Australian Energy Market Commission

REVIEW

FINAL REPORT

Review of Demand-Side Participation in the National Electricity Market

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About the AEMC

The Council of Australian Governments, through its Ministerial Council on Energy, established the Australian Energy Market Commission (AEMC) in July 2005 to be the Rule maker for national energy markets. The AEMC is currently responsible for Rules and policy advice covering the National Electricity Market. It is a statutory authority. Our key responsibilities are to consider Rule change proposals, conduct energy market reviews and provide policy advice to the Ministerial Council as requested, or on AEMC initiative.

Contents

Abbreviations

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
CPRS	Carbon Pollution Reduction Scheme
Commission	see AEMC
DLC	Direct Load Control
DNSP	Distribution Network Service Provider
DSP	Demand-Side Participation
DM	Demand Management
DMIA	Demand Management Innovation Allowance
DMIS	Demand Management Incentive Scheme
ECM	Efficiency Carryover Mechanism
ENA	Energy Networks Association
eRET	Expanded National Renewable Energy Target
FCAS	Frequency Control Ancillary Services
FEMG	Foundation for Effective Markets and Governance
IPART	Independent Pricing and Regulatory Tribunal (NSW)
LRMC	Long-run Marginal Cost
MCE	Ministerial Council on Energy
MPC	Maximum Price Cap
MRL	Minimum Reserve Limit
MW	Mega Watt
MWh	Mega Watt Hours
NEL	National Electricity Law
NEM	National Electricity Market
NEMMCO	National Electricity Market Management Company
NEO	National Electricity Objective
NGF	National Generators Forum
NSP	Network Service Provider
NSW	New South Wales

OCGT	Open-Cycle Gas Turbine
OTC	Over the Counter
RAB	Regulatory Asset Base
RERT	Reliability and Emergency Reserve Trader
Review	Review of Demand-Side Participation in the NEM
RFP	Request for Proposal
RIT-T	Regulatory Investment Test for Transmission
Rules	National Electricity Rules
SCO	Standing Committee of Officials
TEC	Total Environment Centre Inc
TNSP	Transmission Network Service Provider
TUoS	Transmission Use of Service

Summary

In October 2007 the Australian Energy Market Commission (AEMC) initiated a review of whether the demand-side of the National Electricity Market (NEM) is participating effectively and efficiently in the market.

At present there is a strong supply-side focus in the NEM and the demand-side is relatively under-represented. There are a range of possible reasons for this, including that electricity prices are relatively low, and in any event the ability to measure and price electricity use in real time is limited. There are indications that this market environment may change rapidly with the prospective introduction of smart grids and two way flows of energy and usage data. This may create new challenges for regulatory frameworks. However, the purpose of Stage 2 of the Review of Demand-Side Participation in the NEM (the Review) is it test whether the current Rules framework, operating in conjunction with existing market arrangements and technologies, is contributing to the current weakness of the demand-side.

The Review was planned in three stages. This is the Final Report for Stage 2 of the Review. It presents our findings, recommendations, and supporting reasoning on whether there are material barriers to the efficient and effective use of demand-side participation (DSP) in the NEM.

The demand-side is the totality of households and businesses who routinely consume electricity. These customers participate in the market by making decisions about when and how much electricity to consume. Their participation can be relatively passive, such as by deciding when and how much to consume in response to prices. Conversely, participation can be more active. Active participation can be achieved by entering into contractual arrangements with other energy market participants to control or influence electricity consumption decisions.

Whether there are opportunities for DSP to contribute to the overall efficiency of the market depends on the costs and benefits of using DSP relative to the alternative of increasing generation and network capacity. Hence, reductions in consumption will be efficient when the savings in supply-side costs are greater than the benefits that would have obtained by using electricity. Regulatory frameworks should support such opportunities for efficiency-improving use of DSP to be identified and taken up.

Stage 2 of the Review has been focused towards the current scope of DSP in the NEM. We note, however, there are significant drivers for change to both the practical and economic scope for DSP. The introduction of carbon pricing through the planned Carbon Pollution Reduction Scheme (CPRS) will increase the costs of supplying electricity, and hence make DSP more economically attractive. Also, changes in technology will increase the knowledge of, and potential to control, real-time consumption for a much larger number of customers. These developments mean there is an ongoing role for reviewing the regulatory framework from the perspective of DSP. We have provided some directional comments at the end of this summary. Subject to further consultation, this might identify the scope of Stage 3 of the Review.

Findings and recommendations

We have found that, in the context of the current technology that supports DSP and subject to a number of proposed amendments to the National Electricity Rules (the Rules), the NEM framework does not materially bias against the use of DSP. We have found that overall the costs and opportunities to participate provided by the framework are appropriate. However, this finding is made in an environment where the vast majority of electricity use is not capable of being measured, priced, and controlled in real time. This limitation is likely to considerably constrain the ability for the demand-side to participate at low cost. The prospective roll-out of smart meters and smart grid technology may change the market environment significantly. As such, we consider the introduction of this technology, and the need for framework changes to accommodate it efficiently, to be an area requiring further investigation.

Set out below are our specific findings and recommendations for each of the topic areas considered in this stage of the Review. Our findings identify a number of aspects of the Rules that can be improved to enhance the participation of the demand-side. A key part of the Review involves analysis of the role of regulated network businesses. This is because they have important functions in setting network charges, and in being prospective buyers of DSP. We also examine opportunities for DSP in the context of the wholesale market, and in various AEMO mechanisms for managing reliability.

The findings reflect our analysis of public submissions to the Stage 2 Issues Paper and Draft Report, publicly available documents, expert advice from consultants and engagement in bilateral discussions with stakeholders, and our Demand-Side Participation Reference Group (Appendix F). We would particularly like to thank our Reference Group members for their constructive contributions to this process.

Economic regulation of networks

We have analysed whether the framework for economic regulation creates incentives for network businesses to be unduly reliant on building network infrastructure, and consequently overlook more efficient DSP options. This requires consideration of the incentives provided in the framework for network businesses.

To enable customers to make efficient decisions they need to be provided with network charges that accurately reflect costs. Our analysis shows that the existing framework supports the setting of appropriate, cost-reflective, network charges. However, there are practical limitations to how accurate the cost signals can be. These practical limitations mean that network charges are too imprecise to signal costs at different locations and times with sufficient accuracy to attain all the opportunities for efficient DSP. A significant impediment to more accurate real-time pricing is metering technology. The absence of applicable metering technology considerably constrains the ability to charge cost-reflective prices by limiting the ability to set time-of-use charges.

Imprecise network charges mean that it is unlikely that customers are able to make efficient consumption decisions. In this circumstance, bilateral contracts for DSP can be used as a means of complementing the signals provided through imperfect network prices, to ensure consumption at peak times is efficient. We find that network businesses regulated under a price cap have private incentives to contract in a way that is consistent with socially efficient levels of DSP. As a consequence we do not consider, from an efficiency perspective, network businesses need to be compensated for DSP that reduces network demand, and hence revenues.

Network businesses under a price cap will find it profitable to purchase DSP in situations where that purchase is also efficient from the perspective of society. Network businesses have incentives to maximise profits rather than revenues. Therefore, a reduction in revenue, caused by DSP under a price cap, can increase profits if the DSP creates a correspondingly larger reduction in costs. This is also a socially efficient outcome because the loss of revenue ensures that the network business has full regard to the loss of value experienced by customers who are contracted to provide DSP.

Revenue caps, plus other mechanisms that compensate for lost revenues, insulate network businesses from taking this loss of value into account. As a consequence, a network business may find it privately profitable to sign a DSP contract that reduces overall economic efficiency. In practice, however, this risk appears relatively low. Other mitigating features in the framework, such as administrative functions, limit the extent that inefficient outcomes occur.

We have, however, identified two areas where changes to the framework are recommended to better encourage efficient DSP. These areas are the treatment of different types of costs between and over regulatory periods, and the incentives for innovation on DSP and for connecting embedded generators.

The current method for re-setting network prices or revenue allowances for transmission businesses appears to penalise a business who in the previous regulatory period decided to use expenditure on DSP as a means of efficiently deferring capital expenditure. We are recommending this issue be addressed by allowing for operating expenditure used for DSP to be excluded from the Efficiency Benefits Sharing Scheme.

We have also found that, absent additional incentives, the existing framework does not encourage distribution businesses to appropriately innovate for DSP or embedded generation connections. As foreshadowed in the Review of Energy Market Frameworks in light of Climate Change Policies, we are recommending that the Demand Management Innovation Scheme (DMIS) be extended to also include the connection of embedded generators. We are also recommending that the Australian Energy Regulator (AER) consider a number of inclusions to the Demand Management Innovation Allowance (DMIA) (which is a component of the DMIS) when designing a national scheme.

Network planning standards and service incentives

Mandatory planning standards and discretionary service incentives are important for ensuring that customers receive an appropriately reliable, secure and safe level of service. However, it is important in setting standards or service incentives that these are based on economic values of reliability.

We have found that service incentives schemes allow for an economic assessment of the costs and benefits of service outcomes. In addition, we find that probabilistic planning standards are likely to be more consistent with efficient use of DSP as compared to deterministic standards. This is because these standards are more amenable to handling DSP with different degrees of "firmness".

We note, however, there are benefits associated with the transparency and certainty provided by deterministic planning standards. Therefore, consistent with the Review of the National Framework for Electricity Distribution Network Planning and Expansion (Distribution Planning Review), we recommend a review be undertaken to consider whether the form of standards for distribution networks should be derived on an economic basis, and if so, how.

Distribution network planning

At present there is a lack of planning obligations in the Rules. While there are jurisdictional planning arrangements, these are not consistent. The inconsistency in the planning arrangements limits the ability for DSP proponents to be effectively involved in the planning process. The Distribution Planning Review has sought to overcome issues with the distribution planning arrangements. The recommendations from this review include establishing nationally consistent annual planning requirements, and more specifically a requirement for each distribution business to establish and maintain a Demand-Side Engagement Strategy. Given the recommendations in the Distribution Planning review, we have not provided any further recommendations in this area in this Final Report.

Network access and connection

The use by an individual customer of a co-located embedded generator, rather than drawing supply from the main electricity system, is another form of DSP. It is important, therefore, that embedded generators are able to connect efficiently and are appropriately rewarded for any services they provide to the market. We find that the connection process does not appear to be a significant barrier, however, the flexibility afforded in determining minimum technical standards is causing delays and increasing costs for embedded generators. We recommend that the Reliability Panel consider further the appropriate minimum technical standards for embedded generators as part of its Technical Standards Review.

Wholesale market participation

The wholesale market for electricity is another route through which the demand-side can participate. This can be as a direct participant in the market, (as "scheduled load" or by receiving spot price pass-through with a retailer), or by being a counter-party to financial contracts derived from prices in the wholesale market.

We have found that it is simpler, and more cost effective, for customers to access the wholesale market indirectly, through a retailer or through contracting and financial trading. Participating through a retailer overcomes the significant, but proportional, costs of participating directly in the wholesale spot market.

We have also found that the level of remuneration available in the wholesale market is not a barrier to DSP. Therefore, we do not consider that there is a case for demand-side participants to be provided with additional compensation in the form of an up-lift of similar type of payment.

We have, however, identified a barrier in relation to the aggregation of loads to provide market ancillary services. We understand a Rule change proposal is being developed on this issue and therefore expect this barrier to be addressed as part of the Rule making process under the National Electricity Law (NEL).

Reliability

The final policy area considered in this Stage of the Review relates to the use of DSP to provide reliability services to the system operator. In circumstances where the market does not deliver sufficient capacity to meet the desired reliability standards of 0.002 per cent average unserved energy, the system operator can intervene and buy additional capacity or issue directions to existing market participants.

We find that the existing intervention mechanisms, rather than being barriers to DSP, provide opportunities to customers to provide additional services in the NEM. We have, however, identified that there is a need for a mechanism to pay users that are not scheduled, but are willing to modify their behaviour if requested. We consider the recently made Rule, "Improved RERT Flexibility and Short-notice Reserve Contracts", overcomes this issue through the introduction of a short-term reliability mechanism.

We have also found that market efficiency and the use of reliability mechanisms may be enhanced in two ways. The first is by improving the provision of information to the Australian Energy Market Operator (AEMO) on volumes of DSP already in the market. This would allow AEMO to have better information before intervention mechanisms are used. The second is to consider further the role of small-scale embedded generators to provide additional services directly to the market. In the Review of Energy Market Frameworks in light of Climate Change Policies we recommended that existing processes by the Standing Committee of Officials (SCO) and AEMO were appropriate avenues to address these issues.

Future work program

A number of prospective developments are likely to increase the scope for more active DSP in the energy market. In particular, the roll-out of smart grids and smart meters across the NEM will enable two-way flows of energy and information providing greater capacity for active management of energy by consumers or their agents.

On the basis of our preliminary analysis of the implications of more interactive power and data flows between the demand-side and supply-side, we have concluded that there is a need for a further stage of this review to fully analyse those issues and recommend framework changes where necessary. Possible issues we have identified that may fall within the scope of this review include:

- enabling an effective interaction between competitive and regulated services;
- the regulation of access to infrastructure, data and customers;
- encouraging efficient investment in new technology and services;
- enabling more sophisticated price signals to be passed through to customers; and
- ensuring that the rights and interests of customers are protected.

We intend to consult closely with the SCO and the Ministerial Council on Energy (MCE) to further develop the scope of this work program and an appropriate terms of reference. We will also consult with interested stakeholders during this scoping stage. Following these consultations, we intend to publish a terms of reference with a view to commencing Stage 3 of the Review in March 2010.

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1 Background

Chapter overview

This chapter describes the Australian Energy Market Commission's (AEMC) Review of Demand-Side Participation (DSP) in the National Electricity Market (NEM) (the Review), and explains the role of this Final Report within the Review process. It sets out how this Final Report is structured. The chapter also describes what we mean by "efficient" levels of DSP, and illustrates the different forms that DSP can take using examples.

1.1 The AEMC Review of Demand-Side Participation

In October 2007 the AEMC (the Commission) initiated a Review of DSP in the NEM.[1] This was in response to concerns expressed by a number of stakeholders that the current market arrangements placed unnecessary weight on expanding generation and network capacity in order to meet demand for electricity, and overlooked more cost-effective alternatives involving planned reductions in demand at key times. The purpose of the Review is to test this proposition, and identify proposed amendments to the National Electricity Rules (Rules) to enable the demand side (i.e. users of electricity, and their representatives) to participate more actively in the market, such that the overall cost of electricity supply can be reduced over time.

We are undertaking the Review in three stages. This Final Report completes Stage 2. The first stage was to review our (then) existing work program from the perspective of DSP, in order to identify if there were incremental improvements that could be made to improve the scope for DSP as part of that work program. The work program at that time included the Congestion Management Review[2] and the Review of National Transmission Planning Arrangements.[3] We completed the first stage of the DSP Review on 16 May 2008 with the publication of NERA Economic Consulting's Stage 1 Final Report.[4]

The second stage of the Review is a more extensive analysis of the existing Rules to identify how, if at all, the Rules materially disadvantage use of efficient DSP. This also involves recommending proposed amendments to the Rules to address any such material barriers to DSP. An Issues Paper was published in May 2008 and a Draft Report on 29 April 2009. This Final Report and associated proposed Rule changes will be provided to the MCE.

1 The AEMC is undertaking this task as part of its policy development functions under section 45 of the National Electricity Law (NEL). This role enables us to present our findings to the MCE. The MCE, in turn, has the ability to propose changes to the Rules for formal assessment by the AEMC.

2 http://www.aemc.gov.au/electricity.php?r=20070416.102156

3 http://www.aemc.gov.au/electricity.php?r=20070710.172341

4 http://www.aemc.gov.au/electricity.php?r=20071025.174223

The third stage of the Review is contingent on the outcomes of the second stage, and is the vehicle to take forward the assessment of any further reforms which cannot readily be implemented through focused amendments to the existing Rules. Further information on our initial thinking for Stage 3 of the Review is in Chapter 8.

1.2 The Final Report

This Final Report sets out our findings on where in the current Rules we have identified material barriers to efficient DSP. Importantly, it also sets out our reasoning for concluding that barriers do not exist in a number of significant areas. In addition, we also recommend proposed amendments to the Rules, or further work that is required to address the identified barriers.

In considering possible barriers to DSP in the Rules we have been guided by the National Electricity Objective (NEO) under the NEL. The NEO is founded on the concept of economic efficiency. We consider the NEO can be achieved by following the principles of good regulatory design and ensuring predictability, transparency, and where appropriate, flexibility in the regulatory framework.

The substantial content of this Final Report is structured in six chapters. Chapters 2-5 discuss different factors conditioning the use of DSP by regulated network businesses. Chapter 6 discusses the participation of the demand side in the wholesale energy market. Chapter 7 discusses the participation of the demand-side in the Australian Energy Market Operator's (AEMO) active management of reliability in the short term.

1.3 Definition and characteristics of DSP

For the purposes of this Review, we consider that DSP is the "*ability of consumers to make decisions regarding the quantity and timing of their energy consumption which reflects their value of the supply and delivery of electricity*."[5] This includes the participation of the demand side throughout the entire NEM supply chain.

Our definition of DSP is expressed in the energy market in a variety of ways, including:

- when and how much electricity to consume based on the price paid for electricity at the point of consumption;
- whether to seek and enter into contracts with other energy market participants who might place a value on being able to commit a particular user to a specified pattern of consumption (e.g. reduced consumption at times of peak demand); and
- when and how much to respond to financial incentives created through policies and programs implemented by governments.

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5 AEMC, *Statement of Approach, Review of Demand-Side Participation in the National Electricity Market*, 3 March 2008, p.1.

The remainder of this section describes how these different forms of DSP might contribute to improving the efficiency of market outcomes. It also illustrates the discussion with practical examples from the NEM.

DSP for electricity cost savings

The two largest components of an electricity bill are: (a) the costs of wholesale electricity, and (b) network charges. Most electricity users contract with an electricity retailer. How the retailer's costs are reflected in a tariff to the end-user will vary between retailers and types of contract. In most cases, the retailer will offer a contract that smooths out the significant variations that can occur day-to-day in the cost of wholesale energy. This affects the types of DSP that might be observed.

Businesses that consume very large amounts of electricity might have an acute interest in how the risk of wholesale electricity price risk is managed. There are some examples (e.g. the cement company Adelaide Brighton Ltd) of businesses entering into a contract with a retailer that leaves it fully exposed to variations in the wholesale electricity spot price. This enables the business to self-manage its wholesale electricity costs by reducing its consumption at times of very high wholesale prices. In 2008, Adelaide Brighton Ltd estimated that its self-management of electricity cost risk had led to significant savings (>35 per cent) in its electricity costs since 2001 compared to the lowest-cost retail contracts it found available.

However, for many users exposure to the spot price type is not attractive. This might be because they have a different appetite for, and ability to manage, wholesale price risk. It might also be because the potential benefits do not justify the costs. In these cases, DSP is likely to be less "active" and more incremental, for example through energy efficiency or choices of replacement appliances over time.

In addition, for most electricity users the ability to be charged on a more sophisticated time-of-use basis would require the installation of new, more expensive ("smart") metering equipment. This will also influence the relative costs and benefits of managing their consumption more actively. Only customers above a certain threshold of consumption are required to have time-of-use meters.[6] These customers are generally medium-to-large businesses. However, policies to extend "smart" meters more widely would significantly increase the proportion of electricity consumers who were capable, technologically, of being offered a more sophisticated "time-of-use" tariff.

It should also be noted that other policy measures, e.g. those aimed explicitly at energy efficiency, might involve the more active management over time of energy consumption by households and businesses. Such initiatives include longer-term

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6 This threshold is published in the NEM Metrology Procedures and differs between jurisdictions. The NEM Metrology Procedures can be found at: http://www.nemmco.com/met_sett_sra/640-0106.html

forms of DSP such as rebates to install solar hot water systems, and the Australian Government assistance program for ceiling installation.[7]

DSP through contracts with other market participants

An additional facilitator for DSP is through contracts between electricity users and other energy market participants. In theory, these are separable from the contracts for electricity consumption between a retailer and a user. However, in practice, they might be combined in some cases.

In most cases, the contracts will relate to levels of consumption at times of peak demand. There are three main types of potential counter-party:

- Retailers - the main purpose of a retailer is to manage wholesale price risk on behalf of consumers. This is most significant at times of very high prices. Retailers use a range of tools for managing this risk. These tools include entering into contracts with generators (or building their own generation) to ensure that they are not exposed to high spot prices when they occur. DSP represents an alternative means of hedging this spot price volatility. Retailers achieve this through contracting to reduce load when prices are high as an alternative to contracting for generation capacity. The efficiency with which retailers manage risk on behalf of consumers can only be increased by enhancing the range of tools available. Improvements in the cost efficiency of retailing means lower prices, either through competition or through regulated tariffs.

- Network businesses - investment by network businesses is generally driven by the need to build sufficient network capacity to meet peak demand (with an acceptable level of redundancy for unexpected contingencies). There is potential value for a network business where DSP is capable of being used as an alternative to network investment, and is cheaper. A contract with a DSP provider is a means of sharing this value and delivering a more efficient outcome. The framework for regulating networks means that over time these costs savings are shared with consumers through lower transmission charges.

- AEMO - in some circumstances AEMO intervenes in the market, e.g. when there is a predicted shortfall in capacity. In these circumstances, DSP might represent a service provider to AEMO. This is particularly relevant because AEMO interventions tend to be limited to the short term, and hence preclude options which involve new investment because of the required lead times. Effective use of DSP improves efficiency by enabling AEMO to intervene effectively, e.g. to avoid involuntary load shedding, and by enhancing the range of options available to AEMO – which in turn is likely to reduce costs.

To illustrate these points further, the following sections set out some specific examples of DSP through contracts with other energy market participants already evident in the NEM today.

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[7] Australian Government - Energy Efficient Homes Package: see http://www.environment.gov.au/energyefficiency/index.html

Retailers

The detailed hedge positions of individual retailers are, necessarily, not public domain material. Hence, it is difficult to determine how much DSP is used by retailers. However, there is empirical and anecdotal evidence to suggest that the amounts are material.

First, there are a number of businesses active in the market whose business plans are based on the aggregation of loads for the purposes of offering packaged DSP solutions. Secure Energy and Energy Response are examples. Second, Australian Energy Regulator (AER) investigations into high-price events in the wholesale market have identified evidence of probable demand response at times of high prices. For example, there were two apparent demand reductions of up to 350 MW in New South Wales (NSW) following a five-minute NSW price spike to $8800/MWh on 15 January 2009.[8] This is consistent with views expressed at the AEMC's DSP Reference Group concerning active dialogue between retailers and providers of demand response.

Networks

There are a number of examples of distribution network service providers (DNSP) using DSP solutions. For instance, network businesses have undertaken innovative trials using direct load control (DLC) of residential appliances.[9] Recent DLC trials from network distribution businesses include an Energex trial in summer 2007-08 of air conditioners in north-west Brisbane that led to a 17 per cent reduction of the peak demand.[10] In Adelaide, ETSA Utilities' summer 2007-08 DLC trial of air conditioners resulted in reductions in total peak demand of 19 per cent in Glenelg and 35 per cent in Mawson Lakes.[11] EnergyAustralia recently completed a screening exercise of potential demand management solutions, with one project being implemented.[12] This related to converting electric hot water systems to gas hot water systems.

Transmission businesses have also contracted demand-side participation for network support. For example, TransGrid contracted 350 MW of DSP for summer 2008-09 to support a deferral of its 500 kV Western System Upgrade project by one year. This 350 MW of network support was composed of significant blocks of embedded generation and a mix of large and smaller commercial and industrial loads.

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8 AER, *Spot prices greater than $5000/MWh New South Wales: 15 January 2009.*

9 Residential consumers will typically provide permission to distribution businesses to undertake such activities.

10 Energex, *time for a cool change*, February 2008, can be downloaded from http://www.energex.com.au/trial/pdf/8159_cool_change_results_report_summer_2008.pdf

11 ETSA Utilities, *Air conditioner "Beat the Peak" trial to expand following solid results over two summers*, October 2008, can be downloaded from http://www.etsautilities.com.au/centric/news_information/electricity_information/demand_management.jsp

12 EnergyAustralia, Annual Report 2007/08, October 2008, p.91, available from https://www.energyaustralia.com.au

Market Operator

The market operator has contracted for reserves on two occasions when functioning as the National Electricity Market Management Company (NEMMCO) (now AEMO). We understand that demand-side providers made up the bulk of reserve providers in these instances. On both occasions NEMMCO made availability payments but there were no payments made for enabling or usage. In 2004/05 NEMMCO contracted for 84 MW at a cost of $1.04 million for the Victorian and South Australian regions. NEMMCO contracted for reserve again in those regions in the following year. This time 375 MW was contracted at a cost of $4.4 million.[13]

1.4 Characterising barriers to DSP

A barrier to DSP in the NEM is a condition or characteristic of the market that would place potentially efficient demand-side participants at a disadvantage compared to alternative participants. This includes a condition or characteristic that does not facilitate efficient and informed consumption decisions by consumers. In the NEM, this may include participation costs that are higher than necessary or incentives for supply-side options that are not available to demand-side alternatives.

It is important to recognise that not all costs associated with participating in the NEM are barriers. There are legitimate costs, obligations and incentives associated with ensuring the reliability, security and quality of supply, and to enhance confidence in the financial arrangements in the wholesale market. Where these costs and obligations are proportionate and non-discriminatory they are not considered to be impediments or barriers. Legitimate cost differences that can arise due to the characteristics of the service are also not considered to be impediments or barriers to DSP.

We analysed the potential barriers using public submissions to the Issues Paper and Draft Report, publically available documents, and by engaging in bilateral discussions with stakeholders. We prepared this Final Report following input into our preliminary views from our Demand-Side Participation Reference Group.

1.5 Related AEMC work

This section highlights current AEMC work which has relevance to the issues discussed in this Draft Report.

1.5.1 Review of Energy Market Frameworks in light of Climate Change Policies

In July 2008 we were directed by the MCE to undertake a Review of the frameworks of the electricity and gas markets to consider if they were resilient to the introduction

[13] Further detail of this contracting for reserves is available from NEMMCO's financial year reports on procuring reserves to ensure reliability of supply.

of a Carbon Pollution Reduction Scheme (CPRS) and expanded national Renewable Energy Target (eRET).

We provided our Final Report for this review to the MCE on 31 September 2009. The Final Report provides our final advice to the MCE on the areas where the existing energy market frameworks require change, and our recommendations to address identified risks. The Final Report also highlights a ranged of issues which require change but can be addressed under existing regulatory frameworks.

That Review had a similar structure to the DSP Review in that it sought to identify material points of weakness in the existing frameworks, and then sought to identify ways of addressing the identified points of weakness. It also addresses some closely related policy issues, for example, the management by AEMO of short-term reliability and innovation in distribution networks. For this reason, we have to the extent possible, progressed the work of the two Reviews in parallel.

A number of submissions to the Review of Energy Market Frameworks in light of Climate Change Policies referred to the role of DSP in the NEM. We have taken these submissions into account in preparing this Final Report, where practicable.

1.5.2 Demand Management Rule Change Proposal

On 13 November 2007, the Total Environment Centre Inc. submitted a Rule proposal dealing with demand management in the NEM (DM Rule proposal).

On 23 April 2009, a Rule Determination for the DM Rule proposal was published with the following Rule Change Proposals accepted with modifications:

- Transmission Network Service Providers (TNSPs) publish robust data on upcoming network constraints relevant and useful to demand management (DM) providers;
- the AER treat the recovery of TNSPs' operational expenditure on DM activities the same as capital expenditure at the end of a regulatory period; and
- the AER better consider the assessment of DM activities in the revenue determination process for TNSPs.

We decided not to accept a number of the component parts of the DM Rule proposal. The detailed reasoning is set out in the Rule Determination. In a number of instances we identified this DSP Review process as the more appropriate process through which to consider the issues.

1.5.3 Improved RERT Flexibility and Short-Notice Reserve Contracts Rule change proposal

The AEMC made the National Electricity Amendment (Improved RERT Flexibility and Short-notice Reserve Contracts) Rule 2009 No. 19, on 15 October 2009. The Rule change proposal was received from the AEMC Reliability Panel in August 2009. The Rule change amends the Reliability and Emergency Reserve Trader (RERT) arrangements to provide a framework to implement changes to the operation of the RERT to facilitate long-notice, medium-notice and short-notice reserve contracting. It also clarifies that AEMO can form a RERT panel and may use reserve contracts during system security events.

1.5.4 Review of the National Framework for Electricity Distribution Network Planning and Expansion

The purpose of this Review is to examine the current electricity distribution network planning and expansion arrangements which exist across the jurisdictions in the NEM. The Review has proposed recommendations to assist the establishment of a national framework for distribution network planning. The Review has also made a number of recommendations to better incorporate DSP within the planning process.

The Final Report was provided to the MCE on 30 September 2009.

2 Economic Regulation of Networks

Chapter overview

DSP in the market, including that motivated by network businesses, continues to be under-developed for a range of reasons. The focus of this chapter is to ascertain whether the regulatory framework is contributing, and if so, whether framework changes would improve DSP. It describes the framework that applies and considers whether the incentives it creates contribute to the efficient use of DSP by network businesses. It specifically considers the setting of prices, the financial incentives and profitability for DSP, and the incentives to fund innovation for DSP.

2.1 Findings and recommendations

This section sets out our findings and recommendations in respect of the framework for the economic regulation of networks. The detailed reasoning and analysis associated with these findings and recommendations is explained later in the chapter.

The Commission has found that:

- From a first principles perspective, the regulatory framework provides incentives that support the setting of appropriate, cost-reflective network charges that signal efficient consumption decisions by customers.

- However, in practice charges are inevitably too imprecise to signal costs at different locations and times with sufficient accuracy to encourage all opportunities for efficient DSP. The absence of time-of-use metering is one important factor. Hence, there is a case for complementary DSP contracting by network businesses to improve efficiency. The framework provides incentives for profit motivated businesses to enter into such contracts when DSP would improve efficiency.

- Price cap regulation creates private incentives for network businesses to buy DSP that are consistent with efficient levels of DSP. Revenue cap regulation has weaker incentives, but is unlikely to represent a significant barrier to efficient levels of DSP.

- To avoid bias in the choice of expenditure used by network businesses there is a need to better align the way different cost types are treated between and over regulatory periods. We recommend that, consistent with the distribution arrangements, transmission operating expenditure for DSP is excluded from the mechanism that allows network businesses to carry-over savings or cost overruns into the next regulatory period.

- Network businesses may not always be driven only by profits, other cultural or corporate factors can influence behaviours. Therefore, the framework should be strengthened to encourage innovation by network businesses. This includes innovation for the use of DSP as well as connecting embedded generators.

2.2 Background

This section provides relevant background on how economic regulation works and why it is needed, and what constitutes efficient levels of DSP, to help understand the policy issues discussed in sections 2.3 to 2.6 of this chapter.

2.2.1 Cost structures of networks

There are two key cost features of building and operating electricity networks that influence why and how they need to be subject to economic regulation.

First, they demonstrate large economies of scale. This means that the costs of accommodating an extra network user are relatively low, once the costs of establishing the underlying network have been incurred. It is this cost structure that gives network businesses their 'natural' monopoly characteristics. Hence, there is a need to regulate to avoid the monopoly power being exercised to the detriment of consumers.

Second, electricity networks need to be capable of transferring sufficient power to meet demand in the majority of circumstances. It is therefore peak demand that drives costs – even if for most of the time the network has surplus capacity.

2.2.2 Regulation of revenues and prices

The focus of this chapter is to examine the clarity and effectiveness of the *financial incentives* that exist for the network businesses in the regulatory framework and how they impact on the efficient use of DSP.

The revenue that a network business is permitted to recover from customers is regulated. The substantive and procedural framework for economic regulation is set out in the Rules, and implemented by the AER. It involves a revenue and pricing determination being made for a period of at least five years.[14] The process of arriving at such a determination and then implementing it typically involves three steps, which are:

- first, to determine a level of revenue sufficient, in expectation, to allow the business to recover efficient operating costs and financing costs (including a reasonable return) on planned and past capital expenditure;[15]

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[14] Clauses 6.3.2 and 6A.4.2 of the Rules.

[15] Calculating caps to reflect these component costs to the business is known as a 'building blocks' approach.

- second, to translate that forecast of allowed revenue into a formula that sets a cap over the businesses' revenue or prices (referred to as a *revenue cap* or a *price cap*) over the period until revenues and prices are next reviewed;[16] and

- third, on an annual basis between the reviews, for individual network charges to be calculated that are consistent with the price or revenue cap and consistent also with principles for pricing set out in the determination and in the Rules.

An important tool for regulation – including the review and setting of prices as discussed above – is the use of financial incentives to encourage regulated businesses to act in a manner consistent with the long-term interest of consumers. The traditional methods of regulation – such as where a regulator decides on the level of expenditure that is efficient or directs a regulated business to undertake certain actions – are limited in their effectiveness. This limitation arises because the businesses often have knowledge that is unavailable to the regulator, but may improve the outcomes of regulation. However, by designing a mechanism that provides the businesses with higher profits if they achieve socially desirable outcomes – for example, by sustainably reducing costs or improving levels of service – any knowledge the businesses have is "harnessed" to improve outcomes for both the businesses and customers.[17]

Network businesses are subject to a number of such incentive mechanisms, including:

- incentives to minimise expenditure, which occurs through fixing revenue and prices independent of cost during the regulatory period, and potentially also permitting some of the efficiency benefits to continue to be earned after prices are next reviewed (known as an efficiency benefit sharing scheme);

- financial penalties (or rewards) for businesses if they fail to meet (or exceed) specified service standards;[18] and

- incentives about the form and structure of prices (and hence revenue recovery), which is predominately influenced by the form of the control over prices (that is, whether businesses are subject to a price cap or revenue cap).

The framework for economic regulation – which includes the use of incentive schemes – is based on the premise that network businesses, irrespective of their ownership structure, seek to maximise profits. It presumes that businesses will therefore respond to financial incentives created as part of the regulatory regime.

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[16] Price caps limit the rate of change in *prices* (or, more commonly, the weighted average of a basket of prices) from one year to the next. Revenue caps limit the total amount of revenue a business can recover each year (with a mechanism to carry forward any "overs" or "unders" if actual revenue recovered differs from allowed revenue in any given year).

[17] Incentive schemes replicate the disciplines and financial incentives that are observed in competitive markets.

[18] For example, a target level of supply interruptions. The Rules for transmission allow the AER to design such a scheme and to put up to 5 per cent of revenue "at risk".

It needs to be borne in mind, however, that there are limits to the design and effectiveness of incentive schemes. In addition, we recognise that there may be other drivers on network businesses that can influence behaviour. Therefore, more traditional regulatory mechanisms often co-exist with incentive schemes.

2.2.3 Consumption decisions

In principle, effective demand-side participation requires that consumers make efficient decisions on when and how much to consume; that is, they consume (and only consume) when the benefit derived from the last unit consumed is greater than the cost of delivering it. In economic terms, consumption decisions are said to be *efficient* if consumption occurs when consumers value the services provided by the use of electricity at least as highly as the cost to society of producing it, and conversely that consumption does not occur if the value that customers place on the services is less than cost.[19] This is the ideal scenario.

Prices play an important role in encouraging efficient consumption. In general, customers will only purchase a good or service if they believe its value to them exceeds the price being charged. For most markets, competition provides the discipline to keep prices close to the cost of production. When customers choose to consume a good or service it should be the case that the value obtained exceeds the cost of production; recognising that sellers will not offer goods at prices less than their costs and an appropriate margin. In competitive markets, prices *signal* to customers what it costs to produce the good or service, and hence assists those customers to make efficient consumption decisions.[20]

Prices in the context of electricity will be reflected in the tariff or supply contract a customer agrees with their retailer. This price will include the costs of energy, network transportation, and retail supply. However, importantly, price will also include any offers from retailers, distributors, or any other party, for customers to modify their consumption behaviour.

Making efficient decisions in response to prices requires consumers to see the true costs of their consumption. It also requires consumers to know the benefits of different levels of consumption. As will be discussed later, there are practical limitations to this occurring. These limitations constraint the extent we can rely on price signals to drive efficiency in consumption decisions.

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[19] If consumption is inefficient, then it means that it is possible to reduce the production of the inefficiently consumed good or service and use the same resources to increase the production of an alternative good or service and raise the aggregate value that customers receive from consuming those goods and services.

[20] More detail on the efficient interaction between customers and networks can be found in Appendix B.

2.3 Network prices and the ability of consumers to respond

What is the issue?

This section considers the key issue of whether there are impediments in the framework to network businesses setting prices that accurately reflect costs to consumers of electricity. As discussed above, cost reflective prices are a requirement for consumption decisions to be efficient. We also consider whether there are barriers to consumers making informed decisions in the light of those prices.

Findings and supporting analysis

There are significant costs for network businesses associated with creating the infrastructure to be able to levy charges which accurately reflect costs. There are also significant costs associated with consumers obtaining (or being provided with) the information required to make informed decisions based on costs and benefits. This can create a barrier to efficient outcomes occurring. While such obstacles may reflect the costs of transacting rather than impediments in the regulatory framework, their presence means that there can be scope for selective and focused contracting with customers for DSP to promote more efficient levels of consumption overall.

The obstacles to efficient pricing and consumption are not, however, attributable to the current framework for economic regulation. The framework has obligations and financial incentives directed towards businesses setting prices that reflect costs. The financial incentives are strongest under a price cap form of regulation. The revenue cap form of regulation makes greater use of regulatory obligations to promote cost reflective charges.

Impediments to setting cost-reflective prices

A network charge is cost reflective if it is based on consumption at times of peak demand. Noting that this is because peak demand is what drives network costs. Such a charge requires the network business to:

1. estimate what costs it would incur at each point on the network, if consumption increased marginally, and

2. be capable of measuring actual consumption by each user at times of peak demand

The accuracy of network prices is impacted by practical constraints on measuring efficient charges. Estimating the locational costs of the network involves highly detailed analysis and modelling. Given the difficulty involved, network businesses approximate these costs based on stylised estimates of what costs would be in the long-run. They also generally revisit these estimates once per year. These practical constraints can be a barrier to setting efficient cost-reflective prices.

A more significant barrier is created by the inability to measure consumption at peak times. This occurs due to limitations in metering technology. Most meters for small customers only measure electricity on a continuous basis. Therefore, network businesses are unable to measure consumption by the customer at peak times (unless they pay someone to read the meter every 30 minutes or install interval metering technology).

Submissions agreed that the inability to precisely signal costs at different locations at different times meant there is scope for complementary measures to encourage efficient consumption.[21]

21 Grid Australia, Draft Report submission, p.2; United Energy, Draft Report submission, p.2; SP AusNet, Draft Report submission, p.2.

Box 2.1: Deployment of smart meters and smart grids

It is important to recognise the significant work that has been, and continues to be, undertaken to address the barrier of metering technology for small customers.

For example, COAG has committed to a national mandated roll-out of interval meters where the benefits outweigh the costs. The MCE Smart Meter Decision Paper of 13 June 2008 estimated the national net benefits for a distributor-led roll-out with the Home Area Network interface functionality to range between $146 million and $4.6 billion.[22]

In addition, jurisdictions have committed to a roll-out, or further consideration of the possible benefits, of interval meters. Victoria, for example, already has a legislative commitment to roll out interval meters and NSW confirmed in December 2007 its commitment to a roll-out of interval meters. Western Australia and Queensland have acknowledged the potential benefits and will consider a roll-out further.

The Commonwealth Government has also committed to funding a pre-deployment study designed to provide further information on the potential economic and environmental benefits of smart grid technologies. The Smart Grid, Smart City initiative provides up to $100 million of government money to support a trail of smart grid technologies at a commercial scale.[23]

These initiatives have the potential to increase the information customers have about the costs of services at different times of the year or throughout the day. However, this Stage 2 Review is examining impediments to efficient DSP in the current framework with the technology available for the vast majority of customers. Chapter 8 provides a discussion of issues that smart meters and smart grids may create for regulatory frameworks.

We agree with the view expressed by the Customer Utilities Advocacy Centre (CUAC) that customers also face significant costs in responding to price signals.[24] Even if meters that measure peak demand were installed (and efficient prices were determined and passed through to customers), there remains a cost for customers to obtain and assimilate information on when peak demand is likely to occur, and in exploring the costs and benefits of different possible responses at that time. Even when customers consider the benefits of consumption outweigh the costs, they may not be aware of more cost effective ways of achieving the same amount of benefit.

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22 Available at: http://www.ret.gov.au/Documents/mce/_documents/Smart_Meter_Decision_Paper_MCE_13_June_200820080613153900.pdf

23 Department of the Environment, Water, Heritage and the Arts, '*Smart, Grid, Smart City A new direction for a new energy era*', 2009, Canberra.

24 CUAC, Draft Report submission, pp.6-7.

Given the effort involved, for many small customers it may be more cost effective to avoid managing demand too closely.

The implication of the practical challenges is that network and retail price signals cannot be relied upon to promote efficient levels of consumption, and hence DSP. Therefore, the consumption decisions of customers need to be supported to encourage efficient DSP. This can either be through education, reducing the costs of calculating the costs and benefits of consumption, or by providing additional signals through DSP contracts. Whether networks have incentives to contract for DSP where it is efficient is addressed in section 2.6.

An alternative to contracting for DSP can be to introduce arrangements that either legislate or otherwise control consumption decisions. Efficiency standards for new appliances are one such example of this type of legislation. Regulations and mechanisms that allow for the remote control of consumption through smart grids is another example. These approaches effectively make decisions on behalf of the customer. Therefore, the customer no longer needs to consider the costs and benefits of purchasing and using different appliances or industrial techniques.

Framework for regulation of prices

The regulatory framework allows network businesses some discretion with regard to how they propose to set charges, and in how they calculate and update individual charges once a regulatory determination has been made. Revenue caps and price caps are the two forms of price control that apply in the NEM. We therefore need to consider the financial incentives that each form of price control creates to set prices that reflect costs.

Price caps operate by constraining the rate of change in the weighted average of a basket of prices from one year to the next. Price caps that apply in the NEM allow network owners some flexibility regarding how they balance the individual prices that comprise the weighted average.

Network owners have financial incentives to exercise the discretion they have with prices to maximise their profits or, for a given level of profit, to minimise the risk they incur. Consequently, network owners should be motivated to set prices that will deter additional consumption at peak, where meeting that consumption would incur a loss (i.e. the costs of supplying that service exceed the revenue earned). Alternatively, consumption will be encouraged where meeting additional demand can deliver a profit.

Network owners will minimise the risk of revenues being insufficient to recover costs by aligning the price that is charged for different types of consumption with their costs. Accordingly, the network owner will have an incentive to ensure that any unexpected increase in "high-cost" consumption will also deliver commensurately high revenue. In addition, any unexpected reduction in "low-cost" forms of consumption leads to a commensurately low loss of revenue.

The incentives this framework provides to network businesses creates a natural dynamic towards setting peak-use prices that reflect marginal cost. As noted in section 2.1, these are also the "right" prices for efficient consumption. Submissions agreed that the framework supports the setting of appropriate, cost reflective charges.[25] However, the as to whether this incentive works in practice is not yet conclusive. This is because the existing metering technology does not allow network businesses to accurately set tariffs in this way. The implications for network pricing of the roll-out of smart meters and the wide deployment of smart grids is a matter that may be given further consideration as part of Stage 3 of the Review.

Under a *revenue cap* form of control, there is no "natural" dynamic towards prices being set to reflect marginal cost. This is because total revenue is fixed. A network business maximises profit by minimising costs, irrespective of the value of any additional consumption. Network businesses might therefore seek to exercise any discretion they have to set peak-use prices which are too high – as a means of discouraging consumption, and therefore avoiding cost. Given this incentive, there is a greater requirement for administrative regulation of how prices are set under a revenue cap, compared to a price cap. Under a revenue cap, there is more active assessment of pricing methodologies by the AER, to ensure that prices reflect costs at times of peak demand.

Ability for network prices to be passed on by retailers

A number of submissions were concerned that even when smart meters were introduced, price signals would not be passed on by retailers to customers.[26] The reasons cited were the lack of incentive on retailers to set cost reflective prices, and the lack of a direct relationship between the network business and customers.

We agree it is important that price signals are passed through to customers where smart meters and smart grid technologies are introduced. Under the existing framework competition is relied on to provide the incentives for retailers to price efficiently.

In well functioning competitive markets, retailers that price above their costs risk alternative providers offering a lower price to customers. The result of this would be customers switching to the lower cost provider. The risk of this occurring to retailers is reduced where they manage their costs efficiently and pass through prices that reflect these costs, plus an efficient profit margin. Given network costs cannot be managed by retailers, and are the same for each retailer, pricing network charges higher than the efficient costs risks customers being drawn to competitive providers. Alternatively, pricing network costs lower than the efficient cost risks losses being incurred.

However, the effectiveness of competition in each jurisdiction varies. This can limit the extent competitive retail market pressure can be relied on to achieve pricing

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25 SP AusNet, Draft Report submission, p.2; Energy Networks Association (ENA), Draft Report submission, p.1.

26 CUAC, Draft Report submission, p.7; Total Environment Centre (TEC), Draft Report submission, p.5.

efficiency. The task of setting cost reflective tariffs may become more feasible once smart meters are introduced more widely. However, those more complex pricing arrangements can also be more challenging for customers to understand and respond to. Therefore, we consider this is an issue that may be suitable for further investigation as part of Stage 3 of the Review.

2.4 Economic regulation and the profitability of DSP for networks

What is the issue?

The form of price control may influence the decision of a business to use a DSP contract as an alternative to building network infrastructure. This is because it influences how much profit would be earned if the business used DSP. The issue for this section is whether the current forms of price control create incentives that skew against the efficient use of DSP by networks.

Where network costs can be signalled accurately in real time through network prices, the need for separate DSP contracts with individual users is greatly reduced. This is because the value to the network of DSP is signalled through network charges. However, accumulation meters mean that network prices are often too low at peak times. As a consequence the network business does not recover sufficient revenue to cover the costs of augmenting the network to meet peak demand. This creates a profit motive for network businesses to contract for demand response to reduce the costs of meeting peak demand.

Findings and supporting analysis

We have found that where DSP is the more efficient option, network businesses are likely to earn systematically higher profits by purchasing DSP compared to augmenting the network. The alignment of incentives for the profit maximising business and for the long term interests of consumers is strongest under a price cap form of price control. Whereas, a revenue cap form of price control, if anything, biases incentives <u>in favour</u> of DSP.

We have found that this result holds in the absence of incentive schemes to promote DSP explicitly. While such schemes will certainly increase the profitability of DSP further, they do not appear to be required on pure efficiency grounds. However, such measures may be justified as a stimulus to change, if there is a perceived bias against DSP in established cultures of businesses and their management practices.

DSP will be profitable for an individual network business if it delivers a net reduction in costs. The total reduction in costs will be determined by the cost of network investment avoided through the use of DSP. To achieve this cost reduction the business will need to make a compensating payment to the individual user whose load is going to be curtailed at specific times. The compensation payment is the cost of purchasing DSP. The network business may face other costs depending on the form of price control. Under a price cap form of control the network business also faces a cost associated with lost revenue equal to the DSP provided.

The compensating payment made to customers must be achieved through negotiation. This means the payment amount must be acceptable to both parties. For a customer, the amount must compensate them for the benefits they would have obtained from consumption. The total compensation available for a customer is the compensation payment plus any avoided network charges. For the network business to pursue DSP, the payment must be low enough to still make a profit once the payment is made and any additional costs associated with the form of price control are factored in.

The greatest opportunities to improve profits are when the cost savings from avoided network investment are high and / or the compensation payments sought by customers is low. Prioritising in this way also points in the right direction from the perspective of overall efficiency. This is because it leads to a focus on situations where the network costs saved are large relative to the consumption benefits lost by the affected customer. From the perspective of the long term interests of consumers, it is efficient for a network business to contract for DSP when the benefit of doing so exceed the total cost.

Under a price cap form of regulation, the network business is exposed to the same reduction in revenues from network charges as experienced by the customer. Consequently, the network business will factor in this cost when determining the maximum payment it would be willing to make to the customer under the DSP contract. Therefore, under a price cap, the total cost to the network business is equal to the total benefit, or compensation, available to the customer providing the demand response. This is the efficient cost signal for network businesses because it signals the costs to society of supplying DSP.[27]

Conversely, under a revenue cap form of price control, the network business is not exposed to a loss of revenue as network usage falls. Hence, the maximum payment it is willing to make under the DSP contract will be higher and will result in inefficient DSP outcomes. At the extreme, this might involve the total compensation to the customer (including the avoided network charges) being higher than the cost of the network augmentation required to serve that load. That is, it would have been more efficient to augment the network and serve the load.

There are, however, a couple of mitigations to the potential inefficiencies under a revenue cap.

- First, the incentives for using DSP only occur when there are large discrepancies between actual network charges and cost-reflective network charges. The Rules provide for much greater regulatory scrutiny of the year-on-year structure of charges for businesses subject to a revenue cap. Therefore, the risk of prices causing major inefficiencies may be mitigated.

- Second, network businesses are required to apply an economic test prior to undertaking major new augmentation projects. The requirement to undertake an

[27] Further details are provided in Appendix C.

explicit assessment of the economic costs and benefits of augmentation projects and their alternatives should mitigate the risk of undertaking DSP when pursing the network option would be more efficient.

If price caps provide efficient financial incentives for network businesses to procure the right amount of DSP – and to prioritise the cases where efficiency savings are greatest – then it follows that additional financial incentives are not required on pure efficiency grounds. However, this does not mean that such additional incentives are without merit. Factors external to the regulatory framework, such as the preferences of shareholders, culture within a business or misconceptions about the benefits of DSP can mean additional incentives may be beneficial in stimulating changes in management practices and priorities which promote more efficient DSP outcomes.

Where this is the primary purpose, as was recognised by the Independent Pricing and Regulatory Tribunal (IPART) in introducing the D-factor scheme – then it is important to recognise it as such. The policy rationale is to address a transitional attitudinal and behavioural problem, which should therefore not be hard-wired into the Rules on an enduring basis. There are, however, other policy options for addressing what is, in effect, research and development funding for network businesses. There might be merit, if policy measures are deemed to be necessary, in treating such funding explicitly and transparently, rather than through a relatively complex supplement to the design of the price cap. This issue is discussed further in section 2.6.

The majority of submissions tentatively supported our analysis.[28] However, a number of submissions were of the view that the conclusion was based more on theory than the actual incentives on the businesses.[29] We acknowledge, as indicated above, businesses may have other drivers that influence behaviour. However, the incentives in the framework are focused towards efficient outcomes for profit motivated businesses. If a network businesses' behaviour is not consistent with these incentives they may be foregoing profits.

The TEC, referring to a report by Headberry and Lim, claimed that price caps are barriers to DSP.[30] The principal claim against price caps is that they encourage network businesses to seek additional consumption because this also increases revenues. As noted above, network businesses should only encourage additional consumption where the costs of meeting that consumption are lower than the revenue they receive. This is because we assume that network businesses seek to maximise profits, rather than revenues. Therefore, it can be efficient, in some circumstances, for network businesses to smooth peaks by means of DSP and encourage consumption during off-peak times.

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[28] Jemena, Draft Report submission, pp.2-3; ENA, Draft Report submission, p.2; EnergyAustralia, Draft Report submission, p.2; Foundation for Effective Markets and Governance (FEMG); Draft Report submission, p.6; National Generators Forum (NGF); Draft Report submission, p.2; AER, Draft Report submission, p.2.

[29] EnergyAustralia, Draft Report submission, p.2; AER; Draft Report submission, p.2.

[30] TEC, Draft Report submission, p.4.

A number of submissions were of the view that additional arrangements and incentives are necessary given that the actual use of DSP is low.[31] Submissions indicated that the low take-up of DSP projects, even under the NSW D-factor, is evidence of the need for further incentives.

An alternative explanation of the minimal DSP under the D-factor is that other potential barriers to DSP are having a stronger influence on outcomes, and/or the cost of purchasing DSP is higher than the cost to build network in many cases. In this context it is often claimed that DSP is always a lower cost option, and if it is not used it must be due to barriers in the framework. However, as has been demonstrated in this section, the contract price for DSP does not reflect the full cost of DSP. That is, the full cost of DSP also needs to include consideration of the benefits foregone from consumption. These benefits include any production achieved with electricity or the benefits and comfort available from using electricity in the home. Hence, the actual cost of DSP, when the lost value of consumption is included, may be higher than network options in some circumstances.

CUAC, in its submission, presented the view that customers could implement DSP without any loss of value.[32] CUAC cited an example of air-conditioner cycling.[33] While there is still some debate about whether air-conditioner cycling provides customers with the same level of service, if this were the case, and customers were still consuming, it indicates that they are consuming more than is efficient. As indicated previously, this is likely to be due to the costs associated with closely monitoring consumption. In this situation it is efficient for the network business to offer air-conditioner cycling to customers, given the loss of benefit will be low and the compensation that needs to be offered to the customer will also be low.

2.5 Economic regulation and financial risk for networks using DSP

This section considers whether the regulatory framework creates a bias in the type of expenditure that is used to achieve service outcomes. There are two forms of expenditure: capital expenditure and operating expenditure. Capital expenditure is spending and investing in physical assets. Operating expenditure is spending on the ongoing costs of providing the service, which includes operating and maintaining the assets and management. Operating expenditure is also spending for DSP. This is because a network owner will pay a customer for providing a service (rather than

31 TEC, Draft Report submission, p.5; ENA, Draft Report submission, p.2; EnergyAustralia, Draft Report submission, p.3; AER, Draft Report submission, p.2.

32 CUAC, Draft Report submission, pp.2-3.

33 Air-conditioner cycling is when a customer's air-conditioner is remotely cycled on and off over a period time. The intention of this cycling is to maintain the temperature within the room but through lower energy use.

building and owning an asset). The two forms of expenditure are treated in different ways in the regulatory framework.[34]

Incentives in the regulatory regime seek to ensure that network owners make the right choices between capital and operating expenditure and also minimise the costs of each. Regarding DSP, the regime should encourage network businesses to weigh up the costs and benefits of different options, and to make efficient decisions about whether to contract for DSP or build network assets.

We consider two specific issues in this section:

- First, whether expenditure on DSP is inherently riskier for the network business because of the framework for economic regulation, compared to expenditure on network infrastructure.
- Second, whether and how profits for network businesses are affected if they act efficiently (from a cost perspective) in shifting expenditure away from network infrastructure towards DSP.

2.5.1 Differences in revenue stream risks

What is the issue?

Whether ongoing expenditure on DSP is systematically more risky for a regulated network business than equivalent expenditure on network infrastructure. This would create a bias away from contracting for DSP.

Findings and supporting analysis

As a result of recent changes to the Rules, there is not an imbalance in the risk of recovering capital or operating expenditure that creates a bias against DSP. The issue of revenue recovery risk was raised in the TEC Rule proposal on Demand Management.[35] In response to that proposal, the Commission made a Rule determination to align the risks and payoffs between capital and operating expenditure. This means providing certainty that ongoing expenditure on DSP initiatives is recovered and not subject to a review by the AER.

The current framework for economic regulation exposes each network business to the risk of over-spending on capital expenditure only until the next regulatory re-set.

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[34] For example, capital expenditure undertaken during a regulatory period is included in the Regulatory Asset Base (RAB), net of depreciation, without a risk of it being removed. Network owners also receive a return on capital for capital expenditure. Alternatively, there is no ongoing financing requirement for operating expenditure and as it involves elements that are used once or for payments there is no need to include a value of assets in the RAB.

[35] More information on this proposal can be found on the AEMC website: www.aemc.gov.au.

At that time, the residual (i.e. undepreciated) value of capital expenditure incurred during the five-year period just ended is "rolled in" to the Regulatory Asset Base (RAB). This provides, with certainty, a prospective revenue stream sufficient to recover ongoing depreciation and return.

Prior to the Rule determination in relation to the TEC Rule change proposal, if a network business made an ongoing commitment to incur operational expenditure, e.g. in the form of a contract for DSP, there was no "automatic" future revenue allowance. This made DSP options riskier for the business than network investment options, even if the costs and benefits are identical.

The Commission made a Rule on 23 April 2009 that overcomes this issue (National Electricity Amendment (Demand Management) Rule, 2009. The Rule requires the AER to accept forecasts of network support payments made in the previous regulatory period that continue in the forthcoming regulatory control period. This ensures a consistent risk profile for assets that become part of the RAB and network support payments.

2.5.2 Shifting expenditure from capital expenditure to operating expenditure

What is the issue?

The standard building blocks approach to revenue regulation allows network owners to retain profits resulting from cost savings (or losses resulting from overruns) until the next time the cap is set. Where the retention of benefits is limited to the next revenue reset, the incentive to minimise costs gets weaker as the date of the next re-set approaches. To ensure a consistent incentive over the regulatory period an Efficiency Carryover Mechanism (ECM) is used. The ECM delivers a constant retention period irrespective of when the cost savings (or over-run) is incurred.

The application of the ECM is different between transmission and distribution. While the scheme applies to operating expenditure for both transmission and distribution, applying the scheme to capital expenditure is only an option for distribution.[36] Differences in the use of an ECM between capital and operating expenditure can distort the incentives between building network infrastructure and contracting for DSP.

36 The Commission, in its final Rule determination on the Rule for the Economic Regulation of Transmission Services, determined not to provide a more high-powered incentive on capital expenditure. The reason for this was due to the difficulties in forecasting capital requirements, particularly at the end of a regulatory period, and the fact that capital expenditure is typically lumpy, meaning that a more high-powered incentive risks inappropriately rewarding transmission businesses for differences between actual and forecast outcomes that are not in fact related to efficiencies.

The issue is whether differences in the retention period, as set through regulation, for efficiency savings (or losses) across different cost types systematically disadvantages expenditure on DSP.

Findings and supporting analysis

If only applied to operating expenditure, an ECM appears to penalise efficient substitution of network infrastructure (capital expenditure) with DSP (operating expenditure). This can create a barrier to efficient DSP. This occurs because the cost over-run on operating expenditure is retained for longer than the savings that can be made on capital expenditure.

We are recommending, consistent with the arrangements for distribution, that for transmission networks, DSP expenditure be exempt from the ECM. This will be achieved by adding an additional factor the AER is to have regard to in developing the scheme. Specifically, that the AER consider the possible effects of the scheme on incentives for the implementation of non-network alternatives.[37]

Where the scheme only applies to operating expenditure there will be a penalty incurred where expenditure is shifted from capital to operating expenditure. This is because the retention period will differ between the two. Savings on capital expenditure[38] by the network owner are retained until regulated revenues or prices are re-set.[39] In contrast, the savings on operating expenditure, because of the ECM, will be retained for five years, irrespective of when the next re-set occurs.

Applying this framework to DSP illustrates why it might act as a barrier in respect of TNSPs. A contract with a DSP provider involves incurring additional operating expenditure (in the form of payments under the contract) as a means of avoiding capital expenditure. Hence, all other things being equal, it results in the network business <u>over-spending</u> relative to its operating expenditure forecast in order to <u>under-spend</u> against its capital expenditure forecast. An ECM on operating expenditure but not capital expenditure means that a network owner bears the cost of the over-spend for five years, but only retains the benefits from the under-spend until the next re-set. This has the effect of making DSP arbitrarily more expensive

37 The draft Rule can be found in Appendix A.

38 The costs being saved are the annual depreciation charge (based on an assumed asset life) and financing cost (based on the allowed rate of return) on the relevant capital expenditure, and not the total value of the relevant capital expenditure.

39 At the next review, the starting regulatory asset base for the next regulatory period will reflect the actual capital expenditure over the previous period, and so will be lower than otherwise where a saving of capital expenditure is made. Thus, a capital expenditure saving will provide a benefit to the network business until the next re-set, after which the benefit from that saving is passed onto to customers (through prices being lower than otherwise).

than a network infrastructure alternative because the costs are borne for longer than the benefits are retained.[40]

The majority of submissions supported this reasoning.[41] Submissions noted that differences between the incentives for capital and operating expenditure may be a disincentive to choosing non-network options. To overcome this issue the majority of submissions supported excluding DSP from the ECM.[42]

A number of submissions supported further consideration of applying the ECM to capital expenditure to overcome the financial disincentives.[43] We note that the distribution framework allows the ECM to be applied to capital expenditure. Therefore, where the AER deems it appropriate, the ECM can apply to capital expenditure. Ideally, applying the ECM to both forms of expenditure allows the incentives between each to be symmetrical. We maintain the view, however, that applying the ECM to capital expenditure for transmission is more difficult and has the potential to create perverse incentives. This is primarily due to the difficulty of forecasting capital expenditure and the lumpy nature of transmission investments. Therefore, we consider a more effective solution is to remove expenditure on DSP from the ECM that applies to operating expenditure.

2.6 Incentives for innovation

What is the issue?

A network owner will have an incentive to innovate if it expects to earn more profit by doing so. The business can do this by developing its own research and development capability to support innovation investment, contracting with third party research businesses or institute, or some other hybrid approach. In deciding whether to invest in innovation or not, the business will allow for the uncertainty of innovation, including the possibility that the investment will not deliver any usable output.

Innovation in electricity networks is likely to become increasingly important. This is principally because there is likely to be significant activity in connecting new lower carbon technologies to the network and also an increased focused on the ways that energy use can be managed. Much of the expenditure on innovation will be operational expenditure, particularly when undertaking research and developing

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40 Strictly speaking, the incentives are balanced between operating and capital expenditure on the first day of each price or revenue control period, but at no other time.

41 CUAC, Draft Report submission, p.6; Grid Australia, Draft Report submission, p.3; Jemena, Draft Report submission, p.3; United Energy, Draft Report submission, p.4; TEC, Draft Report submission, p.5; SP AusNet, Draft Report submission, p.3;

42 Energex, Draft Report submission, p.1; Grid Australia, Draft Report submission, p.3; Jemena, Draft Report submission, p.3; SP AusNet, Draft Report submission, p.3.

43 United Energy, Draft Report submission, p.4; Grid Australia, Draft Report submission, p.3.

options. In this circumstance, much of the expenditure is likely to be related to the application of existing technologies or methods, rather than developing new technologies or methods.

If networks appropriately innovate, the results will likely lead to more efficient network and energy costs for customers. Therefore, it is important to ensure that network owners have the appropriate incentives to innovate.

Findings and recommendations

As foreshadowed in the AEMC's Review of Energy Market Frameworks in light of Climate Change Policies, we are recommending a change to the existing Demand Management Innovation Scheme (DMIS). The change would be to extend the scheme to include the connection of embedded generators.[44] In addition, we have identified a number of enhancements for the AER to consider when developing a national Demand Management Innovation Allowance (DMIA).

Innovation for DSP

When contemplating innovation, regulated businesses need to consider how any costs incurred and cost savings delivered will be treated from a regulatory perspective. Generally, revenues are re-set in line with costs each five years and explicit allowance is not provided for expenditure on innovation.[45]

The process of resetting allowed revenues periodically may impact on the perceived benefits of innovation. If innovation delivers cost savings, then there is a likelihood that the AER will adjust future revenues downwards at the next re-set to reflect the cost savings. This limits the flow of profits for the business to a maximum of five years while the costs may require a longer pay-back period. Consequently, network owners may decide not to incur costs of innovation, or focus their efforts on projects with relatively short (or certain) pay-back periods.

In the absence of other arrangements such a conservative approach to innovation may lead to under-investment. In a period of significant change in the energy sector, customers may be better off in the longer term if network owners were to take on greater levels of expenditure and risk in respect of innovation.

The AER, under the DMIA, has developed innovation schemes for distribution businesses in the NEM. According to the AER, the purpose of the scheme is to provide incentives for DNSPs to conduct research and investigation into innovative techniques for managing demand. Through this, the AER considers that DSP

44 The draft Rule can be found in Appendix A.

45 The rationale for this is that innovation should be self-funding, and the business is best placed to decide what level of expenditure on innovation is efficient. This protects consumers from the risk that businesses use any allowance wastefully, or simply decide not to spend the allowance and thereby transfer the allowed funding directly to shareholders.

projects may be increasingly identified as viable alternatives to network augmentation.

In general, the scheme is divided in two parts:

- The first part provides an allowance for the recovery of DSP related costs on an ex-ante basis. An ex-post review of expenditure is conducted to ensure compliance with the DMIA criteria. The amounts are proportional to the distribution businesses annual revenue requirement.

- The second part allows distribution businesses to recover foregone revenue as a consequence of energy sold as a result of DMIA approved expenditure. However, as indicated previously, this arrangement should be viewed as a subsidy rather than overcoming any bias within the framework.

The majority of submissions indicated that innovation funding for DSP was important for encouraging efficient DSP outcomes.[46] However, submissions indicated that the existing DMIA is not effective in overcoming the barriers to innovation for distribution businesses. In particular, submissions were of the view that the amount of money available from the AER was insufficient to prove beneficial.[47]

The AER has indicated its intention to develop a national DMIS.[48] Given the issues raised in submissions we consider there are a number of modifications the AER should consider in developing the national scheme:

- Requiring businesses to submit upfront claims for identified projects (rather than providing up-front funding and assessing ex-post) – this requires businesses to consider in further detail possible innovation projects before funding is provided. Including this requirement should assist in better developed proposals for funding. The increased project specification may also assist in allowing more funds to be provided to network business.

- Incorporating a criteria for assessment that is sufficiently broad so to reduce the risks of rejection – this recognises that innovation projects are speculative and uncertain. Therefore, it is difficult for a regulator to assess the benefits of a proposal until after the innovation or research is complete.

- Require consideration to be given to previously funded innovation projects – this will help to ensure that duplication in funding is avoided and the benefits of innovation are shared.

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46 Grid Australia, Draft Report submission, pp.3-4; Jemena, Draft Report submission, p.2; United Energy, Draft Report submission, p.3; TEC, Draft Report submission, p.6; SP AusNet, Draft Report submission, p.3; EnergyAustralia, Draft Report submission, pp.5-6.

47 United Energy, Draft Report submission, pp.5-6; TEC, Draft Report submission, p.6; SP AusNet, Draft Report submission pp.3-4.

48 AER, *Final Decision, Demand Management Incentive Scheme, Energex, Ergon Energy and ETSA Utilities 2010-15,* October 2008, p.14.

- Funds should be provided on a use-it-or-lose-it basis - this seeks to ensure that businesses don't simply avoid using the funds to increase their profits.

- Cost sharing between customers and network businesses should be included - this is to ensure that distribution businesses take a reasonable share of the risk for developing an innovation.

Innovation for generator connections

In the Review of Energy Market Frameworks in light of Climate Change Policies we found that, absent additional incentives, the existing framework may not encourage distribution businesses to deliver cost efficient connections for generators. This is because distributors have a strong incentive to focus on network reliability and safety but weak incentives to manage the costs associated with embedded generator connections. This is a result of the discretion distribution businesses are afforded with respect to minimum technical standards and because the cost of implementing these standards are met by connecting generators.

To overcome the lack of incentive to minimise the costs of connection we propose amendments to the Rules which seek to modify the existing framework. The proposed amendments to the Rules seek to expand the existing DMIA so it also includes consideration for connecting embedded generators. The purpose of the expansion would be to encourage distribution businesses to consider more innovative and cost effective ways of connecting generators to distribution networks.

3 Service Incentives and Reliability Standards

Chapter overview

This chapter considers whether the framework encourages network businesses to efficiently consider DSP when making decisions about how their reliability and service standards are achieved. The chapter first considers the mandatory planning standards and obligations on network businesses followed by the incentive-based service standards that form part of revenue determinations.

3.1 Findings and recommendations

This section sets out our findings and recommendations in respect of service incentives and reliability standards. The detailed reasoning and analysis associated with these findings and recommendations is explained later in the chapter.

The Commission has found that:

- Reliability planning standards that are economically derived do not create barriers to DSP.
- Planning standards that are not based on economic analysis, such as pure deterministic standards, are likely to discourage the efficient inclusion of DSP.
- The planning standards for distribution networks should be reviewed to ensure that the method applied does not bias against more efficient options. This recommendation has been included in a draft Terms of Reference for the MCE to consider as part of the Review of the National Framework for Electricity Distribution Network Planning and Expansion.
- The service incentive schemes in the economic regulation framework do not provide an impediment to efficient DSP.

3.2 Background

The expenditure that network owners incur, and the revenue earned, are for the provision of services to customers. Because one interconnected network serves all customers in the NEM, there are limits to how much individual customers are able to nominate the level of service and reliability they want and are willing to pay for. In addition, financial incentives may encourage network owners to forgo service quality in preference to profits. Therefore, regulation is used to ensure that an appropriate level of service and reliability is provided collectively to customers. This regulation is a mix of obligations and incentives.

There are two types of regulation that relate to network service and reliability: mandatory standards and discretionary standards. The mandatory standards are reliability planning standards. These are licence requirements[49] on network owners to ensure there is appropriate capacity and redundancy in the network to support the delivery of reliable electricity to customers. The discretionary standards are service standards for which financial incentives apply. These service standards are over and above the mandatory standards and are based on performance against specific measures. The network owner is not obliged to achieve them but their profits can be impacted depending on whether they are achieved or not.

3.3 Mandatory service standards – planning and reliability standards

What is the issue?

Network businesses' licence conditions include a requirement to meet planning standards. These standards generally are specified in terms of the network being able to continue to supply all load with one or more network elements out of service (i.e. an "n-k" planning standard).

The question is whether the requirement to consider a pre-determined amount of redundancy when demand is extremely high allows for the appropriate inclusion of DSP to provide reliability services.

Findings and supporting analysis

Planning standards that do not consider the relative cost of an option and its relative impact on reliability can result in bias against DSP. To address this concern in transmission, the Commission's Final Report to the MCE for the Transmission Reliability Standards Review recommended that transmission reliability standards be economically derived using a customer value of reliability or similar measure and be capable of being expressed in a deterministic manner.[50] In the Review of the National Framework for Electricity Distribution Network Planning and Expansion, we recommended that a similar review be undertaken for distribution networks.[51]

Mandatory planning standards seek to achieve a level of network reliability that is desired by customers. Two types of planning standards are predominantly applied in the NEM for this purpose: deterministic standards and probabilistic standards. The majority of jurisdictions apply deterministic planning standards. Traditionally this means that the network needs to be built with a certain level of redundancy. Some network owners, however, apply a probabilistic planning standard. Probabilistic planning standards are economically derived and, compared to a

49 Network owners need to obtain a licence for each jurisdiction they participate in. Among other things, the licence obliges network owners to adhere to certain regulations and legal instruments.

50 AEMC, *Transmission Reliability Standards Review Final Report to MCE*, Sydney, 30 September 2008, p.vi.

51 See: http://www.aemc.gov.au/Market-Reviews/Completed/Review-of-National-Framework-for-Electricity-Distribution-Network-Planning-and-Expansion.html

simple level of redundancy, are generally based on the value customers place on reliability.

When planning standards are not economically derived, i.e. they do not allow for a consideration of the costs and benefits of reliability upgrades, they are likely to discourage efficient DSP use. This is because traditional deterministic standards apply a pass or fail test. If non-network options are not considered to be firm enough to contribute to meeting mandated levels of redundancy in the planning standards, then network owners will dismiss it as an option. Alternatively, the firmness of non-network options could be improved, but this may be at significant cost. Given DSP options and network options are not perfect substitutes, this creates a bias against non-network options such as DSP. This is of concern where a DSP option may have lower reliability, but at a lower cost.

By contrast an economic approach to planning allows different forms of investment, with potentially different reliability impacts, to be compared. Economic planning standards permit the option which ranks best in terms of cost/benefit and overall value to be identified and selected. That is, there is a trade-off between the cost of an option and the level of reliability it delivers. This is consistent with economic efficiency and the achievement of the NEO.

The majority of submissions supported this view. Stakeholders agreed that DSP and network options are not perfect substitutes.[52] On that basis they agreed that where planning standards are not economically derived that there is a potential bias against DSP. In addition, we support the view in submissions that an economic consideration of reliability also needs to consider the costs of DSP failing to achieve expected reliability outcomes.[53]

Some submissions noted that there are benefits from expressing standards deterministically.[54] For instance, EnergyAustralia indicated it is not practicable to apply an economic planning framework to the myriad of augmentations that are associated with distribution networks.[55] This contrasts, however, with the view from United Energy who stated they apply a probabilistic standard to their network planning.[56]

We agree that an advantage of deterministic planning standards over probabilistic standards is improved transparency. This is because the required standard is easier to interpret. However, the Reliability Panel recommended, and the Commission accepted, in the context of transmission networks that even where deterministic planning standards are applied they should be economically derived.

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52 AEMO, Draft Report submission, p.3; Grid Australia, Draft Report submission, p.6; United Energy, Draft Report submission, p.7; SP AusNet, Draft Report submission, p.5; EnergyAustralia, Draft Report submission, p.6.

53 Grid Australia, Draft Report submission, p.6; SP AusNet, Draft Report submission, p.5.

54 Grid Australia, Draft Report submission, p.6; EnergyAustralia, Draft Report submission, p.6.

55 EnergyAustralia, Draft Report submission, p.6.

56 United Energy, Draft Report submission, p.7.

We note, however, the divergence of views about the application of economic planning standards in the context of distribution networks. However, given the increased prospect of non-network options being beneficial for distribution networks we consider it important that the scope for bias against DSP is minimised or removed. For this reason, we consider the review of distribution planning standards is appropriate. The review should consider whether the form of the standards should be derived on an economic basis to promote efficiency, including facilitation of non-network alternatives, and if so, how.

3.4 Discretionary service standards – service incentive schemes

What is the issue?

Service incentive schemes operate in addition to the reliability planning obligations placed on network owners. Service incentive schemes seek to provide a financial incentive to provide levels of service that are desired by customers. These service levels are expressed as target levels of performance against specified key performance measures that are determined by the AER under the Rules.

Service incentive schemes can impact on the amount of revenue earned by network businesses by allowing rewards or imposing penalties for varying levels of service performance. The schemes encourage network businesses to consider the expected financial penalty from the levels of service they provide and compare it to the cost of service improvement projects. Therefore, while other incentive arrangements are designed to encourage network businesses to spend less, the role of the service incentive scheme is to signal to a network business that customers place a value on the quality of the service provided (which is reflected in the performance measures determined by the AER).

The service incentive schemes for transmission and distribution are different. The purpose of the transmission scheme is to ensure that there are incentives to make the network available at times that it is most valued by the market.[57] The scheme for distribution focuses on seeking to ensure a reliable supply for customers.

If either of the schemes do not allow for an appropriate comparison between DSP options and network options for improving service quality then there may be a bias towards one or the other.

Findings and supporting analysis

We do not consider that the existing service incentive schemes for transmission or distribution are an impediment to efficient DSP. This is because the service incentive schemes allows network owners to appropriately compare levels of reliability and continuity of supply with likely penalties or benefits.

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[57] Clause 6A7.4(b) of the Rules.

As indicated, the design of service incentive schemes differs between transmission and distribution. For distribution, the primary service performed by the network owner is to transport electricity from the transmission connection point to consumers. Accordingly, the service that is desired by customers is continuity of supply, with quality of supply (e.g. voltage) within acceptable limits. The measures of service for distribution schemes are 'per customer minutes off supply' and its derivatives such as the frequency of interruptions and the average duration of interruptions.

By contrast, the benefit that a transmission network delivers is both delivery of electricity to final customers as well as the transportation of electricity from generators. This additional role for transmission means that additional network capacity can potentially lead to lower generation costs by permitting additional output from existing and potentially lower-cost generators. Indeed, a potential role for DSP is to provide network support to allow lower-cost generators to be dispatched. However, attaching incentives to these wider market benefits has proved problematic. Currently the transmission scheme:

- provides an incentive to minimise outages to customers; and
- otherwise provides an incentive to have existing assets in service (i.e. available) particularly when those assets are required by the market.

The Rules for the transmission scheme put a limit on the bounds of risk and reward of between one and five percent of regulated revenue.[58]

We note that the introduction of smart grid technology across networks may enable the parameters for service incentives scheme to be more targeted and precise. This is a matter that may be considered further as part of Stage 3 of the Review.

In the context of these schemes, a network business will compare the contribution to performance measures provided by a non-network option with the likely penalty or benefit it will receive from the service incentive scheme should the DSP improve or reduce service performance. That is, service incentive schemes encourage network businesses to compare the likelihood of outages between network and non-network options.

The framework encourages network owners to consider the relative reliability of different service improvement options. As a result, the design of the schemes do not present barriers to the efficient inclusion of DSP. This means that DSP options will be given consideration if they can improve reliability at relatively low cost rather than being summarily dismissed if they are considered less reliable. Rather, the possible penalty from a lower level of reliability will be considered and valued compared to the cost of the option and possible benefit. Therefore, if the cost of the DSP option is sufficiently low, and the risk of it impacting on the quality of supply can also be managed at a low cost, the network owner will prefer the DSP option.

58 The current scheme, as determined by the AER, sets the maximum increment or decrement a transmission network service provider (TNSP) may earn to one per cent of regulated revenue.

Submissions supported this view.[59] Submissions indicated it is important to have reliability factored into any cost-benefit analysis applied to options. Submissions noted, and we agree, that this includes sharing, or managing, the risks associated with operating within the current framework where service penalties are applied to non performance.[60]

EnergyAustralia provided the view that the economic risk associated with DSP should be managed by excluding poor performance arising from non-performance of DSP.[61] We consider, however, that given the schemes allow for an appropriate consideration of these costs and benefits that such an adjustment is not warranted.

59 Grid Australia, Draft Report submission, p.6; United Energy, Draft Report submission, p.7.

60 Grid Australia, Draft Report submission, p.6; SP AusNet, Draft Report submission, p.5.

61 EnergyAustralia, Draft Report submission, p.7.

4 Distribution Network Planning

Chapter overview

While the previous chapter considered the standards network businesses have to achieve, this chapter considers the way that distribution network businesses plan to achieve these standards. This planning process involves identifying the need for investment, and consultation prior to investment. The key considerations in the chapter relate to the extent of transparency in the planning process and how case-by-case assessments for network development are undertaken.

4.1 Findings and recommendations

This section sets out our findings and recommendations in respect of distribution network planning. The detailed reasoning and analysis associated with these findings and recommendations is explained later in the chapter.

The Commission has found that:

- There is a lack of planning obligations in the Rules, and therefore a lack of consistency across jurisdictions, which limits the ability of DSP proponents to be effectively involved in the planning process.
- Consultation on network augmentation options, rather than on a need for a network or non-network response, creates a barrier to DSP as DSP options are not afforded the same prominence as network options in the consultation framework.
- While the existing threshold for the Regulatory Test should not be reduced for DSP, there is a lack of transparency in the current arrangements that limits the potential inclusion of DSP.

The Distribution Planning Review has sought to address each of these issues. Accordingly, this chapter provides our analysis of barriers to DSP in the distribution planning framework in support of the recommendations made in the Distribution Planning Review.

4.2 Background and context

As noted in the previous chapter, network owners have financial incentives to minimise the costs of delivering their services to the required standards. Where DSP is the more cost-effective option, network owners should have the incentive, irrespective of any other obligations, to procure DSP. However, it is also recognised that there is no competition for the provision of network services. Therefore, in order to provide market participants with more assurance that only appropriate augmentations are undertaken, network owners are subject to a number of regulatory obligations in respect of how they plan network investment. It is important in this context to ensure that the arrangements for distribution network planning allow for an appropriate consideration, and efficient inclusion of, DSP.

This is particularly the case for distribution where DSP prospectively has a larger role to play given the majority of customers are connected to distribution networks.

The remainder of this chapter sets out our reasoning for our findings. It identifies specific aspects of the framework that may present barriers to DSP, and, where relevant, appropriate responses to those barriers.

4.3 Distribution network planning

What is the issue?

If information about the need for, and nature of, network investment is not provided in a timely and accurate way, it will be more difficult for demand-side alternatives to be developed. Demand-side participants need sufficient time to consider the identified need, determine if DSP can address the identified need, and determine the costs and benefits of participation. Therefore, the obligations on DNSPs for planning are relevant to the ability of DSP proponents to participate.

Findings and supporting analysis

The Rules do not provide sufficient guidance on planning for DNSPs. In addition, because the majority of obligations are in different jurisdictional based arrangements there is a lack of national arrangements for distribution planning. This inconsistency across jurisdictions creates a barrier to DSP. The Distribution Planning Review has sought to overcome this barrier by recommending annual planning requirements be included in the Rules to replace jurisdictional arrangements. The recommendation also includes a requirement to establish and maintain a Demand Side Engagement Strategy.

At present, the Rules do not require distribution network owners to undertake any annual reporting on how they plan to develop the network. Except for reports provided to AEMO for projects with a value above $10 million, the Rules do not impose any obligation with regard to the publication of information on the potential need for network investment.[62] This contrasts with the arrangements for transmission businesses. The transmission arrangements in the Rules require the businesses to publish information such as forecast loads; planning proposals; forecast constraints and specific information about alternatives considered to augmentations.[63]

In the context of the Rules, the existing arrangements do not provide sufficient transparency or time to enable DSP proponents to develop proposals in response to network augmentations to the distribution network. To date, the impact of these deficiencies have been mitigated because jurisdictions have in place arrangements

62 Clause 5.6.2 of the Rules.

63 Clause 5.6.2A of the Rules.

for reporting on future constraints and development plans by network owners. However, there are different arrangements and obligations in each jurisdiction.

Inconsistency in arrangements across jurisdictions can be a barrier to demand-side proponents. For instance, large customers who operate across jurisdictions are not provided with the same information in each jurisdiction. Consequentially, they face higher administrative costs to identify opportunities and develop proposals.

The majority of submissions supported this view.[64] Submissions noted that consistent obligations across the NEM will improve the ability of DSP providers to offer competitive services and improve their ability to develop technologies that that contribute to network performance. However, a number of submissions cautioned that balance is needed to ensure obligations don't outweigh the benefits.[65]

We agree that the costs of providing transparent planning information should not outweigh the benefits. We consider the arrangements put forward as part of the Review of the National Framework for Electricity Distribution Network Planning and Expansion achieves this balance. The recommendation is for the national planning requirements to encompass planning for all assets and activities carried out by DNSPs that would materially affect the performance of the network.

The Distribution Planning Review also recommended that distribution businesses develop a Demand Side Engagement Strategy. The Demand Side Engagement Strategy would involve distribution businesses publishing a demand side engagement facilitation process document, establishing and maintaining a database of non-network case studies and proposals, and establishing and maintaining a Demand Side Engagement Register. This recommended framework is in recognition of the importance of proactive engagement by both DNSPs and demand-side providers to develop potential solutions to system limitations.

4.4 Consultation and case-by-case assessments

In addition to general planning obligations, DNSPs are required, in some circumstances, to undertake consultation with stakeholders and undertake economic assessments of specific potential network augmentations.

The consultation and assessment framework for distribution businesses is centred around the Regulatory Test. Clause 5.6.5A of the Rules provides for the AER to develop and publish the Regulatory Test, with the purpose of identifying new network or non-network alternatives that maximise the net economic benefit to all those who produce, consume and transport electricity in the market or minimise the present value of costs of meeting reliability requirements.

64 AEMO, Draft Report submission, p.3; Energex, Draft Report submission, p.2; TEC, Draft Report submission, p.7; EnergyAustralia, Draft Report submission, p.7.

65 Grid Australia, Draft Report submission, p.5; SP AusNet, Draft Report submission, p.6; EnergyAustralia, Draft Report submission, p.7.

If demand-side proponents are not aware of options for them to contribute, or are not adequately consulted about opportunities, potential efficient demand-side opportunities may be missed. There are two key components that impact on this occurring, first, the trigger for consultation, and second, the threshold that applies to the trigger. In the context of the potential barriers to DSP, the remainder of this section considers the trigger for consultation under the Regulatory Test and the threshold that applies.

4.4.1 The trigger for consultation

What is the issue?

The Regulatory Test, at present, is focused towards identifying network and non-network alternatives equally. However, the trigger for a Regulatory Test to be undertaken is based on the value of a proposed network augmentation, rather than all or any options that meet the need. That is, it is the value of a network augmentation, rather than the value of alternative options, such as DSP, that determines when consultation is undertaken and the form of reporting required. The issues is whether this creates a bias in favour of network options.

Findings and supporting analysis

The existing triggers for consultation, and their link to augmentation options, are causing bias, and therefore act as a barrier, to demand-side options being given due consideration. Because the thresholds for consultation arrangements are based on a network option, the network option becomes the benchmark for assessment, rather than any other credible option that may address the identified need.

The Review of the National Framework for Electricity Distribution Network Planning and Expansion provided recommendations towards the development of a Regulatory Investment Test for Distribution (RIT-D). The RIT-D proposed by the Commission does not apply a network option as a trigger. Instead, the value of the most expensive option is the trigger for consultation. This is consistent with the arrangement for transmission networks that was developed by the Commission and endorsed by the MCE.

Requiring the extent of consultation to be based on the value of network augmentations create a bias towards network options. This is because by the time consultation starts the business has already done significant work to develop and cost a network option. Therefore, the focus can be on the network option already developed rather than any other alternative.

We note that a number of submissions reaffirmed the view that network options do not act as a default option.[66] However, even if there is only a perception that they act as a default option there are benefits in overcoming this perception. For DSP

[66] SP AusNet, Draft Report submission, p.6; Grid Australia, Draft Report submission, p.5.

proponents to feel they can be genuine participants in the process it is important they don't perceive they are competing against a pre-determined option.

4.4.2 The threshold for assessment

What is the issue?

For assets valued in excess of $1 million and less than $10 million (new small distribution assets), DNSPs are not required to undertake any consultation. However, they are required to carry out an economic cost-effectiveness analysis of possible options.

For those assets that are not new small distribution assets, the DNSP is required to consult with stakeholders on possible options. Options can include: demand side options, generation and market network service options. Following this process, the DNSP must prepare a report to be made available to relevant stakeholders. When the asset is a new large distribution network asset (above $10 million in value), or if it is likely to change distribution use of system charges by more than two per cent, registered participants may dispute the recommendation of the DNSP.[67]

In the case of distribution networks, there is the potential for demand-side options to avoid the need for new small network investments. However, if smaller projects, which DSP can provide a solution for, are not subject to scrutiny or consultation, potential efficient outcomes may be lost.

Findings and supporting analysis

We have found there would not be sufficient benefit to DSP proponents or network businesses to lower the threshold for the Regulatory Test. The Distribution Planning Review also considered the appropriate threshold that should apply to consultation under a new RIT-D. In that Review, the Commission recommended the minimum threshold be increased from $1 million to $5 million.

The reason for applying a threshold to investment assessments is to avoid imposing a regulatory cost that may not be offset by the benefits it creates. Therefore, thresholds are intended to reflect an implicit assessment of the point where the potential benefits of performing the mandatory activity are outweighed by the costs

Noting that the Regulatory Test is an administrative function, we have found that unilaterally lowering the threshold is likely to increase costs without a corresponding benefit. DNSPs already have obligations to justify expenditure to the AER at their revenue determinations. As noted in chapter 2, they also have economic incentives to minimise costs. Therefore, administrative functions in addition to these economic incentives should only be necessary where the potential inefficiencies are large.

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[67] Clause 5.6.2 of the Rules.

We have, however, identified that there is a lack of transparency regarding the assessment of options below the RIT-D or Regulatory Test threshold that can create a barrier to DSP. Therefore, as discussed previously, the Demand Side Engagement Strategy requires DNSPs to publish information to assist DSP proponents to engage in the planning process. Consequently, this strategy allows non-network providers to investigate and propose alternative investment options for all projects including those that fall below the threshold.

5 Network Access and Connection Arrangements

Chapter overview

This chapter is focused on a subset of embedded generators that are co-located with load. In order for these embedded generators to effectively participate they need to be able to access and connect to the distribution network to draw supply and also to support the network. This chapter investigates whether aspects of these access and connection arrangements are an impediment to embedded generators and demand-side resources. Specifically, this chapter considers:

- connection arrangements and minimum technical standards;
- connection charges and the allocation of costs; and
- arrangements to recognise the benefits provided by embedded generators.

5.1 Findings and recommendations

This section sets out our findings and recommendations in respect of the network access and connection arrangements for embedded generators. The detailed reasoning and analysis associated with these findings and recommendations is explained later in the chapter.

The Commission has found that:

- Given the detailed connection process in the Rules we do not consider there is a significant barrier regarding the connection process for the majority of embedded generators. However, we consider the MCE process to streamline the arrangements for micro-generators is likely to be beneficial.
- A barrier exists in relation to the minimum technical standards for connection. Therefore, we recommend the Reliability Panel, as part of its Technical Standards Review, consider the minimum technical standards that should apply to embedded generators. In addition, as discussed in Chapter 2, we recommend an expansion in the scope of the DMIS to include activities related to connecting embedded generators more efficiently.
- The charging frameworks that apply between distribution and transmission connected generators are sufficiently consistent such that they do not present a barrier to embedded generators.
- Due to the long-term benefits - through cost savings - that embedded generators can provide on the transmission network, and practical difficulties of embedded generators negotiating over these benefits directly with transmission businesses, there are benefits in retaining avoided transmission use of system (TUOS) payments.

- Avoided TUOS should not be paid if an embedded generator receives network support payments from a transmission business. We have recommended amendments to the Rules to reflect this intention.

5.2 Background

Embedded generating units are defined in the Rules as generators that are directly connected to the distribution network and do not have access to the transmission network. Customers can use embedded generators as a form of DSP and actively participate by substituting their consumption of electricity from the network with their own generation. A customer would seek to use embedded generation in this way where the benefits of doing so were greater than the costs. While large embedded generators, such as some wind farms, can connect to the distribution network, it is the use of embedded generation as a substitute for electricity from the main network that is the focus of this analysis.

The prospect of more customers using embedded generation as a substitute for electricity generated from the main network is likely to increase as a result of climate change policies. That is, as further incentives are provided by government (such as feed-in tariffs, rebates and initiatives such as the Smart City, Smart Grid[68]), customers will seek to install more embedded generation. In addition, as the cost of high carbon-emitting generation increases, the economics of some of the cleaner embedded generation options, such as photovoltaic generators, may improve.

The remainder of this chapter is split into two parts: the first part considers the connection arrangements; and the second part considers the rewards or benefits available for embedded generators.

5.3 Connection arrangements and minimum technical standards

The connection process for certain embedded generators involves the following steps:

- an application by an embedded generator to a DNSP to commence the connection process;

- an assessment of the application including network studies and the identification of required performance standards; and

- a connection offer, which includes charges for the provision of the required network services.

The remainder of this section will discuss these elements of this connection process and the prospect of the existing arrangements distorting efficient outcomes.

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68 See: http://www.environment.gov.au/smartgrid/

5.3.1 The process for connection

What is the issue?

Generators sized 5 MW or greater are obliged to follow the connection process prescribed in the Rules.[69] The Rules arrange the steps identified above into six discrete phases of the connection application process. For each phase the Rules outline the required information provisions and the timing of responses from each party.[70]

Generators with a nameplate rating of less than 5 MW may choose whether or not to follow the connection process in the Rules.[71] Those who choose not to follow this process do not have to comply with the technical standards set out in Schedule 5.2 of the Rules, but must meet jurisdictional requirements.

If the processes for connection do not provide sufficient guidance to the parties involved, there is an increased prospect that inefficient delays or costs can occur.

Findings and supporting analysis

There is a detailed connection process in the Rules which is available to all connecting parties irrespective of their size. Considering the detailed nature of these arrangements we do not consider that there is a significant barrier regarding the connection process for the majority of embedded generators. Indeed, they provide certain safeguards and protection to connection applicants. In addition, the MCE process to develop national arrangements for small and micro generators will assist in ensuring an efficient connection process in these instances.

As noted, the Rules require generators above a threshold to follow a detailed connection process. This is because generators above the threshold are more likely to have an a material impact on system security and reliability. However, for small generators it may not always be appropriate for such a formal process to occur. The Rules recognise this by not requiring generators that are not Registered Participants (hence generators below 5 MW) to follow the Rules connection framework and instead follow jurisdictional connection frameworks, which tend to be less prescriptive.

The framework appropriately balances the need for detailed arrangements for those generators where such arrangements are made necessary by virtue of the generator's size and possible impact on system security and reliability, while also allowing an

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69 Clause 5.3.1(b) of the Rules.

70 See Appendix D for a detailed description of the connection process in the Rules.

71 Clause 5.3.1(b) requires Registered Participants to follow the connections procedure in the Rules. AEMO, in accordance with clause 2.2.1(c) can exempt generators from being a Registered Participant. AEMO's NEM Generator Registration Guidelines exempt generators below 5 MW from becoming Registered Participants. However, generators below 5 MW can opt into the connection process in the Rules by virtue of clause 5.3.1(c) of the Rules.

appropriate level of flexibility for smaller generators where detailed arrangements would be unnecessary.

This position was supported by United Energy;[72] however, ENA and Energy Response pointed to the MCE process as the appropriate forum to improve the connection process for micro-embedded generators.[73] Energy Response indicated that the Rules process is too detailed and complex for small and mirco-embedded generators.[74]

On 15 December 2008 the MCE Standing Committee of Officials (SCO) published a policy response in relation to electricity distribution network planning and connection.[75] The SCO Policy Response considers a national framework for distribution connection arrangements and specifically the connection process issue for small and micro-generation.[76] The response considers that for small loads and micro-embedded generators[77], DNSPs should be required to specify at least one standard connection service. The standard connection service would be subject to AER approval and the Rules would set out the technical requirements for micro-embedded generators in this circumstance.

We support the process being undertaken by the MCE. We agree with the intention of the proposed arrangements, being to provide scope to streamline the process for smaller embedded generators. In addition, the proposed framework will add consistency to the arrangements across jurisdictions. This has the potential to reduce administrative costs for prospective embedded generator proponents that operate across jurisdictions.

5.3.2 Minimum technical standards

What is the issue?

As part of the connection process, embedded generators are required to meet a number of technical standards relating to their connection to the network.

The technical requirements for connecting generators are set out in Schedule 5.2 of the Rules. These arrangements apply to all generators with a capacity of 5 MW or greater. However, most embedded generators seeking connection are less than

72 United Energy, Draft Report submission, p.8.

73 ENA, Draft Report submission, p.6;

74 Energy Response, Draft Report submission, p.5.

75 The response is in relation to the NERA and Allen Consulting Group (ACG) report titled "Network Planning and Connection Arrangements – National Frameworks for Distribution Networks".

76 The SCO response can be found here: http://www.ret.gov.au/Documents/mce/_documents/2009%20Bulletins/NERA-ACG-report-SCO-policy-reponse.pdf

77 SCO, in their policy for electricity distribution planning and connection, define the classes of generators as follows: micro - a nameplate rating of not greater than 2 kW, small - greater than 2 kW but not more than 1 MW, medium - greater than 1 MW but not more than 5 MW, and large – greater than 5 MW.

5 MW. For these smaller generators, schedule 5.2 does not apply and jurisdictional standards apply instead.

If the technical requirements and standards applied by DNSPs are in excess of the necessary minimum requirements to maintain system security, the additional costs to meet the standards may discourage embedded generation connecting to the network.

Findings and supporting analysis

The framework for determining the minimum technical standards creates an impediment to efficient connection of embedded generators. The jurisdictional arrangements contain minimal guidance for DNSPs and embedded generators. Therefore, DNSPs have considerable discretion with regard to the minimum technical standards they apply. In addition, DNSPs have no incentive to minimise the costs of connecting embedded generators. The extent of flexibility, and the lack of incentive for DNSPs to minimise costs, creates uncertainty about the minimum technical standards that apply for embedded generators.

We are recommending two measures to overcome this barrier. The first is to request the Reliability Panel, as part of its Technical Standards Review, to consider the minimum technical standards that should apply to embedded generators. The second, as foreshadowed in Chapter 2, is a Rule change process that considers an expansion of the DMIS to include connecting embedded generators.

We consider the arrangements in Schedule 5.2 relating to the conditions and standards for connecting generators above 5 MW are necessary and appropriate. This is because the standards also relate to large transmission connected generators that can have significant impacts on network security and reliability. Detailed technical standards are important for these larger generators due to the impact they can have on system security and reliability. Therefore, the focus of our assessment is on smaller generators below the 5 MW threshold.

The technical standards for generators below 5 MW varies betweens jurisdictions. As indicated in the Draft Report, analysis undertaken by NERA for this review only identified explicit minimum technical standards in three jurisdictions: South Australia, Tasmania and Victoria. Therefore, in other jurisdictions, DNSPs have discretion to negotiate the minimum standards for connection on a case-by-case basis. Indeed, NERA commented that distributors appear to take an ad hoc approach to each embedded generator connection.

Distributors have a strong incentive to focus on network reliability and safety. However, they have weak incentives to seek out the most cost effective way of achieving this. This is due to the flexibility afforded to DNSPs and because the costs of implementing the standards are borne by connecting generators. As noted in Chapter 2, to overcome this lack of incentive to minimise the costs of connection, we propose amendments to the Rules which seek to modify the existing framework. The proposed amendments to the Rules seek to expand the existing DMIS so that it improves the incentives for distribution businesses to consider ways of more efficiently connecting embedded generators. We consider this will encourage distribution businesses to consider more innovative and cost effective ways of connecting generators to distribution networks.

Submissions that commented on this issue supported our findings.[78] However, Energex cautioned that micro-generation standards should not be in the Rules.[79] We consider that consideration of appropriate size thresholds or generator types that minimum standards apply to is an issue that can be addressed as part of the Reliability Panel review.

As indicated previously, the Australian Government has initiated the "Smart Grid, Smart City" initiative. It is anticipated that this initiative may identify further areas for facilitating growth in embedded generators.[80]

The "Smart Grid, Smart City" initiative provides up to $100 million to support the installation of Australia's first commercial scale smart grid. A number of the initiative's objectives will support more efficient embedded generation connection, such as

- facilitating the connection of additional renewable and distributed generation and hybrid vehicles to the grid;
- providing customers with improved energy use information, automation, and savings, and
- improved network reliability.

The announcement of a location for the initiative is expected in early 2010.

5.3.3 Connection charges

What is the issue?

The connection of an embedded generator creates costs for the DNSP that must be recovered through charges. However, the basis for allocating costs incurred between embedded generators and other users can determine the viability of embedded generator proposals and the incentives to connect. In particular, whether generators that connect to the distribution network are treated the same as those connected to the transmission network can influence location incentives for generators who can connect to either type of network.

Findings and supporting analysis

The connection charging framework does not present an impediment to efficient DSP and embedded generator connection. The arrangements between transmission and

78 Energy Response, Draft Report submission, p.5; NGF, Draft Report submission, p.3.

79 Energex, Draft Report submission, p.3.

80 See www.environment.gov.au/smartgrid/

distribution connected are substantially similar such that generators should not have a bias towards connection on either network type. Both transmission and distribution connected generators pay for the assets they use, as well as any security of supply upgrades into the shared network that are necessary to achieve relevant technical standards. In addition, generators connected to either network that cannot physically control output would be required to fund augmentations to the network to accommodate their capacity.

In the Draft Report, we considered that differences in the connection charging framework between transmission and distribution did not create a barrier. The reason identified for this was that distribution and transmission connected generators were receiving different services - one a firm access service, the other not - and therefore different charging frameworks are appropriate.

AEMO's submission on this issue, however, indicated that, while it agrees with the conclusion in the Draft Report, it does so on the basis of different reasoning.[81] Principally, AEMO consider that connection costs do not create a material difference in incentives between transmission and distribution choices. The basis for this view is that Schedules 5.1 and 5.1a (which relate to system standards and network performance requirements) do not distinguish between transmission and distribution. In addition, AEMO notes that the Rules do not specify that transmission or distribution connected generators receive any specific transfer capability.

We agree with the reasoning presented by the AEMO. Both transmission and distribution connected generators pay for any assets they cause, as well as any investments required to ensure security of the network. To that extent, both transmission and distribution connected generators are required to fund assets deep into the shared network when they impact on security of supply.

5.4 Benefits of embedded generation

The previous section considered the processes for connection and the costs that can be incurred. However, the connection of an embedded generator also has the potential to provide benefits in the form of avoided upstream distribution and transmission network costs.

Given the size of many of the generators that are the subject of consideration under this Review, the scope for one embedded generator to provide sufficient changes in network demands to allow network costs to be avoided may be limited. However, through smart grid technology the scope for obtaining benefits from small scale embedded generators may improve considerably over time. The increased scope for integration between embedded generation and networks may be a focus for Stage 3 of the Review. The analysis presented here primarily considers the existing use of embedded generators on the network. Hence, where benefits arise from the connection of embedded generation based on existing technology, it is relevant to consider the payments that should be required to be passed through to reflect these

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81 AEMO, Draft Report submission, p.4.

benefits, as well as negotiated arrangements between network owners and embedded generators.

5.4.1 Arrangements for avoided TUOS

What is the issue?

The Rules specify that a DNSP is required to pass on the locational component of the avoided prescribed TUOS charge to a connection applicant.[82]

It is this locational component of the tariff that is meant to reflect costs of meeting peak demand, as described in Chapter 3. The Rules achieve this by requiring the locational component of transmission charges to be based on levels of demand at times of the greatest utilisation of the network, and for which network investment is most likely to be contemplated.[83] In addition, the AER pricing methodology guideline is required to provide guidance on the role of pricing structures in signalling efficient investment decisions and network utilisation decisions. As indicated in Chapter 2, these principles in the Rules reflect a long-run marginal cost (LRMC) approach to pricing such that prices reflect the need to augment for additional capacity.

Previous analysis has identified that there are primarily two possible problems with requiring DNSPs to pass through this long-term price signal to embedded generators in the form of avoided TUOS:

- the locational component of TUOS charges may not be an appropriate proxy for the network benefits derived; and
- there is scope for the TUOS payments not to be avoided by DNSPs because of the revenue cap approach adopted for the determination of transmission revenue requirements.

Therefore, this section considers whether these deficiencies exist and if it is appropriate for embedded generators to receive avoided TUOS payments.

Findings and recommendations

The current arrangements for avoided TUOS are appropriate and proportionate from the perspective of small embedded generators. Embedded generation that causes a reduction in the component of TUOS that signals long-term costs (the locational component) is providing a benefit to the market. This benefit is the cost savings on the transmission network. The most efficient outcome is for this benefit to be reflected in network support payments from transmission businesses to embedded generators. However, there are practical reasons that may limit this occurring. Therefore, when no network support payment is made, there are benefits in retaining

82 Clause 5.5(h) of the Rules.

83 Clause 6A.23.4(e) of the Rules.

the payment for avoided network costs. However, where a generator receives a network support payment from a transmission business, additional avoided TUOS payments should not be made.

The location of an embedded generator can influence the extent to which the transmission network is used to meet peak demand. This is because electricity from an embedded generator can be used to serve customer load in place of electricity transported via the transmission network. When the use of the transmission network is reduced at peak times, the cost of providing network services also reduces. Therefore, the costs to society to deliver electricity are reduced. Given the locational component of TUOS represents LRMC, this element of TUOS will also reduce as costs fall.

In the absence of an avoided TUOS payment, embedded generators are not provided with a signal about how their location impacts on network use. Without this signal embedded generators would have no incentive to locate in areas that would have the largest impact on reducing transmission network costs. This could consequentially create a loss of efficiency and be detrimental to market outcomes. As a result, additional arrangements are necessary to provide a signal that encourages embedded generators to locate in areas that will create the largest overall benefits.

Ideally, the most appropriate way for embedded generators to receive a signal that reflects the benefits they create would be through network support payments. The network support payment would recognise the costs that are avoided by the transmission network owner and the services provided by the generator.

There are reasons, however, to consider that a network support payment will not always be made for embedded generators. Due to the transaction costs involved, network support payments are unlikely to be practical for the majority of embedded generators. For instance, transmission network owners are unlikely to be aware of the existence of an embedded generator and its impact on reducing costs. This is because embedded generators have no relationship with transmission businesses. In addition, there is no incentive for distribution network owners to negotiate on behalf of embedded generators because they obtain no benefit from doing so.

Where there is no network support agreement in place, it is appropriate for embedded generators to receive avoided TUOS payments for the benefits they provide.

Submissions supported this view.[84] However, a number of submissions sought clarification of the treatment of avoided TUOS when a network support agreement is in place.[85]

We consider an avoided TUOS payment should not be made to embedded generators if a network support payment is made by a transmission business. To provide a payment in this circumstance would represent a double-payment to

84 AEMO, Draft Report submission, p.4; TRUenergy, Draft Report submission, pp.1-2'; NGF, Draft Report submission, p.3.

85 AEMO, Draft Report submission, p.4; Energex, Draft Report submission, p.3.

embedded generators. Hence the locational signal would be over-signalled and the long term costs to consumers of electricity would be higher. Therefore, we recommend that the Rules be clarified so that an avoided TUOS payment is not made when transmission benefits are contained within a network support payment. Details of this proposed change can be found in Appendix A.

ENA argued that TUOS is not actually avoided under the revenue cap arrangements that apply to transmission businesses, because the actual revenue received by the transmission network owner doesn't change within the regulatory period even though the use of the network changes.[86]

Avoided TUOS represents and signals avoided *costs* rather than only avoided TUOS *payments*. Even though this reduction in costs may not be reflected in revenues to the network owner in the prevailing regulatory period, when prices and revenues are re-set they will be. In addition, from society's point of view it remains efficient to provide a signal to embedded generators to locate in areas that reduce the overall *costs* of supplying electricity in the long-term.

5.4.2 Network support agreements

What is the issue?

As indicated in the previous section, embedded generators can receive network support agreements to reflect the services and benefits they are providing to the network. In addition to avoided TUOS, network support agreements can be used to reflect avoided augmentation costs to the distribution network where the embedded generator is located close to load.[87] Embedded generators are required to negotiate such agreements with network owners. If an embedded generator is not able to fairly negotiate with a network owner they may not receive payments that accurately reflect the benefits they are providing.

Findings and recommendations

Larger embedded generators are the most likely to have network support agreements and, due to their size, have sufficient capability to negotiate with the DNSP. This is predominately because larger embedded generators have increased capability to negotiate with the network business. Given network support agreements will predominately apply to these generators, and the lack of conclusive evidence in submissions, we do not consider the negotiation of network support agreements to be a barrier to DSP.

As a network owner is a natural monopoly, it is possible that it is in a stronger negotiating position relative to an embedded generator, particularly smaller

[86] ENA, Draft Report submission, p.6.

[87] For the avoidance of doubt, we consider that where a network support agreement is in place, the avoided TUOS payment referred to in the previous section is sufficient to represent any services provided to TNSPs and no other payments are necessary for that purpose.

embedded generators. However, we have not been provided with conclusive evidence to suggest there is a significant imbalance in the negotiation of network support agreements between generators and network businesses. A possible reason for this is that the majority of network support agreements will be negotiated with larger and more sophisticated generators who are better able to provide network support. Indeed, we consider that it is appropriate that larger generators and the network owner are free to negotiate terms and conditions without significant regulatory oversight. Therefore, given we have not been provided with further evidence to the contrary, we do not consider this to be an impediment to efficient embedded generation or DSP.

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6 Wholesale Markets and Financial Contracting

> **Chapter overview**
>
> This chapter is focused on the ways that customers can respond to the wholesale spot price and the arrangements that allow them to participate more directly in the market or to offer risk management products to other parties. It discusses, and compares, the costs and benefits of participating either directly in the wholesale spot market or receiving spot price pass through from a retailer.

6.1 Findings and recommendations

This section sets out our findings and recommendations in respect of wholesale markets and financial contracting. The detailed reasoning and analysis associated with these findings and recommendations is explained later in the chapter.

The Commission has found that:

- The costs of a demand-side resource participating as a scheduled load appear proportionate given the need to maintain system security and confidence in the NEM's financial arrangements.

- Customers can enter into contract arrangements with a retailer that replicate the spot price exposure of a scheduled load but at a lower cost than direct participation in the wholesale market.

- There is a barrier that limits the aggregation of loads to provide market ancillary services. We understand that a Rule change proposal is being developed on this issue. Therefore, we consider this barrier is capable of being addressed as part of the Rule making process under the NEL.

6.2 Background

Most potential demand-side service providers will normally be focused on producing goods and services rather than participating in the wholesale market. Customers use retailers to acquire energy and manage risks on their behalf in the market, and typically pay a premium for that service. However, some customers may believe they can lower their overall costs of electricity by managing the risk of market participation themselves. Therefore, rather than contracting (and paying) a retailer to manage those risks, they may choose to expose themselves to the variable wholesale spot price and make consumption decisions based on the spot price.

Customers will seek to increase their interaction with wholesale price outcomes when they perceive they can reduce costs relative to allowing a third party, such as a retailer, to manage risks and purchase electricity on their behalf. There are many ways in which customers can participate in the wholesale market, including indirectly through financial contracting. The analysis in this chapter focuses on three such mechanisms:[88]

- DSP as a scheduled load in the energy market;
- DSP as a market ancillary service[89]; and
- DSP as a hedging tool for retailers.

6.3 Market participation procedures and costs of participating

Customers can obtain exposure to the spot price by either participating directly in the wholesale market as a scheduled load or by contracting with their retailer to pass through the pool price. To promote an efficient level of participation amongst those customers wishing to engage actively in the wholesale market, it is important that the costs and obligations of participation are reasonable and proportionate.

The remainder of this section considers the costs and obligations of DSP directly in the wholesale market and alternatively through a retailer. It also considers whether these costs and obligations present a barrier to DSP in the wholesale market or via a retailer.

6.3.1 Costs and obligations of participating directly in the wholesale market

What is the issue?

Buyers and sellers trade wholesale electricity via a pool. Generators make offers into the pool to sell electricity, and market customers (i.e. retailers and scheduled loads) may make bids for each five minutes of the day. The market is then settled every thirty minutes. Customers wanting to participate as a scheduled load or an ancillary service load must comply with market operating procedures and, in doing so, necessarily incur costs. If the costs for customers to participate are in excess of those required to ensure a secure and reliable supply of electricity, the demand side may be inefficiently excluded from participating.

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88 In addition to the mechanisms identified here, customers under contract to provide network control ancillary services can also be used by AEMO to enhance the value of spot market trading, however, this does not occur in practice. As AEMO is reviewing this function in its current Review of Network Support and Control Services we do not consider this aspect of DSP in this Draft Report. See http://www.AEMO.com.au/powersystemops/168-0089.html for more information about AEMO's review.

89 Ancillary services are services, such as frequency control, procured by AEMO to assist in maintaining system security.

Findings and supporting analysis

The arrangements in the Rules for participating in the wholesale market are, broadly, necessary for the secure and reliable operation of the system and are therefore not a barrier to DSP. However, we understand a proposal for a Rule change is being developed relating to a minor barrier regarding the aggregation of ancillary service loads. Given the intention of either market participants or AEMO to submit a Rule change to the Commission, we consider this minor barrier can be addressed through the normal Rule change process.

Costs incurred to participate

The costs that are incurred by DSP proponents appear largely proportionate and are appropriately premised on maintaining AEMO's ability to preserve a secure and stable market environment. In addition, applying a common set of standards between scheduled loads and scheduled generation promotes an efficiency principle that the market should be designed to be technology neutral.

To be a scheduled load or to provide an ancillary service, a customer would need to incur the following costs:

- Registration costs – required for a customer to register as a Market Customer and to request AEMO to classify its facility as a scheduled load. These are required due to the administrative costs of registering a participant and also to ensure that only serious participants seek registration.[90]

- Market fees – market fees are fees payable to AEMO to participate in the market. These are the fees that fund the operations of AEMO.

- Metering and communication – customers need to install detailed metering and telemetry to allow AEMO to communicate its five-minute dispatch instructions to scheduled and ancillary service loads.[91]

- Other ongoing participation costs – these costs include obtaining market information and monitoring spot market outcomes.

We consider these costs are appropriate so as to allow AEMO to effectively preserve a secure and stable market environment. Therefore, a customer that is seeking to participate directly in the wholesale market would first need to consider these costs before determining whether it would be economic to participate.

The majority of submissions supported the view that the costs in the wholesale market are appropriate and apply equally to all participants.[92]

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90 Clause 2.3.4 of the Rules sets out the requirements for registration.

91 Customers would also need to have appropriate metering to participate through a retailer, however, these customers are not required to communicate with third parties such as AEMO.

92 NGF, Draft Report submission, p.3; ENA Draft Report submission, p.6; Energy Response, Draft Report submission, p.3.

TEC indicated that the costs of participating were a barrier because generators can afford these costs while customers cannot.[93] However, this does not constitute a barrier to entry. Instead, this means that participation in the wholesale spot market may be less economic for customers. Therefore, customers may be better served by identifying other ways to manage their electricity costs rather than through direct participation in the wholesale market.

Market operation rules and procedures

There are a number of practical limitations in the market rules and procedures for participating in the wholesale and ancillary services markets that may provide a disincentive for customers to participate. However, while these rules and procedures may increase the cost of participation of DSP, their primary purpose is to provide AEMO with sufficient scope to manage its requirements to maintain system security and supply reliability. Therefore, we consider these requirements to be broadly appropriate.

In every market there are rules about how the market operates and obligations on those parties that wish to participate. Rules and obligations are developed for markets to ensure they function well and achieve any other desired outcomes such as meeting technical or safety requirements. Due to the instantaneous and non-storable nature of electricity, the wholesale market rules and procedures for its operation are relatively prescriptive and place strict requirements on participants.

Like a scheduled generator, a customer who decides to participate directly in the wholesale market would need to register with AEMO and be able to respond to dispatch instructions. The market rules and procedures exist to ensure that AEMO can dispatch the market so that supply meets demand in a safe and secure manner. Some practical limitations that may exist for customers to participate effectively include:

- Unlike generators, many large loads are comprised of large discrete load blocks and are unable to reduce consumption in single unit increments (i.e. 1 MW). Therefore, they have reduced flexibility in being able to meet dispatch requirements from AEMO.

- Separate bids to provide Frequency Control Ancillary Services[94] (FCAS) must be submitted to AEMO for each load providing market ancillary services unless they are also scheduled loads. This is the case even if it is technically possible for a single bid to be made for a collection of loads.

- In order for an intermediary, like a customer aggregator, to provide a market ancillary service, all the aggregator's customers must be registered individually with AEMO as scheduled loads. The aggregator cannot participate on behalf of its customers without all those customers also being registered as a scheduled load with AEMO.

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93 TEC, Draft Report submission, pp.8-9.

94 There are eight FCAS markets – "raise" and "lower" service markets for each of the four types of FCAS. For the purpose of the Rules FCAS is referred to as a Market Ancillary Service.

- The difference between dispatch on a five minute basis and settlement on a thirty minute basis means that the dispatch price and the settlement price may be different. This means that there can be differences between a customer's offer price and its settlement price. This difference in price can expose customers to the risk of being dispatched a price that is different to the price the customer offered in its demand reduction.

There are, however, a number of actions that a demand-side proponent can take to overcome some of the practical operational issues identified above. A customer could install multiple meters, use the rebidding arrangements, or the Dispatch Inflexibility Profile[95] to manage their inability to register only part of the total load. It is recognised that undertaking such actions would be likely to increase the costs of DSP. It should be noted that many of the practical difficulties identified above also apply to the generation side and therefore cannot be characterised as a barrier to DSP. This relates, in particular, to the differences between dispatch and settlement, which Energy Response reaffirmed was a concern for DSP.[96] Energy Response indicated this was a bigger issue for customers due to their relatively higher marginal costs. However, this issue exists for both generators and customers, hence the market framework does not place customers in a worse position relative to generators.

In the Draft Report we had identified two other potential practical limitations in the market rules and procedures. However, following advice in the AEMO submission, we are of the view that these problems do not exist, or can be overcome.[97]

The first of these issues related to the prudential obligations that are necessary for scheduled loads or ancillary service loads. In the Draft Report we indicated that the requirement for scheduled loads or ancillary service loads to be registered as a market load meant they had to adhere to additional obligations such as prudential requirements. However, AEMO indicated that if a customer was to become a discrete market load, but remained supplied by its local retailer, then the retailer's prudential obligations should remain unchanged. We support AEMO's reasoning on this issue.

The second issue related to the need for customers to register all of their load and whether, in that circumstance, the entire load would need to respond to dispatch instructions. We agree with AEMO that a scheduled load can avoid this by structuring their bid such that the part of the load that cannot respond to a dispatch instruction is priced at the market price cap. Market bids and offers at this price cap are dispatched only in extreme circumstances. This means scheduled loads can effectively manage portions of their load in the majority of instances.[98] While DSP

95 Dispatch Inflexibility Profile is data provided to AEMO which specifies the limitations or "inflexibilities" of a scheduled load (or scheduled generating unit). The scheduled load provides the data to AEMO in accordance with clause 3.8.19 of the Rules.

96 Energy Response, Draft Report submission, pp.-5-6.

97 AEMO, Draft Report submission, pp.7-9.

98 However, if the load was dispatched it would receive the maximum benefit that is available in the wholesale market, i.e. prices at the market price cap.

providers would still face some risks in this situation, given the limited circumstances of the market price cap being reached, we consider this risk to be low.

The Draft Report also identified a Rule change that AEMO indicated it would propose to the Commission. This related to whether ancillary service loads and scheduled loads must be market loads. In their submission, AEMO indicated that it now considers that the Rules do not prohibit local retailers classifying market loads within their load area. Therefore, AEMO are no longer intending to propose a Rule change in this area.[99]

6.3.2 Costs and obligations of participating through retailers

What is the issue?

An alternative way for customers to obtain direct exposure to the spot price is to have that price passed through by retailers under the terms of a retail contract. This would expose customers to the half-hourly fluctuations in price instead of retailers managing this risk for them and charging a premium for doing so. As with participating as a scheduled load, there are costs and obligations associated with participating through a retailer. In order to offer an efficient and viable economic alternative for DSP as a scheduled load, it is important for these costs and obligations to be efficient. If such costs were found to be inefficiently high, there may be scope to reduce them to promote an efficient level of DSP through retailers.

Findings and supporting analysis

The direct costs of obtaining spot price exposure through a retailer are low. In addition, customers who participate through a retailer can obtain the same benefits that would be available through participation in the wholesale electricity market. Therefore, customers that wish to be exposed to the wholesale spot price can do so through a retailer and avoid the costly and extensive technical market rules and procedures. Evidence from submissions and through the DSP Reference Group has identified that such spot price pass through contracts are available in the market.

Costs incurred to participate

Our analysis indicates that the costs of participating through a retailer are relatively low. Customers have to negotiate contracts with retailers irrespective of whether or not they are seeking a spot price pass-through contract. It is unlikely, therefore, that this imposes a substantial new cost on a customer. Exposure to the spot price may increase the costs to customers to manage their energy use. However, their contract negotiation costs, and retail management costs, may be lower because the level of risk protection, and therefore involvement from the retailer, is lower.

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99 AEMO, Draft Report submission, p.7.

The key cost to obtaining spot-price pass-through with a retailer appears to be the resources to monitor energy prices and to directly manage the associated risks of exposure to spot price volatility. This management includes determining when and how to curb consumption when the cost of electricity exceeds the value of consumption. An alternative option is for the customer to purchase financial contracts to manage its spot exposure at peak periods.[100] While these costs may be significant, a customer is only likely to take on these costs because it considers it can manage the associated risks better and more cost-effectively than paying an intermediary, such as a retailer, to manage them.

Participation through a retailer also has the potential to lower the costs of managing the risk of spot price exposure relative to being a scheduled load. For example, this form of participation avoids the risk of being dispatched at times that do not reflect the load's true value.[101] In addition, customers can negotiate the extent of that exposure with retailers by agreeing to caps on the size of the gains or losses.

Submissions on this issue supported the view that the costs of participation through a retailer are appropriate and a preferred form of participation compared to directly in the wholesale spot market.[102] As noted by one submission, participation through a retailer potentially widens the scope of participation to smaller loads that would find it difficult to manage participation in the wholesale spot market.[103]

Rules and procedures for participation

The rules and procedures for participation through a retailer are effectively only those that are specified in, or consequent to, the contract with the retailer. Therefore, customers can achieve the same exposure to the wholesale spot price without being constrained by technical market rules and procedures that may be necessary for AEMO to ensure system security and reliability.

In terms of rules and procedures, participation through a retailer is relatively straight forward. A customer would need to request spot price exposure with its retailer and the retailer would bill them based on the spot price at the time of use. An interval meter would be required to measure the electricity use in the appropriate increments. This form of participation provides the customer with the freedom to decide if it wants to consume or not at any time. As discussed above, the customer would inform its consumption decisions based on the energy prices, which it would need to monitor as the costs of a delayed response during a high-price period could be substantial.

100 For instance, a customer could purchase a product that provides a capped price should the spot price reach a certain level.

101 This can occur where a dispatch instruction from AEMO makes a customer either constrained-on or constrained-off. These situations mean that a customer can be dispatched either above or below their true value.

102 ENA, Draft Report submission, p.6; NGF, Draft Report submission, p.3.

103 NGF, Draft Report submission, p.3.

On this basis, we consider that spot price pass-through contracts with a retailer afford customers similar benefits to those from being a scheduled load with the potential for lower costs and greater flexibility.

6.4 Remuneration for providing DSP

The previous sections outline the market procedures and costs of participation in the wholesale market, either directly or with a retailer. However, the demand-side will not actively participate if it is not able to obtain appropriate compensation (or remuneration). In the absence of adequate remuneration there may be an inefficient amount of DSP. The two areas where customers could receive remuneration or benefits are:

- direct participation in the wholesale market or ancillary services market; or
- selling financial contracts to retailers.

This section will consider if the remuneration and benefits available through each of these options are efficient and provides appropriate incentives for the demand side to participate.

6.4.1 Remuneration in the wholesale market

What is the issue?

Customers who participate directly in the wholesale electricity market will obtain a benefit of avoiding electricity prices when they are higher than the benefit they would obtain from consumption. That is, customers will bid an amount that reflects when it is beneficial to reduce or stop consumption and will avoid paying for electricity at that time.

The avoided cost is capped at the market price cap[104] (MPC), which is currently set at $10 000/MWh[105] and limited to the customer's wholesale market bid. The issue, therefore, is whether this remuneration is sufficient and whether DSP providers should receive an additional payment for providing services to the wholesale market. Some stakeholders consider that a multi-settlement market is necessary so that demand-side providers can be appropriately remunerated in the market.

Findings and supporting analysis

Customers will provide demand-side services to the wholesale market and ancillary services market when the benefits they obtain are greater than the costs they incur. The price in the wholesale and ancillary services market provides this signal to the

104 The market price cap was formally known as the Value of Lost Load.

105 Clause 3.9.4(a) of the Rules establishes a price cap, clause 3.9.4(b) of the Rules fixes the level to $10 000/MWh. We note that as of 1 July 2010 the market price cap will be set at $12 500/MWh.

demand-side and supply-side on an equal basis. Therefore, the available remuneration does not present a barrier to DSP. In addition, we do not consider that DSP should be subject to an uplift payment when its use reduces overall spot prices. This is because any reduction in price will be a wealth transfer between customers and generators.

Remuneration available in the wholesale market

The remuneration available to customers to participate in the wholesale market is the avoided cost of the prevailing wholesale price. A customer will be willing to reduce consumption, and avoid this cost, where it is higher than the value the customer placed on consumption. In this circumstance, the customer is fully compensated for the value that it would have obtained had it consumed.

We consider the price, or avoided cost, that the customer receives from the wholesale market is efficient. Prices in the wholesale market reflect the marginal cost of supplying electricity at a point in time. The price is, therefore, efficient and customers should not be expected to pay more than this price. Given the wholesale price reflects the efficient price, and hence cost of electricity, it is also the right signal, or remuneration, to be provided for DSP.

We recognise, however, that despite the market price cap being particularly high, its existence means DSP that costs more than the cap is unable to participate in the market.[106] This can create inefficiencies if the real cost of maintaining reliability is higher than the market price cap.

There are reasons, however, that a market cap is used in the market. The main reason for the market cap is it limits the overall risk exposure in markets. Given the non-storable nature of electricity, and hence the prospect of large price spikes, this risk is likely to be significant. Managing risks can incur significant costs for participants, which would ultimately be paid for by customers.

In addition, as will be discussed in the following chapter, there are mechanisms outside the market, such at the RERT, which are well suited to DSP that is valued higher than the market price cap.

While increasing, or removing, the market price cap may increase participation for DSP and some generation, given the other risks this would create, it is unlikely to improve the efficiency of the market.

Impact of load reduction on the wholesale price

In certain circumstances a large reduction in load from a customer may influence the wholesale spot price. However, we do not consider there is an efficiency argument to pay customers who provide DSP an additional up-lift payment in this situation.

106 This is the same for generation that costs more than the market price cap.

A reduction in wholesale prices caused by DSP will create a wealth transfer between remaining customers and generators.[107] The price will fall due to DSP if the identity (and cost) of the marginal producer has changed. The result of this is that, in aggregate, the remaining load will pay less and remaining generation will in turn be paid less. This outcome is a wealth transfer between customers and generators. Therefore, there is no overall improvement in efficiency, and hence no efficiency reason for an additional payment to be made for DSP.

In addition, as noted above, this is also the efficient price signal for DSP. Customers will provide DSP where the savings from reduced consumption (the benefits of DSP) outweigh the value that would have been derived from consuming (the costs of DSP). Therefore, the efficient price for DSP is the price that compensates customers for the 'costs' of providing DSP. Customers will factor in any change in the wholesale price before deciding to offer their DSP to the market. Therefore, any additional payment would be higher than the cost of providing DSP.

Multi-settlement markets

FEMG submitted that experience in two-settlement markets suggest that they can greatly facilitate better demand-side engagement.[108] FEMG notes that in two-settlement markets retailers and customers can fix their position in the organised day-ahead market and sell back their position in real time.

We recognise that uncertainty over the spot price might cause difficulties for DSP. For instance, an instantaneous spot market can create uncertainty about whether there would be benefits from incurring the costs to prepare to respond. This is particularly the case when preparations and costs need to be incurred a day, or several hours, before participation.

A day-ahead market can overcome the uncertainty problem for DSP. Day-ahead markets enable, or require, the supply-side and the demand-side (usually through retailers) to contract for electricity the day before it is sold. A spot market is then used on the day of consumption to allow for differences between contracted amounts in the day-ahead market and actual amounts. This type market of would provide certainty to customers about the value of their participation at a certain time with sufficient notice. This is because information can be provided before customers incur the costs to enable load to be curtailed or cut.

However, we consider that the same outcomes can be achieved through participation in the short-term financial market. Such a market is effectively providing the same service that a day-ahead market is. That is, customers and the supply-side would be agreeing on the timing and price of a service, through contracts, at a period prior to the DSP being provided.

We note, in addition, that developing a mandated day-ahead market would incur costs. Given the customers can undertake similar financial trades to those that would

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107 Assuming that all participants make offers and bids at cost and that the network is unconstrained.

108 FEMG, Draft Report submission, p.3.

occur in a multi-settlement market, we do not consider imposing such development and market change costs on customers and the market would be efficient.

Capacity markets

The Ethnic Communities' Council of NSW considered that a capacity market would better support DSP by improving the participation of the demand-side and as a consequence reducing the potential for generators to control the pool price.[109]

Capacity in the NEM is signalled through the energy only market. The spot price provides the signal for capacity to enter the market so that supply meets demand. For instance, a consideration in setting the market price cap is whether it will incentivise sufficient capacity to meet the target reliability standard of 0.002 per cent average unserved energy. To date this market framework has been able to signal the need for capacity such that sufficient levels of reliability have been provided.

Given remuneration in the existing market has been sufficient to deliver desirable levels of reliability, and it applies to generators and customers equally, we cannot conclude that the energy only framework is biased against DSP.

It may be claimed that formalised arrangements for contacting capacity, as occurs with capacity markets, can increase revenue certainty for DSP. However, revenue certainty that occurs through capacity markets can also occur in the energy only market. In energy only markets this occurs through financial contracting. As with a capacity market, customers can contract with other parties to provide capacity at a point in time in the future. The difference being that the energy only market does not regulate how this occurs.

Market ancillary services

Demand-side participants can also receive revenue by registering as an ancillary services load and providing FCAS. To provide FCAS, an ancillary services load must register with AEMO for each of the separate FCAS markets in which it wishes to provide services. For each market in which they are registered, an ancillary services load can make bids into the market to provide services.

Remuneration is provided to demand-side and supply-side participants on the basis of competitive bids and offers. An ancillary services load will be enabled and remunerated if its bid price is no greater than the clearing price. This market framework, similar to the wholesale market, ensures that ancillary services are paid based on their efficient costs. In addition, all participants are remunerated in the same manner. Therefore, there is no bias towards or against demand-side providers.

109 Ethnic Communities' Council of NSW, Draft Report submission, pp.1-2.

6.4.2 Remuneration by financial contracting with retailers

What is the issue?

Retailers have an interest in minimising their exposure to volatile spot prices. This is because the majority of their customers do not have, or want, retail tariffs that expose them to volatile prices. To help manage their risk, retailers can contract with demand-side providers for those providers (or customers) to change their consumption decisions during times of high spot prices.

In these contracts, the customer effectively agrees to take on some of the retailer's market risk. The customer charges the retailer a premium for this service. The question is whether this premium allows for a fair remuneration for the services provided.

Findings and supporting analysis

Payments from a retailer to a customer for a demand-side service are negotiated between the parties. Therefore, a demand-side service will only be provided by a customer when it is satisfied that the remuneration it receives is enough to compensate for costs incurred. It is the availability of this choice to customers that means there are no impediments to receiving adequate remuneration from retailers when a service is provided.

Retailers contract with customers in order to influence the timing and volume of their consumption. Payments made by a retailer are negotiated between the retailer and the customer. The customer needs to be satisfied that it will be adequately compensated for the services it is providing, otherwise it would have no incentive to change its consumption behaviour. Both the retailer and customer can benefit commercially from these contracts.

The size of the payment made to customers to encourage them to change their consumption decisions depends on the benefits that these customers receive from consuming electricity and the value of the demand reduction to the retailer. Similar to DSP for networks, the customer receives a benefit equal to its avoided energy charge, and then any additional payment made to the customer is required to compensate the customer for the benefits they would have obtained by consuming.

The retailer will agree to pay the customer the amount required where the benefit the retailer obtains is greater than the cost of purchasing the demand reduction from the customer and where it offers net benefits compared to other alternatives. Examples of the services that can be provided to retailers and the benefits retailers and customers can derive are provided in Appendix E.

We understand from our discussions with retailers and through the DSP Reference Group that the major deterrent to the use of DSP in this form is the price being sought by customers to provide the service. When developing a financial portfolio to manage risk, a retailer has a choice between generation options and demand-side options. The retailer has a financial incentive to choose the cheapest option that achieves their desired outcome. If the price being sought for DSP is higher than the price for a generation option, or any other alternative, a retailer will pick the generation option and this will be an efficient decision. Therefore, to the extent that retailers are perceived to not be using enough DSP, we do not consider that this is due to any barriers in the Rules but is most likely driven by the high price of DSP services relative to alternatives.

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7 Reliability

Chapter overview

This chapter considers the mechanisms that are used to achieve reliability when sufficient capacity cannot be obtained through the energy market to achieve reliable supply. It presents our findings and supporting reasoning on whether these mechanisms unduly limit the ability of DSP to contribute to meeting the NEM reliability standard. Specifically, this chapter considers the design of reliability mechanisms and when they are applied.

7.1 Summary of findings and recommendations

This section sets out our findings and recommendations in respect of the use of DSP to maintain reliability. The detailed reasoning and analysis associated with these findings and recommendations is explained later in the chapter.

The Commission has found that:

- There is a barrier with regard to how AEMO manages reliability in the very short term. The barrier is the absence of a mechanism for paying electricity users who are not "scheduled" market participants, but who are willing to modify their behaviour if requested. However, we consider this barrier will be overcome by the recently made 'Improved RERT Flexibility and Short-notice Reserve Contracts' Rule.

- AEMO's market intervention role should not be extended to procuring a "standing reserve" of DSP because of its likely distorting effect on the market, including the routine participation of DSP in the market.

- There are two additional areas where further reform is required: the provision of information to AEMO on volumes of DSP already present in the market, and the processes to register small-scale embedded generation. As part of the Review of Energy Market Frameworks in light of Climate Change Policies, the Commission recommended AEMO undertake a work program to address these issues.

7.2 Background

The role of the market and the Reliability Panel

In the NEM, the primary means of delivering reliability is through investment decisions by market participants based on whether investment in new capacity is profitable. The profitability of new investment will depend on expected wholesale market spot prices (and associated contract prices), which in turn depend on scarcity. If there is already excess capacity, then spot and contract prices will be expected to be low – which will signal new investment as unprofitable. Conversely, if capacity is scarce, then spot and contract prices will be expected to be high – and there will be a profit signal for new investment.

Investment could take the form of new generation, or investment in building capability for new, 'firm' demand-side response. Generation capacity and demand-side response are potential substitutes for each other. The scope for DSP to participate in the wholesale market was discussed in the previous chapter.

The NEM is an "energy-only" market. This means that generators are only paid for the energy they produce; they are not paid for being available. One consequence of this market design is that prices are volatile. If demand is high and capacity is scarce, then prices can be extremely high. Expectations of these periods of extremely high prices are the main driver for investment.

However, the maximum price in the energy market is regulated. The level at which it is set therefore significantly influences whether expectations of high prices are high enough to make investment in new capacity profitable. The Reliability Panel has the role of reviewing and recommending the level of the maximum price to ensure that it can signal as profitable a level of capacity consistent with meeting the reliability standard, having regard to the costs of new investment. This process can result in Rule change proposals to amend the maximum price, such as occurred through the Rule proposal and subsequent determination to increase the maximum price from $10 000 per MWh to $12 500 per MWh from 1 July 2010.[110]

The role of AEMO

If the market delivers a level of capacity consistent with the reliability standard, then AEMO's role is limited to dispatching the market based on bids and offers. However, the Rules provide for a "safety net" for circumstances in which the market does not deliver enough capacity. AEMO can intervene under these "safety net" provisions in three ways:

- First, by using its power of direction AEMO can require any scheduled plant or market generating unit to provide additional energy capability, which would typically be done close to real time, although no specific limitations apply to time frames for direction.

- Second, up to nine months ahead of real time AEMO can use the RERT[111] mechanism to procure additional reserve generation or demand-side response that may be required to meet the minimum reserve levels at times of forecast peak demand.[112] It characterises peak demand for these purposes as a '1-in-10 year' peak, based on historical data.

110 AEMC 2009, *National Electricity Amendment (NEM Reliability Settings: VoLL, CPT and Future Reliability Review) Rule 2009,* Final Rule Determination, 28 May 2009, Sydney.

111 The RERT is established under clause 3.20 of the Rules. Under the Rules, the RERT arrangements are set to expire in mid-2012. Its continued operation beyond that time is to be assessed by the Reliability Panel in 2011, although if the Reliability Panel perceives there are benefits in the RERT arrangements continuing, it could submit a Rule change proposal to the Commission.

112 AEMO has twice contracted for, but has not been required to dispatch, reserve capacity in order to ensure that summer peak demand is met. Contracts for reserve were entered into for the summers of 2004/05 and 2005/06 using the forerunner to the current RERT mechanism.

- Third, AEMO is able to draw on a panel of providers that can be called upon to provide additional capacity at short notice. The panel arrangements allow AEMO to procure reserves ten weeks or closer to the time that reserves may be required.

7.3 The ability of DSP to respond to AEMO interventions

What is the issue?

The issue is whether the design and operation of the Rules which permit AEMO to intervene in the market to manage reliability are likely to make efficient use of available DSP or not.

Findings and supporting analysis

The RERT, in its current form, provides a route for DSP which is not currently active in the market to provide services in support of reliability when it has most value to the market. However, prior to the introduction of a short-term RERT there was not an effective instrument for paying electricity users to provide reliability services close to real time. This was primarily because customers that are not scheduled cannot be compensated for directions under the Rules.

The introduction of a short-term RERT overcomes this issue by enabling reserve procurement ten weeks or closer to the time that the reserves may be required. This is achieved by allowing AEMO to use a panel of providers that can be drawn upon at any time. As a result, the short-term RERT overcomes the gap in the previous arrangements whereby opportunities for targeted intervention were lost due to timeframe constraints.

Within the limitations of contracting up to nine months ahead, DSP is likely to be one of the primary responses available for the RERT. Generation capacity already in the market is not generally eligible to tender for the RERT, and the maximum of nine months notice means that there is only a limited scope to influence new generation investment. That is, only if a new plant is already under construction, and the commissioning date is capable of being brought forward. Therefore, the RERT can effectively incorporate DSP and thus is not an impediment to its efficient use.

The RERT, when it is invoked, provides an opportunity for DSP because it enables the costs of establishing the demand-response capability to be recovered in full and with certainty if the tender is chosen. The RERT allows for payments to be made for availability, and does not constrain the price at which the additional capacity can be offered, other than through the maximum limit jurisdictions decide they are willing to pay. This contrasts with the energy market, where payments are only made for energy and the price is capped at a maximum of $10 000 per MWh.[113] Hence, an

113 As noted previously, the Commission has made a Rule to increase the market price cap from $10 000/MWh to $12 500/MWh, effective from 1 July 2010.

investment to create a demand-response capability under the RERT is a less risky proposition (and requires less technical knowledge of the energy market) than an investment predicated on cost recovery through the energy market.

As acknowledged in a Reliability Panel Rule change proposal and subsequent Rule determination from the Commission, the RERT had an operational limitation in that it could not be used in periods closer to dispatch.[114] This is because the RERT requires sufficient time for tenders to be issued and contract negotiation to be undertaken. A tool that can be used by AEMO in the absence of a short-term RERT is the directions power.[115] However, unless a customer is scheduled with AEMO, they are unable to receive compensation from directions. Absent the introduction of a short-term RERT, this deficiency would create a barrier towards using DSP in periods of short notice.

Submissions to the Draft Report agreed that the lack of arrangements to compensate unscheduled loads inhibited the efficient use of DSP.[116] In this context some support was provided for the development of a RERT panel.[117] We note, however, that submissions to the Reliability Panel's Rule change proposal, "Improved RERT Flexibility and Short-notice Reserve Contracts", raised a number of issues with the proposed Rule. The issues raised included: the administrative costs of the scheme, interactions with the contract market, and the scope for potentially increased market distortions. The Commission's response to these issues can be found in the associated Rule Determination.[118]

7.4 The scope of AEMO's market intervention powers

What is the issue?

AEMO's current powers to intervene in the market to manage reliability are limited. They are only to be invoked when there is compelling evidence of the market failing to present the required level of capacity – and actions are limited to the short term. The RERT can only be invoked nine months or less ahead of real time. Directions are generally only used very close to real time.

114 See: http://www.aemc.gov.au/Electricity/Rule-changes/Completed/Improved-RERT-Flexibility-and-Short-notice-Reserve-Contracts.html

115 A direction is a requirement from AEMO, or a person authorised by AEMO, to do any act or thing if AEMO is satisfied that it is necessary to do so to maintain or re-establish the power system to a secure, satisfactory or reliable operating state.

116 NGF, Draft Report submission, p.4; TEC, Draft Report submission, p.9; AEMO, Draft Report submission, p.8; Energy Response, Draft Report submission, p.3.

117 AEMO, Draft Report submission, p.8; TEC, Draft Report submission, p.9.

118 See: http://www.aemc.gov.au/Electricity/Rule-changes/Completed/Improved-RERT-Flexibility-and-Short-notice-Reserve-Contracts.html

The issue is whether there is a case, based on more efficient use of DSP, for increasing the range of circumstances under which AEMO participates in the market to buy capacity. We consider two options for achieving this:

- first, amending the existing RERT to enable AEMO to trigger it up to two years ahead of real time; and

- second, an obligation on AEMO to procure on an ongoing basis a “standing reserve” of additional capacity in each region.

Findings and supporting analysis

We do not consider an extension of AEMO’s powers to intervene in the market can be justified solely on the basis of promoting more efficient use of DSP. Obliging AEMO to buy additional reserves more frequently would represent an artificial demand for reserve created through regulation, and would be likely to detract from overall efficiency and increase costs to consumers. A “standing reserve” risks making unnecessary availability payments to capacity and distorting the information available to potential investors about the amount, level and form of capacity that is required by the market.

A longer-term RERT

Extending the timeframe of the RERT from nine months to two years would be likely to have the following effects:

- It would require AEMO to forecast likely capacity reserve levels further in advance. This is turn would increase the likelihood of the RERT being triggered in error, given the inherent difficulties in forecasting and the fact that the forecasts are updated annually.

- It could increase the pool of potential parties who could tender for the RERT to include any sources of capacity that can be delivered with more than nine months but less than two years notice. This could include new generation investment where the commissioning date is capable of being brought forward, or DSP which involves reorganisation of business processes requiring more than nine months to organise and deliver.

- It could create an opportunity for existing planned capacity to be reallocated to the RERT, as a more profitable alternative to participation in the energy market without necessarily increasing the amount of available capacity.

Any increase in the error rate with which AEMO invokes its intervention powers is likely to reduce efficiency. Too frequent use of RERT increases AEMO’s costs, and therefore costs to consumers.[119] There are two types of costs that will be passed through to customers. First, the direct cost borne by AEMO in making payments to

[119] There are also risks associated with too infrequent use of RERT, e.g. the heightened risk of unserved energy. However, this risk would not be affected by an increase in the timeframes for RERT from nine months to twelve months or longer.

parties contracted under RERT. Second, the indirect costs imposed on other market participants. When RERT capacity is actually utilised by AEMO, the Rules stipulate that the market should operate as if the RERT capacity had not been used. This is intended to maintain the integrity of the price signals for new investment. However, it also means that market participants have the same risks of high price events to manage, but with fewer options for doing so if the RERT has attracted capacity that would have otherwise participated directly in the market. Hence, it also presents retailers with uncertain additional costs which cannot be hedged, increasing the overall risk of retailing as an activity.

A "standing reserve"'

A "standing reserve" is a generic term to describe an ongoing obligation on AEMO to buy a set amount of capacity. The capacity is for use by AEMO in limited, prescribed circumstances when capacity is tight. By definition, it involves capacity being withdrawn from the energy market to be on 'stand-by'. As with the RERT, contracted capacity would be required to be quarantined from the energy market.

Establishing this form of standing reserve has a number of implications and characteristics worth noting:

- First, it retains the same incentives on market participants to procure sufficient capacity to meet the reliability standard, but reduces the pool of options for doing so. This is because expectations of high prices are unaffected by the establishment of the standing reserve, but some of the potential means of hedging against these prices have been diverted to the standing reserve (i.e. bought up by AEMO).
- Second, if the market responded to the (unchanged) incentives to deliver adequate capacity, then the cost of operating the standing reserve would be a net additional cost to consumers with no benefit.

If we consider the potential cost of this measure against the potential benefits from the perspective of reducing barriers to DSP, then the measure cannot be supported. There are four main reasons:

- First, to the extent that DSP can provide reliability capacity, then this will have a value in the energy market. Any DSP which is, or can be made, commercially viable through this route does not face barriers that would be removed through the establishment of a standing reserve.
- Second, the existing RERT process provides for DSP to be contracted when there is strong evidence of the market failing to deliver sufficient capacity, and where DSP is the most economic means of plugging the gap. Similarly, this category of DSP does not face barriers that would be removed through the establishment of a standing reserve.
- Third, while a standing reserve may reveal new sources of DSP capacity (i.e. which can only be established at more than nine months notice), the associated costs of accessing these by creating a standing reserve appear disproportionate

given the lack of evidence that the market is failing to deliver levels of capacity consistent with meeting the reliability standard.

- Fourth, we do not consider it appropriate to establish a standing reserve as a development mechanism for nascent DSP. Given the existing incentives that the market provides for revealing efficient forms of capacity, including DSP, such a rationale would represent an unnecessary wealth transfer from consumers to DSP providers. This is not consistent with the NEO.

AEMO and Energy Response commented on this issue. AEMO supported our findings, stating that extending the outlook horizon of the RERT beyond nine months is problematic.[120] Energy Response, however, indicated that there is no evidence to suggest that the RERT will increase costs to customers.[121]

The basis for our analysis that the RERT increases costs to customers is that each time the RERT is applied, costs will be higher than if the capacity had been supplied by the market. This is because the RERT will only be used to attract capacity that has not been willing to offer itself to the market below the market price cap. In addition, in this circumstance, contracted parties are paid an availability payment (which Energy Response indicates has, in the past, been $40/MWh[122]). Hence, costs above the market price cap, plus availability payments (which are not received by those who participate directly in the market) will increase costs to customers relative to relying only on the wholesale electricity market.

7.5 Accuracy in the use of AEMO's market interventions

What is the issue?

Intervention mechanisms such as the RERT require AEMO to make a decision on whether the mechanism should be used or not. These decisions are significant for DSP because DSP is likely to form a significant proportion of the responses to a RERT tender exercise. It would be efficient for the market if AEMO invoked the RERT accurately and with consistency, and only at times when there is a very strong probability of a reserve shortfall. It should be recognised that this is not a straight forward task, given the uncertainties around forecasts of both demand and supply.

The issue is whether there are improvements that can be made to the processes and information used by AEMO to determine whether to invoke the RERT or not.

Findings and supporting analysis

We have found that AEMO has to rely on relatively poor information on actual levels of DSP present in the market in assessing whether the RERT should be exercised or

120 AEMO, Draft Report submission, p.8.

121 Energy Response, Draft Report submission, pp.6-7.

122 Energy Response, Draft Report submission, pp.6-7.

not. This appears likely to increase the chance of error by AEMO. We recommended, as part of the Review of Energy Market Frameworks in light of Climate Change Policies, that the AEMO's ability to forecast reserve shortfalls be enhanced by strengthening the quality of demand-side capability information available to AEMO through improved reporting. It was recommended that AEMO establish a working group to explore:

- the obligations on parties to report demand-side capability information to AEMO, including the timeframes for such reporting; and
- the forms of information most valuable to AEMO for demand forecasting:
  - including enabling AEMO to make probabilistic assessments of DSP at times of peak demand; and
  - the reporting of which is not too onerous for the reporting party.

If DSP is estimated poorly, then there is a risk of the actual reserve margin being overstated or understated. If the reserve margin is overstated, then there is a risk that AEMO errs by not invoking the RERT when intervention is required to preserve power system reliability at times of peak demand. If the reserve margin is understated, then there is a risk the AEMO errs by invoking the RERT when it is not required to preserve power system reliability.

There are two potential features of the current arrangements that make these errors more likely than they need to be:

- The terms of the relevant Rules are not sufficiently clear to guarantee that AEMO is provided with full and accurate information with respect to the level of contracted demand-side resources.[123]

  Respondents to the AEMO DSP survey are not under any formal obligation to identify all their DSP capability. Given that DSP under the control of a market participant can have substantial commercial value at times of market stress, commercial advantage may be lost if the extent of DSP under control was fully revealed to the market. Accordingly, there may be incentive to under-report actual DSP capability.

- The use by AEMO of only "committed DSP" and entirely discounting non-committed DSP is likely to produce conservatively low estimates of DSP.

  The volume of DSP reported by AEMO and applied as an offset to native demand, represents the total of individual contracts surveyed parties have indicated to be "committed (or firm) DSP" – that is, a block of DSP with a very high probability of being dispatched in response to adverse market conditions during a high demand period. AEMO also gathers information on

123 The AEMO submission to the 1st Interim Report of our Review of Energy Market Frameworks, p.8, identified a likely proliferation of embedded generation as a problem in demand forecasting.

"non-committed DSP"[124], but this component is entirely discounted in assessments of peak demand (and reserve).

Under-estimation of the volume of available DSP at times of system peak represents a conservative assumption from a reliability perspective. It is likely to result in more intervention than is strictly necessary. This, in turn, is likely to increase costs to consumers as DSP capacity that was already present in the market is switched from the energy market to the RERT – with no net addition to available capacity.

These weaknesses can be addressed by strengthening AEMO's ability under the Rules to gather information regarding DSP present in the market, and by requiring AEMO to use such information in a more sophisticated, probabilistic manner to allow for different degrees of "firmness" of DSP.

The majority of submissions supported strengthening the reporting requirements for DSP.[125] For instance, the NGF, in providing support, indicated that there should be mandatory reporting requirements for loads above 30 MW. AEMO also supported the findings and indicated that it would convene a working group with retailers and other demand-side operators to collectively explore what forms of information can be provide and which are of most value.

7.6 Making effective use of small embedded generation

What is the issue?

One potential source of additional DSP in support of power system reliability is the greater strategic use of small generation units. These units are generally built to provide minimal levels of "back-up" on-site generation in the event of an interruption in supply from the network. They are therefore generally smaller than the peak load to which they are co-located, and were not necessarily designed to export power on to the network.

The issue is whether there are unnecessary barriers to the strategic use of these generation units, as a form of DSP, at times of peak demand and potential stress on the network.

Findings and recommendation

We consider that the process to facilitate coordinated deployment of small embedded generation units and the negotiated connection agreements represents only a small barrier to the emergence of efficient DSP for reliability purposes. This issue was also

124 "Non-committed" (or non-firm) DSP is where controllers of DSP capability are not able to attach a "high probability" that a block of DSP will be available to be dispatched in response to adverse market conditions during a high demand period – the nature of the DSP contract may impose limitations on when (or how often) the contract can be invoked.

125 NGF, Draft Report submission, pp.2-3; TEC, Draft Report submission, p. 9; AEMO, Draft Report submission, pp.6-7.

raised in the Review of Energy Market Frameworks in light of Climate Change Policies. In that Review, we recommended that the existing MCE, SCO and AEMO work programs to investigate embedded generation connection and use is the appropriate way to consider these issues.

Many commercial operations embedded in distribution networks have on-site generation capability in the form of emergency / stand-by units or units specifically designed to offset their load and manage energy flows at their point of connection to the network.

It is likely that a non-trivial proportion of this capability is not yet strategically managed from the perspective of dealing with an electricity market that could be under some stress.[126] Therefore, it is also likely that potentially useful volumes of generating capacity is idle at times when it could otherwise create value in the NEM by:

- mitigating the effects of region- or NEM-wide generation shortage – as signalled through high spot prices; or
- assisting in the management of local network loading problems that, in the absence of local generation support, could lead to local load shedding.

The use of onsite units may need to be managed by third parties, as the primary interest and expertise of the owners of these embedded generators is usually not the electricity supply industry. This ability for this to occur efficiently may be substantially improved through smart-grids and automating their use. Thus, the effective and strategic use of these units relies on a regulatory environment being conducive to third parties managing embedded generators.

As indicated in the Review of Energy Market Frameworks in light of Climate Change Policies, there are two areas in which industry process could be amended to facilitate third parties strategically managing embedded generators:

- addressing inconsistencies between network businesses in their technical assessment and connection processes (we note work being undertaken by MCE SCO in that area); and
- streamlining AEMO's registration processes for small generators.

As noted in AEMO's submission,[127] it expects to commence a project to address the second of these points and hopes to propose any relevant Rule changes by early 2010. Consequently, the MCE SCO and AEMO processes appear to be the appropriate ways to consider the relevant issues.

126 There are no known reasonably accurate estimates of the volume of emergency generation capability that might be legitimate candidates for strategic management. However, anecdotal information suggests that NEM-wide, under-utilised emergency generation capability is likely to be well in excess of 1 000 MW

127 AEMO, Draft Report submission, pp.6-7

8 Proposed focus for Stage 3 of the Review

Chapter summary

This chapter sets our finding that there is a need for a Stage 3 of the Review. We propose that the focus of Stage 3 should be on the regulatory issues likely to arise from new load monitoring and control technology and the services they support.

8.1 Introduction

The conclusions presented in the Final Report reflect the current technology that supports DSP. This is characterised by the vast majority of electricity use not being capable of measurement and control in real time. The prospective roll-out of smart meters and smart grid technology can facilitate a significant increase in participation from the demand-side in energy markets. There is an open question as to whether the current framework will support efficient outcomes for consumers in this new environment. We consider this should be the focus for Stage 3 of the Review.

The remainder of this chapter provides a brief overview of the possibilities available when electricity consumption is measured and communicated in real time We then outline our initial thoughts of issues that may arise for the market and regulatory design. These initial thoughts will form the starting point for our investigation of Stage 3 of this Review.

8.2 Technological change and possible new service offerings

The technology associated with smart grids and smart meters allow for the measurement, communication and control of electricity in real time. This is achieved by integrating information technology and communications with traditional electricity wires. The integration of communications with electricity networks creates new opportunities for a much wider range of customers to engage more actively with the market. For example, in home displays and smart meters can allow customers to receive real time information about energy prices.

The ability to measure and control electricity in real time has potential value throughout the supply chain. For instance:

- Improved information and controllability will have a value for customers by reducing consumption when prices are high. This can lead to lower energy bills.

- Network businesses can potentially avoid investments by either controlling loads at times of network peaks, or by providing customers with strong price signals about the costs of consumption at peak times.

- Retailers are likely to see value through potentially lower cost load reductions as an alternative to contracting with a generator. This is particularly valuable at peak times, when supply is routinely met by very high cost peaking generation.

- Benefits from real time and controllable management of consumption are likely for system operation and network fault management. The reliance on reserve mechanisms, or the frequency of load shedding, may be reduced if consumption over a large number of customers can be effectively reduced. In addition, load reductions for system operation and network fault management may be more targeted and precise.

Given the potential value that exists, new players may enter the market to act as intermediaries for customers to offer services to network businesses, retailers or the system operator. As a result, existing contracts, or interactions with customers may change. Such contracts may include more dynamic pricing or the ability to remotely control consumption.

For these developments to occur, there needs to be clarity on property rights. Specifically, who owns the right to alter a customers' load? Are there any circumstances where it is not the customer? The regulatory framework might have a role in defining property rights. Further, the regulatory framework will influence the commercial environment for developments within smart grids given the likely interface with regulated network businesses.

8.3 Possible impacts of new service offerings for regulatory frameworks

The Rules govern the NEM and place obligations on those who participate in it. It includes obligations and incentives designed to influence or control the behaviour of participants to be in the long term interests of consumers. Smart grids, smart meters, and the services they can offer will become an important element of the Rules, to the extent that activities by parties are subject to economic and other regulation under the Rules. It is important, therefore, that the Rules encourage market participants and customers to make decisions about new technologies and new services that are consistent with the objectives of the NEM. In this context the Rules should seek to:

- promote efficient investment in new technology;
- appropriately allocate costs and risks;
- promote efficient innovation in services that new technologies can support; and
- promote a stable and transparent framework that facilitates market players transacting efficiently in real time.

We cannot assume that the Rules in their current form will support these objectives. Therefore, it is relevant, and appropriate, to consider whether there are any aspects of the regulatory framework that may inhibit the efficient deployment of new load monitoring and control technology and trade in the services they support. Where the challenges imposed by a transition to a new market environment compromise the desired efficiency outcome, changes to the Rules or broader energy market frameworks should be made.

We have undertaken some preliminary analysis to identify issues and stress points, and have identified the following:

- delineation, and regulation of the interface between competitive and regulated services;
- the regulation of access to infrastructure, data and customers;
- investment incentives for regulated networks;
- how more sophisticated price signals might be passed through to customers; and
- ensuring that the rights and interests of customers are protected.

The remainder of this section discusses these potential issues and stress points in more detail.

8.3.1 Interaction between competitive and regulated services

The existing market structure allows for a relatively clear delineation between regulated and competitive elements of the electricity supply chain. The generation and retail sectors are competitive markets. Decisions by participants in these markets are predominately driven by competitive pressures. The transmission and distribution elements of the supply chain are regulated. Standards, obligations and incentives are used in place of competitive pressures to promote the long-term interests of consumers. Limitations are also placed on the activities that can be undertaken by regulated businesses to avoid the distortion of markets in the competitive sectors.

The introduction of new technology and new services creates the potential to blur the boundary between the competitive and regulated sectors of the market. In some circumstances there will be benefits in requiring monopoly network businesses to supply new services and build the enabling infrastructure. This is because there can be benefits from exploiting the economies of scale network businesses hold. In other instances, the long term interests of customers may be promoted by encouraging the competitive provision of services. This is because often competitive markets are better at delivering efficient price and service offerings.

Key decisions in the context of the regulatory framework will be what network businesses are obliged to do, what are they prohibited from doing, and what do they have permission to do. These decisions will influence how competition within smart grids is supported and hence whether competition in the market can develop. For example, if a network business can control load at peak times, should it be allowed to sell this as hedge cover in the contract market? As a principle, obligations should be limited to services which are "natural monopoly" services so that the room for competition is maximised.

8.3.2 Regulating access to infrastructure, data and customers

A large element of the Rules is to provide fair access to third parties to monopoly infrastructure. Access arrangements in the Rules seek to minimise the scope for the misuse of market power by monopoly businesses. This is achieved through regulation of how network businesses provide, and price, access to generators, customers, and other network service providers.

Service providers within smart grids are likely to require access to assets or information owned or controlled by regulated businesses. Service providers may, for example, need access to infrastructure owned by network businesses. This may include access to meters installed in customers' homes or communications assets deeper into the network. Service providers will also require a relationship with customers and access to their consumption data.

Whether third party access to infrastructure, customers and their data, is provided on a fair and reasonable basis can have a significant impact on the efficiency of services provided. In particular, restrictions to access can create barriers to competition such that benefits to consumers are not realised. For example network businesses may want to restrict access to other service providers if the network business is also a significant player in the relevant market.

In the context of a more interactive operating environment with potential new players, regulating 3rd party access needs to serve two purposes:

- first, it needs to ensure that access is made available to infrastructure, data or customers on fair terms for the access seeker; and

- second, it also needs to ensure the interests of the infrastructure or data owners are protected.

This means ensuring prices provide for efficient rates of return for investments made and that the rights of the owners of information are preserved. Where regulation achieves these outcomes new markets will be able to develop and flourish, which is in the long-term interest of consumers.

8.3.3 Economic regulation and the treatment of smart grid technologies

The current framework for economic regulation focuses on providing network businesses with an efficient revenue stream to achieve a defined level of service. Up to now, regulation has predominately needed to accommodate largely incremental investments to increase the capacity of the network, and limited innovation or technological development. The incentives and obligations have, to date, been appropriate for regulating within this paradigm.

Technology developments may substantially change the nature of investments that network businesses make. Rather than only traditional electricity wires, network businesses may increasingly be required to invest in meters, communications technology or direct load control technology.

Considerable uncertainty exists however about the direction investment should take for a smarter network. This largely reflects the different stages of maturity of various smart grid technologies. Therefore, there is debate about which technologies may be commercialised and which of those will provide the greatest benefits to customers and the market. The uncertainty about the benefits or possibilities for some technologies also creates a risk of them becoming quickly outdated or ineffective.

The economic regulation framework has an important function in providing incentives for efficient investment and protecting the interests of customers. The ability for the existing framework to achieve these outcomes in the context of evolving technology developments and new service offerings may be tested. Some considerations that may be necessary in the context of economic regulation include:

- the form of regulation applied to difference services and investments that network businesses may make;
- ensuring an appropriate level of certainty for cost recovery and revenue adequacy;[128]
- the treatment of technology risks and the implications for this on the appropriate rate of return;
- the appropriate level of regulatory oversight or direction for investment in new technologies; and
- flexibility to accommodate rapid changes in directions or new investments needed within regulatory periods.

8.3.4 Price signals for customer response

As indicated in Chapter 2, there are practical limitations to network or retail businesses setting cost reflective prices, recognising that wholesale and network costs vary significantly over time. This is due to limitations in metering technology and the difficulties associated with accurately calculating an individual consumer's contribution to costs in real time.

The limitations of the metering technology also mean that customers don't have much information about the cost of services at different times throughout the year or day. For the majority of customers, the only information that may inform this is the tariff rates printed on their quarterly bills.

The possibilities of more interactive communication between the demand-side and supply-side has the potential to fundamentally change the way customers are priced and the pricing information customers receive. This environment can enable customers to receive real time price signals that can reflect either wholesale or

128 We note that the Commission has been asked to provide advice on whether the economic regulation framework appropriately accommodates cost recovery for mandated smart metering infrastructure. A Terms of Reference for this work was received from the MCE on 22 November 2009.

network costs, or a combination of both. Smart grid technologies may also simplify the way that customers respond to price. This is because technology may be able to notify customers when it would be beneficial to reduce consumption, or such decisions can be pre-determined and automated. This would reduce the costs to customers to respond to price signals and hence increase the extent of their participation in the market.

More dynamic network pricing has the potential to create a number of challenges for regulatory frameworks. Two possible issues are:

- the framework for regulating network tariffs; and
- the incentives and capacity for retailers to pass through price signals to customers

The issue for network tariffs is how much discretion or direction network businesses should have regarding the structure and level of tariffs. This question may be largely determined by the form of price control applied to network businesses. However, given the variety of prices that may be facilitated by communication technology on networks, such as time-of-use prices, capacity prices, or real time critical peak pricing additional guidance may be necessary. Alternatively, guidance may be required to ensure that network businesses develop prices that accurately reflect the costs of providing network.

The effectiveness of price signals is largely dependant on whether retailers pass them though to customers. Challenges for the framework will include ensuring that retailers have the right incentives to pass though charges. At the moment it can be argued that the retail margin, and hence profitability, is largely driven by the volume of electricity sales. Prices that encourage consumers to use less electricity may be contrary to this businesses model. Therefore, alternatives, or additional incentives may be necessary to encourage retailers to pass on price signals.

Even where retailers have the incentive to pass though efficient price signals other constraints may exist. These constraints may include contractual constraints on price changes, the ability to communicate pricing structures to customers or the impact of regulated caps on prices.

8.3.5 Protecting the rights and interests of customers

Supply side businesses are required to adhere to certain obligations and processes that are designed to protect the interests of customers. These obligations and processes relate mainly to retail and distribution businesses. They regulate the way that businesses interact with customers. Also, is most jurisdictions, regulation caps the prices that retailers can charge customers.

While increased communications and controllability on networks may create many opportunities for customers, they can also introduce added complexity. Customers are less likely to have simple and easy to understand prices. Also, a variety of new services providers are likely to want to interact directly with customers.

The added complexity associated with smart grids, plus the possibility of new service providers, raises a number of issues that have the potential to impinge on customers rights and protections. For instance:

- Who can control a customer's load and under what circumstances?
- What are the trade-offs between improved price signals and tariff complexity?
- What information should customers be provided with?
- What are the contractual relationships between customers and new energy service providers and how are they regulated?
- What are the implications of more complex tariffs for retail price regulation?

The absence of effective customer protections may undermine the benefits that can be achieved through smarter networks. Therefore, it is important to ensure that appropriate protections are in place and customers feel assured about the transition to smart grids and its associated technology.

8.4 Proposed Stage 3 work program

Given the range of regulatory issues that arise through more interactive communication between the demand-side and supply-side, we have concluded that there is a need for a further stage of this review to fully analyse the issues and recommend framework changes to address them where necessary. The scope of issues to be covered under Stage 3 are likely to be based the preliminary analysis presented here. We intend to work closely with the SCO and the MCE to further develop the scope of work for Stage 3 and an appropriate terms of reference. We will also consult with interested stakeholders during this scoping stage. Following these consultations, we will publish a terms of reference with a view to commencing Stage 3 of the Review in March 2010.

Stage 3, as with the previous stages, will be conducted under section 45 of the NEL. This requires us to provide a report to the MCE upon completion of the Review. Our intention is to report our Stage 3 conclusions to the MCE by the end of 2010.

We note a regulatory working group is to be established as part of the Smart Grid, Smart City initiative. We intend the work undertaken as part of Stage 3 to be informed input into that working group.

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A Draft Rule for Economic Regulation for Demand-Side Participation and Avoided Prescribed TUOS Services Payments

This appendix provides a draft Rule for the economic regulation for demand-side participation and avoided prescribed TUOS services payments. The intention is for the MCE to consider the draft Rule and submit it to the Commission as a Rule change proposal. If submitted as a Rule change proposal by the MCE, the draft Rule would be subject to further consultation under the Rule making process set out in Division 3 of Part 7 of the National Electricity Law.

For clarity, proposed new wording for the Rules is underlined. Italicised words are references to existing and proposed new or amended defined terms in Chapter 10 of the Rules.

Amendment of the National Electricity Rules

The National Electricity Rules are amended as set out in Schedule 1.

Schedule 1 Amendment of National Electricity Rules – Chapter 5, 6, 6A and 10

[1] References to "demand management incentive scheme"

In clauses 6.3.2(a)(3), 6.4.3(a)(5), 6.4.3(b)(5), 6.6.3(b), 6.6.3(b)(4), 6.8.1(b)(4), 6.12.1(9) and S6.1.3(5), omit all references to "*demand management incentive scheme*" and substitute "*demand management and embedded generation connection incentive scheme".*

[2] Clause 5.5 Access arrangements relating to Distribution Networks

Omit clause 5.5(h) and substitute:

> Except where a *Connection Applicant* receives a *network support payment*, a *Distribution Network Service Provider* must pass through to a *Connection Applicant* the amount calculated in accordance with paragraph (i) for the locational component of *prescribed TUOS services* that would have been payable by the *Distribution Network Service Provider* to a *Transmission Network Service Provider* had the *Connection Applicant* not *been connected* to its *distribution network* ('avoided charges for the locational component of *prescribed TUOS services*').

[3] Clause 6.6.3 Demand management incentive scheme

In the heading of clause 6.6.3, omit "*Demand management incentive scheme*" and substitute "*Demand management and embedded generation connection incentive scheme".*

[4] Clause 6.6.3 Demand management incentive scheme

Omit clause 6.6.3(a) and substitute:

> The *AER* may, in accordance with the *distribution consultation procedures*, develop and *publish* an incentive scheme or schemes (*demand management and embedded generation connection incentive scheme*) to provide incentives for *Distribution Network Service Providers* to implement efficient non-network alternatives, to manage the expected demand for standard control services in some other way, or to *connect* efficiently *embedded generators*.

[5] Clause 6.6.3 Demand management incentive scheme

In clause 6.6.3(b)(4), omit "and" where lastly occurring.

[6] Clause 6.6.3 Demand management incentive scheme

In clause 6.6.3(b)(5), omit "." and substitute:

; and

(6) the effect of the classification of *distribution services*, as determined in accordance with clause 6.2.1, on a *Distribution Network Service Provider's* incentive to adopt or implement efficient *embedded generator connections*.

[7] Clause 6A.6.5 Efficiency benefit sharing scheme

In clause 6A.6.5(b)(2), omit "and" where lastly occurring.

[8] Clause 6A.6.5 Efficiency benefit sharing scheme

In clause 6A.6.5(b)(3), omit "." and substitute:

; and

(4) the possible effects of the scheme on incentives for the implementation of non-*network* alternatives.

[9] Chapter 10 Deleted Definitions

In Chapter 10, omit the following definition:

demand management incentive scheme

An incentive scheme for certain *Distribution Network Service Providers* developed and *published* by the *AER* under clause 6.6.3.

[10] Chapter 10 New Definitions

In Chapter 10, insert the following new definition in alphabetical order:

demand management and embedded generation connection incentive scheme

An incentive scheme for certain *Distribution Network Service Providers* developed and *published* by the *AER* under clause 6.6.3.

B Efficient networks and consumption

The focus of this appendix is on the interactions between networks and customers that encourage efficient DSP.

B.1 Efficient DSP and the efficient use of the network

Networks are designed to meet peak demands (with a level of redundancy built in to ensure continuity of supply if an asset is unexpectedly out of service), and so the use of networks at peak times causes the need for the network to be upgraded and hence the cost of supply. Thus, the dimension of DSP that is most relevant to networks is the use of the network – or, conversely, demand response (i.e. the reduction in use) – at times of peak demand for the assets in question. There are two forms of action that networks may take to encourage an efficient amount of DSP, which are to:

- set prices to encourage customers to undertake an efficient amount of DSP; and
- undertake further measures to encourage consumers not to consume at peak times – such as by paying customers for reducing their consumption at peak times, and possibly also installing technology to either facilitate or verify the demand response.

The *use* of the network and *demand response* are two sides of the same coin. If the use of the network is efficient, then demand response will also be efficient. Conversely, if the use of the network is inefficiently high at times of system peak, then it follows that additional demand response would be efficient. Thus, to understand the circumstances when demand response would be efficient, it is necessary to understand what would characterise an efficient use of the network.

Final customers and businesses benefit from the use of delivered electricity, and hence benefit from the use of the networks that are used to transport the electricity. Final consumers benefit directly from the use of appliances that require electricity, and businesses benefit from the profit made from using electricity to produce goods and services. Indeed, the fact that customers are willing to pay large amounts of money to ensure a reliable and secure electricity supply suggests that these benefits are high. However, constructing and maintaining an electricity network comes at a cost, and providing additional units of capacity to meet peak demand may come at a very high cost.[129]

The consumption of electricity – and use of the network – is efficient if the benefit that customers obtain from using the network exceeds the cost of provision. If the use of electricity is higher than this, then a reduction in usage would save society more cost than the benefits that are foregone, and hence society would be better off. In contrast, if the use of electricity is lower, then the benefits from additional

[129] The last units of network capacity may only be used for a very short period of time and hence only deliver a small amount of energy. Hence, the cost of providing that peak capacity per unit of energy would be commensurately higher.

consumption outweigh the cost incurred, and society would be better off by increasing consumption.

B.2 Efficient prices and DSP

One of the roles of prices in a market economy is to signal to customers the cost of using a particular good or service. If customers are assumed to make efficient choices – that is, consume the good or service only if they benefit more than the price that is paid – then this encourages efficient consumption decisions to be made. For regulated networks, the same logic holds – that is, if prices signal cost and consumers only choose where their benefit from consumption exceeds the price – then efficient consumption will ensue. It can be concluded, therefore, that:

- if networks set efficient prices; and
- customers make efficient decisions given those prices (i.e. only consume if their benefits exceed the cost),

then it would be unnecessary for networks to undertake active measures to encourage further demand response at peak times. Rather, even though it may be costly to augment the network to meet peak demand, the benefits from consumption would exceed the cost and the augmentation should proceed. However, it also follows that a rationale exists for further measures to encourage demand response at peak times if the price for using the network at peak time is less than the cost of supply at that time as the network may be inefficiently overused as a result.[130]

As noted above, networks are designed the meet peak demand, and so the cost of providing networks is driven by use at peak times. An efficient price would reflect a user's contribution to peak demand and the additional (marginal) cost caused by additional usage at peak time, which in turn would reflect the timing and cost of planned network augmentations. However, the fact that networks experience economies of scale and scope means that total cost may not be recovered if prices are set at marginal cost. In this case, economic principles suggest that prices should be set at marginal cost (i.e. based on peak usage, as discussed above) and the residual should be recovered in a manner that has least effect on the use of the network. For example, the residual may be recovered through per customer (fixed) prices, or based on energy consumed, but should not be recovered by adding a mark-up to the price for using the network at peak times.

However, the ability to set efficient prices for the use of the network relies upon having meters in place that permit peak usage to be measured (i.e. interval meters), which are not currently available for the majority of domestic customers. Moreover, given though the network prices that small customers pay are based on a combination of fixed charges and energy-based charges, it is likely that the price that

130 It is also plausible that customers do not make efficient consumption decisions given the prices that they face (for example, because the costs of being fully informed exceed the expected benefits), and that further measures to encourage or assist customers to make better consumption decisions are warranted.

they pay for using the network at peak time is much lower than the cost of providing peak network capacity. Accordingly, it is expected that measures to encourage additional demand response could be efficient where efficient pricing is not possible – provided, or course, that the benefit to society from the measure exceeds the cost[131]

[131] As noted above, measures may also be justified where customers do not make efficient choices given the prices that they face. However, as the problem in this case is a lack of information or motivation to respond, a different set of responses may be appropriate.

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C Price Caps and Efficient DSP

Under a price cap, revenue is linked to consumption, so when consumption increases or decreases so does revenue. This means that a reduction in usage due to DSP implies a reduction in revenue (at least until prices are reset).

It has been argued that this loss of revenue may be a barrier to network businesses encouraging DSP.[132] This concern about a revenue loss under a price cap has led to two conclusions:

- that revenue caps are more compatible with DSP; and
- that network owners should be compensated for the revenue-loss they incur under a price cap where DSP is implemented.

While it is clear that network owners suffer a loss of revenue when they encourage DSP, it is necessary to consider if this creates a barrier to efficient DSP. To determine if incentives are efficient there are two key considerations: do network owners have the incentives to set efficient prices, and where prices are not efficient, do they have incentives to actively purchase efficient DSP.

C.1 Efficient pricing

As was established in Chapter 2, under a price cap network owners have incentives to set efficient prices (or at least superior incentives to other forms of price control). This is because the price structure that the network owner sets will affect the variability of its revenue. Therefore, in order to maximise profits and minimise risk, the network owner will set prices such that revenues align with costs.

It is also in the network owner's interests for customers to respond to the price signals offered. This is because a response from customers to reduce demand when faced with a high price will cause a loss of revenue, but will also cause a reduction in costs. As demonstrated previously, this is the incentive of a price cap, to align revenues with costs. It is important to note that this demand response will <u>not</u> cause a loss in profits for the network owner where prices are efficient. This is because the price that is offered at peak time is based on marginal costs. Hence, any reduction in demand reduces marginal costs. The only circumstance where the demand response will cause a loss is if prices are higher than marginal cost (which would be an inefficient price).

As demonstrated previously, in reality, efficient pricing is not always possible. Therefore, in the absence of an efficient price signal the prospect of efficient consumption decisions is low. The relevant question is, therefore, does a network owner under a price cap have an incentive to undertake additional measures to encourage demand response. This is discussed in the following section.

[132] To be clear, DSP in this instance refers to a reduction in electricity use at times of peak network demand.

C.2 Network driven DSP

Before discussing the incentives for network owners to purchase DSP it is necessary to be aware of two assumptions:

- that the mechanism to encourage demand response is to pay customers not to consume at peak times; and

- that one unit of demand response is purchased so that price is equal to revenue.

The condition for DSP to be efficient is for the benefit to the network owner to be greater than the cost, and the benefit to society to be greater than the social cost. That is, any measure that is beneficial to society will also be privately beneficial, i.e. profitable, for the network. Therefore, in order to determine the efficiency of DSP it is necessary to consider the social benefits and costs and then the private benefits and costs under a price cap form of control.

From society's point of view demand response will result in two outcomes:

- network costs being avoided as augmentations are deferred or avoided altogether, but

- consumption being foregone and hence any benefits customers may have gained from consumption is lost.

It is evident then that the social benefit from subsidising DSP is the avoided network cost and the social cost is the loss of consumer benefit. While it is easy to identify the value of the social benefit (the savings from avoiding augmentation), the value of the lost consumer benefit is less obvious.

The benefit that is lost from a demand response can be identified by considering the size of the inducement required to encourage a reduction in consumption. Where a demand response payment is offered, the effective price for consuming at peak times is equal to the network price plus the demand response payment offered. A customer will consume until the point where its marginal benefit is equal to the price. Thus, the customer pays the network price if they consume, and avoids the network price and receives a payment if they do not consume. This means that where a customer who is offered a subsidy chooses to consume they would be worse off by the network charge plus the subsidy. It is the total cost of not consuming when a payment is offered that is of relevance.[133]

Accordingly, for demand response to be efficient, it must be the case that the payment required to induce demand response must satisfy:

- Avoided Network Cost ≥ Peak Use Network Price + Demand Response Payment.

[133] This would mean the total cost of consumption when a payment is offered is the network price they need to pay plus the demand response payment they will not receive.

Moreover, the Avoided Network Cost associated with a one unit fall in consumption is the (long-run) marginal cost of providing the network. Thus, the equation above can be re-written as:

- Demand Response Payment ≤ Marginal Cost – Peak Use Network Price,

which just says that the payment not to consume should just make up for the extent to which the network price is less than the cost of provision.

We now turn to the question of whether this outcome is consistent with the private incentives of the network owner. To do this we consider the network owners private benefits and costs.

The private benefit to a network owner from a demand response is the avoided network cost, net of any cost incurred to facilitate the demand response. The private cost to the network owner will be the sum of the demand response payment and the loss of revenue arising from the price cap (which will be equal to the price). Thus, the network owner will find it privately profitable to undertake a DSP program if:

- Avoided Network Cost ≥ Peak Use Network Price + Demand Response Payment; or

- Demand Response Payment ≤ Marginal Cost – Peak Use Network Price.

This is also the condition for the demand response to be socially optimal. Due to the private and social benefits and costs being aligned it can be demonstrated that a price cap provides financial incentives for efficient DSP measures.

The implication of the incentives under a price cap is that network owners will suffer a loss of revenue from subsidising demand response and this can discourage DSP programs. However, it is appropriate that network owners incur this loss of revenue because it requires them to take account of the full value that customers gain from consuming. If, when evaluating DSP programs, the cost of the demand response payment was compared only to the network cost it would mean that the true cost of DSP would be understated. This is because it ignores the costs associated with the lost consumer benefit that would have occurred if customers had used the electricity at that time.

An example of the incentives of customers to provide DSP and the incentives of network business is provided in the following section.

C.3 Prices and value of a customer's consumption

Assume that the variable component of the price that is charged for using the network at the time of peak demand is \$80/MWh (if the same variable charge is levied for all consumption, then this will just be the variable charge),[134] and that the

134 \$80/MWh equates to 8c/kWh, the latter being the more typical units used in a residential bill.

charge that is levied for the other parts of the supply chain reflects the marginal cost of that other part.

- If a customer chooses to consume electricity at peak time, then it can be inferred that the value that it places upon the use of the network (in excess of the cost of the other part of the supply chain) is at least $80/MWh.

Assume now that the network business offers a payment of $10/MWh if the customer ceases consumption at peak time, which the customer rejects.

- In this case it can be inferred that the value the customer places on the use of the network (in excess of the cost of the other part of the supply chain) is at least $90/MWh. That is, by continuing to consume, the pays the network charge of $80/MWh and also forgoes the payment of $10/MWh, making a total *effective* price for consumption – and hence a value from consumption – of $90/MWh.

Assume now that the business continues to raise the payment for demand response until the customer accepts the offer. The customer chooses to continue to consume when a payment of $45/MWh is offered, but the customer is wavering, and the customer agrees to not consume when the payment offer is raised by a marginal amount.[135]

- In this case, it can be inferred that the value the customer places on the use of the network (in excess of the cost of the other part of the supply chain) is approximately $125/MWh. That is, by continuing to consume, the customer pays the network charge of $80/MWh and also forgoes the payment of $45/MWh, making a total *effective* price for consumption – and hence a value from consumption – of at least $125/MWh. However, as a marginally higher offer induced a demand response, we know that $125/MWh accounts for the whole of the value that the customer places on the use of the network.

Thus, it can be concluded that the sum of the network business' revenue ($80/MWh) and the required DSP payment ($45/MWh) is a proxy for the loss of customer value that arises when the customer is induced not to consume.

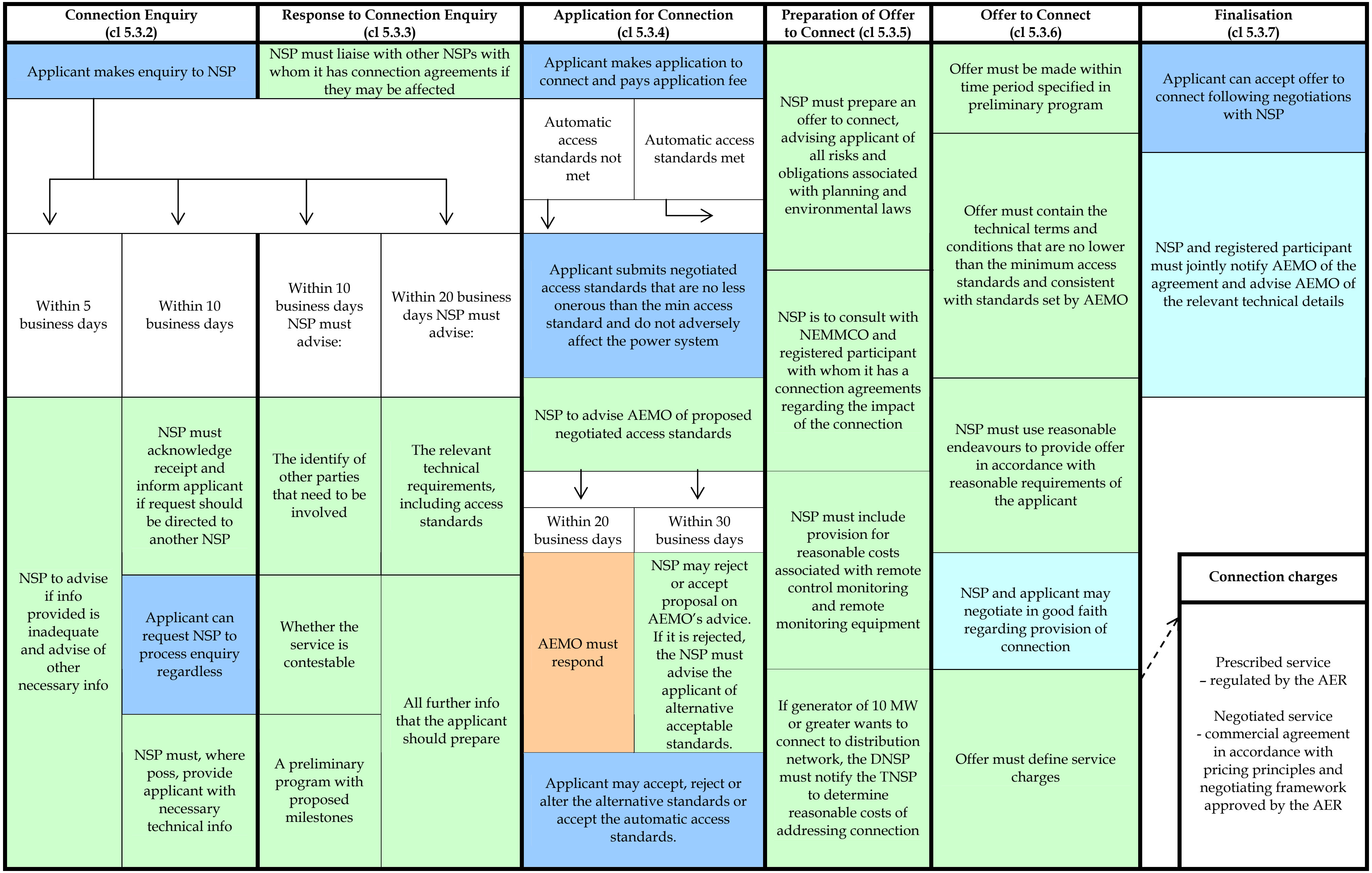
Turning to the network business' point of view, it will find it profitable to purchase DSP whenever the total financial cost exceeds the savings in network costs.

- Under the example above, the network business will purchase DSP if the network cost is higher than $125/MWh (the total financial cost to the network business being the $80/MWh loss of tariff revenue and the $45/MWh payment to induce non-consumption).

However, this is consistent with an efficient choice of DSP. The loss of customer value from DSP is $125/MWh, and so DSP should only be purchased if the savings in network costs exceed this amount.

135 For example, a free energy audit.

D Connection enquiry framework



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E Examples of DSP Financial Contracting with Retailers

In this appendix we give two examples of demand-side participants providing risk management products to retailers and other parties using financial instruments.

We illustrate two such products:

- An electricity consumer that has an electricity supply contract with a retailer allowing the retailer to signal the end-user to turn off. This enables the retailer to exploit arbitrage opportunities between the wholesale price and its contract position to better its financial position.

- A \$300/MWh cap product that a demand-side resource provides off the market developed using a combination of a spot-price pass-through tariff and contracts.

E.1 A demand-side response product

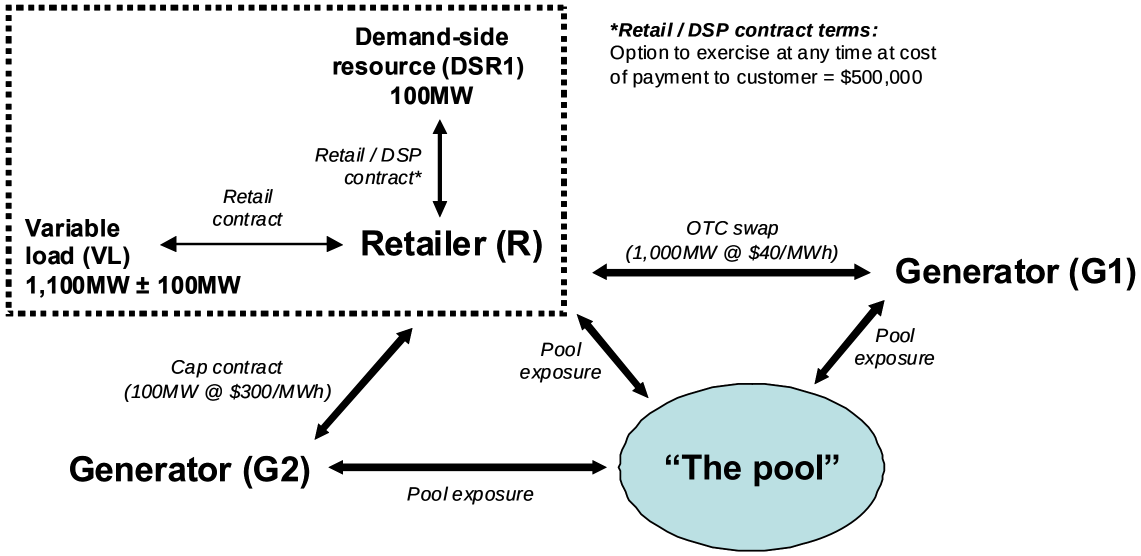
To demonstrate the value of a DSP contract, consider the set of market arrangements outlined in Figure E.1 and the subsequent Scenario A and Scenario B. The example in this appendix has been adapted from one given by CRA in its advice to the Commission.[136]

The following terminology applies:

over the counter (OTC) swap	A contract between two parties to ensure an agreed price (\$/MWh) exposure to an agreed (MWh) volume of energy at a nominated time.
cap	A contract between two parties to ensure a maximum price (\$/MWh) exposure to an agreed (MWh) volume of energy at a nominated time.
fully hedged	A contract position whereby contract coverage for energy at a particular time matches the amount of energy consumed.
long	A contract position whereby contract coverage for energy at a particular time exceeds the amount of energy consumed.
short	A contract position whereby contract coverage for energy at a particular time is exceeded by the amount of energy consumed.

136 CRA International, *The Wholesale Market and Financial Contracting: AEMC Review of Demand-Side Participation in the NEM,* 2008, pp. 26-27.

Figure E.1: Contractual arrangements including DSP



In this example a demand side resource is contracted through a retailer to provide an interruptible service such that it is either on or off. If requested to switch off, the retailer will make a fixed payment to the demand side resource owner.

The retailer has separate contracts with generators for an "OTC swap" (1 000MW at a strike price of $40/MWh) and a "cap" (100MW at $300/MWh).

Scenario A: Shift from short to fully hedged via exercise of DSP

<u>Scenario A1</u>

Market / system conditions force pool price to **$9 000 / MWh** for one hour.

Variable load (VL) 1 200MW; **DSR1 available to drop 100 MW load but option <u>not</u> exercised**. **Total load for R's customers = 1,300 MW**. [**<u>R is short</u>** with contracts ("OTC swap" plus "cap" plus "DSP") for 1,200 MW.]

R's cash flows for this hour would be as follows:

- R ➔ "The pool" as settlement for load = 1 300 x $9 000 / MWh = $11.7M.
- G1 ➔ R as settlement of hedge = 1 000 x ($9 000 - $40) = $8.96M
- G2 ➔ R as settlement of cap contract = 100 x ($9 000 - $300) = $870,000
- **R's net cash flow** = -$11.7M + $8.96M + $870 000 = **-$1 870 000**

Scenario A2

Market / system conditions force pool price to **$9 000 / MWh** for one hour.

Variable load (VL) 1 200MW; **DSR1 available to drop 100 MW load and option is exercised**. **Total load for R's customers = 1 200 MW**. [**R is fully hedged** with contracts ("OTC swap" plus "cap" plus "DSP") for 1 200 MW.]

R's cash flows for this hour would be as follows:

- R ➔ "The pool" as settlement for load = 1 200 x $9 000 / MWh = $10.8M.
- R ➔ DSR1 as payment for exercise of DSP option = $500 000.
- G1 ➔ R as settlement of hedge = 1 000 x ($9 000 - $40) = $8.96M
- G2 ➔ R as settlement of cap contract = 100 x ($9 000 - $300) = $870 000
- **R's net cash flow** = -$10.8M - $500 000 + $8.96M + $870 000 = **-$1 470 000**

Scenario B: Shift from long to longer via exercise of DSP

It can be shown that if variable load (VL) fell to 1,000MW, but all other parameters in Scenario A were unchanged, we have the following situation.

Scenario B1

Variable load (VL) 1 000MW; **DSR1 available to drop 100 MW load but option not exercised**. **Total load for R's customers = 1 100 MW**. [**R is long** with contracts ("OTC swap" plus "cap" plus "DSP") for 1 200 MW.]

- **R's net cash flow = -$70 000**

Scenario B1

Variable load (VL) 1 000MW; **DSR1 available to drop 100 MW load and option is exercised**. **Total load for R's customers = 1 000 MW**. [**R is long** with contracts ("OTC swap" plus "cap" plus "DSP") for 1 200 MW.]

- **R's net cash flow = $330 000**

Conclusion

Under both Scenario A and Scenario B, provided the pool price remains unchanged, after exercising the DSP option R's net position for the hour improves by $400 000. If exercising the DSP option carries no risk of collapsing the pool price below

$5 000 / MWh[137], regardless of whether R is short, fully hedged or long, it makes no commercial sense to not exercise a DSP option if it exists.

E.2 A $300/MWh cap product

This example shows how a demand-side resource can develop and offer a $300/MWh cap product to the market by using a spot-price pass-through tariff and other financial instruments. A key element of the arrangements underpinning this product is that the demand-side resource may be required to monitor the spot price to decide whether or not to consume.

In this example, the demand-side resource is a 10 MW unscheduled load that:

- obtains a spot-price pass-through tariff from a retailer;
- buys a 100 MW swap contract with a strike price of $40/MWh to limit its exposure to the spot price; and
- sells a 100 MW $300/MWh cap contract through the exchange to receive some revenue.

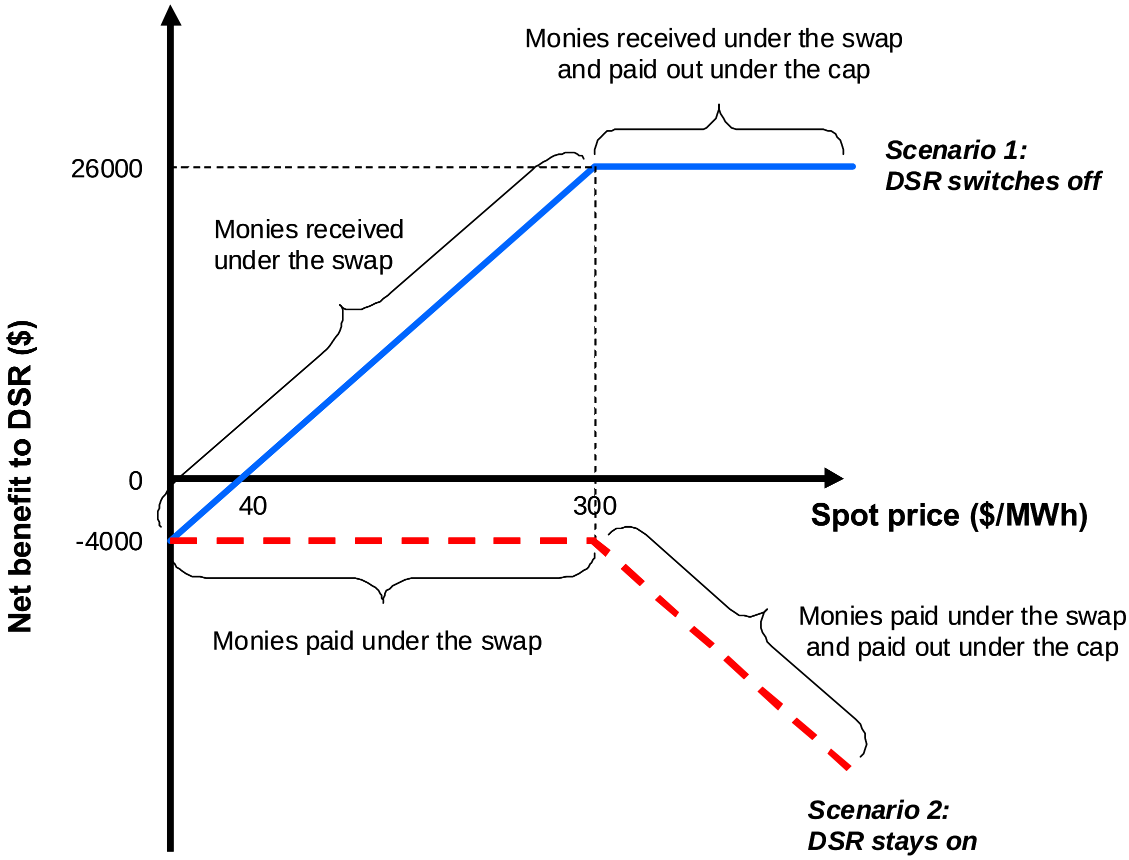
We assume that the demand-side resource is completely flexible in its operations and that it has perfect information about market conditions and spot price outcomes at zero cost.

Figure E.2 presents how the demand-side resource can benefit under these arrangements by detailing the net benefit to the demand-side resource, post wholesale energy costs, in relation to the spot price for the two different situations that:

- the demand-side resource consumes 100 MW; and
- the demand-side resource does not consume 100 MW.

137 Under the scenarios outlined, when the pool price collapses below $5,000/MWh, the cost of exercising the DSP contract exceeds the savings in pool price exposure. Pre-dispatch sensitivities (half hour granularity updated every half hour up to 40 hours ahead; and 5-minute granularity updated every 5 minutes for 1 hour ahead) provide an indication to the market of how much price will change for a given change in demand.

Figure E.2 The net benefit to the demand-side resource (DSR) under alternative scenarios



The following table also presents this information in an alternative way.

Table E.1: The net benefit to the demand-side resource

Scenario	Spot price	
	≤ $300/MWh	>$300/MWh
DSR switches off	$(spot price – 40)/MWh x 100MW	$260/MWh x 100MW
DSR stays on	–$40/MWh x 100MW	$(260 – spot price)/MWh x 100MW

The demand-side resource would manage the financial risks of it having sold a $300 cap contract by probably not consuming electricity when the spot price is greater than $300/MWh. It could be subject to very high payments to its cap counter-party if it continued to consume when the spot price was higher than $300/MWh. This assumes that it is able to stop consuming electricity whenever the spot price is higher than $300/MWh.

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F Demand-side Participation Reference Group

Table F.1 details the membership of the DSP Reference Group.

Table F.1: Membership of the DSP Reference Group

Participant Name	Organisation
Tee Lim	Total Environment Centre Inc.
Alex Cruickshank	AGL
Colin Foye	BlueScope Steel Ltd
Ross Fraser	Energy Response Pty Ltd
Brett Gebert	CS Energy Ltd
Neil Gordon	EnergyAustralia
Rainer Korte	ElectraNet Pty Ltd
Dr Iain MacGill	UNSW Centre for Energy and Environmental Markets
Ben Skinner	AEMO
Oliver Story	Standing Committee of Officials
David Stanford	Consumer Utilities Advocacy Centre
Mark Wilson	Australian Energy Regulator

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