National Energy Customer Framework is amended to include a framework which governs third parties (non-retailers and non- regulated network services) providing energy services to residential and small business consumers. The framework would outline which aspects of the National Energy Retail Rules (NERR) apply, and in what circumstances. AER guidelines would be developed to outline NECF exemptions for these services.**

Consumer information – access to electricity data (Chapter 3)

5. **The NER is amended to clarify the arrangements and provide a framework for consumers to request and receive their energy and metering data from their retailer. The framework would provide for:**

   - **minimum format and standard information that would need to be provided to consumers;**

   - **timeframes for delivery of data (ie no costs for standard data format once a year);**

   - **fees that can be charged when consumers request their energy and metering data;**

   - **ability for a consumers agent to access energy and metering data directly from the consumer's retailer (this would be in accordance with appropriate explicit informed consent arrangements); and**

6. **Amendments are made to the NERR to provide each residential and small business consumer with their consumption load profile. At a minimum this should be on a consumer's retail bill.**

Enabling technology (metering) (Chapter 4)

7. **A new framework is introduced in the NER that provides for competition in metering and data services for residential and small business consumers. The SCER endorsed minimum functionality specification for smart meters would be required for all future metering installations.**

8. **A framework for open access, interoperability and common communication standards is established to support competition in DSP energy management services enabled by smart meters.**

9. **The NER require that smart meters be installed in defined situations (ie new connections, refurbishments and replacements). These would also be as per the minimum functionality specification.**

10. **The option of a government mandated roll out of smart meters in the National Electricity Law is removed. This will provide certainty to the market to proceed with commercial investment.**

Demand side participation in wholesale electricity and ancillary services markets (Chapter 5)

11. **A demand response mechanism is introduced that pays demand resources via the wholesale electricity market (rewards changes in demand). 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. We recommend that AEMO develops the details for a rule change proposal and required procedures, including the baseline consumption methodology.**

12. **The NER is clarified regarding AEMO's role in demand forecasting for its market operational functions.**

13. **A new category of market participant for non-energy services is introduced in the NER to unbundle the sale and supply of electricity from non-energy services, such as ancillary services.**

Efficient and flexible pricing (Chapter 6)

14. **There is a gradual phase in of efficient and flexible retail pricing options for residential and small business consumers through the introduction of cost reflective <u>electricity distribution network pricing structures</u>. The phase in of cost reflective network pricing would be through segmenting these consumers into three different consumption bands and applying flexible, (ie time varying) retail pricing options in different ways as outlined in the final report.**

15. **To complement the gradual phase in of efficient and flexible retail pricing options and support those consumers with limited capacity to respond, governments review their energy concession schemes and target government energy efficiency programs.**

16. **Amend the NER distribution pricing principles to provide better guidance for setting efficient and flexible network price structures that support DSP. This includes improving the existing consultation requirements to ensure that consumer impacts are taken into account in price structures/design.**

17. **Amend the NER to require that a residential and small business consumer's consumption (where they have a meter with interval read capability) is settled in the wholesale market using the interval data and not the net system load profile. This will be the case irrespective of the consumers' retail tariff structure.**

Distribution networks and DSP (Chapter 7)

18. **Reform the application of the current demand management and embedded generation connection incentive scheme in the NER to provide an appropriate return for DSP projects which deliver a net cost saving to consumers. This includes creating separate provisions for an innovation allowance.**

19. **Adopt a two-part approach 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 profit under the revised demand management incentive scheme.**

20. **Make minor amendments to the NER to provide (a) clarity that AER can have regard to non-network market benefits when assessing efficiency of expenditure; and (b) flexibility in annual tariff process to manage potential extra volatility of DSP costs.**

Distribution Generation (Chapter 8)

21. **The AER should give consideration to the benefits of allowing distribution businesses to own and operate distributed generation assets when developing the national ring fencing guidelines for these businesses.**

22. **As part of the review into a national approach to feed in tariffs, consideration be given to the ability of time varying tariffs to encourage owners of distributed generation assets to maximise export of power during peak demand periods.**

Energy efficiency measures that impact or seek to integrate with the NEM.

23. **There needs to be greater coordination of energy efficiency regulatory schemes and DSP options available. The objective is to achieve greater recognition of the value for peak demand reductions and the changes to the load profile from the existing energy efficiency schemes.**

24. **Improve reporting and availability of publicly accessible data on the load shape impacts of energy efficiency measures on both peak and average electricity demand.**

Contents

1 Context and benefits of DSP

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 end use services which require electricity (such as hot water or lighting) 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))[1] commissioned the Australian Energy Market Commission (AEMC) to undertake a review of the market and regulatory arrangements across the electricity supply chain to facilitate efficient investment in, operation and use of DSP in the NEM.[2]

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 Terms of Reference for this review specifically require the AEMC to consider the following key areas:

- the efficient operation of price signals, which includes the tariff setting process and incentives for operating and capital expenditure

1 The Standing Council on Energy and Resources (SCER) was established in late 2011 and replaces the previous Ministerial Council on Energy (MCE). SCER is now responsible for progressing key energy reform elements of the MCE.

2 MCE Terms of Reference for the Review: http://www.aemc.gov.au/Media/docs/MCE%20Terms%20of%20Reference-35e6904a-e39d-4348-8ad5-1a7970af354d-0.pdf

- the market frameworks required to maximise value to consumers from services enabled by new technologies (such as smart grid/smart meter and load control capability); and
- the effectiveness of regulatory arrangements for energy efficiency measures and policies that impact on or seek to integrate with the NEM (such as retailer obligation schemes)

The AEMC's recommendations are assessed against the National Electricity Objective (NEO), having regard to the costs and benefits they confer on the market.

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.

This paper uses the following concepts in discussing the main categories of market conditions that can contribute to facilitating and promoting efficient DSP:

- **Parties in the electricity market** include consumers, retailers, network businesses, aggregators, energy service companies (ESCOs), generators and others involved in making decisions affecting electricity supply or use;
- **DSP options** are the actions that are available to consumers – or to intermediaries acting as agents of consumers – to reduce or manage their electricity use. Examples of DSP by consumers can include (but are not limited to) peak shifting, electricity conservation, fuel switching, utilisation of distributed generation and energy efficiency;
- **Efficient DSP** is an action by consumers (either independently or via an intermediary) to manage or reduce electricity consumption which delivers a benefit (e.g. lower costs of electricity) that is greater than the loss in value and costs of the DSP action incurred by the consumer as a result of the decision to change their consumption;
- **Market conditions** are features that need to be present in the electricity market to enable all parties in that market to make and implement informed decisions, while recognising that it is the consumer who makes the final consumption decision. These market conditions can include appropriate information, systems, pricing structures, and technology
- **Market and regulatory arrangements** refer to the measures that facilitate the market conditions. These can include legislation, regulations, commercial arrangements and incentives that help to achieve the necessary market conditions by influencing the behaviour and informing the choices of participants (including consumers) in the electricity market

- **Contracted DSP** promotes consumer participation through a direct compensation payment or incentive. The consumer agrees to curtail their electricity use under certain defined circumstances in return for an explicit payment. DSP resources which can supply capacity, ancillary services and energy reduction with a high degree of certainty tend to be covered by such payments. Examples include network support agreements and direct load control

- **Non-contracted DSP** or price responsive DSP links prices in retail and wholesale markets, with retail consumers receiving a price signal reflecting the costs of supply and delivery of electricity. When high energy prices are correlated with reliability problems or local network constraints, actions taken by consumers to reduce load can have a positive impact on reliability in addition to reducing overall costs. Such DSP can be achieved without prior knowledge by the system operator, retailer or network businesses.

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.[3]

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.[4] The manufacturing sector has experienced a relative decline over the longer term and currently contributes around 10 per cent of GDP.[5] This trend is shown in terms of relative employment shares, by sector, in Figure 1.1

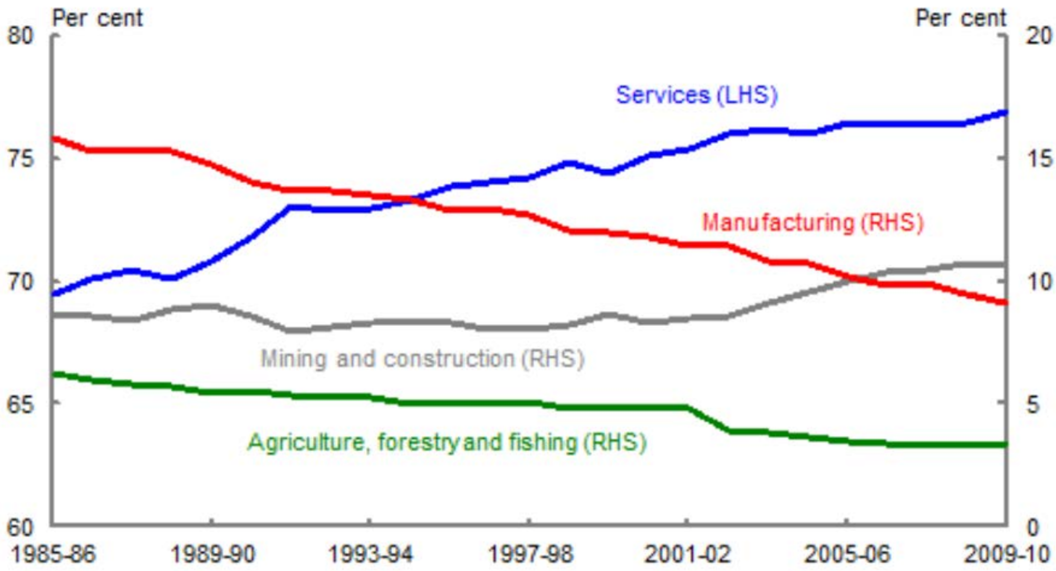
---

3 Energy intensity is the ratio of total final energy consumption to gross value added gross domestic product (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: Bureau of Resource and Energy Economics (BREE), *Economic analysis of end-use energy intensity in Australia*, Canberra, May 2012; BREE, Australian Energy Statistics – Energy Update 2011 Table F, Bureau of Resource and Energy Economics, www.bree.gov.au

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

5 Australian Bureau of Statistics, Year Book Australia 2012, cat.no.1301.0, viewed 20 August 2012, www.abs.gov.au/ausstats

Figure 1.1 Employment share by history

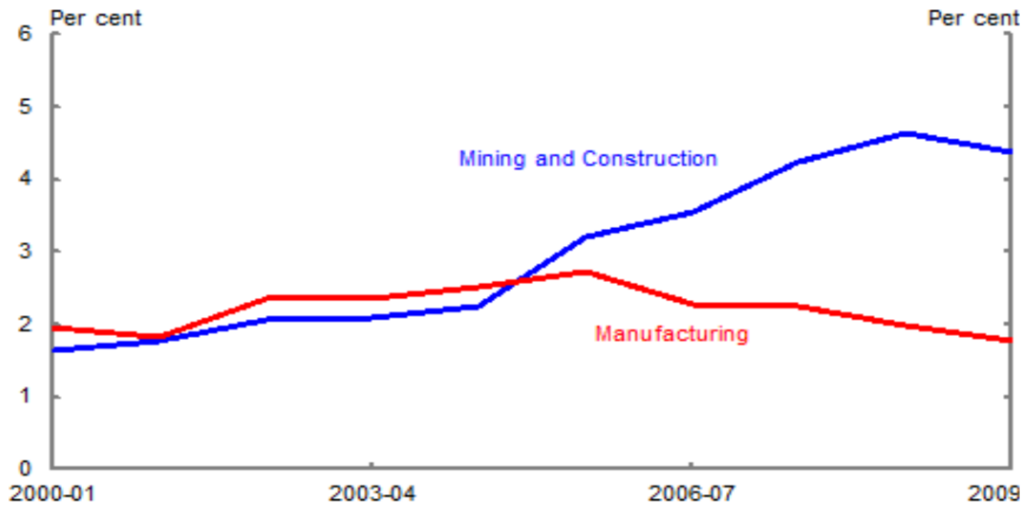


Source: ABS cat. no. 6291.0.55.003 and Treasury.

Source: D Gruen, Economic Roundup Issue 2, 2011, Australian Government Department of the Treasury website (www.treasury.gov.au).

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



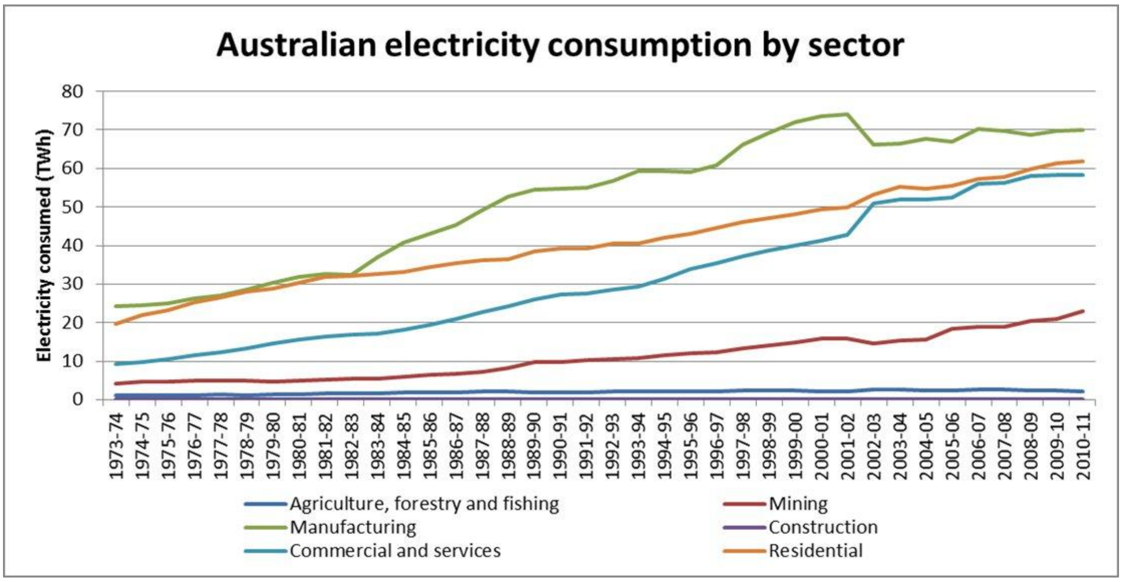
Source: ABS cat. no. 5206.0 and Treasury.

Source: D Gruen, Economic Roundup Issue 2, 2011, Australian Government Department of the Treasury website (www.treasury.gov.au).

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. The global financial crisis (GFC) 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 2008-2009, one of the steepest declines in output since the early 1980s.[6]

These sectoral trends are reflected in the changing electricity consumption patterns of the Australian economy, which is illustrated in Figure 1.3 and 1.4. The relatively energy intensive Australian manufacturing sector has shown a steady increase in total electricity consumed over the long term. The commercial and public services sectors, while substantially less energy intensive than manufacturing, have also shown a steady increase in total consumption over the long term.

Figure 1.3 Electricity consumption in Australia

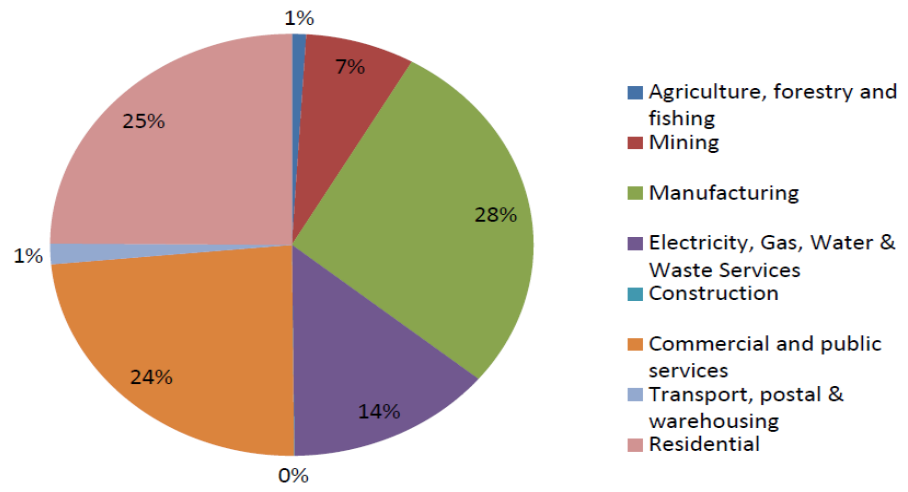


Source: Bureau of Resource and Energy Economics, Australian Energy Statistics – Energy Update 2012.

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, which shows the continuing trend of a decreasing ratio of energy used per unit of GDP in Australia. Changes in residential consumption patterns and the energy efficiency of household appliances have also contributed to this trend.

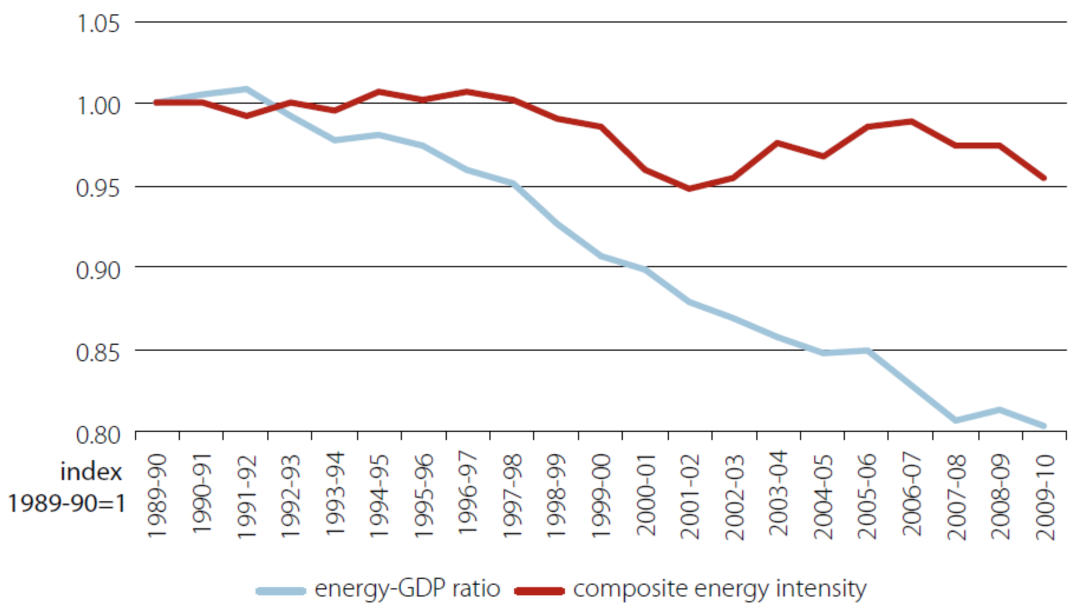
6 Department of Innovation, Industry, Science and Research, *Manufacturing sector overview of structural change: Industry brief 2008/09*, July 2010, p.1.

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

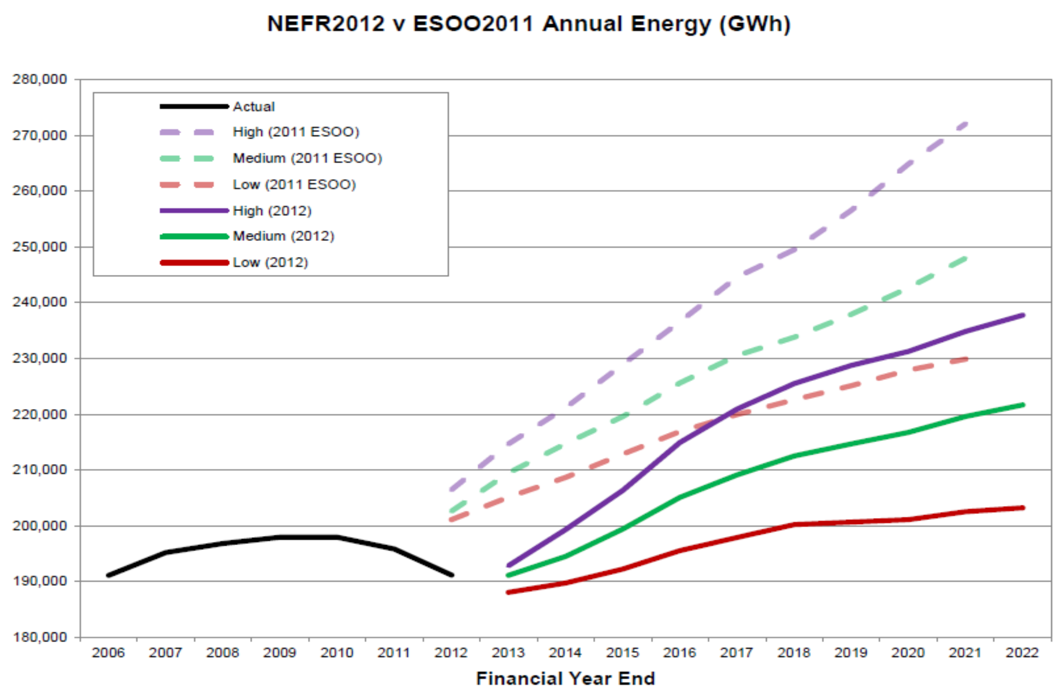
Figure 1.5 Trends in energy GDP ratio



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 this decrease. AEMO also suggest that commercial and residential consumer response to rising electricity costs and energy efficiency measures may be contributing to these changes.[7]

Figure 1.6 Forecast total energy 2011 and 2012



1.2.2 Price of electricity

Electricity prices have increased in recent years. Increases in network costs, particularly in distribution networks, have been a major contributing factor. The introduction of a price on carbon has also begun to place some upwards pressure on prices.

In the future, other factors are likely to begin to influence the price of electricity. While the cost of policies such as the large scale renewable energy target (LRET) are passed on to consumers through retail prices, these policies are also having a dampening effect on wholesale prices in certain jurisdictions. At the same time, various jurisdictional energy regulators around Australia have introduced new approaches to calculating the energy component of regulated electricity prices. These new approaches tend to focus on the current, lower wholesale market price of energy, which may put some downward pressure on regulated retail prices in those jurisdictions.

Although these changes may have some effect on electricity retail prices, it remains likely that prices will increase in the near future. Investment in networks will continue to be a major contributor to these increases. This is primarily due to the replacement of ageing assets, impacts of increasing peak demand, rising costs of finance, input cost

7 Australian Energy Market Operator, *National electricity forecasting report*, Australian Energy Market Operator, June 2012, p.v.

changes (such as the cost of steel, copper, labour), increased reliability standards and connection of renewable generation. Wholesale price increases will continue to be driven by the carbon price as well as input and fuel cost increases.

DSP may help consumers deal with the impacts of any future electricity price rises. Contracting to provide DSP, or responding to new retail tariff pricing offers, may offer an opportunity for 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 the availability of necessary technology. In conjunction with the draft report for the Power of choice review, we released a tariff model from Frontier economics which helps to explain the impacts of different tariff arrangements on consumers' bills and consumption behaviour. In Chapter 10 of this report, we have also included an assessment of the kinds of benefits for consumers that are associated from DSP.

DSP options such as peak demand reduction may 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.[8] 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.[9] Figure 1.7 shows the relative growth of peak and average demand in the NEM over the previous six years. Recently, AEMO has published detailed forecasts to 2021-2022 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).[10]

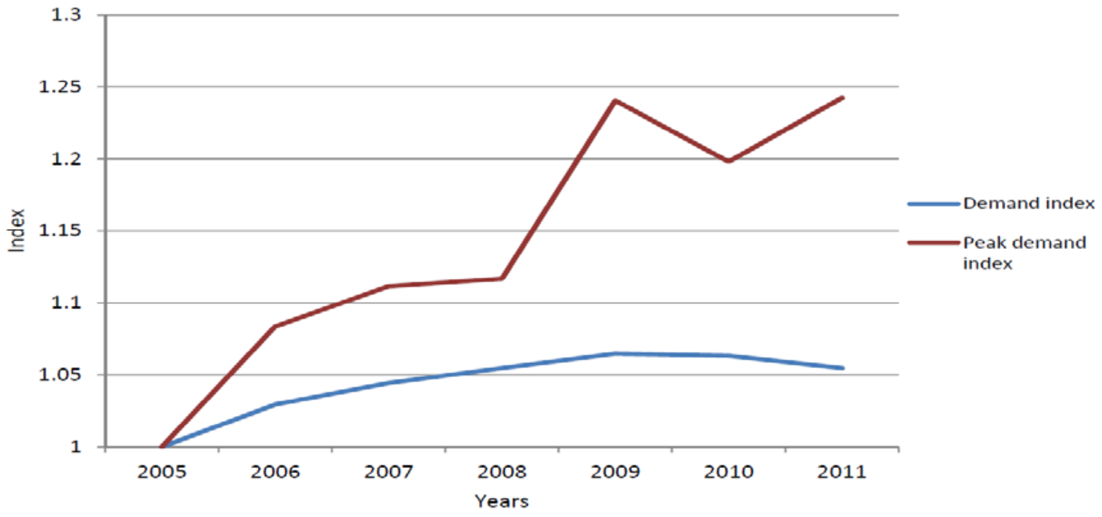
---

8 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.

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

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

Figure 1.7 Peak and 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 expected to outpace growth in peak demand for the industrial sector in most jurisdictions.[11] 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 increase.

It is also important to note the difference between system peaks and network peaks. System peaks occur when demand is highest across the state (as wholesale prices are set at a state level). However networks need to deal with peak demand at the circuit feeder and transformer level which can differ from the time of day from system peaks and also by location. The characteristics of peak demand for a network business will differ by location and season. Individual areas within the network may be summer or winter peaking and may have different proportions of residential versus commercial and industrial loads, leading to different peak demand profiles. This has implications for network costs and tariffs.

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 45 per cent on peak demand days across the system.[12]

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

12 These figures extracted from various reports prepared for the Essential Services Commission of South Australia (ESCOSA), Energex and Ergon Energy including: Charles River Associates (CRA), *Assessment of Demand Management and Metering Strategy Options*, Charles River Associates, prepared

However, this percentage can be significantly higher in certain areas of distribution zones, especially in residential zones. Residential consumers 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.[13]

Higher levels of peak demand relative to average demand can result in a proportion of the power system being under-utilised, except on the peak days. This occurs because network and generation assets built to meet a few short periods of peak demand, may be underused in other periods. The Australian Government estimates that 25 per cent of retail electricity costs are derived from peak events that occur over a period of less than 40 hours per year.[14] This is not efficient if the costs of having such spare network and generation capacity is more than the value consumers placed on the end use services from the electricity supplied during these peak times.

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 peak demand is increasing. 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 here. 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 demand profiles and may have greater discretion to modify their electricity use during peak periods.

For example, in 2008, Adelaide Brighton Ltd estimated that its self management of electricity cost risk had led to savings of over 35 per cent in its electricity costs since 2001 compared to the lowest-cost retail contracts it found available.[15] Boral's Berrima Cement works also seek to manage consumption when possible for some of their processes. For example, plant operators may program the hours of cement milling each day based on the time of use tariff structure,[16] the cement consumption rate, the cement milling rate and the product available in storage. The operators have detailed real time energy consumption data available via their control system displays, if required, and have a decision matrix to simplify their decision making process.

---

for ESCOSA, August 2004; CRA, *Queensland Network Demand Management Framework*, Charles River Associates, prepared for Ergon Energy and Energex, October 2006.

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

14 National Energy Saving Initiative, *Issues Paper*, prepared by the National Energy Savings Initiative Working Group, Department of Climate Change and Energy Efficiency and Department of Resources Energy and Tourism, December 2011, p.71.

15 AEMC Power of Choice Review, Stakeholder Reference Group, First Meeting 8 June 2011. Outcomes of the first meeting are provided at www.aemc.gov.au. ABS, 2008, Environmental Issues: Energy Use and Conservation, Mar 2008 cat. no 4602.0, Australia Bureau of Statistics, Canberra.

16 Boral's Berrima Cement works is in Endeavour Energy's (formerly Integral Energy's) electricity network region. Endeavour Energy has a time of use demand tariff that relates to customer demands registered between the hours of 1pm - 8pm weekdays.

The residential sector can also play a role in addressing peak demand. DSP options for this sector can include technologies that directly reduce consumption at certain times or tariff based DSP. For example, time varying pricing 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.[17]

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".[18]

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.[19] 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 Key issues for the electricity market

This section sets out some of the main issues currently facing the market and which provide the context and rationale for promoting efficient DSP in the NEM.

- Most residential and small business consumers do not have a meter with interval capability and therefore are unlikely to face a retail electricity tariff that reflects the cost of supplying electricity. Some consumers may have static time-of-use tariffs or controlled hot water off peak rates if they have multi-register meters. However such meters cannot support critical peak day pricing or real time pricing. Hence the majority of residential consumers can only be offered retail tariffs that do not reflect the changing marginal cost of supply. This means that such consumers will not be rewarded for shifting consumption away from peak times.

- The costs of electricity supply are mostly averaged out over residential and small business consumers which results in a high degree of cross-subsidisation

---

17 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.

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

19 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 2021-2022, supplying around 3.4 per cent of annual energy.

between types of consumers. Consumers with low consumption and relative flat profiles are subsidising the electricity costs of consumers with large consumption and relatively peaky profiles.

- In the past decade there has been significant capital expenditure in electricity networks in the NEM, with approximately $42 billion invested in distribution networks and $11.5 billion invested in transmission networks in the period 2002-2012.[20] It is expected that in the medium to long term, network investment is likely to continue to be driven by peak demand growth and growth in new consumer connections. In addition, network expenditure is also likely to be required for the ongoing upgrade or replacement of aged network assets installed 30 to 50 years ago.

- Consumers have faced significant increases in the retail tariffs in recent years and are likely to continue to rise. This has led to substantial financial stress for some households.[21]

- Peak demand growth is most largely driven by demand within the residential sector, despite average demand decreasing for this sector. Hence increases in penetration of energy-intensive appliances will have implications for peak demand growth. The projected stock of air conditioning units across Australia is forecast to rise from approximately 6.5 million in 2000 to 12.9 million in 2020, an increase of 97 per cent.[22] It is also estimated by around 500,000 electric vehicles could be in use in the NEM states by 2020.[23]

- Consumer understanding of the relationship between peak demand and electricity price increases is low but improving. Traditionally, consumers have been relatively passive participants in the electricity market. This situation has

---

Australian Energy Market Operator, *National Electricity Forecasting Report*, June 2012; Australian Energy Market Operator, *Rooftop PV information paper*, 2012, p.iii.

20 Australian Energy Market Commission, *Power of choice review - giving consumers options in the way they use electricity, directions paper*, AEMC, 23 March 2012, Sydney.

21 Analysis conducted by the Australian Bureau of Statistics has found that average energy expenditure currently represents just below two per cent of total household expenditure. The Independent Pricing and Regulatory Tribunal of NSW (IPART) has undertaken similar analysis for NSW, finding that NSW household spending on energy will account for around four per cent of household disposable income by 2015. It should be noted, however, that an electricity bill can represent a much higher percentage of weekly income depending on the household. For example, IPART found that for lower income households, median spending on energy will range between five and eight per cent of disposable income. IPART, *Changes in regulated electricity retail prices from 1 July 2012 - draft report*, Sydney, April 2012, p.69.

22 The largest percentage increase is in Tasmania, with the total stock forecast to rise by 276 per cent across the period. Queensland has the second highest forecast percentage rise in sales and total stock growth in the period, with forecast sales of 593,000 in 2020 and forecast total stock of 4.7 million in 2020, an increase of 177 per cent since 2000. It is estimated that air conditioning energy use therefore makes up approximately two per cent of the total forecast electricity consumption in 2020 (*Ernst and Young, Rationale and drivers for DSP in the electricity market - demand and supply of electricity*, 20 December 2011).

23 AECOM, *Impact of Electric Vehicles and Natural Gas Vehicles on the energy markets*, final advice to AEMC, 22 June 2012.

changed in recent times, with consumers becoming increasingly interested in managing their electricity usage and costs. However, most consumers have very little knowledge about the difference between average demand and peak demand.

- Advances in technology will make it easier for consumers to adapt their consumption patterns and participate in demand response (that is, there is growing demand response capability in household appliances).

- Even where consumers are subject to time of use prices, there are a number of shortcomings in those prices structures, which may well reflect the newness of these tariffs and the fact that they apply to few consumers. One shortcoming is a ratio of peak to off-peak prices that materially understated the ratio of the historically observed costs.

The recommendations set out in this final report provide a package of reforms to address these issues.

1.4 The AEMC's approach to the review

1.4.1 NEO assessment

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.

The trends and issues 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.

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.

1.4.2 Efficient DSP

To ascertain the potential circumstances where DSP can be efficient, and hence in the interests of consumers, it is important to understand how consumers value their electricity use and the range of the costs and benefits DSP options have on the electricity markets.

The demand for electricity from consumers is a derived demand. That is, the electricity will be used as an input into providing services or making goods. Consumers are not necessarily concerned with units of electricity per se as it is not required for direct consumption, but rather the amenities that electricity provides (e.g. heat, light, and other goods). The value of electricity to a consumer therefore is a function of the value derived from its end use.

Consumption will be inefficient at times when the value to the consumer is less than the costs of supplying the electricity. If electricity prices do not reflect the cost of supply - which varies by time and location - there is risk that consumers will increase consumption at times then the cost of supply are high. This is because consumers cannot match their cost of consumption to their value derived from consuming.

If consumers do not face the correct signals, there is a risk that they will consume more at certain times when the costs of supply are high. This in turns drives the need for further network and generation investment. Therefore a more effective demand side can help avoid investment in supply side infrastructure.

At an individual consumer level, efficient DSP will occur when the change in the consumers' end use value from adapts its consumption pattern is less than savings in costs incurred in supplying that electricity to the consumer. There will be some actions by the consumer that may not have any loss of value (i.e., switching appliances off at the plug, installing more energy efficient appliances); other actions will have a loss of value (i.e., turning off the television).

For the market, efficient DSP occurs when the cost of doing DSP (which is the change in value of the end uses and the costs associated with the DSP program) is less than the system cost savings and benefits. If there are actions which result in consumers changing their electricity consumption at times when the reduction in its end use value is less than the cost savings incurred in supplying the electricity, then the market and regulatory arrangements should be working in a manner which ensures that such demand side options are enacted. The optimal use of resources from a market viewpoint will occur when the lowest cost combination of DSP and traditional supply options is used to meet demand. This will occur when the all the opportunities for efficient DSP are captured.

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 varying retail tariffs). Different market conditions and participant preferences will determine which options are selected. An overview of the various kinds of DSP options available is provided at Appendix A.

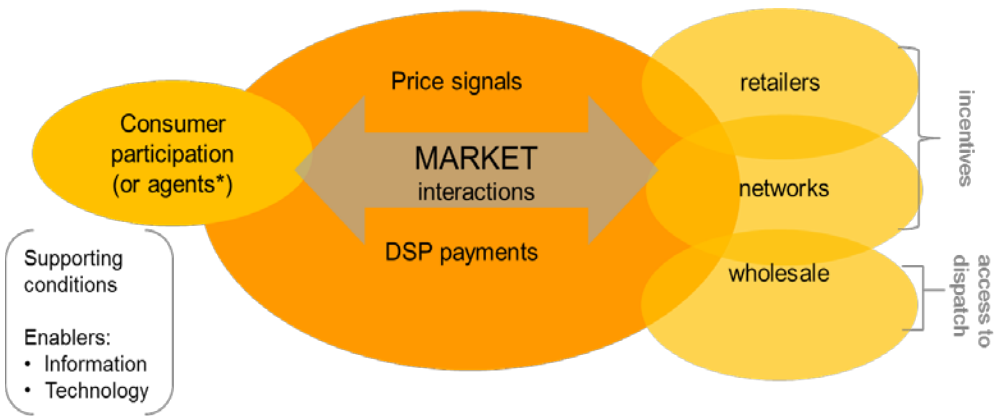
Box 1.1 provides an example of a trial DSP project conducted on Magnetic Island, in Townsville, Queensland. This project demonstrates many of the different DSP options which we discuss in further detail throughout this report.

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. This option will be efficient where these net market benefits outweigh any loss in value faced by the consumer.

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 demand. This will occur when all opportunities for efficient DSP are captured. In the directions paper, we identified a number of key market 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.

Figure 1.10 Market conditions for efficient DSP



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

Box 1.1 Case study: Townsville solar city project[24]

The Townsville solar cities project is part of the Australian Government's Solar Cities program.

The project aims to examine the economic and environmental impacts of cost reflective pricing, uptake of solar generation, demand management and smart metering technologies.

The project commenced in 2007 and is based on Magnetic Island, a satellite suburb of Townsville, in Queensland. As well as providing a number of learning outcomes regarding development of DSP, the project has resulted in substantial reductions in peak demand and contributed to the deferral of network and power system augmentation by several years.

To date, the project has consisted of several components, including:

- Energy assessments of residential and commercial properties to identify energy savings;
- Introduction of peak time rebate tariffs to some consumers;
- Rollout of 1685 smart meters and 355 in home display units to some residential consumers;
- Introduction of direct load control devices; and
- Installation of 1070 kilowatts of solar PV capacity across the island.

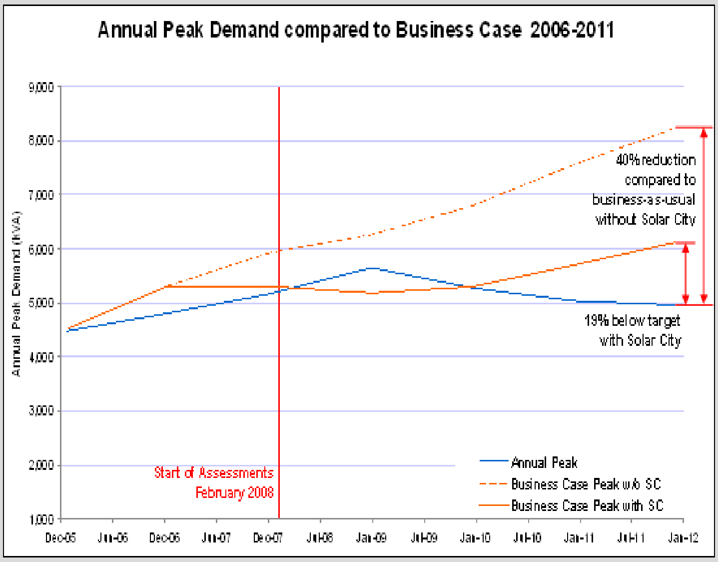
The project involves the introduction of a peak demand rebate programme for residential consumers with smart meters. Consumers on the tariff receive a monthly payment for reducing energy consumption during peak hours, as compared to their consumption during the peak in the same month of the previous year. A final lump sum payment is also provided to consumers at the conclusion of the trial.

The peak demand rebate trial has achieved peak period demand reductions of around 23 per cent while total consumption for consumers involved in the trial decreased by around 16 per cent.

More generally, the peak time rebate programme in conjunction with the other aspects of the solar cities project has resulted in substantial decreases in total consumption and peak demand on Magnetic Island.

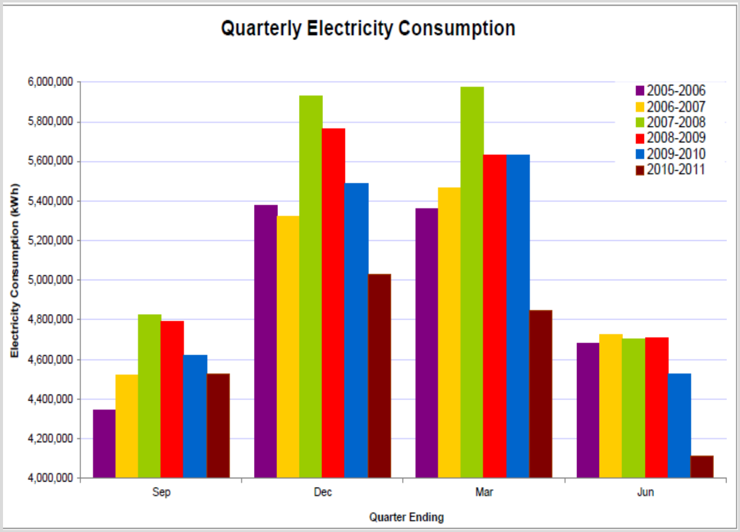
The figure below shows the substantial decrease in annual peak demand. As of January 2012, the solar cities project has resulted in a 40 per cent reduction in peak demand below business as usual forecasts.

Peak demand reductions



Total demand on the island has also shown a sharp decrease since the project commenced. The figure below shows a clear reduction in total demand per quarter since the project commenced in 2007.

Average demand decreases



24 Refer to http://www.townsvillesolarcity.com.au/

1.4.3 Consumer engagement and participation

This derived nature of electricity demand (and the requirement for complementary appliances) will impact on the flexibility of consumer demand and choices. The consumer may consider, along with other factors, both the cost of appliance and the electricity prices when making consumption decisions. Different consumers will place different values on these goods and services, which will in turn shape their willingness to engage in DSP.

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. In order to participate in the market, consumers must have an incentive, ability and willingness to adjust their consumption pattern. However to date, most consumers have been passive receivers of information in the electricity markets

Engaged consumers allow market participants to capture the value of flexible demand and offer different and innovative services and products. A proposed framework for effective consumer engagement is set out in Chapter two of this report.

An efficient market will respond to consumer demand and deliver the desired 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, such as DSP aggregators or ESCOs, may act as an intermediary for small consumers. This action can help to capture and coordinate the value of small consumers DSP by creating a product and service which can be sold to another party. The role of third parties is discussed in Chapters three, five and eight of this report.

1.4.4 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 (eg., medical reasons), 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 households who do not fit this description. 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. Chapter 6 discusses our proposed recommendations with regard to these consumers.

1.4.5 Interaction with the AEMC electric vehicle/natural gas review

SCER has also asked the AEMC to provide advice on the appropriate energy market arrangements necessary to facilitate the economically efficient uptake of electric vehicles (EV) and natural gas vehicles (NGVs) in the NEM, in Western Australia's electricity market and the nation's natural gas markets.

We commissioned AECOM to provide a report which estimated the proposed uptake of EVs to 2030, and analysed the resulting impacts on the electricity markets. AECOM found that if EV charging is left unmanaged it could impose significant costs on the electricity system as EV uptake increases.[25]

AECOM estimated that between 2015 and 2020, unmanaged EV charging could result in costs to the electricity system (in terms of both network and generation upgrades) in the order of $10, 000 per EV in the NEM (the actual amount varying by location and use profile).[26] Of this amount, we estimate that approximately $3,000- $3,500 of these costs between 2015 and 2020 would be paid for by the EV consumer. The remainder ($6,500 -$7,000) would be borne by all consumers if charging is unmanaged. Over a five year period, this equates to just over an extra $1000 per EV per year of costs that would be recovered from all consumers. AECOM's study highlights the importance of cost reflective pricing to facilitate efficient market outcomes.

In relation to EVs, we are proposing recommendations that seek to facilitate efficient EV charging behaviour and to promote consumer choice.

There are two significant interactions between the review into EVs and the Power of choice review. Specifically:

- metering arrangements to enable two or more sellers of electricity services (that is, Financial Responsible Market Participants (FRMPs)) at a connection point; and
- proposal for technical standards for load management services (that is, direct load control, controlled charging of EVs).

With respect to two or more Financially Responsible Market Participant (FRMPs) at a connection point, the rationale for this recommendation is that it would facilitate consumer choice in a range of services, including EV charging services. For example, it would allow one FRMP to supply the household load and another FRMP to supply the load to an EV. Equally, it would enable a premise with distributed generating units (DG) to export its generation to one FRMP while having its household load supplied by another FRMP. We acknowledge that these proposals would entail implementation costs to AEMO and participant systems. However, on balance, we consider that the benefits to consumers resulting from enhanced consumer choice and more flexibility to facilitate a range of DSP services merits the development of these metering

---

25 Unmanaged charging refers to the charging of an EV in the absence of a signal to reflect the costs of charging at times of peak demand.

26 AECOM, op.cit., p.ix.

arrangements. The electric vehicle review will set the required detail to implement this reform and will propose rule changes to the National Electricity Rules (NER).

With respect to technical standards for load management, the rationale for our recommendations is that it would enable more efficient load management and therefore enhance the level of DSP. Technical standards would remove any uncertainty regarding selling of load management services by third parties and the role of network business with respect to load management on their networks.

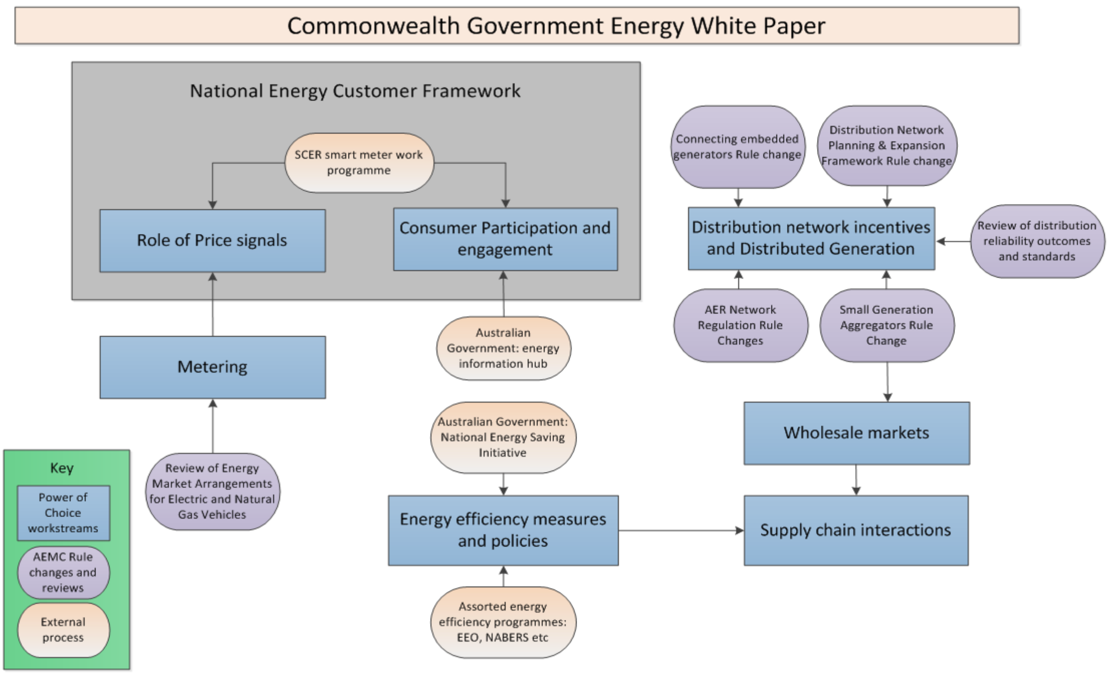
The relevance of load management to EVs arises because the controlled charging of EVs (where a consumer assigns the right to control its EV charging to another party) is a form of load management. We have proposed principles defining the parameters of all forms of load management and propose that further work to develop minimum technical standards and protocols. Further details are included into the electric vehicle review's final advice. To implement this recommendation, we propose that SCER expands the scope of the technical standards for distribution generation review to include load management services.

The final advice for this review is due to be published on in December 2012.

1.4.6 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 SCER and the Australian Government related to smart metering, consumer protections, consumer information provision and energy efficiency.

Figure 1.11 Interactions with other projects



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 1.11.

1.4.7 Productivity Commission's review into Electricity Network Regulatory Frameworks draft report

The Productivity Commission has been commissioned by the Australian government to prepare an analysis of the use of bench-marking to better regulate electricity networks and delivery of interconnectors investment in the NEM. The Productivity Commission released its draft report on 18 October 2012. In addition to addressing these issues, the Productivity Commission also commented on the role of DSP and its potential to limit increases in network costs. Its final report is due on 9 April 2013.[27]

1.4.8 Senate Committee Inquiry into electricity prices

The Senate Select Committee on Electricity Prices has released a report on the drivers of electricity price increases in recent years. The Committee found that a prime driver of these increases was investment in networks. The Committee recommended a number of specific changes, including changes to the form of economic regulation for network businesses, the introduction of cost reflective pricing, the rollout of smart meters, a consumer education campaign and allowing consumers to sell their DSP in the wholesale market.[28]

1.4.9 Energy White Paper

The Australian government recently released its Energy White Paper, which provides a strategic direction for the Australian energy sector. The White Paper examined a wide range of issues, including the need for new investment in the sector, price pressures, improving energy productivity and managing peak demand and promoting informed energy choices. In particular, the paper considers the importance of improving the productivity of the energy sector, through reducing peak demand and improving the overall efficiency of the power system.[29]

---

27 See http://www.pc.gov.au/projects/inquiry/electricity

28 See http://www.aph.gov.au/Parliamentary_Business/Committees/Senate_Committees?url=electricityprices_ctte/electricityprices/index.htm

29 See http://www.ret.gov.au/energy/facts/white_paper/Pages/energy_white_paper.aspx

1.5 Implementation of the recommendations

This final report proposes a package of integrated reforms to market arrangements. These changes will enable the market to utilise the potential of demand side actions as an alternative to investment in network and generation infrastructure in meeting the community demand for electricity services. SCER will consider the recommendations in the final report and decide upon the appropriate way forward for the market.

We have attached an implementation plan to this final report. For each of our recommendations, this plan outlines the required output and the action required by the appropriate energy market bodies including AEMC's view of the appropriate timetable for progressing reforms. For each recommendation, we have also indicated, where appropriate, the linkages to other work that will complement the recommendations from the Power of choice review.

The proposed recommendations from the review will require different levels of action to implement, and fall into two groups. First, changes to the existing market and regulatory arrangements (that is, the NER, National Energy Customer Framework (NECF) and other jurisdictional regimes). The second group includes advice for SCER and individual jurisdictions to consider in accordance with their existing energy reform work programs.

Regarding the changes to the existing rules, we have also attached draft specifications to this final report. The purpose of these specifications is to explain in detail the regulatory requirements for the relevant recommendation to take effect. The specifications are not draft rules and should not be interpreted as such, but would form the basis of any draft rules for the proposed rule changes.

We consider that a significant reform program is required to fully utilise the potential of efficient DSP. This has been supported by stakeholders and other relevant reviews. Co-ordination and sequencing of these reforms plus effective consumer engagement and participation will be crucial for their success. Given this, will be important that there is leadership by SCER to ensure any agreed changes to the market and regulatory arrangements are implemented in a timely manner.

1.6 Project dates and submissions

The AEMC has taken a highly consultative approach in conducting the review, having previously published an issues paper, a directions paper and a draft report. We have also met with stakeholders throughout this review. Submissions have been received from a diverse range of interests such as electricity and gas network businesses, government departments, consumers and consumer groups (representing both large and small consumers), local government organisations, private individuals, metering providers, DSP technology companies, economic consultants, state utility regulators, environmental groups and retailers.

In all, 157 stakeholder submissions have been received to date, including 65 submissions to the draft report. A summary of the key points made in submissions to the draft report is included in Appendix G. Given the large number of submissions received, this summary is necessarily at a high level and may not present every point made by stakeholders.

Two public forums have been held during this review, and the review's Stakeholder Reference Group has met on five occasions. We also held specific industry workshops on metering and wholesale market issues.

Stakeholder participation has been extensive and very valuable to the development of the recommendations presented in this final report. We appreciate the advice and evidence provided by various stakeholders including their time and resources committed to the review. Furthermore the level of consultation during this review has been invaluable in bringing together different interests into a common approach to solving the issues. A consensus has emerged across different stakeholders during this review on the need for significant change and how for the market to move forward.

Table 1.1 Review consultation papers and timeframes

Document	Date of Publication	Submissions received
Issues Paper	15 July 2012	45
Directions Paper	23 March 2012	47
Public Forum	19 April 2012	
Draft Report	6 September 2012	65
Public Forum	3 October 2012	
Final Report	30 November 2012	

1.7 Structure of the final report

The AEMC's assessment of efficient DSP focuses on several key areas. We have structured the discussion in this final report as follows:

- **Chapter two - Consumer awareness, education and engagement**
- **Chapter three - Consumer information - access to electricity consumption data**
- **Chapter four - Enabling technology (metering)**
- **Chapter five - DSP in the wholesale electricity and ancillary services markets**
- **Chapter six - Efficient and flexible pricing**
- **Chapter seven - Distribution networks and DSP**
- **Chapter eight - Distributed generation**

- **Chapter nine - Energy efficiency measures and policies that seek to integrate or impact on the NEM**
- **Chapter ten - Benefits and costs of recommendations**
- **Chapter eleven - Integrating reforms across the supply chain**

Each chapter begins with a summary of the relevant market conditions and then provides an overview of any recommended changes to the regulatory and market arrangements.

2 Consumer awareness, education and engagement

Summary

The extent to which consumers can engage and participate in the electricity market will be a key factor affecting the realisation of the benefits and full potential of efficient DSP. Engaged consumers better enable market participants to capture the value of flexible demand and to offer different and innovative services and products.

A strategic and coordinated approach is required to build consumer energy literacy, enable consumers to make informed choices and quantify impacts of consumption decisions. There are already many initiatives by governments, electricity retailers, local government and community organisations to increase awareness of energy use, promote ways of saving energy and enable consumers to choose retail electricity offers that may better suit their needs. The need now is to build upon these various initiatives. This will need to involve governments, all parties across the electricity supply chain, community and consumer organisations.

There are a number of key principles that will be essential to the development of an effective consumer engagement strategy. These are:

- **Clarity of goals** - the purpose of the strategy is to enable consumer choice, and help reduce peak demand so as to reduce electricity system costs and thus deliver lower prices to consumers.
- **Education and engagement first** - education, awareness and engagement should start before rolling out policy reforms recommended in this review.
- **Clarify the different needs of different types of consumers** – for example, small business, residential consumers in general and consumers with limited capacity to respond.
- **Identify vulnerable consumers (ie limited capacity to respond and change their consumption)** – there are different types of vulnerability that can face people as energy consumers. Early action before rolling out flexible retail electricity pricing options - such as providing advice and assistance with energy saving measures - will be required to protect those consumers.

Robust market arrangements that allow for good engagement between market participants and consumers can also help to build consumer confidence to take up, and realise the value of, DSP products. These arrangements would also support and protect the interests of those who are unable to vary their consumption because of their specific circumstance.

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.

With regard to consumer engagement and awareness, we recommended that there is a:

- Commitment by governments to the principles of consumer engagement;
- Comprehensive communication/education strategy is developed to support implementation of the reforms recommended in this review, and to more broadly improve consumer understanding of energy use and relationship to costs. A SCER working group should be established (with participation of stakeholders from consumer organisations and the electricity sector) to develop and manage application of the strategy.
- Review of government energy related education and information programs (ie energy efficiency programs) to ensure an effective and appropriate focus on specific consumer segments. We also recommend a review of state energy concession schemes/rebates.

To support consumer participation in the electricity market, we also recommend that there is a:

- Review of the existing retailer switching arrangements to better support consumer choice and to make switching retailers more efficient. The review should assess whether a maximum day limit could be introduced in the NEM.
- The National Energy Customer Framework (NECF) is amended to include a framework governing third parties (ie non-retailers and non-regulated network services) providing energy services to residential and small business consumers. The framework would outline which aspects of the National Energy Retail Rules (NER) will apply and in what circumstances. AER guidelines would be developed to outline NECF exemptions for these services.

2.1 Market conditions for uptake of efficient DSP

The reforms that we propose, which will include the provision of tools such as better data and enabling technology are designed to promote more effective consumer choice in the electricity market. They do so by enabling the development of an active demand side. DSP can offer a suite of options for consumers to manage their electricity consumption and, in turn, their bills. These options include directly modifying the timing or quantity of electricity they use - or engaging their retailer (or a third party) to provide energy management services. A full list of DSP options is provided in Appendix A.

Improved data and the development of the DSP market is also likely to stimulate dynamic efficiency and a more competitive electricity market with further benefits for consumers in terms of their bills. For example, with data from their interval/smart meters,[30] consumers will be able to use price comparison sites more effectively to assess competing offers from different electricity retailers. They will also have better information to inform how they use electricity.

The extent to which consumers can engage and participate in the electricity market will be a key factor affecting realisation of the benefits and full potential of efficient DSP. Market participants are more likely to capture the value of flexible demand and to offer different and innovative services and products if consumers are engaged. Without engaged consumers there will not be an effective demand side.

2.2 Issues identified

Consumers generally expect affordable, safe and reliable electricity services.

While there are DSP opportunities available, consumer interests, motivation and willingness to manage electricity use and costs is likely to depend on a range of different factors. These include current and future retail electricity prices, individual preferences, consumer circumstances and the perceived benefits that the DSP option may offer. Other factors may also include size and composition of households or businesses and social expectations, habits and norms. Many consumer groups submissions to the review highlighted that it is important to recognise that consumers' capacity and choices in respect of the type of DSP option taken up is likely to be quite diverse and vary across and within sectors.[31] For example:

- Very large industrial facilities are more likely to have the capacity to manage their electricity consumption. This is because they tend to have the appropriate technologies (such as real-time metering), sophisticated energy management systems and skill-sets in house. These factors allow these businesses to participate in the wholesale market, enter into contracts with a service provider that provides exposure to variations in wholesale electricity spot prices, or engage in DSP where it is cost effective to do so.

  Small to medium enterprises (SMEs) however do not necessarily have specialised personnel with dedicated skills for managing electricity consumption, or in some cases the enabling technology. SMEs may therefore face larger transaction costs to participate in the DSP market, and hence may choose to engage ESCOs to provide energy assessments and consider upgrading existing equipment for their

---

30 Refer to chapter 3, Box 3.1 for summary of types of meters (ie accumulation, interval and smart meters).

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

business operations. Retailers may also work with these companies to offer different products and services to suit businesses operations.

- Generally, small consumers are considered not to have adequate information or knowledge on costs of their consumption (for example, the costs of running the air conditioner) and/or the appropriate enabling metering technology that provides for a greater level of information on their usage profile. Smaller consumers may also lack the capability (and financial capacity) to directly take up some DSP options that may be available. Therefore, householders may choose DSP options that involve directly modifying their consumption patterns such as turning off lights or installing wall or ceiling insulation. Households may also wish to enter into a contract with a retailer or other party (for example, networks or ESCOs) to manage high electricity use equipment during peak times when prices are higher.[32]

In order to maximise effective decision making, consumers need to be sufficiently engaged and have adequate information about consumption patterns, costs, and the products and services that may be available in the market. This will ensure they are better equipped to adjust consumption and behaviour patterns to maximise their welfare. If consumers are not sufficiently engaged, if an appropriate level of information is not available, or if existing arrangements are seen to be too complex and costly to make a decision (that is, if consumers are unable to understand implications of decisions and investment choices), then there is a risk that consumers (or some groups of consumers) will neglect potentially cost effective opportunities that may be available.

- Currently, consumers' understanding of energy use and how to make smarter energy consumption decisions is limited.[33] Most consumers have very little knowledge about how much electricity is used by different appliances and the costs of using them at different times of day. This is important if flexible pricing were to be introduced. The difference between average and peak demand and their impact on electricity system costs is not a distinction recognised by most consumers, as a number of focus group discussions in Victoria found.[34]

  Whereas a broad energy saving message to reduce total usage and save on bills is relatively simple to convey, the time of use message will be novel to most consumers in the energy context (except those who have had night time tariffs for water heating for example). Pricing that reflects time of use will be familiar however, to consumers in other contexts (for example, in relation to telephones, parking meters and transport).

---

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

33 AEMC 2012, *Power of choice - giving consumers options in the way they use electricity*, directions paper, March 2012,

34 Deloitte, *Advanced Metering Infrastructure Customer Impacts Study - Stage 2 Final Repor*t for Department of Primary Industries 20 July 2012

- Research by CHOICE reveals that many consumers are finding it difficult to get a good deal in the electricity market. A CHOICE survey of 1,000 Australians found that only half of those who joined their electricity retailer in the last three years were confident they had made the best choice. One third of respondents who recently joined their provider said they had tried to compare providers but had found it was too hard to work out the best choice.[35]

  When the first time of use tariffs were initially introduced in Victoria, consumer concerns about their effects led to them being suspended. In this context, it is understandable that consumers may have concerns about the potential for the reforms to create greater complexity in the electricity market and concern that such reforms will result in higher electricity retail prices. In addition, it is understandable that consumers may have different levels of confidence in the various parties delivering information (that is, retailers, networks, government and others.[36]

- Although all consumers will benefit in the medium to long term from reductions in the costs of network and generation investment brought about by efficient DSP, this will take time to feed through into all retail electricity prices. In the short term, consumers who have relatively flat load profiles and/or can adjust their consumption to use less electricity at peak times will gain most benefit from flexible pricing.

  Hence it is important that consumers can have the choice of such tariffs and sufficient information to make effective decisions. Smart meters and the provision of data from them will also be important to ensure that consumers can correctly assess whether they would benefit from a switch to a flexible pricing plan.[37]

Consumer behaviour, attitudes and opinions play an important role as to why consumers may take up or make investment decisions regarding DSP. Consumer perceptions and values can be influenced by a variety of factors that include: the ability to process information; price of products and services; knowledge of the issues (for example, energy costs); availability of time; access to finances; and general appetite/commitment to change.[38]

35 CHOICE. October 2012. http://www.choice.com.au/reviews-and-tests/household/energy-and-water/saving-energy/energy-retailer-marketing.aspx

36 AEMC, *Power of choice – giving consumers options in the way they use electricity,* directions paper, March 2012, Appendix D – summary of stakeholder submissions to directions paper.

37 PIAC draft report submission, p2; ACOSS draft report submission, p.3.

38 RIMT submission to the draft report noted that consumers are unable to make informed choices given a wide range of factors which influence thier decision and cites multiple pieces of research to show it.

Given the complexities of consumer decision making, many stakeholders indicated that any approach for engaging consumers in the market should take into account the known factors that shape and constrain peoples' choices toward energy management.[39]

All stakeholders agree that better education, information and incentives are needed to help reduce complex decision making.[40] There are already many initiatives by the federal, state and local governments, electricity retailers, and community organisations aimed at increasing awareness of energy use, promoting ways of saving energy and enabling consumers to choose retail electricity tariffs that better suit their needs.[41] The need now is to build upon these various initiatives to develop a strategic and coordinated approach involving governments and all parties across the electricity supply chain, including the community and consumer organisations.

Submissions from various stakeholders have also called for the establishment of a national consumer advocacy body. This issue was also discussed in the recent Senate Select Committee enquiry into electricity prices, with the Committee supporting calls from consumer groups for the establishment of the national body.[42] This was also supported by the Productivity Commission in their recent draft report of the review of electricity network regulatory frameworks.[43]

2.3 Recommended strategy for consumer education and awareness

RECOMMENDATION

We recommend that:

- **Governments commit to the principles of consumer engagement.**
- **A comprehensive communication/education strategy is developed to support implementation of the reforms recommended in this review, and to more broadly improve consumer understanding of energy use and relationship to costs. A SCER working group should be established (with participation of stakeholders from consumer organisations and the electricity sector) to develop and manage application of the strategy**.

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

40 AEMC, *Power of choice – giving consumers options in the way they use electricity*, stakeholder submissions to issues and directions paper, and draft report.

41 As an example, Refer to Victorian government switch on website, available at http://www.switchon.vic.gov.au/about-switch-on. Others include the Black Balloons program in Victoria , available at http://www.switchon.vic.gov.au/; the Australian government's Energy Efficiency Opportunities Program (EEO), various state government white certificate schemes and the Equipment Energy Efficiency Program (E3), available at http://www.energyrating.gov.au/.

42 Australian Senate, *Reducing energy bills and improving efficiency*, November 2012, Canberra, p.135.

43 Productivity Commission, *Electricity Network Regulatory Frameworks – draft report*, October 2012, Melbourne, p.6.

- **There is a review of government energy related education and information programs (ie energy efficiency schemes) to ensure an effective and appropriate focus on specific consumer segments.**

2.3.1 Key principles for consumer awareness, education and engagement

We put forward the following principles for an effective community engagement strategy.

1. **Clarity of goals** - An effective consumer awareness, education and engagement strategy requires clarity of the goals so that these can be communicated to consumers. The purpose of the strategy is to empower and enable consumer choice in respect of their demand for end use electricity services. The overall objective is to reduce peak demand, so as to reduce electricity system costs and thus deliver lower prices to consumers. This involves communicating messages about reducing both peak and average demand. Measures targeted primarily at average demand reductions can also deliver some benefit at peak times – for example, energy efficient lighting will deliver some of its demand reduction at peak times.

2. **Education and engagement first** - It is very important that education, awareness and engagement starts early – before rolling out efficient and flexible retail electricity pricing options (and other initiatives such as load control). We note that the Victorian government has announced the introduction of flexible prices. As a first step they have established a web site containing information for consumers,[44] the time of use tariffs will not actually be offered until mid-2013.

3. **Clarify the different needs of different types of consumers** – Consumers are not identical in their needs. There will be important differences, for example, between the needs of small business and residential consumers and between consumers in general and those who may have limited capacity to respond or change consumption.

4. **Identify consumers who may be vulnerable and take early action to protect consumers at risk** – there are different types of vulnerability that can face people as energy consumers. Some consumers will have different capacities to manage their energy use.[45] Strategies to protect these consumers need to take into account these different definitions of vulnerability. It is important to take early action (before rolling out flexible tariffs) to ensure that such households are not disadvantaged and can benefit where possible. This should include tailored advice; help with more efficient appliances and insulation and reviewing the effectiveness of help under the various concession schemes in the context of

---

44 Refer to Victorian government switch on, website at http://www.switchon.vic.gov.au/about-switch-on

45 Ethnic Communities' Council of NSW draft report submission, p.2.

flexible pricing. This point has been stressed in a number of submissions from stakeholders (Energy & Water Ombudsman NSW (EWON), Australian Council of Social Service (ACOSS)).[46] We canvass this issue further in the Chapter six - efficient and flexible pricing.

2.3.2 Developing the strategy

A key task will be to consider who is best placed to undertake the engagement with consumers. For credibility, elements of this should be government led but there are also key roles for the industry and trusted third parties. We recommended that SCER convene a working group to develop a strategy and implementation plan. This working group should include stakeholders from consumer organisations, retailers and DNSPs. Funding requirements would need to be considered.

There should be a mixture of communication activities directed to individual consumers and at a community level. The key features could include:

- direct mailings to individual households;
- TV, radio and press advertising;
- web site and use of social media;
- distributing materials in local communities, for example in Post Offices and on public transport;
- information points at, for example, libraries, town halls, shopping centres, council offices etc;
- actions by national, regional and local charity and community organisations and local councils either alone or in partnerships with each other and/or with energy companies (retailers and networks); and
- local events, best organised in partnership with local councils and/or local community organisations.

For some types of consumers, there may be a greater role for the "trusted third parties" to provide more in depth advice and information. It might also be useful to develop a network of 'community supporters', (similar to the UK Digital Switchover Help scheme (Appendix B)) and to encourage families, friends and neighbours to refer eligible households to the help available.

46 EWON draft report submission, p 3, ACOSS draft report submission, p3.

Box 2.1: Solar Cities – an example of effective consumer engagement

The seven cities participating in the Department of Climate Change & Energy Efficiency's Solar Cities program have trialled various engagement strategies that could prove a useful model and recently released a community engagement paper.[47] It is important that the data available from these programs is available and utilised to inform policy and effective communication strategies.

Examples show:

- In Blacktown, the Business Energy Efficiency Program worked with 22 companies, and saved over $1,000,000 in energy bills annually.
- In Moreland the Concession Assist program is available free of charge to healthcare card, concession card and pension card holders. Eligible consumers receive a visit from a home energy advisor and a trained installer who fits energy and water efficiency measures.
- The Adelaide Solar Cities community engagement strategy is focused on understanding consumer behaviour motivators, empowering consumers with knowledge, and using creative technologies to enable them to monitor and better control their energy use. More than 21,000 energy efficiency information packs have been distributed and 21,500 residents in the trial area have received Origin GreenPower accredited products.
- The Living Smart program in Perth provided telephone based coaching to over 6,000 households. Preliminary analysis for 4,768 Living Smart participants shows an average 8.5 per cent reduction in electricity use.
- As part of their Magnetic Island Solar Cities program, Ergon Energy has conducted a series of energy assessments of residential and commercial properties, to identify opportunities for cost savings.

2.3.3 Stages for a consumer education, awareness and engagement strategy

Effective consumer engagement will require a number of different actions at various stages and sequencing of those actions will be key. These are outlined below.

Stage 1: Education and energy literacy

Education and energy literacy activity will aim to improve consumers' understanding of the electricity system, their usage of electricity and the costs involved. So this will include communicating:

---

47 This paper can be found at: http://www.climatechange.gov.au/en/government/initiatives/~/media/government/initiatives/solar-cities-trials/SolarCities-CommunityEngagementPaper-201210.pdf

- the difference between average and peak electricity demand;
- the benefits from reducing peak demand as well as average demand;
- electricity use of different appliances[48]; and
- illustrative comparative costs of using various appliances on flat tariffs and at different times of day under flexible pricing (ie time of use (TOU) tariffs).[49]

This education task will be best led by government(s) or a government appointed agency, or operating under Government branding, so that it has the necessary credibility and authority with consumers.

The task could be undertaken through a combination of web site, social media, advertising, literature, events and activities. A number of existing federal and state level services[50] already provide energy education and information but it would likely be sensible to develop a service more targeted to addressing peak demand.[51] Local and regional organisations (including ones supported through government initiatives such as Solar Cities) could also have an important role to play.

There will also be a role for the electricity supply industry, including retailers and DNSPs. While illustrative examples of the costs of using different appliances (including at different times of day) can be provided by governments and regulators, it will be the retailers who can provide consumers with information based on actual tariffs.[52] It will be important for retailers to provide such information in a relatively standard format to make it easy for consumers to compare.[53]

Retailers and DNSPs could also work in partnership with local councils, community and consumer organisations to organise group discussions and other events with consumers. As part of this review, we are recommending that the existing procedures are improved for DNSPs to consult with consumers, retailers on proposed network price structures - such consultation could also form part of this type of activity. This recommendation is further discussed in Chapter 6.

---

48 Reference Energy Efficiency Equipment (E3) Committee of Commonwealth, State, Territory and New Zealand Officials. This group oversee the trans-Tasman energy labelling and minimum energy performance standards (MEPS) program.

49 Refer to the Frontier retail tariff model published with AEMC Power of choice draft report. This can be accessed at http://www.aemc.gov.au/Media/docs/Retail-tariff-model-157128f5-0dbf-4a44-a00d-c6538987b43f-0.xlsb

50 For example, livinggreener.gov.au; energyrating.gov.au; South Australia's Energy Advisory Service.

51 For example, Energex PeakSmart airconditioning program.

52 Refer to Origin website saving energy - watt's it cost and watt's it mean http://www.originenergy.com.au/3634/Watts-it-cost

53 We discuss provision of consumption data in Chapter three.

Stage 2: Information – on smart meters, tariff options and load control – and data

The actions required to provide consumers with information on smart meters, tariff options and load control call for the involvement of government and the electricity industry. Ensuring that consumers (and/or their agents) have access to their data (on their overall consumption and load profiles) will be the primary responsibility of the retailer. We have proposed rule changes to the NER to clarify the arrangements for consumers to access and share their consumption data. These are presented in Chapter three. We are also recommending that consumers are provided with information about their load profiles.

Where possible (that is, where interval or smart meters are installed) consumers should have access to their load profile for a reasonable period before being offered flexible pricing. For example, EWON in its submission to the draft report proposed that a transition period for consumers, that is to remain on a flat rate for two periods before introduction of the flexible pricing offers. They considered that the new flexible pricing offer costs would be provided, at a minimum on the bill, so that consumers can make a real comparative assessment of the value or otherwise of the new tariff based on their actual energy consumption.[54]

As we propose in chapter three, where consumers do not have an interval or smart meter, they would be provided with information (on their bills as a minimum) on the net system load profile for their area. This net system load profile information needs to be provided to consumers in a clear and meaningful way. For example, diagrams could be used to make clear that the information relates to the average residential consumer's use of electricity across a 24 hour period (including differences between winter and summer). Within this profile many consumers will have a usage pattern that is different.

Clearly, retailers will provide information about the retail offers. It would be helpful for consumers if retailers could provide such information in reasonably standardised forms to make it easier for consumers to compare available offers. Guidance to retailers on this could be provided by the AER. Similarly, guidance on the format for provision of consumption data and load profiles will also be important to enable consumers to use the data effectively. Such information could be provided on bills or in electronic formats.

Consumers in all states and territories will also need access to trusted, reputable price comparison sites. These would need to be run either directly by government or regulators or be accredited by them (for example the AER - energy made easy website).

In addition, consumers need to be provided with sufficient information so that they can make effective use of their smart meters to monitor and adjust their consumption. Retailers and/or distributors (whoever has the job of installing smart meters) will have the primary task of providing consumers with information on the meters and associated systems of data feedback (for example, in home displays and web portals).

54 EWON submission on draft report, pg.3.

It would be good practice for the retailer or distributor, at or around the time of installation of the meter, to provide options to the consumer for using the smart meter to monitor their consumption. Appendix B provides the Great Britain smart meter consumer engagement plan as an example of the sort of strategy that could be put in place.

Stage 3: Choice - making it easy for consumers to choose the actions that are right for them

There are potentially a number of quite complicated choices that consumers will need to make to be able to take action on their electricity use. They also may want to identify ways to reduce their overall energy demand as a means of making their energy bills more affordable (and this will also deliver some benefits in terms of peak demand reduction). The more disparate decisions that need to be made, the more likely it is that consumers will give up or make sub-optimal choices. Thus the goal, as far as is possible, is to make it easy for consumers to make choices that are right for them and this can be greatly assisted by means of a “one stop shop” approach. Although focussed on energy saving rather than peak demand, the United Kingdom Green Deal is an example of such an approach.[55]

An energy audit could be designed to produce recommendations about ways of reducing peak and average demand and thereby saving money on bills. Energy audits can be “do it yourself” (for example, web based questionnaires) or can involve a qualified energy auditor making a home visit. Some state governments already provide web based audits and/or toolkits for consumers to do their own audits and/or have initiated schemes to require energy retailers to provide audits free of charge for some households. This is also an area that offers potential for involvement of community based organisations to encourage and assist their members to undertake energy audits (for example, a number of the Solar Cities projects have done this).

It is likely that most of the energy audits currently on offer focus their advice on reducing average demand, but clearly they could be adapted to provide advice as well on peak demand. Audits can also provide advice on how consumers can make choices about when to use their own generation and when to export it (for example, for those with rooftop PV). Following the audit, consumers then need to be signposted to ways of acting upon the recommendations (this will include links back to price comparison methods as outlined in Stage 1 above). We consider that the changes in retail price structures and move to more flexible pricing options will encourage this type of information.

55 The UK ‘s Green Deal is aiming to make energy efficiency an easy choice for consumers by providing a clear and linked process through from assessment (via a home visit), advice on cost effective improvements, quotes for work, through to finance provision and installation. http://www.decc.gov.uk/en/content/cms/tackling/green_deal/green_deal.aspx.

Stage 4: Extra help – financial assistance and/or extra advice and support

Some consumers will need additional help to be able to make effective choices. This may include financial assistance to pay bills, assistance with the costs and installation of some measures (funded through energy efficiency schemes) or additional personalised advice. As noted in Section 2.3.1, it is important to develop clarity on the consumers who might have limited capacity to respond in the development of flexible pricing and to put in place appropriate arrangements before flexible pricing is introduced. Our proposals on the arrangements are provided in Chapter six.

Clearly provision of extra help may cost money. A number of stakeholders proposed that retailers and/or distributors should fund measures to assist vulnerable and low income households.[56] Victorian legislation for example, currently requires retailers to offer hardship consumers free home energy audits and assistance with the purchase of energy efficient appliances.

Face to face advice may be very important for many consumers (households and small businesses). This was stressed in the submission by the Ethnic Communities Council NSW.[57] There could be a key role here for trusted third parties such as community and welfare organisations. A number of the Solar Cities schemes and other state and local government initiatives have developed particular strategies for providing assistance to vulnerable consumers and the lessons from these schemes should be learnt and adopted. However, it is important to note that such organisations will need funding support to engage in these activities. However, it may often be more cost effective (and more likely to gain the trust of such consumers) for retailers and networks to support community organisations to undertake this task rather than to do it themselves.

As outlined in the draft report and further considered in Chapter six, key components of extra help could include:

- Targeting energy efficiency schemes (such as the three state-based programs) [58] by, for example, using them to fund energy saving measures, smart meters, in home displays and tailored advice packages to low income and other households.

- Targeting bill concessions schemes to people with high electricity (and high peak electricity) needs to ameliorate the impacts of electricity costs in general and time of use tariffs in particular.[59]

---

56 EWOV draft report submission, p.2; EWON draft report submission, p.3. Also refer to *AEMC Power of choice review – giving consumers option in the way they use electricity*, directions paper, March 2012.

57 Ethnic Communities Council draft report submission, p.2.

58 The three state based programs put an obligation on electricity retailers to achieve a targeted level of energy efficiency with end use consumers in Victoria, New South Wales and South Australia.

59 It may, however, make more sense for households with unavoidable high peak demand not to be on time varying tariffs.

- Targeting energy audits and advice to low income and other households to provide them with customised advice on ways to reduce their electricity bills.[60]

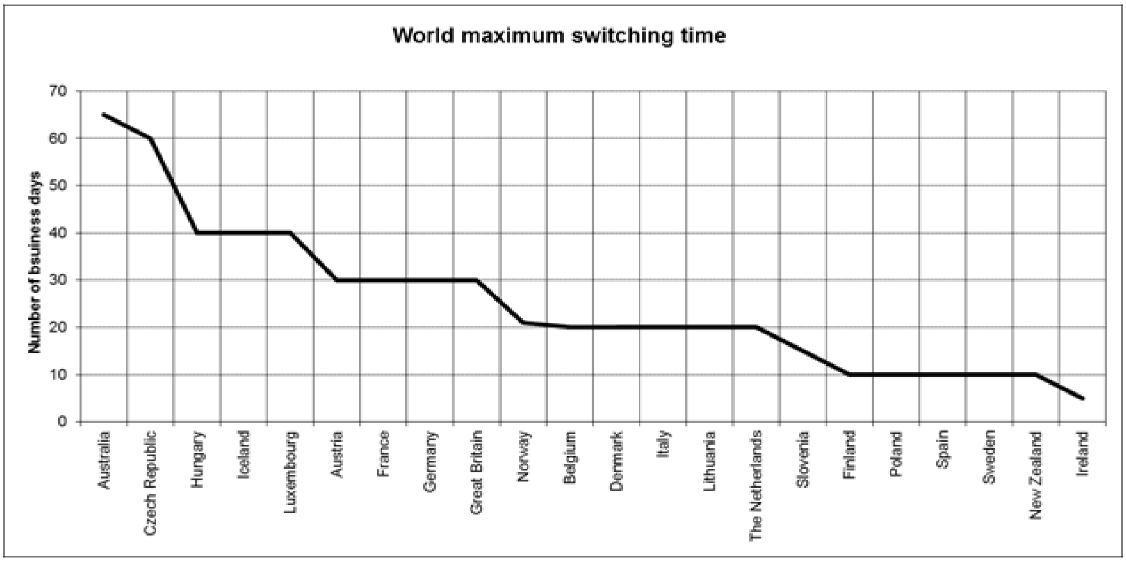
2.4 Consumers switching retailers

RECOMMENDATION

We recommend that there is a review of the existing retailer switching arrangements to better support consumer choice and to make switching retailers more efficient. The review should assess whether a maximum day limit could be introduced in the NEM.

Currently the main way in which residential consumers participate in the electricity markets is through seeking competitive offers from retailers which may result in them switching retailers. The market arrangements for processing switching requests, including timeframes, will therefore influence the level of switching. The easier and quicker the process, the more likely consumers will be willing to switch retailers. During this review, we have identified an issue with the current arrangements in the NEM regarding the length of time allowed to process retailer switching requests. Figure 2.1 provides an international comparison of maximum allowed switching times. Australia allows the longest period with 65 days.

Figure 2.1 International comparison of maximum allowed switching times



Source: Electricity Authority New Zealand, Review of timeframes for customer switching, Final Report, 3 October 2011

60 For example, the Moreland Solar cities program. Information about this program can be found at http://www.morelandsolarcity.org.au/

New Zealand has achieved significant improvement in the switching times over recent years. This is mostly due to the introduction of new rules in 2010 which reduced the switching timeframe for non-half hour switches to a maximum of ten business days, and required at least 50 per cent of "standard" switches to be completed within five business days (where the incumbent retailer has responsibility for the installation control point for more than two calendar months).

The New Zealand rules require a gaining retailer to notify the registry within two days of entering an arrangement with a consumer. The losing retailer has three days in which to provide information to complete the switch or to notify a withdrawal. The switch can take place based on estimated final reading and both parties have to use the same final reading. As they are based upon estimated readings the switching times do not depend upon the metering technology, however smart metering will improve the accuracy of the switch readings.

Improving the arrangements for switching retailers would improve competition and residential consumer participation in the market. Better metering technology will enhance the process. In this context, we consider that there should be a review of existing NEM and jurisdictional arrangements regarding processes for consumers to switch retailers. This review would assess whether a maximum day limit could be introduced in the NEM (for example, 10 days for processing requests in accordance with international precedence). We advise SCER to request the AEMC to undertake such a review, with relevant market bodies and stakeholder input.

2.5 Engaging with consumers – providing energy management services

To encourage consumers to participate and realise the benefits of DSP, there need to be arrangements that support consumer decision making and not introduce, nor lead to, increased complexity. It is also important that sufficient consumer protection and other support mechanisms are in place.

This review has considered 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 section specifically considers the provision of DSP products and services by third parties who seek to have direct contact with consumers. It also considers how existing arrangements to protect consumers apply and how dialogue can take place in a transparent manner.

The industrial and commercial sector has had access to DSP products for some time. Generally, there are arrangements in place to support consumers in this sector to engage with a range of parties in the market.[61] This section therefore focuses on residential and small business consumers.[62]

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 for the issues raised in this review.

Given the work of SCER, we have not attempted to address all the issues associated with the introduction of DSP energy services.[63] 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.

2.5.1 Provision of energy services by third parties to residential and small business consumers

RECOMMENDATION

We recommend that the NECF is amended to include a framework which governs third parties (non-retailers and non- regulated network services) providing energy services to residential and small business consumers.

The framework would outline which aspects of the National Energy Retail Rules (NERR) apply, and in what circumstances. We consider the relevant elements of the NERR that may apply at a minimum include: consumer contract arrangements and provisions relating to marketing, sales, informed consent, and dispute resolution. AER guidelines would be developed to outline NECF exemptions for these services.

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 (energy services) that can extend beyond the meter.[64] We further discuss competition in metering and data services in Chapter four.

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

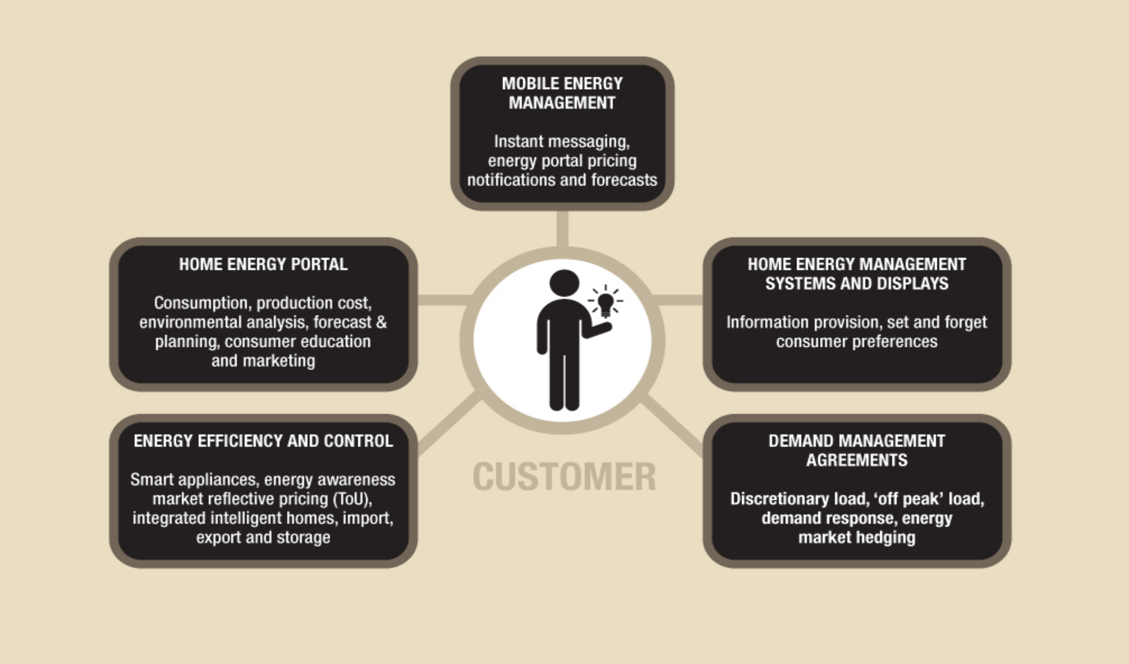
62 As defined under the National Energy Retail Law and supporting regulations (ie a residential consumer who purchases energy principally for personal, household or domestic use at premises and business consumer who consumes energy at a business premise below the upper consumption threshold of 100MWh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

63 We do discuss smart metering services further in Chapter four.

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

Energy services include the provision of energy market information to assist consumers to better manage and understand the cost drivers of their consumption;[65] energy efficiency services that seek to improve efficiency of use,[66] uptake of distributed generation (for example solar and PV systems; and storage 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 2.2 Emerging energy services to consumers



During this review, retailers and other consumer stakeholders raised concerns in relation to the governance of new energy management services and how they will be delivered to the market. Specifically, these stakeholders wanted to know how these services, as opposed to traditional retail energy services under the NECF, will be treated. Key issues that were raised included:

- 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 so that these parties can be brought under the NECF efficiently and effectively. These stakeholders considered that consumer law is not adequate to protect consumers

65 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

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

in the context of activities provided by the third parties. Stakeholders noted that there is the potential to create consumer confusion, given that these parties may have different business models and arrangements for communicating with consumers than electricity retailers.[67]

Current arrangements

A range of consumer protection obligations and support mechanisms are in place. These include national and state arrangements such as the NECF[68], jurisdictional safety and concession regimes, and the Australian Consumer Law (ACL) which provides contractual and market conduct requirements to engage with consumers.[69]

The NECF (and supporting regulations)[70] 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 consumer connection services.[71]

As noted, the NECF relates only to the sale and supply of electricity or gas to consumers.[72] 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.[73]

While there are mechanisms in place, such as ACL, the NECF does not generally apply to the services provided by energy service provider businesses. Hence, obligations relating to consumer protection and support do not apply to them.

---

67 AEMC, *Power of choice review – giving consumers options in the way they use electricity*, Draft Report, September 2012, Appendix D – stakeholder submissions summary to Power of choice review directions paper.

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

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

70 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).

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

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

73 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).

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.[74] Various views include:

- It is essential that new entrants are subject to the same regulatory obligations that apply to retailers, to ensure 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
- 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.
- There is a need for broad parameters for protections, for example, where energy management service provider is providing advice, retrofit services, and energy efficiency products, normal ACL protections will be sufficient.
- Certain parts of the NECF should apply such as energy marketing and membership to ombudsman schemes to ensure protection for consumers and certainty for energy service providers.[75]

The provision of energy management services by third parties and the applicability of the NECF will depend on a number of factors including the type of product and sale conditions which are offered to consumers (for example, price comparator websites as opposed to a service offering a contract for load management control, which are 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 sell and supply electricity or whether the sale of electricity has been combined or bundled with other goods and services, for example, a hotel tariff which includes energy costs in the charged amount.[76] 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.

In regards to electricity, we do not consider that the test under the National Energy Retail Law (NERL) for retail licensing or authorisations should be amended to include the "sale of energy services". We do consider however that NECF should be broadened to have a framework that deals with energy management services as appropriate.

---

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

75 Refer to Stakeholder submissions to Power of choice review, issues and directions paper, and Appendix D – draft report.

76 This issue is also discussed in the AEMC *Review of Energy Market Arrangements for Electricity and Natural Gas Vehicles*.

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

Stakeholders expressed a range of opinions regarding this issue. United Energy stated that as this was an emerging field, regulation should be such that new service providers are not stifled by regulation. Other parties suggested that different regulatory approaches may be appropriate. Energy Australia called for some services to be subject to regulation, if they fell within the energy market (such as demand reduction). Essential Energy suggested that the NECF should be amended to recognise the role of service providers operating in the DSP space. Jemena suggested called for a centralised accreditation process for third party providers of DSP services and that these parties are subject to the NECF and ACL.

The AER stated that there is a need to clarify the treatment of energy services. The AER suggested that the NECF, as it currently stands, may not be appropriate arena to address this issue, given that the NECF was designed around the sale of electricity to residential consumers. Rather, the AER suggested that this issue should be dealt with in the NER or in primary legislation, as this would also capture industrial and commercial consumers.

Principles to apply

There are a number of key principles that should be applied when considering the development of an appropriate compliance and accreditation system for energy services providers. These are:

- Facilitating new entry to the electricity demand management market, to stimulate competition for the benefit of consumers.
- Ensuring that (residential and small business) consumers are effectively and adequately protected.
- Ensuring that barriers to entry are not created by requiring potential new entrants (many of whom may be small businesses) to meet onerous and unnecessary compliance and accreditation requirements.

Defining energy services

We consider that it would be sensible to develop some clarity on the definition of "energy services". Any agreed definitions could apply to any energy services providers whether they are supplying large (industrial and commercial) or small (residential and small business) consumers. We set out the following as a potential basis for developing a definition of energy services.

The definition of energy services should exclude the sale of network distributed electricity to the consumer. The consumer would continue to have a contract with a licensed (or exempt) electricity retailer for the purchase of network distributed electricity (unless they are completely self-sufficient from own generation). As noted, energy services providers sell a range of products and services that can enable consumers to better manage and/or reduce their peak or average demand for network distributed electricity (including use of on-site generation through PV or co-generation, for example). However, they cannot sell or supply network distributed electricity. We note that on-site generation is a means of generating electricity on the customer's own premises or property (for example, a PV or co-generation system or wind turbine).

Taking this into account, energy services can include the following:

- Information services – for example, the analysis of data and provision of advice on how to reduce total or peak consumption.
- Energy management system – that is, installation of equipment that provides sophisticated control of appliances to reduce energy wastage (for example, switching off lights when rooms are empty).
- Smart metering – that is, installation of the meter and associated meter services of maintenance -, ensuring linkage with the consumer's electricity retailer and distributor as required, data analysis and advice.
- Installation of energy saving measures – for example, efficient lighting, insulation, more efficient heating or cooling system.
- Installation of on-site generation for example PV, co-generation, electric vehicle (vehicle to grid).
- Contracting with the consumer to provide DSP services to electricity retailers or networks – this might include via on-site generation or load control.
- In all the cases above, billing the consumer for such services – either via one off charges (eg for installing energy saving measures) or through ongoing charges or fees for service.
- In all the cases above, contracting not with the end customer directly, but with the customer's electricity retailer or distributor who will then bill the consumer for such services or equipment.
- Aggregating the DSP services of a number of consumers and selling those services to retailers or networks.

Energy services plus network distributed electricity

It is feasible that some providers of energy services may also wish to enter the business of retailing network distributed electricity (and gas) to end consumers. This is because they may wish to offer a service which aims to maximise the cost efficient supply of electricity and gas and/or the services of heat, cooling and hot water to the consumers. In such cases, the energy service provider would need to become a licensed electricity and/or gas retailer (unless they met the criteria for exemption). In the UK there are exemptions from the requirement to hold a retail licence on a de minimis basis (that is, for supply of less than a specified number of kWh per annum). This approach (or the alternative of a "stripped down", simplified – licence) could be useful for new entrants. This would be a matter for the AER to consider in accordance with requirements under the NEL.

Accreditation, compliance and obligations on energy services providers

Energy services providers should not need to hold electricity retail licences as they are not selling network distributed electricity (except in the case of those who wish to be energy services providers as outlined above).

Whether there should be a special accreditation scheme for energy services providers is a matter for debate. This may not be necessary if there are other accreditation and compliance regimes that apply to any products or services that they are selling or supplying. For example:

- Where they are providing metering services they should have to comply with standards set for smart metering such as a minimum functionality, interoperability and open access.
- For access to consumer data they will need to have informed written consent from the consumer and will be subject to data security and privacy conditions that apply to all who handle consumer data.
- Where they are designing or installing solar PV and wish their consumer to be able to claim government incentives such as Renewable Energy Certificates (RECs), solar credits and feed-in tariffs, they will need to meet the requirements of the Solar PV accreditation scheme.
- Where they are installing insulation, they will need to meet standards set under the Building Code of Australia.
- If appropriate parts of the NECF can be applied to them to ensure adequate and effective consumer protection and support.

There is a question as to whether energy services providers should be required to notify the consumer's retailer and/or DNSP about the services that it has contracted with the consumer. Some such services could have significant impacts on retailers and networks (particularly where the energy services provider has contracted with large numbers of consumers or large users in a particular distribution network or a large number/large users of one retailer). In some cases, there will clearly need to be a contact between the energy services provider and the retailer or network (where DSP services are being sold to the retailer or network).

In other cases the energy services provider would not need to contact the retailer or network, but its actions with consumers might impacts them (for example, network quality, network loading, financial risk for retailer in terms of wholesale contracting.) These issues would support the case for notification.

However, there are two reasons why a requirement for notification may not be so desirable:

- a requirement for notification could be burdensome and constitute a barrier to entry for energy services providers.
- notification could be used by retailers to attempt to forestall competition by contacting the consumer to suggest that the retailer could provide these services instead of the energy services provider (there is clear evidence of such "win back" behaviour in many markets).

Therefore the issue of notification merits further discussion among all relevant stakeholders.

Relevant elements of the NECF and supporting NERR to apply

We consider that the existing arrangements should be clarified to provide certainty to energy service providers and confidence that robust arrangements are in place. This would include reviewing the NECF to establish the framework to govern third parties providing energy services (insofar as these issues are not adequately covered under general ACL or any other requirements (for example, under accreditation schemes) to consumers. The elements of the NECF that could apply as a minimum include:

- consumer contracts;
- marketing and sales;
- informed consent;
- dispute resolution; and
- privacy, data sharing and data security.

Energy services - the way forward

The issues raised about definitions, development and regulation of an energy services market will require further consideration, assessment of issues in detail and development of an agreed policy framework. SCER is considering some of the issues in its work under the SCER Smart Meter, Consumer Protection and Safety Program. Specific work on the framework to support third parties providing energy services to consumers could be undertaken as part of this program. Alternatively, this could be achieved by establishing a working group led by the AEMC in consultation with stakeholders (market bodies, retailers, DNSPs, energy services providers and consumer groups) to consider a reasonable approach.

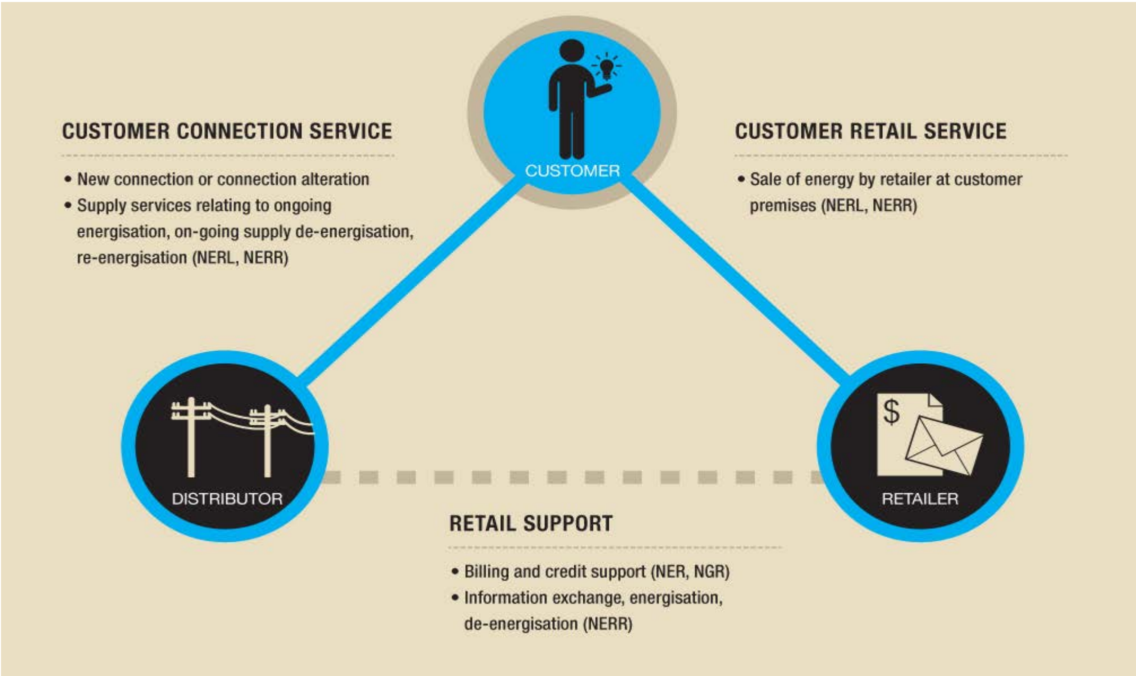
2.5.2 Retailer and distribution network service providers – consumer engagement

FINDING

We consider that the existing rules and guidelines applied by the AER could be enhanced to clearly outline the circumstances in which distribution businesses are able to deliver DSP network management services/programs. We therefore do not propose regulatory changes to the NER and NECF.

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

Figure 2.3 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).[77] 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

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

deployment of DSP options that are more efficient than buying and transporting additional electricity.

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 (for example, off-peak hot water).[78]

In recent times, network businesses have explored DSP solutions and innovative products through pilots and trials.[79] 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 consumers. They have also worked in partnership with third party providers to develop network support arrangements with large consumers. 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. The Energy Retailers Association of Australia and some retailers consider that where distribution network businesses are providing contestable energy services, these should be ring-fenced and the businesses should have the same obligations imposed on them as are imposed on retailers (that is, the marketing code, informed consent arrangements under the NECF).[80]

Distribution businesses and the ENA were of the view that they 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. These businesses noted that it would be impractical for distribution network service providers to have no contact with consumers. Firstly, this is not consistent with the arrangements under the NECF and commercial practice on the ground, and secondly, such arrangements are important for consumers and network businesses to realise the benefits from DSP. It was also noted that these activities would be undertaken by a ring fenced entity, reducing the scope for any negative competition impacts.[81]

---

78 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

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

80 AEMC, *Power of choice review – giving consumers options in the way they use electricity*, directions paper and draft report, retailer stakeholder submissions

81 AEMC, *Power of choice review – giving consumers options in the way they use electricity*, directions paper and draft report. network stakeholder submissions.

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.[82]

Considerations

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.

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. 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.

Network businesses generally undertake DSP as part of their regulated network services as approved by the AER. These can be price-based DSP (such as tariffs) or contracted DSP (such as contracts with third party providers). Generally, network services tariffs are recovered via the retailer, and not directly from end 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.[83] This aims to ensure that monopoly network businesses do not have priority access, information or cheaper 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 generally prefer to facilitate the delivery of DSP by contracting with other parties such as retailers and third parties.[84] 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 consider that the existing rules and guidelines applied by the AER could be enhanced to clearly outline the circumstances in which distribution businesses are able to deliver DSP network management services/programs. This approach was

---

82 AEMC, *Power of choice review – giving consumers options in the way they use electricity*, Draft Report, September 2012, Appendix D – stakeholder submissions summary to Power of choice review directions paper.

83 Refer to AER ring fencing guidelines at http://www.aer.gov.au/node/12493

84 Energy Networks Association (ENA) directions paper submission, p. 7.

supported by many stakeholders, including the AER.[85] The AER indicated that the incentive framework and ring fencing guidelines will seek to deal with networks involved in DSP.

85 AER draft report submission, p20. United Energy draft report submission, p 6, Jemena draft report submission, p 7.

3 Consumer information - access to electricity consumption data

Summary

We recommend that changes are made to the NER to enable consumers to access and use their electricity consumption data.

The amendments include:

- Clarifying the existing arrangements and providing a framework for consumers to access their electricity consumption data and share with third parties (in accordance with explicit informed consent arrangements).These provisions would not limit consumers from accessing their personal data for use by other parties if they so wish.
- New provisions in the NERR to provide each residential and small business consumer with their consumption load profile (that is, timing of use over a period).

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

The ability of consumers to easily access and have sufficient and relevant information about their consumption will help:

- improve awareness of electricity consumption and use patterns;
- enable more informed choices about different DSP products and services that better suit consumers circumstances and needs; and
- promote efficient retail electricity markets through better products and services available to consumers.

We note stakeholder views on the need for better market information on consumer load profiles to support the development of DSP products and services by third parties. We are not proposing any specific changes to regulatory arrangements; rather we propose to allow the market to drive the provision of such information. We expect that distribution network businesses will publish relevant information as part of their annual planning reports, where it is available.

We propose that SCER submit two rule change proposals to the AMEC to make the necessary changes to the existing electricity market rules. The procedures to support provisions in the rules should be developed by AEMO in consultation with stakeholders. The changes to the rules/procedures would have regard, as appropriate, to the work by SCER under the Smart Meter, Consumer Protection and Safety program.

3.1 Market conditions for uptake of efficient DSP

To facilitate uptake of DSP, an important condition is that consumers have accessible and timely information about their electricity consumption use and patterns. As discussed in Chapter two, this information would help consumers understand how much, and when electricity is used. This would assist them to quantify the impacts of their decisions (that is, costs of using appliances and/or equipment), compare electricity retail tariff offers and consider the value of different DSP products and services to help manage their costs.

This chapter focuses on consumers' access to their energy and metering data under current regulatory arrangements. Energy and metering data is the information recorded by a consumer's meter, retrieved from that meter, and then validated through NEM processes and systems for market settlement and retail billing. We have not considered consumers access to "live" or "real-time" data that may be available if a consumer has a smart meter.

There are a number of other work programs that are also considering how consumers can be provided with their electricity consumption information. These include: the SCER program to review the existing consumer protection arrangements under the National Energy Consumer Framework NECF, including the need for additional arrangements in the context of smart meters and associated services in the market and[86] the Australian Government scoping study on the need for establishing an energy information hub.[87] We have had regard to this work in forming our proposed recommendations for this area of the review.

3.2 Issues identified

We consider that the existing market and regulatory arrangements need to be improved to support consumers or their agents in accessing and receiving their energy and metering data.

Consumers can obtain information about their electricity consumption in a number of ways. They have some information on their retail electricity bills/invoices. Alternatively, consumers can request access to their detailed energy and metering data (historical or current) from their retailer as provided by the NER. Consumers who have smart meters may also have instant access to energy data through communication devices such as home area networks (HAN), and in home displays (IHD).[88]

---

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

87 http://www.ret.gov.au/energy/energy_markets/electricity_market_development/data/Pages/default.aspx

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

Box 3.1 outlines the different types of energy and metering data available according to meter type.

Each of the above sources provides consumers with different levels of information regarding their energy use. While retail electricity bills generally provide the average historical consumption for a specified period (for example, total kWh for a three month period), metering data may, depending on a consumers metering capability, provide more detailed and, in some cases, more accurate energy consumption data.

Where accumulation data is used to determine the consumer's billing, the average consumption profile of a defined distribution area (known as the net system load profile) is applied to represent the timing of energy use of each consumer and calculate the costs of supplying and delivering electricity to those individual households. Therefore, this technology is not capable of providing consumers with accurate information on the relationship between energy use and costs.[89] We discuss our proposals regarding the investment in more advanced metering technology in Chapter four.

Box 3.1: Types of meters and electricity consumption data recorded

Accumulation meters – record accumulated consumption data on a periodic basis (typically three month periods to match billing cycle). This data provides consumers with their total historical consumption (total kWh) and does not provide timing of energy use (either both how much and when electricity is used).[90] The data is retrieved manually from the meter at a consumer's premises.

Interval meters – record consumption on a near real time interval basis (that is, 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 (that is, without having to visit the consumer premises).

Smart meters/data – record consumption on a near real time interval basis (that is, half hourly consumption). Smart meters also have communication technology that enables data to be retrieved remotely, provides other smart services (for example, network support such as faults/problems on network or load management, and can link to devices such as through HAN and IHD to enable instant access for the consumer to their electricity use profile.

89 We note that if consumers have meters with two registers and are peak and off-peak charges, this may help with understanding energy use and the drivers.

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

Under the NER, consumers have the right to request and access their energy and/or metering data from their retailer. 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 the FRMP is a consumer's retailer. The NER also includes other provisions regarding the ability of consumers to electronically access their energy data in metering installation.[91] Figure 3.1 shows the flow of information under the existing rules.

Other national and jurisdictional arrangements also require that residential and small businesses consumers are provided with energy consumption information. The National Electricity Retail Rules (NERR) requires retailers to provide consumers with their historical data (up to two years) at no cost, if requested by the consumer.[92] Distribution network businesses also have a requirement under the NERR to provide consumers with energy consumption information if requested by a consumer, or by the consumer's retailer.[93] Other provisions also set out the information that retailers are required to include on consumers' bills.[94]

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

While these arrangements exist to enable consumers to receive their data, a number of stakeholders engaged in the review indicated that consumers (or their agents) face practical issues when they seek to access their validated energy and metering data under the existing provisions. Specifically stakeholders noted that it can be difficult for consumers or their agents to obtain energy and metering data, and then to use this data to understand consumption patterns. In turn, this limits the ability for consumers to take up DSP offers or packages that are most suited to their needs.[95]

Specific issues raised by stakeholders included:

- When consumers request billing or metering data from retailers, they experience no response, time delays, or the data provided is too difficult to interpret or use.
- Current arrangements limit the ability of consumer agents to access data directly from retailers (in accordance with explicit informed consent provisions). This includes when those consumers change retailers, but not the agents acting on their behalf. This has limited the ability of third parties to provide consumers with DSP products and offers.

---

91 clause 7.7 (b).

92 NERR clause 28.

93 NERR clause 86.

94 NERR clause 25.

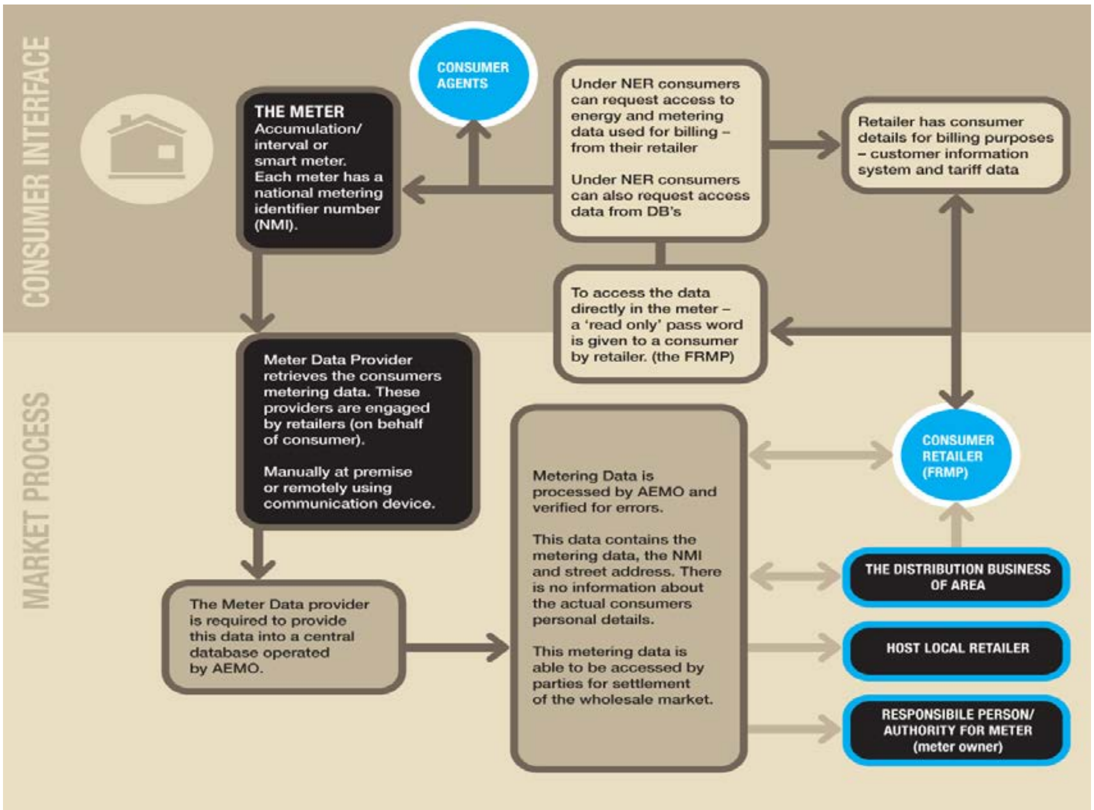
95 AEMC, *Power of choice review – giving consumers options in the way they use electricity*, directions paper, March 2012, p. 46-47.

- Ambiguity in the NER as to whether distribution network businesses or Meter Data Providers (MDPs)[96] are able to provide metering data directly to consumers. Distribution and third party stakeholders considered that these rules provisions should enable consumers to access their data directly from distribution businesses or MDPs.

- Ambiguity in the current rules relating to the fees that can be charged. Some third parties have noted that they have been charged significant fees to retrieve a consumer's data on behalf of industrial and commercial businesses.[97]

Broader concerns were also raised in relation to the lack of general market information available on consumer energy and consumption data. This includes information on consumer sector load profiles and the ability to access data independently of a retailer. It was noted that such issues may be impeding innovation, choice for consumers, and delivery of energy services.

Figure 3.1 NER arrangements for consumers to access their energy and metering data



96 A person who meets the requirements listed in schedule 7.6 of the NER and has been accredited and registered by AEMO as a Metering Data Provider.

97 AEMC, *Power of choice review – giving consumers options in the way they use electricity*, draft report, September 2012, Appendix D – Summary of stakeholder submissions to Power of choice review directions paper.

3.3 Recommended changes to market and regulatory arrangements

Recent price rises have generated significant interest from consumers wanting more information about their electricity usage in order to identify opportunities for energy cost savings. This interest in consumption is also being driven by smart technology (ie interval/smart meters) that provides better information about actual consumption.[98]

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

There is consensus across the industry that better information should be made available to consumers to improve awareness of energy use. In addition, there is general agreement that consumers should have the right to access, use and share their electricity consumption data. This was made clear by stakeholders in submissions to the directions paper and draft report.[99] 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. Given new technologies for imparting information on consumption and costs, some market participants have already moved to supply more accessible electricity consumption information through online channels.[100] It is expected that these market developments will improve information flow to consumers over time.

While there are already moves to provide consumers with access to their personal electricity and metering data, most stakeholders agreed that it was appropriate to clarify the existing rules to ensure they are workable and fit for purpose. In light of recent market developments, increased clarity and transparency in the rules may make it easier for consumers to access their data and afford a better understanding and awareness of their energy use.

---

98 The 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. AEMC, *Power of choice review – giving consumers options in the way they use electricity*, draft report, September 2012., Appendix D – Summary of stakeholder submissions to Power of choice review directions paper.

99 AEMC, *Power of choice review – giving consumers options in the way they use electricity*, draft report, September 2012, Appendix D – Summary of stakeholder submissions to Power of Choice review directions paper. AEMC, op.cit., Appendix G - stakeholder submissions to the draft report.

100 Origin Energy "Origin smart" consumer access portal, released in June 2012 http://www.originenergy.com.au/originsmart/. 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; Refer to Ausgrid Smart city, Smart grid trial - see http://www.smartgridsmartcity.com.au/.

In the next section we provide our recommendations for:

- timely and accessible energy and metering data to consumers; and
- broader market information to develop DSP products and services.

3.3.1 Timely and accessible energy and metering data to consumers

RECOMMENDATION

We recommend that:

- **The NER is amended to clarify the arrangements and provide a framework for consumers to request and receive their energy and metering data from their retailer. The framework would provide for:**
  - **a minimum format and standard information that would need to be provided to consumers;**
  - **timeframes for delivery of data; (ie no costs for standard data format once a year);**
  - **fees that can be charged when consumers request their energy and metering data;**
  - **ability for a consumers agent to access energy and metering data directly from the consumers retailer (this would be in accordance with appropriate explicit informed consent arrangements); and**
- **Amendments to the National Energy Retail Rules to provide each residential and small business consumer with their consumption load profile. At a minimum this should be on a consumer's retail bill.**

Framework to support consumer requests for energy and metering data

We are recommending that a transparent framework be established in the NER to clarify the requirements on a retailer when a consumer requests their personal energy and metering data. This framework will clearly specify the type and format of data to be provided, timeframes for delivery and clarify costs that can be charged. It will enable consumers to authorise their agents to access data on their behalf (with written explicit informed consent). The arrangements would not limit the ability for consumers to request their data or prevent consumers from accessing their data from other parties (such as distribution business or metering data providers).

The proposed changes will promote the NEO, as they aim to provide certainty to consumers in respect of the arrangements for requesting and receiving personal energy and metering data. This will also provide consumers with transparent, consistent and comparable data regardless of their retailer.

The changes also seek to reduce the transaction costs associated with obtaining, interpreting and using the data to better understand the relationship between energy use and energy costs. In turn, this will encourage consumers to: investigate appropriate DSP products and services (including more flexible pricing options); engage with third parties; and make efficient decisions (ie purchasing of electrical appliances) that reflect individual circumstances.

Providing a transparent and consistent approach may also promote greater competition in the retail market, as it would assist market participants and third parties to develop innovative DSP products and services for consumers.

In considering the proposed framework that should apply when consumers request their energy and metering data under the NER, the following two principles were considered:

- consumers have the right to access their personal electricity and metering data.
- They should know the data exists, be able to share it, and know how it will be used (in accordance with explicit informed consent, privacy and confidentiality provisions).[101]

To achieve these principles we have developed the following framework:

- All consumers will be able to access and receive both 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.
- The information given to consumers will be in a form that enables them to understand their consumption patterns. For those consumers with interval/smart meters it is important that the information shows how their consumption use varies across different time periods (for example, across peak, off peak, and shoulder periods). Information should be provided in a standard format to facilitate ease of use. For consumers on accumulation meters, they will be provided with better information (ie net system load profile of their distribution area).
- Response to consumer requests will be in a timely manner.
- Consumers should be able to access their consumption data in the standard format at no cost. This is consistent with the existing principles applied under the NECF and current practice by retailers.

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

- Consumers are able to authorise third parties to access data on their behalf. Transfer of energy and metering data to consumers' agents should be in accordance with explicit informed consent arrangements, having regard to data security and protection of consumer privacy.
- The requirements will not limit the delivery of more detailed information to consumers by retailers or other third parties. This is particularly relevant in the case for large industrial and commercial consumers who currently have direct relationships with distribution businesses and metering data providers.

Below we discuss the elements that underpin the framework in the rules. This includes:

- standard format for the provision of the data;
- timeframes for delivery;
- fees that are able to be charged; and
- ability of third parties to access data directly from retailers or other parties (with explicit informed consent).

Table 3.1 summarises the existing arrangements and our recommended changes. The next section outlines the key elements outlined above and our proposals for each. We have attached supporting drafting specifications to support the rule change proposals.

Table 3.1 Summary of the existing and proposed arrangements

Area of change	Existing arrangements	Recommend changes
Consumer request for energy and metering data	NER and NECF give consumers the right to access energy and metering data. No framework regarding how data is provided.	Clarifying the NER by providing a framework that provides for standard form and format of data
— Fees	NER allows a retailer to charge a consumer for the cost of providing the metering data. NECF requires that historical metering data is provided to residential and small business consumers at no cost.	Clarify NER provisions so that consumers are able to receive their energy and metering data in standard format at no cost.
— Timeframes for delivery	NER/NECF do not provide timeframe provisions.	NER to include provisions relating to timeframes for delivery.
— Informed consent provisions	NECF requires average consumption information to be provided on bills.	New provision in the NECF to require retailers to provide consumption load profiles to residential and small business consumers.

Area of change	Existing arrangements	Recommend changes
Provision of electricity consumption profile information to consumers	NECF requires average consumption information to be provided on bills.	New provision in the NECF to require retailers to provide consumption load profiles to residential and small business consumers.

Standard format and timeframes for data provision

Consumers' ability to make informed decisions will depend on a variety of factors, including the how and the way in which data is provided. As noted in Chapter 2, consumers generally want information that is easy to understand, convenient, cost effective to access, and available in a timely manner.

The ability of different consumers to access their personal data will differ, as will the type of information they require.[102] 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.

Requests for energy or metering data have traditionally been provided by retailers in a variety of ways, for example: raw data on bills; summary data printed invoices; and/or excel files sent via email/post. A number of stakeholders have highlighted that the lack of a standardised approach has translated into significant time and effort to process the variety of formats currently provided by retailers or responsible parties.[103]

Under the rules, there are common arrangements for the exchange of energy and metering data between market participants to facilitate wholesale market settlement.[104] There is no standard approach for provision of energy and metering data to consumers or their agents by retailers (or other parties).

Standard format of data

We have recommended that there should be clear standard provisions in the rules for the form and format of data that is provided to consumers upon their request. As discussed in Chapter 2, this would provide clarity to all consumers and their agents on

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

103 AEMC, *Power of choice review – giving consumers options in the way they use electricity*, draft report, September 2012, Appendix D – stakeholder submissions summary to Power of choice review directions paper.

104 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)

the type of data they are able to receive, and that it will be delivered in an easy to read format. This would also help to build consumers understanding of their electricity consumption and relationship to costs. It will also help to promote retail competition by facilitating price comparisons. We do not expect that provision of data in a standardised format will incur significant additional costs to retailers (or other market participants) given that systems are already in place for exchange of data to enable market settlement. This would also be consistent with the direction taken by some industry participants where smart meters are being rolled out.

We propose that the following provisions should be included in the rules framework:

- Raw energy and metering data in standard format. This should be provided in a format akin to the existing electronic "NEM 12/13" file format for exchange of metering data between AEMO and market participants.[105]

- Summary data that supports pricing offers and other DSP products and services. This should provide at minimum, monthly total electricity consumption, and a chart showing peak, off-peak and shoulder electricity consumption over a specified period (e.g. one moth, six months etc).

We consider that AEMO should develop supporting guidelines that outline the details of standardised format of data. It would be sensible for AEMO to consult with all stakeholders about these guidelines. In developing the guidelines, the level of summary data should take account of differences between residential and industrial/commercial consumers. We are not proposing to include provisions regarding the delivery method (that is, e-mail, internet web portal, hard copy). We note that consumers are likely to drive how the data is delivered. For those consumers with interval/smart meters, retailers should be able to utilise either bill or their web portals if available. It is important to ensure the arrangements are flexible to allow any approach.

Stakeholder responses to the draft report generally supported the need for standard format of data. Key points raised included:

- Minimum standard of format should be simple and practical for consumers to use, and not unduly restrictive. Consumer groups noted that recognition should be given that not all consumers are able to use or access technology, thus this should not be only means by which information is sent to consumers.[106] Generally it was felt that the data/technology channels to engage consumers should be left to evolve via the market.

105 www.aemo.com.au/Electricity/.../Files/.../0630-0002%20pdf.ashx

106 ACOSS submission to draft report.

- The current "NEM 12" data/CSV format that is currently used for the exchange of data for market settlement purposes could be utilised as a suitable standard data format for provision of energy and metering data to consumers.[107]

- Need for an independent, or new category of market participant "market intermediaries" that would allow a third parties to perform function of transfer of data (this would be similar to CATS (monitoring and facilitating transfers).[108]

Provision of consumption load profile information to consumers

It is recognised 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.

We recommend that a new provision is included in the NERR that requires, retailers, to provide consumers with their consumption load profiles. For those consumers on accumulation meters, their actual consumption profiles will not be available due to the type of metering technology. As highlighted, these consumers should be provided with the net system load profile of their distribution area. This information should be provided on a consumer's bill in an appropriate standard format. We note stakeholder comments regarding consideration of what and how much data is useful for decision making, as opposed to introducing additional complexity and confusion.[109] It is important that consumers know what is driving their costs.

Timeframes

The level and timing of energy and metering data available to consumers will depend on their metering installation. 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.[110] We consider 10 business working days to be appropriate; however in developing the rules and procedures AEMO's validation processes and protocols would need to be considered.

Fees payable by a consumer (or agent)

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

107 Refer to Appendix G – Summary of stakeholder submissions to Power of choice review draft report.

108 Energy action submission to draft report, p.3.

109 Refer to Appendix G- Summary of stakeholder submissions to draft report.

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

the cost of providing the metering data.[111] Although such provisions exist, it is unclear in what circumstances the consumer is liable.

In most cases, residential and small business consumers are provided with 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.[112]

All stakeholders support a minimum level service of free data requests per annum as current the case.[113] The need for a reasonable fee for any meter data service provided in addition to minimum market obligations was also supported. It was noted that such fees would need to be proportionate to additional service/s provided (ie any charges to consumers or their agents should only reflect the cost of providing the service rather than the value of the data).[114]

We are recommending that the rules should clarify the existing provisions and specify that:

- Requests by a consumer for their energy and metering data in the standard data format must be supplied at no cost to that consumer.
- Where consumers (or their agents) request information more than once per billing period over a twelve month period; a retailer (responsible party) is able to charge a reasonable fee. This is consistent with existing NECF provisions.
- Additional data services provided by retailer or responsible party should be specified and a reasonable fee can be applied.

Transfer of energy and metering data to authorised consumer agents

It is unlikely that most residential and small business consumers are going to want (nor may have the ability in some cases) to spend time trying to decipher raw energy or metering data to determine the potential DSP options available to manage energy use. For this reason, some consumers may engage third parties to help them understand

111 Clause 7.7 (a) and 7.3A (d) of the NER.

112 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.

113 Refer to Appendix G – Stakeholder submission summary to Power of choice review draft report.

114 Better Place draft report submission, p.3. Metropolis draft report submission, p.[x], AEMO draft report submission, p.8.

their consumption patterns and provide advice on options or investments that can be made to manage costs.[115]

To facilitate decision making, some consumers will want to authorise these third parties (agents) to access information, including energy and metering data, directly on their behalf. Under the existing rules framework for consumer requests, consumers have to contact their retailers' call centre to request their energy and metering data. They then have to forward data to their agents (refer to Figure 3.1). Some third parties acting on behalf of industrial or commercial businesses have sought data directly from the retailer. In these cases the third parties are required to forward a letter of authority from the consumer.[116]

In submissions to the review, stakeholders indicated that these arrangements limit the ability of consumers to engage third parties and ability to therefore manage use. It was considered that the rules framework should include arrangements that enable consumer to authorise the transfer of their data from retailers to consumers' agents (with informed consent). This would be similar practice to consumers switching retailers, and/or transfer of consumer information in the banking and telecommunication industries.[117]

Many stakeholder submissions to the draft report indicated support for provision of energy and metering data to third parties. However, this was conditional on these parties being appropriately authorised and sufficient safeguards being in place. Retailers,[118] networks, and some metering providers indicated that it is important to clarify the requirements for third parties in order to: obtain explicit informed consent from consumers; confidentiality[119] and privacy arrangements (for example, National Privacy Principles (NPP)) that would apply; and the accreditations/registrations for third parties where utilising consumer data to offer energy management services.[120]

We propose that the rules should allow for consumers to authorise the transfer of their personal energy and metering data to third parties where explicit informed consent has been obtained. 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

115 This is evidenced by the work under Solar Cities programs - refer to case studies at http://www.climatechange.gov.au/solarcities.

116 EnerNoc directions paper submission, p.9.

117 AEMC, *Power of choice review – giving consumers options in the way they use electricity*, draft report, September 2012, Appendix D – stakeholder submissions summary to Power of choice review directions paper.

118 Refer to Energy Retailers Association of Australia (ERAA) *Smart meter working paper 4 - Privacy of personal information: how to ensure appropriate use and disclosure of smart meter data* (see http://eraa.com.au/wp-content/uploads/ERAA_WP4-Privacy.pdf).

119 United Energy submission to draft report, p.3.

120 Refer to Appendix G - Summary of stakeholder submissions to Power of choice review draft report.

retailers, or responsible parties; rather they will provide clarity to the market on how the current arrangements should be applied.

Informed consent arrangements

Retailers are currently responsible for obtaining informed consent from consumers and are also subject to provisions under the NECF, jurisdictional codes and NPP regarding consumer protection, support and privacy of information. We consider that it is appropriate for third parties to obtain explicit written (either through hard copy or e-mail form) informed consent from the consumer in accordance with existing confidentiality and privacy provisions. This consumer consent for a third party to access their data should be provided to the consumers' retailer. Arrangements should be flexible enough to enable consumer switching of retailers (that is, consent could continue to apply for a specified period such as two years or the length of any fixed term contract with a third party, even where the consumer changes retailer). We discuss the issues regarding the broader question of provision of energy services by third parties and accreditations and elements to apply under the NECF in Chapter two.

We note similar issues are being considered by the SCER Smart Meter, Consumer Protection and Safety work. Changes to the rules should have regard to the outcomes of this work.

3.3.2 Market information to develop DSP products and services

FINDING

We consider that new regulatory arrangements to support the provision of broader market information are not required. We expect distribution businesses to publish similar information as part of their annual planning reports and demand side engagement strategies.

The data emerging from the suite of pilots and trails should be used to inform policy making and broader market information about different consumer segments and groups with those sectors consumption load profiles.

Smart technology will significantly improve the quality of information in the medium to long term. This will, in turn, encourage the release of more innovative products and services to help consumers manage and control their energy use. Better metering data will also enhance and improve existing market processes and systems.

A key condition for third party service providers developing innovative products and energy services is the provision of information about different consumer sectors' consumption patterns and representative load profiles. As shown in Figure 3.1, 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 (for example, ESCOs, aggregators and other retailers) seeking to develop 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 review about the information disadvantage these energy service providers face, and also how this is limiting the ability of consumers to use these parties' energy services. We note suggestions for a potential central information repository, with multi party access, akin to the approach in the United Kingdom as part of its roll out of smart meters to all consumers by 2019.[121]

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. 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 (for example, business to businesses/accreditations).[122]

There is a divergence of stakeholder views on the need for a central repository for consumer data and on exchange protocols for third parties to access energy data. Some note that web portals are in place or under development, thus 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.[123] Others consider a single repository may limit future consumer confusion regarding which entity they should approach to access their data.[124]

Our recommended changes to the rules address concerns raised by stakeholders regarding the ability of consumers to get easy access to their data. However, given concerns about information asymmetries between parties, we consider that there may be merit in the availability of broader market information about consumer sector (ie industrial, commercial and residential) 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.

In the draft report, we proposed that AEMO could publish information about consumer sector load profiles. AEMO indicated in their submission, that they would not currently be able to produce this profile. They do not have access to all of the data required to publish this profile information as AEMO data is only referenced by National Metering Identifier (NMI), and has no link to actual consumer or classes of

121 AEMC, *Power of choice review – giving consumers options in the way they use electricity*, draft report, September 2012, Appendix D – stakeholder submissions summary to Power of choice review directions paper.

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

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

124 Smart Grid Australia, directions paper submission, p.2; Listening post, directions paper submission, p.2, CACL draft report submission, p 6, CEC draft report submission, p.4.

consumers.[125] It was noted that retailers have access to the demographic information required to develop consumer segments, and distribution businesses have feeder level load profile data. Both networks and retailers considered that information to develop profiles may add additional cost to already large amount of published information and were uncertain of the benefits of the proposal. They recommended that any new market information role for AEMO should be supported by cost/benefit analysis to ensure clear net benefits for end users.[126]

We are not recommending new regulatory arrangements for the provision of broader market information. We expect distribution businesses to publish similar information as part of their annual planning reports and demand side engagement strategies.

Furthermore, we consider that it is important that data which is collected from a number of pilots and trials is made available and utilised to both inform policy development and market participants. Information that could be published from the data could include illustrative examples of different load profiles for different types of consumers (for example, small households, large households, those with air conditioning and/or electric heating and those without; consumers at home most of the day and those out most of the day). This is a task that could be usefully undertaken by government, in partnership with AEMO, and/or the Australian Bureau of Statistics.

Access to this type of data supported by planning information published by distribution business will help third party service providers to understand the nature of consumption patterns across the NEM and different groups. Therefore this will support their ability to develop DSP products to offer to residential and businesses consumers.

125 AEMO submission to draft report, p.8.

126 Refer to Appendix G - Summary of stakeholder submissions to the Power of choice draft report.

4 Enabling technologies (metering)

Summary

Enabling technology is a key condition to enable consumers to take up DSP options and mange consumption. There is a wide range of enabling technology available for consumers and market participants that includes metering capability, automated control systems, and energy management services.

For the review, we have focused our assessment specifically on the opportunities to improve the existing market and regulatory arrangements to facilitate investment in metering that supports uptake of efficient DSP. As part of our analysis we considered whether the current arrangements adequately facilitate consumer choices to take up a DSP product or end use service which are enabled by better metering technology. We also considered if the existing arrangements enable the full value of DSP and end use services to be captured across the supply chain. This is consistent with the terms of reference for the review.

We recommend that:

- A framework in the NER is introduced that provides for competition in metering and data services for residential and small business consumers. The SCER endorsed minimum functionality specification for smart meters would be required for all future metering installations.
- A framework for open access, interoperability and common communication standards is established to support competition in DSP energy management services enabled by smart meters.
- The NER require that smart meters be installed in defined situations (ie new connections, refurbishments and replacements). These would also be as per the minimum functionality specification.
- The option of a government mandated roll out of smart meters in the National Electricity Law is removed. This will provide certainty to the market to proceed with commercial investment.

We expect that the benefits of introducing the new reforms for investment and use of smart meters and other end use services are expected to exceed the costs involved to consumers who install the meters and the market as a whole.

The proposed approach will support efficient markets as it promotes innovation, greater DSP options for consumers and efficiency in metering costs. This is preferable to retaining networks as the monopoly provider of metering services to households and small businesses.

Under our proposed model, the onus will be on the retailer or DSP service provider to elicit consumer consent to a smart meter through offering

appropriate retail pricing offers and value added services. We expect that consumer's decision to take up a pricing offer or other DSP product will include (if required) the enabling metering technology as part of that package. Ultimately, it will be up to consumers to make choices based on the net benefits that end use services provide. The net benefit to the system will ultimately be realised through the choices that consumers will make.

The workings of the proposed arrangements would be simple from the consumer perspective. It will be up to market participants to ensure any changes are seamless for the consumer. There will be a role for them to inform the consumer of the potential opportunities and benefits that more advanced meters can provide. For example, better information about a consumer's consumption to understand use and its relationship to costs.

There are a number of reasons why the current arrangements are inhibiting the ability of consumers and market participants to make commercial decisions and invest in metering technology that supports efficient DSP tariffs and services. To address this we are recommending a framework that encourages commercial investment in smart meters and services they enable to promote consumer choice.

There will be some further work that will be required to progress implementation of the competitive approach and DSP end user services enabled by smart meters. Specifically, the requirements for open access and common communication protocols/standards. We propose that SCER direct the AEMC to establish an advisory stakeholder working group to work through implementation details building on the work already undertaken by the National Stakeholder Steering Committee (NSSC).

4.1 Market conditions for uptake of efficient DSP

A key condition for facilitating efficient DSP is the availability of enabling technology and systems. Technology provides a tool that can help consumers to monitor, manage and adjust their electricity consumption, and importantly, capture the value of doing so.

There have been different forms of technologies that support the uptake of various DSP options in the NEM for many years (as an example ripple control of hot water operated by some distribution businesses).

Advances in technologies such as smart meters, two way or wireless communication systems between the consumer and suppliers significantly expand the range of DSP options available for consumers to take up, as with the functions that traditional meters and other demand response technologies can provide.

"Smart grids" are a new, more advanced way of supplying electricity. It combines innovations in digital communications, sensing and metering with the electricity network to create a two-way, more interactive grid.[127] For example, the technology is able to provide real-time information to householders about their energy use, and also better information to distribution businesses about their network to help limit, for example, interruption time.[128]

More advanced technologies can also help to improve the operation of the power system and enable market benefits to be captured along the supply chain with market participants offering more innovative DSP products and end use services to consumer that better suit their preferences. This will ultimately allow both greater consumer receptivity and higher confidence to the market that consumers can and will respond to DSP offers (ie pricing).

It is important that regulatory arrangements provide market participants and consumers with the confidence and certainty to make investments in enabling technology to enable uptake of DSP products and end use services. We consider that the arrangements must provide prospective investors with:

- access to appropriate information so that investment risks can be assessed and transaction costs minimised;
- 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 capture the value of the benefits the technology brings to the market.

This chapter starts with a summary of the existing issues we have identified for investment in enabling technologies to support efficient DSP. We then focus the rest of the chapter on the existing arrangements for the market to invest in metering capability that supports efficient DSP. We consider how the existing arrangements particularly enable consumer choice and facilitate uptake of DSP products and end use services. In addition, how investment in more advanced metering help to promote the value of DSP to be captured across the supply chain. We conclude with our recommendations for reform across this key area for the review.

In the context of this review, metering provides one of the enabling tools to facilitate better information to the consumer about their consumption, and also uptake of different DSP product or service that may be offered by the market. We expect that consumer's decisions on DSP products or energy services will include the enabling

127 Refer to http://www.ret.gov.au/energy/energy_programs/smartgrid/pages/default.aspx

128 The Australian Government's Smart Grid, Smart City Initiative is testing large scale deployment of such technology and is gathering information about the costs and benefits.

metering technology as part of that offer. Ultimately, it will be up to consumers to make choices based on the net benefits that end use services provide. The net benefit to the system will ultimately be realised through the choices that consumers will make.

Our analysis and recommendations specifically focus on the residential and small business consumer sector.[129] The industrial and commercial sector has had access to more advanced metering and competition in the end use service enabled by them for some time. We do consider that our recommendations have broader application, and thus could be applied to all consumer sectors of the NEM.

We note the work of the SCER work program to review the national smart meter, consumer protections and safety arrangements. We have taken this work into account in proposing our reforms.

4.2 Issues identified

We have noted more advanced technologies which are available in the market today can help consumers take up a broader range of DSP products and services, including more flexible retail pricing options. As outlined in Chapter 3, more advanced metering technology (ie interval/smart meters) can record electricity use at a premise on a more frequent time interval basis. This provides consumers with better information about their consumption, and hence more control about how they manage their use consistent with their preferences and choices.

Other devices that have programmable thermostats and communication systems provide consumers with the ability to “set it and forget it” and reduce the need to manually respond to a high-priced event or period of the day.[130] For example, such devices are able to receive a signal and where a consumer has agreed (and receives a reduced energy rate) a supplier can remotely cycle a consumers’ appliance (ie air-conditioning) to a specified level as a way of helping to manage peak demand on the system. This type of technology can be extended to other end-uses and appliances and controlled 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. Other examples of enabling technologies that can facilitate the uptake of efficient DSP are provided in Box 4.1.

Given the advances in technology to enable DSP options, the SCER asked the AEMC as part of the terms of reference for this review, to assess energy market frameworks that

129 Refer to Appendix F - Defining residential and small business consumers.

130 Enabling technologies can also help consumers manage their electricity consumption by providing new information about energy use that they otherwise would not have access to. For example, in-home displays can give consumers 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.

would maximise the economic value to consumers of services enabled by smart meter and smart grid technologies, including load control technologies. The following matters were to be considered:

- enabling effective interaction between competitive and regulated services;
- regulating access to infrastructure, data and consumers;
- encouraging efficient investment in new technology and services;
- enabling more sophisticated price signals to be passed through to consumers; and
- protecting the rights and interests of consumers.

Box 4.1: Examples of enabling technologies for take up of efficient DSP

- Meters with the capability to allow consumer electricity bills to reflect their actual usage pattern rather than an average load profile for that consumer class;
- Whole house gateway systems that allow multiple devices to be similarly made price sensitive (for example smart thermostats that respond to high prices with an automated adjustment to their setting);
- Multiple user-friendly communication pathways to notify consumers of load curtailment events;
- Energy-information tools within the household that enable near real-time access to interval load data and provide analysis of actual performance relative to baseline usage;
- Thermal or electric storage facilities that respond to high-price or electric system emergency scenarios;
- Load controllers and building management control systems that provide demand response from automated load curtailment strategies at the consumer level; and
- Distributed generation used for emergency back-up or to meet the primary power needs of a facility.

4.2.1 Investment in enabling technology to support efficient DSP

In this review, we identified a number of challenges with existing arrangements relating to how they currently support market participants and consumers to invest in DSP technology as a mechanism to take up or offer DSP products and services.[131] The challenges included:

- The *existing market characteristics that may reduce the attractiveness of investment in DSP technologies.* For example: transaction costs (ie acquiring information and evaluating risks); high upfront costs, a desire for short pay back periods, and split incentive issues.

We have recommended that opportunities could be improved to facilitate opportunities for consumer investments, including a role for third parties to support consumer decision making. As noted, ESCOs provide a range of business models aimed at capturing the market's potential to respond to consumer demand for increased DSP. Such companies can help consumers with the technical and commercial implementation and operational risks associated with DSP technology investment. Such an approach can minimise transaction costs and provide some certainty of costs and returns for the end-consumer. We consider there are a range of opportunities to facilitate third party participation in the market, and have made some proposals as part of this review.

- *How existing market and regulatory arrangements encourage commercial investment in metering technology that enables and better supports the uptake of efficient DSP.*

Network businesses, retailers or consumers may wish to invest in DSP technology (ie metering) that enables more opportunities to offer/take up flexible pricing options, or obtain better information to support more efficient network/retailer operational functions. We have identified that there a suite of issues for consumers and market participations which include: cost recovery and risk of the investment; the need for improved information technology systems and platforms to manage the volume of data which becomes available from interval/smart meters; and the additional costs that this may impose. For consumers, such as those in the residential sector, it is currently unclear how a request to install a smart meter would be handled if the consumer is seeking to take advantage of flexible pricing options (ie offers that are time varying), or manage energy use of household appliances. These issues are discussed in more detail in the next section.

- *The ownership and usage rights of consumers and other market participants with respect to DSP technology means that consumers are unable to fully capture the benefits enabled by the investment.*

There are a number of DSP technologies that may offer consumers, third parties (acting on behalf of consumers), retailers or network businesses the capability to provide DSP solutions on the consumer's behalf. Therefore, it is important that the role of

131 Refer to AEMC, *Power of choice – giving consumers options in the way consumers use electricity*, directions paper, March 2012 Chapter 6.

consumers and the rights of other parties in those investments, including the appropriate usage arrangements are clear and transparent. We discuss this issue further in section 4.3.5 -recommendations on energy services enabled by smart meters.

The next section considers these issues in the context of existing arrangements for commercial and consumer investment in metering capability and services enabled by the technology. By commercial investment we refer to the following situations, where a:

- consumer wishes to upgrade their meter as a response to making a decision to take up a product offering;
- retailer (or third party provider) wishes to install a meter at a consumer premise as part of its DSP product or service (ie flexible retail pricing option); and
- distribution business wishes to initiate a roll out of smart meters in parts of its distribution area as part of a DSP program to address network constraints.

Our discussion and proposed recommendations regarding investment in metering cover the following:

- arrangements for competition in, investment in and use of metering and data services;
- arrangements for when a smart meter must be installed in the residential and small business sectors;
- the minimum functionality specification of the meters to support commercial investment;
- the principles that will guide the development of the metering communications infrastructure; and
- energy services enabled by smart meters.

Load control technologies

We recognise that there are other forms of enabling technology for DSP which do not necessarily need to rely on the installation of more advanced metering (ie a smart meter). A form of this technology is that which enables direct load control (DLC). Direct load technologies allow remote control of electrical appliances in a home (or a business) to manage electricity demand. A common form of DLC is where, the consumer agrees (through taking up a product offer from a retailer or distribution business) for remote cycling or 'on-off' switching of a certain appliances/equipment in the home for short periods of time. Communication to interrupt or cycle an appliance can be via radio controller, ripple control, or web based.[132]

DLC of hot water loads has been used since the 1960s to shift the electricity consumption use for this service to pre-determined off-peak times. This form of DLC has used time switches, audio-frequency load control (AFLC) or ripple control.

In more recent years there have been trials of direct load trials utilising more advanced communication technology available for operating pool pumps and air conditioners. Direct load control of pool pumps can operate all year round, similar to the off-peak programming of electric hot water services.[133]

For air-conditioners, the trials of direct load control have been typically offered as a service during the handful of hottest days each summer. This is because cooling is highly valued during critical peaks on the system on extremely hot days. If consumer has agreed to take up such a product offer,[134] the fan in the air conditioning unit continues to operate, but its compressor is cycled on and off. Generally, there is not a reduction in comfort for the consumer. This type of DLC acts as a tool to help avoid the potential for network congestion over a certain period (ie 4 hours). SA Power Networks have stated that they consider this most appropriate mechanism to effectively reduce residential peak demand within the South Australian environment, given that consumers are unlikely to reduce air conditioning use in response to high prices on heatwaves.[135]

Such load management technologies play an important role in managing peak demand today. In its assessment of DSP options, Futura found that households participating in direct load control for hot water are having the greatest impact currently for peak demand management. Current status of residential hot water lad in the NEM indicates that DLC accounts for around 1750 MW shifted from peak load in summer and 2500 MW shifted in winter annually (representing around 4 and 6 per cent of total peak demand respectively).[136] Given this, we have included in our recommendations, that where an existing metering installation is being upgraded, the existing load management capability must be maintained in the new metering installation.

---

132 Futura 2011, *Investigation of existing and plausible future demand side participation in the electricity market*, Final Report for the AEMC, December 2011.

133 For example, Ergon Energy and Energex, in third quarter 2011, introduced an incentive based DSP program to actively encourage consumers to manage pool pump loads. Participants can receive a $350 rebate for transferring their pool pump to Tariff 33 and a $250 rebate for installing a 5-star variable speed drive pool pump. The 5-star pool pumps are estimated to deliver a 0.33 kW reduction in energy use at peak times.

134 Futura, op.cit., p.12.

135 ETSA Utilities implemented the business' first residential air conditioner DLC trial in 2006. The trials involved installing a 'Peakbreaker' external radio activated load controller to the external compressor of larger split and centrally ducted air conditioners. See Futura Final Report, Investigation of existing and plausible future demand side participation in the electricity market, December 2011.

136 Futura, op.cit., p.45

During this review, some stakeholders argued that such load management technology should be pursue instead of smart meters as this technology is a cheaper, more effective form of DSP.

We have stated that this review is not about assessing the viability of neither existing technology solutions nor assuming a particular range of technology types. Technology is constantly changing and developing policy based upon particular mechanisms may run the risk of blocking new, more efficient solutions and lead to stranded costs for market participants and consumers. This review is about establishing the right market arrangements to support investment in and application of DSP, consistent with consumer preferences and the demand circumstances.

Direct load control will continue to play an important role in managing peak demand across the NEM. We have focussed our analysis more on establishing the arrangements for metering because we consider that there are significant issues with the current arrangements that are preventing efficient investment. With respect to direct load control, we note that the recommendations regarding the demand management incentive scheme (as discussed in chapter 7) will aid networks investment and use of load management technologies. The proposed standardisation of air conditioner DLC control mechanisms and functionality through the AS 4755.3.1 interface is also expected to reduced transaction costs and enable more use of DLC.

It is important to note that DLC and smart meters are not substitutes. In fact, smart meters can assist and complement load management solutions. Smart meters can give consumers greater ability and information to customise the direct load management solutions to their own circumstances. It is noted that DLC incentive payments may be a blunt and inefficient instrument to reduce peak use.[137]

4.2.2 Current arrangements for investment in metering and data services

Currently, about 88 per cent[138] of residential and small businesses consumers still have meters that are being read on an accumulation basis.[139] As we have stated in this review, enabling metering technology is important for consumers to have the ability to take up some DSP options and be able to capture the value of their decisions. Currently, where a consumer makes an informed decision to switch to a flexible retail offer or take up of different DSP products (ie install smart appliances); the market is generally unable to support that choice due to a lack of installed advanced metering capability. We also note that for the introduction of more flexible retail pricing options,

137 To avoid excessive administration costs associated with contracting each end-users, 'participant' households are typically offered a uniform flat incentive payment. Since end-users users value the use of power (or particular appliances) at peak times differently, compared to a price mechanism, incentive payments are a blunt and inefficient instrument to reduce peak use. Moreover, financing such payments through a higher average consumption price can distort pricing efficiency or lead to distributional concerns.

138 AEMC, *Power of choice review – giving consumers options in the way they use electricity*, directions paper, March 2012, p.56.

139 http://www.dpi.vic.gov.au/smart-meters

metering technology that differentiates consumption at different times so that the consumption is responsive to tariffs (ie interval/smart meters) is required. We outline our recommendations regarding efficient and flexible pricing options in Chapter 6.

The differences and capability of the different meter types used in the NEM is set out in Chapter 3 (ie accumulation, interval and smart meter). The important distinction is that both interval and smart meters are capable of recording and delivering consumption on a near real time interval basis, which matches the trading intervals in the NEM metering and market settlements systems.[140]

Smart meters are even more advanced technology. When we refer to a smart meter this includes, the "meter" and communication software (typically a chip inside the meter). This communication software or functionality enables data to be retrieved remotely (ie not manually read at a consumers premise), and also allows for other smart services such as network monitoring (quality, continuity of supply) and other functions such as load management. Smart meters in this context are also able to link to devices in the home if consumers choose (ie through HAN and IHD), enabling instant access to electricity use profile for example. Smart meter technology effectively enables:

- Better information on a consumers' energy consumption that can assist them to control and manage their costs.
- Retailers to be settled in the wholesale market on the actual consumers' consumption as opposed to the average load profile of consumers in a distribution area – hence improving the accuracy of the settlements arrangements.
- Improved speed of consumer switching and the possibility of more frequency billing which could help to reduce consumer exposure to bill shock.
- A high degree of flexibility for retail tariff options that can be offered to consumers.
- The possibility of peak demand pricing for Distribution Use Of System (DUOS) and cost reflective flexible pricing.

As noted, utilising smart meters also presents opportunities for market development and business operational efficiencies. These efficiencies were identified by Deloitte in a cost benefit assessment of the Victorian AMI program.[141] This work estimated the size of a number of benefits to consumers, retailers, and network businesses from the period of 2008 to 2028 from upgrading existing metering technology.[142]

140 Such as, Market Settlement and Transfer Solution (MSATS).

141 The Victorian government Department of the Treasury and Finance – Advanced metering infrastructure cost benefit analysis", Deloitte, 2 August 2011. The Deloitte report references two similar earlier studies undertaken by Futura and Oakley Greenwood.

142 The Deloitte report estimated the benefits at approximately Net Present Value of $2 billion. Refer to AEMC Power of choice review – giving consumers options in the way they use electricity,

In 2008, SCER agreed to apply a staged approach to facilitating a national roll-out of smart meters in areas where the benefits outweigh the costs. The NEL was amended in 2009 to make this mandated rollout framework available to jurisdictional Ministers. It provided for mandated smart meter roll-outs to be exclusively performed by distribution businesses and in accordance with the minimum specification recommended by the NSSC. SCER considered that the potential benefits of a roll-out of smart meters were split between various parties across the supply chain in such a way that individual parties are unlikely to independently establish a positive business case for investing in a roll-out.

To facilitate a rollout of smart metering technology, amendments were also made to the NEL to enable Energy Ministers in participating jurisdictions to make a determination to require distribution businesses (operating in their jurisdiction) to roll-out smart meters and services to consumers within their jurisdiction.[143] Currently, there are no plans for a government-mandated roll-out in jurisdictions other than Victoria.

The mandated roll-out by jurisdictional governments does not preclude market participants from installing metering technology on their own accord which is referred to as a commercial investment. We note that some distributors have installed a large number of interval meters as part of introducing more time varying tariffs (eg Ausgrid) and that retailers have in certain circumstances facilitated replacing existing meters with interval meters as part of the product offering regarding installation of solar panels.[144]

Issues with current arrangements

In the draft report, we pointed to a number of issues limiting market participants and consumers investing in more advanced metering technology that supports efficient DSP products and services. The main reasons identified can be attributed to the following:[145]

- 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

supplementary paper to draft report - principles for metering arrangements in the NEM to promote installation of DSP metering technology, p.8.

143 To help inform this process, the amendments to the NEL also enable a Minister to direct a DNSP to conduct trials and undertake an assessment of the costs and benefits of SMI and other related technologies, including direct load control.

144 ActewAGL draft report submission, p.6.

145 AEMC Power of choice review – giving consumers options in the way they use electricity, supplementary paper to draft report - principles for metering arrangements in the NEM to promote installation of DSP metering technology, p. 13-15.

- some misalignments between the party who pays for the costs of the metering installation and the parties that may benefit.

We also considered that there are some risks facing market participants if they invest in installing more advanced metering technology as part of their DSP product or end use service offering to a consumer. These include:

- the replacement of a consumer's meter if that consumer changes retailer;
- uncertainty over who has rights to use the non-metering control functions included in the meter;
- the stranding of metering investments by retailers, if a government mandated smart meter roll out were to proceed; and
- uncertainty of the consumer protection arrangements for smart meters as these are still being developed.

In some jurisdictions, retailers and consumers also face a number of other disincentives to invest in smart meters. In Queensland, New South Wales and Tasmania, networks bundle all their costs into a single charge that includes regulated metering costs (ie are not unbundled from distribution use of system charges). This means consumers in those jurisdictions who want to take up an DSP product or end use service offer , which includes a new meter (ie use an alternative metering provider),would end paying twice for their metering.[146] In addition, there is also not a clearly defined exit fee (except for South Australia) that applies when a consumer chooses to upgrade its accumulation meter to a more advanced smart meter. Currently, under the NER, the retail and distribution businesses are required to negotiate in good faith on the appropriate value of the accumulation meter being replaced. In reality, that negotiation may not be working as intended.[147]

Distribution businesses also have a strong incentive to invest in manually read meters. Under the NER, retailers are responsible for providing remotely read interval meters, unless they confer this responsibility to the local distribution network business of the consumer. In addition, distribution businesses can only seek regulatory approval for metering expenditure and metering charges for investment in manually read interval meters, given that the NER classifies remotely read interval meters as a contestable service.

146 That is, the consumer would be paying the LNSP a charge that includes metering as well as the cost of the replacement metering installation.

147 Refer to Appendix G – Summary of stakeholder submissions to the power of choice draft report.

4.3 Recommended changes to market and regulatory arrangements

To facilitate uptake of efficient DSP options by consumers and the market, we consider that a policy decision and a series of reforms to the NER are required for how investment of more advanced metering technology is treated and provided for in the residential and small business consumer sector.

In considering the arrangements needed for the market, two approaches can be considered, this is either:

- **The investment and maintenance in metering hardware and data services is open to competition.** That is it would be contestable and can be provided by any metering service provider accredited by AEMO. The overall responsibility would be with the retailer to manage and contract metering services on behalf of the consumer at its premise, unless the consumer chooses to contract directly with an approved provider. Under this model, consumers have the right to retain the same meter when it changes retailers or chooses to take up DSP products with different service providers.

- **The network business is the exclusive coordinator of the metering installation and data services (monopoly, single provider).** The LNSP would be responsible to arrange for an upgrade of a consumers meter based on consumer decision (either directly or via their retailer or a third party). This arrangement is equivalent to the approach taken by SCER on the mandated rollout by distribution businesses.

The overarching difference between the monopoly and the contestable approach is that network businesses would be the exclusive entity for metering installations and metering data services for all residential and small business consumers. This does not mean that the roll-out of meters is mandated. Instead, whether a consumer had a smart meter or not will depend on arrangements for when the meters reach the end of their economic life and need replacing by the network business. A detailed discussion of the two models is provided in the supplementary paper attached to the draft report for the review.[148]

Currently, there is debate within the industry as to which model would result in the efficient delivery of metering and data services for consumers. The questions regarding a competitive approach relate to whether the additional functionalities to support smart grid operations will be captured, the investment in the supporting communication platform will be of sufficient quality, speed of rollouts, and the potential complexity for the consumer. Regarding the mandated regulated approach, the main issues relate to whether the arrangements inhibit:

- innovation;

---

148 http://www.aemc.gov.au/Media/docs/Principles-for-metering-arrangements-in-the-NEM-to-promote-installation-of-DSP-metering-technology-2dbde592-1280-4c4f-8c00-380889b4122f-0.pdf

- the performance of LNSP who is the coordinator of the metering installation and data services;
- the ability of third parties to access the functionalities enabled by more advanced meters; and
- the efficiency of the network metering charges.

Many stakeholder submissions commented that the AEMC is advocating a contestable, retailer model over a government mandated rollout. Distribution network businesses and some meter data providers argue mandated rollout have economies of scale and are hence more efficient.[149]

We recognise the divergence of views between some market participants about the approach needed for the NEM. Currently, other than government decisions to roll out smart meters, there is no rollout of more advanced metering technology on broad scale by industry. We consider it is important that there are alternative arrangements in place to encourage more investment and uptake of smart meters, in the absence of a government decision. These arrangements are needed to achieve the conditions and recommendations for facilitating uptake of efficient DSP in the market.

Irrespective of which model is applied, an important consideration is that consumers able to have an effective choice in the type of metering technology. As noted this will be through their decision to take up DSP products or end use services. Simple and practical arrangements should be in place to support those choices.

Our proposals are not based on the premise that all consumers need to have a smart meter, rather consumers having the choice to install better metering technology consistent with its preferences. We do recommend that in some specific circumstances, better metering technology is utilised so that the benefits of efficient DSP can be captured more broadly by the consumer and the market. We consider that continued installation of accumulation meters today will lead to increased costs for the consumer and system costs in the long term. This is discussed in section 4.3.2.

149 Refer to Appendix G – Summary of stakeholder submissions to draft report.

4.3.1 Proposal to promote competition in metering and data services

RECOMMENDATION

We recommend that:

- **A new framework is introduced in the NER that provides for increased competition in metering and data services for residential and small business consumers. The SCER endorsed minimum functionality specification for smart meters would be required.**

- **The option of a government mandated roll out of smart meters in the National Electricity Law is removed. This will provide certainty to the market for future commercial investment.**

The original NEM principles for investment in metering were based on competition in metering responsibility, metering installation and data services. Currently, competition in this area has been restricted (in a practical sense) to large and medium sized consumers in the NEM where interval metering is used. For these consumers, the retailer has responsibility unless it accepts an offer from the local distribution network business. Retailers, when accepting responsibility for the provision of metering installation and data services must subcontract the metering services to an accredited third party provider (metering provider and metering data provider).

As noted, most residential and small business consumers have accumulation meters, which are the responsibility of the network business to manage and provide services on behalf of the consumer. This was originally adopted as a transitional measure so that consumers had effective metering services at the commencement of full retail competition. This transitional measure was subsequently developed into a permanent arrangement[150] and has subsequently led to a lack of uptake of smart meters across the NEM.

In considering how to improve the metering arrangements in the NEM, the following principles consistent with the NEO have been taken into account. These build upon the original NEM principles for metering. The key principles are:

- Metering choices are simple and practicable from consumer's perspective. This would mean that consumers are more likely to be engaged and be attracted to flexible pricing offers/DSP products that would include a smart meter as part of the package. We also consider that the consumer's choice of metering would not be necessarily tied to a specific retailer.

---

150 Recommendations 4.3 and 4.4 of the 2004 "Joint Jurisdictional Review of the Metrology Procedures – final report", available at http://www.icrc.act.gov.au/__data/assets/pdf_file/0006/16746/jointjurisdictionalreviewoctober2004.pdf

- The responsibility for coordinating and providing metering and data services to consumers sis open to competition, that is any person who is suitably registered and accredited is able to perform the services required.
- Sufficient levels of investment are facilitated with a view to:
  - Maximising overall market efficiency (making investment risks more transparent so that they can be effectively assessed). The metering arrangements need to consider the overall efficiency of the market, including the impacts on retailers, LNSPs and consumers, rather than being efficient for their own sake.
  - Promoting innovation in the metering services - as well as improving operating efficiently in the short term, the metering arrangements need to promote certainty for investors in the long term.
- Transaction costs of metering arrangements are appropriate:
  - Alignment of costs and benefits – if the metering arrangements align benefits and costs for parties across the supply chain then an efficient level of investment in smart meter is likely to occur.
  - Minimise risks to market participants – the metering arrangements must consider the potential risks to market participants and consumers and allow the market to develop mechanisms to mitigate these risks.
- Avoids meter churn unless a consumer has agreed to upgrade its meter.
- Any consumer who wants to move to a time varying tariff has the choice to do so (hence can upgrade its meter).
- Exit fees are appropriate, clearly defined and transparent.

Recommended approach

We are recommending a competitive approach for investment in metering and data services for the residential and small business consumer sector. The framework we have proposed aims to facilitate greater innovation in metering services at a lower cost through their competitive provision. During the review a number of third parties indicated that there is an appetite and keenness for companies to enter the market and provide efficient solutions if competition in metering responsibility was expanded to include residential and small business consumers. This is because we consider that these services are not characteristic of monopoly services and therefore do not necessarily need to be regulated to protect consumers.

The approach we are proposing means that no entity has the exclusive right to be the person responsible for coordinating and providing metering and data services under the NER. The potential advantages of this type of model include:

- a large range of innovative DSP services, enabled by metering technology, could potentially be offered to consumers;
- no need for the AER to regulate the return on all metering services - decreases regulatory and administrative costs (assets removed from the regulatory asset base);
- the onus will be on the retailer or DSP service provider to elicit consumer consent to a smart meter through offering appropriate retail pricing offers and value added services.
- an incentive for metering services providers to be continuously innovating metering services that they provide; and
- ability for consumers to have greater choice and be more interested in the usefulness of metering and other services that may be leveraged from the provision of modern metering technology.

There were a number of stakeholder submissions to the draft report that supported a competitive approach.[151] However, there were also a number of other stakeholders that raised three main issues for consideration regarding the competitive approach. These included arguments relating to:

- Economies of scale that a single entity rollout brings. This relates to opportunities regarding large scale mass purchasing and hence potential reduced costs, and density and speed of rollouts in geographical areas (roll-out meters on the same street at the same time).
- Loss of network functions and hence benefits for network management and opportunities would realised; and
- The communication platform that would be used; inter-operability, benefits of mesh to mesh network versus point to point arrangements; and back end meter data management IT systems.

We consider that under the proposed approach, both large scale purchasing and the appropriate communication platform would not necessarily be lost. This is because under the contestable model smart meter costs would be driven by: (a) international prices, (b) some retailers who elected to contract metering services have a large market share to rollout out smart meters to its consumer base, and (c) other parties who were accredited as metering coordinators could provide services to multiple retailers across more than one region in the NEM. It is worthwhile noting that in Victoria, each distribution area has responsibility of rolling out smart meters in their local area (ie five DNSPs, rather than a single entity).

Under the proposed framework, the onus will be on the retailer or DSP service provider to engage with and inform the consumer of the benefits of having a smart

151 Refer to Appendix G – Summary of stakeholder submissions to draft report.

meter through the product offer of retail price tariff and/or value added end use services.[152] This is considered more preferable than retaining network businesses as the monopoly provider of metering services to households. We also expect that competition will place a commercial pressure on the metering service providers to improve the metering services that they offer, including where retailers are competing to offer flexible pricing options, DSP products and services. It would be more difficult to impose an equivalent commercial pressure on a monopoly metering services provider.

It is likely that innovation both on meter type and end use services that are desired by the consumer could be limited by a monopoly provider. We note that the recently released Energy White Paper indicated that there is merit in looking at whether some services undertaken by networks businesses could be made contestable.[153]

A framework that supports competition, operating effectively and able to capture network operation benefits would be expected to facilitate an efficient overall market. This is because the benefits of flexible pricing options and network peak charges can only be realised with meters that can record on an interval basis. Therefore, consumers need to have access to such meters at an efficient price to be able to maximise the total market benefits. Our proposed minimum functionality specification includes network functions so under the propose model the network benefits will be captured. We would expect that the value of these savings will be passed through to the respective consumers who install smart meters.

Monopoly provision would also mean that there may need to be regulations for service performance. This creates regulatory risks and administration costs as such service performance standards must be in the form of obligations, such as strict timetables for installing a meter, or incentive arrangements that provide a distributor with either a financial reward or penalty for either achieving or failing to achieve certain performance parameters (ie meter reading and data provisions).

Ultimately, we consider that there are benefits from having a competitive approach that allows retailers, network businesses and third parties to install meters in accordance with their individual business drivers. This is because market participants will need open access to smart meter services to be able to develop and deliver their consumer flexible pricing offers, DSP products and end use services.

As noted, a number of stakeholders raised concerns regarding investment in the appropriate communication systems under a competitive approach. We have not made any specific recommendations on what metering hardware and software technologies should be deployed. Rather, we consider that over time the market will provide the most efficient metering hardware and software investments if an appropriate and robust framework is in place.

---

152 Refer to Futura 2011, *Investigation of existing and plausible future demand side participation in the electricity market*, Final Report for the AEMC, December 2011.

153 Refer to Australian Government *Energy White Paper*, Department of Resources, Energy and Tourism, 2012.

If our proposed framework is agreed to, then we recommend that the governments remove the possibility of a mandated roll-out of smart meters.[154] This is because the approach of mandating roll-out of smart meters may no longer be required. The removal of the provision would facilitate commercial participants entering into the market and coordinating the provision of metering services. We are concerned that the risks created by the possibility of a government-mandated roll-out occurring in the future could be inadvertently stall speed of commercial investment, and hence take up of potential DSP opportunities.

If governments decide to retain this option, we recommend that they make a commitment to protect (or compensate) any commercial investment that occurred prior to the start of a mandated roll-out. This might provide confidence to encourage commercial investment in the market.

We note that the NSW government has recently released a discussion paper regarding a range of consumer focused options and the issues associated with the potential introduction of smart meters in NSW. This includes a market led, or competitive approach for provision of such meters.[155]

In next section, we describe the how our recommended approach would work and considerations for each. This seeks to address a number of specific stakeholder issues raised in submissions to the draft report.[156] The stakeholder issues broadly related to:

- the role of the responsible person under contestable approach;
- avoiding the need for a consumer to change its meter when they change retailers or pricing offer (meter churn);
- how the arrangements work with an existing regulated rollout of smart meters (ie Victoria);
- investment by retailers and other parties in smart meter functionality;
- the extent of functionality to be applied to meters and metering installations;
- smart meters and related communication infrastructure that supports open access and interoperability; and
- contestability of smart meter functions (ie energy management services).

Key elements of the proposal

The key elements of the proposed approach include:

154 Governments could retain the provision to undertake smart meter/smart grid pilots and trials.

155 NSW Government, *NSW Smart Meter Task Force – Discussion Paper*, November 2012.

156 Refer to Appendix G - Summary of stakeholder submissions to draft report.

- Retailers are obligated to arrange for a working meter (NEM compliant) at a consumers premise.[157] This obligation will require the retailer to manage (and contract if necessary) the metering installation and data services on a consumer's behalf, if a suitable metering installation does not already exist. This approach is identical to the existing role of the retailer if it elects to be the responsible person.

- Consumers would be able to contract with any accredited coordinator of metering services (one possible option is via a third party) if they so wish.

- Where consumers change retailers, they would not be required to change meters (that is the existing metering contracts would be honoured by the new retailer). Consumers could choose to upgrade meter if they so wish.

- A transparent exit fee would exist where a consumer upgrades its meter owned by distribution network (ie where LNSP is the metering coordinator) to cover sunk costs.

- Network businesses would be able to fund smart meters and additional functionality as part of a network DSP program (regulated by AER).

Our proposal is based on the key principle of consumer choice and that the benefits from the investment in metering technology can be captured by both the consumer and also market participants. As noted, we expect that consumer choice of metering capability will be when a consumer accepts an offer from a retailer or to be part of a DSP product or end use service. There may be a few consumers who are sufficiently engaged to negotiate and contract directly with a metering services provider. We also note that retailers may decide to invest in smart meters to reduce their operational costs (ie undertaking special meter reads as consequence of increases in bill enquires associated with inaccurate meter profiling).[158]

Therefore, investment in more advanced metering is likely to occur in following circumstances:

- a consumer chooses to have a smart meter to obtain monthly bills as a mechanism to reduce bill shock and control their use and costs;

- a consumer accepts a package from a retailer that has time varying pricing and includes the provision of a smart meter as part of the offer;

- a consumer accepts an offer a DSP product or end use service, such as electric vehicle charging or direct load control of an air-conditioner, and that service needs an enabling smart meter, hence part of the offer; or

---

157 That is, ensure that a metering installation is assigned to a settlements point prior to the consumption of electricity through that settlements point.

158 EWON submission to draft report, p.4. Refer to EWON website for latest figures on consumer complaints regarding bill enquires. http://www.ewon.com.au/index.cfm/publications/newsletters/newsletter-23/latest-complaint-statistics/

- a consumer accepts an offer from an independent service company for the metering and data services, includes provision a smart meter.

We consider that there are a number of complementary rule changes that can be made that would facilitate the proposed arrangements and framework. These include:

- **The distinction between the provision of metering services between retailers and network businesses based upon the type of meter would be removed (ie the difference in arrangements for types 1-4 meters compared to type 5 and 6 meters).**

We are recommending that all new and upgraded metering installations would be classified as type 1-4[159], that is smart meters consistent with the proposed minimum functionality specification. Currently, LNSPs generally install manually read interval meters in preference to remotely read ones because the provision of remotely read metering installations is contestable. We consider that the choice between remote and manual meter reading should be made on the basis of costs and the advantages to consumers and retailers (ie from the faster access to metering data provided by remotely read meters). The method for reading the meters must not depend on who is responsible for meter provision to ensure that open access is available to all parties.

Where the LNSP is the responsible person for type 5 and 6 meters,[160] under our proposed approach, the retailer will have overall responsibility and the LNSP will transit to becoming the metering co-ordinator. This should be a seamless transition for the DNSP/retailer.

- **There is unbundling of metering costs from the distribution use of system charges.**

We recommend that metering costs (ie meter installation, maintenance, and data management services) are unbundled from DUOS. This will allow smart meters to be installed with the consumer being confident that they are not required to continue paying for the existing meter (that was removed) and that they are only paying for the upgraded metering installation. This will also allow the consumer to consider the costs of smart metering compared to their existing metering charges, and to make informed decisions when considering a smart meter upgrade.

As noted, unbundling of metering charges already occurs in the ACT, Victoria and South Australia. The AER is proposing that unbundling be introduced for the New South Wales distribution businesses with metering becoming an alternative control

159 Type 1-4 metering installations under the NER must be capable of measuring energy flows in 30 minute intervals in both directions, and be remotely read (ie data extraction via a communications link).

160 Type 5 metering installations include interval meters that are manually read (ie data extraction is at the consumers premise).Type 6 metering installations include accumulation meters that are remotely read.

service at their next revenue determination.[161] Many stakeholder submissions to the draft report were in favour of unbundling of DUOS charges.[162]

- **There are clearly defined exit fees when consumer upgrades a meter that is currently managed and maintained by the local distribution network provider.**

We are recommending that the existing arrangements regarding exit fees when a consumer upgrades its regulated network meter, the exit fees which can be charged by the DNSP are transparent and clearly defined. Having a transparent approach will remove the need for negotiation between the market participants about the loss of value to the network business. We discuss this issue in more detail under the workings of the proposed approach.

How would the recommended approach work?

Respective roles and responsibilities

As a first step, the provision of metering services must 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 and data services would be expected to provide additional competition for the provision of these services and remove the incentive for distribution businesses to continue installing manually read meters instead of remotely read.

With respect the respective roles of each party in the market we are proposing that for all metering types:

- The retailer would be obligated to ensure a working meter at a consumers premises (NEM compliant at a settlements point).[163] It would also be responsible for managing and contracting with a metering coordinator (MC) to engage metering service providers on a consumer's behalf.[164] Separating the MC role from the retailer means that a consumer can change its retailer without the need for it to change MC, thus reducing the need to replace the meter.

- The MC would be responsible for the day to day co-ordination of a Meter Provider (MP) and Meter Data Provider (MDP) for those metering installations to which it was engaged by either the Retailer or the consumer. The MC would be accredited by AEMO in accordance with appropriate procedures. The MC would:

161 Refer to AER 2012 *Framework and approach paper Ausgrid, Endeavour Energy and Essential Energy*: Regulatory control period commencing 1 July 2014,, June 2012

162 Refer to Appendix G – Summary of stakeholder submissions to draft report.

163 The agreed point of supply established at a connection point between a financially responsible Market Participant and Non-Registered Customer or franchise customer.

164 Metering service providers means Metering Providers (MP) and Metering Data Providers (MDP).

— be financially liable for metering installations that were found not to comply with the NER (for example, data accuracy);

— ensure that the provision, installation and maintenance of a metering installation were performed by a Metering Provider;

— ensure that the collection of metering data and processing / delivery of the processed data to the metering database and to parties entitled to that data was performed by a MDP; and

— be responsible for paying the accredited MP and MDP.

- In this arrangement:

  — the MC can also be accredited as the MP and MDP or it can engage separate entities to perform these roles.

  — the existing roles of the MP and MDP remain unchanged;

  — the MC is able to assign its responsibility to another MC so long as there were no changes to the consumer's underlying contract. Subject to the metering services contract (as outlined below), this transfer should be at no cost to the consumer and the consumer should be provided with a service that is equivalent or better than the service it is currently getting.

The NER would specify the provisions to be adopted in a standard contract between the retailer (or consumer) and the MC for metering services (particularly in regard to service protocols such as performance standards). We consider this will limit transaction costs for consumers when switching (ie contract renegotiation every time) and maintain commercial interoperability of retailer-MC relationship. The Rules would not specify the MC's fees (including exit fees); this would be subject to commercial arrangements (except where the meter is part of the network regulated service).

At the consumer's request, the retailer would be able to upgrade a meter subject to any regulated exit fees and the existing metering services contract. The retailer would need to obtain explicit informed consent from the consumer where its wishes to upgrade the meter beyond that of the minimum functionality specification. If the upgrade was to meet the minimum functionality specification there would be an obligation to inform the consumer of this action but no obligation to obtain an explicit informed consent from the consumer. We note that a retailer would be able to upgrade a meter to enable DSP product or value end services to be offered. In this situation, the retailer would need to inform the consumer of the benefits of the smart meter and opportunities that it presents for helping the consumer to manage their energy use. We expect that the existing arrangements that provide consumer protection and other support mechanisms under the NECF would be in place.

Consumers would have the option to contract with any accredited metering coordinator (one possible option is via an ESCO). In such circumstances the retailer would be required to respect the contract arrangements in place with the existing MC.[165] We would expect the MC would inform the consumer's retailer of any change.

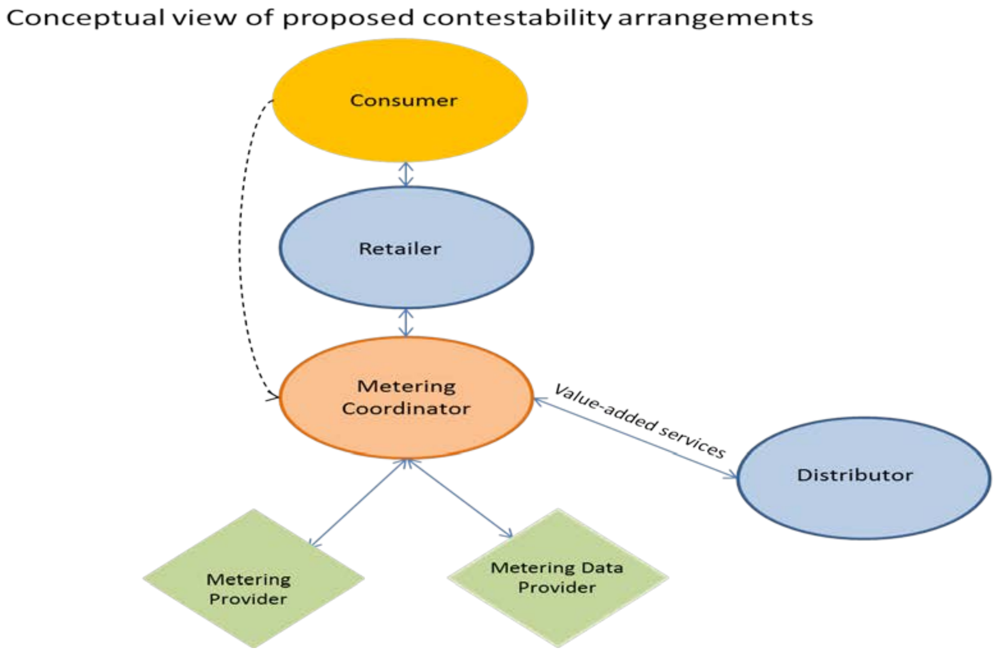
When a new smart meter is being installed, it must at least be equal functionality to the smart meter being replaced. This will ensure that any advanced functionality, over and above the minimum functionality specification, is retained for use by the consumer. We note that there are some distribution businesses with type 5 meters (ie interval and manually read). We understand that these meters can be easily upgraded to type 4 meters (ie remotely read). To ensure that these meters are not necessarily replaced (unless the consumer requests an upgrade) we consider that there is merit in including a temporary exemption in the rules regarding the application of the proposed minimum functionality for those type 4 meters that can be upgraded. This issue will be explored during the rule change process.

At the commencement of the new rules, the party who was the responsible person for a metering installation would become the MC for that metering installation. This means that the MC for a type 5, 6 and 7 metering installation would be the LNSP who was assigned to the metering installation. However, the exclusivity for the responsible person in place prior to the rule change would not be available under the MC arrangements. It also means that the smart meter type 5 derogation in Victoria no longer need apply as the LNSP will automatically be the MC for the smart meter, which would be classified as a type 4 metering installation. Transition arrangements in this context will be important. Hence, AEMO will need a retailer/network working group to work through any operational issues. The transition would need not to be unduly complex market participants involved.

For consumers particularly, it is expected that the transition would be seamless, that is are no provided with complexity of implementation details, but rather information about the new opportunities and benefits that the more advanced technology of smart meters provide. The only change for the consumer, other than having a broader range of DSP products that could be available to them to take up is that metering costs would be separate in their bills. The metering services that were performed for them should be the same under the new arrangements. The arrangements are effectively a change to the responsibilities who undertake the functions on behalf of the consumer.

165 Refer to ERAA, smart meter working papers at http://eraa.com.au/policy-submissions/policy/.

Figure 4.1 Conceptual view of proposed contestability arrangements



Exit fees for regulated meters

As noted, the NER requires that the retail and distribution businesses to negotiate in good faith on the appropriate value of an accumulation meter being replaced (ie exit fee). We are recommending that the rules are changed so that there is more transparency and clarity on the charges that should apply when consumers choose to upgrade their meters.

Generally stakeholder submissions to the draft report considered that a transparent exit fee was needed. This is because the current uncertainty of what the LNSP is able to charge, and in some circumstances the significant fees which are requested to be paid by the retailer. There was some divergence of views to the draft report proposal, ie flat regulated exit fee of 30 per cent of an equivalent new meter. Some network businesses specifically noted that the proposal did not take into account the operating costs that are incurred for processing changes/transfers.[166] Powercor and Citipower highlighted in their submission that exit fees are crucial so that DNSPs recompensed for the fixed and variable costs network businesses have and would have incurred for any metering installation no longer required. They noted fees should consider the meter, the communications infrastructure, and IT support systems.[167]

166 Refer to Appendix G – Summary of stakeholder submissions to draft report.

167 Powercor/Citipower submission to draft report, p.9.

The NER specifies that a LNSP is reasonably compensated for alternation to an accumulation meter.[168] The objective of the exit fee is to essentially assist the LNSP to recover the stranded costs of the meters being replaced.

We consider that the local distribution network may recover an exit fee for existing regulated accumulation meter, however this should be determined by the AER. This will provide sufficient transparency for all parties regarding fees, and certainty to networks that they are able to recover costs appropriately. This also addresses the concern raised by some stakeholders about risk of under-recovery as any difference between exit fee and remaining costs would be recovered through DUOS.

We have proposed a set of criteria for the AER to have regard to when making an exit fee determination. Among other things, these include:

- the exit fee must be reasonable;
- the exit fee must be based on the average remaining asset life of the existing meter type[169] and operating costs;
- the exit fee may include efficient and reasonable costs of processing the consumer transfer to another MC;
- a cap must be placed on the exit fee. We consider that this should be, at a maximum, no more than three times the annual metering charge. This is to provide consumer confidence that costs will not be exceedingly high when willing to change their meter;
- no exit fees are to be applied to type 5 and 6 metering installations installed after 1 July 2013;
- the LNSP must remove the cost of the replaced metering installation from its asset base and reduce the DUOS tariff to the retailer accordingly; and
- the existing contribution that consumers have already paid towards the existing metering stock.

Capturing network benefits – regulated network rollout within a framework that provides for competition

It is important that there is a mechanism that allows the potential network operational benefits available from smart meters to be captured. Our recommended changes to the minimum functionality specification will achieve this. It is also important to consider

168 Clause 7.3A(g)

169 For example, AER has determined that the standard life for Energex metering assets is 25 years and has an average 10 years life remaining. See AER, *Queensland Distribution Determination 2010-2015, Final Decision, May 2010.* p.236

how regulated network service provision can operate under the recommended arrangements.

As indicated, some stakeholders consider that the network businesses are the best placed to manage a roll out of smart meters – given that they can capture economies of scale and enable network benefits. We note this was the position the Productivity Commission took in its draft report for electricity network regulatory frameworks.[170]

We have proposed that network businesses would be able to do targeted roll outs of smart meters in a defined area subject to AER approval as part of the DNSPs regulatory determination (ie as a regulated network service). Network businesses are also able to install meters under the framework when it is competing with other metering co-ordinators (ie as a ring fenced competitive service).

The framework for governing the network target roll out would work as follows:

- Be part of the 5 year regulatory determination, as the AER will need to assess metering rollout proposals as part of the package of DNSPs investment proposals.
- The RIT-D is used as the basis for the cost benefit analysis, although the AER may use information from pilots and trials projects to estimate the benefits and costs, and conditions of any DM innovation allowance must be to provide data/results to AER.
- In principle, the proposal would be subject to the normal incentive regulation arrangements. Two possible additional mechanisms that may be included and raised by the AEMC in the final report on cost recovery of smart meters review are: (a) "revenue driver adjustment" to remove any timing benefit from delaying the proposed roll-out schedule, and (b) the possible of depreciation being excluded from the capital incentive scheme for smart meters given short asset life.[171] The need for these mechanisms would be considered as part of the broader rule change.
- The AER would have regard to both the costs of commercial smart meter provision and data services, and the likely penetration of meters in that area under the specified arrangements. The AER is to consider and determine the exit fee that would apply.
- The AER would have regard to the communication systems being installed in that area.
- Access to a register of the number of smart meters installed in a DNSPs area (we expect that AEMO will have this information).

170 See Productivity Commission 2012, *Electricity Network Regulatory Frameworks*, draft report, October 2012.

171 See AEMC 2010; *Request for advice on cost recovery for mandated smart metering infrastructure*, final report, November 2010.

- Co-ordination between retailers and network businesses. The network businesses are to notify the associated retailers and their consumers of proposals. Also retailers will have the opportunity to comment on the DNSP proposals as part of the consultation on the distribution determination.

- A DNSP cannot remove a retailer led installed meter if it complies with the minimum functionality specification. Even if the AER approves a targeted roll-out by a network business in a specify area, retailers can still install a meter in that area under the competitive arrangements prior to the DNSP installation. This would be after a specified notification period.

- Network businesses would have the option of funding the roll-out of smart meters via the retailer or becoming the metering co-ordinator. Where the DNSP becomes the metering co-ordinator it still must enter into the retailer-MC contract.

- A metering services agreement must be subject to standard terms and conditions that must include at the least the quality of the service to be provided, and a complaints handling arrangement.

- The AER's approval does not give the LNSP an exclusive right to roll out meter upgrades in its local area.

Consideration where a government rollout has been mandated

As noted, the Victoria government initiated a rollout of smart meters in 2009. It is expected that all households and small business in Victoria will have their meter upgraded with a new digital smart meter by the end of 2013.[172]

Given that, we have considered how our proposal would apply to a mandated situation such as Victoria, including following the end of the period where distributors have exclusivity over meter provision. We are of the view that our approach does not impede a rollout that has been undertaken on smart meters. Overall, the recommended arrangements would be complementary to the existing rollout because they:

- Enable the local network service provider to be the exclusive MC (could be for a defined period). This aligns with Victorian roll-out (ie LNSP exclusive MC for the AMI meters already rolled) and overcomes smart meters being classified as type 5 (allow the AMI meter to be part of a type 4 metering installation without disturbing the party who is MC).

- Do not allow a new meter to have a lower functionality than that the smart meter being replaced. We note that if the rules are changed to allow for a competitive approach, all new meters would need to meet the minimum functionality specification as recommended. In Victoria's case, if the rollout is not complete at

172 See http://www.dpi.vic.gov.au/smart-meters.

that time, there may be a need for exemptions to apply for application of the minimum functionality specification.

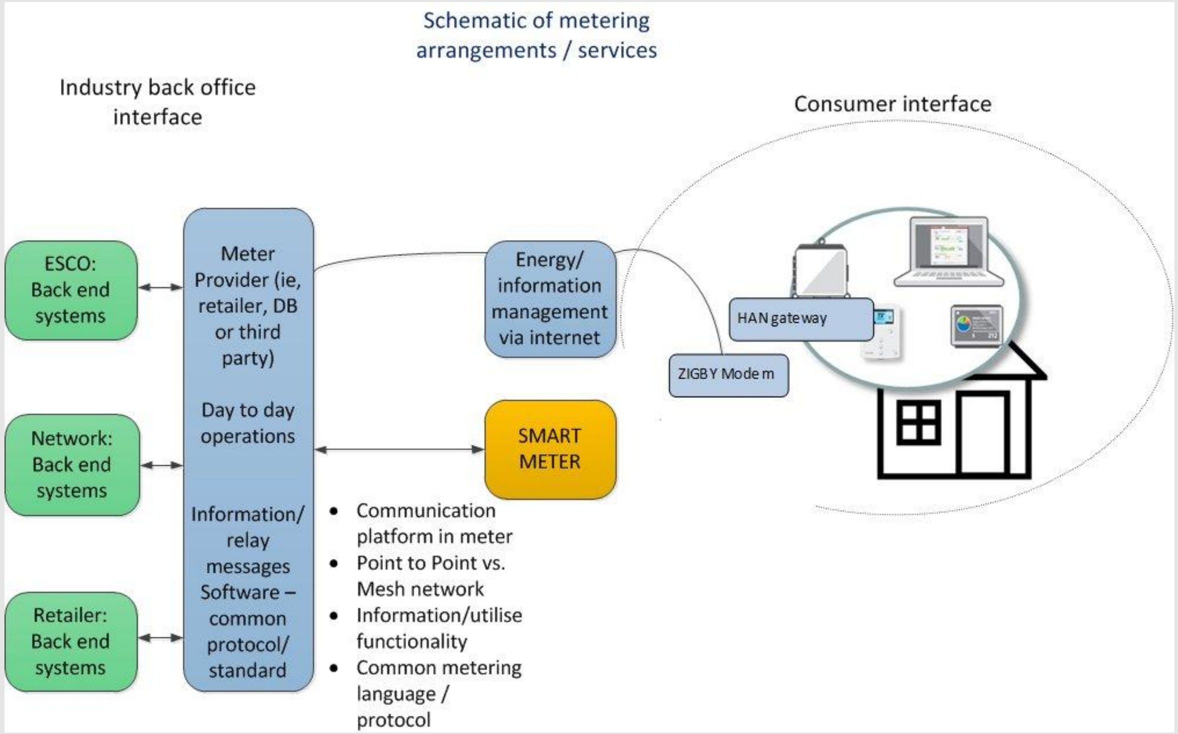
- Allow DNSPs to fund smart meters, utilise their functionality and undertake direct load control as part of DSP program.
- Meet the principle that communications to the metering installation permits DSP service providers to provide services directly to consumers.
- Provide for an explicit exit fee to allow a retailer to subsequently remove a mandated installed meter (Victorian provisions allow the DNSP to decide upon its own exit fee).

Box 4.2: Framework for competition in metering and data services – summary of arrangements

- The Retailer (FRMP) is required to arrange for a workable meter at a consumer's premise, including managing and contracting with an MC to perform metering services on the consumer's behalf if a suitable meter does not already exist and unless the consumer has chosen to directly engage an MC.
- The MC is responsible for day to day operations (provision, installation and maintenance of a metering installation) and co-ordination/engagement of MP and MDP. The MC:
  - is financially liable for metering installations that were found not to comply with the NER (for example, data accuracy);
  - can be the meter provider and meter data provider or it can engage separate entities. The existing roles of the MP and MDP remain unchanged;
  - is responsible for paying the accredited MP and MDP; and
  - is able to assign its responsibility to another MC so long as there are no change to the consumer's the underlying contract.
- The rules would specify the requirements of a standard contract terms and conditions for metering coordination services.
- All metering services fees (including exit fees) under the MC role would be commercial arrangements.
- Consumers would have the option to contract with any accredited MC (one possible option is via an ESCO). In such circumstances the retailer would be required to respect that contract arrangements.
- Where consumers change retailers, they would not be required to change meters, noting that consumers could choose to upgrade meter if they so wish. Their retailer would also need to respect the existing contract arrangements.
- A new smart meter must at least be equal in functionality to the smart meter being replaced.
- A defined exit fee would exist to cover the network business' sunk costs where a consumer upgrades a network regulated metering installation.
- Arrangements to apply to current type 5/6 metering installations. Local network service provider will be the metering co-ordinator in those situations. LNSP

must enter into contract with retailer.

- Networks would be able to fund smart meters as part of a network DSP program (regulated by the AER) in specific constrained area.
- Need for open access to allow entitled parties to access energy data in meters irrespective of what process the meter was installed (commercial or mandated).
- Need for a common metering language, communication software standards to support this. Work is needed to specify those standards (NSSC have completed some work in this area).



4.3.2 Arrangements for installing DSP enabling meters in the residential and small business sectors

RECOMMENDATIONS

We recommend that:

- **The NER is amended to require smart meters to be installed in defined situation such as refurbishments, new connections and replacements. The installation of the smart meters would be consistent with the proposed minimum functionality specification.**

We understand that there are at least two distribution businesses who routinely install accumulation meters in new construction and refurbishments where a new meter is required. While they have made this decision on a straight business case basis, it is clear that this is a lost opportunity to take advantage of the latest available metering technology.

Given the enabling technology that is available, we are recommending that the NER and relevant jurisdictional codes are changed to require the installation of appropriate metering technology when the opportunity arises. Specifically, this refers to the following situations:

- all new constructions;
- 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 faulty or at the end of its useful life.

All meters installed would be consistent with the proposed minimum functionality specifications outlined in section 4.3.3.

In the above situations, the consumer's retailer will have an opportunity to install the required meter and the costs would be charge to the consumer. Consumers receiving the new meters will pay for them as part of their bills, just as all consumers currently pay for their existing meters. As smart meters may be similar in price to conventional meters, consumers' bills may not change significantly. The costs are likely to 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. The metering hardware is only one part of the cost of the total cost to the consumer.

A large proportion of the costs associated with a smart meter will be the installation costs. However the costs of installing a smart meter are similar to the costs incurring an accumulation meter, as it driven mostly by labour time. Hence for the consumer, the incremental costs associated with this proposed policy will be cost difference in the different types of meters (which is estimated to be less than $100) minus the net savings from avoided manual metering reading (which is approximately $5 -$10 a year)[173] and other operational benefits. It is expected that competition will drive fair costs to the consumer given that if costs are excessive, the risk of transferring responsibility of networks may be enabled.

It is important that the metering charge is unbundled from DUOS and is clearly indicated on a consumer's bill to ensure transparency of costs. For the above circumstances, we advise that there is a transition period of one year from the time of the changeover of metering installation to when those consumers are provided with a flexible pricing offer. This will give these consumers and their retailer time to build up a load profile history which will enable a more informed judgment of the options. This will also ensure that appropriate information is received by the consumer to assist in making informed choices and benefits of taking up DSP options.

There are significant cost savings to be had from installing smart meters, largely attributable to the avoidance of meter reading costs and enhanced operational efficiencies.[174]

As we have provided through this review, those consumers who have smart meters 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.

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. Smart 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 the draft report, we provided some cost estimates for interval/smart meters.[175] It was noted in submissions that the costs for these meters have, and are likely to reduce

173 AER, *SA Power Networks Distribution Determination 2010-2015 Final Decision* May 2010, p.260.

174 Refer to MCE, Smart meter cost benefit analysis, 2008 found at http://www.ret.gov.au/Documents/mce/emr/smart_meters/default.html

over time and hence those costs should reviewed. A number of stakeholders have provided varying cost estimate and there seems to be no consensus by industry. For example, GE energy submits that prices for residential meters with minimum functionality specification, and with mobile technology for order volumes in the 100,000 unit range for Q2 2013 delivery will range from $130 to $250 (depending upon the number of metering elements).[176]

Generally, there was some support for smart meters to be installed in certain situations. There were a few stakeholders who did indicate that decisions should be left to the retailers discretion.[177] There were a few stakeholders that questioned whether requiring installation of smart meters that meets the minimum functionality specification specifically for new replacements would be efficient. They indicated there is potential to do a cost and benefit analysis on such a proposal and pointed to the findings of the Phase 2, 2008 MCE National smart meter cost benefit analysis as evidence.[178]

We consider that the use of findings from the 2008 Phase 2 Study may not reflect the benefits of investment in more advanced technology. Firstly, the study did not assess the benefits and costs of a new and replacement program as compared to the continued use of accumulation meters, and secondly, did not consider a new and replacement policy for smart meters. It only addressed installation of manually read interval meters which has a significantly different benefit as well as a different cost profile.

Secondly, there a number of reasons why the 2008 study may no longer hold. These are:

- The costs of smart meters have changed and may have fallen since 2008.
- It is likely that any new accumulation meter will be replaced before the end of its life given the new technology in household appliances - so new accumulation meters are creating the risk of extra stranded costs in the future and will increase the costs of any future roll-out.
- The value of demand response benefits have increased since 2008 given the increase costs of network investment.
- Accumulation meters have created extra costs for retailers and inconvenience for consumers. The rise in consumers questioning their bills, the problem of erroneous meter reads and estimated reads and hence the need for retailers to do special meter reads to address consumer complaints (in the absence of the ability to do remote metering) are creating losses in the market.

175 Refer to *AEMC Power of choice review – giving consumers options in the way they use electricity*, supplementary paper to draft report, p. 50-51.

176 GE Energy submission to draft report, p.4.

177 Refer to Appendix G – Summary of stakeholder submissions to draft report.

178 See MCE Cost-Benefit Analysis of Options for a National Smart Meter Roll-Out (Phase Two – Regional and Detailed Analyses) Regulatory Impact Statement, for decision, June 2008.

- The benefits for consumers, specifically for ease of switching (shorter switching periods is possible with smart meters), potential for monthly billing, and connection and disconnection processes.

It is therefore our opinion that the new and replacement proposed changes for existing consumers to small businesses and larger residential users is the best and most cost-effective way to (a) enable the near-term introduction of flexible pricing options for the smaller end of the electricity market, and (b) allow for further technology and service innovation and avoid technology stranding within the present circumstances of the electricity market. It is worthwhile to note that a report has been provided to the Department of Climate Changes and Energy Efficiency recommending that state and territory laws are changed to require the installation of smart meters whenever substantial building work is undertaken on a dwelling.[179]

4.3.3 Minimum specification to support the framework for investment in metering and data services

RECOMMENDATION

We recommend that:

- **The Smart Meter Infrastructure Minimum Functionality Specification developed by the National Smart Metering Program is included in the NER for all new and future meters to support competition in metering and data services. This would support interoperability and open access.**

The advanced in technology are improving and expanding the functions that traditional meters provide. As discussed, this is allowing for new DSP products and end services to consumers and market participants.

Currently, the functionality of the metering installations in the NEM (as defined in the NER) is limited to recording consumers' energy consumption on a 30-minute interval basis and making this information available for remote reading. The functionality of most meters is further limited by being manually read or only able to measure consumption on accumulation basis (ie every three months).

As part of our assessment of arrangements for a competitive approach to metering and data services we have considered what would be the required minimum functional specification of meters that enable take up of DSP options and therefore do the existing minimum standards in the NER for meters need to be changed.

179 Refer to Energetics submission to draft report, p. 2. Report indicated is "Energetics - Inclusion of energy generation in building energy efficiency standards", available from http://www.climatechange.gov.au/en/publications/nbf/inclusion-of-energy-generation-in-building-energy-efficiency-standards.aspx.

Having a minimum functionality specification for new metering installations is necessary so that its operation is coordinated with AEMO and other market participants billing and settlement systems. That is, the metering data is of sufficient accuracy and the correct format, and that agreed communication protocols are used. Specifying a minimum functionality is equally important when more advanced functions are included so that these functions can be utilised by relevant stakeholders.

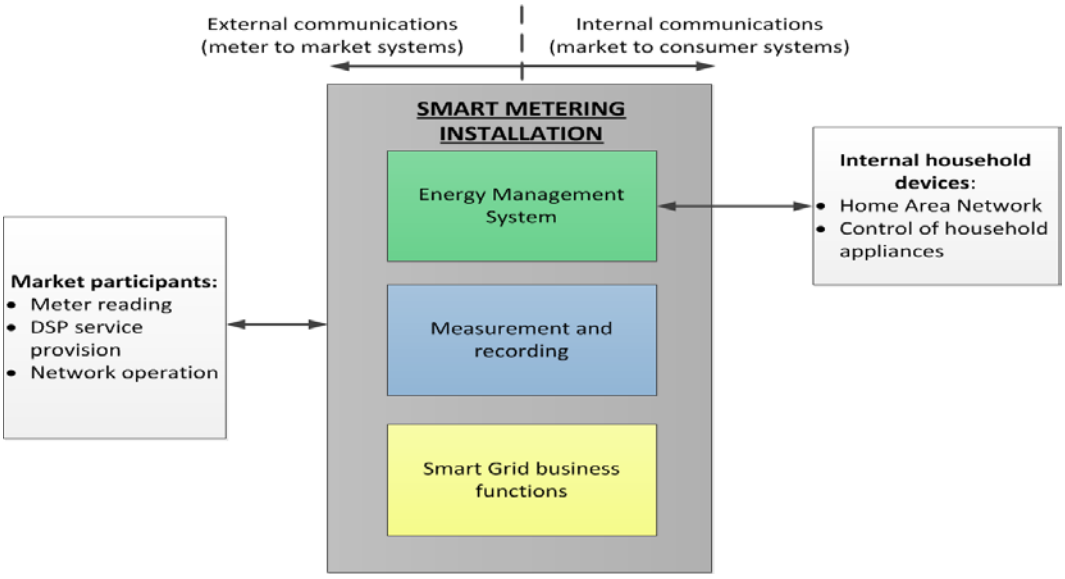
When determining the minimum functionality specification to be applied for future metering installations, it is useful to consider the range of possible functions that can be made available in a smart meter. There are potentially up to three components to a smart metering installation (as shown in Figure 4.1. These are:

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

2. Energy management system functions - allows messages to be sent via the meter into the consumer premise and communicate with its appliances (ie for load control, home area networks).

3. Smart Grid business functions - enable LNSPs and retailers to communicate with the meter, to both receive information and send messages/instructions to the metering installation. These could support such network operational functions as supply capacity control, loss of supply detection and energisation/de-energisation of a load at a settlements point.

Figure 4.2 Figure 4.1 - Potential functionality of Smart Metering Infrastructure



SCER has endorsed a minimum functionality specification for smart meters (known as the Smart Meter Infrastructure (SMI) Minimum Functionality Specification)[180]as part of its National Smart Metering Program. The SMI Minimum Functionality Specification is currently available to jurisdictional Ministers if they wish to evoke a mandatory rollout of smart meters.

Regarding the specification, SCER took a system wide view of the role and functions of the smart meter and developed its minimum functionality specification which best captures all the potential benefits of smart grids (capturing the value of benefits across the supply chain).

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. The functionality of the Victorian smart meters is broadly similar to that endorsed by SCER but is not identical.[181]

There are two differing approaches when considering the functionality and architecture of the meters. That is:

1. All smart meter functions (ie the second and third components) are delivered through the meter and are part of the required metering installation functionality.

2. Alternatively, 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 the second 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 (ie outage detection, remote energisation).

For the purpose of facilitating a 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. The remote electronic communications allow real time access to the meter data.

In the draft report, we recommended the minimum functionality to be included in the NER be a meter which has, amongst other features, the ability to record interval consumption and have remote communication. We referred to this specification as

---

180 "Smart Metering Infrastructure Minimum Functionality Specification version 1.3", National Smart Metering Program, published 18 March 2012. The document is available at http://share.aemo.com.au/smartmetering/Pages/BRWG.aspx

181 An analysis of the differences between the NSMP and Victorian minimum functionality specifications is contained in the report "Comparison Victorian AMI to NSMP SMI Functionality Specification", which is available at http://share.aemo.com.au/smartmetering/Document%20library/Work%20Stream%20documentation/BRWG/BRWG%20-%20Vic%20AMI%20and%20SMI%20Func%20Spec%20comparison.pdf

minimum functionality specification for the advanced metering infrastructure.[182] This was based on the premise that the consumer has the choice to influence the characteristics of its metering installation and decide whether it is appropriate to include any additional functions. This would enable the consumer to pay for the meter that best meets its ability and preference to do DSP, at a lower cost. When a metering service provider would be able to derive benefits from a meter with additional functions then it may be able to offer a meter with these functions at a lower cost to the consumer. We highlighted that given the work by SCER, there may be merit to also expand the proposed minimum functionality to include some of the smart grid business functions.

Many submissions to the draft report were concerned that our proposed minimum functionality specification was too narrow and that we should recommend the SCER endorsed Smart Metering Infrastructure (SMI) Minimum Functionality Specification.[183] For example, Jemena supports the SMI minimum functionality specification because: it considered that the benefits of the additional HAN and smart grid functions are likely to exceed the additional cost (less than $50), and adding these smart grid functionalities after the meter is installed could be costly.[184] The Victorian Department of Primary Industries supports the SMI minimum functionality specification and suggested a cost-benefit analysis be conducted on any reduction in the minimum functionality specification.[185] In addition, GE Energy warned that setting the minimum functionality specification too low could result in Australia not benefiting from economies of scale flowing from international markets.[186]

Some stakeholders supported our approach in the draft report that the functions of smart meters be limited to only recording interval consumption with an appropriate communications technology.[187] Greenbox, for example, was concerned that SMI minimum functionality specification is gold-plating with the danger of such technologies being rendered obsolete.[188] Better place suggested that the costs of any additional features be paid by the consumer.[189]

We have considered stakeholder views and considerations such as ensuring the full value of DSP can be captured across the supply chain and cost estimate of the meter. We recommend that the SMI Minimum Standard Functionality developed by the National Smart Metering Program, and endorsed by the SCER in December 2011 is

---

182 AEMC 2012, *Power of choice review - giving consumers options in the way they use electricity*, draft report, September 2012, p 47.

183 Refer to Appendix G - Summary of stakeholder submissions to draft report.

184 Jemena submission to draft report, p.9. SA Power Networks and United Energy also raised the point that additional smart meter functionality comes at a small incremental cost.

185 Victorian Department of Primary Industries submission to draft report, p.7.

186 GE Energy submission to draft report, p.2.

187 Better place submission to draft report; Greenbox submission to draft report; Metropolis submission to draft report.

188 Greenbox submission to draft report, p.4.

189 Better place submission to draft report, p.3.

adopted and included into the NER for all new future meters installed for residential and small business consumers.

Adopting a more comprehensive minimum standard functionality, such as that developed by the National Smart Metering Program and endorsed by the SCER, is likely to provide consumers with a greater range of DSP options and end use services. In addition, consumers moving premises to those that have a smart meter installed are also less likely to need to upgrade that existing meter.

There would be competitive pressures on metering service providers to install meters with some degree of increased functionality to avoid their meters being changed however, there is a risk that retailers may not be sufficiently incentivised to install more expensive meters with network functions as they would not be able to capture the associated network benefits. This risk arises as there is no framework that allows network businesses to negotiate with the retailers to include these additional network functions in any new meter when it is efficient to do so.

We consider that, if the network related functions are included in the meter, then it is likely to be efficient to include the additional functions such as remote software upgrades, plug & play commissioning, and meter setting reconfiguration. These functions were not included in the minimum functionality recommended in the draft.

With respect the network related functions within the meter, we expect that the metering coordinator will charge a fee to the network businesses to utilise such functionalities, hence an individual consumer will not pay for those for those additional functionality to be utilised. As noted, the AER would only approve the network paying for the use of such functionalities if it improves the distribution network businesses ability to deliver network services at an efficient cost, consistent with the revenue determination framework.

The benefits of the increased options available in the meter, and the associated reduced risk the meters will need to be changed, is likely to be in the long term interests of consumers as the incremental costs of additional functionality is relatively low. The cost of a new meter is dominated by the labour needed to install the technology at the consumer's premises.

The minimum specification is to include:

- the measurement and recording of consumption and generation at a consumer's premises;
- the ability to read the recorded metering data either locally at the meter or remotely via a communications link;
- functions to support the network businesses manage their networks such as direct load control, loss of supply detection, safety monitoring and monitoring power quality;
- remote connection and disconnection of the consumer;

- supporting a home area network using an open communication standard protocol; and
- a requirement for interoperability of the meters, the communications infrastructure and the metering management systems.

We also recommend that all future meters must retain any pre-existing load control capability that is at the consumer premise, such as ripple control of hot water heating load, unless that function is obsolete. Such load control schemes have been integrated into the design and operation of some distribution networks and an equivalent functionality would need to be retained, at least as a transitional arrangement, to avoid significant network augmentation.

Table 4.1 shows a comparison between the changes our draft report and this final report, and how this compares to the SMI Minimum Standard Functionality that was endorsed by SCER. A full description of the minimum functionality specification that we have recommended is provided in the draft specification attached to this report.

Table 4.1 Comparison between the changes our draft report and final report on Minimum Functionality Specification

Function	Draft report	Final report	NSMP
Measurement and recording of consumption and generation	y	y	y
Local and remote data reading	y	y	y
Network functions (direct load control and monitoring)		y	y
Remote connection and disconnection of the consumer		y	y
Supporting home area network with open communication standard		y	y
Industry standards supporting interoperability		y	y
Retain existing distribution load control schemes (such as ripple load control)		y	

4.3.4 Communication infrastructure - open access and interoperability

The communications platform is the system that provides the communications link to a smart meter at a consumer's premises. This link conveys metering data and status information to the AEMO, network business and retailer, as well as commands, messages and software updates to the meter. The communications platforms for smart meters can be divided into two types, namely point to point and mesh networks:

- Point to point communications platforms operate with an open access communications link to the metering installation such as mobile phone technology (GPRS wireless infrastructure). Authorised entities are able to communicate with the metering installation through the use of passwords. Point to point communications are used for the existing type 1 to 4 metering installations in the NEM.[190]

- Mesh communications platforms are formed when the communications modules in the metering installations communicate with each other to form a meshed radio network. Mesh communication platforms are generally operated by monopoly service providers (ie usually the distribution business). Third parties, such as retailers, must gain access to the metering installation through 'facilitated access'.[191]

Generally point to point communicates platforms evolved when a limited number of individual metering installations are deployed in a given geographic region using different metering service providers. This is because communication relies on an existing third party telecommunication networks. Mesh radio communication platforms can become more attractive and cost effective when a single entity deploys all the meters in a given geographic region.[192] This is because the radio communications inherently in the meters forms its own communications network.

We are not recommending any particular communication platform. This is because the choice of the most efficient platform may vary over time and is likely to require different approaches in geographical areas. We consider that the market should be incentivised to deliver the most efficient platform for the particular circumstances of the metering services provider. However, we do consider that the remote acquisition function in the meter be designed on open access principles to allow entitled parties to gain access to the energy data. There is a potential risk to the performance of the communication platform deployed for a larger smart meter roll out. For example, under competitive approach the retailers may have a commercial incentive to install a communication platform that suits their needs, but insufficient to effectively operate some network functions during an emergency event. Similarly, a platform deployed by

---

190 SP AusNet smart meter network in Victoria uses point to point.

191 Meshed radio networks are being deployed for example, in the United Energy, Jemena smart meter networks in Victoria.

192 Silver Springs submission to the draft report.

a distribution business may not meet all the needs of other stakeholders such as retailers.

Therefore, we consider the functionality and performance for the communication platforms deployed would be sufficiently well specified to:

- support all the functionality in the SMI minimum functionality specification, including remote acquisition to support open access to energy data;
- Allow for network operational data to be communicate to the LNSP;
- provide authorised stakeholders open access to the meter's functionality; and
- manage the volume of data to and from the metering installation, including being able to operate the network functions expeditiously during an emergency event.

To allow all the functionality of the meter to be accessible it is imperative that all the relevant stakeholders have access to functionality. This is most easily achieved if a common communication protocol or language is agreed by the industry. We expect that the market to determine the protocol or language that has wide international acceptance and delivers all the functionality of the SMI minimum standard functionality.

The minimum functionality specification includes the ability to communicate with a HAN and to control "smart appliances" at the consumer's premises. That is, control of the operation of a smart appliance in response to change in tariff or other time of use price signal, as part of a DSP scheme operated by a network business, retailer or ESCO. Examples of this include simply turning on or off the appliances at times of peak demand or high prices, adjusting an air conditioner set point via a communicating programmable thermostat. To effectively integrate smart appliances into a DSP program or otherwise provide the consumer with more control of it consumption requires open access communication protocols from the smart meter or HAN to the smart appliances. We note that the ZigBee Smart Energy Profile appears to be emerging as an industry standard for this communication protocol and is being widely applied in new appliances.[193]

4.3.5 Energy services enabled by smart meters

As discussed in Chapter 2, smart meters will enable a suite of smart energy services. These may be provided by retailers, networks or third parties (ie ESCOs). Generally there is support for such services enabled from smart meters to be open to competition (ie energy management services).

---

193 Further information of the Smart Energy Profile 2.0 is available at http://www.eetimes.com/design/smart-energy-design/4229848/SEP--Smart-Energy-Profile--2-0-Uncovered.

We are recommending that the provision of communication infrastructure and associated services are contestable given there is a variety of potential third party vendors for these services (eg public and private telecommunication companies).

Stakeholders did raise some specific issues regarding several services and communications. For example, who should send messages to the consumer through in home displays and who should undertake and control load functionality (ie direct load control). In regards to the direct load control that can be undertaken using the meter (ie rather than external communication device), distribution network businesses indicated concern about the potential for impacts on system security and reliability of varying demand on their networks. This related to large synchronised switching impacts - network interruption, damage to network equipment, voltage variation and damage to consumer equipment. There have been some suggestions for technical standards to apply as a means to address such issues.[194]

As highlighted the SCER working group on smart meters is considering a range of issues, including those identified above, along with privacy and consumer protection issues.

We consider it is important to clarify the how the MC provides access to functionalities enabled by the smart meter for multiple DSP providers. There may be a need to assess whether fees should be regulated or left to competitive arrangements. Also, there are some functions which are only of value to the network business, and therefore may not need to be classified as contestable. It is important that it is clear and transparent what these services are.

Networks will need to have access to the operational data emerging from smart meters, and also ability to do load control and for network planning and operations. In general, we consider that there is need to clarify the arrangements for load management services, including the need for appropriate technical standards that must be complied with. We are canvassing these issues in the Electric Vehicles/NGV review and will provide principles for load management by networks in that report.

4.4 Way forward

The reforms present a package for SCER to consider. Ultimately they seek to support efficient investment in DSP technology that enables consumers to have choice in take up DSP products and end use services, and hence metering capability. The proposed framework and arrangements will require further work with respect to details of implementation. There are also areas where work will need to be progressed on the arrangements for communication protocols and open access arrangements.

We are recommending that governments commit to the overarching policy framework that enables more competition in metering and services. This policy framework is based on the key principles outlined in this chapter, specifically:

194 Refer to Appendix G – Summary of stakeholder submissions to draft report.

- Arrangements to support interoperability of meters and open access to energy data. Issues to consider include: a common meter protocol; a common means of supporting remote communications with all installed meters; and to provide for compatibility across the meter communications networks.

- Competition in metering and data services, supported by the minimum functionality specification. Chapter 7 of the NER will need to changed, and NERR to ensure consistency with policy; and

- Access by third parties (single gateway) irrespective of who installed the metering hardware. This links to access to energy and metering data by third parties.

To progress details of implementation, we are proposing that:

1. SCER tasks the AEMC to establish an advisory stakeholder working group to develop arrangements to support the principles building on the work of NSSC;

2. Make amendments to the NER based on the proposed rule changes (ie draft specifications); and

3. Remove the current NEL provision allowing for a government mandate for distribution businesses (operating in their jurisdiction) to roll-out smart metering services to consumers within their jurisdiction.

These reforms can be made in parallel.

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 and transaction costs that for most commercial and industrial users cannot be efficiently managed. For various reasons, these arrangements have only been partially effective in exploiting the many opportunities for efficient demand response to spot prices.

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 promote accurate demand forecasts of the increasing levels of DSP in the NEM.

To achieve this we recommend to SCER that:

- A demand response mechanism is introduced that pays demand resources via the wholesale electricity market (rewards changes in demand). 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. We recommend that AEMO develops the details for a rule change proposal and required procedures, including the baseline consumption methodology.
- The NER is clarified regarding AEMO's role in demand forecasting for its market operational functions.
- A new category of market participant for non-energy services is introduced in the NER to unbundle the sale and supply of electricity from non-energy services, such as ancillary services.

The proposed mechanism would mainly assist large electricity users, such as C&I users that prefer to have an energy retailer mange 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 appropriate metering technology in place.

We expect these recommendations will result in efficiently meeting supply and demand for electricity in the wholesale electricity and ancillary services markets. In particular, the demand response mechanism allows consumers to capture the value of their reduction in consumption.

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 to reach efficient market outcomes. At present, direct access to the wholesale electricity market is typically limited to producers of electricity (generators) and large scale buyers of electricity (retailers). Generators will adjust their production over the short term in response to the wholesale electricity spot price, and will make investment decisions based on the longer term changes to the levels of demand.

Because of the risks associated with participating in the wholesale electricity market, namely spot price volatility, most consumers will choose to purchase their electricity needs through a retailer that can better manage spot price risk. This means that a consumer's demand for electricity is not reflective of the changes in market conditions of supply and demand, as signalled by the spot price.

In addition, there are a range of costs in managing spot price volatility, such as building organisational capacity and implementing processes to monitor and forecast the spot price, installing technology, and other transactions costs that may render this type of activity uneconomic for many C&I users.

Consumers 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 electricity 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. As a result most consumers are not directly exposed to the costs of electricity supply in the wholesale market, and efficient levels of consumption are not achieved.

5.2 Issues identified

The directions paper outlined the different ways consumers can currently access the wholesale electricity and ancillary services market. In assessing the uptake of the current options available, we considered that the regulatory arrangements could be improved to facilitate better consumer access and participation in these markets. We also considered that third parties, such as aggregators, are likely to play an important role in facilitating participation by coordinating consumers' demand resources into wholesale electricity and ancillary services markets.

Throughout the review stakeholders have generally been supportive of improving consumers' ability to access the wholesale electricity and ancillary services markets. End – users identified a number of key issues that currently limit their participation in the wholesale electricity market, including the risks of being exposed to the spot price and the costs of participation relative to the benefits.[195]

Stakeholders also noted that under the current arrangements, demand response opportunities could not be unbundled from the sale and supply of electricity.[196] This means that a consumer with the flexibility to benefit from a reduction in electricity demand could only do so through its supplier of electricity – a retailer. For retailers, the flexible electricity demand of a large end-user can be used as a hedging instrument against spot price exposure. A retailer's incentive to provide demand response services is typically aligned with their interest in managing spot price risk. For consumers, this means they may not be realising the maximum value of their changes in consumption.

The incentive for retailers who also own generation assets to provide demand response products is less clear, as the generation asset acts as a natural hedge against spot price exposure. In its submission to the issues paper, EUAA had surveyed its members on the extent to which demand response products were offered in the market. Based on the survey results, EUAA observed that demand response contracting opportunities are only used when retailers are unhedged. However, most retailers are covered against price strikes with financial market hedges or their own generators. The predominance of 'gentailers' in the National Electricity Market (NEM) has further blunted incentives for retailers to utilise demand response.[197]

A similar issue arises in the ancillary services market, whereby the sale and supply of electricity cannot be unbundled from the provision of ancillary services. During the review,[198] we considered that retailers may be reluctant to arrange for market load to be classified as an ancillary services load if the appropriate system to participate is not in place, or the associated ancillary services response may have negative financial implications.

This chapter sets out our recommendations for addressing these issues:

- Sections 5.3 – 5.5 outlines our recommendation to amend NEM settlements to enable consumers to participate directly in the wholesale market, or via a third party, and to be rewarded for a change in consumption. This section also addresses issues raised by stakeholders in response to this proposal, and the process for implementing the demand response mechanism.

- Sections 5.6 – 5.10 outlines our recommendation to strengthen AEMO's role in developing both long and short term forecasts. This includes the price responsiveness of DSP, for the purpose of forecasting more accurate price information to the market, which assists in planning and investment decisions.

---

195 Energy Users Association of Australia (EUAA), directions paper submission, p. 6; Major Energy Users (MEU), directions paper submission, p. 38

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

197 EUAA, issues paper submission, pp 8 - 10, 15

198 See AEMC Power of choice review webpage for information on the ancillary services workshop held in Melbourne in April 2012.

- Sections 5.11- 5.12 outlines our recommendation to create a new category of market participant to enable parties other than those responsible for the sale and supply of electricity to provide non-energy services on behalf of a consumer.

5.3 Demand response mechanism

RECOMMENDATION

We recommend that:

- **A demand response mechanism is introduced that pays demand resources via the wholesale electricity market. 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.**
- **AEMO develop the details for a rule change and supporting procedures associated with implementing this mechanism, including the baseline consumption methodology. AEMO would establish an advisory stakeholder working group to work through implementation issues.**

The key principle for the implementation and operation of the demand response mechanism (DRM) is competitive neutrality. In practice, this means that to the greatest extent possible, demand resources participating under the DRM are treated in a manner analogous to generation, including remuneration at the prevailing wholesale electricity spot price for the amount of demand response delivered to the market.

Under this proposal the spot price would continue to be calculated on the basis of the marginal scheduled bands of generation or demand resource. The demand resource is paid according to the amount of 'demand response' delivered to the market, which is calculated as the difference between consumers' estimated 'baseline consumption' and their actual metered consumption for the 'demand response interval'. The baseline consumption is an estimate of consumers' electricity demand had they not provided a demand response under the DRM.

The consumer's reward in the wholesale market for participation is the amount of demand response delivered to the market multiplied by the spot price, which will factor in the impact of the demand response action.

The proposal requires consumers to continue paying their retailer for electricity according to their estimated baseline consumption. Similarly, consumers' retailers are required to pay the spot price according to the estimated baseline consumption. In principle, retailer energy settlement is the same as if no demand response action had occurred. This arrangement allows for AEMO to recover enough funds to pay consumers[199] for their demand response at the spot price.

The benefit to consumers of providing the demand response under the DRM is the spot price minus the energy component of their retail price (and excludes the opportunity cost of not consuming).

For example, assume a consumer has in place a retail contract for $40/MWh. If the spot price is $50/MWh and a consumer provides 2MW of demand response to the market, the total benefit to the consumer would be $20; that is the spot price reward ($100) minus the retail contract ($80). The consumer would also factor in the opportunity cost of undertaking the demand response action (i.e. lost production) before participating in this mechanism.

The following points describe the operation of the DRM, including the role of participants. Greater detail on individual aspects of the DRM can be found in the drafting specifications attached to this final report.

Contractual arrangements and the consumer's estimated consumption

- Consumers participating in the DRM must have a retail contract in place with a registered 'Market Customer'[200] (that is, a retailer).

- The retailer will be settled in the wholesale electricity market according to the consumer's estimated baseline consumption for the period of the demand response interval.

- Consumers will continue to pay their retailer for the energy only component of their retail tariff according to their estimated baseline consumption for the period of the demand response interval.

- Consumers, or parties representing consumers, are required to register their participation in the DRM with AEMO. In doing so, consumers must meet eligibility criteria and provide relevant information as set out by AEMO. Consumers can choose to participate in the DRM on a scheduled or non-scheduled basis, subject to any threshold requirements required by the rules or AEMO.

- Overtime, under AEMO's strengthened demand forecasting role, and with greater experience of the DRM program, non-scheduled demand response may form part of the dispatch process's demand component. This means that the imperative for demand resources to participate on a scheduled basis may lessen.

---

199 We note that in practice, the registered person receiving funds is likely to be an aggregator on behalf of the consumer.

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

- The demand response supplied to the wholesale electricity market during the demand response interval is calculated as the difference between a consumer's estimated baseline consumption and their actual metered consumption at the facility providing the demand response action.
- AEMO is responsible for establishing the methodologies used to calculate a consumer's estimated baseline consumption consistent with a defined set of principles (as outlined in the draft specifications). AEMO also is responsible for developing performance evaluation methodologies that are to support the establishment of the baseline consumption.
- In transitioning to the DRM, contractual arrangements may need to be amended to facilitate participation by consumers. During this transitional period, a retailer cannot refuse to host a consumer providing a demand response under the DRM.

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

- All consumers providing a demand response will notify parties potentially impacted by their actions, including AEMO, their retailer or DNSPs, of their intention to enter and conclude a demand response interval. The notification requirement would also include information regarding intended duration of the demand response interval.
- Dispatch operations would not change, and the spot price would continue to be calculated as it is currently where the marginal scheduled bands of generation or demand resource are the basis of the spot price.
- To the greatest extent possible, consumers should be encouraged to participate as scheduled demand resources. Scheduled demand resources appear in AEMO's central dispatch process and are dispatched in accordance with its bid. This can result in price being set by the demand resource bid.
- All consumers providing a demand response, including both scheduled and non-scheduled, face the same spot price and are therefore exposed to the same risks.
- Consumer, or a party acting on their behalf, providing a demand response that consume more than their estimated baseline consumption during the demand response interval would be liable for the amount consumed above the estimated baseline consumption at the spot price.

Settlement and the impacts on retailers and consumers:

- AEMO pays consumers for the quantity of demand response supplied to the market for the duration of the demand response interval at the prevailing spot price. Consumers participating in the mechanism pocket the difference between the spot price and the retail price (energy component).

- A monitoring and verification scheme may be required to confirm the amount of demand response supplied to the wholesale market by the consumer for the period of the demand response interval.

- Subject to the accuracy of a consumer's estimated baseline consumption, the wholesale electricity market transactions would leave the retailer cost neutral. The consumer providing the demand resource would benefit from the difference between the retail tariff and the prevailing spot price net of any lost production or other costs from not consuming.

- Retailers' hedging strategies would need to be aimed at supporting the baseline, and subject to baseline accuracy, would be unchanged.

- Consumers pay the network use of system charges based upon their actual consumption volume, not their estimated consumption. Retailers will be required to separate the energy and network components of a consumer's contract price.

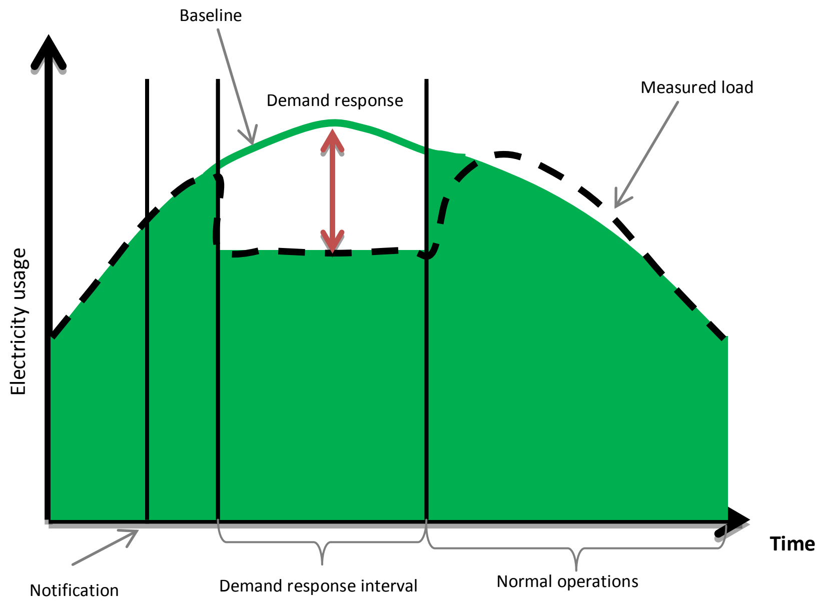
Figure 5.1 illustrates how baseline calculation is applied during the demand response interval. The consumer, or the third party responsible for coordinating demand response, would notify AEMO of their intention to enter into a demand response interval.

During the demand response interval, the retailer pays the wholesale market according to its consumer's baseline consumption (the green line titled 'baseline'). Similarly, the consumer pays its retailer according to that same baseline consumption. During the demand response interval AEMO uses the actual metered load (the dashed line titled 'metered load') to calculate the amount of demand response delivered to the market during the demand response interval, which is the difference between the baseline consumption and the metered consumption (the green line minus the dashed line).

For the periods before and after the demand response interval, the consumer should be at normal levels of operation, and the retailer would be responsible for paying for the consumer's consumption according to its metered consumption (the dashed line titled 'metered load'). In Section 5.5.3 we discuss some of the issues retailers have raised in relation to consumers needing to increase their electricity demand above normal operational levels in the periods adjacent to the demand response interval (i.e. where the dashed line is above the normal levels of consumption forecast by the retailer as part of its demand forecasts and therefore included in its hedging strategies).

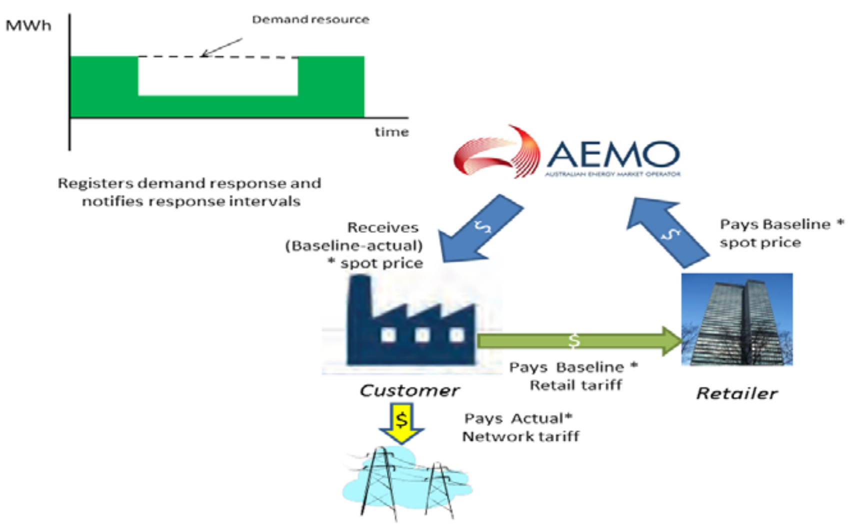
Figure 5.1 Payment of the baseline consumption during a demand response interval[201]

Figure 5.2 provides a high level overview of the general design of the DRM, and the



different financial relationships that would arise under the DRM. Figure 5.3 provides an example of the flow of payments between a consumer, retailer and AEMO, as it relates to the wholesale electricity settlement only. In Section 5.5.3 we discuss how the DRM may impact on hedging arrangements beyond the wholesale electricity spot market, and address the concerns raised by retailers and generators on this issue.

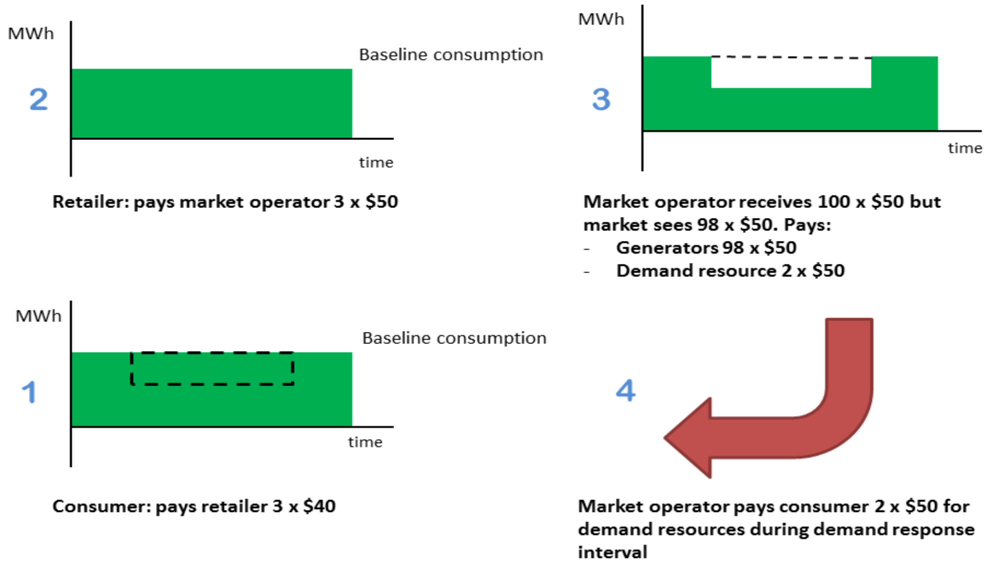
Figure 5.2 General design of demand response mechanism[202]



201 *AEMC Power of choice review – giving consumers options in the way they use electricity*, final report, November 2012.

202 *AEMC, Power of choice review – giving consumers options in the way they use electricity*, draft report, September 2012.

Figure 5.3 Settlement in the wholesale electricity market[203]



The DRM would mainly assist commercial and industrial (C&I) users. Typically, these types of consumers prefer to have an energy retailer manage spot price risk for their electricity demand, yet have the capacity to offer their demand response to the wholesale electricity market. In the future, the DRM could be adapted by aggregators to include demand response from residential consumers that have appropriate metering technology in place (i.e. smart meters).

The DRM does not replace existing options available to C&I users from their retailers, or from participating in the wholesale electricity market as scheduled load. Rather, the DRM adds to the suite of options available to C&I users for managing electricity demand. We would expect retailers would be incentivised to develop innovative tariffs and other demand response services independent of the DRM.

5.4 Rationale

The following section outlines the high level rationale for recommending the introduction of the DRM in the wholesale electricity market. We consider the impact of the DRM on consumers, market participants such as retailers and network businesses, as well as the market more broadly.

Our overall assessment of the DRM is that it meets the NEO in a number of ways. Firstly, it enhances consumption participation in the wholesale market and allows consumers to see the value of changing their consumption in line with market signals, such as the spot price. In turn, we consider that informed consumer choices leading to

203 *AEMC Power of choice review – giving consumers options in the way they use electricity*, draft report, September 2012

efficient consumption in the market will result in lowered generation and network costs, as well as increased competition in the energy market that will benefit all consumers.

- *Facilitating consumer participation*

The DRM enhances consumer participation in the wholesale electricity market and will enable consumers to see the value of reducing their consumption in response to spot prices. In the longer term, the ability for consumers to respond to spot prices will result in lower spot prices and spot price volatility, and deferred investment in generation and networks. These cost savings will be passed onto all consumers in the NEM, consistent with the NEO.

The DRM enhances consumer participation in the wholesale electricity market and overcomes those issues identified by stakeholders during this review. In particular, the mechanism enables consumers to participate in the wholesale electricity market without incurring the range of costs described in section 5.1 that would otherwise inhibit their participation. We consider that specialist third parties will be able to efficiently manage these types of activities for consumers participating under the DRM.

In doing so, the DRM allows consumers to respond to market signals and see the value of reducing their consumption. Providing a way of participating in the wholesale market that is separate to a consumer's electricity supply contract recognises that consumers and retailers may have different energy needs. It also allows consumers to seek competitive offers for demand response from a range of suppliers. Overall, giving consumers the ability to respond to price signals will promote efficient consumption, and thereby contribute to the efficient operation of the demand side.

- *Estimated level of demand response*

Over the mid-term, we estimate that the DRM has the potential to capture up to 2,100 – 2,800MW of demand response from C&I users. This 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.[204] Appendix C provides a summary of the literature used to estimate the potential demand response from C&I users.

SFS Economics[205] note in their report "Economic Implications of the proposed Demand Response Mechanism" that comparison to international demand response programs will result in overestimating the potential for demand response in Australia. This is because international demand response programs also include reliability

---

204 In the near term C&I users market would be likely to account for almost all of demand response, and up to 80 per cent in 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.

205 See SFS Economics report, *Economic implication of the proposed Demand Response Mechanism*, attached to Energy Supply Association of Australia (ESAA) draft report submission.

demand response programs, which often constitutes the majority of the demand response. Nonetheless we consider that international comparisons provide a relevant measure of potential demand response as they indicate the capacity for consumers to provide a demand response, irrespective of the objectives of the program.

We asked Frontier Economics to model the potential impacts of the DRM in the market. They assume the DRM attracts levels of demand response in the market of between five to ten per cent of peak demand in the C&I sector.[206] Based on this assumption, Frontier Economics estimate that the DRM could deliver up to $2.8 to $4.3 billion in delayed supply side investments (generation and network) over a ten year period through to 2022/23. Chapter 10 outlines in greater detail Frontier's modelling on expected savings from the recommendations proposed in the final report.

We 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 an aggregator to provide a demand response to consumer who already have infrastructure in place to accommodate a demand response.[207] We have asked AEMO to consider this issue in closer detail as part of the draft specifications attached to this final report.

Table 5.1 below gives practical examples of how demand response has been used by small and large industrial end-users and commercial consumers in the United States over recent years.

Table 5.1 Examples of demand response in the United States[208]

Participant	MW	Method
Walmart (retail)	0.1 and 0.3 MW	Automatic energy management systems respond to pre-programmed strategy. Advanced metering used to shut down or lower store loads in order to comply with emergency events.
Severstal Sparrows Point (steel plant)	230 MW peak load	Curtail operations at plant, such as shutting down blast furnace, or use distributed generation.
Bridesburg	0.9 MW	Controls to shut down foundry, shifting production to earlier in

206 See AEMC Power of choice website for Frontier Economics presentation at public forum on 3 October 2012.

207 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.

208 See RAP report, *Examples of dispatchable demand response clearing the ISO-New England and PJM forward capacity markets*, August 9, 2011

Participant	MW	Method
Foundry (heavy industrial)		the day to avoid production during on-peak period. Majority of furnaces are shut down during DR emergency.
Four Seasons Produce	1.0 MW	Remote or in-person shut down of refrigeration systems for short periods. For longer periods, a behind the meter back-up generator is used.
Bryn Mawr College	1 MW	Automated curtailment. Building automation systems randomly turn off fans in many buildings, causing chillers to back off and pumps to ramp down. As building temperature rises, fans and AC units are reactivated to maintain 77F maximum. Payment: $300,000 over 3 years in PJM market.
Harpoon Brewery	350 kW	Reschedules bottling processes, modifies settings and their chillers and makes lighting and HVAC adjustments.

- *Efficient consumption*

We consider the most economically efficient outcome for the market is when consumers face the true costs of supply (see Box 5.1). In the absence of fully cost-reflective pricing, the DRM creates a similar set of incentives and behaviours with respect to efficient consumption during wholesale electricity market peak and non-peak times. The DRM is similar to a Peak Time Rebate (PTR) in this respect. Under the 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, that is, 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.

- *Peaking generation and lower spot prices*

The DRM allows consumers to participate in the wholesale electricity market in a similar manner as peaking generation. Where a consumer can provide a demand response at a cheaper dispatch bid to peaking generation, then it will displace the peaking generator in the bid stack. The extent to which this occurs depends on the volumes at which demand response participates in the market. In this regard, the spot price is expected to be lower. Spot price volatility would also expect to dampen under these conditions.

As outlined in the cost benefit analysis in Chapter ten, a lack of participation in the demand side can contribute to extreme price events in the wholesale market and which feeds through to higher consumer costs. Figure 10.12 in that section shows the average daily spot price across NEM states over the past financial year.

- *Sustained demand response*

Generator behaviour in the wholesale market is predictable and reliable, which contributes to efficient dispatch volume and pricing. Therefore, an important condition for achieving both lower overall spot prices and reduced spot price volatility is that the demand response provided under the DRM is also predictable and sustained.

We consider that consumers providing demand resources are likely to have sufficient incentives to be reliable, especially where they participate via an aggregator's portfolio, and has incurred costs in establishing infrastructure to coordinate their operations. The incentive is likely to be stronger if the full potential is realised and the interruptible feature is used as the basis of a financial instrument or a network contract. For reasons outlined in Box 5.2, demand response is likely to create a new source of hedging contracts to manage uncertain revenue, and should help to achieve this outcome.

For C&I users any additional revenue stream would likely be incorporated into longer term business planning, further strengthening the predictability of demand response.

Box 5.2: Uncertain revenues and hedging arrangements for consumers

Uncertainty in the spot price can potentially hinder DSP in the wholesale electricity market. For instance, an instantaneous spot market can create uncertainty for a consumer on the costs of preparing a demand response, particularly when these costs may need to be incurred 24 hours in advance of the demand response action.

Generators face a similar issue when participating in the wholesale electricity market, and need to make commitments a day ahead of when it is dispatched, and before the spot price is known. One of the ways in which generators overcome this spot price uncertainty is by entering into hedging arrangements with a retailer.

Consumers, faced with a similar set of issues and risks when participating under the DRM, can enter into similar arrangements to manage spot price uncertainty and volatility. The more likely scenario is that an aggregator, with a portfolio of different consumers, will be the source of hedging contracts. This is because the length of an individual contract may be too long for a single consumer, but can be achieved through a portfolio of consumers.

When this scenario arises, demand response actions in the wholesale electricity market will be predictable and sustained, and efficient for the market. Further, consumers and aggregators can act as counter-party to retailers seeking to manage the financial risks of spot price volatility.

- *Retailer impacts*

The DRM impacts retailers in a number of different ways. Potentially lower spot prices, especially peak demand spot prices, will lower a retailer's hedging costs.[209] In a competitive market retailers should pass the cost savings on to all consumers. This is because the benefit of reduced wholesale electricity costs is not just limited to consumers who participate in the wholesale market, but should extend to all consumers including residential consumers.

The transition to the DRM may impose some costs on retailers. For the interim, a retailer of a consumer participating under the DRM would have to more closely monitor changes to a consumer's load profile as the consumer may need to increase electricity demand in periods adjacent to the demand response interval. These changes to a consumer's load profile may impact on the risk management and hedging portfolio of a retailer.

We consider that this is likely to be a transitional and minor matter, and one that can be resolved through the contractual terms and conditions between the retailer and the consumer providing the demand response. We would consider that a substantial proportion of consumers participating under the DRM would not have equipment to significantly increase short run electricity demand. Further information on this is provided later in this chapter.

- *Level of unserved energy*

Sustained demand response is 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.[210] 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

209 Another way to view the impact on retailers of the DRM is to consider the impacts of a new peaking generator entering the market may have on the peak spot price, as well as options for a retailer managing peak demand spot price.

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

consumers to respond, thereby lessening the potential for a rolling blackout, which affects a number of consumers. As NERA note in their submission to the directions paper, "effectively load is reduced in the order of value to consumers".[211]

In turn, we would expect that over the longer term, once the mechanism is established to be reliable, the market would benefit from a new source of capacity of lower capital cost than traditional supply, and should therefore move to a new demand-supply balance. Market settings that aim to keep involuntary load shedding within the reliability standard could then be reconfigured downwards in recognition of the new demand-supply balance. We consider that this outcome will promote the achievement of the NEO.

- *Impact on network management and operation*

Facilitating greater participation in the wholesale electricity market 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 the DRM, possibly through aggregators, they are more likely to participate in arrangements to manage network flows/contingencies. This is because 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.[212]

We do not consider that the DRM introduces perverse incentives by working in opposition to existing and successful demand response programs, such as SPAusnet's critical peak pricing program. Some stakeholders considered that a perverse incentive can arise between critical peak pricing programs and the DRM.[213] This situation arises where critical peak pricing days are included in a consumer's estimated baseline consumption, which would lower the overall level of the consumer's estimated baseline consumption. We consider that this potential scenario can be easily remedied by excluding critical peak pricing days from the baseline consumption estimated.

The two arrangements represent an opportunity for consumers to maximise the value of their demand response actions, especially where there is a coincidence between peak demand in the wholesale market and network load.

The ability for DNSPs to manage network flows under the DRM has the potential to lower capital infrastructure investment. The DRM complements a number of other reforms proposed in the Power of choice review aimed at incentivising the use of DSP by network service providers in place of capital investment where it is efficient to do so. For example, the contractual arrangements established between a consumers and an

211 NERA, directions paper submission, p. 10.

212 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.

213 See AEMC Power of choice webpage for ESAA's presentation at the public forum held in Melbourne in October 2012.

aggregator could also be utilised as a demand response to manage peak demand on the network.

Further, 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. Proposed clarifications to AEMO's role in demand forecasting should further support this outcome (see Section 5.7).

- *Implementation costs*

The proposed DRM will incur some costs to the market. Initially, AEMO will incur administrative costs as it establishes the framework for the DRM and augments operational needs. In addition, there will be some ongoing costs relating to settlement and verification. The impacts of these costs, however, are likely to diminish over time as AEMO's proficiency improves. The AER may also incur costs as it monitors the impacts of the DRM and potential breaches. 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 significant cost.

Participation under the DRM will come at some cost for consumers participating under the DRM. The consumer, or third party, will need to recover costs arising from metering, equipment, controls, IT infrastructure, as well as any requirements placed on these parties to establish the baseline consumption.

Consumers are likely to determine the costs and benefits of participating under the DRM before proceeding with registration. This means that participation under the DRM will be self-selecting to consumers that are likely to benefit from participation, which should ensure that costs of participation are efficient.

- *Other issues*

The proposed DRM is different to other mechanisms previously considered under reviews of demand side participation. For example, uplift charges to fund DSP payments have previously been considered in the context of the Parer Review and Demand Side Participation Stage 2 Review. In each of these reviews, it was 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. In contrast, our proposal for a 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 Issues raised by stakeholders

In developing this final recommendation we have taken into consideration the views of stakeholders and submissions provided in response to the draft report. This section addresses some of the key issues raised by stakeholders in response to the DRM. Key issues include the following:

1. **Competitive neutrality.** The extent to which the proposed DRM creates a level playing field for generators and consumers, and does not advantage one party above the other in meeting supply and demand in the wholesale electricity market.
2. **Investment signals and wholesale electricity prices.** Generators and retailers argue that the DRM will dampen investment signals in the wholesale electricity market, and risk supply side investment falling short of market demand. Further, a reduction in wholesale electricity prices does not represent economic value
3. **Hedging risks.** Stakeholders have raised concerns that the DRM unbalances the hedging market by thinning market liquidity that will in turn, drive up costs for retailers. These costs will be passed onto all consumers.
4. **Baseline consumption.** Concerns have been raised regarding consumers 'gaming' the system by inflating their electricity demand prior to a demand response event to overestimate their baseline consumption. This concern also includes accuracy in measuring the estimated baseline consumption.
5. **Implementation process.** The final report provides terms of reference and draft specifications for AEMO to develop the DRM recommendation into a rule change proposal for consideration by the AEMC. A working group will be established to provide guidance on some of the policy issues that may need to be resolved in developing the rule change proposal and procedures.

Appendix C 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.

5.5.1 Competitive neutrality

We consider that a key principle underpinning the design and operation of the DRM is competitive neutrality, meaning that demand resources dispatched under the DRM are subject to similar conditions and obligations as a generator. This principle will ensure that demand response entering the market is economically efficient and does not displace efficient generation. Over the longer term, competitive neutrality in this regard should ensure that risks to the supply side, such as generation investment not occurring in adequate time, are minimised.

There are a number of ways that competitive neutrality can be reflected in the arrangements developed for the DRM including through: metering, scheduling and non-scheduling requirements, dispatch, aggregation, settlement, and market participants.

This principle forms part of the high level objective outlined in the draft specifications for AEMO's consideration in developing the rule change proposal. This should address the concerns raised by stakeholders in response to this issue.

5.5.2 Investment signals and wholesale electricity prices

A concern raised by retailers and generators in response to the proposed DRM related to investment signals and the economic value of reduced wholesale electricity prices.[214] Generators contended that spikes in the spot price are needed to signal that new investment in generation is needed. If wholesale spot prices were dampened by the introduction of the DRM, then there would be a risk of new generation investment not happening when it is needed, which adds to the supply side risk.

The SFS Economics consultancy report (attached to a number of submissions from retailers and generators) considered that lower spot prices do not constitute an economic benefit to society, but represent a transfer from producers to consumers. Alinta Energy also put forward a similar argument in their submission.[215]

We have addressed the impact of the DRM on spot prices, and therefore investment signals, in the draft report, and in Section 5.4 of this chapter. We consider that where a consumer can provide a demand response at a lower cost than a peaking generator, and where that demand response provides a substitute to more expensive generation over time, the market will reach a new, more efficient outcome.

We consider that it is crucial for demand response availability to be sustained over a period of time, that is, be reliable. In Section 5.4 we addressed why we considered that demand response under the DRM will be sustained and predictable. In the draft specifications attached to this report we also require AEMO to develop a reporting and performance program for the initial years of the DRM's operation. The program should monitor the impacts of the DRM on system reliability and security, including its utilisation during peak wholesale market demand, and peak load.

We do not consider that lower prices in the wholesale electricity spot market constitute a transfer from produces (generators) to consumers. The DRM's potential impact on wholesale electricity prices represents the avoided cost of funding new investment generation and avoided generation fuel costs. If the need to fund new generation is deferred then it is logical that the wholesale electricity market will signal this through lower electricity spot prices. Ultimately, the potential impacts on the spot price

214 Origin, draft report submission, p. 10; International power, draft report submission, p. 9; EnergyAustralia, draft report submission, p. 5; ERAA, draft report submission, p. 11

215 Alinta Energy, draft report submission, p. 3

resulting from the introduction of the DRM represent improvements to market efficiency.

5.5.3 Hedging risks for retailers and generators

Many retailers and generators raised concern in submissions that the DRM would potentially unbalance hedging arrangements.[216] The following points were made to support this argument:

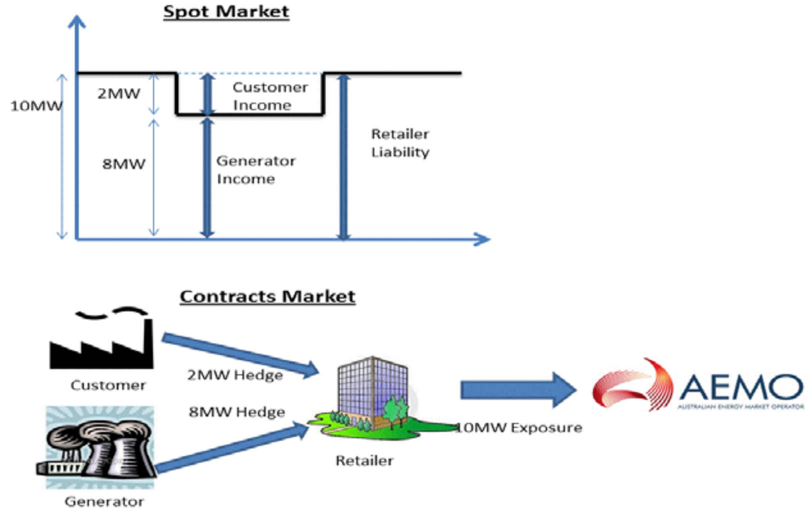
- Under the DRM, generators will only seek to contract to the level of estimated actual demand. However, because of the baseline consumption of a consumer, a retailer will need to contract to levels above its estimated actual demand.
- Or, if the generator hedges up to the baseline consumption level, the DRM will result in generators being over hedged and liable for unfunded difference payments on their contracts. This means that generators will be required to make cash payments on contracts that are not funded by revenue in the spot market.
- If this occurs when spot prices are high (when the DRM is most likely to be used), then generators will be exposed to substantial spot price risk.
- The consumer will not be better off under the DRM as generators will adjust their hedges to reflect the unfunded difference payments. This cost will be passed onto retailers, which will be reflected in higher retailer tariffs to the consumer. The net gain for the consumer could be zero.

We have considered in detail a range of numerical examples provided in submissions to support this argument. In the closed system examples of one generator, one retailer and one consumer, a reduction in electricity demand by a consumer of 2MW would be met with a reduction in output by a generator of 2MW. However, if the generator had contracted with a retailer for 10MW, but was only paid 8MW by the wholesale electricity market the generator would be required to fund the additional 2MW difference in the hedge contract. To respond to this new situation, generators would increase their hedge contracts costs, which would eventually flow through to consumers in higher retail tariffs.

This closed system example does not take into account that the DRM offers a new source of hedging contracts from the consumer providing the demand response. If the closed system scenario recognised this potential, there would be no need for the retailer to contract all 10MW of the estimated baseline consumption with the generator, as 2MW could be sourced from the consumer. Subsequently, the generator would contract to the level of estimated demand and would not be over-hedged or liable for non-dispatched generation. Figure 5.4 illustrates the new contractual arrangements under the DRM, and the role of consumers or third parties becoming a new source of hedging contracts.

216 See draft report submissions from ESAA, National Generators Forum (NGF), the Private Generators Group, Origin, ERAA, International Power, EnergyAustralia, and Alinta

Figure 5.4 Potential hedging arrangements under the DRM[217]



On this basis, generators may lose some of the demand in the contract hedging market, but this is no less an unmanageable scenario than a new entrant generator entering the market and capturing a portion of market demand. Indeed, it would appear illogical for a generator to increase its contract hedging prices in the face of a new entrant generator, given that the purpose of the DRM is to allow demand resources to compete in a manner equivalent to existing and new entrant generation. Subsequently, we consider that, in the longer term, demand response actions are likely to place downward pressure on the price of peaking caps hedging contracts.

More broadly, we consider that the energy market is far more complex than the closed system outlined above, as there are many buyers and sellers of electricity. In the absence of consumers not providing a new source of hedging contracts, it is likely that the 2MW of generation in this example would be lost from whichever is the most expensive operating plant. Therefore, the impacts of the change in actual consumption are likely to be spread across a range of participants, for which the impact is likely to be less than that stated in submissions.

Under the example given, it is not clear why a generator would be exposed to unfunded difference payments where the spot price payment is greater than the contract price. A rational generator would not bid above its contract price in the spot market; to do otherwise would create dispatch risk on behalf of the generator. Further, this means that if all contracted generators did not bid above their contract price, the spot price would not rise to levels above the retail price. In turn, this means we would be unlikely to see any demand response from the consumers, which requires the spot price to be greater than their retail price (assuming that the retailer set the retail price at a level greater than or equal to the generator hedge contract).

217 *AEMC Power of choice review – giving consumers options in the way they use electricity*, final report, November 2012.

In their submission to the draft report, EnergyAustralia argued that an effective contract market is vital to the efficient operation of the NEM.[218] Energy Australia considered that a reduction in contracting across the NEM leads to increased volatility in the spot price, which, in turn, leads to increased costs for retailers that is passed onto consumers. As considered previously, consumers participating under the DRM are likely to provide a new source of hedging contracts as their position in the market changes. This will allow consumers, or third parties with a portfolio of demand response options, to offer contracts for difference up to the level of demand response available through their portfolio, which is similar to the types of arrangements that generators enter into with retailers.

As noted in Section 5.4, the DRM may introduce some costs to retailers. The retailer of a consumer participating under the DRM would need to closely monitor changes to the consumer's load profile. This is because the consumer may need to increase its electricity demand in periods adjacent to the demand response interval. We consider that the costs of this can be reduced by retailers requiring consumers to notify them of where and when the changes in electricity demand are likely to occur. Over time, we would expect that retailers would become experienced in better understanding the consumption profile of consumers participating under the DRM, such that they could predict with reasonable accuracy how consumption will change in those adjacent periods. We note that this is not an issue for consumers that can reduce demand without the need to shift consumption to adjacent periods.

The draft specifications require AEMO to consider the notification arrangements in greater detail when developing the draft rule proposal, and with guidance from the industry reference group.

5.5.4 Baseline consumption

Stakeholders raised concerns that the baseline consumption would introduce a number of risks into the wholesale electricity market that would impact on market participants including generators and retailers.[219] These risks related to the following:

- Baselines are always imperfect and can exacerbate the hedging issues that the DRM potentially introduces into the market.
- The potential for consumers to game the estimated baseline consumption by inflating their electricity demand so that the demand response delivered to the market appears greater than what it actually was.[220]

Performance evaluation methodology and establishing baseline consumptions

In the draft report, we recognised that the process for establishing the baseline consumption is an important part of the DRM design. More generally, inaccurate

218 EnergyAustralia, draft report submission, p. 62

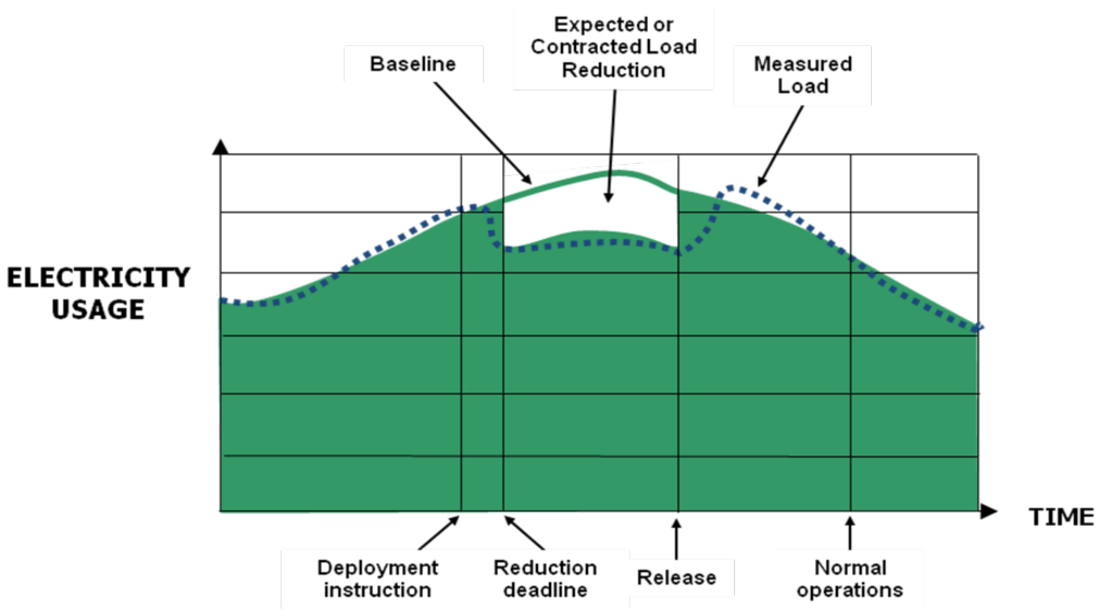
219 See draft report submissions from: Alinta Energy, Origin, International Power, Energy Australia, ERAA, and the SFS Economics report attached to ESAA, NGF and the Private Generators Group submissions.

220 See ERAA, draft report submission, attached SFS Economics report.

baselines and opportunities to game the baseline would undermine the integrity of the DRM and efficiency of demand response in the wholesale market. We consider this aspect of the design will need careful consideration when developing the rule change proposal, as well as when the supporting procedures are developed.

Determining consumers' theoretical 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 5.5. [221]

Figure 5.5 Calculating the demand response



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

Table 5.2 below sets out the key components that are required to calculate a consumer's baseline consumption. Appendix C provides a more detailed description of the various baseline calculation methodologies.

---

221 See Recommendation to the North American Energy Standards Board (NAESB) Executive Committee, *Review and develop business practice standards to support demand response (DR) and DRM – energy efficiency (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.

Table 5.2 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.

The performance evaluation methodology can go some way in dis-incentivising consumers from engaging in gaming opportunities. Components of the performance evaluation methodology, such as 'look back' windows and additive adjustments prior to the demand response interval, can be persuasive in encouraging consumers to maintain actual electricity demand.

For example, the longer the time period for the look back window, the less incentive there is for a consumer to inflate their electricity demand, as it would have to be sustained over an extended period of time which may diminish any benefits to arise for gaming the baseline consumption. Additive adjustments specify a maximum amount the baseline can be adjusted prior to a demand response event. Such adjustments can cap movements in electricity demand above and below the baseline consumption.

We note that in other jurisdictions where baseline consumptions are used, and there has been evidence of gaming, the performance evaluation methodology has been adjusted. For example, the New England Independent System operator remedied gaming opportunities by changing the performance evaluation methodology such that consumers now had 'long tail' load profiles, meaning that the baseline consumption takes a longer time to move. This also included changes to when actual meter data could be used in establishing the baseline consumption.[222]

Principles for minimising gaming opportunities and ensuring accuracy

222 See KEMA, *Analysis and Assessment of Baseline Accuracy*, Final Report, 4 August 2011

In the draft report we developed the following principles for minimising gaming opportunities and promoting accuracy that we consider should be upheld when developing the rule change proposal. These are included in the draft specification attached to this final report.

- *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.
- *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 consumer owned metering equipment, or metering equipment acquired by a third party for the consumer.
- *Accuracy.* The performance evaluation methodology should accurately reflect what the DR participant's consumption would have been if the demand response event did not take place.

To give confidence to the DRM program, and that baseline consumptions are an accurate reflection, we consider that AEMO should develop a statistical method to support its risk assessments of an individual consumer's baseline consumption. For example, a probability of exceedance with a relatively high threshold could be used to ensure baseline consumption accuracy. This may mean that certain types of end-users with a highly variable load may be excluded from participating in the program. However, we would consider that as expertise and confidence in the program grows, the probability of exceedance could be relaxed.

The draft specification also outlines the different types of scenarios that must be taken into account when developing the performance evaluation methodology, and includes:

- the nature of consumption and the use of variable load equipment, maintenance schedules and peak periods for electricity consumption;
- energy efficiency potential of the facility;
- seasonal and weather influences; and
- participation in other demand management schemes, such as critical peak pricing, to avoid these responses being included in the baseline consumption

The extent to which gaming opportunities can arise under the DRM is also dependent on the governance arrangements for establishing the baseline consumption. In the draft specifications attached to this final report, we have asked AEMO to consider the costs and benefits of different approaches for establishing baseline consumption. For example, governance arrangements can place the burden of proof on the consumer to develop the consumption baseline, with the market operator verifying the estimation. An alternative approach may place greater emphasis on AEMO to establish the consumption baseline. In determining the optimal set of arrangements, we have also asked AEMO to consider the needs of consumers and retailers to ensure the integrity of the DRM.

5.5.5 Implementation plan

The process for developing the rule change proposal for the DRM, and its eventual implementation and operation in the market will be long and involved and will require concerted coordination amongst market institutions and industry.

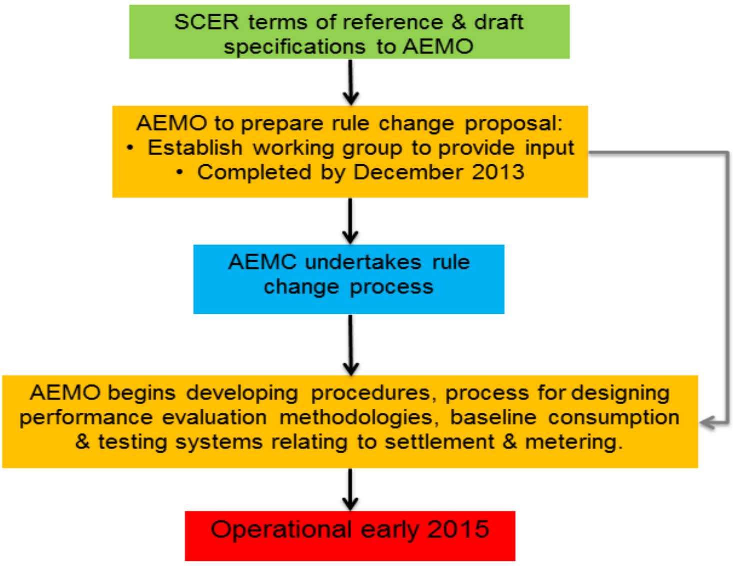
To ensure that policy and implementation issues are considered in adequate detail, we recommend that AEMO develop the rule change proposal for the DRM. Attached to this final report are terms of reference and draft specifications that set out the process and scope of the rule change proposal and procedures. The terms of reference require that AEMO establishes an industry working group to provide input into, and guide the specifications of, the rule change proposal and procedures. While the working group would provide important guidance to AEMO on the components of the rule change, it is AEMO's responsibility to develop the rule change.

The process for developing the rule change proposal and accompanying procedures should be a transparent process. Transparency in the development process should help to inform and prepare market participants for the introduction of new, and changes to existing market design parameter, including metering and settlement, as well of any changes to the expected operation date.

The terms of reference require AEMO to submit the rule change proposal to the AEMC for consideration by December 2013. In parallel AEMO will be required to develop in consultation with stakeholders, procedures to support the development of performance evaluation methodologies and the process for estimating baseline consumptions. Given the detail issues for consideration by AEMO, it is likely that the process for developing these procedures will be lengthy.

Given the time for the AEMC to consider the rule change proposal and for the AEMO to develop systems and procedures to support the DRM, we would not expect it to be in operation before 2015. Figure 5.6 illustrates the process for implementing the DRM.

Figure 5.6 DRM implementation plan



5.5.6 Other issues

Scheduled demand response

The terms of reference and draft specifications attached to the final report outline a number of other policy issues for AEMO's consideration. Specifically, we have asked AEMO to develop arrangements that will enable demand resources to participate under the DRM on both a scheduled and non-scheduled basis, subject to any threshold requirements it views as appropriate.[223]

As outlined in the draft report, including demand resources in AEMO's central dispatch process will assist AEMO to accurately forecast demand, thereby leading to efficient dispatch volume and pricing. In order to develop a suitable framework for the participation of scheduled and non-scheduled demand resources under this mechanism, AEMO should:

- review the current scheduling requirements and assess their adaptability for the type of consumers likely to participate under this mechanism; and

223 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.

- consider reporting and monitoring arrangements for non-scheduled demand resources delivered under the 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.

Transparency

The integrity of the DRM should be supported by transparent procedures and information being readily available to the market. Readily available information should reflect similar arrangements to those in place for generation and load, such as the location and quantity of demand response delivered to the market. It may be necessary for the purpose of system security to provide even greater clarity of information for DNSPs, which we consider can be resolved through notifications processes.

Information regarding entities registered under the program, aggregators acting on their behalf and the amount of demand response being made available to the market under the DRM should also be readily available to the market.

All of these types of information should be published on a frequent basis, such as on a quarterly basis. We have asked AEMO to consider the frequency with which this information should be published and have provided some guidance as to the types of information that should be published. We have also asked AEMO, with guidance from the working group, to consider what other information should be made available through this reporting function.

Performance and reporting program

Given the uncertainty on the rate of uptake under the DRM, we recommended that a performance and reporting program is included during the initial years of operation. The 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.

Notification

In the draft specifications we have asked AEMO to consider a notification process to signal to the market a consumer's intention to enter into a demand response interval. The notification process should be designed in such a way as to maintain accuracy and efficacy of the market operator's central dispatch, and to ensure that entities impacted by the demand response action have sufficient notice. This requirement may also extend to network businesses potentially impacted by this action.

The notification process may also require a participating consumer to estimate the period in which the demand response action will be sustained, and when it expects electricity demand to return to 'normal' pre-dispatch levels.

National Measurement Act

We have considered whether calculating a consumer's baseline consumption is consistent with the National Measurement Act. The Act only prescribes conditions that are to apply when an Australian unit of measure, such as kWh or kW, is used to determine the value of a good. However, if the value of a good is determined without use of an Australian unit of measure, then the Act does not apply.

Hence, a consumer's baseline consumption can be developed as an estimate that is partly based on an Australian unit of measure, and partly based on other data. The baseline can be applied to actual metered data to determine a difference in consumption without infringing on the Act's provisions. A similar arrangement has been in place for the Greenhouse Gas Abatement Scheme in NSW over the last 10 years.

New category of market participant

In the draft report we asked stakeholders whether a new 'sub-category' of market participant (most likely under the category of market generator) would be required to facilitate participation of consumers in the DRM. In its submission to the draft report, AEMO suggested that this issue should be considered in conjunction with the need to create a new category of market participant for the provision of non-energy services (see Section 5.11).

We agree with AEMO's recommendations and have asked AEMO to consider this issue more closely when developing the rule change proposal for the DRM. The rule change proposal will provide the opportunity to consider in detail the costs and benefits of this proposal, as well as the potential uptake. We consider that where it is feasible, AEMO can provide a separate rule change proposal on the new category of market participant.

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 AER'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 (RERT).

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 actions represent the greatest majority of demand side response. However, there is poor visibility of the volume of this response to AEMO, and therefore the market.

In their submission to the draft report, AEMO noted that networks, along with retailers and aggregators, provide an important source of information about non-scheduled demand and generation response, by way of their:

- direct control of small generators and loads in order to manage network congestion; and
- impact upon consumption when invoking critical peak pricing.[224]

AEMO considered that this information could be fed through to them as soon as a decision is made to invoke the response to inform demand forecasting processes.

Other stakeholders generally supported the proposal to improve clarity regarding AEMO's role in demand forecasting.[225] However, some network businesses raised concern that the creating such a role for AEMO would result in a central planner approach. For example, if forecast penetration of DSP does not occur as planned, and the extent of DSP on the day required does not eventuate, networks will not have the capacity to meet the needs of consumers for a safe and reliable supply.

We consider that an expected increase in the uptake of DSP in the NEM over the next 15 to 20 years will entail AEMO developing a more sophisticated understanding of price responsive DSP as it relates to their market operations. This information can be used by the market and participants to support and improve the quality of decision making in relation to electricity production and consumption.

We consider that network businesses will prepare their own forecasts of demand for their network areas, and that this information would be used in preference to, or in conjunction with, the information provided by AEMO regarding DSP capabilities in the NEM.

5.7 Demand forecasting

RECOMMENDATION

We recommend that:

- **The NER is clarified regarding AEMO's role in to demand forecasting for its market operational functions.**

224 AEMO, draft report submission, p. 6.

225 See draft report submissions from EnergyAustralia, AER, SP Ausnet, GridAustralia, Clean Energy Council, Greenbox, and Total Environment Centre.

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

We recommend that the rules are amended to include a high level clause that clarifies AEMO's information gathering powers[226] in relation to its market operations such as the Projected Assessment of System Adequacy (PASA) reports and pre-dispatch modelling. The clause should outline that AEMO must report on, and attempt to represent, managed non-scheduled load and non-scheduled generation in relation to:

- 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.[227]

An overarching obligation should also be placed on AEMO to require it to update its expectations regarding DSP capabilities in the NEM on a regular basis, as they relate to its market operation functions.

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

In addition to these amendments to the rules, we also recommend that AEMO clearly outline in its procedures the process and requirements for collecting information from participants on non-scheduled load and non-schedule generations. The procedures should also outline any processes that AEMO may undertake, if at all, to assess the compliance of participants in providing information by comparing to an ex-post analysis of a consumer's behaviour.

Draft specifications for this rule change proposal are attached to this final report.

5.8 Rationale

Currently, the rules provide AEMO with specific guidance on its ability to gather information with respect to pre-dispatch, Short Term PASA,[228] (ST PASA), Medium Term (MT PASA),[229] (MT PASA) and the Electricity Statement of Opportunities

---

226 For the various clauses relating to AEMO's demand forecasting responsibilities, see NER clauses: 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.

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

228 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.

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

(ESOO).[230] The rules do not outline any specific requirements for AEMO to develop forecasts with respect to non-scheduled load and non-scheduled generation. The combination of these two factors means that AEMO does not have clear enough guidance on its ability to gather information regarding DSP capabilities in the NEM.

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

We consider that there is scope to better enable AEMO to perform its responsibilities with respect to demand forecasting, and to improve its ability to forecast price responsive DSP in the NEM. Under the proposed changes, AEMO will be able to develop a better understanding of the factors that drive average and peak demand in the NEM, and more broadly in the national market.

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. In the shorter term, participants can benefit from improved market signals to enhance the quality of their decision making as it relates to either electricity consumption or generation. In the longer term, improvements in the quality of decision making enabled by accurate pre-dispatch, should lead to a better allocation of resources, and therefore potentially more efficient investment in generation and networks.

The proposed DRM encourages price responsive DSP in the wholesale market, that is in addition to any DSP actions coordinated through the bilateral contracts between a retailer and consumer. It is expected that over the next 15 to 20 years there will substantial additional DSP stock operating in the market. In this regard, demand forecasting will likely play an increasingly important role in understanding the level of activity of DSP in the market, and also assisting in efficient decision making on behalf of consumers providing a demand response.

For example, prior to entering into a demand response interval under the proposed DRM or any existing demand response arrangements, a consumer will need to make an economic decision that is based on the potential value of providing a demand response according to plant operating levels. For consumers, the risks involved in making such decisions are minimised when pre-dispatch price signals closely reflect actual dispatch. Pre-dispatch timeframes as particularly important as price responsive demand side resources use this information to ascertain the potential value of providing a demand response.

There may be administrative costs to the market and 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

230 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.

have the required information on DSP capabilities. The market benefits therefore are likely to outweigh the costs of increased reporting obligations.

5.9 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).[231] 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 in the market. We also recommend that AEMO be required to use this 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 requests information in relation to interruptions that would occur in Market Price Cap[232] conditions, which, although useful to AEMO in forecasting reliability, 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 on an annual 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 price 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.

---

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

232 The NER sets a maximum spot price, also known as a Market Price Cap, of $12,900 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 describes how improved demand forecasting could potentially be used by AEMO to develop a pre-dispatch schedule for non-scheduled demand response.

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. However, these prices are 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.

5.10 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[233] and meet a number of requirements which were 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[234] 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

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

234 We consider 'non-energy services' to be 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.

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 there is potential for the associated demand response to have negative financial implications. Submissions on this noted that third parties, such as aggregators, may wish to provide ancillary services from loads, but are precluded from doing so because the registration provisions in the rules effectively require that they become retailers in their own right.[235]

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

5.11 Creating new category of market participant

RECOMMENDATION

- **We recommend that a new category of market participant is introduced 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 why the provision of ancillary services should be bundled with either the consumption or supply of electricity, as per 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 new 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. This is consistent with the current situation of registering a generator and classifying it as an ancillary service unit.[236]

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

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

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

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.

5.12 Considerations

A key feature of the proposals outlined in this chapter is that the sale and supply of electricity is unbundled from non-energy services, including the ability to provide a demand response. In this regard, the issues involved in creating a new category of market participant for the provision of non-energy services has application to facilitating the participation of consumers and third parties under the DRM.

As described in Section 5.2, stakeholders expressed concern that the sale and supply of electricity cannot be unbundled from the provision of non-energy services, including ancillary services and demand response. This means that a consumer with the flexibility to benefit from a reduction in electricity demand could only do so through its supplier of electricity – a retailer.

For this reason we consider that the development of a rule change proposal to introduce a new category of market participant should happen in conjunction with the development of a rule change proposal for the DRM. This is AEMO agreed with this approach in its submission to the draft report.[237]

237 AEMO, draft report submission, p. 7.

6 Efficient and flexible pricing

Summary

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 energy usage and costs.

Addressing these issues will require a balance between managing consumer impacts, addressing the needs of vulnerable consumers and strengthening the arrangements for retailers and distributors to set prices more cost reflectively.

We propose the above objectives are met in the following way:

- A gradual phase in of efficient and flexible retail pricing options for residential and small business consumers through the introduction of cost reflective electricity distribution network pricing structures. The phase in of cost reflective network pricing would be through segmenting these consumers into three different consumption bands and applying flexible, (ie time varying) retail pricing options in different ways:
  - Large residential and small business consumers above a defined annual consumption threshold will be required to have an efficient and flexible network tariff as part of their retail price offer (this group of consumers are referred to as Band 1).
  - Medium residential and small business consumers - with an annual consumption level below the band 1 threshold but above a small consumer defined threshold, will transition to a retail price offer that includes an efficient and flexible network tariff. This only applies to those consumers who already have a meter with interval read capability which enables-such flexible retail price offers. These consumers (band 2) will have the option not to move to a flexible retail pricing offer but instead remain on their existing retail price structure.
  - Small consumers (ie all other residential consumers and small businesses) - with consumption below the small consumer threshold will remain on their existing retail price structure (band 3). Those consumers in this band which have with the appropriate enabling metering technology will be able to choose an efficient and flexible retail price offer, if they so wish.

We are proposing that jurisdictions develop transition plans that would include a series of stages to implementation. Consumer education and information is to occur before introduction of pricing reform changes.

- To complement the gradual phase in of efficient and flexible retail pricing options and support those consumer with limited capacity to respond we recommend that:
  - governments review their energy concession schemes and target government energy efficiency programs. This is to ensure adequate information and protections are in place for those consumers with limited capacity to respond/ change their consumption.
- Amend the NER distribution pricing principles to provide better guidance for setting efficient and flexible network price structures that support DSP. This includes improving the existing consultation requirements to ensure that consumer impacts are taken into account in price structures/design.
- Amend the NER to require that a residential and small business consumer's consumption (where they have a meter with interval read capability) is settled in the wholesale market using the interval data and not the net system load profile. This will be the case irrespective of the consumers' retail tariff structure.

6.1 Market conditions for uptake of efficient DSP

Electricity retail prices that accurately reflect network and other supply costs are an important condition in promoting the uptake of efficient DSP in the electricity market. If consumers have access to prices which reflect the costs of supplying electricity at different times of the day and/or year, many may choose to reduce or cease consumption in these high demand periods, which may both reduce their electricity costs in the short term, and avoid the need for some investment which would otherwise be required in the long term.

With such retail pricing structures, consumers electricity costs will depend upon their own consumption pattern and therefore would be appropriately rewarded if they adapt their consumption patterns and shift usage to off peak periods.

Other consumers may prefer the certainty of a tariff that does not vary with time, even if that tariff includes a premium for the retailer to take on the price risk. Where tariff structures (including any risk premium) are transparent and consumers are informed about the options, any consumption choice they make will be equally efficient. We note that price will only be one component of a decision on when and how much to consume; other factors such as convenience, awareness and understanding will also determine consumption behaviour, as described elsewhere in this report.

Perfectly efficient electricity prices would mean that for each unit of electricity consumed, consumers are charged the full costs (and no more) that are incurred in supplying that unit of electricity. This means that (a) suppliers recover the costs of providing electricity; and (b) consumers spend no more than they need to on the services that electricity provides. Where prices are higher than the cost of provision, some consumers will choose not to consume an extra unit even though they would be willing to pay the cost of producing that unit.

Currently, most residential and small business consumers do not face cost reflective prices for their consumption. As we identified in the directions paper, consumers generally face flat[238] or inclining block prices,[239] which bear little relationship to the actual impacts they impose on network and electricity supply costs. For example, inclining block tariffs provide some signalling by increasing the level of the charge once a particular consumption threshold has been reached, but they do not reflect that actual costs consumers are imposing on the network and are unlikely to be effective.

This chapter considers the improvements that can be made to market and regulatory arrangements to better facilitate cost reflective pricing for residential and small business consumers.

Cost reflective pricing in theory and in practice

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 structure reflecting these characteristics would include the following:[240]

- A variable component that recovers efficient wholesale energy costs. Wholesale costs refer to the costs retailers incur when acquiring electricity in the wholesale market to supply the needs of their consumers. 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 the fixed network and retail costs and does not vary by time or location.

---

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

239 Inclining block prices 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

240 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.

In practice, there are limitations on achieving complete cost reflectivity for consumers, even with enabling metering technology in place. This is due to the difficulty of:

- designing associated network and retail tariff structures,
- 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 spot price is unlikely to be viable or desirable for most residential consumers; and designing network tariffs for every consumer that reflects 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.[241]

Consequently, when we refer to cost reflective prices – which we label as flexible pricing - in the context of this review we do not mean prices that are perfectly cost reflective from a theoretical stand point; rather we mean prices that will provide a more efficient signal to consumers for valuing consumption and energy services than those which exist currently. Below we discuss what such pricing options might look like.

Efficient and flexible pricing options

Flexible pricing, or prices that vary depending on when consumption occurs, is not new concept. In fact, this approach to pricing is already used in many other industries. Airlines, hotels, parking meters and car rental companies are some of the most common examples of industries that dynamically vary prices in response to fluctuations in demand. The advent of smart meters now makes such pricing approaches viable for electricity markets. There is an increasingly wide range of flexible pricing options, either currently available or in their trial stages, providing varying degrees of cost reflectivity compared with existing arrangements. These can broadly be categorised into energy based pricing options and demand based pricing options.

Energy based pricing options

Energy based pricing options include time of use (TOU) and variations of TOU such as seasonal TOU, full wholesale spot price pass through (real time pricing (RTP)); critical peak pricing (CPP); variable peak pricing (VPP) and peak time rebates/incentives. These options operate through a price that varies by when consumption occurs and is

241 There is an information sheet on the AEMC website that explains the different components of the electricity price. See http://www.aemc.gov.au/Media/docs/Information%20sheet-b6ea33d3-73c8-4e89-b767-d619f3149d3e-1.PDF.

based on $ per kWh. The standard TOU simply applies a different price during peak and off-peak periods (and sometimes shoulder periods).

CPP is a form of TOU pricing which sets a price that is significantly above the peak price during a small percentage of hours each year to reflect seasonal system peaks (for example, the price can be usually more than 5 or 7 times that of non-peak periods).

Prices during non-peak times will then be reduced below the regular rate. These pricing options can be used by retailers to signal peaks in wholesale costs or by distribution businesses to signal system peak demand impacts on the network.

Critical periods are generally pre-specified and consumers are given forewarning over when they are going to occur so that they are able to adjust their behaviour. Consumers are typically notified one day in advance of a critical peak event, and these are generally called on the few days when wholesale prices are the highest or when the network is most stressed (i.e., typically up to 15 days per year during the season(s) of the system peak).[242] The CPP is relatively simple to calculate and understand for consumers, which makes it a desirable implementation option. We note that CPP is currently used in a number of the Solar Cities trials.[243]

VPP is a variation on CPP where the CPP is not a pre-specified fixed price but the real time price applying during the critical peak period. RTP is simply full pass through of wholesale spot prices to consumers. While the consumer would be exposed to full cost reflectivity of wholesale spot prices, this would also have the effect of shifting the full risk of managing pool price volatility onto the consumer. This may not be a desirable option for most residential or small business consumers who are unlikely to be in a position to respond to prices on a half hourly basis.

Peak time rebate (PTR) uses rebates to encourage participating consumers to reduce their consumption (estimated relative to a forecast of what the consumer otherwise would have consumed) during critical peak events. Under a PTR approach there is no price discount during non-peak event hours, but consumers also face no additional price increases of not reducing their consumption during peak times - they just pay the existing rate.[244] An important limitation of PTR approaches is that the demand reduction to which the rebate applies needs to be verified against a baseline. This option is therefore more complex to implement, and issues arise with respect to how to the baseline should be determined.[245]

These options can 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

---

242 The Brattle Group, *Managing the costs and benefits of Dynamic Pricing in Australia*, Ahmad Faruqui, PhD, Neil Lessem, PhD., 21 September 2012, p 7

243 See information on the Solar Cites website at: http://www.solarcitiesaustralia.com.au

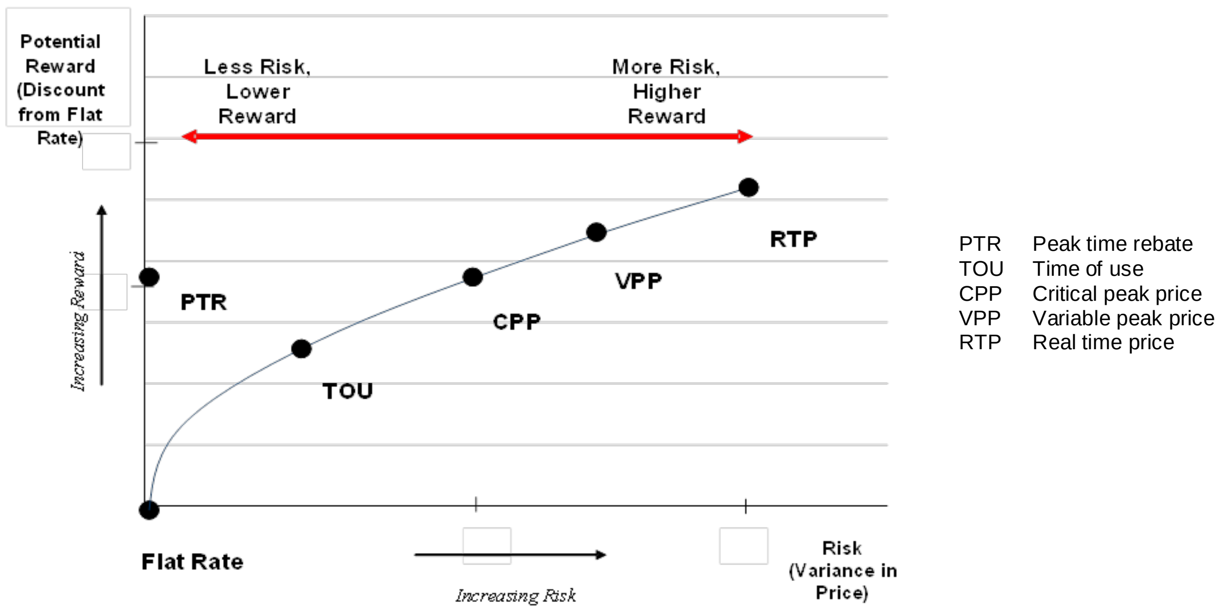
244 Ibid, p 8

245 Ibid, p 8

these options is a price that varies over time to capture the impact of consumption on the costs of electricity supply at different times.

We summarise the key options in Appendix E, and illustrate in Figure 6.1 below that they imply different levels of risk versus reward for consumers.

Figure 6.1 Flexible pricing options[246]



Demand based pricing options

Demand charges (which are sometimes referred to as capacity charges) apply to the network component of the retail tariff structure. Unlike existing network charges which applies a price in cents per kWh; demand based pricing applies a price in dollars per kW or kVA per day.[247] Demand charges are of a static character, as they generally charge the consumer's demand peaks at a predetermined rate. That rate is calculated to reflect the incremental cost of providing network capacity to the consumer.

Network costs are driven by the size of the peak demand, i.e. the highest coincident level of consumption at any one point in time. This tends to occur for only a few hours every year, while wholesale costs can vary every 5 minutes. The objective of a demand charge is to align the charge paid by consumers with the cost structure of electricity networks. This is because most of the costs are directly related to the capacity of the grid, which must be large enough to transport the peak demand, which occurs only

246 Source: The Brattle Group, Managing the costs and benefits of Dynamic Pricing in Australia, Ahmad Faruqui, PhD, Neil Lessem, PhD., 21 September 2012

247 While these are usually interchangeable kVA differs from KW in that it includes the reactive power of the load, and is therefore technically considered to provide a more accurate measure of the impact of load on the network

during a couple of hours each year. Furthermore, demand charges would provide more revenue certainty for networks.

The effectiveness of demand charges in minimising network costs depends on whether they provide strong enough signals to consumers about the costs of their consumption at times of peak network demand and to reward consumers for changing their consumption patterns. This will depend upon the methodology used to determine the demand charge and whether demand should be based on individual consumer peaks or system peak demands. Some of the options for the methodology are discussed below.

Anytime maximum demand approach

This approach applies the predetermined rate to the consumer's peak use over a relevant period, say a month or season. Preferably demand would be estimated on a weekday and at the time of the typical daily peak. For example, the demand charge is settled and billed on a monthly basis for highest registered hourly kilowatt consumption on working days between 2 pm and 8 pm. An example of this approach is discussed in the case study in Box 6.1.

This approach has a number of advantages. The first is that it is relatively straight forward to calculate. Secondly, because it is straightforward to calculate, it makes it relatively simple for consumers to respond to the price signal. A consumer knows that if it is able to reduce its maximum demand over the relevant period it will be rewarded with a reduced bill.

A limitation of setting a demand charge on the basis of a consumer's own anytime maximum demand is that it may not be aligned with local maximum demand. A consumer's own maximum demand will only impact on network costs if it is coincident with local peak demand. It is not clear, however, how material this problem actually is. This is because there is good reason to expect that for most consumers their own maximum demand would be reasonably aligned to maximum demand at their location on the network.

Historical coincident maximum demand approach

The second approach is to base the network price on the consumer's contribution to peak demand when it occurs. In order to account for possible variations in consumption on peak days a typical approach might be to take an average of a consumer's maximum demand on the five peakiest days over the past 12 months. A variation to this approach would be to make it more forward looking by basing the price on that consumer's use of the network during expected peak demand periods. This would make it similar to a CPP approach, and like that approach it would be important to give consumers advanced warning of when the price would apply, so that they can effectively respond to the signal.

Defined capacity allowance

Under this approach, the consumer is either allocated a fixed level of capacity of buy an amount of capacity for use on maximum demand days. This approach would be similar to consumers choosing a download limit from their internet service provider. The charge would reflect the network cost associated with providing that level of capacity on a maximum demand day. The consumer would be incentivised to keep their consumption within the allocated or nominated capacity and pay an additional charge where they consume more than their capacity allowance.[248]

Our view on demand charges

Demand charges are currently permitted under the current rules and are applied to commercial and industrial consumers. Aside from trials run by the distribution businesses, demand based charging is not yet available for residential and small business consumers. This means that there is a need to consider the implications of a transition to this form of charging for these consumer types.[249]

Under our proposed changes to the distribution pricing principles, such demand charges will still be permitted. Networks will have new obligations to have regard to consumer's understanding of such charges and their ability to respond.

Demand charging would be a fundamentally different approach to electricity network pricing for residential and small business consumers. Therefore, prior to it being introduced it would be necessary for a targeted and comprehensive education campaign to be employed. The main objectives of the education campaign would be to explain what demand charging is and how consumers can minimise their maximum demand. This is so consumers are armed with sufficient information to enable them to be able to reasonably predict the impact of demand charging on their overall electricity costs. This will be a requirement under our proposed rule change.

In section 6.3.6 we propose to implement a number of measures that will require distribution businesses to take proper account of the potential impacts of new network pricing options on consumers. That is they need to be simple, understandable and capable of being responded to. Also we are proposing the need for consultation on network tariff structures with retailers and consumers groups.

A concern that has been identified with respect to demand charges is that it will lead to a larger proportion of consumers' retail bills being recovered through a fixed demand rate. This is because the charge is intended to be set at time of the consumer maximum peak demand and will not change over that period even if consumption is reduced substantially in other periods.

248 Such a charge would only need to be applied on maximum demand days given all other times breaching a capacity allowance would have no impact on the costs of the network.

249 We understand that SA Power Networks is about to commence a trial of demand tariffs for residential customers in South Australia, This aims to determine how well such customers will understand them, and to what extent they will respond to the highly cost reflective pricing signals they offer.

What impact this would have on the overall cost of electricity for a consumer would depend on their maximum demand at the time of local peak demand and their total volume of electricity consumption over a year. Given the basis for determining a demand charge, those consumers that use less electricity at times of network peak should expect a lower charge than those that have higher demand at this time. A demand charge which is based upon monthly peak demand might be easier for consumers to understand and manage than a demand charge calculated on the consumers maximum peak demand over the past year. It is likely to be very hard for a consumer to remember what its usage and consumption pattern was on that one day.

The incentive for consumers, therefore, is to reduce demand at times of local network peak to the extent it is possible to do so. If consumers respond to this signal by reducing their demand at times of network peak demand, it will potentially allow for network augmentations to be deferred or avoided altogether. This in turn would reduce the overall costs of supplying electricity. However while demand charges may provide more certainty for consumer in their electricity costs, this could have negative implications for consumers who have low consumption levels.

Will consumers respond to flexible pricing options?

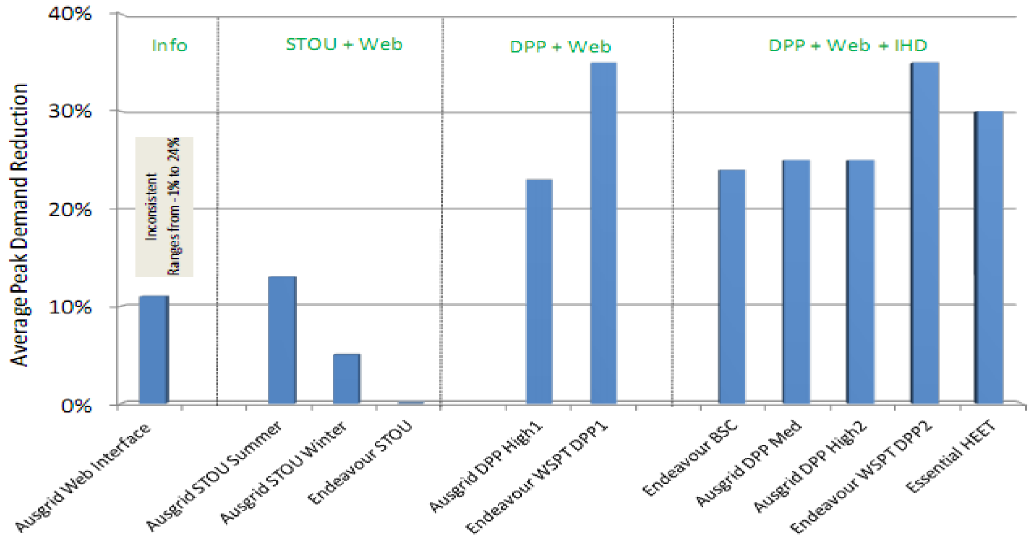
The key purpose for implementing flexible pricing options is that this better reflects the actual costs of supplying and transporting energy to consumers, which means they can more accurately value, and thereby efficiently respond to, ways to help minimise these costs over time. This in turn will ensure energy expenditure is as low as efficiently possible 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. Nevertheless, we believe that prices play a central role in driving efficient consumption decisions. Work we commissioned from Futura Consulting for the directions paper shows that where consumers are exposed to flexible prices they will respond, with peak demand reductions of up to 30 or 40 per cent achieved in a range of domestic and international trials.[250] This indicates that expanding the scope of flexible pricing options in the NEM could drive significant longer term reductions in system costs.

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 flexible prices in the NEM. It also shows that the impact can be greater where the prices are supported through better communication channels (for example, webpages or in house displays).

250 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, p 24

Figure 6.2 Summary of peak demand reduction results from DSP trials in Australia[251]



Analysis of international flexible pricing pilots demonstrates the willingness of consumers to respond to flexible pricing options. In their submission to the draft report AGL shared their analysis, which clearly demonstrated that how a flexible pricing option is packaged – including information and enabling technology - is a key determinant of the level of response from consumers. In particular, AGL's analysis shows that successfully packaging enabling technology, such as metering, delivers the highest level of demand response from consumers.[252]

Box 6.1 is a case study of SPAusnet's distribution network CPP for commercial and industrial (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.

While flexible pricing will act to influence consumer demand directly, it is also important to note flexible pricing options improve the economic attractiveness of certain types of distributed supply resources, such as rooftop solar with energy storage, which allow owners to avoid consuming electricity during higher priced peak hours. Flexible pricing options may also be a way to encourage more efficient charging of electric vehicles. In our electric vehicles and natural gas vehicles review, we found that if users of these vehicles 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 expenditure.

While achieving longer term reductions in total system costs is one reason to transition to more flexible pricing options, another is to provide consumers with the information and tools necessary to maximise their welfare.

---

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

252 See AGL, draft report submission, p. 12. Note that the underlying data for AGL's analysis was provided by Dr Ahmad Faruqui from The Brattle Group, from the 2010 article "The ethics of dynamic pricing", *The Electricity Journal*, 23(6): 13 – 27.

Box 6.1 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:

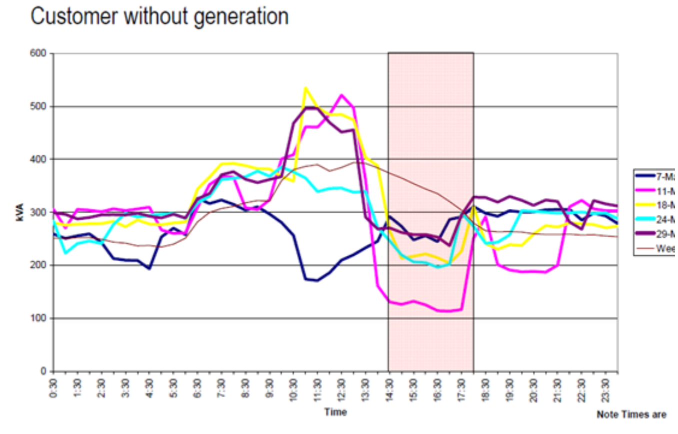
- Summer days that are nominated and communicated to consumers at least one day in advance. SP AusNet uses both SMS and email to notify its consumers of the intended critical peak period.
- The period is only ever between 2pm – 6pm on the nominated day.
- The five maximums are averaged and used as the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

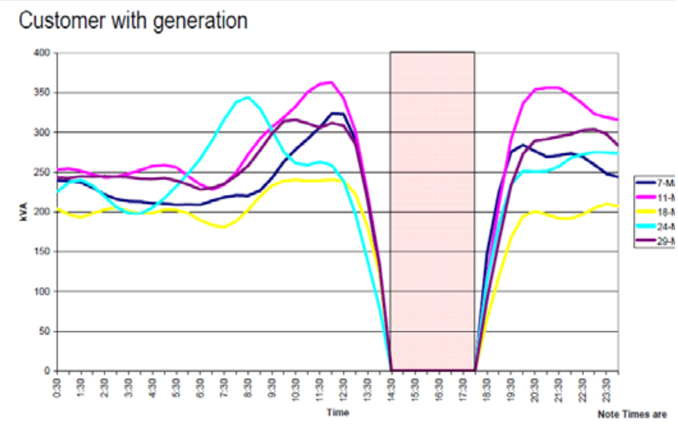
- Two thirds of all consumers responded by reducing demand; and
- Over 300 reduced peak demand by more than 50 per cent. Of these, 75 reduced peak demand by more than 90 per cent.

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.

Under existing retail tariff structures, the share of network and wholesale costs for each consumer is determined on the basis of an average consumption profile applied to all consumers (who do not have the appropriate metering technology). This means that consumers wishing to reduce their energy expenditure by adjusting their consumption pattern will not realise the full benefits of doing so; rather these benefits are shared with all consumers settled on that profile.

Metering data combined with better price signals will increase consumers' awareness of their own consumption patterns and their understanding of what is driving their costs. This in turn will create stronger incentives for consumers to implement measures and strategies to help reduce their energy expenditure (since they will capture the full benefits in doing so).

It is important to note that more flexible pricing options 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 flexible pricing. We discuss this potential cost in Chapter four. 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 price period (including the upfront costs of appliances used for reducing or shifting consumption).

There has been a range of empirical work undertaken on estimating the potential benefits of residential consumers moving to flexible pricing options. 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 regulated flat prices, with 69 per cent of consumers better off under flexible pricing. They also found that on average families were using 78 per cent of power outside peak times.[253]

In another study, AGL found that over 37 per cent of consumers would be significantly better off under flexible prices, and approximately 31 per cent would be overall worse off, while the remainder would be indifferent.[254] This however, assumes no change in the consumer's consumption patterns. One of the key findings of flexible 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.[255]

Flexible 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 flexible prices are necessary, they are not a sufficient condition on their own to facilitate efficient DSP. They may

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

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

255 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

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

Are flexible pricing options 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 most 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 very difficult for the consumer 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 also 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 across residential consumers. Under these DSP options, the consumer 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 flexible pricing options 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 retail tariff structure which the consumer is on. If the consumer is on a retail tariff that does not vary with time, the business would need to offer a larger reward to compensate the consumer for altering its consumption pattern. In addition, in the absence of interval metering the consumer who participates 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 the consumer will not be able 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 structures set at points within the distribution system (i.e., at the sub-station level).

The first approach seeks to segment the current NSLP, on which retailers are settled, into a number of different load profiles that better capture the impacts of different groups of consumers. This was approach was used in the United Kingdom 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.[256]

We have published a paper from Oakley Greenwood with the Power of choice draft report which assessed the viability of this option.[257] 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, and the benefits could be more easily delivered through interval metering.

The second approach is based on a more limited application of flexible pricing. There would be an interval meter and an associated flexible network tariff set at substation connection points. The network tariff would be applied to retailers who would then have the option of passing it through to their consumers, many of whom would not necessarily have smart meters. Under this approach retailers, in principle, would have an incentive to encourage consumers to install smart meters so the retailers could better manage the risk of being exposed to the flexible network tariff.

This is an approach which has been applied in New Zealand where Orion has introduced demand based charging at an aggregated level; 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 expenditure relates to transmission costs. While the MEU agreed that network tariff structures 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 a smart meter. We consider that the full benefits of DSP are unlikely to be achieved without deployment of smart meters and cost reflective pricing for consumers.

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

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

6.2 Issues identified

There are a number of issues that are contributing to the current lack of flexible pricing in retail markets for residential consumers. There are two core themes: a lack of consumer engagement with flexible pricing options and weak incentives for retailers and network businesses to introduce flexible pricing and the underlying metering technology to support it.

First, flexible pricing will expose consumers to a range of new and potentially complex tariff structures. Retailers may be reluctant to implement flexible pricing if there is a lack of interest or acceptance for them to do so. In this regard it is important to note that not all consumers will benefit from flexible 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 retail bills.

We consider that unless the needs of these consumers are specifically addressed, it is unlikely that such flexible pricing options will attract broad public acceptance. Eliciting consumer engagement is a critical aspect of realising the benefits of flexible pricing and this will depend on how the transition is managed.

Second, also important is the extent to which retailers and network businesses themselves have an incentive to implement flexible pricing. A lack of metering capability is a key factor and our recommendations for supporting investment in better metering technology are set out in Chapter four. Improving arrangements for metering is a necessary but not sufficient condition for flexible pricing. Whether flexible pricing becomes prevalent will also depend upon the extent to which it is profitable for retailers and can lower costs for network businesses. There may also be other impediments in the regulatory arrangements that may discourage distribution businesses and retailers from offering flexible prices to residential consumers.

To address these issues we consider an integrated strategy is required. One that removes regulatory impediments and strengthens incentives for retailers and network businesses to implement flexible pricing options, while at the same time making sure that consumers have sufficient understanding of, and confidence in, the benefits that flexible pricing can deliver for them. The approach we propose comprises the following key components:

1. Arrangements that support investment in metering technology (see Chapter four);

2. Garnering consumer confidence by:

   (a) educating and informing consumers;

   (b) addressing the needs of vulnerable consumers; and

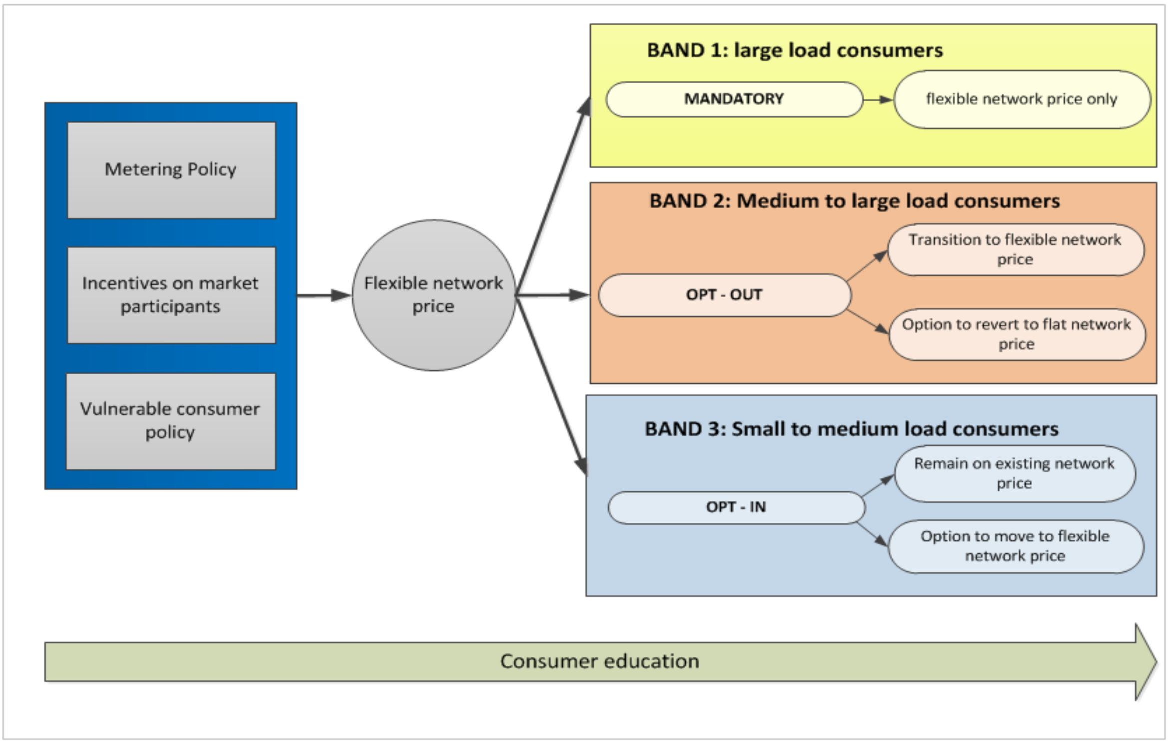
(c) phasing in flexible prices in a way that manages consumer impacts (we propose a gradual process beginning with large residential consumers).

3. Amending the rules to ensure that network businesses have the appropriate obligations and latitude to implement flexible tariff structures.

4. providing arrangements which appropriately address any risks that retailers might face under flexible tariff structures.

We set out our proposed approach diagrammatically below.

Figure 6.3 Strategy for introducing flexible pricing



While over the short term, exposure to flexible pricing will impact consumers in different ways, over the longer term we envisage that flexible pricing should lower energy expenditure for all consumers, due to more efficient consumption patterns. Hence it is important that the arrangements for managing impacts on consumer expenditure in the short term (the first round effects) do not undermine the ability to capture the benefits of better asset utilisation and lower system costs over the longer term (second round effects).

We also note that the SCER Smart Meter, Consumer Protection and Safety program is considering a range of issues associated with the roll out of smart meters, including price based DSP products enabled by smart metering technology. It is also considering how NECF arrangements might need to be amended in light of the roll out of smart meters.

6.3 Considerations

6.3.1 Impacts of flexible prices on consumers

Before we set out our recommendations for change it is important to consider how consumers might be affected by these recommendations. Understanding the impacts of moving towards flexible pricing for small consumers is necessary so that such pricing options are implemented in a manner that provides for both:

- an opportunity for consumers to understand and respond to those impacts; and
- more informed consideration of how to protect those consumers who have difficulty in managing such impacts, and which affect the consumer's financial ability to meet their electricity expenditure.

How the current retail tariff structures allocate system costs across consumers, and the extent to which introducing flexible pricing changes that allocation, will largely determine the nature of consumer impacts. Energy and network costs are spread evenly across the vast majority of residential and small business consumers, resulting in each consumer paying a proportion of total costs that depends on their absolute consumption level, rather than when they consume.

There are two reasons for this. First, wholesale energy costs are recovered on the basis of the NSLP and not the individual consumers' consumption patterns. In most cases, each consumer faces the same unit charge for electricity irrespective of when they consume electricity. Second, distribution network businesses similarly tend to recover their costs on a total consumption basis for the majority of residential consumers, which means residential consumers once again face a network charge that does not vary depending on the profile of their consumption, or the location where they consume. Overall, this results in cross-subsidisation across residential consumers, with those who have a lower than average peakiness in consumption subsiding those with above average peakiness in consumption.

Moving to more cost reflective pricing, including the installation of better metering technology, will reduce this averaging effect. It will allow for consumer's electricity expenditure to be based upon their individual consumption pattern. Therefore, consumers who use more electricity in the peak hours than the average consumer would see higher electricity expenditure, while consumers who use less electricity in the peak hours than the average consumer would see lower electricity expenditure.

While this reflects a more equitable allocation of system costs, some consumers may face a level of 'price shock' as their overall electricity expenditure increases. As discussed in Chapter two, 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 education strategy that resonates with consumers, there are other ways to help them understand and benefit from flexible prices. One is to provide consumers with information on their usage profiles and likely impacts of flexible pricing for a period before flexible pricing is introduced.

The other is to offer products that provide 'bill protection' for a core volume of consumption, with opportunities to experiment with flexible pricing for consumption in excess of this level of consumption. This would give consumers a level of protection while at the same time offering them a chance to become familiar with flexible prices at the margin with limited impacts on bills. We have published a paper from The Brattle Group which describes such bill protection pricing products, which may be provided in the competitive market as a way for retailers to attract or win consumers. Provision of these types of products should not be regulated however, as this would complex and could potentially expose retailers to financial risks.

Overall, the impact on an individual consumer's energy bill of moving to a flexible price will depend upon:

- the consumer's load profile pattern relative to the average NSLP 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 retail tariff structures relative to existing tariff structures; 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.[258] The model is available on the AEMC's website and allows stakeholders to assess how flexible pricing options could be implemented and how these might affect electricity expenditure.

An important issue to keep in mind is that even where consumers are not subject to flexible prices, their electricity expenditure could also be affected by the adoption of flexible pricing by others. This is because a greater penetration of flexible 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 flexible pricing:

- Even under voluntary arrangements, those consumers who remain on non-flexible pricing options may over time experience greater electricity expenditure, as they continue to be settled on the basis of the NSLP. Those consumers who voluntarily seek out flexible prices will likely be those with the better load profiles (as they have most to gain) while those with peakier profiles

258 Refer to Frontier Economics, Retail Tariff Model Final Report and tool developed for the AEMC as part of this review. This can be accessed at www.aemc.gov.au.

are likely to remain on the non-flexible tariff structures. Hence, the cost of serving these remaining consumers will likely rise, placing upward pricing pressure on retail prices.

- 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. Therefore the cost per consumer of meter reads, for example, will be higher.
- 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 non-flexible tariff structures (because they may be less likely to respond by adjusting their consumption).

The extent of such impacts will depend on the number of consumers that transition to flexible prices and how the underlying tariff structures of flexible pricing options are determined. In the long term, more cost reflective pricing could lead to lower system costs and hence lower electricity expenditure for consumers.

6.3.2 Managing the impacts on vulnerable consumers

RECOMMENDATION

We recommend that:

- **Governments review their energy concession schemes and target government energy efficiency programs. This is to ensure adequate information and protections are in place for those consumers with limited capacity to respond to the impacts of increased flexible pricing in the NEM.**

Throughout the review we have recognised that not all consumers will have the ability to respond to, or manage the impacts of, the transition to flexible pricing. To manage the impacts of flexible pricing a consumer would need to have the capacity to shift their electricity demand or adjust their consumption levels, or be willing to pay for consumption during higher priced times of the day.

In this review we have intentionally limited the scope for defining 'vulnerable consumer' to have meaning only within the context of a transition to flexible pricing and demand side management. However, we have been informed by the characteristics that are typically applied to vulnerable consumers such as those considered in Appendix D and Chapter two of this report.

In the directions paper we considered that a vulnerable consumer is one that is affected by changes to pricing structures which results in a deterioration in their ability to manage their electricity consumption.

In the first instance, a consumer may simply not have the capacity to shift their electricity demand in response to new flexible pricing structures. Examples of these types of consumers include those at home during the day (such as the elderly), those with chronic medical conditions, shift workers, the unemployed and parents with pre-school aged children. For these types of consumers the transition to flexible pricing may lead to increased financial distress, including their ability to pay meet their electricity expenditure.

Low income consumers who are able to shift their demand are likely to benefit from transitioning to flexible pricing. The Brattle Group analysis shows that in the United States, more than three quarters of low-income consumers are overpaying under flat retail offers, and if allowance is made for their likely response to dynamic pricing rates, one would expect more than 80 – 90 per cent of low income consumers to benefit from such rates.[259]

In their submission to the draft report ATA supported pricing policies that would remove cross subsidies between consumers, such as public housing tenants (as noted by SACOSS), who have a less 'peaky' load profile than the NSLP, and would stand to benefit from transitioning to flexible pricing. [260]

PIAC offered a similar observation and cited its research into electricity use and people with physical disability, which found that people were highly motivated to change behaviour in order to make savings on electricity expenditure, even though circumstances beyond their control, such as the need for heating and cooling or in-home services, may reduce their opportunities to do so.[261]

Analysis from The Brattle Group and supporting information from stakeholder submissions highlight the challenges of capturing consumers that may be impacted by the transition to flexible pricing. While many low income earners may benefit from the transition to flexible pricing, some will not. Existing concession schemes may not capture all consumers who are financially constrained and at the same time may not be able to efficiently manage the impacts of flexible pricing.

Due to the differences in the ability of consumers to respond to flexible pricing, energy concession schemes and government assistance programs need to be reviewed to support an orderly transition to flexible pricing. In this context, government support programs need to be effectively targeted to offer the right protections to consumers that may be impacted by the transition to flexible pricing.

---

259 Wood, Lisa and Ahmad Faruqui, Dynamic Pricing and Low-Income Customers: Correcting misconceptions about load-management programs, Public Utilities Fortnightly, November 2010, pp. 60-64

260 See ATA submission to the draft report

261 See PIAC, submission to the draft report, page 1

6.3.3 Strategy for vulnerable consumers

Review of energy concession schemes and assistance programs

Some sections of the community currently qualify for government support towards meeting their electricity expenditure. This income support takes the form of community services obligations (CSOs); Appendix ED provides details on the design of these schemes 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 flexible pricing. However not all consumers who qualify for income support will be worse off under flexible pricing because, as explained above, the impact depends upon the consumer load profile pattern relative to the average system load profile.

Energy concessions 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. In addition, there will be other categories of consumers who do not qualify for such schemes but for whom flexible pricing may lead to a significant deterioration in their ability to meet their electricity expenditure. For example, the eligibility criteria will not capture those low to medium income households (approximately $40,000 - $80,000) who face a price increase (due to their load profile) but may not be in a position to reduce or shift their consumption patterns.

IPART analysis shows that for NSW, energy consumption for concession card holders is lower than those who do not hold a concession card. The same survey results also show that while low income earners most likely have access to a concession card (around 75 per cent), other income distribution levels ranging between $31,200 to over $104,000 may also have access to a concession card.[262] In the majority of cases, consumers that receive a concession card are also eligible to receive energy concessions.

This highlights that state governments may need to review their energy concession schemes 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.

Energy concession schemes should be reviewed to ensure that they are appropriately targeted to capture the types of consumers that may face increased financial stress in transitioning to flexible pricing, including consumers that would not be captured by current eligibility requirements for energy concession schemes. Any review of energy

262 IPART report, *Residential energy and water use in Sydney, Blue Mountains and Illawara*, published 2008

concession schemes should be consistent with the Ministerial Council on Energy, Energy Community Service Obligations National Framework[263]

While affordability is one component of a consumer's ability to manage the impacts of flexible pricing, it is also important that government assistance programs include non-income support measures. The types of measures outlined below are likely to have a longer lasting impact on consumer's ability to manage electricity consumption, and strongly complement income support such as energy concession schemes.

Non-income support includes measures to improve the thermal efficiency of households and energy efficiency appliances. An example of this type of measure is the South Australian Residential Energy Efficiency Scheme, which provides free items such as draught proofing tapes, energy efficient light globes and water efficient shower heads to vulnerable consumers. These types of measures are likely to have a longer lasting impact on a consumers' ability to manage the impacts of flexible pricing, and can also be used as an educational tool to help consumers understand the relationship between energy use and costs.

We also consider that the transition to flexible pricing must be supported by effective information campaigns, targeting consumers that would require particular assistance to transition to flexible pricing, such as those consumers outlined above. Through information campaigns these consumers should be enabled with the appropriate tools and knowledge to manage electricity use during peak demand. Consistent with our recommendations from Chapter two, state governments should consider whether there is a role for third parties that have good access to a range of consumers to support such information campaigns.

Submissions to the draft report provided strong support for our recommendation for managing the impacts of flexible pricing for vulnerable consumers, in particular with respect to making flexible pricing optional, and the broader need to review existing concession mechanisms. SACOSS suggested that governments be required to provide a formal commitment to these recommendations before flexible pricing is introduced.[264]

Improved reporting under hardship provisions

The existing energy concession schemes and the NECF provide a useful basis for identifying the types of consumers who may face financial difficulties under the impacts of flexible pricing. However, we consider that there is scope for better reporting and identification measures. This would help to develop better targeted, cost-effective policies in the long term. One option is for the NECF hardship indicators to be extended to cover how hardship consumers are managing the transition to flexible pricing.

---

263 Ministerial Council on Energy, 2009: http://www.ret.gov.au/Documents/mce/_documents/MCE_Energy_Community_Services_Obligation20080929151353.pdf

264 SACOSS submission to draft report, p 2

While there is no existing operational definition of 'vulnerable consumer' used by government, the National Electricity Retail Rules (NERR) requires the AER to determine a range of hardship indicators. At a minimum the hardship indicators must include entry and participation in retailer hardship programs, as well as requiring retailers to outline the types of assistance available to consumers. We therefore advise the AER to also require retailers to monitor and report on the impacts of flexible pricing on consumers in hardship programs. In their submission to the draft report the AER recognised that while the current indicators did not include reference to monitoring the impacts of flexible pricing on consumers, there was scope to include it through its consultation procedures.

Consumers who do not take up flexible pricing options

Some consumers may choose to remain on existing retail tariff structure because they are unable to shift their electricity demand in response to flexible pricing. Throughout the review, stakeholders have raised concerns that as the penetration of flexible pricing increases in the market, and as those consumers on flexible pricing option adapt their behaviour, retailers and networks will seek to recover any resulting lost revenue from consumers that remain on non-flexible retail tariff structures. For example, this could happen by increasing the fixed charge payable by consumers.

We consider that this scenario is unlikely to arise. For commercial businesses operating in a competitive market, behaviour is driven by profit and not revenue. If consumers adapt their consumption in response to flexible pricing options and shift consumption to off peak times, then their retailers' energy purchase costs will also decrease as the risks associated with buying electricity from the wholesale market during off peak times are reduced, due to lower spot price volatility. There should be no need for a retailer to recover lost revenue from other categories of consumers, as its costs will have fallen. Doing so will mean it runs the risk of losing market share.

In relation to network businesses, we note that a sizeable proportion of network tariff structures cover costs associated with past investment. Increasing the penetration of flexible pricing may change the allocation of such costs across the consumer base. We note that our proposed reforms to the distribution pricing principles and the demand management incentive scheme will help alleviate the risk that flexible pricing options will result in a material shift of sunk costs to consumers that remain on their existing retail pricing offers.

6.3.4 Phasing in flexible pricing options

RECOMMENDATIONS

We recommend:

- **A gradual phasing in of efficient and flexible retail pricing options for residential and small business consumers through the introduction of cost reflective electricity distribution network pricing structures. The phase in of cost reflective network pricing would be through segmenting these consumers into three different consumption bands and applying flexible, (ie time varying) retail pricing options in different ways:**
  - **Large residential and small business consumers above a defined annual consumption threshold will be required to have an efficient and flexible network tariff as part of their retail price offer (this group of consumers are referred to as Band 1).**
  - **Medium residential and small business consumers - with an annual consumption level below the band 1 threshold but above a small consumer defined threshold, will transition to a retail price offer that includes an efficient and flexible network tariff. This only applies to those consumers who already have a meter with interval read capability which enables such flexible retail price offers. These consumers (band 2) will have the option not to move to a flexible retail pricing offer but instead remain on their existing retail price structure.**
  - **Small consumers (ie all other residential consumers and small businesses) - with consumption below the small consumer threshold will remain on their existing retail price structure (band 3). Those consumers in this band which have with the appropriate enabling metering technology will be able to choose an efficient and flexible retail price offer, if they so wish.**

Supporting amendments are made to the National Electricity Rules, National Energy Retail Rules and/or mirroring jurisdictional legislation to give effect to the phased implementation approach.

A key theme in this review is that informing and educating consumers on how flexible pricing is likely to impact them, both the potential costs and benefits, will be an important first step in giving consumers the necessary confidence to take up flexible pricing options. This is discussed in detail in Chapter two. In this chapter we consider how the transition to flexible pricing could take place to further underpin such confidence and encourage wider community acceptance of flexible pricing.

In the draft report we recommended that regulatory changes to encourage more flexible pricing should be focussed on the network component of retail bills. We proposed this for two main reasons.

First, network costs driven by peak demand are a significant component of overall resource costs required for meeting electricity demand. This is reflected in retail prices where the network component (both transmission and distribution averaged across the NEM) makes up approximately 50 per cent of a typical retail bill.[265] Thus more efficient pricing of networks in its own right should have significant flow on impacts to overall electricity expenditure faced by consumers. Retailers are likely to pass through flexible network tariff components, because doing so is the most effective way for them to manage the risk of price structure mismatch (the difference in the profile of payments the retailer receives from consumers and what it has to pay the network business).

Also we note that network costs are a straight pass through to regulated retail prices in jurisdictions other than Victoria, thus we would expect regulated retail offers to be based on flexible network tariff structures.

Second, we consider that there are adequate market incentives to encourage retailers to offer flexible pricing options to consumers as a way of managing wholesale energy costs.[266] Offering innovative flexible pricing products to consumers that reflect consumer profiles and/or consumer willingness to adjust behaviour will allow retailers to compete and increase market share. Imposing greater prescription in retail prices to deliver this outcome could amount to over regulation.

Submissions to the draft report supported our recommendation for changing arrangements for pricing at the network rather than the retail level.[267] We have decided to retain this approach for our final recommendations.

We also considered three different mechanisms for introducing flexible pricing options to consumers, so as to effect an orderly transition and encourage consumer engagement and confidence in flexible prices:

- Under an “opt-in” approach consumers would remain on their existing retail price structure, but would have the option of voluntarily moving to a retail price structure with a flexible network tariff component (and the opportunity to move back to a non-flexible retail tariff structure if they didn’t like the flexible pricing options).

- Conversely, under an “opt-out” approach consumers would be automatically transitioned to a retail price structure with a flexible network

265 See AEMC Final Report, Possible Future Retail Electricity Price Movements: 1 July 2011 to 30 June 2014, p 18 available on our website.

266 Provided our other recommendations in relation to deployment of remotely read smart meters are implemented.

267 See for example submissions to the draft report by AGL, p 8; Simply Energy, p 12; Origin , p 16; AER, p 8, Alinta, p 2

tariff component, but these consumers would be given the option of remaining on their existing retail tariff structure if they chose to do so.

- A third approach –"mandatory" would require consumers to be on retail tariff structure which has a flexible network tariff component. Such consumers would not the option to have a retail price structure, which does not contain a flexible network tariff component.

The manner in which flexible pricing is introduced can have a significant effect on the speed and degree of adoption of flexible pricing. International experience with flexible pricing demonstrates that with an opt-out approach as much as 80 per cent of the eligible population chooses to remain on flexible prices, while participation in an opt-in approach might be closer to 20 per cent.[268] While the potential gains or costs for consumers are the same for either approach, the significant variation in participation rates appears to reflect consumer biases; in particular a bias towards sticking with the status quo; or to be more concerned over losses rather than gains when it comes to changing their behaviour.[269]

However, while from the perspective of timely adoption a mandatory or opt-out approach is more desirable, there is also a risk that transitioning all consumers onto flexible pricing too quickly may cause confusion and resistance. This is because many consumers will be unfamiliar with flexible pricing. They will need to be well informed and have the appropriate knowledge and tools in place before they can respond effectively to flexible prices. Consequently, not giving consumers sufficient time to adjust to new arrangements may undermine broader community acceptance in flexible pricing.

For these reasons, we proposed to use a combination of all three approaches to introduce flexible pricing to consumers.[270] For consumers above a certain threshold we recommended that it should be mandatory to have a smart meter and flexible network tariff component included as part of their retail tariff structure (the large use residential and business consumers), because any adjustments in their consumption patterns are likely to have the biggest impact on reducing system costs at the margin.

For consumers with an average consumption level, we recommended an opt-out approach, which seeks to expose consumers to flexible pricing but provides the security of remaining on a retail pricing structure that includes a non-flexible network

268 See *Time- Varying and Dynamic Rate Design, Global Power Best Practice Series*, The Brattle Group, RAP, July 2012.

269 See Ofgem discussion paper, *What can behavioural economics say about GB energy consumers*?, 21 March 2011, page 6,available on the Ofgem website, and the Brattle Group, *Managing the costs and benefits of Dynamic Pricing in Australia,* Faruqui & Lessem, 21 September 2012, p. 6.

270 It is important to note that some consumers in all bands will already be on some form of static time-of-use prices or controlled hot water off peak rates offered by networks if they have multi-register meters. Regardless of whether or not their meters are upgraded to support flexible pricing, they should continue to have the option of remaining on such price products if they choose to do so. We discuss this issue in Chapter 5.

tariff component if this is their preferred option. This would only apply to those consumers who have the enabling metering technology.

We consider that a different approach is necessary for small to medium load consumers. Given the nature of their consumption and electricity use, some of this class of 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.

Therefore such small consumers (who have enabling metering technology) 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 flexible network tariffs.

We recommended that the categorisation of consumers into different bands would occur as follows:

- Large residential and small business consumers above a defined annual consumption threshold will be required to have an efficient and flexible network tariff as part of their retail price offer (this group of consumers are referred to as Band 1).
- Medium residential and small business consumers - with an annual consumption level below the band 1 threshold but above a small consumers defined threshold, will transition to a retail price offer that includes an efficient and flexible network tariff. This only applies to those consumers who already have a meter with interval read capability which enables-such flexible retail price offers. These consumers (band 2) will have the option not to move to a flexible retail pricing offer but instead remain on their existing retail price structure.
- Small consumers (ie all other residential consumers and small businesses) - with consumption below the small consumer threshold will remain on their existing retail price structure (band 3). Those consumers in this band which have with the appropriate enabling metering technology will be able to choose an efficient and flexible retail price offer, if they so wish.[271]

Consumers in Band 1 would be required to move flexible pricing, as outlined above. Such pricing offers may need to have as part of their package appropriate enabling

271 We note that there are likely to be consumers in this band who may already have meters with smart reading capability or will have such metering technology installed over time. Some of these consumers will already be on flexible rates (i.e. simple time of use prices). Where this is the case these prices should continue to form the default rate

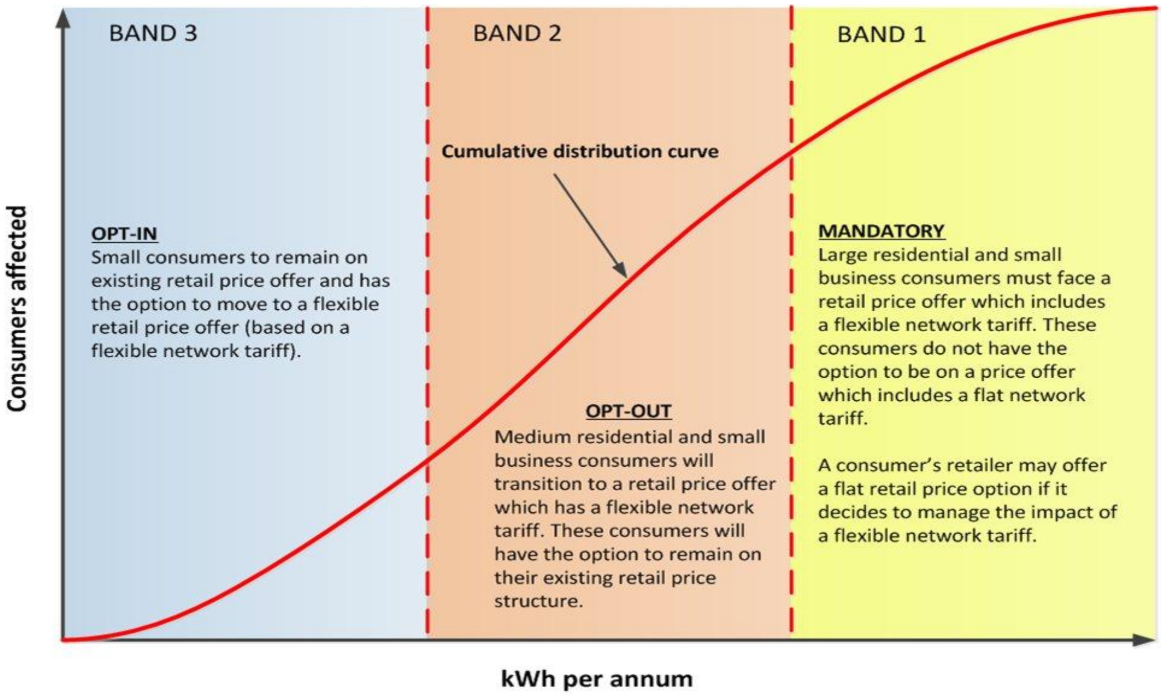
metering technology. This will be a matter for the retailer and consumer. The approach therefore complements the recommendations we have made for improving commercial investment in metering technology in Chapter four.

We also consider it is important that where a policy of reversion is allowed that provided consumers move between retail tariff structures that no termination or other fees related to switching should be applied in this process for a period, as this would discourage switching to a flexible pricing options, and undermine the benefits of the phased approach we are proposing. This issue has also been identified and addressed by the Victorian government in development of its flexible pricing policy.[272]

We did not define in the draft report what the thresholds should be for the consumption bands, noting only that the mandatory flexible pricing Band 1 should be focussed on larger consumers, capturing those consumers with multiple heavy load appliances such as electric vehicles and/or large air conditioning systems.

The approach is shown diagrammatically in Figure 6.4 below.

Figure 6.4 Applying flexible pricing to consumption thresholds



Most submissions to the draft report were supportive of a phased approach to implementing flexible prices, particularly allowing some consumers to test flexible pricing options for a period first, with the availability of the retail tariff structure they

272 The Victorian government's policy on flexible pricing can be accessed on www.switchon.vic.gov.au

were on originally as a backstop.[273] This was considered important to engender broader community confidence in the transition to flexible pricing.

Most stakeholders considered the requirement for three bands either unnecessary or too complex. For example, Origin noted that current price structures are already complex with around 30 business standing prices across NEM jurisdictions. Therefore, they argued that three consumption bands were likely to add significant complexity to the market for both consumers and businesses providing these services.[274] AGL also supported two bands, noting that flexible pricing should be rolled out as widely as possible and that only vulnerable consumers should have the availability of a retail tariff structure that did not include a flexible network tariff component.[275]

There was also range of perspectives on where thresholds should be set. Origin considered the dividing threshold for two bands should be set at around 30MWh to 40MWh. They argued that a high threshold is necessary to ensure most consumers have as their default product one with which they are most familiar.[276] ATA proposed that consumers should be divided into two categories:[277]

- Consumers with less than 10 kWh/day consumption should have the choice of 'flat' or flexible pricing options. These consumers do not contribute significantly to peak demand growth, have less opportunity to reduce energy consumption, and lack significant peak loads such as pool pumps that can be efficiently engaged for demand response; and
- Consumers with greater than 10 kWh/day consumption should have flexible prices apply on a mandatory basis, as they have energy costs exceeding $1000/year, and therefore are more likely to be in a position to benefit from the use of advanced metering and flexible tariff structures.

On the other hand, Ausgrid outlined the results of its Strategic Pricing study that revealed low income consumers (who volunteered to participate), actually responded better to price signalling than other income ranges in the trial. Consumers with an annual income between $25,000 and $41,200 reduced their energy usage by an average of 41 per cent in response to price signals, compared to higher income households who responded on average between 12 and 27 per cent.[278]

Ausgrid also made the important point that consumption patterns are likely to be variable, with consumers potentially moving between bands in a volatile manner, which may become administratively difficult to manage.[279] For these reasons they

---

273 See for example ATA submission to draft report, p 18 ; AGL, submission to draft report, p 9; ACOSS submission to draft report, p 2; AER submission to the draft report, p. 8.

274 Origin submission to draft report, p 16

275 AGL, draft report submission, p 9

276 Origin, draft report submission, p 16

277 ATA, draft report submission, p 20

278 Ausgrid, draft report submission, pp.18 -20

279 Ibid, p 20

propose that transfer between consumption bands should not occur unless a sustained increase in consumption occurs over a period of no less than two years.[280]

Submissions have therefore provided a range of perspectives on how the banding approach should be implemented.

We are not persuaded that the three bands approach will be significantly more complex to implement than a two bands approach. We also consider the benefits of making sure that consumers are either on an opt-out or mandatory flexible retail tariff structure in terms of maximising the potential for timely adoption is likely to exceed the costs of having an additional band primarily intended to manage impacts for lower income consumers. Importantly, there would be little additional complexity from the perspective from consumers, who would only face one new retail tariff structure, one with a flexible network tariff component. In fact, consumers do not need to know what band they are in but the range of options available to them.

A further important aspect of our approach is that consumers in all bands will have access to the 'standard' retail tariff structure if they want one. Thus if as Ausgrid notes that many consumers who might initially be placed within the opt-in band potentially could respond more significantly to flexible prices than consumers placed in the mandatory band, then such consumers are free to move to a retail offer that incorporates a flexible network tariff if they wish to do so. Our banding approach is based on the premise that all consumers should be able to choose a flexible retail pricing offer.

We remain of the view that jurisdictions are best placed to decide on how to phase in flexible pricing in a way that manages impacts on their constituencies. Particular circumstances and preferences in each jurisdiction will dictate what these should be and how they may change over time as consumer acceptance and understanding increases. The approach we outlined in this report can readily be tailored to suite the preferences and circumstances of the jurisdictions. Victoria has already decided on implementing an opt-in approach for all consumers under 40 kWh.[281]

While, we consider that jurisdictions should tailor the consumption thresholds to their specific market conditions. We agree with stakeholders that a set of principles would facilitate consistent implementation of banding.[282] In particular, we consider the banding must meet the following principles:

- Consideration should be given to allowing a transition period from the introduction of these reforms to when the consumer is required to move to flexible pricing, unless the consumer consents otherwise. This will give these consumers and their retailer time to build up a load profile history which will enable a more informed judgment of the flexible pricing options. We suggest that one year would be an adequate period.

---

280 Ibid, p18

281 The Victorian Government's policy on flexible prices can be accessed on www.switchon.vo.gov.au

282 See for example Origin energy submission to the draft report, p 17

- High use residential and business consumers should be the first to be transitioned to flexible prices, as any consumption changes they make at the margin will have the greatest impacts on system costs.
- The threshold for these consumers (Band 1) should be substantially above the average consumption, so that it captures those consumers with multiple heavy load appliances such as electric vehicles, or large air-conditioning systems.
- Flexible pricing options should, if possible, be provided on a voluntary opt in basis for consumers who have limited ability to respond to such options and may face increased financial difficulties if required to do so.
- Distributed generation should face flexible pricing regardless of their size.
- A methodology will need to be established for defining the consumption thresholds. For example, they could be determined on the basis of the total consumption over the last 12 months. An option to determine bands on KW rather than kWh should be explored where smart meters are already in place.
- Once bands are set consumers within those bands should only be able to shift into higher consumption band if their consumption increases to above the threshold over a period of two years; they should further not be able to shift into lower bands if their consumption drops. This is consistent with an overall focus of driving consumers to more cost reflective pricing over time.

To illustrate how these principles might be implemented we show typical annual electricity consumption for a range of typical households in Victoria in Table 6.5 below. In each case the household was assumed to have an electric hot water system, an electric cooker and oven, a refrigerator, dishwasher and clothes dryer. These households have been differentiated based on the types of appliances, the number of occupants and whether the dwelling was a house or a flat. In addition the table includes the estimated consumption both with and without the charging for a typical electric vehicle. It is important to note the table includes typical consumption levels for average households but this will not necessarily be representative of all households. We would expect households A and B and C to be in band 1; D to be in band 2; and E and F in band 3. If household D brought an electric vehicle, it should transfer into band 1.

Figure 6.5 Typical appliance annual energy consumption data[283]

Household	A	B	C	D	E	F
Occupants	4	3	3	2	2	1
Dwelling	house	house	house	house	unit	unit
Ducted electric heating and cooling	yes	yes		yes		
Room air conditioning	yes	yes	yes	yes	yes	yes
Swimming pool	yes	yes				
plasma TVs	2	1	1	1		
LCD TV	1	2	2	1	2	1
computers	3	3	2	2	1	1
kWh – without an EV	15,751	14,583	10,244	9,769	5,932	5,073
Annual cost	**$3,938**	**$3,646**	**$2,561**	**$2,442**	**$1,483**	**$1,268**
kWh – with an EV (15,000 km)	18,751	17,583	13,244	12,769	8,932	8,073
Annual cost with EV	**$4,688**	**$4,396**	**$3,311**	**$3,192**	**$2,233**	**$2,018**

Changes required to retail and distribution arrangements to give effect to our phased implementation approach

Retail arrangements

We anticipate that retailers will seek to pass through the flexible network tariff component into both their retail and standing offers, to do otherwise will expose retailers to the risk of price structure mismatch. This means that regulatory arrangements for standing offers in each jurisdiction will need to make provision for availability of both a standard offer which includes a non-flexible network tariff component and one which includes a flexible network tariff component. One or the other will be offered by a retailer depending on which consumption band the consumer falls within.

To give effect to this approach we therefore propose that changes are made to the National Electricity Retail Rules (NERR), or mirroring legislation in each of the jurisdictions where the NERR does not apply. The NERR will be amended so that the retailer advises the consumer of either:

- a standing offer with a flexible network tariff component[284]; or

283 Analysis based on data from the Victorian Government website “switch on take control of your power bill”, available at http://www.switchon.vic.gov.au/why-are-power-bills-so-high/what-makes-up-my-power-bill-costs

- a standing offer with a non-flexible network tariff component.

How this would work in practice is shown is shown in table 6.1 below.

Table 6.1 Network and retail price regulatory arrangements

	Standing offer including flat network price	Standing offer including flexible network price
Band 1: Large residential and small business consumers	no	yes
Band 2: Medium to large residential and small business consumers	yes	yes
Band 3: Small to medium residential and small business consumers	yes	yes

We consider that it is possible to incorporate time varying network tariffs into retail price regulation. The potential issues associated with developing time varying standard offer price caps, arise in setting flat regulated retail tariffs, if not more so.

In particular, any regulated retail tariff, whether flat or time varying is based on an assumed load profile and hence will over-charge some and under-charge others. This 'cross-subsidy' is more profound under flat regulated tariffs than under flexible regulated tariffs. Similarly, the disincentive to reduce peak demand is stronger on a flat tariff than on a regulated flexible pricing offer. Also, the value of incorporating geographic variations also applies to flat regulated tariffs.

We note that in many states (eg NSW), retail regulation applies in the form of a weighted-average of tariff revenue. Therefore, it is up to the retailer to devise its own 'regulated' tariffs, so long as the expected weighted-average revenue from those tariffs does not exceed the regulated level. In principle, a retailer could offer several regulated flexible tariffs.

We anticipate that new provisions will also need to be added to the NERR that sets out details regarding the banding and applicable thresholds, including the following types of information:

- The applicable consumption thresholds for each jurisdiction that define the bands and the applicable standing offer for consumers;
- How the bands are determined;
- The type of meter that will be required for a consumer in a particular band; and

284 This will also apply to jurisdictions that have tariff equalisation schemes in place.

- Relevant information to provide to consumers with respect to the bands, and the manner of how such information should be provided.

The AER will need to ensure this new information is reflected in its Retail Pricing Information Guideline (and the fact sheets retailers are required to provide consumers).

Distribution arrangements

The distribution pricing arrangements will also need to be amended so that distributors make available both a flexible and non-flexible network tariff component for consumers in Bands 1 and 2 and flexible network tariff component for consumers in Band 3. This is discussed in detail in section 6.3.6.

Evolution of the competitive market under our phased approach to flexible pricing

The banding approach we outline above is focused on introducing flexible pricing in a gradual fashion for the majority of consumers in the NEM. While we propose a flexible standing offer and a continuing flat standing retail offer remain, these are simple options that should not constrain development of innovative alternatives in the competitive market.

We anticipate a competitive retail market will deliver a range of potential options over time to manage the differing risk preference of consumers. For a detailed review of such products see the attached report by The Brattle Group.

The key benefit identified relative to the existing flat retail price 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. These types of products are likely to be attractive to many consumers, and could provide a way for retailers to secure market share. We discuss the basics of one such an approach in Box 6.2 below.

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 compare with purer forms of flexible pricing. If consumers maintain the same usage as their historic baseline, then their electricity expenditure 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 electricity expenditure 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.

We consider our phased approach through banding provides the appropriate balance between ensuring an orderly transition for consumers to flexible pricing, while at the same time providing the majority of consumers with strong incentives to managing their consumption in ways that reduce system costs and maximise their own welfare.

6.3.6 Strengthening arrangements for network tariffs

RECOMMENDATIONS

We recommend that:

- **Distribution network pricing arrangements are amended so that distribution network businesses have sufficient guidance for setting efficient and flexible network tariff structures that support DSP. The amendments would include:**
  - **Changes to the existing distribution pricing principles.**
  - **The rules are amended so that distribution network businesses are required to develop and consult with retailers and consumer groups on a statement of proposed network pricing structures as part of their regulatory proposals.**
  - **A more robust consultation and verification framework is applied to the annual network tariff setting process. This includes consulting on any requested changes to the approved statement of network pricing structures.**
  - **Possible changes to the pricing side constraints.**
- **AER develops and publishes a guideline for network tariff arrangements that covers two purposes. Firstly, to provide more detailed interpretation of how the pricing principles can be applied. Secondly to set out consultation and information requirements with respect to development of network pricing structures statement and its annual updating in the pricing proposals of distribution businesses.**

In the draft report we noted that a cost reflective network price would comprise two components: one component recovering the fixed and sunk costs of the network (a fixed component that does not vary with consumption), and a second component reflecting those network costs that vary with consumption (the marginal costs of providing network services). The marginal costs of the network are essentially those associated with transport energy and are primarily congestion and losses. The costs of providing a network service become very high when network limits are breached, potentially leading to load shedding and black outs. For this reason governments have implemented reliability standards to ensure these latter outcomes occur only in rare situations.

Marginal cost is an important principle for efficient pricing, because presenting consumers with the opportunity costs of their consumption decisions should encourage consumption choices that trade off the value of consuming against its supply costs. This principle lies at the core of the Power of choice review and its focus on driving more flexible pricing options for consumers.

We put forward a range of reasons in the draft report for why we considered distribution network businesses had typically not set network tariffs on the basis of marginal cost, including:

- interval or smart 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 smart meters was the key deterrent to them setting more cost reflective (flexible) prices;
- the 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 maximise utilisation; and
- the incentive on network businesses to price at marginal costs may be complicated by how costs are treated under the regulatory arrangements and how incentives interact with the need to meet reliability standards. 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 flexible network prices that reflect marginal cost.[285]

A lack of incentive for marginal cost based pricing discourages distribution network business from setting flexible network prices that might facilitate DSP. Consequently, we recommended in the draft report that the pricing principles and other parts of the distribution rules be amended to provide greater guidance to distribution network businesses for setting flexible prices that reflect marginal cost.

285 We discuss this issue further in Chapter 8, where we examine the incentives for distribution network businesses to undertake DSP more broadly.

A number of stakeholders supported review of the pricing principles to make them more focused.[286] The AER considered existing principles provided insufficient prescription to encourage network businesses to reflect the peak demand impacts on costs, and they considered this to be the key driver of future network costs.[287] Origin argued the existing pricing principles were ineffective in guiding current network price setting.[288] Conversely, the majority of distribution businesses generally considered the existing principles were sufficient to support setting of cost reflective prices and that moves to greater prescription would reduce flexibility and discourage innovation.[289] One distributor, Ausgrid, did note however that providing greater level of guidance on how distributors should interpret the pricing principles would be worthwhile. They proposed the AER develop and publish a guideline, rather than changes being made to the pricing principles themselves.[290]

Our final recommendations for the distribution pricing rules we set out below seek to provide an appropriate balance between facilitating more flexible (cost reflective) network pricing while at the same time not constraining innovation in the types of approaches that might be used by distribution businesses. We include a summary of all our proposed changes to the rules in the attached draft specification.

Pricing principles

The way distribution businesses set their network charges is governed by the pricing principles, set out in Chapter 6 of the NER. The substantive distribution pricing principles in clause 6.18.5 are as follows:

- Principle 1: the revenue of each price class should lie on or between avoidable and standalone cost (6.18.5 (a));
- Principle 2: the distribution network business must "take into account" the long run marginal cost (LRMC) for a network service in setting network prices and pricing parameters (6.18.5 (b) (1));
- Principle 3: network prices must be determined having regard to transaction costs (6.18.5 (b) (2) (i);
- Principle 4: network prices must be determined having regard to the ability of consumers to respond to the price signals (6.18.5 (b) (2) (ii); and

286 Energy Australia submission to draft report, p 22, Origin submission to draft report, p 18, AER submission to draft report, p 9

287 AER submission to the draft report, p 9

288 Origin energy submission to draft report, p 18

289 See for example SPAusnet submission to draft report, p 12, United Energy submission, p 18, ENA submission p 8, Powercor/Citipower submission p 16

290 Ausgrid submission to the draft report, p 21

- Principle 5: where prices that are based on the above principles do not recover expected revenue for the distribution business the distribution business must adjust its prices in a way that recovers the outstanding amount in a way that minimises distortion to efficient patterns of consumption (6.18.5 (e)).

We consider each of these principles below.

Principle 1: Stand-alone versus avoidable costs

The principle requiring that revenue for each category or class of consumers lies between avoidable and standalone cost has little operational meaning. This is because of the predominantly fixed and sunk nature of distribution costs, which means that:

- the standalone cost of any network service to a given consumer class is effectively the cost of the entire distribution network; and
- the incremental cost of any network service is arguably as low as distribution losses.

As such, the range of network tariffs that could be set to reflect this principle would be extremely wide. The requirement for expected revenues from a consumer class to lie between stand alone and avoidable costs should remain, given its theoretical importance, but we consider this should be a final check on the prices set on other grounds rather than the primary requirement.

Principle 2: The long run marginal cost of network services

The rules have not made explicit how long run marginal cost (LRMC) should be defined with respect to network services, or how distribution businesses should reflect LRMC in network tariffs. Consequently, it has been interpreted in a range of ways not necessarily consistent with its theoretical underpinnings. For example, most distribution network businesses use an Average Incremental Cost approach (AIC) to determine the LRMC of the network. The effect of this approach is to average out incremental costs over the period that demand is expected to change. This has the property of dampening price changes over time relative to other approaches that more precisely attempt to capture LRMC, such as the Turvey approach.[291]

The Turvey approach focuses on the cost of bringing forward planned investment to accommodate an incremental increase in demand for the relevant network service, and is therefore more consistent with conceptual underpinnings of LRMC.[292] The Turvey approach would calculate the present value of an increase in distribution businesses'

291 See for example PwC, Investigation of the efficient operation of price signals in the NEM, report prepared for the AEMC directions paper, p 13

292 See Turvey, R (2000) What are Marginal Costs and How to Estimate Them?, Centre for the Study of Regulated Industries (CRI), University of Bath

costs due to a sustained one unit increase in demand for a particular network service.[293]

Another important point to note is that this pricing principle does not make explicit the requirement for distribution businesses to set network prices based on LRMC; they only need to take LRMC into account in their price setting. They can use their own judgement in weighing efficiency against a range of other factors including jurisdictional requirements with respect to geographic averaging (clause 6.18.3 (d) (1)), complexity, transactions costs (6.18.5 (b) (2) (i)) and the degree to which network businesses consider consumers will respond to the prices they set (NER clause 6.18.5 (a) (2)). Consequently, while LRMC is a fundamental concept for efficient pricing, it is reflected as a relatively weak obligation in the rules.[294]

For these reasons, we consider that LRMC could be more clearly defined in the rules, both in terms of what LRMC means with respect to network services and how it should be reflected in network prices. We propose a definition is included in the pricing principles for LRMC based on the Turvey approach, such as the following:

> *"In relation to a given network service, distribution prices should be set in a way that reflects the long run marginal cost (LRMC) of the network, whereby LRMC refers to the present value cost of bringing forward network capital and operating costs to meet a particular user's sustained incremental derived demand for the relevant network service."*

The requirement for derived demand for the network service reflects the point that network prices need not necessarily be based on a consumer's demand for electricity.

The quantum of LRMC for providing a network service (primarily transporting energy) to a particular consumer will largely depend on:

- the existing level of excess capacity in that part of the network where the consumer is located; and
- the degree to which a consumer' consumption is coincident with the demand of all other consumers within the network, and thus requires the shared network to be augmented.

Consequently, the LRMC of the network is driven primarily by the need to augment the network to meet coincident peak demand.[295] Efficient network prices are therefore those that encourage consumers to reduce their contribution to coincident peak demand. This principle has been recognised in the transmission pricing rules in 6A.23.4

.293 PwC, Investigation of the efficient operation of price signals in the NEM, report prepared for the AEMC directions paper, p 13

294 This point was also highlighted by the Productivity Commission in its draft report Electricity Network Regulatory Frameworks, volume 2, p.389-393.

295 Energy Australia, p 30 and PwC, Investigation of the efficient operation of price signals in the NEM, report prepared for the AEMC directions paper, p 12.

(e) where there is an explicit requirement for at least half of all transmission costs to be recovered in a way that signals peak demand:

> *"Prices for recovering the locational component of providing prescribed TUOS services must be based on demand at times of greatest utilisation of the transmission network and for which network investment is most likely to be contemplated."*

We recommend therefore this principle is also included in the distribution pricing rules, by amending Clause 6.18.5 (b) (1) to require that network prices:

- must be based on demand at times of greatest utilisation of the distribution network and for which network investment is most likely to be contemplated.

This provision recognises that it is the interaction of peak demand and available network capacity that matter. Locational variations in network costs will be driven by factors such as the amount of excess capacity available at a location and the size of peak demand in an area. Providing a locational signal to the residential and small business consumers in the distribution network is likely to be challenging however. This is partly because of the absence of the appropriate metering technology, but more significantly also because of the shared nature of many of the assets they use, which makes it difficult to attribute precisely the cost of the assets 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 country 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 distribution businesses to signal difference in locational costs (for example, by allowing scope for distribution businesses to implement a CPP in constrained parts of the distribution network). We consider this should be made more explicit in the pricing principles by amending (6.18.5 (b) (1)) so that:

- network prices reflect, to the extent practicable, current or future constraints on the network.

We anticipate that a broad range of network pricing structures are likely to be consistent with the requirements we set out above. We aim not to be too prescriptive in this regard. The focus is on achieving the right outcomes with respect to minimising future network costs while allowing network businesses scope to be innovative in developing network prices and using a range of approaches that match their particular circumstances and preferences. In Appendix E we set out the types of price structures that could be considered consistent with signalling peak demand impacts (both energy based and demand based charges). In the next section we discuss a number of important considerations for network businesses to keep in mind when devising new network pricing structures, in particular how such pricing structures may impact on consumers.

We propose that the AER develops and publishes a guideline that would assist distribution businesses to interpret the pricing principles by setting out the appropriate methodology/s for calculating LRMC and the kinds of pricing structures that would be consistent with LRMC. As we discuss in the next section, such a guideline could also set out the kinds of pricing structures that are likely to be simple to understand and respond to.

We have reflected this proposal in the draft specification attached to this report.

Principle 4: Whether a consumers is able or likely to respond to the price signal

Clause 6.18.5 (b) (2) (ii) is intended to reflect the notion that there is only value in setting charges based on LRMC if consumers will be able to respond to those charges by changing their behaviour. While this is an important requirement, there also a risk that as we move to arrangements where network businesses are required to provide both flexible and non-flexible network tariff options to consumers, that this provision may encourage network businesses to shift more of their costs onto consumers with non-flexible retail tariff structures. This is because consumers on these types of structures are less likely to respond to such prices by adjusting their behaviour.

The need for network businesses to take into account the potential impacts of new tariff structures on consumers is an important consideration, particularly moving forward into an environment where innovative new network tariff structures are likely to be introduced.

For example, network businesses currently tend to favour demand based pricing options for larger business consumers, which focus on increasing the fixed price at certain times of the year based on their maximum demand (based on kW or kVA). Such pricing options are likely to become more popular going forward in an environment where network prices will be required to more efficiently reflect the impacts of peak demand. Residential consumers will have little familiarity or experience with demand based pricing, it is important therefore that the pricing principles take into account the impacts of potentially complex or unfamiliar price types on consumers (not just the extent of their efficiency properties).

For these reasons we consider that network businesses should be required to demonstrate that the particular network prices they intend to implement are not excessive or onerous and are likely to elicit efficient behavioural responses in reducing future network costs. To achieve this outcome we recommend that the existing Principle 4 (6.18.5 (b) (ii)) is replaced by two new requirements:

- that the development of network prices take into account the likely impacts of pricing structures on consumers, and
- take into account relevant consultation requirements on proposed price structures in the rules.

Guidance on how network businesses should interpret these requirements should be set out in the AER guideline we propose above. The guideline should specify that network prices consistent with the consumer impacts criterion would be proportionate, simple, and transparent. Such that, the consumer is able to understand the tariff structure including how it signals network costs and hence has the capability to respond to that signal.

These proposed amendments will help ensure that network prices are developed that consumers understand and can respond to while at the same time avoiding the potential cost shifting we have highlighted above.

Principle 5: Recovering residual costs in a way that minimises distortion to consumption

NER clause 6.18.5 (a) (2) is intended to reflect the monopoly characteristics of networks, where large fixed and sunk costs mean that charges set to recover LRMC will lead to under recovery of total network costs (since the LRMC cost curve lies below the average costs curve for the relevant range of output). The remaining costs need to be recovered in an efficient manner.

Given that recovery of the remaining costs will perform no signalling function (since otherwise they would have been included in the LRMC charge), efficiency requires such a charge is recovered with minimum distortion to consumption. Two pricing approaches are generally considered consistent with this criterion. First is the Ramsey pricing approach, which proposes costs are allocated to consumers, or at times, when demand elasticity is lowest.[296] The second approach is to recover the remaining costs in the form of a postage stamp (where the unit charge does not vary with consumption) that is applied as widely as possible so as not to affect existing utilisation of the network. This is the approach taken for setting prices for recovery of sunk costs under the price structure principles in the transmission rules (6A.23.4 (j)).

The current wording of clause 6.18.5 (b) (1) implies a Ramsey pricing approach should be used for recovering residual distribution network costs. As noted above, one concern with Ramsey pricing (recovering costs from non-price responsive consumers) is that distribution network businesses may choose to recover any remaining costs not recovered under flexible pricing approaches from consumers on non-flexible network tariffs, since their demand elasticity will be lower relative to consumers on flexible network tariffs. Accordingly, consistent with the transmission rules, we propose this should be addressed by amending clause 6.18.5 (c) so that in the circumstance where the network business does not recover all its expected revenue through LRMC based prices then:

---

296 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

- the outstanding amount should be recovered in the form of a postage stamp charge spread across all tariff classes.

Pricing side constraints (6.18.6)

One issue that also needs to be considered in light of more focussed pricing principles is how this interacts with the side constraint provisions. Clause 6.18.6 (b) requires that the expected weighted average revenue from each price class for a particular regulatory year must not exceed the corresponding expected revenue for that price class (assuming the same quantities) in the previous year by more than two per cent of the average price increase. Clause 6.18.6 (e) seeks to clarify that 6.18.6 (b) does not limit the ability of distribution network businesses to set network prices that vary with time and usage for interval metered consumers (that is, so set flexible prices for these consumers). There are two issues that will need consideration moving forward into an environment where flexible pricing becomes more prevalent.

First, while 6.18.6 (b) may perform a role in smoothing price volatility over time, there is a risk this may also restrict the distribution businesses' ability to develop more innovative flexible pricing options. We consider the two per cent pricing constraint may need be review to ensure it provides appropriate scope for wide spread implementation of flexible pricing.

Second, while clause 6.18.6 (e) specifies that distribution businesses are able to charge flexible prices, this appears redundant given that neither price capped nor revenue capped businesses are prevented from structuring their prices as they see fit under the rules (provided overall revenue constraints are adhered to). This provision has the potential to create confusion as it could be read to mean that consumers with smart meters are not subject to the overall two per cent pricing constraint. Consequently, we propose that this provision is reviewed as part of the rule change process to assess whether it is needed.

Finally, the distribution rules use the concept of 'tariff class' to define what consumer groups the side constraints and pricing principles should apply to. The rules define tariff class simply as "a class of retail customers who are subject to a particular tariff or particular tariffs." It is left to the discretion of network businesses to determine tariff classes and assign customers to these classes; conceivably, allowing a network business to define it either very broadly (all customers in the distribution area) or narrowly.

Under the current Rules the side constraints and avoidable/standalone cost bounds apply at the tariff class level not the individual tariff level. One concern this raises is that where a network businesses defines a tariff class very broadly this could allow significant rebalancing of tariffs within that class, potentially exposing individual customers to significant price volatility despite the overall revenue constraint being met. We consider this issue needs to be considered as part of the of the distribution pricing rule change we have proposed in this chapter, so that consumers do not face excessive price shock in the transition to more flexible pricing approaches.

Consultation on network price structures with retailers and consumers

In an environment where network businesses are likely to develop more complex network price structures, it will be important that this occurs in a way that ensures prices are simple, relevant and effective in eliciting appropriate behavioural responses. To support this outcome we consider it will be important for retailers and consumer groups to have a greater role in reviewing such network prices. In the draft report we discussed the value in creating a more formal review role for retailers and consumer groups.

Submissions generally supported the concept of a greater role for retailer and consumers groups in the network price setting process. Origin considered that a formal requirement for network businesses to consult on network prices was important for innovative network prices to be developed that could be passed through to consumers.[297] The AER also support greater consultation, but considered this would be done at the distribution determination; as since due to tight time frames there would be little scope for consultation of network prices during the pricing proposal stage.[298] We have sought to reflect these considerations in our final recommendations, which we set out below.

There are currently two process and opportunities for public consultation relating to network tariff setting: the regulatory determination process and the annual pricing setting process. We consider that both processes need to be strengthened to provide for more meaningful consultation with key stakeholders and also allow for more regulatory verification to ensure that network tariffs are complied with the rules.

Currently distribution network businesses are required to submit a 'regulatory proposal' to the AER which forms the basis for a distribution determination on allowable revenues. The regulatory proposal is subject to consultation with stakeholders under clause 6.9.3 of the NER before the AER approves the proposal. As part of the regulatory proposal network businesses are already required to provide an 'indication of future prices' under clause 6.8.2 (c) (4).

Distribution network businesses are also required to publish on their websites a 'statement of expected price trends' (6.18.9 (3)) and submit these as part of their 'annual pricing proposals' for review by the AER (clause 6.18.2 (a)).

We consider that this requirement could be strengthened through addition of the following:

- A statement of proposed network pricing structures to apply for the 'regulatory period'; and

- That network businesses have regard to the views of retailers and consumer groups in developing the statement of network pricing structures, and to demonstrate this through appropriate consultation.

---

297 Origin submission to the draft report, p 18

298 AER submission to the draft report, p 9

The AER would then assess the proposed network pricing structures and approve or change the proposal as part of the distribution determination. This would happen in discussion with the networks and other stakeholders.

We also consider the rules should be amended to include a requirement for network businesses to publish on their websites, as well as include in their annual pricing proposals, a statement of proposed pricing structures (developed in the regulatory proposal). Further, any variations to this statement of pricing structures should be consulted on with stakeholders and approved by the AER. Variations should be permitted if they continue to the consistent with the rules and further promotes the achievement of efficient pricing.

To support this, we recommend that the AER as part of its consultation and information guideline specify the following:

- the consumer consultation to be undertaken as part of developing pricing structures statement that forms part of the distribution business regulatory proposal;
- the consumer consultation to be undertaken by a distribution business in updating its statement of expected price trends and pricing structures in its annual pricing proposal;
- the information required to be provided regarding the consumer consultation to be undertaken by a distribution business in developing its statement of expected price structures as part its regulatory proposal; and
- the information required to be provided regarding any proposed changes to the network pricing structures contemplated in annual pricing proposals.

In this regard we note that IPART has also proposed the inclusion of new consultation requirements within the rules, focussed specifically on distribution businesses annual pricing proposals. They have submitted a rule change request to the AEMC for consideration.[299] We intend to publish on our website and commence consultation on these proposals after the publication of this final report.

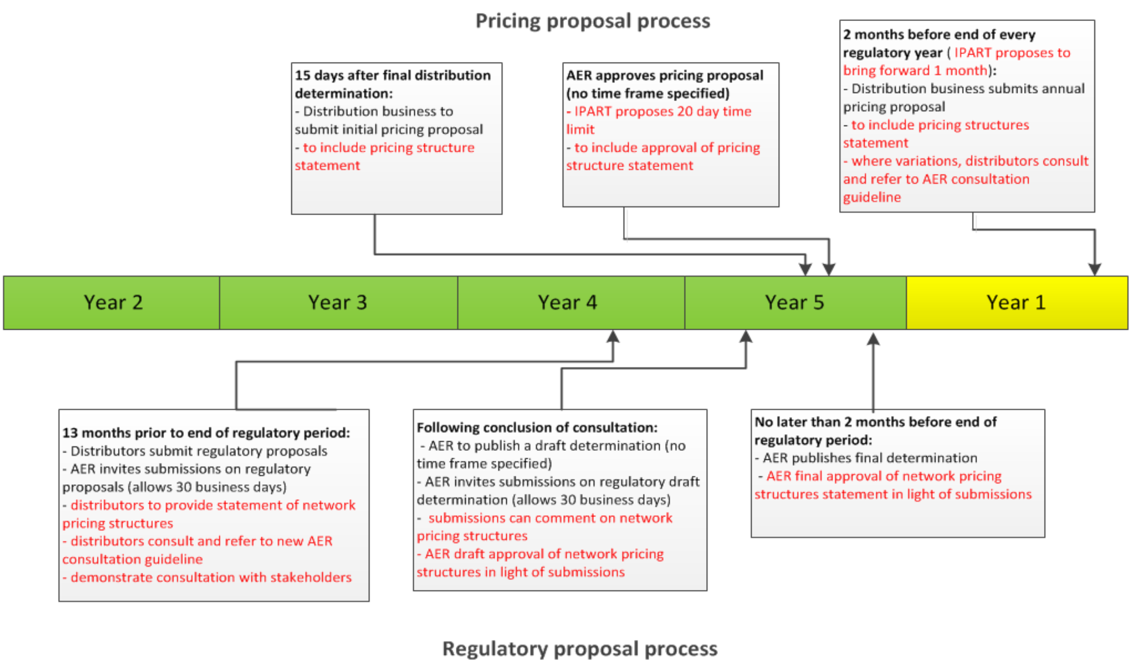
IPART has additionally proposed to bring forward the timing for network businesses to submit pricing proposals to the AER (by one month) and place a time limit for AER to review these price proposals and publish them (20 days), so that retailers have sufficient time to consider and incorporate network prices in their retail prices. At this stage we consider that 20 days may not be sufficient time for the AER for approving pricing proposals given that additional consideration will need to be given to pricing

299 IPART, Proposed Changes to Annual Network Price Setting Arrangements in Chapters 6 and 6A of the National Electricity Rules, 12 September 2012. The proposed rule change can be accessed at: http://www.ipart.nsw.gov.au/Home/Quicklinks/IPART_Submissions_to_External_Reviews/IPART_Submission_-_Proposed_changes_to_Annual_Network_Price_Setting_Arrangements_-_September_2012

structures - where there are changes from the initial document. We will address these issues in the consultation process.

In figure 6.6 below we set out diagrammatically how we see our recommendations and those of IPART reflected in the distribution determination and annual pricing proposal processes.

Figure 6.6 Incorporating new consultation requirements on network pricing structures in the rules



6.3.7 Addressing risks for retailers under flexible pricing

RECOMMENDATIONS

We recommend that:

- **The rules are amended so that where interval or smart meters are in place they are always read on an interval and not on an accumulation basis. The NEM metrology procedure Part A and any supplementary Jurisdictional metrology metering codes should be amended accordingly.**

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 and flexible pricing options that better reflect consumers' actual consumption profiles.

Retailers operate in a competitive market so they should, in principle, have incentives to offer flexible pricing options and smart meters to consumers where there is a commercial benefit in doing so. Consumers with a flatter than average profile would be expected to save money by moving from a non-flexible retail price to a flexible retail price on the basis of that consumer's actual wholesale energy costs.

Retailers would benefit by offering flexible pricing options to these consumers and sharing in the cost savings. In addition, smart meters would allow retailers to offer a range of flexible pricing options (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 smart meters nor more innovative and flexible pricing options have been implemented by retailers.

One potential disincentive for retailers implementing flexible 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 (due to critical peak pricing (CPP) for instance). We do not consider this to be a significant issue however. 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 flexible prices, for the following reasons:

- First, even with demand response, demand on days when a CPP is likely to apply is likely to be higher than normal for a typical day of that season. So to the extent a retailer has contracted (usually, several months in advance) in anticipation of a typical day for that season, the retailer is unlikely to become significantly over-hedged as a result of demand response from CPP
- Second, to the extent a retailer is over-contracted due to demand response (perhaps because it contracted in anticipation of a hot day for which no CPP would be called), demand response would provide it with a windfall gain, as the contract strike price is likely to be lower than the wholesale spot price on such a day
- Third, putting contracting to one side, there is less wholesale energy purchase risk to manage with CPP because much of the risk from high wholesale prices is transferred to the consumer, who pays a higher price for energy consumed during a CPP period.

All this means that demand response is unlikely to impose harmful risks on retailers. If anything, demand side participation by consumers could reduce retailers' costs and their need to hedge their expected wholesale price exposures.[300]

300 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

In their submissions to both the directions paper and draft report participants have identified three other issues that may be contributing to a lack of flexible pricing at the retail level: risks associated with recovering costs of installing smart meters; perceived regulatory risks associated with retail price regulation; and risk associated with a policy of reversion between the different types of prices. We consider metering issues in Chapter four. The remaining issues are considered below.

Price regulation

A potential issue for retailers offering flexible pricing options themselves is if they simply follow the standing offer prices set by first tier retailers (incumbent retailer)[301] required under price regulation. To determine whether existing standing offers are likely to present such obstacles, it is worth examining how second tier retailers (new entrant retailers in a distribution area) typically set their retail offers. If they usually reference their prices to standing offer prices – such as offering a percentage discount on standing offer prices published by the default retailers – then this could discourage more flexible pricing options.

New entrant retailers appear however to be publishing their own prices without reference to the standing offers of incumbent retailers.[302] Many retailers offer discounts on their gazetted rates for direct debit/prompt payment.[303] In other words, new entrant retailers do not appear to be defining their retail offers as a percentage discount off standing offers. This suggests that the structure of standing offers should not in itself deter retailers from developing and offering flexible pricing options.

In the directions paper, we asked if specific aspects of the state based retail price regulation were deterring retailers from offering innovative prices and products. No stakeholder raised any specific problems with how price regulation might impair setting of flexible pricing options in each of the states. Most of the points raised by retailers are concerns about the general impact of retail price regulation on profits. This was reiterated in submissions to the draft report. For example, AGL noted that it did not see retail regulation as preventing setting of flexible prices, but that it did see retail regulation as squeezing profit margins.[304] This view was echoed by the ERAA who also noted that competition appeared to be strongest in Victoria, which was the only state without retail price caps.[305]

We are not convinced that simply removing price regulation will result in all retailers offering a wide range of DSP products to consumers. Under the existing arrangements

301 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

302 In Victoria, all retailers have to publish all their prices in the Government Gazette – they cannot simply set prices referenced to other retailers' prices

303 In NSW, second-tier retailers like AGL and Red Energy typically publish their own prices for single rate, controlled load and time of use structures for each distribution area

304 AGL submission to the draft report, p 8

305 ERAA submission, p14

in states which have retail contestability, retailers are already able to provide diverse market offers, including innovative DSP related tariffs, to retail consumers.

While we do not agree that retail price regulation per se should discourage retailers from introducing flexible prices (provided sufficient headroom is allowed for in regulated prices), we do consider that price regulation could add 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. The AEMC has responsibility for reviewing retail competition periodically in each of the states and territories of the NEM. A focus in these reviews going forward will be to examine whether the regulated retail pricing framework in anyway hinders introduction of efficient and flexible pricing options by retailers.

Reversion risk

As discussed above, one measure governments may consider in assisting the market to transition to flexible prices is to allow consumers to revert between flexible and non-flexible retail tariff structures. The purpose would be to increase consumer confidence in flexible pricing by allowing them to test the benefits of flexible pricing options while facing limited exposure to the impacts.

Retailers have noted that they could face risks when their consumers revert between the two different tariff structures. There are two types of risk:

- If the retailer continues to be charged a flexible network tariff by distributors in respect of their consumer's consumption after they move to a non-flexible retail price structure; and

- If the consumer is settled on the smart data and does not revert to being settled on the NSLP after moving back to a non-flexible retail price structure.

We have addressed the first of these potential risks through our recommendations for linking standing retail tariff structures to network tariff component. Thus we would expect that where a consumer moves back onto a non-flexible retail tariff structure this will be underpinned by a non-flexible network tariff component.

Regarding the second potential risk, we note that this will depend, going forward, upon the methodology employed by the state regulators for setting regulated retail prices; in particular whether this will continue to be done on the basis of the NSLP.

We consider that once consumers have smart meters installed and an accurate consumption profile can be developed obtained for those consumers, that settlements should occur on the basis of interval data and not the NSLP (that is, on an accumulation basis). This is consistent with removal of cross subsidies and moving to more cost reflective pricing for consumers over time. As more smart meters are installed the NSLP will increasingly become less relevant, as interval based data will allow for more accurate profiling and less averaging for the purposes of calculating regulated retail prices.

In the meantime the difference between the NSLP and actual consumption profile of the reverting consumer will provide the retailer with either a gain or loss depending on whether that consumer is more or less peaky relative to the average consumer profile encapsulated in the NSLP. State regulators will need to have regard to this potential issue in setting regulated prices.

Some stakeholders questioned whether any amendments to the market arrangements are needed to introduce this policy. In this regard, we note however that there are specific derogations in place in the NEM metrology procedure Part A that mean the arrangements differ across NEM jurisdictions. For example, if a consumer has an interval meter in Victoria or South Australia then that meter will be settled on the basis of actual interval data.

If the consumer has a type 5 (manually read) interval meter in New South Wales, Australian Capital Territory or Queensland and the annual consumption level is below a certain threshold (referred to as the type 5 accumulation boundary) then the distribution company as responsible person has the discretion to collect accumulation data rather than interval data, in which case the retailer must settle the meter on the basis of an accumulation reading and the NSLP. In New South Wales and Australian Capital Territory the type 5 accumulation boundary is set at 100 MWh per annum; in Queensland the boundary is set at 750 MWh.

We recommend therefore that the rules are amended so that the type 5 accumulation boundary value is set to zero MWh per annum in all jurisdictions. The NEM metrology procedure Part A and any supplementary jurisdictional metrology codes would need to be amended accordingly.[306]

Some distribution network businesses raised issues with the costs of applying this policy to manually read interval meters. Ergon Energy noted that if this recommendation is adopted then there may be an impact on meter reading costs. They argued that additional infrastructure would be required to read and house interval data which will in turn result in additional costs to consumers.[307]

All other things being equal, we agree that the manual meter reading costs would be slightly higher for the interval data collection based on the additional time spent at each meter downloading the data if the metering installation classification remained as a type 5. We also note however that Section 2.4.27 of the AEMO Metrology Procedure Part A states “A type 5 metering installation must have provision for future upgrade to a type 4 metering installation without the need for replacement of the measurement element”. Therefore we question the rationale of installing interval meters without the

306 The Rules (7.14.1) require AEMO to publish the Metrology Procedure (MP). The MP was initially a jurisdictional responsibility. The Rules (7.14.2) allow the MP to include “jurisdictional metrology information” (in the way of standards or requirements) in relation to type 5, 6 and 7 metering installations (only). For example, how interval (type 5) meters must be read or when interval meters can be replaced by accumulation meters, etc. Only jurisdictional Ministers can impose or change the jurisdictional metrology information for that jurisdiction – ie the AEMC cannot change it acting alone

307 Ergon Energy submission to the draft report, p 22

supporting systems to manage interval data. It would also seem inappropriate for the regulatory to have approved the extra costs for interval meters installed by distribution businesses if the interval meter can only be operated as an accumulation meter.

7 Distribution networks and DSP

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 support the delivery of DSP by other parties, such as aggregators, through efficient and flexible network tariffs and publishing planning information.

Under the current arrangements, networks may not be fully capturing the value of DSP. 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 may not be developing the best solutions for consumers.

The regulatory arrangements governing distribution network businesses are subject to significant change which will help to address these issues. The framework for revenue determinations is being amended through the economic regulation of network service providers rule change and a national distribution network planning and expansion framework has been introduced.

To complement these reforms, we recommend that changes are made across the following areas:

- Reform 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. This includes creating separate provisions for an innovation allowance.

- Adopt a two-part approach 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 profit under the revised demand management incentive scheme.

- Make minor amendments to the NER to provide (a) clarity that AER can have regard to non-network market benefits when assessing efficiency of expenditure; and (b) flexibility in annual tariff process to manage potential extra volatility of DSP costs.

DSP must make financial sense for both consumers and network 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.

We are not recommending introducing a peak demand reduction target obligation on distribution network businesses. Such targets may not actually lead to any reduction in capital investments, are very complicated to apply and do not recognise that peak demand growth is not solely within the control of the

network business. Also, imposing targets which are external to the incentive regulation framework could lead to conflicting objectives for the businesses and the regulator to manage.

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 need, want and are willing to pay for, and to do so efficiently. With respect to DSP, the objective of the regulatory framework is for the outcome where network businesses pursue and develop DSP projects when such projects are more efficient than capital investment.

The regulatory framework will not be consistent with this objective 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. Relevant considerations in this regard concern the arrangements governing the way in which distribution businesses get approval to recover their expenditure and how they determine network tariffs.

Evidence suggests that under the application of the current regulatory framework, in combination with other influences, network businesses may not be reacting to the incentives in the way intended with respect to pursuing efficient DSP projects. This review has 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 1, 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 flexible 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. This review has highlighted that moving from this current pilot and trial stage to mass deployment of DSP is a pertinent issue facing the industry.

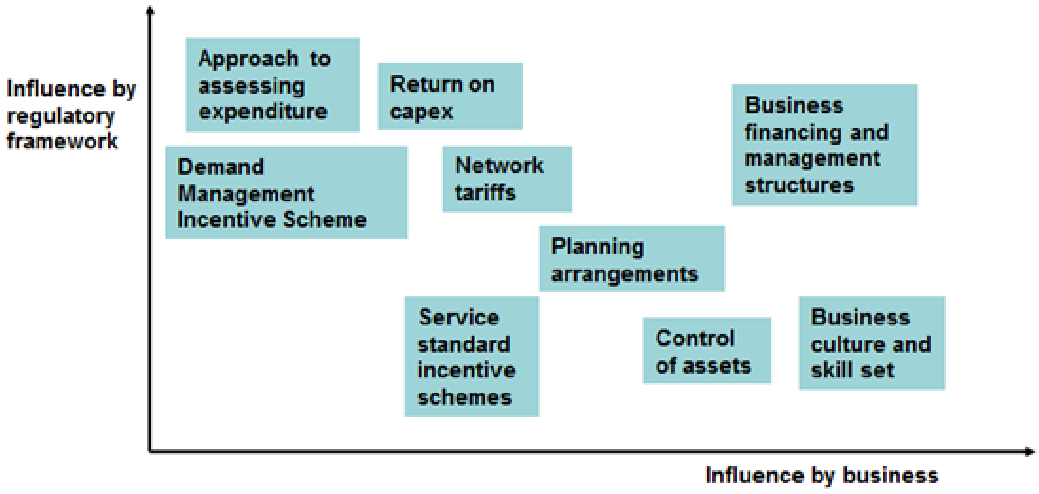
In the directions paper we found that the current arrangements could be discouraging distribution businesses from pursuing efficient DSP projects. Stakeholders – and the businesses themselves – generally agreed with this finding. According to the businesses, under the current arrangements there is insufficient financial reward to motivate them to undertake 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 relate to the business' planning and investment decision making framework:

- the regulatory framework for assessing and approving operating expenditure (opex) and capital expenditure (capex) and the potential profit associated with DSP projects;
- differing financial returns of opex and capex (the regulatory framework has a powerful influence on this);
- the ability of businesses' planning process and procedures to generate network and DSP solutions;
- the businesses 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 one solution may have difficulty in adequately addressing all the issues. Also, it is important to note that some of the incentives that businesses face may not be the direct consequence of the regulatory framework. Favouring capital investment solutions can relate to engineering preferences and an understandable tendency to continue to rely on processes and approaches that have been successful in the past and that the organisation is very comfortable in executing. 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 influenced by both the regulatory framework, other legal requirements outside the NEL, 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



Source: AEMC

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 6 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 the efficiency of the expenditure proposed by network businesses;
- 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 has progressed a number of rule changes on the regulatory framework for network businesses.[308] These address, among other issues, how the current arrangements provide incentives for efficient capital expenditure and determine the

308 AEMC, *Economic regulation of network service providers Rule change*, final position paper, 15 November 2012.

allowed rate of return. As such, they relate to the issues being addressed in this chapter. We took into account the final position paper on these rule changes when developing our recommendations on these issues.

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 efficient and flexible 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. The AEMC has recently made a rule which establishes a national framework for electricity distribution network planning and expansion, including new demand side obligations on distribution businesses[309]. This new rule requires the distribution businesses to have greater regard to DSP potential, and publish more information to assist potential DSP providers identify DSP opportunities and understand their value and operating requirements. Also businesses will be required to engage more with DSP service providers. These new arrangements will commence from the 1 January 2013 and represent a positive step forward and will complement appropriate financial incentives.

We recognise that additional DSP and distributed generation may make forecasting network demand over a distribution determination period more difficult. A number of submissions from distribution businesses recognised that this will create additional revenue risks for businesses which are subject to the price cap form of control. We note that our recommendations to increase AEMO's role in demand forecasting for market operational purposes may help to address this risk.

Another implication of increased volatility in demand is that capital investment approved at the start of the regulatory determination period may become unnecessary during the determination period if forecast increases in demand do not materialise as expected. This issue can be addressed through the inclusion of option value as a category of market benefits for consideration under the regulatory investment test for distribution (RIT-D).

Option value is a benefit that can result from a DSP option delaying a network investment by a short period of time, allowing new information to become available that can affect the need for, or specification of, the original network investment. The improved information, say on outturn demand as compared with forecast demand, allows a network investment to be more appropriately specified, leading to potential cost savings. The benefit therefore of a network investment deferral is a combination of

---

309 AEMC, Distribution Network Planning and Expansion Framework final determination, AEMC, 11 October 2012. This includes 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.

the deferred and reduced capital expenditure, plus the associated option-value that it creates.

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 consumers.

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 consumers. 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. 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 2012-2013. 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 SA Power Networks 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.

- 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. The critical peak demand tariff resulted in a significant customer response, with a reduction of 88MW in summer peak demand (see Box 6.1).

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 networks incentive to undertake DSP;
- potential bias towards capital investment instead of operating expenditure;
- placing a target obligation on network businesses regarding DSP; and
- improving clarity and flexibility for DSP related expenditure.

The next sections step through each of the above areas and present the reasoning behind our recommendations. Where we are recommending rule changes, we have provided draft specifications which detail the nature of the rule change attached to this report. 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 to consumers over the asset life of the capital investment.

Stakeholders have different opinions on the best way to address this matter. Distribution businesses 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 solution was to amend existing arrangements to provide it with the ability to develop better capex incentive mechanisms and to reform the demand management incentive scheme. Some consumer and environment groups want to impose targets on network businesses to require them to spend more on DSP (and distributed generation) solutions. These groups consider that incentives alone will be insufficient to result in all network business promoting DSP.

7.3.1 Potential return for network businesses implementing DSP projects

RECOMMENDATION

We recommend that the NER is amended to reform the application of the current demand management and embedded generation connection incentive scheme so that it:

- **a) provides an appropriate return for DSP projects that deliver a net cost saving to consumers; and**
- **b) better aligns network incentives with the objective of achieving efficient demand management.**

This would include creating separate provisions for an innovation allowance.

This section looks at the potential return a network business could earn if it pursues DSP options and assesses whether the current arrangements provide a sufficient profit opportunity. This opportunity must be sufficient to motivate businesses to use the potential of DSP as an efficient alternative to capital infrastructure.

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, transaction 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 extra costs and raise risks for the business. However, the extent of this will vary according to the nature of each specific project. Given that very little DSP has been activated today by networks, another relevant factor is that it is likely that implementing a DSP solution will take some time.

. 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. This scheme has the objective of providing an incentive for distributors to implement efficient non-network alternatives or to manage the expected demand for standard control services in some other way. However to date, this scheme has been applied in a very limited manner and operates as a pass through of costs incurred in undertaking approved DSP activities plus an innovation allowance.

This means the scheme is not a "true" incentive scheme; that is, a scheme which allows a business to earn extra rewards where it has delivered defined goals. For this reason networks may not be properly incentivised to explore and develop DSP options instead of capital investment given the relative risks and characteristics of such projects. We also note that both the AER and network businesses have raised concerns about the administrative burden and costs of the current scheme.[310]

To address this, we are recommending that a more comprehensive demand management incentive scheme is available to be applied to distribution network businesses. We are proposing that this is implemented through a rule change which adds more principles and criteria for the application of the demand management incentive scheme.

The rule change will also include an objective to clarify the purpose of the incentive scheme – that is to correctly incentivise the network business to develop and pursue DSP option as an efficient alternative to capital investment. This includes permitting the network businesses to retain a share of the non-network related market benefits arising from the DSP option.

The majority of stakeholders agreed with the need to reform the current incentive scheme and supported the inclusion of guiding principles and an objective clause into the NER. The AER accepted the inclusion of the proposed principles for the revised incentive scheme in the NER but noted that it is important the principles provide appropriate discretion for the scheme to be adapted over time. Also, the network business raised concerns that some of the proposed principles may make the scheme too complicated.

We note that the NER already provides the AER with broad discretion with respect to the design and application of the demand management incentive scheme. However for a number of reasons the current scheme has been applied in a very limited manner. The AER has for some time refrained from making any material changes to its current scheme while various DSP reviews have been ongoing. We consider that it would promote the NEO to provide more principles, criteria and an objective into the rules on how the incentive scheme can be applied.

This change will address current ambiguities and clarify the application of the demand management incentive scheme, and hence put beyond doubt the interpretation of the provisions. The change will also promote flexibility and adaptability, enabling the regulator to make decisions that take account of changing circumstances and different characteristics of network businesses. Overall the change will provide more opportunity and certainty for networks to pursue DSP projects which deliver savings to consumers and therefore will in the long run interest of consumers. This position has been supported by all stakeholders, including network businesses and the AER. We

310 The Productivity Commission draft report on network regulation also makes the recommendation that the AER should review the operation of, and the incentives provided by, the Demand Management and Embedded Generation Connection Incentive Scheme.

also consider that this recommendation will support other reforms set out in this final report.

Proposal for the reformed incentive scheme

An incentive payment scheme is only effective if it changes the business' behaviour and can only be permitted where such change in behaviour results in a net cost saving 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. Reforming the scheme in such a manner would help to level the playing field between capital investment and DSP projects.

The draft report put forward two mechanisms for the reformed scheme which would capture situations where both consumers and network businesses can gain a net benefit. We do not intend to mandate these mechanisms in the new rule but instead give the AER the ability to develop similar mechanisms.

In the final position paper 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. We propose that the same approach is applied to the recommendations put forward in this chapter's reforms to the demand management incentive scheme. 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.

The reformed demand management incentive scheme will now include the following objective:

- to provide an appropriate return to the network businesses for DSP projects which deliver a net cost saving to consumers to support efficient demand management by networks.

The application of the reformed demand management incentive scheme will have the following features:

- Complement the normal expenditure determination process and planning arrangements.

- Not reward a network business for doing DSP activities which do not deliver a corresponding net benefit across the supply chain to consumers. Therefore DSP projects assessed as being efficient quantify for the potential incentive payment offered under this scheme.

- Coverage of all forms of demand side participation, including distributed generation.

- Payment of reward to reflect the timing of benefits in order to smooth the bill impact on consumers.

- Inclusion of a maximum percentage of non-network expenditure related market benefits (i.e., generation cost savings) which can be retained by network businesses (the actual percentage may vary by business and by time).

- Provision that projects approved under this scheme must undergo the same cost approval process as all capital or operating expenditure.

- DSP projects must address an underlying network issue in order to qualify for inclusion in the incentive scheme.

- Recognition of the need to incentivise networks over the long term and not just the forthcoming regulatory period.

- The inclusion of methodologies to measure the extent of the consumer demand response should be consistent with the baseline consumption methodologies approved for the demand response mechanism proposed for the wholesale market (see Chapter five).

- Inclusion of an allowance for profit foregone due to the decrease in throughput volumes due to DSP projects approved under the DMEGCIS or as part of the distribution determination process.

- Inclusion of the ability for the AER to impose penalties for non-compliance with performance standards.

In developing the reformed demand management incentive scheme, the AER must have regard to:

- market rates for comparative DSP services;

- the value that consumers would have obtained if they had used the electricity at that time they participated in the DSP (this foregone benefit is should be treated as another cost in the assessment);

- the range of market benefits permitted under the regulatory investment test for distribution;

- the effect of a particular control mechanism on incentives to adopt or implement efficient non-network alternatives;

- the extent which the network business is able to offer efficient pricing structures;

- the possible interaction with other incentive schemes; and

- the willingness of consumers to pay for any increases in network tariffs at certain times resulting from the implementation of the scheme.

We also consider that the scheme will include some performance indicators applied to measure its success so that consumers can be certain that they are getting 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.

We also note that establishing performance standards could lead in the long term to the AER imposing penalties for non-compliance with performance standards. We recognise that there are a number of issues with this, and hence this is not likely in the short term. However the ability for the AER to do this would be in the rules to be consistent with other incentive schemes. These issues will be addressed through the rule change process.

The specific application of the scheme will be developed through consultation between the AER, network businesses and other interested stakeholders. There may be merit in allowing each network business to propose how it thinks the incentive scheme can be applied. The AER would approve or adapt the application based upon the set of principles, and the 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 efficient and flexible pricing offers.

Section 8.3.2 discusses the impact of DSP projects on reducing volumes and hence potentially networks' profit and the role of compensation mechanism as part of incentive scheme. In this regard, any compensation should be reference to profit and not revenue as there may be some costs savings associated with DSP projects. 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 when or where needed.

Incentive scheme to capture boarder market benefits

Under the present arrangements a network business would only retain the benefit that the DSP project creates for the delivery of network services (that is, a share of reduced cost, assuming the quality of other aspects of network service do not change). However, the DSP project may create benefits at other levels of the supply chain – for example, as well as avoiding distribution costs, a distribution-driven DSP solution may:

- reduce losses on the distribution network;
- avoid capital expenditure and reduce losses on the transmission network; and
- avoid generator operating and capital expenditure.

As these wider benefits do not translate into a financial outcome for the network business, some DSP initiatives that would be efficient from a NEM-wide perspective (that is, where the NEM-wide benefit is greater than NEM-wide cost) may not be privately profitable to the network business and so do not proceed. Network businesses have argued that the current incentive scheme does not provide sufficient reward for pursuing DSP that, in turn, generate wider social benefits.

Under our proposed reforms to the incentive scheme, networks will be able to retain a share of the benefits which the approved DSP projects creates at other levels of the supply chain. This will encourage network businesses to take into account these external benefits when undertaking a financial evaluation of projects.

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 11, by motivating network businesses to consider and implement DSP projects which deliver market benefits across the supply chain. This happens because the ability of the network to retain a portion of the market benefits will make certain DSP efforts that provide net benefits to consumers, financially rewarding to the network. Without the ability to retain that portion of the additional benefits the network business would have not undertaken the DSP and costs would have been higher for consumers.

Doing so would mean that the incentives for the network business are better aligned with the interests of consumers consistent with the NEO. It also means that the incentive scheme will not be rewarding a network business for doing DSP, without there also being corresponding net benefits to consumers.

We believe that the value of the share of market benefits must 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. However some network business disagreed with any caps. Ausgrid argued that the establishment of a cap would discourage DSP projects with low positive market benefits and severely limit innovation. Ausgrid instead proposed that the network incentive be established at 30 per cent of net market benefits with 70 per cent to be retained by consumers. Under our proposals, the maximum percentage share will be a matter for the AER to decide upon.

Need for standard methods to valuing DSP costs and benefits

These 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.[311] 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:[312]

311 Ausgrid, directions paper submission, p.3.

312 Energy Networks Association, directions paper submission, p.15.

- accrue outside the network business boundary (that is, to another network level and generation);
- are not directly assessable (for example, network benefits to low voltage (LV) or medium voltage (MV) feeder levels); and
- 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 incentive scheme. Ausgrid suggested that the AEMC may be best placed to calculate standardised values related to peak demand reductions in the generation and transmission sectors.[313]

Other stakeholders suggested alternative approaches. AGL considered 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.[314] 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.[315] 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.[316]

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. Estimating the broader market benefits from a particular DSP project is feasible but can be complicated.

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 for distribution (RIT-D) process. We note that the work on defining the baseline consumptions for the proposed demand response mechanism (Chapter five) plus the modelling of benefits study (see Chapter ten) could assist the AER in developing standard methods. The ability for the AER to allow an innovation allowance will be retained under separate provisions from the incentive scheme.

313 For a summary of the issues raised by stakeholders in submissions to the draft report, see Appendix G.

314 AGL, directions paper submission, p.7.

315 EnerNOC, directions paper submission, p.17.

316 MEU, directions paper submission, p.37.

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 can lead to more cost effective investment in the future. To date the DMIA allowance is small, totalling no more than $1 million a year for each DNSP.

The draft report consulted on whether is merit in retaining and separating out the arrangements for an innovation allowance in light of the proposals regarding the incentive scheme. That report noted that the costs of such allowances are borne by electricity consumers and that there are sources of government funding being offered for investment in clean energy technology (for example, Smart Grids, Smart Cities trial). An innovation allowance for distribution network businesses must not duplicate these arrangements.

We also noted that 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.

The network businesses submissions supported the DMIA being retained. Ergon stated that the innovation allowance should remain to fund pilots and trials which do not demonstrate an immediate benefit. Both SA Power Networks and Ausgrid thought that it would not be appropriate to fund DSP innovation solely through government programs. Essential Energy commented that if the DMIA was a government program, the entire process becomes a higher risk category and with less reliable funding sources, resource constraints and shorter time periods for planning would most likely result in less valuable outcomes.

The AER questioned the need for a separate innovation allowance given the other reforms. It argued that a revised incentive scheme, plus the new regulatory framework will provide the right incentives for DNSPs to do DSP and information on the potential of DSP will be improved under the new distribution planning framework.

The Productivity Commission draft report into network regulation argued for an increase in the size of innovation allowance. They considered that extra allowance is needed to fund trials in new time tariff structures and calculate demand elasticity because both the AER and networks need more data and understanding of consumer responses in order to set appropriate cost reflective network tariffs.

Ausgrid also argued for an increase in the size of the innovation allowance, given the growth of embedded generation.[317]The network businesses commented that the growing penetration of smaller generators will prove challenging for networks and there is a need to find better technical and commercial answers to this. The AEMC recently made a rule to expand the scope of the demand management incentive scheme

317 AEMC, *Inclusion of embedded generation research into demand management incentive scheme*, final determination, 22 December 2011.

to also include connecting embedded generation. We agree that any innovation scheme for demand management must also cover issues relating to embedded generation.

Our final advice is that the ability for the AER to allow an innovation allowance should be retained under separate provisions from the incentive scheme. The ultimate objective of the innovation allowance scheme is to deliver benefits to end consumers by enhancing efficiency in network operating costs and capital expenditure. Therefore giving the regulator the flexibility to apply an innovation allowance as part of the regulation determination is consistent with the NEO.

With respect to the design of the innovation allowance we consider that a framework which gives the AER discretion to design the scheme and determine the size of the allowance, subject to certain principles, remains appropriate. The scope of the innovation allowance should cover all forms of DSP, including connecting and exporting of distributed generation units. The need for such an innovation scheme is likely to decrease over time as networks expertise increases.

Some networks questioned whether an allowance which only recovers costs would incentivise innovation. The purpose of the innovation allowance should be to give networks money to try things and keep them whole in those efforts. The trials are unlikely to be big enough to significantly endanger profits or to entail the sacrifice a significant level of longer term benefits. The opportunity for profits in the future from successful DSP and being made whole in the present to engage in activities to prove up what will be successful should be enough.

We also recommend that as a condition of the innovation allowance, the network business must be obliged to share all results and data with the AER and other networks businesses. Furthermore, we consider that the results should be published so that they can be seen by other participants. This will improve AER's knowledge of demand side activities and the degree of consumer behaviour and therefore will assist it in carrying out its regulatory functions. This requirement will also make the innovation more efficient as each network can learn from the experience of the others – this is justifiable given that (a) the networks don’t compete with each other in this regard, and (b) the learnings are being funded with consumers’ money.

We propose that these new arrangements will be implemented as part of the reformed demand management incentive scheme rule change.

A demand management incentive scheme for transmission network business is not recommended

Transmission services can and do contribute to more effective demand side participation, albeit in a more limited capacity compared with retailers and electricity distributors. Also transmission businesses are required to consider the potential for DSP options under the regulatory investment test for transmission.

Under the current rules, the demand management incentive scheme is only available for distribution businesses and not transmission businesses. Therefore the draft report asked for stakeholder views on whether including provisions for a demand management incentive scheme should be included in the transmission rules.

Grid Australia considered that focussing on improved incentive design through the network regulation rule change is preferable to additional prescription in the NER requiring the use of demand side participation by transmission network businesses or further administrative requirements on transmission network service providers.

Both Jemena and United Energy considered that it is not necessary to apply demand management incentive schemes to transmission businesses given the existing tariff structure for transmission tariffs and because such businesses have limited opportunity to control load. Other parties argued that similar principles should apply across both distribution and transmission.

We do not recommend a rule change that would include a demand management incentive scheme in the transmission arrangements. The incentive regulation framework for transmission business is subject to change under the network regulation rule change plus the AEMC Transmission Frameworks Review is looking at the issue of transmission incentives generally.

7.3.2 Network tariff structure influencing networks incentive to undertake DSP

RECOMMENDATION

We recommend that a combination of two approaches to mitigate the problem of network profits being linked to actual volume.

First, the pricing principles in Chapter 6 of the NER need to be amended to provide greater guidance on how network businesses set their tariffs to reflect their costs. Secondly, we recommend that the AER considers expanding the current application of the foregone profit component of the demand management incentive scheme to cover DSP tariff based projects as well.

When a network business develops tariffs which are based on consumption volumes, its profits could depend upon the level of actual volumes. With such a tariff structure, the business may 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:[318]

- the form of regulatory control applying to the business;[319]

---

318 Further explanation on profit incentives for distribution businesses is provided in *AEMC Power of choice review – giving consumers options in the way they use electricity*, supplementary paper to directions paper, DSP and profit incentives for DNSPs, March 2012.

319 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

- the relationship between volume, and the business' costs; and
- whether the network tariff structures and levels appropriately signal its costs and thereby promote efficient consumption.

Typically it has been assumed that distribution network businesses have an incentive to set efficient tariffs. The NER's pricing principles have been based upon this assumption.[320] 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. If volumes decreased, the corresponding reduction in costs would offset any revenue loss, thereby leaving the network's profits unchanged. This assumption does not hold in practice. There are two main reasons for this:

(a) the technical and policy restrictions on networks to price at cost reflective levels; and

(b) the link between volumes at peak times, higher costs and lower profits is not straightforward for a network business. This is 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.[321] That said, the degree of this incentive will differ by network business and situation.

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 (and as a result, consumers bear all risks associated with the energy and demand forecast). 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.

320 *Distribution Pricing Rule Framework*, NERA report to the Network Policy Working Group, December 2006, p.12.

321 This is being driven because a proportion of the fixed costs are being recovered in the variable charge.

The AER has carried out an 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 2006–2010 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.[322]

The point is that the networks are exposed to this revenue risk under the weighted average price cap. Those that can forecast better, and can present those forecasts more convincingly to the regulator and that price creatively can profit under this form of control.

The AER has questioned whether, where interval meters are available, distribution businesses will set a network tariff that which reflects efficient costs.[323] 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, 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 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 ten times the off peak tariff.

As explained above, if network businesses are not setting tariffs which are equal to the 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:

1. pricing principles in Chapter 6 of the NER are amended to provide greater guidance on how network businesses should set their tariffs to reflect their costs; and

2. expanding the application of the foregone profit component of the demand management incentive scheme to cover DSP tariff based projects as well.

---

322 AER, *Preliminary positions, Framework and Approach Paper for NSW Distribution businesses*, June 2012, p.55

323 AER, *Preliminary positions, Framework and Approach Paper for NSW Distribution businesses*, June 2012, p.47

Reforming the distribution pricing principles

We consider that it will be necessary to amend the pricing principles in Chapter 6 of the NER, in order to provide greater guidance on how network businesses determine 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 for changes to the distribution pricing principles.

The aim of any revisions to the existing pricing principles will 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 will be encouraging distribution businesses to actively develop and improve their tariff structures to meet the defined principles.

The objective of this amendment is for distribution network business to have appropriate incentives and guidance to develop network tariffs which reflect their cost drivers. In addition, that there is sufficient regulatory scrutiny from the AER and stakeholder consultation during the tariff setting process. This will provide the right framework to prevent the network businesses from developing network tariff structures which increases their profits at the expense of DSP projects. Further discussion on this recommendation is contained in section 6.3.6.

Application and scope of the foregone profit component of the demand management incentive scheme

Given the practical limitations and transaction costs of applying fully 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. changing the form of control from price cap to revenue cap regulation;
2. selective compensation for the loss of allowed revenues due to their DSP programs;
3. recover costs through a high fixed charge which results in revenue not being significantly dependent upon volumes; 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 profit component.[324]

In the draft report, we presented our view that changing the form of regulation from price cap to revenue cap would not be the appropriate answer. We have retained this position for the final recommendation.

Under clause 6.2.5 of the rules, AER has the option to impose such forms of control on regulated distribution network services. Depending on the form of regulation, the regulated business can be exposed to anything from none of the volume risk (for total revenue caps) to all of the volume risk (for price caps).

Under a revenue cap, businesses will most likely be motivated to collect revenues in a manner that generates the least amount of consumer 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 tariffs 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. Further while a revenue cap may make the network less interested in actual volumes it will not on its own make them less interested in supply-side solutions. Increased forecast demand, once approved by the regulator, will translate into a higher Regulatory Asset Base (RAB), which a revenue cap will guarantee the network will be able to recover (including financial return).

For these reasons, any move towards revenue cap regulation would need to be supported by introducing more detail prescription in the rules on how distribution network businesses set their network tariffs.[325] In addition 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 note that the Productivity Commission draft report on network regulation recommended that all distribution businesses become subject to the weighted average price cap form of control.

Instead, we recommend that the AER expands the current application of the foregone profit 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. This is a change from the current mechanism which includes a foregone revenue allowance. This change recognises that a decrease in volumes may have cost savings for the business and therefore a foregone revenue allowance could over-compensate the business.

324 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 DMEGCIS. This applies to businesses with a price cap and only covers non-tariff based schemes.

325 Also under a revenue cap, a DNSP will not be incentivised to meet additional demand if that additional demand delivers increases costs.

If DSP projects are not included in the foregone profit component of the scheme, this may lead network businesses to design tariff based DSP projects which minimises the impacts on their revenue (that is, revenue neutral). Networks need to 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 profit.

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. Therefore such tariff based DSP projects should be included in the foregone profit component of the incentive scheme.

This aspect of our proposed approach may not be required in the short term. Over time the networks should be expected to understand the elasticity of these tariff structures and to incorporate them correctly into their forecasts and tariff structures.

Some submissions disagreed with this recommendation and argued for the AEMC to require full de-coupling of volumes and prices. However we consider that our proposed recommendations set out in this chapter provide the most efficient framework as it permits the AER to decide the best course of action taking a combined view of the relevant parts of the distribution determination. These include the form of control and the application of the reformed demand management incentive scheme.

PricewaterhouseCoopers (PwC) state that there may be merit in exploring alternatives to a tariff basket form of price control.[326] They propose a possible alternative to the current price cap form of control which is a hybrid form of price control. Under this alternative revenue is de-linked from prices and linked instead to more direct causes of cost (it takes the form of a revenue cap with a cost-driver element). Exploring different forms of control is permitted under the rules, and a change of the sort proposed for consideration by PwC would only require a change to the AER's practice.

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.

---

326 PwC, *Incentives for network driven DSP*, Report to Energy Networks Association. Attachment to the ENA submission to of *AEMC Power of choice review – giving consumers options in the way they use electricity*, draft report, September 2012.

We stated in the directions paper (and supporting supplementary paper) that there could be a bias towards capital expenditure and 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;

- the current rules provide a greater guarantee of recovery of actual capex rather than opex based projects; and

- 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 able to finance its capital investments at a lower rate than the allowed WACC. This opportunity does not exist for opex. Again, this could give the businesses a preference to increase the proportion of allowed expenditure allocated to capex.[327]

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 perceive that having direct control of assets will increase their ability to service their assets and meet reliability requirements, thereby potentially creating a preference for capex.[328] 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 have investigated a number of approaches which aim to remove any difference in achievable profit between pursuing capex rather than opex solutions. Such approaches attempt to balance the financial incentives through either:

- assigning a rate of return on operating expenditure;

- capitalising all DSP projects; or

- removing any distinction between capital and operating expenditure by assessing total expenditure (referred as the "totex approach").

---

327 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.

328 The separation of opex and capex in business structures and decision-making is another issue. Additionally, while it may be easier to benchmark opex, 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.

The totex approach has been advocated by some stakeholders during this review and is explained in Box 7.2.[329] It is currently being applied by Ofgem to electricity distribution businesses in Great Britain.

We are not recommending making amendments to 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 where opex projects make more financial sense for the business.[330]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, subject to change as part of the network regulation rule changes. The proposed amendments set out in the final position paper 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.

Hence it is intended that the AER will have the powers to trial and apply regulatory schemes which incentivise efficient expenditure on capex, and influence the balance between capex and opex.

Approaches such as the totex approach are highly complicated, and could lead to other perverse incentives. It needs to be carefully applied in practice and the determination of the ratio between opex and capex will probably be contentious. Ofgem's use of this approach clearly indicates that the difficulties associated with it are not insurmountable, although given how recently it was introduced, it remains to be seen whether it will have the desired effect.

Box 7.2: Totex cost recovery model for incentive regulation

In this approach, the regulator attempts to incentivise the business to treat actual opex and capex the same by fixing in advance the ratio between them that it will assume in setting revenues either at the upcoming price review for planned expenditure or at the following price review for unanticipated expenditure. For example, it may announce that it will treat expenditure as 80 per cent opex and 20 per cent capex, whether the business incurred 100 per cent opex or 100 per cent capex, or some ratio in between.

Since the ratio is fixed in advance, the business's revenues are insensitive to the actual split between opex and capex. So, the business can make decisions on

329 Energy Efficiency Council, draft report submission, p.12.

330 For example, where capital markets are tight or the distribution business is approaching its debt limits, it may not want to incur capital expenditure.

which type of expenditure to incur without considering how its decision will affect its price controlled revenues, although – like a business in a competitive industry – it will still need to consider how its decision will affect its costs or quality of service.

Ofgem fixed the proportion of administrative costs to be treated as opex at 100 per cent, while treating 85 per cent of the remainder of the costs as capex and the other 15 per cent as opex. Ofgem then assigns a deemed average asset life to this 85 per cent. Ofgem based the 85 per cent proportion on the total ratio of opex to capex at the previous price control review. Originally, it contemplated setting different ratios for each distribution business, but in the end set the same ratio to cover all of them.

In theory, this approach could eliminate a preference for capex because of the regulatory framework in place. Since the proportion of expenditure that is treated as capex is fixed, the regulated business should be indifferent in deciding between incurring a certain sum of capex and the same sum of opex.

However even under a totex approach, the businesses may still have an incentive to treat projects as capex rather than opex. In particular, this would apply if the ratio of capex to opex is determined on a business-by-business basis, and if it the business expects that the regulator will revisit this ratio at the next price review taking account of the outturn ratios of capex to opex during the price control review period. In this way, if the business incurs as much capex as possible, it may be rewarded with a higher ratio at the next price review. This incentive would be diluted if the same ratio were applied across all the appointed businesses and/or were fixed over time.

But there is a disadvantage to fixing a single ratio. It would be impossible to allow for the likelihood that the businesses' circumstances differ substantially. The proportion of capex to opex projected at the last price review could vary significantly from business to business and over time for each business. There could be arbitrary winners and losers.

The determination of the ratio would probably be contentious. For example, basing it on the ratio at the last price control period could mean that it is inappropriate to use at the next price review because of changing legal, regulatory or technological requirements, or economic circumstances. But price reviews routinely involve subjective judgements and forecasting. Ofgem's use of this approach clearly indicates that the difficulties associated with it are not insurmountable. Although given how recently it was introduced, it cannot yet be clear whether it is having the desired effect.

7.3.4 Target obligation on network businesses

FINDING

Introducing a peak demand reduction target obligation on distribution network businesses is not necessary given our proposed reforms. Targets may be ineffective and could lead to increased costs for consumers.

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 suggested placing a target on distribution business will reduce peak demand.[331]

There are several different approaches in which a peak demand reduction target could be set for distribution businesses:

- ***Expenditure on DSP*** – This approach would simply set a target for the amount of money to be spent by the distribution business on DSP (for example, a specified percentage of the capital which is forecast to be spent on peak demand related augmentations). 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

- ***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 with augmentation capex) and the amount of peak demand reduction the distribution business would be expected to achieve

331 Alternative Technology Association, directions paper submission; Energy Efficiency Council directions paper submission.

- ***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 consumer numbers.

- ***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.

In the draft report, we recommended against introducing any such peak demand reduction target obligation on distribution network businesses. We noted that such schemes could lead to over-investment in DSP and may not actually lead to any reduction in capital investments. We also recognised that the level of peak demand growth is not wholly within the control of the local distribution businesses.

A number of consumer and environment groups argued against introducing a peak demand target. These groups consider that incentives alone will be insufficient to get all network business to capture the full opportunities for efficient DSP on their networks. The Energy Efficiency Council stated that as consumers pay the costs of networks lack of focus on demand side activities, it is appropriate that networks be directed to undertake demand side activities through a target scheme.

We retain our draft report recommendation against imposing peak demand reduction targets on networks. The changes to the regulatory and distribution network planning frameworks will achieve the same objectives but will be more efficient. We also note that our proposals for the demand management incentive scheme would give the AER the ability to set performance standards and impose penalties. Imposing targets which are external to the incentive regulation framework will lead to conflicting objectives for the businesses and could affect the distribution determination process.

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. Some of possible approaches are linked to the aggregate peak demand across the distribution business's entire service area. For networks, DSP outcomes should be measured on a project by project basis, given that the value of DSP will be specific to the location and demand characteristics. Higher level measures may be too volatile to be helpful.

Given this, such targets might not defer any network capex in the short term.[332] 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.

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 easily by the distribution business, while others cannot. Conversely, achievement of the target must not be able to be gamed by the businesses.

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 carrying out 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 Improving clarity and flexibility for DSP related expenditure

In the draft report, we consulted on four minor amendments to the regulatory framework 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 included:

- 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.

The following sections explain the potential issue with DSP related expenditure and presents our final recommendations on each.

---

332 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).

Inclusion of market benefits into the AER regulatory expenditure reset assessment

RECOMENDATION

We recommend that the NER is amended to clarify that the AER is able to consider potential non-network benefits when assessing the efficiency of proposed DSP activities included in business revenue proposal.

This rule change will be implemented with the proposed rule change to the reformed demand management incentive scheme (section 7.3.1).

The expenditure criteria in the rules determine those projects for which network businesses may obtain funding. 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/or improved generation and/or transmission system reliability.

During the review, 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. These businesses repeated their support for this amendment in their submissions to the draft report. The AER stated that this reform is needed to achieve consistency with the objectives of the new distribution planning framework (e.g. RIT-D). For these reasons, we recommend that such a rule change is proposed.

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 will 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 (beyond the benefits to be provided at the distribution network level). Our reasoning for this recommendation is that it will address ambiguities and clarify provisions, to put beyond doubt the interpretation of NER provisions. This may also help to overcome some of the supply chain interaction issues raised in Chapter eight and would support the suggested reforms to the demand management incentive scheme mentioned in section 8.3.2.

The network businesses encouraged the setting of guidelines or deemed values for the assessment of such non-network benefits. Ausgrid stated that this should be identified in the framework and approach paper so that there is a clear basis for both networks to develop their revenue proposals and also for the AER to evaluate such proposal.

Given the overlap with the proposed reforms to the demand management incentive scheme we advise that this rule change is implemented as part of that proposal. We also consider that such consideration of non-network market benefits must be additive, in the sense that there must be an underlying network issue being addressed. It is not appropriate for the business to receive a regulated expenditure allowance for non-network projects which only provide non-network benefits, such as a peaking generator.

Managing volatility in DSP expenditure

RECOMMENDATION

We recommend that the NER is amended to provide distribution network businesses with additional flexibility in their annual tariff setting process to reflect changing DSP costs.

This amendment will be progressed as part of the proposed rule change on the distribution pricing arrangements (section 6.3.6).

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.[333]

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 if 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 there are extreme temperature 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

333 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.

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, the draft report recommended that additional provisions are added to the annual tariff process.

Most submissions supported this recommendation. However Ergon Energy thought that there was no need to amend the rules as it considered that the existing cost pass through arrangements can do this. AER considered that any arrangement must be neutral in its treatment of one form of DSP over another.

We continue to consider that appropriate arrangements are made to the rules for this issue and note there are additional provisions included in the transmission rules. 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.

However, we have concerns over the design and application of any arrangement as it would be inappropriate if it resulted in a material transfer of risk onto consumers, without any corresponding benefit to consumers. Further work on the appropriate design of such an arrangement is needed and we recommend that this is assessed as part of the proposed rule changes for the distribution tariff arrangements.

Clarifying treatment of DSP operating expenditure at regulatory resets

The costs of a DSP project can 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 but which was not approved at the start of the previous regulatory period.[334]

The draft report commented that this could be discouraging DNSPs from funding such long term DSP projects, if they are unclear how the AER will treat the expenditure on such DSP projects in future regulatory determinations. It was also noted that arrangements have been included in the transmission rules to deal with this issue. Clause 6A.6.6 of the rules guarantees that the remaining costs of a network support agreement must be accepted as allowed operating expenditure in future revenue determinations for transmission businesses.[335] Given this, we proposed including a similar clause into the distribution rules.

334 The business would be funding this DSP project through it allowed capital expenditure set at the start of the previous regulatory period.

335 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. Payments made in the previous period 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.

However, we have now decided not to recommend making such an amendment to the distribution rules. The AER in its submission stated that it will be better to consider the efficiency of expenditure at each reset than implementing a rule change which requires the AER to automatically accept future costs of an earlier agreement. We agree with the AER that it would be superior for the AER to consider the efficiency and prudency of all on-going DSP costs at each reset than locking in expenditure that might not be required in future periods.

The network business can substantiate a case to the AER for such costs as part of its revenue proposals. It might be useful (as a means of reducing uncertainty for the businesses) for the AER to consider issuing some principles or guidelines regarding the factors that it would take into account when considering the efficiency of a DSP project expenditure at the time of a reset.

We also note that the transmission rule is specific to one form of DSP – network support payments. We consider that it would be very hard to draft and apply a similar clause which covers all forms of DSP. For these reasons, we have decided not to recommend the rule change suggested in the draft report.

Temporary exemption from the service target performance incentive scheme

RECOMMENDATION

We recommend that the AER amends its Service Target Performance Incentive Scheme in order to grant temporary exemptions from the reliability service standards for appropriate DSP pilots and trials.

The current incentive schemes for service standards, the Service Target Performance Incentive Scheme (STPIS) rewards or penalises varying levels of service performance. Hence the scheme can impact on the amount of revenue earned by network businesses. The presence of minimum standards and penalties could drive risk-averse behaviour.

Specifically, distribution businesses have stated that DSP projects are currently typically less reliable than network options in ensuring reliable supply is maintained. They stated that businesses should not suffer liability and hence a penalty payment under the STPIS for non-performance in the initial period of a DSP project.[336]

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 perceived 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 carrying out pilots and trials of DSP projects to a wider deployment of DSP across its network. In addition, it could also limit the

336 Related comments were made by Powercor Citipower, Energex, ETSA Utilities, SP AusNet, United Energy, and Essential Energy.

ability for the DSP market to foster and encourage DSP service providers to enter the market and develop products.

Given this, the draft report recommended that the NER be amended to permit the AER to grant temporary exemption from the reliability service standards under the STPIS for specific DSP pilots and trials, where it considers this to be appropriate.

This recommendation was supported by the majority of stakeholders including the AER. It was recognised that the potential fines from reliability service standards could create a signal that can make networks averse to novel demand-side activities. There were some differing views among network businesses as to whether the exemptions is limited to pilots and trials or applied more generally to all DSP activities[337]. However, we consider that an unqualified exemption for all DSP projects would be inappropriate as consumers cannot manage the extra risk of unserved energy.

The AER noted that in implementing this proposal, it will not be necessary to implement a rule change, as it can be achieved through amending the AER's STPIS. We have considered this proposal and have concluded that it would be an appropriate approach. We have therefore changed our recommendation accordingly.

The AER's suggestion is appropriate because as the businesses develop more experience and expertise in DSP, they will gain a better understanding of the likely response from DSP options. Hence, exemptions may only be required in the medium future.

Any exemptions for DSP trials, must not remove appropriate consideration of the relative reliability and quality of supply impacts of DSP projects within the DSP planning framework. Furthermore, the application of any exemption must not affect consumer's entitlement to guaranteed service level compensation payments.

---

337 Citipower/Powercor argued that exemptions should not limited to only pilots and trials because DNSPs are responsible for the s-factor liability arising from any non-performance of a non-network solutions even where they are not the proponent of the DSP initiative. Ausgrid support an exemption only for DSP trials and not commercially driven DSP.

8 Distributed Generation

Summary

This review has identified a range of issues that influence the development of the distributed generation sector under the current arrangements. These relate to engagement with network businesses and the ability of distributed generation to capture all of the benefits that it provides to the market. However, these issues are largely addressed through other processes and rule changes currently underway. The AEMC is currently progressing rule changes relating to the connection framework and the aggregation of small generation units.

We have also recently made a rule which establishes a national framework for electricity distribution network planning and expansion. This change will result in more relevant planning information being available for prospective embedded generation developers and greater engagement with distribution businesses. These new arrangements will commence from the 1 January 2013.

Accordingly, the Power of choice final report does not provide any recommended changes in relation to distributed generation issues and nor does it consider that there is a need for a separate incentive scheme for distribution business to assist distribution generation connections.

We have provided some advice in regards to the development of feed in tariffs. We recommend that in developing a national approach to feed in tariffs (FiT), the value of time varying feed in tariffs should be included. This is to encourage owners of DG to maximise the export of their energy during peak demand periods.

8.1 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. A necessary market condition is for the market arrangements to facilitate the installation and export of power from DG, where, from the market’s perspective, this would be an efficient outcome.

8.2 Issues identified

In the directions paper, we canvassed a wide range of issues that influence the development of the distributed generation sector. We indicated that a number of these issues are being addressed in other processes and rule changes.

For this final report, we have focused on two key issues relating to distributed generation. These are:

- whether the current arrangements provide the right incentives for distribution businesses to engage with and connect DG installations, in an efficient and timely manner; and
- whether distribution businesses should be allowed to own and operate distributed generation.

We have also considered feed in tariff arrangements and how these may influence DG projects. Specifically, we have considered how different tariff arrangements may be used to better reflect the value of power exported from DG units at different times of the day.

We have previously identified that the inability of DG installations (as well as other forms of DSP) to sell energy to parties other than their existing retailer may act as a barrier to the efficient development of DG. We consider that this issue has been addressed through:

- our recommendation for having two financially responsible market participants at the same consumer site; and[338]
- our proposal for a different classification of market participant to facilitate the unbundling of DSP products from the energy component of the retail contract.

Other relevant matters

Although our focus in this report is the key issues identified above, we note that there is substantial work in progress addressing other issues related to DG.

One such issue is the process for connection of DG units to the distribution network. Stakeholders have identified that the current connection process may impede the development of new DG projects. In particular, the degree of discretion available to distribution businesses and the potential for multiple sets of technical standards may result in inefficient outcomes during the connection process.

The AEMC is currently assessing the *Connecting embedded generators* rule change request from the Property Council of Australia, Seed Advisory and Climateworks. This rule change will involve consideration of the overall connection process, including the technical standards which are applied during the connection of DG units to distribution networks. This will include consideration of whether a uniform set of technical standards is viable and whether this will help improve the efficiency of the connection process.

338 This issue will be discussed in further detail in the final report of the *AEMC's review of energy market arrangements for electric and natural gas vehicles.* This report is due to be published in early December 2012 and will be available on the AEMC's website, www.aemc.gov.au

The AEMC is also currently assessing the *Small generator aggregator framework* rule change from AEMO. This rule change seeks to introduce a new category of market participant, a small generation aggregator, which would allow the registration of multiple small generation units by one entity. This should promote the efficient exploitation of DG resources in the NEM by reducing registration costs and allowing DG units to choose to be exposed to the wholesale spot market.

A number of processes external to the AEMC are also considering issues related to DG. The recent report published by the Senate Select Committee on Electricity Prices considered the role of DG within the NEM. This report made a number of recommendations regarding the connection process and facilitation of export of power from DG units.[339]

The Productivity Commission has also recently published a report which considered several DG related issues, including the potential for more tailored feed in tariff structures to drive more efficient DG investment.[340]

In our Directions Paper, we identified issues with the current application of the avoided transmission use of system (TUOS) payments and the implications this may have for DG. Under the avoided TUOS arrangements contained in clause 5.5(h) of the rules, distribution businesses must develop a methodology to calculate the portion of TUOS charges avoided due to the connection of a DG unit.

Stakeholders have identified several problems with the existing avoided TUOS arrangements, including uncertainty regarding the calculation of TUOS charges and a lack of transparency regarding the different methodologies used by distribution businesses in calculating avoided TUOS charges.

We recognise that there is merit in considering these issues and note the desirability for transparency in relation to the calculation of avoided TUOS payments. However this review focussed on other issues, which we considered to be more material. However, we consider that this issue warrants further investigation, as part of the broader question of the appropriate basis of payments made to DG in the NEM.

8.3 Considerations

8.3.1 Distribution businesses' incentives regarding DG

FINDING

There is no need for the introduction of a separate distributed generation incentive payment to distribution businesses given our proposed reforms to the demand management incentive scheme.

---

339 Senate Select Committee on Electricity Prices, *Reducing energy bills and improving efficiency*, the Australian Senate, November 2012.

340 Productivity Commission, *Electricity Network Regulatory Framework - Draft Report*, Melbourne, October 2012.

As we identified in the directions paper, distribution businesses may not have strong incentives to engage with DG proponents to facilitate connection and export of power from DG units.

We consulted on how distribution businesses might 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 distribution businesses 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 distribution businesses 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 a distribution business plans its network. A distribution business 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 may affect the revenue of a distribution business. 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 these revenues; and
- whether or not a distribution business is incentivised to connect DG is likely to reflect the extent to which connection of the DG unit will provide the distribution business 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 CitiPower Powercor, Ausgrid, SP AusNet and EnerNOC all supported some form of distribution business incentive mechanism to drive connection of DG. SP AusNet stated that this could take the form of a $ per kW incentive rate. CitiPower Powercor reiterated their support for an incentive mechanism in their submission to the draft report.[341]

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.

---

341 Refer to stakeholder submissions to draft report in Appendix G.

Box 8.1: 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 per cent 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 distribution businesses 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.

The framework also contains a mechanism to facilitate ongoing network access for DG units that have been connected by the distribution business. This incentive is set at a rate of £0.002/kWh and is paid by the distribution business to the DG in the event that the distribution business 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 distribution business.

In 2009, Ofgem reviewed the framework as part of the next distribution 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 Chapter 7, we recommended the introduction of a broader mechanism to incentivise distribution businesses’ 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 the provision of incentive payments to distribution businesses for connection of DG will not necessarily translate into additional benefits for the market. In circumstances where a distribution business 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 distribution business 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 distribution businesses 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. CitiPower Powercor also supported the fee for service model in their submission to the draft report.[342]

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 June 2013. Given that this work is under way, we will not undertake any further consideration of a fee for service model in this review.

8.3.2 Ability of distribution businesses to own and operate DG

RECOMMENDATION

We recommend that the AER should give consideration to the benefits of allowing distribution businesses to own and operate distributed generation assets when developing the national ring fencing guidelines for these businesses.

342 A summary of stakeholder submission to the draft report is contained in Appendix G. Stakeholder submissions to the directions paper are summarised in Appendix D of *AEMC, Power of choice review – giving consumers options in the way they use electricity*, draft report, September 2012.

As we identified in the draft report, 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 any potential impacts on competition and overall efficiency.

A key factor which affects the ability of distribution businesses to own DG assets and export power from these assets are the various jurisdictional ring fencing arrangements. These arrangements separate the operation of the regulated and non-regulated arms of vertically integrated businesses, in order to limit the capability of a monopoly business to discriminate against upstream or downstream competitors.

Each jurisdiction of the NEM has its own set of ring fencing arrangements. In some cases, these arrangements limit the ability of distribution businesses to own and export power from DG units; the extent of these limitations varies between jurisdictions. For example, the AER has highlighted that distribution businesses are actively prohibited from engaging in generation activities in Queensland and the ACT. In South Australia, distribution businesses are only permitted to own generation for the purpose of providing network support, meaning that South Australian distribution businesses are prohibited from obtaining revenue from selling energy.[343]

The AER is currently reviewing these jurisdictional arrangements and has advised that it intends to develop a single nationally consistent set of ring fencing guidelines. The AER has indicated that it favours a reasonably open and flexible approach to national ring fencing arrangements, to allow for the development of new market conditions and changed circumstances.[344]

Stakeholders have expressed widely varying opinions in regards to this issue. In its submission to the draft report, Ausgrid stated that concerns regarding distribution business ownership can be adequately addressed through development of nationally consistent ring fencing guidelines. Ausgrid also suggested that distribution businesses are likely to build DG primarily for the purposes of network support and that this would not have any negative impact on competitiveness in the wholesale market.[345]

Submissions from distribution businesses to the directions paper also argued that ring fencing arrangements should not prevent distribution businesses from participating in the provision of non-regulated services. In particular, ETSA Utilities argued that distribution businesses should be able to bid generation into the NEM, where the primary purpose of that generation was network support.

Other stakeholders argued against allowing distribution businesses to own and operate DG units. EnerNOC suggested that ring fencing provisions would be insufficient to prevent distribution businesses discriminating against third party DG providers. Energy Australia argued that incentivising distribution businesses to export

343 AER, directions paper submission, p.11.

344 AER, *Electricity Distribution Ring-Fencing Guidelines Review*: Position Paper, AER, September 2012.

345 Ausgrid, draft report submission, p.26.

energy from their DG assets would distort energy market function and have negative implications for competition. This argument was also made by the Energy Efficiency Council, who considered that there was a risk of distribution businesses using their regulated revenue to support activities in non-regulated markets.[346]

In submissions to the directions paper various 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.[347]

We consider that distribution businesses 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 distribution businesses to export power from these assets to the wholesale market. We acknowledge that both of these outcomes must be considered in the context of their impacts on competition in non-regulated markets. However, we consider that effective regulatory arrangements and the development of nationally consistent set of ring fencing guidelines by the AER should address these concerns.

Construction of a DG asset may represent the most efficient option for augmentation of a distribution network. By developing a non-network solution, distribution businesses may be able to reduce total system costs, ultimately helping to minimise price increases for consumers. However, as stakeholders have identified, there is a risk that distribution businesses 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 distribution business 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 distribution businesses 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 distribution businesses go about acquiring these solutions. This should go some way to addressing concerns that distribution businesses will favour building their own non-network solutions, or favouring related parties.

More generally, the nature of economic regulation suggests that distribution businesses 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 distribution businesses 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 distribution business will weigh the

---

346 A summary of stakeholder submission to the draft report is contained in Appendix G. Stakeholder submissions to the directions paper are summarised in Appendix D of *AEMC, Power of choice review – giving consumers options in the way they use electricity*, draft report, September 2012.

347 Ibid.

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 final position paper 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.[348] The AER also indicated in its ring fencing guidelines discussion paper that distribution business generation services will not form part of standard control services and that any unregulated services will be appropriately ring fenced.[349]

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, a DG asset owned by a distribution business which is 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 distribution businesses 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. We note the AER's comments in its submission to the draft report that it will consider the impacts on competition and efficiency that may result from distribution business ownership of DG units.[350]

8.3.3 Feed in tariffs and value of export from DG units

RECOMMENDATION

We recommend that as part of the review into a national approach to feed in tariffs, consideration be given to the ability of time varying tariffs to encourage owners of distributed generation assets to maximise export of power during peak demand periods.

---

348 AEMC 2012, *Economic Regulation of Network Service Providers*, Final Position Paper, 15 November 2012, Sydney, p.205.

349 AER, *Electricity Distribution Ring-Fencing Guidelines Review*: Discussion Paper, AER, December 2011.

350 AER, draft report submission, p.20.

In the draft report, 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 stakeholder submissions to the draft report commented on this issue. The Australian Photovoltaic Association supported the introduction of net feed in tariffs or location based tariffs, in order to encourage west facing arrays, which would help meet peak energy demand. Adam McHugh, of Murdoch University, stated that while west facing rooftop PV arrays may make a valuable contribution to meeting peak energy demand, existing tariff structures based on total energy production are ultimately biased against these kinds of installations.

SA Power Networks supported the concept of time varying tariffs, but stated that any such tariffs should be provided on a gross basis. They stated that this would enable distributors to more effectively provide cost reflective pricing signals to such consumers without the potentially conflicting driver for consumers to minimise their in-house consumption so as to maximise their payment under the feed-in arrangements.[351]

The draft report of the Productivity Commission's review of Electricity Network Regulatory Frameworks made similar recommendations regarding feed in tariff arrangements. The Productivity Commission suggested that existing feed in tariff arrangements be replaced with tariffs that reflect the varying value of power produced by DG at different points in time. The Productivity Commission also suggested that arrangements be put in place to allow for payments from distribution businesses to DG providers, to reflect the network value of their generation capacity and output.[352]

Stakeholder submissions to the directions paper also discussed 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.[353]

We consider that well designed feed in tariffs have significant potential to provide beneficial outcomes to the market, for relatively little cost. For example, there is likely

351 SA Power networks, draft report submission, p.15.

352 Productivity Commission, *Electricity Network Regulatory Framework: Draft Report*, Melbourne, October 2012, p.457.

353 A summary of stakeholder submission to the draft report is contained in Appendix G. Stakeholder submissions to the directions paper are summarised in Appendix D of *AEMC Power of choice review – giving consumers options in the way they use electricity*, draft report, September 2012.

to be merit in encouraging the installation of west facing PV units in order to maximise energy production during the late afternoon peak demand period. This is a relatively minor change with low associated costs but with the potential to provide significant benefits. More broadly, relatively minor refinements to the design of feed in tariffs may provide real benefits to the market as a whole, at a relatively low overall cost.

We note that the SCER is currently developing guidelines for a consistent national approach to feed in tariffs. Given the issues identified in submissions, we recommend that SCER considers how different feed in tariff structures 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.[354]

The interactions between feed-in tariffs and flexible pricing options for electricity usage will also need to be considered. The aim should be to encourage consumers to make effective and efficient choices between maximising the use of their PV generated electricity for their own on-site needs (and thus reducing their need to import electricity at peak times) and exporting at peak demand times. Clearly the interactions may be complex and will involve different considerations in terms of network capacity and quality issues and the power supply/demand balance. However it is important that the combination of both the feed-in tariff and the consumer's own retail tariff should be providing the right efficiency signals.

354 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.

9 Energy Efficiency measures and policies that impact or seek to integrate with the NEM

Summary

Energy efficiency (EE) measures and policies can help consumers manage their electricity use and their bills. Energy efficiency measures are usually aimed mainly at tackling overall (or average) demand, but they can also help to reduce peak demand. For this review, therefore, we have characterised energy efficiency opportunities in the electricity sector as a form of DSP.

The terms of reference for this review, required the assessment of the regulatory programs that impose a direct obligation or incentive on NEM participants to promote efficient DSP in the NEM. The energy efficiency schemes we looked at included the New South Wales, Victorian and South Australian regulatory energy efficiency schemes, and the Commonwealth Energy Efficiency Opportunities (EEO) program.

We consider that facilitating efficient DSP and energy efficiency can be addressed within the electricity market rather than externally to its regulatory arrangements. Our reforms to change electricity market and regulatory arrangements specifically seek to support the market conditions necessary to facilitate efficient DSP.

We note that where governments consider energy efficiency schemes are required, in light of our assessments we consider that:

- Schemes need to consider and 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 full range of DSP options (that is, options that have peak as well as average demand reduction potential) should be available to consumers through the schemes, so that the right information on total DSP options and rewards are 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 by, providing 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 schemes 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.[355] Energy efficiency opportunities can be those offered under the suite of regulatory programs in place or energy efficiency actions taken up by consumers independently.[356]

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 (that is, white certificate schemes). Further discussion and description of these various policy and regulatory measures are outlined in the Stage 1 Report undertaken for this area of the review.[357]

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.[358] We have had regard to this work in forming our advice.

---

355 Australian Government, *Report of the Prime Minister's Task Group on Energy Efficiency*, Final Report, July 2010, p.27.

356 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.

357 See Oakley Greenwood, *Stocktake and Assessment of Energy Efficiency Policies and Programs that Impact or Seek to Integrate with the NEM: Stage 1 Report,* February 2012, available at www.aemc.gov.au.

358 See Council of Australian Governments Meeting Communique, 25 July 2012, available at www.coag.gov.au.

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 obligation schemes).[359] 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 (for example, retailers).

Approach to analysis

We undertook the work, in two stages. The first stage identified those programs that would be part of the stocktake and analysis, with commentary on other domestic and international programs in place. The Stage 1 Report consultant report by Oakley Greenwood (OGW) was published with our directions paper in March 2012.[360]

The second stage assessed the effectiveness and cost-efficiency of those regulatory measures and policies identified and consideration of the areas outlined in section 8.3. This work was also undertaken by OGW and is also available on the AEMC website.[361]

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

The static approach for assessing the economic benefit of an energy efficient program:

- assumed that every unit (MWh) of energy saved and every unit of reduction in system-coincident peak demand[362] that results from implementing specific

359 See the Ministerial Council on Energy (MCE) terms of reference for this review, available at www.aemc.gov.au

360 Oakley Greenwood, *Stocktake and Assessment of Energy Efficiency Policies and Programs that Impact or Seek to Integrate with the NEM: Stage 1 Report*, February 2012.

361 Oakley Greenwood, *Stocktake and Assessment of Energy Efficiency Policies and Programs that Impact or Seek to Integrate with the NEM: Stage 2 Report*, August 2012

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.

The approach enabled 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.

The static approach however 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 (that is, 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.[363] Generally, this cannot be projected with accuracy for more than about five to seven years, and investment 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.[364]

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 allowed 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 this data allows estimation of the impact of the programs on the cost of electricity at the wholesale level.

---

362 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.

363 Most importantly the current headroom between installed capacity and current peak demand, and the rate of growth in peak demand.

364 A smaller quantum of demand reduction can still have value either by 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.

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 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).[365]

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 as follows:

- 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.

365 See Department of Climate Change and Energy Efficiency and the Department of Resources, Energy and Tourism, *Progress Report, National Energy Initiative*, August 2012, available at www.climatechange.gov.au

9.3 Outcomes of analysis of regulatory EE schemes

This section discusses our findings from the analysis undertaken for the programs included in the stocktake. It also provides our considerations with respect to the interaction of EE and DSP more broadly. Our assessment specifically considered, in accordance with the MCE terms of reference, the extent to which the policies and 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 (for example, market settlement systems, smart metering and smart grid technologies) to support efficient use of, and investment in, DSP.

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.[366]
- 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.

366 www.ret.gov.au/energy/efficiency/eeo/extension/Pages/EEOElectricityGas.aspx

9.3.1 Key findings

The key findings from the study relating to the impacts of the programs on the electricity supply chain are presented below. The OGW Stage 2 final report provides more detailed discussion of the analysis undertaken.

- At the time of the analysis, the three state-based retailer obligation programs were quite small. However, these 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 the following:
  - 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 compared to business as usual (there were some instances in the early years of some of the programs, where the technologies being incentivised had already achieved a significant level of take-up in the market without incentivisation).
    - Most of the consumers targeted by these programs, have accumulation meters, meaning that only energy savings (as compared to load shape changes) would provide benefits. There is, however, 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 tariffs, 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.

It must be noted, that the impacts above are entirely a function of the change that the energy efficiency measures installed under the programs engender in the electricity supply load profile. The 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 on the basis that: the various measures within each program reach market saturation levels; are removed from eligibility; other measures become attractive due to price changes or program target levels; or the programs are expanded to additional market sectors.

Generally, stakeholders[367]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;
- 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;[368] and
- 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.

Large consumer user groups noted that many of the energy efficiency programs are inefficient and require cross subsidisation to provide the funds for them. They considered that levying consumers with the cost of these programs and then giving them something “free” would not drive consumers to be involved with DSP. Rather, these stakeholders considered 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.[369]

Based on the analysis undertaken there are a set of considerations that governments should have regard to when aiming to establish or develop energy efficiency measures and policies. These are presented in Box 9.1.

---

367 AEMC, *Power of choice review – giving consumers options in the way they use electricity*, Draft Report, September 2012, Appendix D – stakeholder submissions summary to Power of choice review directions paper.

368 Clean Energy Council, directions paper submission, p.6.

369 MEU, directions paper submission, p.42.

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.
- A regulatory EE scheme could be utilised to:
  - address information and behavioural barriers by enhancing consumer education about how electricity consumption impacts their bills (for example, cost impacts of using different appliances/equipment);
  - reduce the costs of using appliances, and provide rebates and low interest finance to invest in more efficient appliances; and
  - 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.
- The design of EE policies and regulatory schemes should ultimately include consideration of the following::
  - 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 (that is, 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.[370]

[370] We note that the AEMC, AEMO and the AER have been involved in the Australian government's work on considering a NESI.

9.4 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, 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, this may increase demand response market penetration, allowing energy savings to be captured and consumer bill-reduction opportunities that might otherwise be lost.

An example, of coordination of DSP and EE is the work under the Energy Efficiency Equipment (E3) Committee of Commonwealth, State, Territory and New Zealand Officials. This group oversee the trans-Tasman energy labelling and MEPS program.[371] As part of this work, Standards Australia developed the Australian/New Zealand Standard 4755: Demand response capabilities and supporting technologies for electrical products. This standard is intended for certain appliances (ie air conditioners, pool pumps) that are manufactured with interfaces which will allow them to be controlled remotely (ie direct load control). There is evidence of some air conditioners with this demand response capability.[372] We note the Productivity Commission in its recent report on electricity network regulation highlighted the potential for greater use of DLC and demand response capability into household appliances.[373]

Other examples, where DSP and EE could be better coordinated are: the existing Australian Government EEO program and the requirements under the National Australian Built Environment Rating System (NABERS)[374]. The EEO program could be expanded to include a greater suite of DSP opportunities, particularly those that have peak reduction potential. This program could also inform participants of the availability of programs, such as the proposed demand response mechanism if it was implemented. There is also an opportunity under the NABERS program to consider advances in technology to contribute to a building rating system (ie having ADR functionality).

371 See www.energyrating.com.au/naeeec.html.

372 Department of Climate Change and Energy Efficiency issues paper submission, p.1.

373 See Productivity Commission, *Electricity Network Regulatory Frameworks*, Draft Report, Volume 2, October 2012, available at www.pc.gov.au.

374 http://www.nabers.gov.au/public/WebPages/Home.aspx

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 in the Futura report commissioned for the AEMC.[375]Box 9.2 presents some other examples of EE and DSP interaction which have helped to deliver savings to parties.[376]

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 that offset the cost of demand response-enabling equipment, such as load-shedding controls and automation equipment.

During the review, stakeholders have reiterated their views on the importance of coordinating EE and DSP, noting 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.

375 Futura Consulting, *Investigation of demand side participation in the electricity market*, report for the Australian Energy Market Commission, 8 December 2011.

376 Ernest Orlando Lawrence Berkley National Laboratory, *Coordination of Energy Efficiency and Demand Response*, Report for the United States Department of Energy, January 2010

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. For example, some energy efficiency measures may 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 concerns relating to the on utilisation of EE measures and policies to address peak demand. The key issues included:

- EE schemes should aim to overcome barriers to allocative efficiency and hence EE schemes should not be utilised to specifically target peak demand. In addition, 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.

- 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 efficient DSP responses for the constrained areas of networks, at the right time to appropriately capture network infrastructure cost savings benefits. This is because they were typically designed to achieve carbon reductions, rather than focus on reducing peak demand.[377]

External processes

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,"[378]"

In its response to the Prime Minister's Task Group on Energy Efficiency, the Australian Government stated that the NESI itself would:

> "have broad coverage (that is residential, commercial and industrial sectors); and create an incentive or a requirement to create certificates in

377 AEMC, *Power of choice review – giving consumers options in the way they use electricity*, draft report, September 2012, Appendix D – stakeholder submissions summary to Power of choice review directions paper

378 Australian Government, *Report of the Prime Minister's Task Group on Energy Efficiency*, Final Report, July 2010, p. 81.

both low income homes and in ways that reduce peak electricity demand.[379]"

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.

We are of the view that processes and mechanisms within the electricity market and associated regulatory framework will be 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). This is informed by the work undertaken in Stage 2 of the stocktake and assessment by OGW and stakeholder submissions to the review.

We note 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 consumers 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 NESI and other EE programs by reducing unanticipated deleterious impacts of those programs on both program participants and non-participants.

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 environmentally desirable 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 electricity itself, but, depending upon how it impacts upon average and peak demand, may increase pressure on infrastructure requirements throughout the value chain. This may increase supply chain costs, thereby putting upward pressure on

379 Australian Government, *Securing a Clean Energy Future – The Australian Government's climate change plan*, July 2011

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 (even though every kWh of electricity reduced is not of equal value) - a price signal that incorporates the time differentiated cost of supplying electricity, and 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 consumers) and to include mechanisms within those programs and policies that can mitigate to the extent possible any such deleterious impacts.

10 Benefits and costs of recommendations

Summary

This chapter summarises Frontier Economics' modelling of the potential cost savings for consumers from the recommendations set out in the draft report. Frontier looked at the benefits associated with greater cost reflective pricing for residential and small business consumers as well as introducing the demand response mechanism in the wholesale energy market.

Frontier Economics found that our recommendations will reduce the direct costs incurred by the electricity supply in chain meeting consumers demand for electricity. Reducing peak demand growth will avoid some future network and generation investment and save generation fuel costs. Assuming that the recommendations put forward in with regard to pricing and demand response mechanism are fully adopted, Frontier Economics have estimated that the reduction in NSW, QLD, and VIC could be between 400 MW to over 1300 MW by 2020. These reductions are estimated using likely consumer behaviour based upon results emerging from tariff trials and other DSP mechanisms both domestically and internationally.

Frontier estimated that economic cost savings of peak demand reduction in the NEM could be between $4.3 billion to $11.8 billion over the next ten years (net present value, 2013/14 to 2022/23). This equates to roughly between 3 per cent and 9 per cent of estimated total system expenditure over the period. The majority of these savings occur in the network sector given the current over supply of generation capacity and relatively conservative view of baseline demand growth. This is based on the assumption that network investment continues at current levels. Also the extent of savings varies across the NEM.

Savings are highest in regions with stronger assumed peak demand growth and could be approximately $500 per consumer per year (in South Australia and Queensland). In NSW, the savings per consumer is around $350. Savings are less in Victoria, around $120 per consumer per annum. Frontier also note that there may be additional benefits that accrue to consumers via reductions in both the level and volatility of wholesale pool prices due to the flatter load shapes achieved if our recommendations are introduced.

In addition, a consumer could also benefit from a change in their tariff structure and/or adapting their consumption patterns. A consumer with a relatively flat consumption pattern could save around $50 from just changing its tariff structure to a time varying tariff, without any change in consumption. The same consumer could save an extra $100 a year if able to shift around 20 per cent of their consumption from the peak afternoon period of 2pm to 8pm. This could involve changing the time when the dishwasher or washing machine are in use and would reduce that consumer's annual electricity costs by 6 per cent.

Other households -which have high peak time usage - can reduce their costs by up to $200 a year if they are able to reduce their afternoon peak time consumption by around 15 per cent of original use. This could involve cycling of air-conditioning, installing more energy-efficiency appliances or not using certain household appliances at that time.

Some of the savings which an individual consumer can achieve through changing tariffs and adapting their consumption patterns may be passed through to other consumers. However in the long term, more flexible pricing could lead to lower system costs and hence lower retail prices for all consumers.

Frontier Economics' modelling has also found that cost of peaking generator may not be the best proxy to use to value the impact of DSP on wholesale energy market costs of MW reductions and the importance of taking a view of existing and planned generation stock when estimating the benefits of DSP.

Frontier Economics (Frontier) was engaged by the AEMC to provide advice regarding construction of a tariff model and estimation of the long term benefits of reducing peak demand. This chapter provides an overview of Frontier's findings.

10.1 Frontier Economics' engagement

Frontier's advice to the AEMC covered two areas:

Construction of a retail tariff model

The retail tariff model is intended as a tool to inform stakeholders and allow high level assessment of issues around incentivising DSP via tariff structures. This is likely to foster further debate amongst stakeholders and consumers around the role of DSP, and time varying retail tariffs, in the NEM. This model is highly customisable and able to consider a wide range of consumer load data, tariff structures and varying levels of demand response. This model can be used to investigate a range of issues, including:

- Understand the impact on consumer electricity expenditure of different retail tariff structures;
- The degree of cross-subsidisation under existing tariff structures between consumers with different consumption patterns (such as the cross subsidisation between peak-use consumers and off-peak use customers on existing tariff structures);
- The level of incentives needed to encourage consumers to switch to more dynamic tariff structures;
- Quantifying the extent to which changed patterns of consumption lead to savings on an annual expenditure; and
- The tariff structure that provides the highest incentives for DSP.

The framework underpinning the results calculated by the tariff model has been designed to investigate the impact of altering tariff structures for different consumer load profiles and for different levels of assumed demand response. Whilst the model has been linked to actual costs in the electricity market, it is not intended to be used for the purpose of a consumer retail bill estimation for a specific retailer offer and it would be potentially misleading to do so. The intended use of the model is to investigate the impact of changing tariff structures or altering the level of demand response relative to a reference case.

The tariff model has been initially configured by Frontier using the best available data. Many of the assumptions regarding load data and cost information have been based on the more populous jurisdictions of NSW and Victoria. However Frontier are of the opinion that this does not significantly reduce the model's ability to assess the impacts of alternate tariff structures and DSP in other jurisdictions. Furthermore, the majority of these inputs can be altered by the user of the model if required.

Estimation of the economic benefits of long term reductions in peak demand and the impact on end use consumers.

This work focussed on outcomes in terms of energy and network costs of the impacts of our recommendations on peak demand levels in the NEM, where:

- Network benefit estimates were based on historical network expenditure data extrapolated into the future.
- Energy (wholesale electricity market) benefit estimates were based on long term, cost-based modelling of the NEM.

10.2 Tariff model analysis

To date, the tariff model has been used to conduct an analysis of the impact of different tariff structures and demand response levels and to estimate the impact of delayed (post-10pm) charging of electric vehicles.

10.2.1 Tariff structure and response

The model provides useful insights into the impacts of time varying tariffs in a number of areas:

- An "off peak use consumer" saves around $40 to $60 a year from just changing from a flat retail tariff to a time varying tariff (either a 3 time band Time of use tariff or a critical peak price tariff structure) without any changes to its consumption pattern. This result can also be interpreted as a reduction in the degree of cross-subsidisation between consumer types.[380]

380 The model defines OFF PEAK USE CONSUMER as a residential consumer who has a slightly flatter profile than the current Net system load profile for NSW, is assume to consumer 19% at peak

- Demand response can provide consumers with the ability to reduce annual expenditure on electricity via reduced and/or altered patterns of consumption. However, the magnitude of the reduction would be relatively small compared to total annual expenditure unless significant reductions in consumption occur (greater than 10% usage reductions).

- For a typical average annual consumption level of 8 MWh and retail bill of $2000, reductions in peak consumption (of around 14 per cent to 18 per cent of original usage during the peak period (between 2pm and 8pm)) are required to achieve savings in the order of $200 on an annual bill (approximately 10% of the annual retail expenditure).

- More dynamic tariff structures could provide more opportunity for consumers to avoid high marginal electricity prices. Critical Peak Pricing (CPP) structures provide the greatest incentives for consumers to alter patterns of consumption.

- The combination of highly dynamic tariff structures (such as CPP) combined with Consumption Baseline Load (CBL) mechanisms could strongly incentivise consumers to reduce peak demand whilst protecting consumers.

An important implication of these annual retail costs results is that changes in tariffs and demand response may diminish the revenues earned by retailers and network businesses. Reductions in revenue are not necessarily a problem as long as they accompany reductions in cost such that profit margins are maintained for both network and retail businesses. Retailers should be able to match reductions in revenue due to reduced consumption with reductions in costs in the short term. Most retailers contract on a rolling basis and would be able to readjust their position rapidly and at the very least from quarter to quarter.

For network businesses, most costs represent capital investment decisions that are already sunk and which cannot be reversed or altered. Network businesses would find it difficult if not impossible to reduce costs in line with reductions in revenue due to lower consumption in the short term. Absent any other measures, this would be likely to lead to reduced profit for the network businesses in the short term and may lead to under-recovery of costs for the businesses.

In practice, the regulatory arrangements may ensure cost recovery by allowing increases in revenue from other areas (for example via higher fixed charges on consumers who remain on time-invariant tariffs). To the extent that this occurs, savings made by individuals on time varying tariffs may be offset by increased charges applied to all consumers. In the longer term, new capital investments would be made with regard to reduced peak demand levels leading to lower overall costs to meet demand.

In performing this analysis, Frontier in general focused on typical or average consumer load shapes, moderate peak pricing levels for network tariffs and relatively conservative levels of demand response. Individual consumers that achieve larger

---

times (2pm to 8pm), 47% at shoulder times (7am to 2 pm and 8pm to 10 pm) and 35% at off peak times (other times).

demand reductions at times of high prices will be able to capture greater cost savings under dynamic tariff structures. Such outcomes can be easily quantified in the model given alternative load data.

10.3 Benefit of peak demand reduction analysis

The second piece of Frontier's analysis sought to estimate the potential benefits that could arise from peak demand reductions if the recommendations in the draft Power of Choice were adopted. There are two stages to this modelling exercise. The first stage of this work was to estimate a likely range of peak demand reductions that could arise from our recommendations. In the second state Frontier estimated the benefit that would arise from these reductions in terms of avoided energy and network costs.

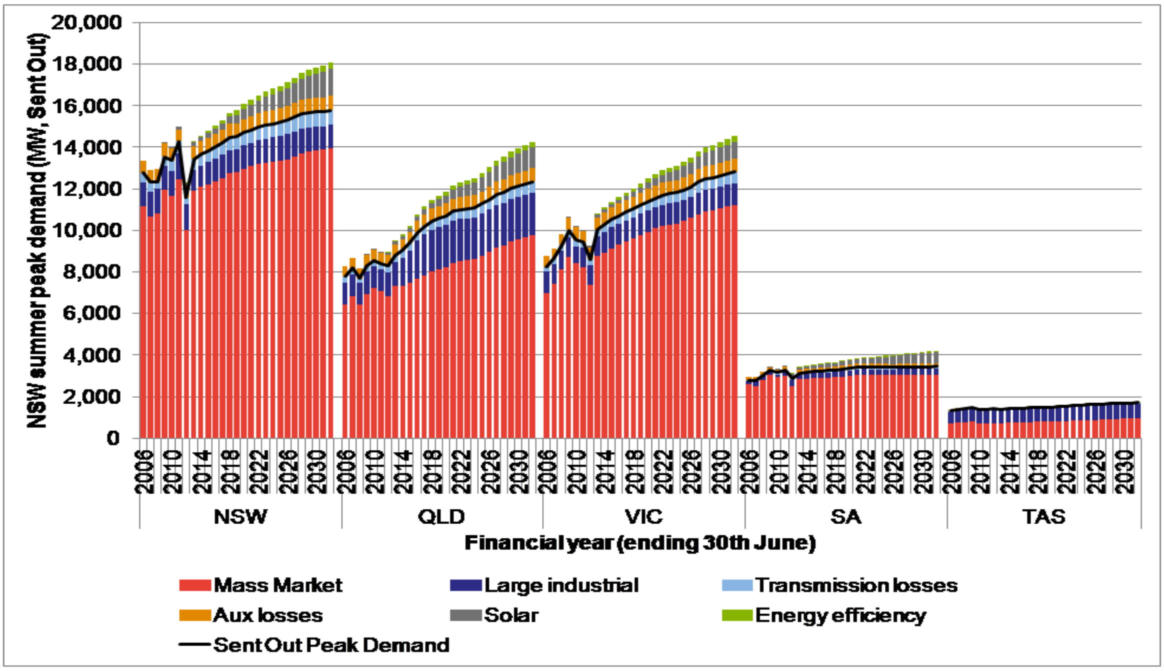
10.3.1 Level of peak demand reduction

Demand response was considered to arise from three sources:

- **Energy Efficiency (EE):** representing changes to usage by both large and small consumers that lead to reductions in consumption (for example via more efficient appliances)
- **Demand response (DR)**: representing changes to patterns of consumption by large consumers in line with incentives created by payments for reductions in demand
- **Efficient pricing (EP)**: representing changes to patterns of consumption by small consumers in line with incentives created by more dynamic retail pricing of electricity.

Frontier used demand forecasts from AEMO as a baseline for their analysis. The specific case used was AEMO’s 2012 ESOO Medium 50% probability of exceedence (POE) forecast. Summer peak demand for each region is shown in figure 10.1. The black line represents the sent out demand (net of demand unrealised due to energy efficiency, auxiliary losses within power stations and production from solar generation reducing demand for electricity from the NEM pool).

Figure 10.1 Baseline summer peak demand forecast by region and source of demand



Source: AEMO 2012 ESOO / 2012 NEFR

Relative to this baseline, Frontier constructed two demand reduction cases – Lower and Upper – that represented a lower and upper bound respectively on the magnitude of peak demand reductions that could be achieved via increased DSP. This was done as follows:

1. Reduce aggregate peak demand in line with assumed energy efficiency reductions to obtain a residual aggregate peak demand

2. Split this peak demand into commercial and industrial (C&I) and residential components of peak demand using a 45%/55% (C&I / Residential) ratio

3. Reduce peak demand for each component in line with an assumed percentage reduction.

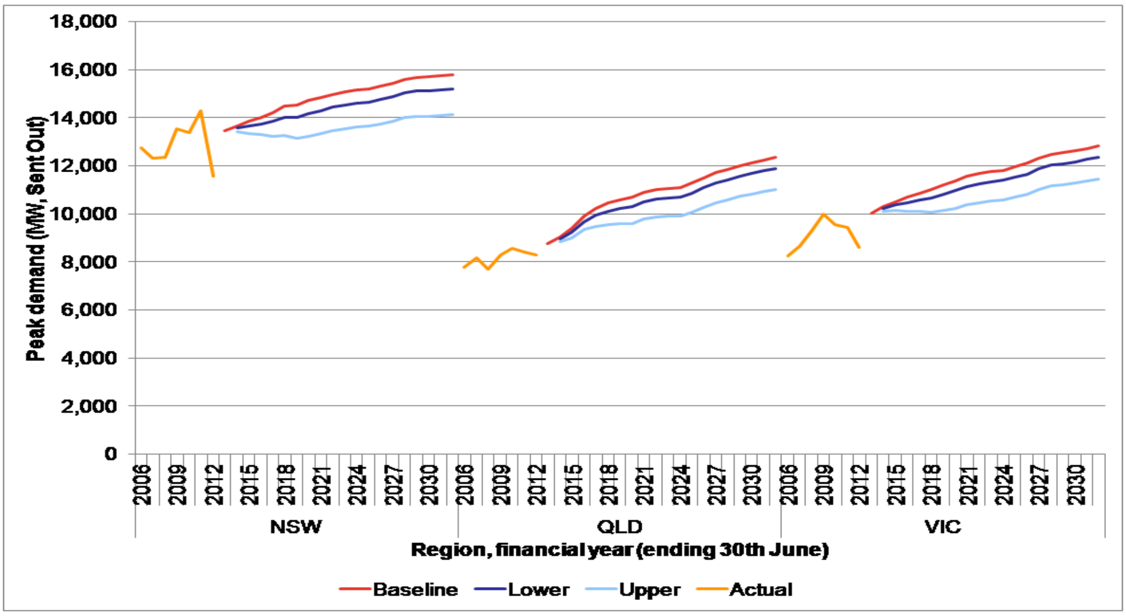
The assumed levels of demand response were determined with reference to outcomes for dynamic pricing and demand response trials in Australia and internationally (see Figure 6.2). Frontier considered that the estimate of possible reductions were likely to be conservative relative to outcomes in many jurisdictions. The energy efficiency levels were determined with reference to AEMO's "Fast rate of change" scenario. Assumptions are summarised in Table 10.1 below.

Table 10.1 Summary of peak reduction assumptions

Source	Lower case	Upper case
Energy efficiency	no change to baseline (AEMO estimate)	200% of baseline
Demand response	5%	10%
Efficient pricing	2.5%	7.5%

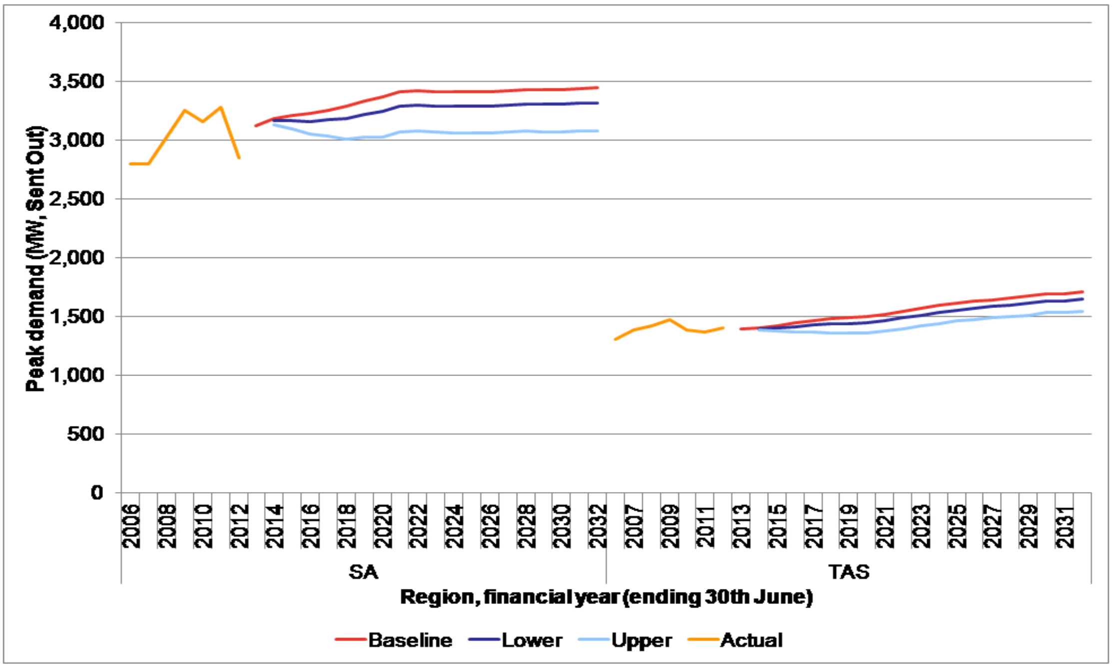
These assumptions lead to reductions relative to the peak demand baseline as shown in figure 10.2 and figure 10.3 for the summer peak

Figure 10.2 Baseline peak demand (summer) and reduction cases – NSW/QLD/VIC



Source: AEMO 2012 ESOO Medium 50% POE baseline and Frontier Economics reduction cases

Figure 10.3 Baseline peak demand (summer) and reduction cases – SA/TAS



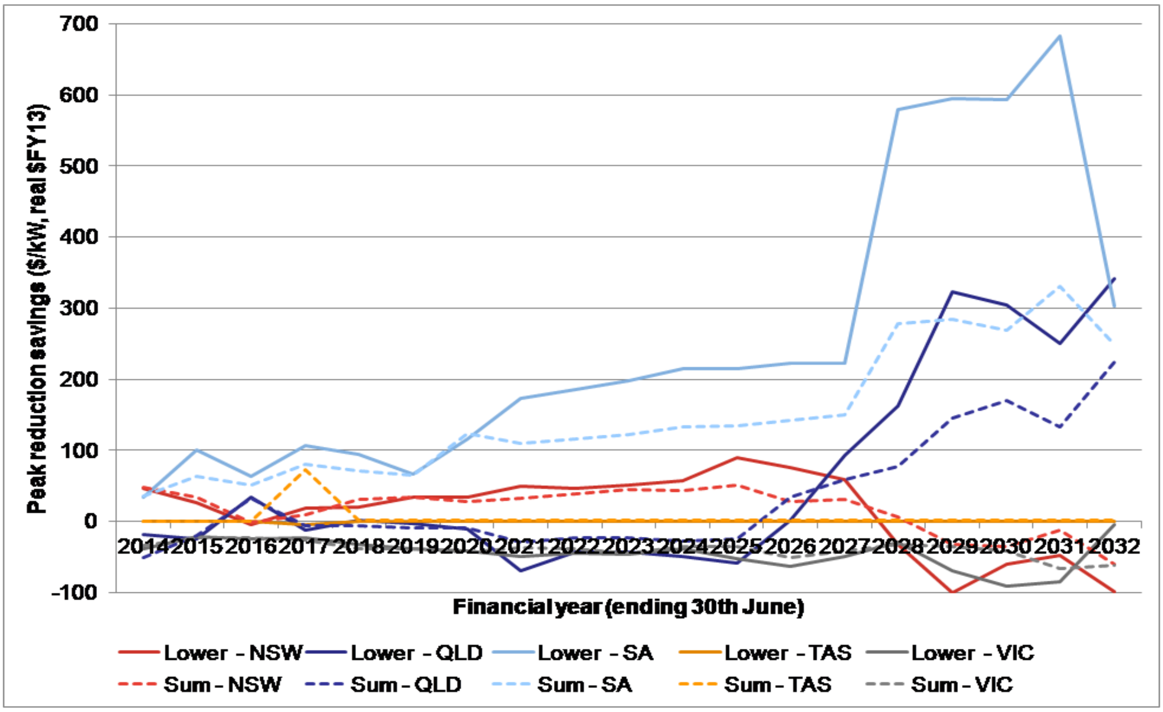
10.3.2 Savings from avoided energy costs

Frontier used their proprietary electricity market model WHIRLYGIG to estimate the benefits arising from avoided energy costs. WHIRLYGIG optimises total generation costs in the electricity market, calculating the least-cost mix of existing plant and new plant options to meet load subject to relevant constraints (such as the LRET target). WHIRLYGIG was used to model the baseline, lower and upper demand cases. Modelling the NEM in WHIRLYGIG and determining optimal investment patterns requires modelling the entire year, not just the peak demand levels.

Frontier assumed that while peak demand would fall, annual consumption would remain unchanged, as demonstrated in figure 10.2 and figure 10.3.That is, reductions in peak usage of electricity would be exactly offset by increased consumption during the off peak such that total consumption across the year remained unchanged. This assumption is consistent with the concept of time-shifting demand for electricity (for example by delaying the time at which appliances like dishwashers are used). It is also conservative to the extent that any changes in costs are due solely to reductions in peak demand and not net reductions in annual consumption.

Comparing the change in costs relative to the baseline case gives an estimate of the change in cost due to reduced peak demand. This estimate reflects changes in investment and the dispatch of generation across the entire NEM over the modelling period. This is a change in resource or economic costs as distinct from a change in the marginal cost of meeting demand. These costs can be used to determine $/kW/annum savings, comparable to a capital cost of generation, which are presented for both demand cases and for each region of the NEM in figure 10.4 below.

Figure 10.4 Savings - Energy ($/kW/annum)



Source: Frontier Economics

Frontier's results showed that:

- Savings arising from generation are less than those estimated for network in all regions, particularly in the pre-2025 timeframe. This is consistent with the current over supply of wholesale generation and the level of baseline demand growth.

- In the longer term, savings rise considerably in regions with stronger assumed peak demand growth in the baseline – namely South Australia and to a lesser extent Queensland.

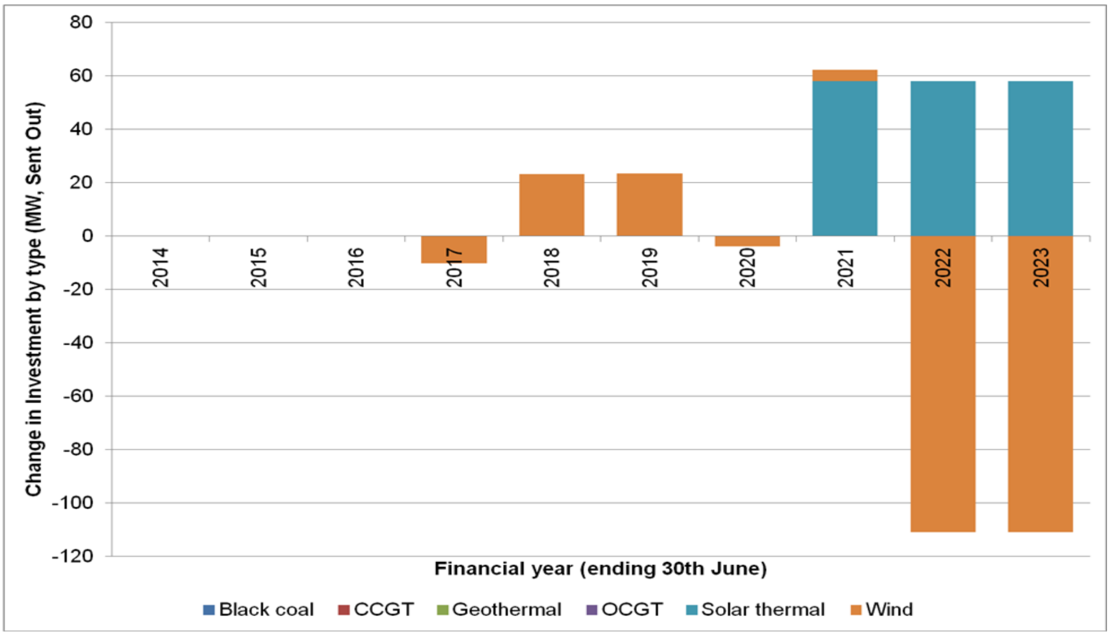
- In $/kW terms, savings are larger in the Lower case relative to the Upper. This is consistent with the concept of diminishing returns. On the margin, there are larger savings obtained in the Lower case relative to the baseline for each unit of reduced peak demand. Although absolute savings are higher in the Upper case, they are 'spread' over a larger demand reduction, this results in lower $/kW savings.

- In some regions, most notably Victoria, savings are negative. This result is due to the assumption that reductions in peak demand are offset by increased consumption during off-peak times. During the off-peak, low cost generation operates at higher levels to meet this increase in demand. In the case of Victoria, where there is a large quantity of very cheap brown coal that is not completely utilised during off-peak times, this generation runs to meet increased off-peak demand across the NEM. In most years the increased variable costs due to overnight operation of Victorian brown coal generation exceed costs savings at time of peak within Victoria – resulting in a negative saving overall for the region. Similar situations arise periodically in NSW and Queensland when excess, cheap black coal fired generation is available. It should be noted that savings across the NEM are net positive in all years of the modelling period.

- The different demand assumptions between the modelling scenarios and the base case will change the mix and timing of investment across the NEM. Over the next ten years, the change in generation mix is similar for both the lower and upper cases, where small amounts of wind investment are brought forward into FY18 and FY19 and in the back of the 10 year period there's a switch from investing in southern Wind to investing in Solar Thermal in Queensland as a result of lower demand. This is shown in figure 10.5 below (although larger changes which occur in the post2025 years are not shown).

- The analysis is a result of cost based, long term, modelling. There may be additional benefits that accrue to consumers via reductions in both the level and volatility of wholesale pool prices due to flatter load shapes. This could be captured in market modelling that accounts for strategic behaviour by market participants. If realised, such reductions in the level and volatility of pool prices are likely to flow through to wholesale energy contracts and ultimately, end users of electricity. It is not necessarily the case that such benefits would be similar to, or exceed, the resource cost savings reported here.

Figure 10.5 Changes in investment (Upper case)



Source: Frontier Economics. Note: Positive values represent great investment in the Baseline case relative to the Upper case.

10.3.3 Savings from avoided network costs

Frontier's modelling took a relatively high level approach to estimating savings that may arise from avoided network cost due to reductions in peak demand. Long term network investment is difficult to forecast due to both the physical complexity of electricity networks and economic factors arising from such networks being regulated natural monopolies. Frontier's approach relied on historical expenditure data to determine average network investment costs rather than detailed forecasts. This data came from two sources:

- 2011 AER State of the Market report and analysis of cost components performed by the Reserve Bank of Australia (RBA); and
- SKM MMA analysis of EY report to the AEMC as part of the Department of Climate Change and Energy Efficiency (DCCEE) - Department of Resources, Energy and Tourism (DRET) review into a national energy efficiency scheme.

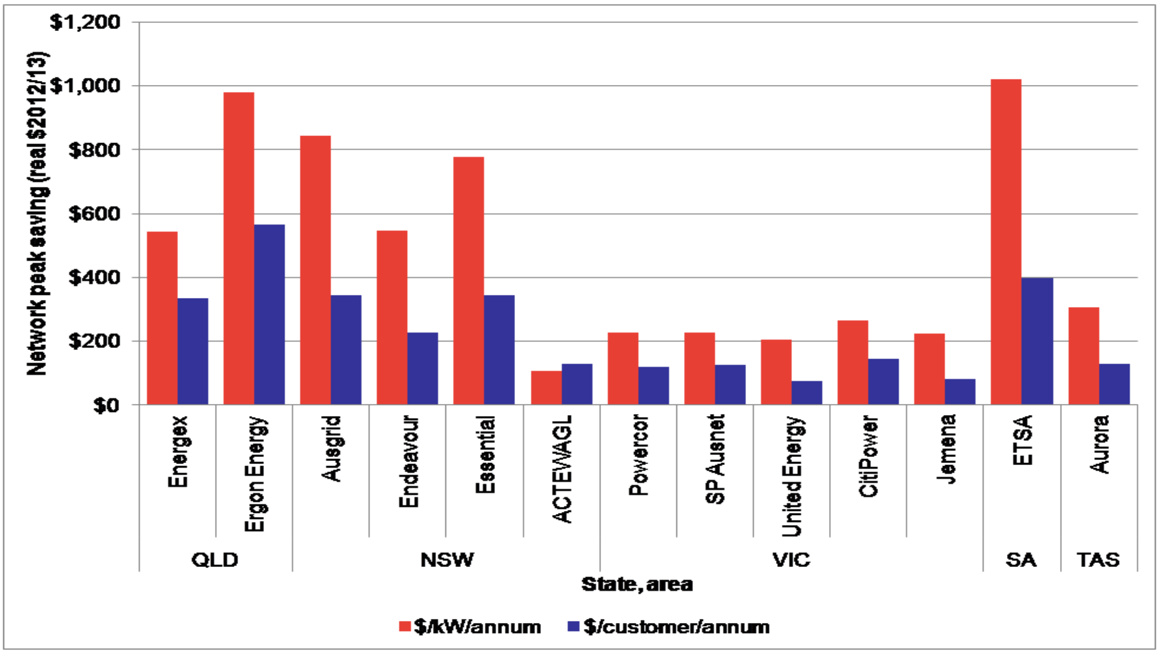
Using this source data Frontier were able to determine network costs on a $/kW/annum and $/customer/annum basis. Most of these estimates were based on average network costs over the previous four to five years, a period of historically high network expenditure, and could not be disaggregated into a network expansion component. As a result, these estimates tend to overstate the magnitude of benefits associated with peak demand reductions (as they reflect a high expenditure baseline and include costs not solely related to network expansion, such as asset replacement and reliability costs). The exception to this is the AER data which was able to be disaggregated into a network expansion component. Given that this data is based on a period of high levels of investment in networks in most areas, Frontier considered the AER's network expansion estimate to be the most reasonable.

The four estimates are:

- Network expansion: based on the AER 2011 State of the Market report and broken into components using RBA cost allocation data;
- Regional: based on the SKM MMA analysis at a regional level;
- Average investment: based on the AER 2011 State of the Market report; and
- DNSP: based on the SKM MMA analysis of each distribution area.

Figure 10.7 presents the conservative network expansion estimate for each distribution area on both a $/kW/annum and $/customer/annum basis. However, even this conservative estimate is based on expenditure data over the 2009-2015 where spending has been high relative to likely post-2015 expenditure. Both the Ergon and South Australian distribution areas, which have peakier load shapes and wide geographic spread/low population density, have the highest potential for savings due to reductions in peak demand. These savings are roughly $1000/kW which is similar to the capital cost of a new entrant peaking generator (which could potentially substitute for network investment). In other distribution areas potential savings are lower but still considerable.

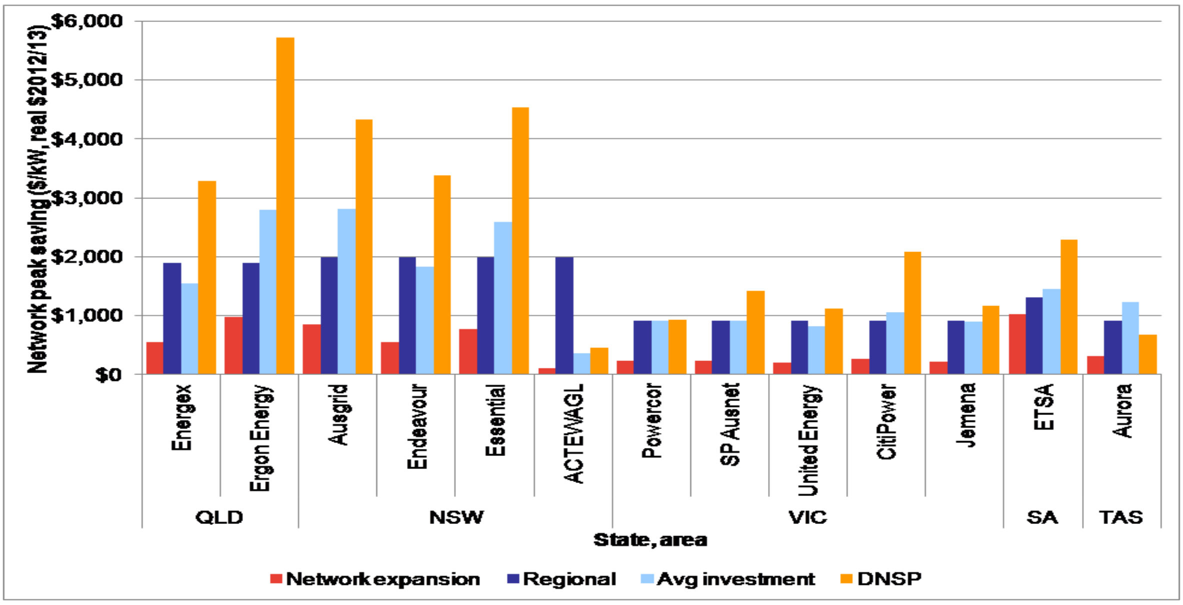
Figure 10.6 Conservative network savings (based on AER network expansion data)



Source: Frontier Economics analysis of AER 2011 State of the Market Report

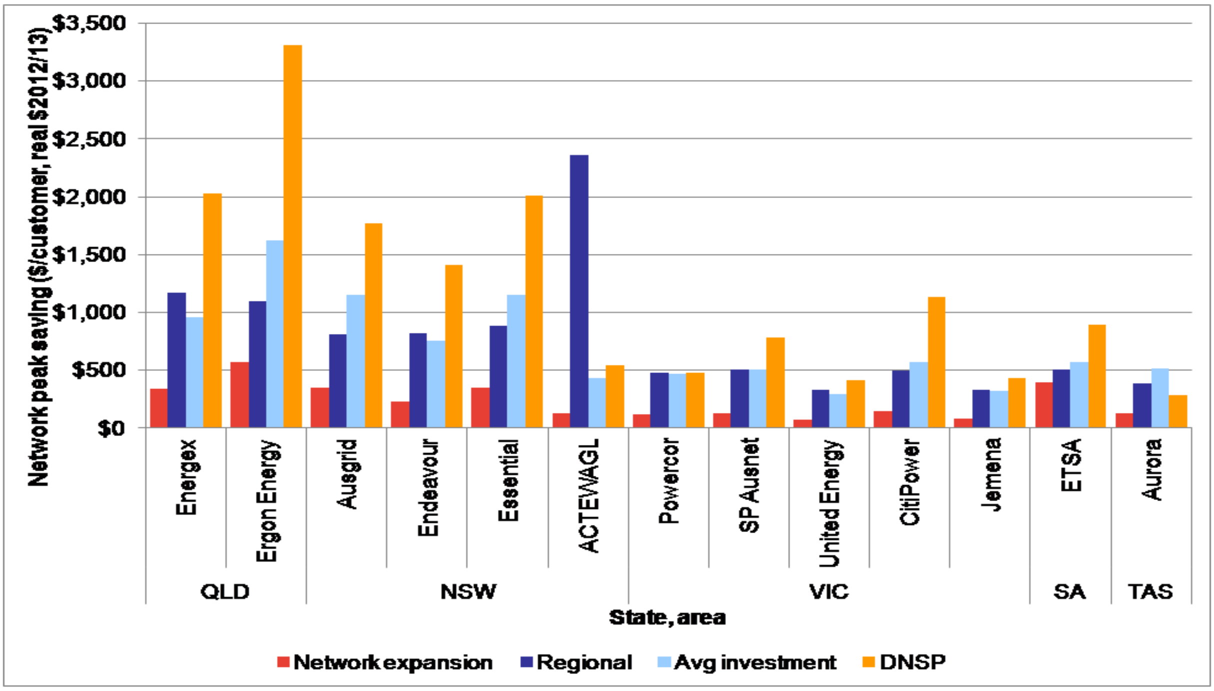
Figure 10.7 present all four estimates on a $/kW/annum and $/customer/annum basis respectively. The alternative estimates, which are based on average expenditure and include costs not directly related to network expansion, are much higher than the estimates presented in figure 10.7. Given this, Frontier has calculated the network benefits using the relatively conservative figures shown in figure 10.6.

Figure 10.7 Savings – Network ($/kW/annum)



Source: Frontier Economics analysis of 3rd party studies

Figure 10.8 Savings – Network ($/customer/annum)



Source: Frontier Economics analysis of 3rd party studies

10.3.4 Conclusion

Frontier's estimate of the total benefit of peak demand reductions is a combination of the relatively conservative network expansion savings estimate and the Lower case energy savings. In absolute dollar terms, economic cost savings in net present value terms (NPV) over ten years from 2013/14 to 2022/23 are:

- $4,316 million 10-year NPV in the Lower case; and
- $11,760 million 10-year NPV in the Upper case.

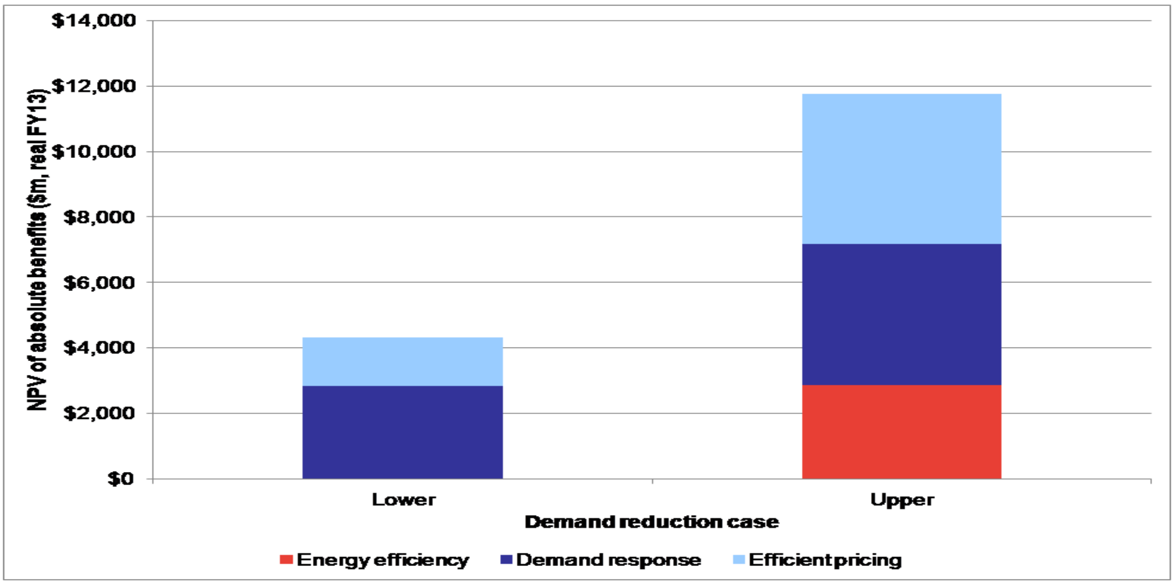
These savings estimates do not include any costs associated with implementing the Power of Choice recommendations (Frontier did not conduct a cost-benefit analysis). These absolute benefits are shown in figure 10.9 and table 10.2, where they have been broken down by the source of peak demand reduction. This equates to roughly between 3% and 9% of estimate total system expenditure over the period, consistent with the magnitude of assumed peak demand reductions. A rough estimate of total infrastructure investment plus variable costs of energy production over the next ten years is $129 bn (NPV basis). This is split between $63,246m for energy costs (variable costs of production + fixed cost of new entrants) and approximately $ 66,322m for network capital expenditure.[381] This is based on the assumption that network investment continues at current levels.

381 This is calculated using an average network cost per MW figure. The figure Frontier used is equal to the same AER data for total expenditure divided by total peak demand (not growth).

Table 10.2 Total absolute benefits from recommendations ($m, real$FY2013)

	Energy Efficiency	Demand Response	Efficient Pricing	Total Absolute benefits
Lower case	$0	$2,825	$1,482	$4,316
Upper case	$2,852	$4,328	$4,579	$11,760

Figure 10.9 Total absolute benefits (AER network expansion plus energy savings)

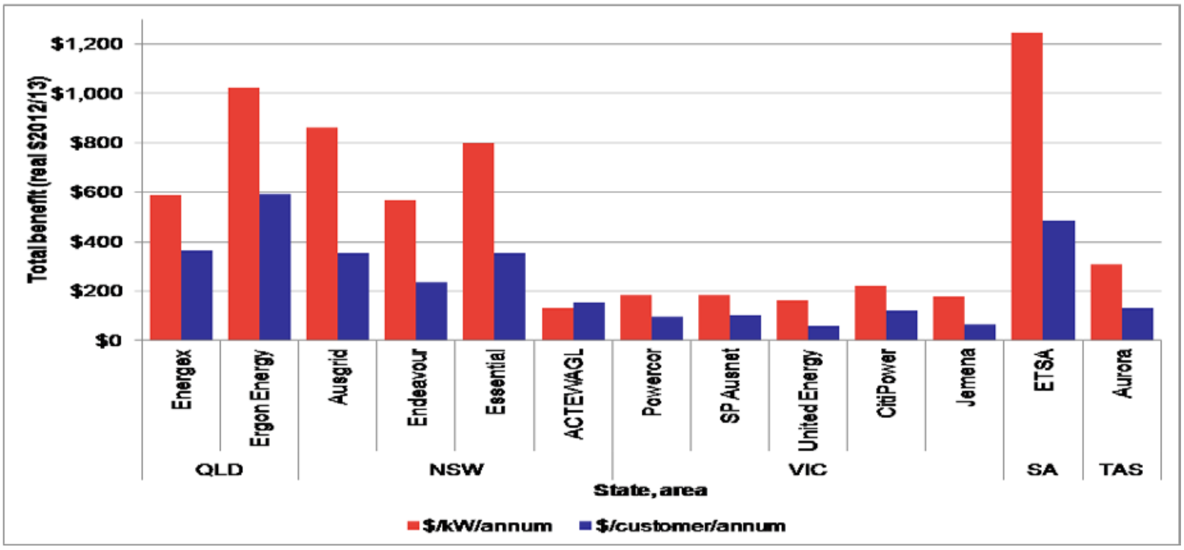


Source: Frontier Economics

Whilst absolute savings are higher in the Upper case, unit savings (in $/kW terms) are less than the Lower case as a result of the diminishing returns to marginal reductions in peak demand growth.

Savings stem primarily from avoided network expenditure. Large savings could be captured in South Australia and Queensland due to peakier load shapes and more geographic dispersion in those regions.

Figure 10.10 Total unit benefits (AER network expansion plus lower energy savings)



Source: Frontier Economics

10.4 Additional benefits to the market

The analysis presented above identified savings arising in the energy market due to changes in underlying economic (resource) costs. With regard to networks, it is likely that these cost savings will accrue to end users via lower regulated prices. To the extent that network businesses are only allowed to recover efficient expenditure via regulated prices then changes in underlying costs should flow through to consumers. This ultimately reflects the structure of the network side of the energy market – a natural (and regulated) monopoly.

Outcomes are different for the energy side of the market due to its different structure – a competitive, partially privatised and de-regulated market for both wholesale and retail electricity.

The analysis presented above used a cost-based modelling approach to quantify potential savings arising from changes in investment and dispatch in the NEM relative to a base case. The identified savings were measured as changes in economic costs, predominantly those associated with deferred or delayed capital investment in generation plant. The extent to which these savings are captured by end users will be driven by outcomes in the (mostly competitive) markets for wholesale energy – namely the NEM and derivative markets – and by the form of regulation in each jurisdiction. This is because the prices that end users pay for electricity are driven by a combination of marginal pricing outcomes in the competitive sectors of the NEM and the form of regulation in each region.

Regulators in Australia use a range of methodologies to regulate retail prices including no explicit price regulation (Victoria), cost-based methodologies and market based approaches. These broad approaches, and the manner in which savings due to peak demand reductions might be captured by them, is discussed below:

- **No explicit price regulation**: To the extent that peak demand reduction leads to a flatter load shape over time, this should result in lower and less volatile wholesale pool and contract prices. Where retail competition is effective these reductions in cost will be passed through to end users;
- **Market-based approaches**: Market-based approaches to regulating electricity prices try to forecast outcomes in the wholesale market. To the extent that such forecasts include flatter load shapes as an input, presumably they will lead to lower and less volatile wholesale pool and contract prices and pass these through to end users. From a practical perspective, whilst forecasting over the longer term is particularly difficult when using a market-based approach as pricing outcomes are highly dependent on the ownership structure of the market being modelled, as new investment comes online assumptions need to be made about how it is bid into the market;
- **Cost-based approaches**: There are two broad approaches to cost-based price regulation – stand-alone and incremental LRMC methodologies:
  - **Stand-alone LRMC**: Ignores the regional structure of an actual market and its existing stock of generation and instead determines an efficient investment mix for meeting a specific load shape. To the extent that the assumed load shape is flatter due to realised reductions in peak demand then this will lead to lower cost estimates to serve the load and consumers will capture these benefits
  - **Incremental LRMC**: In contrast to the stand-alone approach, an incremental LRMC includes the regional structure of a market and the existing stock of generation and determines marginal costs over time. There are different methods for doing this but the key feature is the manner in which fixed costs are accounted for. The approach taken may have different implications regarding how end users might capture the benefits of peak demand reductions.

Of the methodologies outlined above, all except the incremental LRMC approach will lead to consumers capturing reductions in the cost of energy due to reductions in peak demand. However, it is not necessarily the case that any marginal savings would be greater (or less than) savings arising from changes in resource costs as estimated by Frontier. This occurs via either:

- a direct reduction in wholesale prices (in the absence of explicit regulation);
- a reduction in modelling wholesale prices (via market-based price regulation); or
- a reduction in efficient costs, including hedging costs (under a stand-alone LRMC).

All the jurisdictions in the NEM currently use one of these approaches.

With regard to the incremental LRMC approach, which is not used in any jurisdiction, outcomes are less clear. This is because, whilst prices are likely to tend towards LRMC in the long term, the current oversupply in the NEM leads to estimates of LRMC using an incremental approach that in fact only reflect short-run (i.e. variable) costs. This is because no new investment is needed to meet demand due to existing over supply, meaning that there are no incremental fixed costs associated with serving a marginal unit of demand.

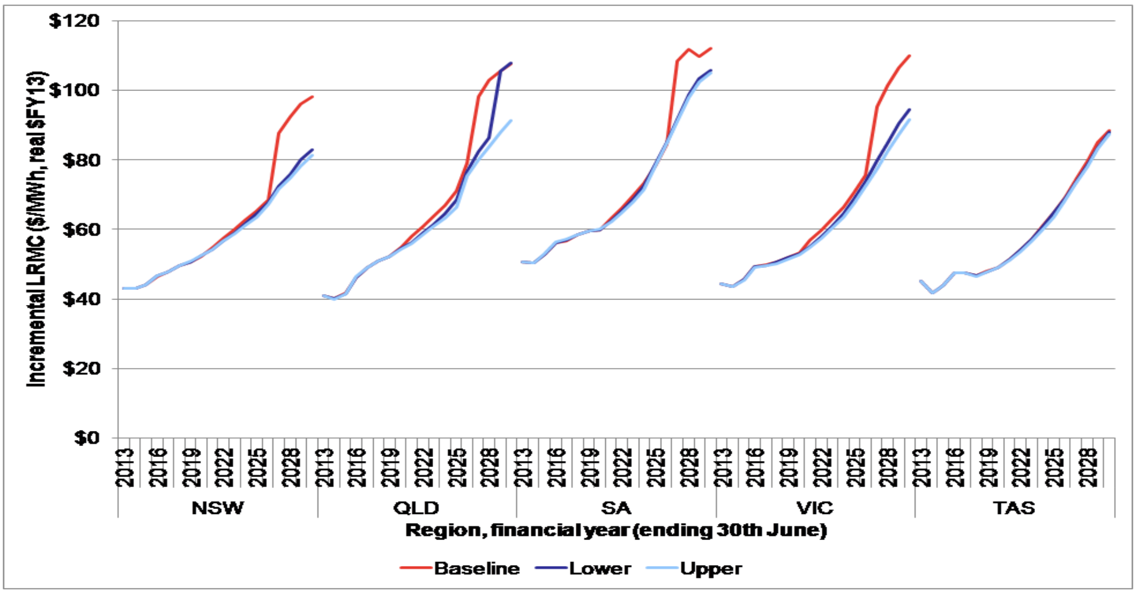
This outcome is highlighted in figure 10.12, which shows the incremental LRMC by NEM region for each of the three cases modelled. The approached used is a strict or pure incremental LRMC that measured the incremental cost of meeting an additional unit of demand in terms of:

- incremental variable costs (carbon/fuel/variable operating and maintenance); and

- incremental fixed costs to the extent that additional capacity is needed to meet incremental demand *in each specific year*.

Figure 10.12 highlights the issues with incremental LRMC approaches. LRMC in all regions start at around $40-50/MWh in 2012/13 including carbon. This cost is essentially a short run marginal cost (SRMC) result as no new investment in needed to meet incremental demand. LRMC rises over time due to assumed increases in variable carbon and fuel costs. It is only from around 2026 onwards that fixed costs entered the LRMC estimate and even then only in some cases. In the Baseline case, investment in needed in all regions except Tasmania in the late-2020's, and a step change increase in LRMC is observed. This also occurs in the Lower case for Queensland and both the Lower and Upper cases for South Australia. There are a number of instances where there is no significant need for new investment, given the assumptions underpinning the analysis, over the modelling period. Tasmania is the clearest example of this, estimates of LRMC simple rise in line with assumed increase in variable costs and never involve a step change to reflect fixed costs associated with new investment.

Figure 10.11 Incremental LRMC by case and region



Source: Frontier Economics

These LRMC estimates clearly show that reductions in peak demand defer the need for new investment. However, it is difficult to use such estimates for the purpose of an accurate quantification of the benefits that may flow through to consumers. Two major issues arise:

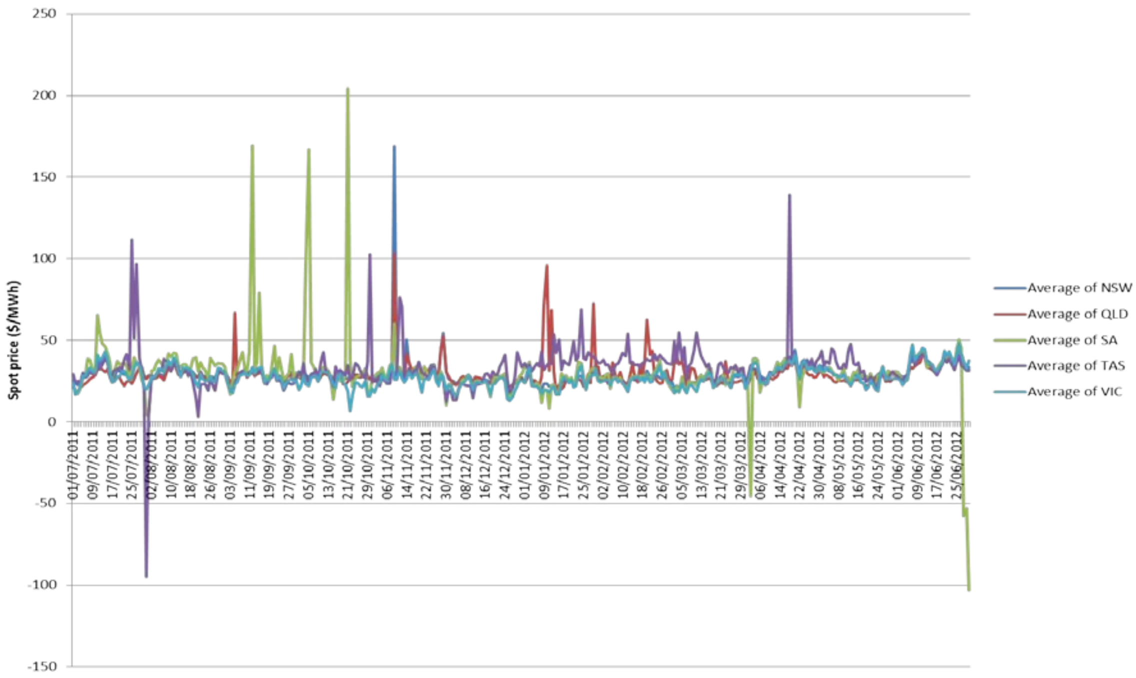
1. Pricing outcomes are unlikely to result in only perfectly competitive, short-run costs being recovered from consumers under any of the currently used forms of regulation (including the absence of explicit price regulation). Any inclusion of fixed costs associated with existing capacity will apply equally to cases with and without an assumed reduction in peak demand and will not result in 'savings'; and

2. In some regions, there may be no forecast change to LRMC using an incremental approach over any reasonable modelling period. This is the case for Tasmania in figure 10.11.

It is likely that substantial benefits may accrue to consumers due to reductions in the marginal cost of energy. However, such benefits are difficult to estimate, more difficult than changes in resource costs (such as those presented in figure 10.12). This reflects the difference in measuring changes to average as opposed to marginal costs, where the latter task is substantially more difficult, particularly over long timeframes.

A lack of participation on the demand side can contribute to extreme price events in the wholesale market and which feed through to higher consumer costs. Figure 10.12 shows the average daily spot price across the NEM states over the past financial year.

Figure 10.12 Daily Average Spot price in NEM regions 2011/2012



Analysis performed by PricewaterhouseCoopers (PwC) for this review, found that demand response at high price periods will have a significant impact on the average cost of energy in the NEM. By removing the top and bottom one per cent of half-hourly trading prices from 2010, PwC found there were considerable reductions in the average price in each region. In particular, in South Australia this saw the average price in 2010 fall from $40 to $25. What this demonstrates is that there is the potential for demand response at high price periods to have a significant impact on the average cost of energy in the NEM. We note that however, high demand may not always be the main driver of extreme prices in the NEM. High prices can result from moderate demand where unexpected events occur that reduce supply (such as network outages, transmission congestion).

Table 10.3 Impact of the top and bottom one per cent of prices on average energy price (2010)[382]

	NSW	VIC	QLD	SA	TAS
Average price	$30.89	$34.44	$25.53	$40.28	$30.89
Average Price with top and bottom 1 per cent removed	$25.13	$23.95	$21.60	$25.42	$24.65

382 PricewaterhouseCoopers report to Australian Energy Market Commission, *Investigation of the efficient operation of price signals in the NEM*, December 2011.

10.5 Costs of the recommendations

It is important to recognise that there will also be costs involved in uptake and implementation of different DSP options. These include the administrative and technology costs involved in running the DSP options, as well as implementation costs and ongoing changes to market incentives and market efficiency. Areas where costs may arise are discussed qualitatively below. This discussion focuses on areas of cost across the sector and does not focus on transfers between producers, transporters and consumers of electricity. However, costs associated with changed incentives arising from transfers between participants are discussed:

- **Implementation costs:** Frontier suggested that the Power of Choice recommendations, if fully implemented, are likely to necessitate a significant change to the National Electricity Law and a complex transition path. There would also be costs associated with education for consumers, particularly residential consumers. There will be also costs of software changes for market participants (i.e., retailers and AEMO).

- **Technology costs:** Primarily these are associated with the provision and installation of smart meters plus the communications systems. This may not represent an additional cost to consumers depending upon existing metering costs and the extent that smart meters are widely rolled out across the NEM in any case, Additional costs, may also arise around technologies for disseminating information – such as home alerts. Consumers will decide whether to incur such costs, if they see a benefit to themselves from such enabling technology. There are also likely to be technology costs for back-end systems to record, settle and switch on the basis of extensive half hourly data, including an increased role for AEMO, retailers and distributors in particular.

- **Administrative costs:** Additional to the direct technology costs associated with wide spread use of half hourly data across the market there are likely to be additional administrative costs associated with processing data, complaint resolution, etc. Again, AEMO, retailers and distributors will bear a large proportion of these costs. Again, in the absence of our recommendations, there may still be a need for market participants to incur such costs as more consumers move to smart meters.

- **Incentives and market efficiencies:** Our recommendations are designed to lead to increases in allocative and dynamic efficiency with regard to consumers' choices to consume. However, the incentives created by the recommendations may lead to unintended consequences that reduce market efficiency in some areas. For example, whilst the recommendations are likely to increase allocative efficiencies via an increase in dispatchable load in the NEM (which can receive compensation when bid out of the market), in the long-run this may have implications for dynamic efficiency with regard to investment in new entrant generation in an energy only, gross-pool market like the NEM. This is because new entrant (and existing) generators will now be competing against dispatchable load which is likely to have no fixed, or much lower, costs.

- **Opportunity cost of consumption:** The analysis has not tried to place a value on the activities which are foregone when consumers of electricity reduce or time-shift consumption. Whilst there may still be benefits net of this opportunity cost, assuming a value of zero for such activities will tend to overstate any calculated net benefits.

These costs can be very difficult to accurately model and quantify. The modelling estimates of the value of avoided network and generation costs are substantial and may outweigh such costs.

The Power of choice review is seeking to give consumers more opportunities to actively participate in the market and capture the value of their consumption decisions. The costs associated with our recommendations, on a disaggregated level, will mostly be incurred only if a consumer decides to opt for a DSP service or tariff. They will only do so if they consider the potential benefits will exceed those costs. Consumers will reveal this through their actions.

With adequate information to make effective choices, consumers are only likely to opt for time varying tariffs or other DSP options if they expect to benefit from either by a) using less energy when prices are high, or from shifting usage to lower-priced periods; or b) any explicit financial payments/rewards the consumer receives for agreeing to or actually curtailing usage in a demand response program. Only the individual consumer can fully understand the net benefit from DSP because it can appreciate the end use services and value it derives from consuming electricity.

The purpose of engaging Frontier economics was to provide a high level estimate of the potential benefits that could be realised under our recommendations. Ultimately, the realisation of such net benefits will depend upon consumer choice and behaviour. The value of our recommendations is through giving consumers more opportunities to better manage their expenditure on electricity.

11 Integrating reforms across the supply chain

Summary

The impediments to the market delivering efficient DSP include a lack of efficient and flexible prices, high transaction costs, information asymmetry and split incentives, as some DSP benefits may not accrue to parties who incur the costs.

In this review, we have addressed these issues related to each individual part of the supply chain and recommended reforms to current market and regulatory arrangements. These reforms will support more flexible and efficient pricing and strengthen regulatory incentives for DSP. Our reforms will provide greater opportunities for both commercial businesses and residential households to participate in DSP.

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. We also minimise transaction costs by allowing reforms to be phased in, focussing initially on larger residential consumers.

Sequencing and co-ordinating reforms, plus developing consumer awareness and acceptance are crucial to the success of DSP initiatives. Many aspects of our recommendations address this point, including the distinction between large and small residential consumers, our use of mandatory, opt-out and opt-in approaches for the transition to flexible pricing options and our approach to the progressive deployment of smart meters enabling price signals.

Pricing and regulatory reforms principally apply to individual elements of the supply chain. Measures to reduce transaction costs should bring benefits across the supply chain. The risks of any under-utilisation of DSP within the supply chain are reduced through greater use of price signals and increased transparency.

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.

11.1 Market conditions for uptake of efficient DSP

Other chapters have discussed the uptake of efficient DSP in particular elements of the supply chain. In this chapter we consider the challenges in optimising and coordinating DSP across the supply chain and set out how our conclusions will achieve this.

Our preference, where feasible, is for market based solutions. However efficient DSP may not be fully captured through market based solutions alone because:

- Energy markets are subject to major price spikes. These act as a signal for peak generation capacity but appear less effective as a signal for reducing or shifting peak demand.

- Networks are also subject to spikes in marginal costs, when peak demand drives new investment. Marginal network costs vary significantly by time and location. However these high marginal costs are only partially reflected in price signals, and not at all for the small business and residential sector. There are challenges in ensuring a price signal which is efficient but also practical to implement, and in ensuring consumer protection.

- Introducing more efficient price signals for both energy and networks is likely to require more accurate measurement of time of consumption (interval data) and changes to market settlement, with transaction costs. Providers of DSP also face significant transaction costs in participating in a potentially complex market. Our policy recommendations and implementation plans attempt to minimise such costs.

- DSP will create different costs and benefits for different parts of the supply chain, from the wholesale market to the retail sector. An important condition for efficiency is that these external costs and benefits are reflected in decisions by each part of the supply chain. The costs for consumers participating in the market can be alleviated by third parties with specialist skills to advise, manage and co-ordinate DSP options.

We have proposed a package of reforms that are designed to address these problems within the supply chain and to also promote better coordination across the supply chain. This chapter summarises these recommendations with a particular focus on interactions across the supply chain, and the way our recommendations address the four key issues discussed below.

11.2 Issues identified

This review has 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 four principal factors that may be limiting efficient provision and coordination of DSP across the supply chain:

- The absence of efficient prices that give consumers accurate signals on the costs of supplying and delivering electricity;

- The existence of substantial transaction costs both in providing those price signals and in managing DSP in the market;

- Information asymmetries between DSP providers and DSP users and between regulators and regulated businesses; and

- Externalities across the supply and split incentives for incurring the upfront costs of DSP provision and realising the benefits.

Our recommendations address these factors.

11.3 Considerations

Figure 11.1 shows the mix of arrangements we have proposed. Among other things, these include:

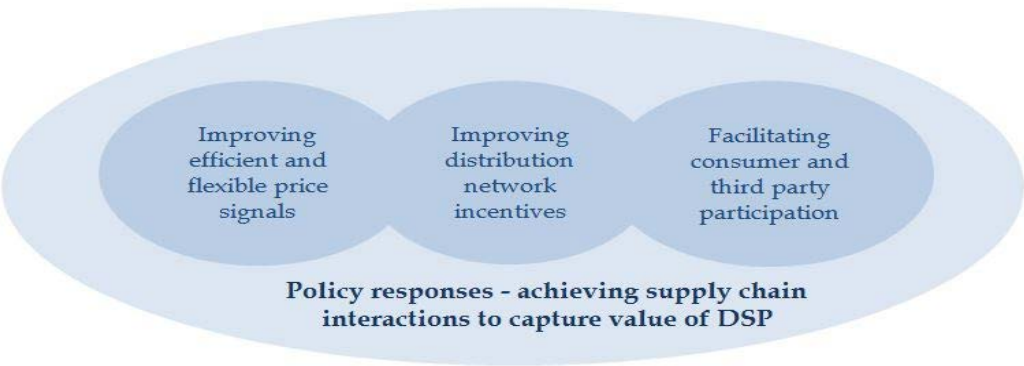
- rewarding consumers demand response action through efficient and flexible pricing options and the wholesale market demand response mechanism;

- improving distribution network incentives; and

- facilitating consumer and third party (eg ESCOs and aggregators) participation.

In the following sections we provide a discussion of our recommendations in the context of promoting co-ordination across the supply chain and the different market participants.

Figure 11.1 Proposed policy responses in draft report



11.3.1 Energy markets

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.[383] In the NEM, there are periods when energy prices can 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

383 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.

revenues would not be sufficient to cover the fixed costs of capacity. As these fixed costs are reflected in energy prices during those infrequent periods of high demand, the price distribution is inevitably skewed.

These arrangements mean that the marginal costs in the wholesale market vary significantly by time of use and location. Therefore we consider that in the NEM wholesale energy charges are reasonably cost reflective.

For most large industrial and commercial consumers the marginal costs of supplying and delivering electricity are partially reflected in their pricing structures. Evidence suggests these consumers to some extent respond to these price signals -- adjusting their consumption in short periods in response to high wholesale prices.[384]

Other industrial and commercial consumers and residential consumers have relatively blunt price signals with limited time varying prices. We do not consider it desirable to fully expose consumers to the price volatility in the wholesale market. Peak prices in the NEM wholesale market can be around 300 times greater than average prices.[385]It is unrealistic to expect all consumers to monitor energy prices in real time and adjust consumption accordingly. 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, in some cases through vertical integration.

Given these constraints on the use of price signals we have proposed a demand response mechanism to give incentives for demand side response based on price signals in the wholesale market. Participation in the mechanism is voluntary and the consumer has the ability to choose when to offer demand response to the market. This will enable the consumer to participate in demand response without being exposed to levels of risk they are poorly placed to manage. It is also likely that third party providers will co-ordinate consumer demand response under this mechanism in order to minimise transactions costs on individual consumers. Participation in this mechanism is likely to be initially confined to the commercial and industrial sectors but could be extended to the residential sector in the future.

There are material transaction costs both in enabling greater DSP participation and in effective management of DSP. We have recommended measures to improve the stock of metering technology and changes to settlement arrangements. Over time these measures will ensure that the consumer is able to capture the value of changing its consumption pattern. This will form the basis both of better informed consumer decisions and progressive extension of the new pricing mechanisms set out in this report.

---

384 AER directions paper submission, p. 13.

385 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.

We have also recommended several steps to reduce the transaction costs of participating in the market. Steps to increase the information available on consumption patterns will enable consumers, or their representatives, to make more informed decisions on managing their consumption. Measures to promote the participation of aggregators and other third parties will reduce the transaction costs of DSP. By increasing competition in energy management service entry of third party providers may help to ensure that benefits flows to consumers.

We anticipate that there will be a high, but not a complete, degree of coincidence between price spikes in the wholesale market and demand spikes within networks. This will reduce the potential conflict between different uses of DSP and increase the benefits from the proposed demand response mechanism.

Our recommendations also include monitoring the impact of the new mechanism over time. The monitoring will report on the extent to which demand reductions attributable to the new demand response mechanism can be considered reliable in network planning and investment.

Our recommendations establish a transparent demand response mechanism related to price signals in the wholesale market. We match this with measures to reduce transaction costs in measuring and rewarding DSP and measures to improve information. This will support third party participation to better enable the benefits of the consumption decisions flows to consumers.

11.3.2 Networks

The NEM is characterised by 'needle' demand 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 consumption decisions do not take account of the very high costs of serving these demand spikes. Efficiency would improve if consumers were better exposed to the costs of their consumption and consider their consumption in light of those costs.

Our analysis indicate significant benefits if DSP could be used to defer network investments. We have therefore recommended the introduction of cost reflective network tariffs (i.e., time of use, critical peak pricing, and demand charges) and amendments to the distribution tariff arrangements.

However we also recognise that there are greater difficulties in relying on price signals to realise these benefits than in the energy market:

- Consumers require protection from potential network price volatility which they may be poorly placed to assess and manage. We have addressed this through ensuring cost reflective network tariffs are mandatory for large residential and commercial consumers; applied to medium-sized consumers with an option to revert to their existing tariff structure; and not applied to small consumers unless they choose to opt-in, and

- The marginal cost of distribution services is less straightforward to define or measure and then convert into a price which the consumer understands and accepts. We consider this problem can be overcome through appropriate regulatory approaches and guidance from the AER.

Marginal costs of networks will vary by location as well as by time. Analysis in the directions paper showed that marginal costs can vary by minor changes in location within a distribution network. While it may not be not practical to impose highly variable locational charges for distribution networks, the rules should permit networks to introduce locational difference (for example, critical peak tariffs). However we also note that currently some jurisdictions do not permit locational network tariffs at the residential levels. As a result price signals could remain a limited proxy for marginal costs.

In addition to price based measures we have therefore proposed a number of measures and principles to reinforce existing regulatory incentives for the use of DSP to minimise network costs.

The use of flexible pricing options requires consumer data to be measured on a time interval basis and the availability of information for consumers to determine their response to these new price signals. Our measures to address transaction costs through cost effective improvement of the meter stock, information disclosure and a possible role for third parties in aggregating or otherwise managing DSP.

This change potentially introduces more volatility into consumers' tariffs. We have ensured consumer protection through our mix of mandatory, opt-out and opt-in approaches varying by consumer size. We also recommend specific measures to address vulnerable consumers through the state energy concession schemes and government programs.

Our recommendations establish a significant improvement in the efficiency of network price signals, coupled with proposals to improve the incentives to use efficient DSP under the regulatory regime. This is supported by our measures to address transaction costs in measuring and rewarding individual consumption patterns and in participating in this market and by measures to ensure adequate consumer protection.

11.3.3 Co-ordination across the supply chain

There are differing cost drivers between network and retail businesses. Network businesses 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 businesses 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.

Currently, the commercial frameworks for DSP are based on bilateral agreements between DSP providers (i.e. consumers or third parties) and energy retailers or network businesses. These agreements differ between DSP which is used to reduce energy costs and DSP which is used to reduce network costs. We have noted in this review that it is difficult for a DSP provider to negotiate with multiple potential users of the DSP. In the directions paper, we raised the possibility of moving from the current bilateral state of DSP contracts to multilateral arrangements.

There are a number of issues for bilateral contracts. In most cases they will provide external benefits (DSP to reduce peak energy will to some extent reduce peak network flows, and vice versa) but are not well designed to ensure the highest combined benefits. Consumers are not well placed to judge value but users may require firmness through long term contract. This raises the risk that DSP gets locked into sub-optimal uses.

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 could be realised through the pricing signals.

Concerns about consumer protection, consumer behaviour and preferences, also mean that there are likely to be significant practical limitations on moving to fully cost reflective pricing. A further possible issue is that increasing the time varying nature of retail tariffs 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, consumers may hesitate to support new investment in long-lived, capital intensive DSP.

We have proposed new pricing arrangements to promote the transition of more flexible pricing options for residential consumers. We anticipate this will enable more DSP as consumers respond to the demand response incentive and to cost reflective tariffs for networks, without having to enter into contracts. It is probable that over time, the response to these new price signals will be reasonably firm and predictable to be reflected in price and demand forecasts by the businesses affected.

We also anticipate there will be a continuing requirement for contracted DSP. This is particularly likely to be the case in distribution networks, where firm DSP contracts will be required to enable network businesses to defer investment. The introduction of demand response mechanism and the reforms to the demand management incentive scheme will complement each other and enable consumers to access both the energy value and the network value of their consumption decisions.

The draft report considered three principal options for a multilateral contractual framework. One would be to enter into a firm contract with the end user of their choice and then seek to negotiate additional revenues from other energy businesses. A second would be to require agreements to be negotiated through third parties, reducing the transaction costs and potentially increasing the firmness through aggregation. A third would be to rely on an obligation on the contracting parties, whether energy or network businesses, to seek additional value from other end-users.

On balance, we concluded 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 third parties and retailers to negotiate 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 can be supported by standard methods for valuing DSP costs and benefits.

Our recommendations for technical standards for load management services[386] and open access for multiple DSP service providers to access smart meters (see Chapter five) will improve the framework for multi-party negotiation. This is because these reforms will establish clear procedures and rules regarding offering DSP services to consumers and remove potential points of conflict (i.e., right to do load management).

Our recommendations should enable non-contracted DSP in response to both energy and network price signals. Networks in particular may also seek contracted DSP in response to regulatory incentives. We anticipate the potential conflicts over efficient allocation of DSP should be low. We intend to monitor this. If material conflicts emerge we would propose to engage with industry to develop multilateral arrangements.

11.3.4 Energy Service Companies (ESCOs) and third parties offering DSP services

Third parties can play an important role in coordinating the actions of parties in 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 acting 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

386 See section 1.4.5. The recommendation for technical standards for load management services is developed further in our Final Advice to SCER on the *Electric Vehicle/Natural Gas Vehicles Review*, which will be published on the 30 November 2012.

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. Chapter three considered that broader market information could 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 projects 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 itself 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.[387] 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.

The recommendations set out in this final report should assist with the market conditions necessary to enable ESCOs to operate effectively in the energy market. We expect 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 energy efficiency and DSP policies and actions.

387 For example, Green Building Fund, Melbourne City Council 1200 Buildings initiative.

11.3.5 Establishing a virtual DSP market/exchange

An alternative mechanism could be to establish 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 still leave a significant amount of 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. A network would presumably include information on the price at which DSP is offered.[388]
- 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 provide more certainty to the offers. Pricing rules would be needed. Prudential and settlement 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. There is nothing to prevent a DSP adopting this approach currently. There may also be other benefits from the DSP project which are less developed[389].

---

388 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).

389 The Capacity to Customers project in Electricity North West (ENW's) distribution network in the UK suggests that significant value can be realised through using demand side response (DSR) very infrequently – perhaps only once every few years – to assist with fault response and reduce

The requirement for a virtual market or exchange depends on the existence of substantial unrealised potential for DSP. The recommendations in this report have established much stronger incentives for the use of DSP in response to energy price spikes and time-varying network tariffs. They have also reinforced the regulatory incentives for DSP and reduced transaction costs through increasing information availability and enabling third party entry. The response to these new incentives is likely to develop over time.

These recommendations may well result in a significant increase in efficient DSP and reduce the need for other interventions. 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.

network redundancy for this purpose. Further details at http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=153&refer=Networks/ElecDist/lcnf/stlcn

Table 11.1 Summary of how our recommendations address the key impediments to efficient DSP

	Lack of price signals	Transaction costs	Information asymmetry	Externalities and split incentives
Wholesale Energy markets	Introduce a demand response mechanism to reward changes in consumption	Recommendations on metering and on settlement to enable gradual and low cost improvement in ability to participate in demand response mechanism. Measures to enable role of third parties in reducing transaction costs for DSP providers.	Recommendations on information disclosure to enable DSP providers and/or aggregators and other third parties to assess possible value of DSP	Impact of demand response mechanism likely to be largely but not fully coincident with requirements of network businesses. Need to monitor future coincidence or divergence.
Networks	Introduce flexible pricing options	Recommendations on metering and settlement to enable gradual and low cost improvement in ability to move to flexible pricing options. Potential role of third parties in aggregating DSP for contracts with distribution businesses.	Regulatory processes and regulatory incentives to respond to greater information within distribution businesses of potential value of DSP.	Impact of flexible pricing options to be largely but not fully coincident with peak reduction for retailers. May improve incentives for efficient use of distributed generation (e.g. greater use of solar generation to reduce distribution network peaks in response to price signals).
Co-ordination across the supply chain				Additional measures not currently required due to potential impact of existing recommendations. Monitor over time whether package of measures results in efficient DSP.
Role of third parties		Third parties (ESCOs, aggregators) can reduce transaction costs for DSP providers.	Third parties (ESCOs, aggregators) assist with efficient DSP provision and realising value for providers.	Role of third parties may assist with allocation of DSP to highest value uses.

Abbreviations

ABS	Australia Bureau of Statistics
ACL	Australian Consumer Law
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AIC	Average Incremental Cost
AMI	Advanced metering infrastructure
AUTO-DR	Automated demand response
BREE	Bureau of Resource and Energy Economics
CATS	Consumer Administration and Transfer Solution
CBL	Consumption baseline load
COAG	Council of Australian Governments
CPP	Critical Peak Pricing
DCCEE	Department of Climate Change and Energy Efficiency
DG	Distributed generation
DLC	Direct load control
DM	Demand management
DMEGCIS	Demand management and embedded generation connection incentive scheme
DMIA	Demand management innovation allowance
DMIS	Demands management innovation allowance
DNSP	Distribution Network Service Provider
DRET	Department of Resources, Energy and Tourism

DRM	Demand response mechanism
DSP	Demand side participation
DSR	Demand side response
DUOS	Distribution Use Of System
EE	Energy efficiency
EEO	Energy Efficiency Opportunities
ENW	Electricity North West
ESCOs	Energy service companies
ESOO	Electricity Statement of Opportunities
ESS	Energy Saving Scheme
EUAA	Energy Users Association of Australia
EV	Electric vehicles
FRMP	Financially Responsible Market Participant
FRMPs	Financial Responsible Market Participants
GDP	Gross domestic product
GFC	Global financial crisis
HAN	Home area networks
IBT	Inclining block prices
IHD	In-home displays
IPART	Independent Pricing and Regulatory Tribunal
LNSP	Local Network Service Provider
LRET	Large scale renewable energy target
LRMC	Long run marginal cost
LV	Low voltage
MC	Metering coordinator

MCE	Ministerial Council on Energy
MEPS	Minimum energy performance standards
MEU	Major Energy Users
MP	Metering Providers
MSATS	Market Settlement and Transfer Solution
MT PASA	Medium term PASA
MV	Medium voltage
NABERS	National Australian Built Environment Rating System
NAESB	North American Energy Standards Board
NECF	National Energy Customer Framework
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rule
NERL	National Energy Retail Law
NERR	National Energy Retail Rules
NESI	National Energy Savings Initiative
NGF	National Generators Forum
NGVs	Natural gas vehicles
NMI	National Metering Identifier
NPP	National Privacy Principles
NPV	Net present value
NSLP	Net system load profiles
NSMP	National smart metering program

NSP	Network Service Provider
NSSC	National Stakeholder Steering Committee
OGW	Oakley Greenwood
PIAC	Public Interest Advocacy Centre
POE	Probability of exceedence
PTR	Peak time rebate
PV	Photovoltaic
RAB	Regulatory asset base
RECs	Renewable Energy Certificates
REES	Residential Energy Efficiency Scheme
RERT	Reliability and Emergency Reserve Trader
RIT-D	Regulatory investment test for distribution
RTP	Real time pricing
SCER	Standing Council on Energy and Resources
SMEs	Small to medium enterprises
SRMC	Short run marginal cost
ST PASA	Short term PASA
STOU	Seasonal time of use
STPIS	Service Target Performance Incentive Scheme
TOU	Time of use
TUOS	Transmission use of system
VEET	Victorian Energy Efficiency Target
WACC	Weighted average cost of capital