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Review of the role of demand side participation in the National Electricity Market

Australian Energy Market Commission

NERA
Economic Consulting

Stage 1 Final Report

Project Team

Greg Houston

Adrian Kemp

Astrid Dahl

NERA Economic Consulting
Darling Park Tower 3
201 Sussex Street
Sydney NSW 2000
Tel: +61 2 8864 6500
Fax: +61 2 8864 6549
www.nera.com

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1. Introduction

NERA Economic Consulting (NERA) has been engaged by the Australian Energy Market Commission (the Commission) to review the impediments to, and develop recommendations for, facilitating demand side participation within the context of three current Commission projects. This review is the first stage of the Commission-initiated Review of Demand Side Participation in the National Electricity Market (NEM) (the Review).[1]

The Review is being undertaken in three stages, ie:

- **Stage 1:** Review the Commission's current work program in order to develop recommendations that can be incorporated into its assessment of relevant future Rule change proposals and reviews;

- **Stage 2:** Review demand side participation in the context of the broader Rules, subsequent to the finalisation of the national distribution and retail Rules, in order to develop recommendations to the Ministerial Council on Energy (MCE) that will promote demand side participation; and

- **Stage 3:** Undertake a final assessment of the Rules in order to identify any remaining gaps so as to make further recommendations to the MCE on potential Rule changes.

We understand that the motivation for the Review arises from concern about the potential impediments to demand side participation, which may lead to sub-optimal investment in demand side solutions, as compared with network/generation investments. To the extent that demand side options are impeded within the regulatory framework, the removal of these impediments would enhance market efficiency, and thereby promote the national electricity objective. The particular focus of this review is the potential impediments to demand side participation within the regulatory framework as relevant to the Commission's current reviews.

The main purpose of Stage 1 is:

- to develop a conceptual framework for subsequent consideration by the Commission of the role of demand side participation in the NEM; and

- to make recommendations that facilitate demand side participation within the bounds of the National Transmission Planner Review, the Congestion Management Review and the Comprehensive Reliability Review, again for consideration by the Commission.

The scope of Stage 1 is therefore limited to the current Commission work program. Many important questions relating to demand side participation will therefore be considered in subsequent stages of the Commission's Review.

Our approach to Stage 1 has been first to articulate how demand side participation operates within an efficiently operating wholesale electricity market and within the associated

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[1] See http://www.aemc.gov.au/electricity.php?r=20071025.174223

electricity system network planning and investment framework. In so doing, we consider how demand side participation might be better incorporated into the operation of the market.

The second phase has been to consider international experience in the treatment of demand side participation in network planning and wholesale generation markets. We have focused on three case studies being:

1. the grid exit point pricing of transmission in New Zealand, which provides network pricing signals that can promote demand side participation;

2. the provision of transmission pricing discounts to distributed generation in the United Kingdom; and

3. an overview of reliability-based demand response programs in the United States.

The final phase has involved examining the three main reviews currently being considered by the Commission, to develop recommendations to address any of the impediments identified from the earlier analysis. The current reviews that we have been asked to consider include the:

- National Transmission Planner Review;
- Congestion Management Review; and
- Comprehensive Reliability Review.

Separately, the Total Environment Centre (TEC) has recently submitted a rule change proposal on demand side participation within the regulatory framework.[2] We have not been asked to consider the TEC proposal, although we acknowledge that it touches on many of the issues that are the subject of our paper.

Finally, this Stage 1 review does not consider all potential impediments to the promotion of demand side participation in the NEM, since it is limited to areas already being considered by the Commission in the above reviews. This review does not therefore address:

- potential impediments to demand side participation in the operation of the wholesale market;
- concerns about the regulatory treatment of demand side participation costs for the purpose of network tariff setting;
- the incentives of network service providers to invest in demand side participation options compared with network alternatives; or
- potential impediments to demand side participation in the rules governing distribution network service regulation, including distributed generation.

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2 See, http://www.aemc.gov.au/electricity.php?r=20071115.124352

These areas will be considered in greater detail during the subsequent stages of the Commission's Review.

A draft report for Stage 1 of the Review was published on 3 March 2008. Since then the Commission published its draft report for the National Transmission Planner Review on 2 May 2008. In this final report for Stage 1 we set out our final recommendations, having regard to comments made in submissions on the draft report.

1.1. Structure of the draft report

The remainder of this draft report is structured as follows:

§ Chapter 2 develops the framework for considering demand side participation as a substitute for network and generation investments;

§ Chapter 3 presents the international case studies as outlined above;

§ Chapter 4 considers the impediments to demand side participation in the current network planning and investment frameworks. In particular we focus on the role of and framework for the National Transmission Planner;

§ Chapter 5 considers the relevance of demand side participation for the provision of network support and control services, as relevant to the Congestion Management Review;

§ Chapter 6 outlines the integration of demand management into the current reserve trader arrangements within the rules, as relevant to the Comprehensive Reliability Review and subsequent proposed Rule changes intended to be submitted by the Reliability Panel; and

§ Chapter 7 concludes and draws together the various recommendations.

Appendix A provides a list of submissions received on the Draft Report.

2. Economics of demand side participation in the NEM

In this chapter we outline how demand side participation fits within the current institutional, regulatory and market structure of the National Electricity Market. This includes defining what we understand demand side participation to mean, how it relates to the national electricity objective (the NEO), and the importance of pricing for wholesale markets and network services to achieve optimal demand side participation. Finally we identify the potential impediments to efficient demand side participation in the wholesale electricity market and the network planning and investment frameworks.

2.1. What is demand side participation?

Demand side participation (DSP) encompasses a variety of actions that might be undertaken by consumers with the effect of changing the quantity and timing of their electricity use, as compared with their usual practices. Importantly, DSP does not always imply that electricity use must be curtailed, since changes in the timing of electricity use (with no overall change in total electricity use) can still deliver both network and wholesale market benefits.

DSP can include, without limitation:

§ conservation practices, such as the installation of energy efficient light bulbs, and more efficient energy using appliances;

§ shifting the time of use of appliances or overall industrial plant operations within a day, to reduce demand during daily peak periods, or on extreme critical peak network usage days;

§ investing in distributed generation such as photovoltaic cells (PV cells) to reduce reliance on existing generation and network capacity; and

§ substituting away from electricity to alternative fuels such as gas for space and hot water heating, and cooking, and thereby reducing reliance on electricity for the provision of these services.

While all DSP involves actions by end-use customers, there are also firms engaged in the aggregation of demand side services for those who may benefit from them.[3] These firms enrol end-use customers in programs where they can be directed to reduce electricity consumption as required. By aggregating many small end-use customers, a demand aggregator can provide sufficient demand curtailment to assist electricity retailers with wholesale price risk management, and network service providers to manage peak demands.

2.2. Demand side participation and the National Electricity Objective

Section 7 of the *National Electricity Law* sets out the national electricity objective (NEO) as follows:

[3] For example, Energy Response Pty Ltd in Australia.

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

Promoting efficient investment in electricity services is a fundamental objective of the electricity market, and the market rules, with the promotion of the NEO is the principal test applied by the Commission when assessing rule change proposals. For efficiency to be promoted, network businesses must undertake investments to provide electricity services at least cost, without compromising requirements for reliability, safety and network security. In some circumstances, expenditure on DSP can alleviate or delay a need to undertake a network investment, with associated network cost savings. Any impediments to DSP within the market rules may give rise to less than optimal investment in DSP. To the extent that these impediments are material, this may result in inefficient investment in network assets, which could have been avoided if the DSP impediments had not been present.

Consequently, the network planning framework specified in the rules, and the associated approaches to congestion management should ensure the consistent treatment of DSP options vis-à-vis network investment alternatives. In particular, each framework should not give rise to incentives for market participants systematically to favour network investments over DSP, or vice versa. Removing any artificial impediments to DSP from the rules is therefore consistent with the national electricity objective, and would be likely to promote efficient investment in electricity services.

In addition to promoting *efficient investment in* electricity services, the national electricity objective also requires the promotion of the *efficient operation and use of* electricity services. Efficient use of electricity services is achieved when the value associated with electricity use is maximised, given the cost of its provision. For an individual consumer this occurs when the value from using electricity exceeds the cost of producing and delivering it to the customer.

For electricity use to be efficient, customers should face the marginal network and generation costs of providing electricity services to them. This allows customers to make judgements about whether and how much electricity to consume given the value obtained relative to its cost. This means that setting prices by reference to the marginal cost of network services and wholesale energy can be expected to give rise to optimal demand side participation, because:

- for generation, customers would choose to reduce load (or invest in more energy efficient processes/technologies), if the marginal benefit of doing so outweighed the associated marginal cost, as approximated by the wholesale market price; and
- for network investment, customers would choose between paying the marginal network investment costs associated with using electricity during, for example, peak network capacity periods, compared with the alternative of reducing electricity demand.

The importance of marginal cost pricing signals to facilitate optimal DSP does not mean that all customers should directly pay for electricity based on the half hourly wholesale price. Rather, customers should be able to choose how they manage half hourly variance in wholesale prices, which may involve purchasing electricity from a retailer that offers a flat tariff product.

Similarly, all customers need not face the marginal cost[4] of network provision for DSP to be facilitated. Rather, it is likely to be sufficient for the promotion of DSP for customers to be able to choose to manage variations in network costs directly.

Removing impediments to consumers being presented with the marginal costs of network provision and electricity generation is therefore an important first step to ensuring that DSP is optimal within the NEM. For this to occur, it is necessary to record electricity consumption for more frequent time intervals, which is not able to be achieved with current accumulation meters.[5] In addition it would be necessary to reconsider the degree of averaging of network prices within geographic areas. "Postage-stamp" network prices have been a predominant form of network pricing for some time, particularly within distribution networks. This means that most customers are not currently presented with the marginal cost for the provision of network services in their particular location; rather they face prices that are averaged over a wide geographic area.

However, for transmission networks the new pricing rules provide a greater emphasis on location-based charges through the allocation of a proportion of annual revenue requirements to transmission connection points. [6] It is therefore expected that a greater proportion of annual revenue requirements will be recovered through locational charges than postage-stamped charges into the future, thereby improving the pricing signals for use of the transmission network.

Examining the regulatory constraints on efficient pricing is an important first step in the process of examining the impediments to DSP. However, impediments may also arise from planning or other restrictions on distributed generation, which limit the extent to which consumers may invest in these alternative technologies.

2.3. Characteristics of demand side participation

In the presence of practical or other constraints on customers being presented with the marginal cost of network provision, the regulatory framework for network investment needs to ensure that a network service provider (NSP) faces appropriate incentives to consider alternative non-network options. For DSP to be a viable alternative solution to satisfy an NSP's responsibility to ensure the supply and demand for network services are in balance its characteristics must allow it to be either entirely or partially substitutable for a network investment, to allow the NSP to rely upon the DSP to satisfy its system reliability (or, supply side) requirements.

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4 We note that the marginal cost of providing network services can be expressed in either short or long run terms, and both will vary over time and between locations. The efficient presentation of such costs to network users inevitably requires a degree of averaging, both over time and locations, in order to optimise the transaction and information costs associated with measuring costs and presenting prices to an increased degree of granularity.

5 This is likely to change through the introduction of smart metering technology, which allows for the collection of electricity usage information for each 30 minute interval.

6 AEMC (2006), National Electricity Amendment (Pricing of Prescribed Transmission Services) Rule 2006 No. 22, Rule Determination, December.

As with any alternative means of satisfying a requirement, it is likely that the risks associated with a non-network investment for maintaining system reliability will differ from those associated with a network investment. In part this arises because non-network investments typically rely on customers responding in certain ways when required. By contrast, the risks associated with a network investment are typically managed through the design specification.[7] Similarly, the risks associated with non-network investments are typically managed in a number of ways, including through:

§ contracting for a greater amount of demand response, on the assumption that not all of it will be available at any given time; and

§ directly controlling customer usage rather than relying on customer intervention, to remove the uncertainty as to whether a customer will honour contractual commitments.

Given the relatively high costs associated with a failure to provide contracted non-network services, where these are being relied upon to maintain system reliability standards, it is necessary to consider how the risks of failure are to be shared. This may involve NSPs seeking to provide for significant financial penalties on DSP providers within the contractual arrangements. However, this itself may give rise to an impediment to DSP since it increases the expected costs of providing such services. Finding mechanisms to manage these risks and to ensure the appropriate allocation and balance of risks is maintained will therefore be critical to reducing any impediments to DSP as a non-network solution to network capacity constraints.

2.4. Demand side participation and the wholesale electricity market

The NEM involves an auction-based wholesale electricity market that equates supply and demand by means of price offers submitted for each thirty minute trading interval of each day. The wholesale market clearing price is determined by the market dispatch model that seeks to find the lowest cost combination of generation and schedule load to meet forecast demand over each five minute dispatch interval. The settlement price for each 30 minute trading interval is the average of the five minute dispatch prices for the relevant period.

The wholesale electricity market does not preclude customers from exercising their discretion to use more or less electricity at any point in time during a day and over a year. Under these arrangements, demand response currently occurs through customers individually choosing to reduce electricity demand, in accordance with their preferences for the time of use of appliances, notwithstanding that differences in the marginal costs of that use are masked by tariffs that are averaged over time.

The reason why electricity prices are constant over time for most end-use customers is the flat tariffs generally offered by electricity retailers. Retailers act as risk managers on behalf of end-use customers, by purchasing and on-selling electricity from the wholesale market. Retailers charge a fee for this service in the form of a retail margin.

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7 Networks are generally designed to meet the reliability standard when unanticipated events occur.

Retailers manage wholesale price variability to satisfy their customers' electricity demand by a variety of means including contractual hedging contracts, contracts with large electricity use customers, and direct ownership of electricity generation capacity. Inevitably, some customers are likely to impose costs on a retailer that exceed the price it charges them to provide electricity, particularly if the customer's load profile involves the use of electricity predominately during peak periods. Similarly other customers are likely to impose costs on a retailer that fall short of the price it charges them, because of a load profile that uses more electricity during off-peak periods.

Retailers could choose to manage the electricity demand of its customers through contractual arrangements directly with them. These could take the form of arrangements whereby during peak periods a customer can be asked to reduce its electricity demand. Such demand side participation is therefore a substitute for alternative, price-based means of managing wholesale price volatility to meet customer electricity demands.

As noted in section 2.3 above, if end-use customers were able to be presented with the wholesale price of electricity directly, in principle this would enable them to choose between managing price volatility via contractual means such as through a retailer variable tariff product offering, or through managing demand directly. It is therefore relevant to consider the potential impediments to customers choosing the optimal approach to managing wholesale price risks, including through retailers versus engaging directly in demand side participation. We consider this for small and large end-use customers below.[8]

2.4.1. Wholesale market prices and large end-use customers

The National Electricity Rules allow end-use customers to become registered market participants and thereby to respond to wholesale market price risks directly. In this way end-use customers that are able and willing to satisfy the registration criteria can choose to respond to wholesale market price volatility through, for example, operational controls such as plant shutdowns during periods of high wholesale market prices. The prudential requirements of NEMMCO mean that registration as a market participant is likely only feasible for large end-use customers.

By way of alternative to such arrangements, large end-use customers may choose to negotiate directly with a retailer for tariff concessions in return for restrictions on the use of electricity during certain times. This might include interruptible tariffs where a retailer is entitled to request the large end use customer to reduce demand for certain periods, or where electricity is predominately used during off-peak periods.

The market rules therefore provide flexibility as to the form of tariff offerings to some end-use customers, and by allowing these customers to manage wholesale price risks directly, thereby ensuring that choices can be made between retailer-administered demand side participation arrangements and direct exposure to wholesale market prices.

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8 'Small' customers have been taken as being those with a total annual demand below 160/MWh as they are defined for most jurisdictions with the exception of Queensland (100 MWh/year), Tasmania (150 MWh/year) and the Northern Territory (750/MWh/year).

Finally, the market dispatch rules also allow load to bid demand side reductions directly into the market. This allows the dispatch model to factor load changes directly into the dispatch outcomes. However, we understand that there is little incentive for a customer to do this, since there is no opportunity to be paid for any reductions in load that arise (other than the avoided cost of its own reduced load).

For some end-use customers the rules allow wholesale price signals to be presented directly to customers. This has led to improvements in demand side participation amongst large load customers, as they seek to manage their electricity costs. Despite this flexibility, many eligible customers choose not to manage wholesale prices directly by becoming a market participant. For these customers, the costs associated with managing wholesale price volatility directly, including the costs associated with registration as a market participant, presumably outweigh any potential input cost reduction benefits.

This suggests that any impediments associated with greater demand side participation by large end-use customers are likely to be the result of:

§ insufficient awareness of the potential cost savings associated with directly managing wholesale electricity prices; or

§ high transaction costs associated with directly managing wholesale prices.

Impediments to demand side participation in the wholesale market are outside of the scope of this review, so are not considered further in this report.

2.4.2. Wholesale market prices and small end-use customers

For small end-use customers the rules do not readily provide for these customers to be presented with and so to respond directly to wholesale market prices, due to their inability to satisfy the market participant registration criteria. This means that small end-use customers have little ability or incentive to respond to wholesale market price fluctuations, through investing in demand side options as an alternative to using more electricity, particularly during high wholesale cost periods.

This suggests that to encourage optimal demand side participation, it would be helpful for end-use customers to be given the ***option*** to be presented with wholesale prices directly. This would mean that small end-use customers could choose to respond to variances in wholesale prices directly through better management of their own demand, or to contract out that responsibility to retailers offering tariffs that do not vary with wholesale market prices.

However, there are two principal impediments to a customer choosing to pay for electricity on the basis of the wholesale market prices. These are:

§ the inability of current standard meters to record electricity consumption in half hourly intervals; and

§ the absence of retail tariff products that pass through wholesale market prices.

Recent developments in metering technology and the COAG's commitment to a rollout of smart metering technology means that in the near future small end-use customers' electricity consumption will be recorded for every 30 minute interval (see Box 2.1).[9] Smart meters will facilitate the introduction of new tariff products to small end users, including those that pass through some or all wholesale price fluctuations to customers.[10]

Box 2.1
Implications of a mandatory rollout of smart metering for demand side participation

At its April 2006 meeting the Council of Australian Governments (COAG) committed to a mandatory rollout of smart metering to all small use customers across Australia, where the benefits outweigh the costs.[11]

Smart electricity meters record electricity consumption over 30 minute intervals throughout the day, and allow this data to be remotely collected and recorded. By recording consumption for each 30 minute interval, electricity retailers and network service providers are able to charge different electricity tariffs according to the time of day, and during particular network peak periods throughout a year.

Smart metering therefore provides distribution network service providers (DNSPs) with the capability:

§ to charge a differential tariff according to the time of day - known as time-of-use tariffs;

§ to charge a significantly higher tariff during network critical peak events - known as critical peak pricing; and

§ to control directly high energy using appliances such as air conditioners and pool pumps.

Charging higher prices during network peak periods provides a signal to customers as to the cost of providing network capacity to satisfy peak demand. Most of the capital costs associated with network provision are not only being driven by growing demand for electricity, but also in many jurisdictions, increases in maximum demand.[12] The increases in maximum demand have been driven predominately by the growth in air conditioner uptake.[13]

Time-of-use tariffs improve the signals faced by customers as to the costs of peak network capacity, although they may be muted since they are likely to be uniform across wide ranging locations of the end-use customer. In practice however network service costs can vary considerably according to the location of customers.

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9 Council of Australian Governments Meeting Communiqué, 10 February 2006.

10 Smart metering will also improve the demand forecasts provided by DNSPs to better determine transmission connection point locational TUOS charges.

11 NERA is currently concluding a study into the costs and benefits of a national mandatory rollout of smart metering for the Ministerial Council on Energy's Smart Metering Working Group, see www.mce.gov.au.

12 Queensland in particular has had maximum demand growth of over 3.6 per cent, NEMMCO Statement of Opportunities 2007, Pages 3-35 to 3-39.

13 See Energy Efficient Strategies, Status of Air Conditioners in Australia – A report prepared for NAEEEC, January 2006.

Critical peak pricing is where a higher electricity usage tariff is charged during critical peak events that are called by the network service provider to manage network peaks. The number of annual critical peak events is usually limited and there are requirements on the length of notice of the critical peak event that must be provided. Customers are compensated for participation in a critical peak pricing program through reduced ongoing charges for electricity use.

Smart metering also provides network service providers with the capability directly to control high energy using appliances such as air conditioners and pool pumps. Customers can be recruited to participate in direct load control programs in areas that are facing significant network augmentation costs. This allows demand side participation to provide a direct substitute for network investment.

Future rollouts of smart meters to small end-use customers will therefore provide NSPs with an opportunity to provide improved signals on the costs of network augmentations to end-use customers, and also to provide a direct demand management substitute for network investment in specific locations, as well as to improve the management of maximum demand growth, which in turn drives network augmentation investment.

However, these initiatives are insufficient to resolve all of the problems associated with customers not facing the true costs of network provision. This is because:

§ they require network businesses to have sufficient incentives to offer time-of-use tariffs to end-use customers, and engage customers in direct load control programs;

§ time-of-use tariffs do not reflect the marginal costs of network service provision to each customer, because they are unlikely to vary within a NEM region; and

§ there is no guarantee that retailers will pass through differential network tariffs to end-use customers.

Many of these issues have been raised by NERA in the context of its work for the MCE on the costs and benefits of smart metering, and may form the basis of future rule change proposals to the Commission. In light of that separate process, it would be premature to consider these issues in greater detail here.

At this time the possible tariff product offerings that are being considered include:

§ time-of-use tariffs, where the retail electricity price varies according to the time of day; and

§ critical peak pricing, where the usage tariff is increased for a period of time when the retailer calls a critical peak pricing event.

These new tariff products will allow the electricity prices faced by small end-use customers to track fluctuations in wholesale market prices more closely. This in turn will improve the incentives small end-use customers have to manage their demand efficiently. Whilst ideally customers should face wholesale prices directly, the transaction costs of doing so may well outweigh the benefits. Time-of-use tariffs and critical peak pricing are likely to provide a next best pricing signal to improve the incentives for demand side participation.

Finally, distributed generation acts as a substitute for demand from the wholesale electricity market, and may be a more cost effective energy source for individual small end-use customers, particularly where it avoids increased network investment and reduces energy losses. It is therefore relevant to consider the impediments to increased investment in distributed generation, if any. These potentially include the connection arrangements for distributed generation, particularly where there is potential for such generation to import electricity into the distribution network.

This discussion highlights that customers, and particularly small end-use customers, may not engage in optimal demand side participation because they do not face the wholesale price of electricity directly. One of the principal impediments to optimal demand side participation is therefore likely to relate to the scope for end-use customers to receive pricing signals that better reflect fluctuations in wholesale market prices.

2.4.3. The operation of the National Electricity Market

There are two relevant aspects of the operation of the national electricity market, where the potential for demand side participation to play an additional role should be further considered. These are the provision of network control and support services to support the maintenance of system reliability and security, and the Reserve Trader arrangements.

Network control and support services are currently provided by both generators and load through contractual arrangements with transmission network service providers (TNSPs) to be constrained on (or off) in specified circumstances, and via contracts with NEMMCO to provide network control ancillary services. There is potential to facilitate a greater role for demand side participation in providing these services within the operation of NEM.

In addition, the rules provide NEMMCO with powers to contract for reserve capacity in circumstances where the market is not expected to be able to provide sufficient capacity to meet forecast demand. Demand side participation has been used to provide reserve capacity when the Reserve Trader arrangements have been used; however, there may be scope to facilitate a greater role for demand side participation in these arrangements.

We consider demand side participation and network control and support services in section 5.2, and the Reserve Trader arrangements in section 6.4.

2.4.4. Potential impediments to DSP in the wholesale market

Having considered the possible impediments to demand side participation by end-use customers, the relevant areas of investigation for the wholesale market are:

§ impediments to end-use customers accessing tariff products that reflect wholesale market prices directly;

§ the transaction costs associated with managing wholesale market prices directly, particularly for large end-use customers;

§ the awareness of large end-use customers of the potential to manage wholesale market costs directly;

- connection arrangements for distributed generation;
- the incentives for retailers to offer time-of-use or critical peak pricing tariff products to end-use customers;
- the incentives for retailers to manage wholesale price risks via demand side options;
- the scope for demand side participation in the provision of network control and support services; and
- the scope for demand side participation in satisfying Reserve Trader arrangements.

Most of these areas are beyond the scope of Stage 1 of the Commission's review since they are not related to the three reviews we have been asked to consider. However, the scope for DSP to provide network control and support services and to assist in satisfying Reserve Trader arrangements is relevant to the Congestion Management Review and the Comprehensive Reliability Review and is discussed further in Chapters 5 and 6 below.

2.5. Demand side participation and network planning and investment

As with the wholesale market, if customers face the direct cost associated with the provision of network services to satisfy their electricity demand, then an optimal degree of demand side participation would be expected to occur. This is because customers would choose between using the network and paying its associated cost, or reducing their demand.

The principal impediment to demand side participation in network planning and investment therefore arises because charges for the provision of network services are often independent of a customer's location within the network, whilst the marginal costs associated with providing network services to a location vary.[14] In other words, the demand forecasts that underpin network planning and investment processes are based on network prices that at times may mask the cost of meeting demand at each relevant time and location. If it was possible to set network usage charges so as to reflect the marginal costs incurred to provide network services at each relevant time and location, then customers would adjust their demand accordingly and we would expect demand side participation to be optimal.

In the first instance, it is therefore relevant to consider the impediments to pricing network services by reference to their marginal cost. These impediments include:

- uncertainty about the load profile of customers, such that the actual network costs cannot be presented to those customers who contribute most to network constraints; and
- policies of postage-stamp pricing for network charges.

As for wholesale market prices, smart metering technology will assist with addressing the first potential impediment, particularly for distribution network service providers. This is because smart meters record electricity usage for each 30 minute interval, allowing individual

[14] The introduction of locational prescribed transmission use of system services will help to improve the locational cost signals associated with providing transmission services to connection points.

customer load profiles to be recorded. This provides a platform from which network charges that reflect the costs of providing network services can be presented to each relevant customer.

Postage stamp pricing for network services is commonly applied by distribution and transmission network service providers. The relative absence of location-based prices for distribution network services results in end-use customers not responding optimally to the costs associated with the provision of network services in that location. This in turn leads to sub-optimal demand side participation.[15] In considering a possible shift away from postage stamp network charging, it is necessary to consider the likely costs as compared with the potential benefits.

For transmission network services, the rules provide for the annual aggregate revenue requirement for prescribed services to be allocated to connection points in line with transmission customers' demand at peak times within the network. The cost allocation process is based on the cost reflective network pricing (CRNP) or modified CRNP methodologies as specified in Rule S6A.3.

Direct load control programs also provide scope for locational signals associated with distribution network provision to be provided, whilst retaining postage stamp pricing to all customers. These involve the network service provider directly controlling a customer's large energy using appliances, such as air conditioners and pool pumps, to reduce their associated electricity usage. The customer participating in a direct load control program is usually paid a fee for participating, and also benefits from lower electricity use. In this way, the customer participating in a direct load control program pays a lower average price of electricity compared with those who do not participate in the program.

In the absence of network price signals that fully reflect the cost of network service provision, second best options need to be considered. These include incorporating demand side participation directly in the network planning and investment framework. It is therefore also relevant to consider the incentives NSPs have to consider non-network solutions in the investment and planning frameworks. The current planning framework involves both NEMMCO and NSPs. NSPs undertake annual planning processes including forecasting network maximum demands and subsequent network requirements, the results of which are published in their Annual Planning Reports. NEMMCO also publishes on an annual basis the Statement of Opportunities, which is its assessment of the network requirements within the national transmission flow paths. These network planning arrangements form the basis for network investment decisions, as NSPs seek to meet the network reliability standard, as determined by the Reliability Panel and the appropriate jurisdiction.

It is therefore relevant to consider the impediments to demand side participation as a substitute for network investments within the current planning and investment framework.

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15 ETNOF argues that this statement is unfounded (page 6, ETNOF Stage 1 Submission). In principle, however, the averaging of network costs is likely to lead to sub-optimal DSP because the associated network charges are likely to depart from the marginal cost of delivery for any particular customer. This means that a customer's decision to use electricity (particularly in the short run) is likely to be based on prices that do not fully reflect the marginal cost of providing network services at that time. The customer will therefore make decisions about demand reducing activities that do not fully reflect the costs that would be avoided if demand was reduced, giving rise to a risk of sub-optimal DSP.

The potential impediments for demand side participation within the planning framework may include:

- the practicability of demand side participation, as a substitute for both short-term and medium to long term network investment requirements;
- a lack of awareness by network service providers about the scope for demand side participation as a substitute for network investment; and
- a lack of information for proponents of demand side participation of the opportunities potentially available for demand side participation as a substitute to network investments.

In principle, improving awareness of DSP and additional information provision could be expected to improve the integration of demand side participation within the network planning framework. However, as highlighted by ETNOF it is necessary for the benefits arising from the provision of information to be balanced against the costs of making information (or more information) available.[16] This in turn requires some consideration of the materiality of any information deficiencies within the existing obligations placed on TNSPs.

In addition, there may also be biases against network service providers adopting non-network solutions resulting from incentives created within the network investment framework. Any such bias against non-network solutions would give rise to an impediment to optimal demand side participation.

Network service providers have incentives to invest in the network arising from their obligation to satisfy the reliability standard across the network. The incentive for cost minimisation in meeting that obligation arises from the rules for network cost and price regulation, and its interaction with the application of the regulatory investment test. It is therefore necessary to consider potential biases both in the incentives within the rules for cost and price regulation, and in the application of the regulatory test.

Only the incentives arising from the application of the regulatory test are within the scope of Stage 1 of the Review. For this reason, the potential for biases against demand side participation within the incentives created through transmission network service cost and price regulation is not considered further in this report.

The potential impediments that are within the scope of our study include:

- impediments to demand side participation within the existing network planning framework;
- ensuring that the treatment of demand side participation resulting from the incentives created within the regulatory investment test is unbiased; and
- information provision arrangements that facilitate demand side participation.

We consider each of these potential impediments further in Chapter 4.

16 Page 9, ETNOF Stage 1 Submission.

3. International experience of demand side participation

Over the last decade, policy makers and electricity businesses throughout the world have been focusing on demand side participation as a potentially cost effective alternative to traditional network and generation investments, in order to satisfy increasing demands on the transmission and distribution networks and existing generation capacity. A particular motivation has been rising generation, network and environmental costs, with demand side participation potentially encouraging more efficient energy use and thereby reducing these costs.

In the United States and Europe the focus has been on improving price signals through the introduction of time-of-use (TOU) and critical peak pricing (CPP), and also by improving the network constraint information made available to the public. The improvements in information provided are expected to support more efficient network and non-network investment decision making by all market participants.

This chapter presents three international case studies that are relevant to a consideration of approaches to facilitate demand side participation in Australia. These are:

1. Pricing for transmission network services at nodal exit points – Transpower New Zealand;
2. Removing impediments for distributed generation connecting to the transmission network – the Ofgem small generator discount; and
3. Reliability-based demand response programs in the United States.

3.1. Pricing for transmission network services at nodal exit points – Transpower New Zealand

The approach used by the New Zealand Electricity Commission to determine transmission prices charged by Transpower in New Zealand differs from that applied by the Australian Energy Regulator in Australia. Whereas transmission prices in Australia are based on usage of the transmission network, Transpower's transmission prices are based on the cost of assets used to provide services to an identified nodal exit point, and an amount associated with assets connecting the exit point assets, without regard to the actual electricity transferred through the exit point.

This approach to transmission charging improves the price signals for DSP, as compared against a flat undifferentiated transmission charge. However, the potential benefits of this approach for DSP are diminished because transmission prices are generally then averaged by distributors or retailers, such that end-use customers face a single flat transmission charge.

In the remainder of this section we outline the approach to transmission pricing by Transpower in New Zealand.

3.1.1. Background and context

Substantial restructuring of the electricity industry occurred in New Zealand from the late 1990's through to the early 2000's. Since this period, transmission pricing has been overseen by the Electricity Commission, with revenues being established by reference to a building block approach. Transmission prices have been controlled within a price threshold established by the Commerce Commission.

The current industry structure in New Zealand is characterised by a small number of large generator/retailer companies and regional distribution network service providers. Retail contestability was introduced with reasonable success in 1994, although the number of competitors remains small. Retailers are responsible for the installation and maintenance of meters at the premises of end-use customers.

3.1.2. Approach to transmission pricing by Transpower

Transpower's transmission prices consist of:

- connection charges – levied on all customers connected to the transmission network on an annual basis; and
- interconnection charges – levied only on distributors and large users directly connected to the transmission network, on an annual basis.

Both charges are in the form of a fixed annual fee determined for each customer, based on historic usage patterns and set to recover the forecast revenue requirement for each pricing year (April to March). Interconnection charges make up the bulk of Transpower's transmission revenue.

The methodology used to derive each charge is set out below.

3.1.2.1. Connection charges

Connection charges are set to recover the cost of assets associated with a specific connection point. This requires:

- attribution of asset values to each connection point; and
- allocation of associated costs between one or more users connected at that point.

This approach ensures that the cost of providing network services at a specific connection point is identified, so that the full cost of connection assets at that point is borne directly by the respective users.[17]

Network service costs that are allocated to each connection point include an asset cost component, asset maintenance component, operating cost component and injection overhead component. The asset cost component is calculated as the replacement cost of identified connection assets, plus an allowance for a capital return on the assets. These capital costs are calculated based on Transpower's regulatory cost of capital, plus an allowance for

[17] Connection assets are defined in technical terms and are primarily nodes or transmission links between connection nodes. In the case where a customer is connected at a node defined as an "interconnection node", any assets directly related to connecting that customer are deemed connection assets, as well as an allocation of shared land and buildings at that location.

depreciation. Asset costs are allocated to a connection point based on the proportionate asset replacement value.

Maintenance, operating and injection overhead costs are similarly allocated to a connection point based on relative asset replacement value.

Once costs have been allocated to connection assets, individual customer tariffs are determined based on the historic contribution to maximum demand.[18] Monthly charges are estimated by pro-rating the allocated connection costs to each customer. The monthly connection charge is therefore independent of actual electricity usage.

3.1.2.2. Interconnection charges

Interconnection charges recover the balance of Transpower's annual revenue requirement, after costs have been allocated to connection charges. Unlike connection charges that are based on a customer's contribution to maximum demand and the associated asset costs at the connection point, interconnection charges are the same for all customers on a per kilowatt basis. Interconnection charges equal:

- the interconnection charge cost base – calculated as the total revenue requirement less connection charge revenue, divided by the sum over all connection points of all customers' average contributions to regional coincident peak demand (RCPD) at each connection point;[19] multiplied by
- an individual customers' average contribution to RCPD at a particular connection point.

This approach averages the cost of providing interconnection services that satisfy regional coincident peak demand on a national basis, then allocates the average cost according to the historic contribution to regional coincident peak demand at a connection point. This approach results in customers connected at multiple points to the transmission network incurring more than one annual interconnection charge. Similar to connection charges, the annual customer charge is then pro-rated to arrive at a flat monthly fee.

3.1.3. Implications for transmission investment and demand side participation

3.1.3.1. Pass through of transmission charges

The effect of transmission charges on the demand for electricity is dependent on how those charges are passed through to retailers and then on to end users. Electricity retailers in New Zealand have different approaches to passing through Transpower's charges to end-use customers. For example Orion, a distributor in the Canterbury region of the South Island of New Zealand, converts connection and interconnection charges directly to variable peak and capacity charges levied on customers (retailers and large users only), reflective of the long-

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18 Where customers are connected at an interconnection point, their level of maximum demand is compared to the total capacity at that point rather than other users' relative levels of maximum demand.

19 Each customer's average contribution to regional coincident peak demand at an individual connection point is determined by averaging contributions over the 12 highest half hour peak incidences in the prior period for constrained regions, and 100 highest half-hour intervals for unconstrained regions.

run marginal cost of providing transmission capacity to customers during peak (at the connection point) and regional coincident peak periods.[20] In contrast, Vector Electricity, a distributor in the Auckland area, structures charges so as to reflect retail consumption charges (outlined below). In other words, Vector's charges are not reflective of the cost of providing network capacity during peak and regional coincident peak demand events.

The way in which retailers' structure prices for end users is limited by existing electricity meter installations (which is principally the responsibility of the retailer). Where existing meters are unable to record electricity usage information based on time of day intervals, there is little scope for retailers to pass on charges based on a customer's contribution to network peak demands. The main metering technology currently used in New Zealand are single element accumulation meters or dual element accumulation meters that are capable of recording peak and off-peak usage.[21] Electricity usage rates differ by day and night, and controlled and uncontrolled consumption.[22]

3.1.3.2. Efficiency of price signals

The principal objective of the Electricity Commission is to:[23]

> ensure that electricity is produced and delivered to all classes of consumers in an efficient, fair, reliable, and environmentally sustainable manner and promote and facilitate the efficient use of electricity

Consistent with this objective, the Electricity Commission is required to work toward ensuring that:[24]

> the full costs of producing and transporting each additional unit of electricity are signalled.

The current transmission pricing structure was adopted by the Electricity Commission, after extensive consultation, in large part as a response to practical barriers to the implementation of more efficient price structures, that would support greater DSP. In addition, a key consideration of the Electricity Commission was that connection and interconnection charges should not distort the price signals for DSP provided by the nodal pricing regime in the wholesale market.[25]

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20 Orion is able to charge customers on a ToU basis due to its practise of invoicing retailers and large customers only, and measuring consumption at the grid exit point (GXP) rather than at end user premises.

21 Source: MED New Zealand Energy Outlook to 2025.

22 Controlled consumption refers to consumption utilising an interruptible power supply. Specifically, controlled consumption may be defined as separately metered consumption at any time under the condition that the distributor may interrupt the power supply at their discretion (up to a cap) or during specified time periods. Interruptions are centrally executed by the distributors via ripple control signals. This requires a separate meter to be permanently connected to the specific appliance (predominantly hot water cylinders).

23 October 2006 Government Policy Statement on Electricity Governance, http://www.med.govt.nz/templates/MultipageDocumentPage____23098.aspx

24 Ibid.

25 Electricity Commission Consultation Paper, *Proposed Guidelines for Transpower's Pricing Methodology*, September 2004, Page 3.

The current wholesale pricing regime in New Zealand incorporates a nodal element allowing for differing network losses as well as network congestion. Generators effectively engage in simultaneous nodal capacity auctions, where prices are automatically set to network-wide short run marginal cost in unconstrained areas, and the marginal cost of local generation where constraints are binding (this approach naturally results in a revenue shortfall, hence the need for connection and interconnection charges).

In general, there is concern in NZ that this approach does not provide good signals for efficient transmission investment.[26] In particular, the long run marginal cost of network augmentation is not fully attributed to the drivers of those costs due to the averaging effect of postage stamp interconnection charges. Spreading costs in this manner implies that the causer only pays a proportion of investment that they have necessitated (although there are recognised difficulties with charging for marginal use – especially identification of the marginal user), and can result in inefficiently high network investment.

Regardless, the current pricing regime, which utilises historic contributions to peak demand, does provide some signals and incentives to reduce peak demand, where signals are passed through to end users.

3.2. Small generator discount – United Kingdom

In the United Kingdom, small generators are provided with a network charge discount to account for the additional benefits that they provide. While this discount was provided to address disadvantages associated with differences in the definition of transmission and distribution networks following the amalgamation of the England/Wales and Scotland electricity networks, it also recognises the wider network benefits that are associated with these forms of generation. In this section we outline the approach to the embedded discount for small generators in the UK.

3.2.1. Background and context

The current small generation discount arrangements were initially put in place as a temporary measure in 2005 partially to correct disparities between the treatment of small distributed generators (DGs) in Scotland and England/Wales following the creation of a single integrated network and competitive wholesale market servicing the entire UK. The discount is available to eligible small generators in Scotland until mid-2009, who were disadvantaged relative to counterparts in England and Wales following the amalgamation.

Ofgem recognises that licensing and transmission charging regimes in the United Kingdom (UK) have largely been developed for the needs of large generation and network service providers, and that operational impediments and barriers to entry exist for small generators,[27]

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[26] A general review of industry submissions to the transmission pricing consultation process suggests that the majority view was that efficiency had been largely traded off with ease of implementation and oversight, in particular with respect to postage stamp interconnection charges.

[27] "Small generation" with respect to the UK mainly refers to generation operations with a maximum capacity of less than 100 MW and connected to the network at 132 KV. This includes technologies such as photovoltaic (PV) cells, wind turbines and combined heat and power (CHP) plants. It should be noted that very small generation with capacity less than 50KW, or "micro-generation" at the domestic/ small commercial level, is subject to separate requirements and regulatory treatment in the UK and is being separately reviewed by Ofgem.

with respect to participation in wholesale trading as well as access to both the transmission and distribution networks.[28]

The wider issue of the treatment of embedded generation in the distribution network remains the subject of substantial ongoing review by Ofgem,[29] from which a permanent policy solution is scheduled to be implemented after the current period of application expires. In the interim, Ofgem enacted the small generator discount via a standalone amendment to the license condition of the transmission network operator, now National Grid.

3.2.1.1. Jurisdictional differences in treatment

Disparities in the treatment of small generators stemmed from different definitions of transmission for regulatory purposes between Scotland and England/Wales, as well as different application of license exemptions. Jurisdictional differences in treatment arise principally because:

- in north Scotland, small generators with capacity greater than 5MW face the same obligations as large generators;
- 132KV lines are classified as distribution in England and Wales, but transmission in Scotland, rendering some small DGs in Scotland liable for high voltage transmission network tariffs.

In light of these definitional differences, some small DGs in Scotland do not receive embedded benefits in line with DGs located in England and Wales, and additionally incur costs associated with meeting the obligations of large generators.

3.2.2. Small distributed generation as negative demand

Under the transmission network charging rules, small distributed generation connected to the distribution network is treated as negative demand. In other words, electricity generated and fed into the network is netted off against demand by the supplier, for the purposes of assessing network usage tariffs, thereby allowing suppliers to avoid demand tariffs. In addition, small DGs do not require a generation license, subject to certain specific conditions.

3.2.2.1. Tariff structure in the UK

Transmission charging in the UK is comprised of a locational component, which seeks to recover the marginal cost of network augmentation driven by increasing imports or exports to the network, and a non-locational component (the “residual tariff”) that recovers any remaining revenue requirements year to year that are not recovered through locational charges. The allocation of the residual tariff between demand and generation components is derived so as to maintain the regulated revenue recovery ratio between demand and generation, currently set at 73:27.

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[28] Ofgem Consultation Paper, *Distributed Energy - Initial Proposals for More Flexible Market and Licensing Arrangements*. 18 December 2007.

[29] A number of relevant reviews around distributed generation are incorporated into the ongoing British Electricity Trading and Transmission Arrangements (BETTA) reform programme being conducted by Ofgem.

Generation locational tariffs, imposed on large generators connected to the transmission network, are positive in zones where additional network investment is incurred, and negative in zones where local generation allows National Grid to avoid investment.[30] Demand locational tariffs for a given point are approximately equal and opposite to generation tariffs. However, under the current pricing methodology negative demand tariffs (after allowing for the residual component) are set to zero.[31] Since locational tariffs represent only a small proportion of total revenue[32], and given the revenue contribution ratio that must be maintained, demand tariffs are in general positive. DGs can therefore operate to reduce network demand tariffs in effectively any region, however, the magnitude tends to vary by zone, dependent on the significance of avoided investment.

Under this regime, small (unlicensed) DGs may access "embedded benefits", defined by Ofgem as avoided transmission use of network charges, but more broadly encompassing avoided network losses and balancing service charges.

The manner in which DGs may access benefits depends on the registration of the meter: negative demand may be offset against a supplier's positive demand, in which case the pass-through of benefits may be governed by private contract,[33] or a DG may contract directly with National Grid and receive direct payment of the demand charge. Small generators may also need to contract with distributors for use of their network: as a result, generators will not realise the full embedded benefit value of their output.[34]

3.2.2.2. The small generator discount

Ofgem has, as an interim measure, assessed the value of embedded benefits (per kW) as the sum of the generation and demand residual tariffs. Due to the tariff structure in which avoided demand and generation locational transmission charges will approximately sum to zero at a given location, the net benefit to small generators of remaining unlicensed is equal to the sum of the residual tariff components that are always positive for both generation and demand. National Grid has determined a combined residual tariff component of around £17.93/kW for small generators in 2007/8.

The small generator discount is set at 25% of the assessed embedded benefits. In 2007/8, this is estimated by National Grid[35] to be valued at £4.48/kW (25% of the residual tariff), equating to an aggregate estimated value of £3.03m in 2007/8. The discount results in a

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30 Small DGs can elect to participate in this charging regime but are not required to.

31 Under the current pricing methodology, where a demand zone is assessed to have a negative total tariff, the tariff is set to zero, and the unrecovered revenue component is allocated across remaining demand zones on a non-locational basis.

32 In 2007/8, National Grid forecast that locational tariffs will recover only 20% of revenue requirements in that year.

33 This is also true of benefits in the form of avoided balancing service charges.

34 A related issue that is being reviewed by Ofgem as part of its wider review of the regulation of embedded generation is the level of distribution charges being levied under relevant private contracts, where the negotiating position of distributors is superior to small generators. A significant proportion of embedded benefits may potentially be appropriated by distributors with market power.

35 National Grid Transmission Charging Tutorial. http://www.nationalgrid.com/NR/rdonlyres/F32EE909-557F-4340-B937-43120CEBD011/21979/TransmissionChargingTutorial.pdf

regulated revenue shortfall, which is fully recovered from remaining net demand tariffs on a flat charge basis.

A small generator in Scotland therefore receives a discount in transmission charges, either in the form of a payment directly from National Grid, or through reductions in associated transmission charges, where these would otherwise be positive.

3.2.2.3. Valuation of embedded benefits

The principal qualification to valuing the benefits of embedded generation by reference to avoided transmission tariffs is that it may not reflect the true costs and benefits of embedded generation - an issue currently under examination by both National Grid and Ofgem. As in the case of New Zealand, residual tariffs based on a postage-stamp charges are not fully reflective of the savings provided by embedded generation, which vary by time and location. In addition, additional costs associated with incorporating embedded generation into network management and wholesale markets may not be fully reflected in the residual tariff.

A second area of investigation is the appropriation of embedded benefits by distributors via unfavourable distribution charges. In some cases small distributed generators have limited means by which to connect to transmission networks and participate in wholesale markets: the potential appropriation of benefits may act to depress investment in distributed generation below efficient levels.

3.3. Reliability-based demand response programs – United States

Our final case study examines the range and extent of reliability based demand response programmes in the US, as recently surveyed by the Federal Energy Regulatory Commission (FERC).[36] The evidence in the US suggests that since 2006,[37] there has been a significant increase in DSP, particularly within planning processes.

The term 'reliability-based' demand side participation generically refers to programs aimed at controlling or curtailing demand primarily in order to maintain system reliability, particularly during critical peak demand periods, and excludes time of use or critical peak pricing regimes. Variable pricing regimes, in contrast to reliability based programs, can be differentiated in the sense that they primarily aim to price energy efficiently, rather than to achieve specific load reductions, although clearly the outcomes are interrelated and in some cases the delineation becomes blurred.

Reliability based programs have historically been adopted as an indirect form of time of use pricing due to technological constraints, utilised to manage critical peaks in the absence of efficient price signalling in the retail market, and integrated wholesale spot and forward markets. These markets continue to evolve and develop, and increased capability to implement efficient, integrated pricing regimes is consistent with an observed move away

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36 FERC *Assessment of Demand Response and Advanced Metering 2007*. Staff Report, September 2007.

37 Estimated customer participation in either rate-based or incentive based (reliability) programmes was around 5 per cent: FERC *Assessment of Demand Response and Advanced Metering 2006*. Staff Report, August 2006, Page 45.

from controlled and interruptible load programs to more dynamically priced reliability based programs such as demand bidding initiatives and forward capacity markets.

3.3.1. Summary of programs

This section provides a brief summary of the various forms of reliability-based demand response programs. Programs can be broadly categorised as voluntary or mandatory (upon participation), as well as predominantly utilised by lines companies or in the wholesale market to address network versus generation peak demand.

3.3.1.1. Direct load control

Direct load control refers to programs generally operated by network service providers allowing energy use to specific appliances at an end user premises to be directly controlled during pre-specified times or critical peak events. In return, subscribers (principally residential users) receive a rate discount or credit to their account.

Recent developments in technology such as “smart grids”, which allow finer control of localised consumption in response to grid stress or real time prices, have improved the operation of demand response initiatives and led to new initiatives in some regions. However, a number of transmission and distribution network service providers are winding down programs utilising older technology associated with legacy systems, or (as noted above) in response to state level industry restructuring.

3.3.1.2. Interruptible load

Customers subscribing to interruptible load initiatives receive a rate discount or credit to account in exchange for enforceable agreements to curtail load by a pre-specified amount, principally during network peak periods, or to curtail a specific block of load. These programs are directed more at large users who can respond to short notifications. However, they have declined in use due to decreased returns (price differentials) and perceived increases in risk.

3.3.1.3. Demand bidding / buyback

Demand bidding allows large customers to post price or quantity bids (for a given level of curtailment or price respectively) reflecting their individual demand curve for curtailment. Demand bidding or buyback programs, a relatively recent development, are operated by network as well as market operators, and attract involvement by demand aggregators and large users.

There are several forms of demand bidding participation in various markets: bids may be directly incorporated into dispatch processes by market operators, or alternatively participants may elect to curtail and receive the market price. In addition, network operators may post offers to which participants may respond and receive the offer price in return for curtailing load. These programs, only recently introduced, are arguably a proxy for wholesale market participation by subscribers that would occur with efficient critical peak pricing.

3.3.1.4. Emergency demand-response

Unlike interruptible load contracts, demand response programs involve voluntary curtailment by participants upon request, without incurring a penalty for non-participation for a given event. The incentive to curtail is typically in the form of a pre-agreed payment. Emergency demand response initiatives were recently successfully used in conjunction with capacity programs in 2006 to avoid rolling blackouts in critical summer peaks, however the voluntary nature of agreements reduces their reliability and consequently degree of incorporation into network planning processes.

3.3.1.5. Ancillary Services markets (contracted load curtailment)

Ancillary services are similar in principle to the other forms described in this section: participants place curtailment bids into wholesale markets as operating reserves. If bids are called, participants must curtail and generally receive the spot price. Ancillary markets differ in the degree of responsiveness and technology required. Notification is shorter than other mechanisms (hence participation requires real time telemetry) and minimum bid quantities tend to be higher. Consequently these programs, although growing, are much less widespread than other, more accessible, demand-response initiatives.

3.3.2. Results of FERC survey

The table below summarises the results of the 2006 survey of DSP programs available within the USA.

Incentive-Based Demand Response Program	Number of businesses offering program
Direct load control	234
Interruptible/ curtailed load	218
Demand bidding/ buyback	18
Emergency demand response	27
Ancillary services markets	1

Source: Adapted from Table IV-1, FERC 2006 survey results.[38]

The above table highlight the predominance of "traditional" load control and interruptible load initiatives. The number of new demand response programs is increasing, while participation in controlled and interruptible load programmes has been in overall decline since the late 1990's. FERC has noted that this trend may be partly attributable to mandated industry restructuring at the state level which has diluted or reduced the benefits of investment in load control infrastructure, as well as increased reserve capacity.[39] In some states demand response and load curtailment services have been deemed a competitive service. Following this, distributors were required to (or voluntarily opted to) divest these operations, which were subsequently scaled back or shut down.

Following the low level of participation identified in the 2006 survey, FERC has taken steps to encourage DSP initiatives: notably, it has revised its Open Access Transmission Tariff regulations to require that demand response be incorporated in transmission planning by grid operators.

A number of industry and regulatory barriers have been identified as potentially impeding the adoption of DSP initiatives. In terms of incentives to implement initiatives other than time of use pricing, uncertainty around the regulatory treatment of investment in DSP-related infrastructure that may become stranded is one risk identified as discouraging DSP initiatives. In addition, certain states are reviewing potential compensation models for network operators, who may be disadvantaged in the short run by DSP programs that reduce energy demand.[40]

FERC has previously canvassed this issue, identifying regulation and legislation around wholesale and retail markets as inadvertently impeding participation in reliability based DR programs, including settlement and payment procedures for wholesale markets and state restructuring legislation that particularly inhibit the participation of demand aggregators in wholesale markets. In addition, regulatory risk due to uncertainty over federal-state jurisdiction of demand response initiatives operating in the wholesale market have also been identified as potential impediments.[41]

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38 FERC *Assessment of Demand Response and Advanced Metering 2006.* Staff Report, August 2006, Page 63.

39 Ibid, Page 10.

40 Ibid, Page 127.

41 For further discussion of this issue see FERC *Assessment of Demand Response and Advanced Metering 2006.* Staff Report, August 2006, Pages 125 to 133.

3.4. Relevance of case studies to the Review

These case studies provide insights into alternative approaches to addressing impediments to facilitating demand side participation, based on experiences in international jurisdictions. However, their relevance is limited to the context of the particular international jurisdiction considered.

The first case study outlines the New Zealand approach to transmission charging, based on transmission network capacity at grid exit points, designed to provide locational signals for demand. In principle this approach would be expected to facilitate optimal demand side participation, although its application to end-use tariffs as applied by retailers may limit the incentives created.

The second case study outlines the approach to determining discounts for distributed generation in Scotland. Unlike in Australia, transmission charges in the UK are imposed on both demand and generation. A locational component seeks to recover the marginal transmission costs of both demand and generation (set as a negative tariff for generation, where it reduces transmission requirements). In addition, a residual non-locational component is recovered from both demand and generation based on a set ratio of 73:27. The discount to small generators is calculated as a proportion of the avoided non-locational transmission charges otherwise imposed on generators.

This case study highlights how the transmission charging regime in the UK provides a mechanism to provide discounts to small generators to account for the transmission network benefits they create.

The final case study outlines the approach to reliability-based demand response in the US. In particular it highlights the FERC requirement that demand side participation be included in transmission planning by grid operators. Since this requirement, there has been an increase in demand side participation programs in the US, although these are predominately through direct load control or interruptible supply arrangements.

4. DSP and network planning and investment

The arrangements for network planning and investment are important for ensuring the efficient use of demand side participation. This is because end-use customers generally are not presented with the marginal cost of providing the electricity network to their location, and so do not receive price signals that encourage them to take account of the costs of network use when making decisions on electricity demand. It is therefore necessary to consider the regulatory incentives created for network service providers to take account of demand side participation.

In this chapter we outline the current arrangements for network planning and investment within the NEM, and proposals on the role of the National Transmission Planner that are being considered by the Commission. The remainder of the chapter focuses on how best to facilitate efficient demand side participation in network planning arrangements, and demand side participation within the new regulatory investment test.

4.1. Current arrangements for network planning and investment

Transmission planning is conducted throughout the world to ensure that transmission networks meet reliability requirements and deliver economic benefits in the face of ongoing changes in network loads. While the specific approach varies, network planning generally involves:

- modelling of the power system to identify network requirements under a number of scenarios as to future electricity demand;
- identifying deficiencies in existing network capacity to satisfy these scenarios, and making this information publicly available;
- transmission network service providers identifying network investments, or non-network alternatives to satisfy the identified network deficiencies;
- the network options being evaluated by applying an economic cost benefit test to determine the most beneficial option; and
- the network solution or non-network solution being constructed or engaged, and the efficient costs incorporated within the cost base for the purpose of determining tariffs charged to end-users.

In the context of the NEM, network power system modelling and the identification of constraints within the National Transmission Flow Paths is undertaken annually by NEMMCO as part of its annual national transmission review. The result of this modelling is the Annual National Transmission Statement, which is published annually as part of the Statement of Opportunities (SOO). In addition, the SOO reports forecasts of supply and demand, including forecasts of committed and uncommitted demand side participation.[42]

[42] Committed DSP based on a survey conducted by NEMMCO in 2007 was 132MW, with an additional 532MW of uncommitted DSP – NEMMCO, 2007, 2007 Statement of Opportunities, page 4.

The current regulatory test requires transmission network service providers to evaluate both network and non-network options for satisfying identified network inadequacies.[43] The Commission recently reviewed and refined the framework for the making of the regulatory test, which includes an explicit requirement that transmission network service providers formally seek information from non-network providers as to possible non-network alternatives to a proposed network investment. This requirement was included to ensure that non-network solutions are appropriately considered by the transmission network service providers as part of their evaluation of the merits of a network solution.

In Victoria the evaluation of network investments is undertaken by a jurisdictional planning entity – VenCorp. VenCorp applies the regulatory test to proposed network investments in accordance with the rules.

Finally, the costs of a transmission network investment are included in a transmission network service provider's (TNSP's) regulatory capital base so long as the Australian Energy Regulatory (AER) is satisfied of the requirements specified in Rule 6A.6.7(c), the capital expenditure criteria. Where a non-network solution is considered to be more cost effective, its cost would be appropriately included within the operating costs of the business and thereby included in the cost base used for the purpose of setting transmission tariffs.

The potential impediments to demand side participation may therefore arise from:

- a potential lack of awareness of demand side participation as a substitute for network investments by network service providers;
- a potential lack of information as to the nature and extent of potential opportunities for demand side participation, by demand side proponents; and
- the potential undervaluing of demand side participation by network service providers, because it may lead to wider benefits than simply the avoidance of network investments.

As outlined in section 2.5, there may also be impediments to DSP in the incentives created within the regulatory framework for network pricing. However, these regulatory incentives go beyond the scope of Stage 1, but are relevant to the Commission's consideration of the Total Environment Centre's rule change proposal and Stage 2 of this Review. We therefore focus on impediments to information provision and the role of the National Transmission Planner in facilitating DSP.

4.2. Proposed role of the National Transmission Planner

Following recommendations made by the Energy Reform Implementation Group as part of its review of reforms to achieve a fully national transmission grid,[44] the Ministerial Council on Energy directed the Commission to undertake a review to develop a detailed implementation plan for a national electricity transmission planning function. The direction requires

[43] Rule 5.6.5A(c).

[44] Other elements of the review included measures to address structural issues affecting the competitiveness and efficiency of the electricity sector, and measures to ensure transparent and effective energy financial markets.

consideration of the establishment of a National Transmission Planner (NTP) within the newly created Australian Energy Market Operator (AEMO). The primary responsibility of the NTP will be the annual publication of a national transmission network development plan (NTNDP).

In its recent Issues Paper, the Commission identifies those matters where it is seeking further guidance through submissions. These include:[45]

- the appropriate boundary between national planning and local planning;
- the breath (in terms of scenarios) and depth (in terms of level of detail on investment options or solutions) included in the NTNDP; and
- the areas where the NTNDP, and the wider function that might be undertaken by the NTP, can add most value to the planning purpose.

The Commission has recently released its Draft Report for the National Transmission Planner Review, which outlines its preliminary views on each of these matters.

Irrespective of the final decisions of the Commission on these issues, there is likely to be merit in clarifying how demand side participation is included within the planning and information framework applied by the NTP in developing the NTNDP. We consider this in greater detail below.

4.3. Facilitating demand side participation in network planning

We discuss in Chapter 2 that, because end-use customers do not face the marginal cost of providing electricity network services to them, they are not provided with adequate price signals to facilitate optimal demand side responses. While pricing signals are likely to be improved through the introduction of smart metering throughout Australia, there are a number of areas where demand side participation may also be able to be facilitated in the context of the current network planning arrangements. These include:

- improving information provision on potential demand side participation opportunities from both networks to demand side aggregators, and demand side aggregators back to network service providers; and
- determining the role the NTP should play in facilitating demand side participation, if any.

Our analysis of each of these maters is set out below.

4.3.1. Information provision

In section 4.1, we noted that the network planning framework currently involves both national and state approaches, and varies between each state. While this balance may change with the introduction of the NTP, it is relevant to consider how the provision of additional information within the planning framework can facilitate demand side participation.

45 Page 19, AEMC, 2007, National Transmission Planning Arrangements, Issues Paper, 9 November.

Network service providers have historically sought to meet network reliability requirements placed upon them by managing the operation of and investment in the network. This has meant they have developed considerable expertise in evaluating when network investments are required and the least cost solution to address reliability concerns.

The emergence of demand side participation as a substitute for network investment has occurred relatively recently. It has been driven by concern about the cost of network investments as compared with cheaper non-network solutions, and the additional benefits that non-network solutions may have through reducing total electricity use.

There may be a number of reasons why network service providers may have difficulties in properly evaluating non-network options including:

§ NSPs do not have a direct relationship with end-use customers, which is instead managed by electricity retailers;

§ uncertainties associated with demand side options, making them less attractive;[46] and

§ a reliance on the regulatory test to provide incentives to consider non-network options, because of the absence of incentives arising from competition in the provision of network services.

This suggests that improving the awareness by network service providers of demand side alternatives to network investment is likely to raise the likelihood that these alternatives may be implemented. Improved understanding and awareness should reduce the perceived risk cost premium that may otherwise be attached to demand side options, thereby making them relatively more attractive.

Similarly, demand side aggregators that are engaged in bundling disparate demand side opportunities to provide viable alternatives to network options need to be aware of the potential opportunities within the network. Information on these potential opportunities needs to be provided with sufficient degree of certainty and advance notice to allow a viable demand side response to be developed as an alternative to a network investment.

There are therefore two potential information impediments that might arise for DSP proponents. These are:

§ a potential lack of opportunity to present non-network options to TNSPs, and for these options to be seriously considered; and

§ the availability of insufficient information on network constraints to allow DSP opportunities to be identified and non-network options developed.

ETNOF and Energex indicate in their submissions that the rules already require NSPs to make significant network information publicly available, and that the current information provision obligations should be sufficient for a demand side proponent to identify non-

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46 These might include, for example, uncertainty about the risks involved with a particular demand-side program, or the technical viability of a proposed demand-side program, due to a lack of experience with such programs.

network alternatives to network investments.[47] In addition, they argue that the process surrounding consultation on the Annual Planning Report (APR), in addition to the RFI process associated with the application of the Regulatory Test is sufficient to provide opportunities for demand side proponents to present alternative non-network options for network investments.

On the first potential impediment, while there are no formal obligations for TNSPs to work with DSP proponents on the development of non-network options, we are unaware of any DSP proponents having difficulties presenting non-network options to TNSPs for their consideration. The formal RFI requirement as part of the regulatory test require TNSPs to take account of non-network options that may be presented. In the absence of specific evidence of demand side proponents having problems presenting options to TNSPs, we believe that the current arrangements are sufficient to address any concerns.

To consider whether sufficient information is already provided to allow DSP options to be developed, we have more closely examined the information provision obligations in the rules, and the actual information provided in the APRs.

The rules give NSPs an obligation to conduct an annual planning review, as the basis for the investment planning activities of the business. The first step of the annual planning review requires Relevant Registered Participants (generators, customers[48], market participants and network service providers) to supply TNSPs with "short and long term electricity generation, market network service, and load forecast information in relation to each connection point which connects the Registered Participant to the transmission network."[49] Where this information leads to the identification of potential network constraints, TNSPs "must advise *Registered Participants* and *NEMMCO* of the expected time required to allow the appropriate corrective network augmentation or non-network alternatives" and "must undertake joint planning"[50] (involving only DNSPs) in order to identify solutions that can be considered by consultation participants to alleviate the constraint. The minimum planning period for transmission networks is ten years.[51]

The results of the annual planning review are required to be published by 30 June each year in TNSPs' Annual Planning Reports.[52] The APRs are required to provide information on forecast loads, planning proposals for connection points and anticipated constraints on transmission networks along with details of proposed solutions to these constraints, eg augmentation of existing or construction of new transmission assets.[53] TransGrid describes the primary purpose of the APR as the provision of "advance information to market

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[47] ETNOF Stage 1 Submission, pp9-10; Energex Stage 1 Submission, p. 3.

[48] 'Customer' is a defined term in the rules and means a person who: a) engages in the activity of purchasing electricity supplied through a transmission or distribution system to a connection point and b) is registered by NEMMCO as a customer under Chapter 2.

[49] Rule 5.6.1(a).

[50] Rule 5.6.2(c) and 5.6.2(e).

[51] Rule 5.6.2(d).

[52] Rule 5.6.2A(a).

[53] Rule 5.6.2A.

participants and interested parties on the nature and location of emerging constraints in the NSW electricity transmission network." It further points out that "the timely identification of emerging constraints allows the market to identify potential demand management solutions."[54]

For all proposed *augmentations of existing assets*, Rule 5.6.2A(4) requires TNSPs to provide information in their Annual Planning Reports (in sufficient detail relative to the size or significance of the project and the proposed operational date of the project) on the:

- project/asset name and the date when it would become operational;
- reasons for the actual or potential constraint, if any, or inability to meet the network performance requirements, including load forecasts and all assumptions used;
- proposed solution to the constraint and its total cost; and
- other reasonable network and non-network options considered to address the constraint or inability to meet network performance requirements.

If a TNSP decides that a potential constraint or inability to meet network performance requirement necessitates a construction of a *new transmission asset*, it needs to satisfy a separate set of requirements. To begin, a TNSP must decide whether the proposed new asset would be classified as small or large.[55] For *small* assets, the APRs must include an explanation of the rankings of reasonable alternatives to the project including non-network alternatives. The rules require that "this ranking must be undertaken by the TNSP in accordance with the principles contained in the regulatory test."[56] Each TNSP is then required to consult on the subject of new small transmission assets with any interested parties and seek submissions from these parties "within 20 business days of publication"[57] of the APR. TNSPs are required to take account of and publish any information arising from the submissions, provided it constitutes material different from information originally published in the APR.

If a project is classified as a *large* new transmission asset, Rule 5.6.6 requires TNSPs to undertake the following steps:

- to consult all Registered Participants, NEMMCO, and interested parties about the proposed new asset;
- to provide all Registered Participants and NEMMCO with an application notice that would set out a detailed description of:
  - the proposed asset;
  - reasons for proposing to establish the asset;

[54] TransGrid Annual Planning Report, 2007, p. 1

[55] A small new asset is currently any asset that is expected to cost less than $10 million, while a large new asset is any asset expected to cost greater than $10 million.

[56] Rule 5.6.2A(5)(i).

[57] Rule 5.6.6A(a).

- – all other reasonable network and non-network alternatives;
- – all relevant technical details, construction timetable and commissioning date;
- – an analysis of the ranking of the proposed asset and all reasonable alternatives undertaken in accordance with the principles contained in the regulatory test; and
- – a detailed analysis of why a TNSP considers that the asset satisfies the regulatory test. If a TNSP considers that the regulatory test is satisfied on a reliability basis, it must provide reasons for considering the new asset to be a reliability augmentation.

§ to provide a summary of the application notice to NEMMCO, which it is required to publish it on its website within 3 business days of receipt; and

§ within 30 business days of publication of the summary on NEMMCO's website, interested parties may make written submissions to a TNSP on any matter in the application notice, and may request a (public) meeting.

We understand that as part of the consultation process undertaken prior to the submission of a large new asset application notice, TNSPs generally publish a Request for Information (RFI) on non-network alternatives to the proposed new large asset. The Regulatory Test currently only requires RFIs to be published for projects undertaken under the 'market benefits limb', although this is expected to change following the Commission's review of the regulatory test as part of the National Transmission Planner Review. The RFI process is not currently required for new *small* transmission asset projects.

We have reviewed the 2007 Annual Planning Reports prepared by TransGrid, Powerlink, VENCorp and ESIPC, and observe that each TNSP provides information at varying detail, in compliance with the rule obligations. The scope and depth of information also differs between proposed large as compared with small augmentations.

For example, in its APR VENCorp provides maximum demand and energy forecasts, proposals for future connection points, discussions of committed network augmentations and forecast constraints along with an overview of existing network's adequacy to meet both the actual and forecast maximum demand. However, VENCorp also provides details on the probability of occurrence and the cost of anticipated constraints in terms of the number of hours the constraint is expected to last, anticipated peaks in MW, rescheduled generation and its value, and background information on the project. VENCorp also provides more detailed information for larger as compared with smaller new transmission asset projects. This additional information is likely to be of use to demand side proponents in the development of non-network options, but are not formally required by the rules.

Having considered submissions on the draft report, the question to be addressed is whether the information provision obligations presently contained in the rules provide sufficient information to allow a DSP proponent to identify possible non-network opportunities, with sufficient advance notice to allow it to be developed into a viable alternative to a proposed network augmentation. In the draft report we indicated that, in principle, there was likely to be an informational market failure because TNSPs would have little or no incentive to make sufficient information publicly available to allow DSP proponents to develop viable non-network alternatives. Our Draft Recommendation sought to address potential concerns about the difficulties faced by DSP proponents in engaging with the Annual Planning Review process. In light of the absence of any evidence or expressions of concern about access by DSP proponents to TNSPs to present alternative non-network options, we have withdrawn our recommendation that TNSPs be required to meet on an annual basis with DSP proponents.

4.3.2. The role of the National Transmission Planner in facilitating DSP

We discuss in section 4.2 above that one element of the Commission's review into the implementation of the National Transmission Planner is to examine and determine its role within the overall planning framework. It is therefore relevant to ask what role should the National Transmission Planner have in facilitating demand side participation in the NEM, if any?

In Chapter 2 we set out our view that facilitating demand side participation is likely to require some regulatory intervention because end-use customers do not face the relevant marginal cost of network services through the network tariffs they face. The NTP can therefore play a role in providing information to the market on the opportunities available to DSPs, in addition to the information requirements placed on network service providers discussed above. Such a role would be in addition to direct requirements on NSPs to take DSP opportunities into account as part of the regulatory investment test, outlined below.

There is a spectrum of possible roles that the NTP could play in facilitating demand side participation. At one extreme, the NTP could actively seek and invest in demand side options.[58] This approach would remove any obligations on network service providers to consider non-network options but would raise other regulatory problems such as:

§ how would the demand side options be funded; and

§ how would appropriate tradeoffs be made between network and non-network solutions?

Separating the process for investing in network and non-network solutions therefore seems unlikely to be appropriate.

At the other extreme, the NTP could simply take demand side participation into consideration in developing its own forecasts of network demand.[59] This would be analogous to the inclusion of DSP within demand forecasts made by network service providers. This would require the NTP to develop a methodology for collecting information on available demand response within the market and either modify expected load forecasts or identify it as an 'at call' responsive resource, according to the characteristics of the demand response identified.[60]

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[58] However, COAG did not contemplate the NTP having a role in network investment. The COAG communiqué outlining the agreement to establish a National Energy Market Operator with a new national transmission planning function confirms that COAG does not intend for transmission companies to lose any responsibilities for transmission investment - COAG communiqué 13 April 2007.

[59] We have assumed for the purpose of this paper that the NTP would undertake demand forecasting as part of its overall information provision role.

[60] In developing its methodology the NTP, it will be necessary to balance the accuracy of the demand response forecasts against the costs associated with obtaining demand response forecasts. The current technique used by NEMMCO of surveying retailers may not produce accurate forecasts of DSP because they may have little incentive to provide accurate information.

Somewhere between these extremes, the NTP could more proactively identify and pre-approve demand side options within the planning framework. This might involve:

- requesting information on demand side options to address identified network constraints, say, up to ten years into the future, on an annual basis;
- evaluating the viability of the demand side option against a set of criteria designed to ensure that the demand side option could act as a viable substitute, including identifying any wider market benefits; and
- providing detailed information on the demand side options to network service providers, for consideration within their network investment planning processes.

Such a role for the NTP would help to address concerns that there is no formal 'market' to allow demand side options to be adequately revealed with sufficient lead time to be a viable alternative to a network investment.

In evaluating the alternative roles for the NTP in facilitating demand side participation, it is relevant to consider the materiality of the market failures within the existing planning framework. These failures stem from the relatively weak incentives that TNSPs have to give equal weight to non-network options, and provide opportunities for demand side proponents to develop and present viable alternatives to proposed network investments.

At present, the rules require TNSPs to consider non-network options as a way of addressing the inherent lack of incentives they otherwise have. Involving the NTP in strategically identifying DSP opportunities might strengthen the incentives for DSP to be considered on a more equal footing to network options. However, the need for additional incentives presupposes that the existing incentives for TNSPs to give proper consideration to non-network options are insufficient. We note that the question of incentives will be considered in detail in Stage 2 of the Commission's Review. The role that the NTP should play in providing incentives for the consideration of DSP should be therefore considered within the broader question of the incentive framework.

In the Draft Report we recommended that:

- the Commission evaluate the materiality of the informational market failure that creates an impediment to demand side participation;
- the NTP be required to develop a methodology for the inclusion of demand side participation within the expected load forecasts to be published on an annual basis in the NTNDP, by transmission exit point; and
- if the informational market failure is considered material, develop a framework for the NTP to identify and evaluate non-network options, with the information being provided to network service providers for consideration in the regulatory investment test.

In general, a number of submissions were supportive of the National Transmission Planner having a more active role in facilitating DSP through the provision of information.[61] ETNOF argued that there is a "role for the NTP in facilitating DSP, this role should be focused on the strategic potential of demand side options, particularly in assessing the impact of low carbon emissions on future interconnection development."[62]

NEMMCO highlighted that to allow the NTP to have a more active role in providing information on DSP there would be a need to source further information from NSPs, which in turn would require further obligations to be placed on NSPs for the provision of information.[63]

Our final recommendation suggests that the role of the NTP for DSP should be limited to the development of a methodology for its inclusion in expected load forecasts. In addition, drawing upon ETNOF's comments, the NTP could provide a more strategic role for DSP as an approach to managing demand over a ten year time frame and this should be considered further by the Commission in Stage 2 of its Review.

Recommendation: We recommend that:

§ the NTP be required to develop a methodology for the inclusion of demand side participation in the expected load forecasts to be published on an annual basis in the NTNDP, by transmission exit point; and

§ the Commission consider the role of the NTP in providing strategic direction for DSP, as part of Stage 2 of its review into the role of demand side participation.

4.4. Demand side participation and the regulatory investment test

The rules currently require TNSPs to conduct the regulatory test prior to undertaking new network augmentation investments.[64] The regulatory test provides a cost benefit framework for assessing network augmentations and ensures that alternative non-network solutions are also taken into consideration. It is part of the regulatory framework to provide incentives for NSPs to make optimal network and non-network investment decisions.

4.4.1. Brief history of the regulatory test

The regulatory test has evolved since its early inception in the from of the customer benefits test as part of the original National Electricity Code in December 1997, which was originally applied by NEMMCO. The regulatory test arrangements included guidance as to its operation, with version 1 being published in March 1999. In light of a number of identified concerns, version 2 was developed and published in May 2002 In 2006, the Commission developed a framework of principles within the rules for the regulatory test, following the

61 ETNOF Stage 1 Submission, p.11; TRU Energy Stage 1 Submission, p. 3; NGF Stage 1 Submission, p. 2.

62 ETNOF Stage 1 Submission, p. 11.

63 NEMMCO Stage 1 Submission, p. 3.

64 Rule 5.6.6.

submission of a proposal from the Ministerial Council on Energy.[65] Subsequent to the regulatory test principles coming into effect, the AER has made a revised regulatory test.[66]

Each of the various versions of the regulatory test has sought to improve upon its predecessor by providing further clarity as to its operation. In addition, the Commission sought to provide incentives for NSPs to consider non-network options more formally within the regulatory test principles. The rules require an NSP to conduct a request for information on non-network alternatives to a network augmentation investment.[67]

4.4.2. Operation of the regulatory test

The AER recently amended the regulatory test (the Test) to comply with the requirements of the regulatory test principles outlined in Rule 5.6.5A. An option is considered to satisfy the Test if one of two circumstances hold:[68]

> (a) in the event the option is necessitated principally to meet the service standards linked to the technical requirements of schedule 5.1 of the Rules or in *applicable regulatory instruments* – the option minimises the present value of the *costs* of meeting those requirements, compared with *alternative option/s* in a majority of *reasonable scenarios;*
>
> (b) in all other cases – the option maximises the expected *net economic benefit* to all those who produce, consume and transport electricity in the national electricity market compared to the likely *alternative option/s* in a majority of *reasonable scenarios*. *Net economic benefit* equals the present value of the *market benefit* less the present value of *costs*.

In previous versions of the regulatory test, these two limbs have commonly been referred to as the reliability limb and the market benefits limb respectively. They can be characterised as a cost minimisation test, where a network or non-network option is principally required to meet a technical service standard, and a cost benefit assessment for all other circumstances.

Additionally, and in response to the regulatory test principles incorporated into the Rules, the test places an obligation on network service providers to request information on alternative non-network solutions, for any analysis undertaken under the market benefits limb of the Test.[69] This information request requirement does not apply for an option being considered under the reliability limb.

In practice most applications of the regulatory test have been based on the reliability limb, which has led to concerns that there are insufficient incentives to consider wider economic benefits associated with network or non-network options.[70]

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65 National Electricity Amendment (Reform of the Regulatory Test Principles) Rule 2006, No. 19.

66 AER, 2007, Regulatory Test version 3 and Application Guidelines, Final Decision, November.

67 Rule 5.6.5A(c).

68 Clause 1, Regulatory Test version 3.

69 Clause 24, Regulatory Test version 3.

70 It is uncertain at this time whether the changes to the regulatory test, initiated in response to the inclusion of regulatory test principles in the rules, will change the approach used by NSPs in the application of the test.

4.4.3. Problems with the regulatory test for demand side participation

As part of its considerations in to the NTP, the MCE has asked the Commission to establish a new project assessment and consultation process that:[71]

- Amalgamates the, currently distinct, reliability and market benefits limbs; and
- Broadens the definition of market benefits to include national market benefits.

In its consideration of the regulatory test the Commission renamed it with the working title of the regulatory investment test (RIT).

The amalgamation of the two limbs of the current formulation of the regulatory test is designed to ensure that options that deliver greater market benefits in addition to satisfying reliability requirements are appropriately considered when deciding between a proposed network investment and a non-network alternative. Arguably, the current formulation resulted in network (or non-network) investments that represented the least cost approach to satisfying the reliability requirement, but which did not maximise the potential net benefits when compared to alternative options.

It would be expected that by amalgamating the two limbs of the Test, potential biases against non-network options would be removed. The potential biases arise because some non-network options may not be the most cost effective means of satisfying a reliability requirement, but may deliver greater market benefits (although, it should be recognised that network options may also be so affected). By avoiding consideration of market benefits, a network service provider is able to set aside demand side options that may otherwise result in higher net economic benefits. Amalgamating the two limbs will therefore remove a potential bias in the application of the regulatory test and, in principle, may assist facilitating DSP.

However, it is also necessary to balance the benefits from amalgamating the two limbs with the additional administrative costs resulting from the requirement to estimate the market benefits. The decision criteria for the regulatory investment test should not unnecessarily impede NSPs from efficiently delivering network investments when required to meet the reliability standard.

4.4.4. Commission's proposal for a new regulatory investment test

The Commission has set out a number of options for the form of the regulatory investment test including:[72]

- full cost benefit approach;
- least-cost approach; or
- combined criteria approach.

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[71] Page 37, AEMC, 2007, National Transmission Planning Arrangements, Issues Paper, 9 November.

[72] AEMC, 2007, National Transmission Planning Arrangements, Scoping Paper, August.

In its recent Issues Paper, the Commission has highlighted that it believes that the decision criteria is now a choice between the full cost benefit or combined criteria approaches. In considering a full cost benefit approach it highlights that it would be therefore necessary to value the benefits associated with satisfying reliability criteria. The Commission goes on to indicate that a multi criteria approach such as maximising the ratio of the market benefits to costs may therefore be more appropriate. Since the draft report was released, the Commission has indicated its preference for a multi criteria approach.[73]

In our view, it is important that the decision making criteria do not induce a bias against demand side alternatives that deliver greater market benefits, but which may not be the least cost option. Setting aside the question of the increased cost of administering a more comprehensive test, society can be expected to be better off if a full cost benefit approach is applied to all proposed network and non-network options.

It is therefore necessary to consider whether it is appropriate to develop a common methodology for the valuation of reliability benefits for the purpose of undertaking a full cost benefit analysis. In our view it is possible to apply a full cost benefit methodology that does not require reliability benefits to be valued, irrespective of whether standards are deterministic or probabilistic.

The cost benefit analysis could simply require an evaluation of the extent to which an option satisfies, or contributes to the maintenance of, the reliability standard, and then consider the additional market benefits that would result. The option with either the highest net benefits, or the lowest net negative benefits that still satisfies the reliability standards would then be the preferred option.

Consider for example a proposed upgrade of a transmission line at a cost of $500 million. If this upgrade was found to be necessary to maintain reliability standards, but otherwise did not deliver any market benefits, the net benefits of this option would therefore be $0 minus $500 million or negative $500 million.

Now consider an alternative demand side participation option that can defer the investment for up to three years, and subsequently result in a lower cost transmission line investment, while maintaining the same reliability standards. If the cost of the demand side option is $100 million, but it delivers market benefits of $145 million in the form of deferred and reduced capital expenditure. The net benefits of this option would then be negative $455 million (being minus $500m, plus deferral benefits of $145m, minus $100m of the demand side option). This would suggest that the demand side option would delay the original project delivering net positive benefits, and thereby lowering the cost of meeting the reliability standard.

Critical to the application of the full cost benefit approach will be the qualitative assessment of the extent to which reliability standards are maintained. It will be necessary to allow a group of projects involving both network and non-network elements to be assessed against a pure network alternative, where a non-network alternative would not of itself satisfy the reliability requirements. In will also be necessary to consider the extent to which alternative

73 See, NTP Public Forum, Regulation Investment Test, Presentation by Colin Sausman, 2 April 2008.

options, both network and non-network, exceed the reliability benefits as compared to the proposed NSP option.

In principle therefore, a full economic cost benefit decision making criteria is likely to facilitate investment in demand side participation. In addition to the decision criteria, the regulatory investment test should:

- ensure that the request for information on non-network alternatives provides sufficient time for potentially viable non-network options to be developed and presented; and
- clearly define how ‘national market benefits’ should be interpreted for non-network options.

In addition demand side participation is likely to have a different risk profile as compared with network investments. There is merit in ensuring that NSPs appropriately account for these differences through the use of risk-adjusted costs and benefits for each network or non-network option considered during the application of the regulatory investment test. While the current formulation of the regulatory test does not currently preclude such an approach, we understand that in practice differences in the risks underlying a project may not necessarily be adequately accounted for.

Risk-adjusted cost benefit analysis can involve the use of different discount rates for each alternative project, in accordance with differences in the risks among projects. Alternatively, it can involve explicit inclusion of costs associated with actions to manage risks arising from one option compared against another. For example, the costs of preparatory work for a network augmentation in the event that a non-network alternative does not provide the expected network deferral.

Some concern was expressed in submissions about the appropriateness of adjusting costs and benefits to take account of risk as part of the application of the RIT.[74] In our view, the way in which risk should be accounted for in the application of the RIT requires further consideration, since a non-network option may otherwise be excluded simply because it has a perceived greater likelihood of failure. To ensure that DSP is not impeded in the application of the RIT, we believe that it is necessary to account for differences in the risk profiles between network and non-network options, while ensuring that the reliability standard is met. By explicitly accounting for any risk profile differences, non-network options that may have a different risk profile will be treated on an equal (risk-adjusted) basis, as compared with a proposed network option.

Finally, a benefit that may not be currently considered when evaluating non-network alternatives to a network investment is the option-value associated with the deferral of a network investment. The option-value is a benefit that can result from a non-network option delaying a network investment by a short period of time, allowing new information to become available that can affect the need for, or specification of, the original network investment. The improved information, say on outturn demand as compared with forecast demand, allows a network investment to be more appropriately specified, leading to potential

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[74] VenCorp Stage 1 Submission, p.4; Total Environment Centre Stage 1 Submission, p.7.

cost savings. The benefit therefore of a network investment deferral is a combination of the deferred and reduced capital expenditure, plus the associated option-value that it creates.

In the draft report we recommended that the regulatory investment test:

- ensure that the timeframe over which demand side participation options are required to be presented as alternatives to a network solution is sufficient to allow these options to be considered viable;
- clearly define how 'national market benefits' should be interpreted for non-network options;
- use risk-adjusted costs and benefits to take into account differences in risk between alternative options; and
- define an option-value benefit associated with an investment that defers a proposed network investment.

VenCorp outlined in its submission the importance of the amalgamation of the reliability and market benefits limbs of the regulatory test, to ensure that the RFI process for DSP is applied to all proposed projects subject to the RIT.[75] In addition, VenCorp highlights that it believes the RIT should be developed so that a market benefit is calculated for all options regardless of whether it is a network or non-network option.

In light of the comments received in submissions we have modified the recommendation on the use of risk-adjusted costs and benefits, indicating simply that differences in the risk profile between projects should be explicitly accounted for in the application of the RIT.

Recommendation: We recommend that the regulatory investment test:

- ensure that the timeframe over which demand side participation options are required to be presented as alternatives to a network solution is sufficient to allow these options to be considered viable;
- clearly define how 'national market benefits' should be interpreted for non-network options;
- take into account differences in risk between network and non-network options; and
- define an option-value benefit associated with an investment that defers a proposed network investment.

The Commission's draft decisions relating to the RIT have been outlined in its recently released Draft Report for the National Transmission Planner Review. The Commission is seeking comments on these issues as part of the consultation process for that Review.

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75 VenCorp Stage 1 Submission, p. 2.

4.5. Summary of recommendations

In this chapter we have considered the impediments to demand side participation within the regulatory planning and investment framework. In so doing we have made a number of recommendations including:

- improvements to the information available to demand side proponents, to facilitate the identification of demand side opportunities as a substitute to network investment;
- requiring the National Transmission Planner to develop a robust methodology for the incorporation of demand response within the forecasts of expected load for the purposes of network planning; and
- a number of modifications to the application of the regulatory test to facilitate greater participation of demand side response.

Finally, we acknowledge that these recommendations only address information provision within the network planning and investment framework and the operation of the regulatory investment test. Our focus has been on addressing potential informational market failures and ensuring there is no inherent bias in the formulation of the regulatory investment test against non-network solutions.

We have therefore not considered whether there are biases in the regulatory treatment of non-network costs that may also create a bias against non-network investments. This will need further consideration as part of the Commission's review of the TEC's rule change proposal and Stage 2 of this Review.

5. Demand side participation in congestion management

This chapter reviews demand side participation in the context of the Congestion Management Review. The areas where considerations relating to demand side participation are relevant to the Commission's draft Congestion Management Review recommendations are:

- the benefits associated with the development of measures of transmission capability for the identification of opportunities for demand side participation; and
- the extent that demand side participation can be a substitute to existing generation service provision for network support and control services.

For both the congestion management and the transmission regulatory framework, the Commission has indicated that the newly reformed regime should be given time to work. For this reason the Commission did not make specific recommendations on these two issues.

We understand that, in light of the near completion of the Congestion Management Review there is insufficient scope for the Commission to consult on any recommendations that we may make on the review recommendations to facilitate demand side participation. However, the Commission may choose to pass on these recommendations for further consultation or consideration as the MCE develops any future rule change proposals to implement the recommendations of the congestion management review.

5.1. Measures of transmission capability

The Commission has acknowledged that the major interaction between transmission and congestion management is the provision of transfer capability. This interaction, and specifically the potential for demand side participation to alleviate congestion within the transmission network, means that transmission network transfer capability is also relevant to our review.

In its draft report the Commission observes that the absence of effective measures of transfer capability of the transmission network limit the promotion of efficiency in transmission services. Similarly, as we discuss above, it should be acknowledged the lack of specific information on transfer capability also limits the scope for demand side proponents to identify opportunities. The Commission has indicated that work should be undertaken to develop better measures of transmission transfer capability, and then be given effect through obligations in the Rules. In our view the further development of measures of transmission transfer capability is warranted to provide information on the opportunities for demand side participation as a means of managing congestion within the transmission network.

In developing these transmission transfer capability measures, it is therefore relevant to consider how they may allow proponents of demand side participation to identify potential demand side opportunities. From a demand side participation perspective, transmission transfer capability should be specified at the connection point to distribution networks, since this allows the targeting of demand at locations where transfer capability is potentially limited.

Finally, in our view there is merit in the National Transmission Planner having responsibility for developing measures of transmission capability. For clarification, we envisage that this role would be for longer-term transmission capability, as distinct from the role TNSPs already have in developing demand forecasts for the near term for each connection point – up to 10 years. This would allow the NTP to fulfil its role to provide general information on opportunities for demand side participation within the load forecasting role at a strategic level.

In the draft report we recommended that the NTP be given the responsibility to develop measures of transmission transfer capability and, where feasible, publish transfer capability at each distribution network connection point.

VenCorp supported this draft recommendation and indicated that it would also be useful for the NTP to:

> prepare data that is forward looking, identify areas of congestion (including near congestion) and estimate the amount of DSR needed and the timing of when the DSR would be required.

We agree that there is merit in some consideration being given to the amount of DSP that would be required and when to address identified areas of congestion. This would more clearly identify the potential scope for DSP as a viable alternative. It is likely that such a requirement would place an additional information burden on TNSPs. It is therefore appropriate to examine the likely costs that would be imposed on TNSPs, for comparison against the benefits, before such a requirement was imposed.

Recommendation: We recommend that:

§ the NTP be given the responsibility to develop measures of longer term transmission transfer capability and, where feasible, publish transfer capability at each distribution network connection point; and

§ the Commission further examine the costs and benefits of placing an obligation on TNSPs to estimate the amount of DSP needed to address identified areas of congestion, and when the DSP would be required.

5.2. Current arrangements for network support and control services

Network support and control services are currently procured by network service providers or NEMMCO to manage network flows and thereby maintain the security and reliability of the network. In addition, network support and control services can be procured to improve transmission transfer capability, where there are benefits to the market as a whole associated with increases in transfer capability.

Network support and control services currently procured and delivered include:[76]

> § **Network Support Services –** procured by TNSPs via contracts with third parties (network support agreements (NSAs)); e.g. generators or load agreeing to be constrained on (or off) in specified circumstances;

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[76] Page 136, AEMC, 2007, Congestion Management Review, Draft Report, 27 September.

- **Network Control Ancillary Services (NCAS) –** procured by NEMMCO via contracts with Market Participants (not TNSPs) as either reactive power ancillary service (RPAS) in the form of voltage control, or network loading control ancillary service (NLCAS) e.g. rapid generator unit loading or load tripping.

In addition, TNSPs can substitute for NCAS procured by NEMMCO through investments in capacitor banks or static var compensators to manage reactive power. Appendix I of the Congestion Management Review draft report provides a comprehensive overview of the historical development of NSCS.

5.3. Potential impediments to DSP in the provision of network support and control services

In its draft report the Commission identified that there may be a bias against DSP in NSCS because of its regulatory treatment for the purposes of revenue control.[77] The implications are that there would also be a bias against demand side participation as a substitute for network investments to manage the security and reliability of the network.

In principle however, we believe that there is unlikely to be a practical or material bias against NSCS compared with network solutions resulting from its treatment in the regulatory framework. Any biases in the regulatory framework between costs allocated to operating expenditure compared with capital expenditure are not unique to NSCS or to investments in non-network solutions. There is always a risk that, providing the regulatory WACC is set at a cautiously high level, there will be incentives to maximise capital expenditure over operating expenditure due to the scope to earn a return on the risks incurred.

In addition to the incentives in favour of network over non-network services due to their treatment within the regulated revenue requirement, the current framework blurs responsibility for network support and control services between TNSPs and NEMMCO. This is of particular concern because investments by TNSPs in capacitors and static var compensators are a direct substitute for network control ancillary services. By splitting the responsibility between NEMMCO and TNSPs it is unlikely that efficient investment in these alternatives will result.

It follows that there is merit in considering the respective responsibilities for the procurement of network support and control services. The Commission characterises the current arrangement as NEMMCO acting as a "NSCS procurer of last resort". This may indeed be a suitable approach, however, there is merit from the perspective of ensuring optimal demand side participation for this or an alternative approach to be clarified within the rules. The current NEMMCO review of NCAS may be an appropriate means to develop such clarification.

The current framework for the procurement of NCAS does not formally preclude demand side participation being a substitute for alternative approaches, particularly for the provision of reactive power. We are unaware of any rule requirements that preclude NCAS from being provided by DSP. Any impediments are therefore likely to arise from its regulatory treatment as outlined above, or concerns with its technical feasibility. We believe that there is merit in

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[77] Page 137 ibid.

NEMMCO considering whether the technical requirements for the provision of NCAS may be modified to allow DSP to be a viable means of providing NCAS.

In general, submissions were supportive of our draft recommendations on impediments to DSP in network support and control service provision.

Recommendation: We recommend that:

§ the Commission request NEMMCO to consider how technical requirements may be modified better to facilitate DSP as a means of providing NCAS as part of its current review of network support and control services; and

§ the roles and responsibilities for the provision of NSCS between NEMMCO and TNSPs be clarified to ensure that DSP is facilitated.

We note that since the draft report, NEMMCO has indicated its intention to examine the clarity of the boundaries for NSCS procurement between itself and individual TNSPs as part of its review of network support and control services.[78]

5.4. Summary of recommendations

In summary, we have considered the recommendations made by the Commission in its recent draft report on the Congestion Management Review to determine whether any further recommendations should be made to facilitate demand side participation. In our view there are three areas where demand side participation could be enhanced being:

§ through the provision of information on transfer capability, to allow for the identification of opportunities for demand side participation to manage network congestion;

§ the provision of information on the amount of DSP needed and its timing to address an identified point of network congestion and

§ improving the approach to procuring NSCS, by clarifying the roles and responsibilities between NEMMCO and TNSPs and evaluating whether the technical requirements for the provision of NCAS can be modified to enhance DSP.

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[78] Page 12, NEMMCO (2008) Review of Network Support and Control Services, Draft Scoping Paper, March.

6. DSP and the Comprehensive Reliability Review

The Comprehensive Reliability Review (CRR) was undertaken by the Reliability Panel, made up of representatives from the electricity sector and consumers, and is chaired by Mr Ian Woodward, who is also a Commissioner. The terms of reference for the CRR required the Reliability Panel to review the NEM reliability standard, the Tasmanian reliability and frequency standards, the level of the Value of Lost Load, market floor price and cumulative price threshold, and whether the reliability safety net should be allowed to expire.[79]

In its final CRR report released in December 2007, the Reliability Panel indicated that it intends to submit a series of rule change proposals to the Commission. One of these relates to the existing 'Reserve Trader' provisions within the rules, which it proposes to rename the Reliability and Emergency Reserve Trader (RERT). In particular it intends to facilitate demand side participation through the RERT provisions.

Another intended rule change is to increase the Value of Lost Load (VoLL) from its existing level of $10,000/MWh to $12,500/MWh, in addition to changing its name to the Market Price Limit. A change to the Market Price Limit is expected further to facilitate DSP.

In the remainder of this chapter we outline the current reserve trader provisions within the rules, and detail the Reliability Panel's proposed changes to those provisions to implement the RERT arrangements. We examine whether the existing and proposed provisions provide any impediments to DSP, before making recommendations and drawing conclusions.

6.1. Context for interventions in the operation of the NEM

The NEM has been designed to be an energy-only market meaning that the incentives created through the interaction of supply and demand for the dispatch of energy at the market clearing price are expected to deliver sufficient capacity in the medium to long term to meet the NEM reliability standards.

Critical to the operation of the market is the level of the Value of Lost Load (VoLL). The VoLL, which the Reliability Panel has proposed is renamed the Market Price Limit, is a cap on prices within the market and is currently set at $10,000/MWh. The Market Price Limit is intended to represent the cost to customers of unserved energy.

It is the potential for generators to earn returns sufficient to cover their risk adjusted costs that provides incentives for investment in new generation capacity. The Market Price Limit is therefore a critical parameter for the operation of the NEM. The Reliability Panel is required to review the Market Price Limit on an annual basis.

Given concerns about the potential for the energy-only market to provide sufficient incentives to deliver the required generation capacity in the medium to long run, the rules also provide for interventions in the market to ensure that reliability requirements are satisfied. The interventions provided for are:

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79 Appendix A, AEMC Reliability Panel, 2007, Comprehensive Reliability Review, Final Report, December, Page 93.

- reserve trader arrangements where NEMMCO contracts for the provision of reserve capacity, as provided in Rule 3.12.1; and
- directions to market participants to do any act or thing to maintain or re-establish the power system, as provided in Rule 4.8.9(a).

6.2. Implications of changes to the Value of Lost Load

In the final report of the CRR, the Panel recommended an increase in the VoLL, which it also proposed to rename the Market Price Limit (MPL), from $10,000/MWh to $12,500/MWh. The increase is proposed to take effect from 1 July 2010.

The justification for an increase in the VoLL was the Reliability Panel's modelling that indicated that the reliability standard was likely not to be met under the existing VoLL. Increasing the VoLL has the effect of increasing the potential returns from spot prices, thereby increasing the incentives for investment in new generation capacity to equate demand and supply in the medium term. The model results indicated that insufficient new capacity would be created in the medium term under the current VoLL.

As the value of new generation capacity increases, so does the potential value of demand side participation as a means of equating supply and demand. The increase in the VoLL is therefore expected to lead to increases in DSP as a substitute for new investment. For this reason, any increase in the VoLL would be expected to be beneficial to the provision of DSP.

6.3. Current Reserve Trader arrangements

Rule 3.12.1 provides NEMMCO with the power to contract for energy reserves if it forecasts that reserve capacity has fallen to a level where the reliability standard may be compromised. The associated guidelines, as developed by the Reliability Panel, limit NEMMCO from entering into Reserve Trader contracts to a period within six months of a projected shortfall.

The Reserve Trader arrangements provide a safety net for any failures in the energy-only market to provide sufficient market capacity investment to meet the reliability standard in each NEM region. Nothing in the rules prevents DSP being contracted to provide reserve capacity. In recent years, NEMMCO has triggered the Reserve Trader arrangements and contracted for the supply of reserve capacity in Victoria and South Australia.

For example, on 23 September 2005, NEMMCO released a tender for the supply of reserve capacity for the Victorian and South Australian NEM regions for the period 16 January 2006 to 10 March 2006, in response to low reserve forecasts for that period. Following the tender process, four tenders were selected, being:

- VicPower Trading – 180MW;
- Energy Response – 125MW;
- The Australian Steel Company (Operations) – 55MW; and
- Zinfex Port Pirie – 15MW.

The successful tenderers in 2005 were a combination of demand response providers and additional generation capacity.

Once reserve capacity is available, NEMMCO is able to dispatch the capacity in circumstances where the market price reaches the Value of Lost Load. NEMMCO is obligated to dispatch the contracted capacity so as to minimise distortions in the market spot price.[80]

6.4. Proposals to change the Reserve Trader arrangements

In the final report of the Reliability Panel's Comprehensive Reliability Review, the Panel indicated that it considered the Reserve Trader arrangements to be a market distortion, but that the costs were minimal compared with the costs of the market overall and there were benefits associated with the provision of such a safety net.[81] The Panel considered that it was appropriate for the Reserve Trader arrangements to be enhanced and renamed the Reliability Emergency Reserve Trader (RERT).

The recommended enhancements to the RERT include:

- extending the time limit within which NEMMCO can contract for reserve capacity from six months to nine months; and
- providing greater flexibility in the tendering arrangements employed by NEMMCO, including a rolling tendering process and scope to negotiate with previous providers at short notice if required.

In addition, the Panel will request NEMMCO to examine the nature and form of the RERT contracts to facilitate demand side participation.[82]

The Panel's proposed modifications are likely to enhance the scope for DSP to provide reserve capacity. These proposed changes should be considered in the context of potential impediments for DSP, which we consider in the following section.

6.5. Potential Impediments to DSP in the Reserve Trader arrangements

The potential impediments to demand side participation in the Reserve Trader arrangements arise in two ways. First, the current process for contracting for reserve capacity creates a potential bias against DSP because reserve capacity cannot be contracted at a time greater than six months before the anticipated breach of the minimum capacity limits. The second potential impediment relates to the incorporation of known demand side participation into the assessment of reserve adequacy, which is then compared against the minimum reserve level to determine when the Reserve Trader arrangements are triggered. We consider each of these areas in detail below.

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80 Rule 3.12.1(g).

81 Page 76, AEMC Reliability Panel, 2007, Comprehensive Reliability Review, Final Report, December.

82 Page 78, AEMC Reliability Panel, 2007, Comprehensive Reliability Review, Final Report, December.

6.5.1. Are there impediments to DSP in the provision of reserve capacity?

On its face, there does not appear to be biases against demand side participation for the provision of reserve capacity. In recent tenders for the provision of reserve capacity in Victoria and South Australia, a significant proportion of the contracted reserve capacity was provided by demand side participation, On face value, this would suggest that there are few substantive impediments to demand side participation acting as a substitute to generation in the provision of reserve capacity.

However, potential concerns do arise in relation to the process for contracting for reserve capacity, which may affect the scope for demand side participation to be a viable option. These arise from:

- the length of time prior to a forecast shortfall that reserve capacity can be contracted – currently six months, and recommended for extension to nine months; and
- the inflexibility of the tendering process imposed on NEMMCO.

The Reliability Panel proposals to extend the period prior to a forecast shortfall during which reserve capacity can be contracted to nine months is expected to enhance the likelihood that demand side participation can be made available. Similarly, increased flexibility of the tendering process is also expected to improve the extent to which demand side participation will participate in the provision of reserve capacity. In summary the Panel's proposed changes to the Reserve Trader arrangements are expected to be beneficial to the promotion of demand side participation.

Given that the Panel has already reviewed and made recommendations on this matter, we do not believe that there is a need to increase further the time within which NEMMCO can contract for reserve capacity. In our view, there is no need for additional enhancements to the reserve trader arrangements to further facilitate demand side participation.

6.5.2. Incorporation of DSP in the medium-term projected assessment of system adequacy

Currently the trigger for the Reserve Trader arrangements is an assessment of the difference between forecast load and aggregate supply, which is compared against the minimum reserve level. This assessment is undertaken weekly as part of NEMMCO's medium-term projected assessment of system adequacy (MTPASA). Demand side participation is effectively incorporated within the MTPASA, as part of the daily 10 per cent POE peak demand forecast for two years ahead. As NEMMCO explains:[83]

> DSP available to the NEM is explicitly considered in the regulator assessments of reserve adequacy, as it effectively reduces the forecast maximum demand. In this way the amount of DSP available allows for a lower level of installed generation capacity to deliver the required minimum reserve level.

[83] NEMMCO Stage 1 Submission, p. 5.

We understand that NEMMCO surveys retailers to determine the extent of contracted demand response available, so that this can be incorporated into MTPASA. Given there is no real incentive on retailers to provide accurate information on contracted demand response, it is unlikely that these estimates are particularly reliable. We would expect the current estimates (approximately 132 MW of contracted demand response) of demand response to underestimate actual contracted amount available.

In addition, we understand that there may be problems with the survey approach used by NEMMCO, since the timing of the survey may not coincide with decisions by retailers to contract demand response, and thereby may not capture all actual demand response that becomes contracted. There may therefore be merit in re-examining the survey methodology and developing forecasts of DSP, rather than simply relying only on information provided by retailers on contracted DSP. The Total Environment Centre also suggests that NEMMCO survey distributors on their contracted DSP.[84]

Given the uncertainty around the demand response forecasts, there is potential for significant uncertainty in the assessment of reserve adequacy for the purpose of maintaining reliability standards. The effect of this uncertainty, if it is biased downwards, may be to lead to the contracting for reserve capacity in circumstances where, if better demand response information were available, the reserve capacity would not have otherwise been contracted. The costs associated with the reserve trader, while small, would therefore be inefficiently incurred.

In our view it would be beneficial for the promotion of demand side participation within the operation of the Reserve Trader arrangements if:

§ a methodology were developed for forecasting available contracted demand response for the purpose of incorporating DSP into the demand forecasts that form the basis of calculating the available reserve; and

§ retailers were obliged to provide information on actual contracted demand response, on a confidential basis.

We understand that NEMMCO has committed to improving its methodology for incorporating DSP in the reserve trader arrangements. This is expected to ensure that demand side participation is appropriately factored into the reserve adequacy calculation.

Submissions on the Draft Report indicated general agreement with the recommendations made on the reserve trader arrangements. We therefore affirm them in our final recommendations.

Recommendation: We recommend that:

§ NEMMCO continue to improve its approach to the inclusion of demand response within its methodology to determine reserve adequacy;

[84] The Total Environment Centre recommends that “NEMMCO overhaul its methodology for surveying and reporting on retailer demand response arrangements in reference to the AER development of distributor reporting”, and also develop a similar methodology for distributors, TEC Stage 1 Submission, p8.

- a methodology for forecasting available contracted demand response be developed, such that DSP is appropriately incorporated into the demand forecasts that form the basis of calculating the available reserve; and
- retailers be obliged to provide information on contracted demand response, on a confidential basis to NEMMCO.

6.6. The concept of a standing demand side reserve

As part of the Comprehensive Reliability Review, Energy Response proposed the inclusion of a standing reserve to alleviate its concerns about the potential impediments within the current Reserve Trader arrangements for the participation of demand side response. The key principles for the proposed standing reserve are:[85]

> - Unbundling the pricing of Reserve from the pricing of Energy;
> - Based on NEMMCO's forward Reserve projections NEMMCO call for tenders for the provision of all Reserve 2 years ahead (rolling ahead each year);
> - Minimum blocks of 30MW;
> - Initially (say for 2 years) a minimum amount of say 20% of the Reserve must come from the Demand Side (to encourage this to develop);
> - Enable generators to have a choice of providing the reserve or if they prefer to contract firm and appropriately located DSR to provide the reserve so they can supply energy;

The Reliability Panel has indicated that:[86]

> The Panel has given some consideration of the concept of a standing demand side reserve similar to that proposed by Energy Response. The Panel's modelling indicates there may be a role for medium-term demand side responses as an alternative for generation responses, as the level of USE achieved is very similar.

It is not clear from the CRR Final Report or the original Energy Response proposal what precisely is meant by the introduction of a demand side standing reserve, but it appears that the Energy Response proposal contemplates:

- continuous or regular contracting for reserve capacity, with a minimum amount from the demand side (of say 20 per cent); and
- partially moving away from the standing reserve as a 'safety net' for the provision of capacity within the operation of the market, through the separate identification and pricing of reserve capacity.

While this proposal would promote demand side participation, to ensure that it does not result in inefficient costs being incurred through the crowding out of market capacity investment, it would be necessary to contract only when reserve capacity is required. If it resulted in

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[85] Page 2, Supplementary submission Energy Response to the Comprehensive Reliability Review.

[86] Page 47, AEMC Reliability Panel, 2007, Comprehensive Reliability Review, Final Report, December.

reserve capacity being continuously contracted, then this is likely to result in excess reserve capacity being purchased, leading to inefficient costs being passed onto all consumers.

In our view, it is not clear that a standing reserve is warranted at this time. An alternative approach to reducing any barriers to demand side participation associated with the limited timeframe within which contracting for reserve capacity occurs would be to adopt a staged contracting approach, involving:

- on an annual basis, NEMMCO would invite proposals for the provision of reserve capacity, for the purpose of pre-approving providers of reserve capacity in the event that it is required. This would be similar to panel contract arrangements, where the terms and conditions for the provision of services are negotiated, with no commitment to contract for the services during any given period;

- where it is forecast that reserve adequacy limits will be breached, invite pre-approved reserve capacity providers to quote for the provision of specific reserve capacity for the identified period; and

- select reserve capacity providers on the basis of these quotations until the required reserve capacity is contracted.

A condition of the panel contract arrangement would be that reserve capacity would need to be provided within a period of months, say nine, of a request for quotation. This would prevent reserve capacity being unavailable when NEMMCO calls for quotations because it is contracted to network service providers or other market participants for other purposes. Alternatively the reserve capacity could be funded as an option, like insurance, to manage the risk of the market not providing sufficient capacity.

The advantage of this approach is that it would provide opportunities for the identification of demand side participation well in advance of the actual need to supply reserve capacity. This should address many of the concerns identified with the current Reserve Trader arrangements without creating the problems associated with a standing reserve.

6.7. Summary of recommendations

Having reviewed the recommendations made by the Reliability Panel on the reliability safety net, Market Price Limit, and demand side standing reserve, we believe that the only additional recommendations that should be made to facilitate demand side participation are that:

- NEMMCO continue to improve its approach to the inclusion of demand response within its methodology to determine reserve adequacy;

- a methodology for forecasting available contracted demand response be developed, such that DSP is appropriately incorporated into the demand forecasts that form the basis of calculating the available reserve; and

- retailers be obliged to provide information on contracted demand response, on a confidential basis to NEMMCO.

On the operation of the reliability safety net and the proposed demand side standing reserve, there is insufficient evidence to suggest that the current arrangements impede demand side participation sufficiently to warrant further modification. In our view, the current arrangements do not inhibit demand side participation from providing reserve capacity, and the additional enhancements recommended by the Reliability Panel should improve the timeframes in which demand side participation can provide reserve capacity. This should enhance its ability to provide reserve capacity.

7. Conclusions and summary of recommendations

This report presents our analysis and recommendations relating to Stage 1 of the Commission's Review of Demand Side Participation in the National Electricity Market. In accordance with the terms of reference for our review, we have focused on identifying impediments to facilitating demand side participation within the context of the National Transmission Planner Review, the Congestion Management Review and the Comprehensive Reliability Review.

In so doing we have focused on the following elements of the National Electricity Market:

- the network planning and information provision framework;
- the regulatory investment test;
- arrangements for network support and control services, including network support contracts by TNSPs and network control ancillary services contracted by NEMMCO;
- proposed changes to the Value of Lost Load;
- proposed changes to the Reserve Trader arrangements; and
- proposals relating to the concept of a standing demand side reserve capability.

In each of these areas we have considered how the National Electricity Objective could be enhanced through facilitating greater demand side participation. A fundamental premise of our framework for analysis is that further intervention is only required where current arrangements inhibit the presentation to customers of appropriate wholesale or network price signals, that would otherwise be expected to result in optimal choices on demand side participation. Further, where this is not feasible, the incentives on NSP's to consider DSP as an alternative to network investments should be unbiased.

For network planning and information provision, we had suggested that NSPs be required to seek information from demand side proponents on an annual basis on potential non-network solutions to emerging network constraints in order to facilitate greater demand side participation, outside of the existing APR consultations and requirements under the regulatory test. Having considered matters raised on this issue in submissions, we believe it appropriate to withdraw our earlier recommendation to place additional obligations on NSPs. Stakeholders have not identified any significant impediment to demand side proponents being able to present non-network options to NSPs. We expect that the integration of DSP into planning processes, as is currently occurring in some jurisdictions, for example by TransGrid and EnergyAustralia who are actively seeking non-network solutions to specific identified network constraints, is therefore likely to continue without further obligations being imposed.[87]

[87] Transgrid Annual Planning Report 2007.

To address the possibility that NSPs may have insufficient information about the likely feasibility of non-network alternatives to network investments, we recommend that:

- the NTP be required to develop a methodology for the explicit inclusion of demand side participation in the expected load forecasts published on an annual basis in the National Transmission Network Development Plan, by transmission exit point; and

- the Commission consider the role of the NTP in providing strategic direction for DSP, as part of Stage 2 of its review into the role of demand side participation.

Providing information on demand side participation by transmission connection point, in addition to the current practice of providing demand forecasts by transmission connection point would also be likely to assist with the identification of opportunities for demand side participation. However, there may also be merit in considering whether the reliability standard should also be determined by connection point, as suggested by the Australian Energy Regulator.[88] This may enhance the incentives that transmission network service providers have to use DSP to satisfy the reliability standard at particular locations within the network. In our view, the Reliability Panel should therefore consider the implications for demand side participation of the specification of the reliability standard as part of its current review of the transmission network reliability standard.

We also recommend that to facilitate demand side participation the regulatory investment test should:

- ensure that the timeframe over which demand side participation options are required to be presented as alternatives to a network solution is sufficient to allow these options to be considered viable;

- clearly define how ‘national market benefits’ should be interpreted for non-network options;

- take into account differences in risk profiles between network and non-network options; and

- define an option-value benefit associated with an investment that defers a proposed network investment.

To assist with the management of transmission network congestion, we believe there is merit in the NTP having responsibility to develop measures of longer-term transfer capability and, where feasible, publish transfer capability at each distribution network connection point. We anticipate that this might be a technically difficult task, but if feasible it would be likely to assist with the targeting of DSP efforts.

In addition, we believe there is merit in the Commission further examining the likely costs and benefits of placing an obligation on TNSPs to estimate the amount of DSP that would be needed to address identified areas of congestion, and when the DSP would be required.

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88 AER (2008), Submission to the Reliability Panel Transmission Reliability Standards Review, February.

For network support and control services we recommend that:

- the Commission request NEMMCO to consider how technical requirements may be modified to better facilitate DSP as a means of providing NCAS as part of its current review of NCAS; and
- the roles and responsibilities for the provision of NSCS between NEMMCO and TNSPs be clarified to ensure that DSP is facilitated.

Finally, for the Reserve Trader arrangements, we believe that efficient demand side participation would be enhanced through improving the methodology for incorporating demand side participation in the approach to determining the reserve adequacy. Specifically, retailers should be required to provide information on contracted demand response on a confidential basis to NEMMCO.

Appendix A. List of submissions on Stage 1

TRUenergy

Energy Networks Association

VENCorp

Ethnic Communities Council of NSW Inc

Energex

Ergon Energy

Energy Supply Association of Australia

NEMMCO

Total Environment Centre

Transgrid

Essential Services Commission

Electricity Transmission Network Owners Forum

SP Ausnet

National Generators Forum

Energy Users Association of Australia

Consumer Utilities Advocacy Centre

NERA Economic Consulting
Darling Park Tower 3
201 Sussex Street
Sydney NSW 2000
Tel: +61 2 8864 6500
Fax: +61 2 8864 6549
www.nera.com

NERA Australia Pty Ltd, ABN 34 092 959 665