FINAL REPORT

Prepared for:

Australian Energy Market Commission

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The Wholesale Market and Financial Contracting: AEMC Review of Demand-Side Participation in the NEM

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Date: August 2008

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GLOSSARY

BB	bulletin board
contingency	An event such as sudden disconnection of a generation that causes a sudden drop in frequency
CPP	critical peak pricing
Demand-side participation (DSP)	The ability of consumers to make decisions regarding the quantity and timing of their energy consumption which reflects their value of the supply and delivery of electricity – the act of deployment of a **demand-side resource** either manually or via automated control systems
Demand-side resource	The facility or facilities (prospectively) contracted to provide controllable load reduction capability
DNSP	Distribution Network Service Provider
Facility Agent	A party involved in the commercial aggregation of loads who would act on behalf of the end-user. Proposed as a possible new category of Participant – see Section 6.2.1.
FCAS	frequency control ancillary service
NCAS	network control ancillary service
NEMDE	National Electricity Market Dispatch Engine
NER	National Electricity Rules
NSP	Network Service Provider
RERT	Reliability and Emergency Reserve Trader
TNSP	Transmission Network Service Provider
ToU	time of use

1. INTRODUCTION

The Australian Energy Market Commission has engaged CRA International to provide advice in relation to:

- ways in which DSP can be used in the NEM;
- limitations on use of DSP due to the design of the Rules (National Electricity Rules); and
- options for change to the Rules where limitations on use of DSP are found to exist.

[**Note:** The purpose of the paper is to consider demand-side matters and thus excludes detailed consideration of embedded (distributed) generation.]

Demand-side resources can participate in the NEM as part of two broad groups of service:

- DSP within central dispatch; and
- DSP independent of central dispatch.

The focus of this report is on the rules and other incentives that facilitate participation. Within each group there are a number of forms of deployment, the sub-groupings of deployment can have a similar effect on market outcomes and therefore are not necessarily mutually exclusive – that is, DSP initiated for one form of deployment may also be available to be deployed through other forms and have similar effects on market outcomes, but be brought to market by different parties who have quite different motivations. The ability to deploy demand-side resources for multiple purposes can be an important determinant of the overall value of DSP to the provider and, therefore, is directly relevant to the aggregate volume of demand-side resources that may be available across all forms of deployment.

Central dispatch is the process by which NEMMCO receives input data from participants and uses this in conjunction with its own forecasts of demand and parameters that describe operating limits on the power system to develop dispatch instructions and prices. The central dispatch process runs each 5 minutes. The spot price used for settlement of the market is formed from the average of the 5-minute prices in each 30-minute trading interval. NEMMCO uses software known as the National Electricity Market Dispatch Engine (NEMDE) to develop the 5-minute dispatch instructions and prices. Section 2 focuses on demand-side resources that are deployed in the market directly through the NEMDE – that is, DSP within central dispatch. Section 3 deals with other forms of DSP – that is, DSP independent of central dispatch. Each group of deployment affects some of the participant inputs and network operating limits to dispatch, and therefore indirectly affect the outcome of dispatch. However, demand-side resources deployed independent of central dispatch are not optimised within the dispatch process, nor are they operationally deployed as a result of a dispatch instruction developed in the central dispatch process. The primary motivation for Market Participants to use these forms of deployment is often unrelated to dispatch outcomes. The motivations can be management of network loading (irrespective of pool prices) or management of hedge positions (where changing pool price could be counter productive).

The structure we have applied to our analysis is as follows:

- There are 5 different categories of industry stakeholder considered:
  - **End-users** – facility owners / operators who face the decision as to whether to make demand-side resources available to other market agents to manage deployment of the facility on their behalf;
  - **Market Customers** – probably (although not necessarily) a Retailer. Under existing Rules, energy services, FCAS and NCAS must be provided by either a Generator or a Market Customer;
  - **Facility Agent**[1] – not (currently) a formal Market Participant, but a party involved in the commercial aggregation of loads who would, under existing arrangements, act on behalf of the end-user in:
    - structuring financial hedges around demand-side resources;
    - dealings with a Generator or a Market Customer for the purpose of deploying demand-side resources as energy services / FCAS / NCAS;
    - dealings with NEMMCO for the purpose of deploying demand-side resources in the RERT process; and
    - dealings with NSPs seeking to manage network loading;
  - **NSPs** – TNSPs or DNSPs; and

1 Proposed as a possible new category of Participant – see Section 6.2.1.

- **NEMMCO**.

- Effectiveness is judged against the following 6 characteristics:

  - **Incentive to participate** – How do current arrangements affect the willingness of the various parties to play a role in each form of DSP?

  - **Opportunity to participate** – What opportunities exist for various parties to play a role in each form of DSP;

  - **Flexibility of participation** – When DSP occurs, how flexible is the extent of that involvement?

  - **Transparency of demand-side resources** – Is the volume of demand-side resources being deployed apparent to all parties with a legitimate commercial or system interest in that deployment?

  - **Firmness of demand-side resources** – How accurately does the offered volume of demand-side resources match actual deployment and how are variances from expected deployment handled by each party?

  - **Managing interactions with other parties** – How is communication of deployment managed between interested parties?

This paper is structured as follows:

- Section 2 describes the forms and effectiveness of demand-side resources that are deployed in the market directly through the central dispatch process;

- Section 3 describes the forms and effectiveness of demand-side resources that are deployed independent of the central dispatch process;

- Section 4 outlines lessons that can be taken from previous reviews of DSP mechanisms;

- Section 5 summarises the identified limitations to greater utilisation of demand-side resources; and

- Section 6 suggests some area where Rule change could be considered as a means to facilitate greater utilisation of demand-side resources.

2. DSP WITHIN CENTRAL DISPATCH

2.1. DSP AS A SCHEDULED LOAD IN THE ENERGY MARKET[2]

Service description

Scheduled loads are potentially the most well understood form of demand-side resources dispatched through the dispatch process. "Scheduled load" in the NEM is a load registered with NEMMCO as such[3] and is managed in a manner analogous to that of scheduled generation. In the central dispatch process scheduled load and scheduled generation have similar requirements – each must be able to respond with an acceptable degree of accuracy to dispatch instructions issued by NEMDE and have appropriate telemetry to communicate with NEMMCO's Energy Management System (EMS). EMS facilitates confirmation of response by scheduled units to dispatch instructions and management of the consequences of scheduled units failing to conform to dispatch instructions.

In responding to dispatch instructions, scheduled generation is assumed to ramp linearly from its current position to an output target 5-minutes hence. Given the (often) discrete nature of scheduled loads, the movement from current position to the new consumption target 5-minutes hence could occur at anytime within the 5-minute interval. Conformance and non-conformance is measured on the basis of actual position vis-à-vis target position at the end of each 5-minute interval[4].

"Remuneration" for scheduled loads in the settlement of the spot market is on the basis of avoided liability for energy payments – that is, through a reduction of cost, not additional revenue. As the market clearing price rises, scheduled loads will progressively be switched off in response to dispatch instructions; and as the market clearing price falls, scheduled loads will progressively switch back on.

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2 Part of a scheduled load may include a generator located behind the customer connection (metering) point. For the purposes of this paper it will be assumed that metered load at the connection point is all that matters. It is considered immaterial as to whether or not that metered load is affected by the use of local generation.

3 Pursuant to NER clause 2.3.4(d): "A *Market Customer* may request *NEMMCO* to classify any of its *market loads* as a *scheduled load*."

4 To the extent that the combination of actual dispatch of load and generation does not match changes in non-scheduled demand, ancillary services will be used to smooth out the differences.

Many loads capable of being scheduled are comprised of large discrete load blocks, they would be generally unable to follow an instruction to dispatch part of their load. Hence, to avoid a position where a load is regarded as non-conforming with dispatch instruction, the challenge for discrete scheduled load blocks is to ensure that it is never "marginal" in the dispatch process[5]. Smaller loads or controllable aggregations of small loads do not face restrictions of this nature.

Historically, the only loads to have registered as scheduled in the NEM are hydro pumping facilities (typically 50MW and greater) and, in the early years of the NEM, some aluminium smelter loads (typically 100-200MW) – it is understood that there is zero load currently operating as scheduled. Other load types such as smelters and refrigeration facilities are obvious candidates with technical characteristics that also lend themselves to periodic use or short-term interruption, but these facilities choose to either ignore the dispatch process or respond to market prices through other mechanisms.

Effectiveness of current Rules & processes

- **Incentive to participate**

  A load classified as a scheduled load is required to be capable of complying with dispatch instructions [NER clause 2.3.4(e) and (g); 4.9.3(d)]. Although it is technically possible, it is likely that for many customers it would be impracticable for an end-user to manage all market interactions themselves, as this would involve substantial transactions costs with respect to managing the administrative (NEMMCO registration) challenges of:

  - registering as a market customer;
  - establishing suitable telemetry communication facilities to be able to respond to dispatch instructions from NEMMCO;
  - classifying the facility as a market load;
  - complying with the prudential requirements associated with being a Market Customer [NER clause 3.3].

  The transactions costs identified above seem like a high cost to pay for the opportunity to be rewarded in the form of avoided liability for pool prices. The extent of the "reward" for end-users and Market Customers (Retailers) will be governed by:

5 "Marginal" is a term to reflect the status of a unit whose dispatch is (at least partially) determining a regional reference price and is thus likely to be required to dispatch only part of the generation (load) that has been offered (bid) into the scheduling process.

- the volume of load not consumed multiplied by the price that would have been observed had the load been taken less the value the foregone energy would have derived[6]. The level of price cap (VoLL) will affect the magnitude of the incentive to respond to price but will be similar for demand-side resources participating directly in the dispatch process and those responding indirectly; and

- the share of the saving that is negotiated between an end-user and its Market Customer. Where a load is a customer of a Retailer and has an agreement with that Retailer to allow it be registered as a scheduled load[7], it will generally receive a share of the saving the Retailer makes because its purchase from the spot market is reduced.

As market dispatch is on a 5-minute basis and settlement is on a 30-minute basis, fast responding demand-side resources (and generators) can find that they are dispatched for only some of the 5-minute dispatch intervals within a 30-minute trading interval. If the 5-minute prices are changing rapidly during the 30-minute period, a demand-side resource can find that it is dispatched during the 30-minutes, even though the 30-minute price is below the bid price. This is a feature of the market that each participant needs to manage; Market Customers may respond to the settlement risk through bid structures that reflect a distortion of the true economic value of the scheduled load.

Being involved directly in the scheduling process does not provide any real advantage to loads in terms of their ability to respond to changes in the spot price – response can be automated regardless of whether or not a load participates in central dispatch.

Demand-side resources (and generators) may be dispatched to manage an intra-regional constraint, even though the regional reference price was below the price where dispatch was economic. Should dispatch of a scheduled load be affected by an intra-regional network limitation[8], NEMDE effectively makes a decision to dispatch (or not) based on the "pseudo-nodal price" implied by the relevant constraint equation, when the demand-side resource manager is likely to be trying to manage exposure to the RRP. Depending on the nature of the difference between the spot price and the value of the load (pseudo-nodal price), it could be disadvantageous for a load to participate in the dispatch process under current arrangements. Other markets use constrained on/off payments to bridge the difference and, in principle, network support contracts with network service providers fill a similar role.

6 The fact that load is not taken could have the (intended) effect of reducing the pool price below the point that would otherwise have been observed.

7 See Footnote 3.

8 Reflected in NEMDE through a constraint equation.

Depending on the size of the load involved, decisions to be involved in central dispatch could have a significant impact on overall network flows. In this respect there is an advantage to the economic efficiency of dispatch where loads are scheduled as this allows reductions in operational margins otherwise must cater for uncontrollable variations in load patterns.

TNSPs and DNSPs are not directly involved in the dispatch process and are therefore largely indifferent as to whether loads become scheduled, except to the extent that network flows could be affected through the dispatch process. If participation of scheduled loads reduces total energy flows, there will be lower order impacts on energy-dependent regulated revenues.

On the other hand, one incentive for Market Customers to be involved with scheduled loads is that any opportunity to diminish liability for market settlement payments will have a favourable impact on Market Customers' assessed maximum credit limit and, hence, could reduce the level of financial guarantee they are required to provide to NEMMCO[9].

- **Opportunity to participate**

  Participation as a scheduled load is limited only to the extent that a facility is prepared to submit to and pass NEMMCO's formal process of classification as a scheduled load (noted earlier).

  The relevant Rules for participation as a scheduled load are "tight" in terms of the requirement to conform accurately and in a timely manner to dispatch instructions. Current market arrangements deem it appropriate that the Rules for scheduled load be restrictive, as there are significant implications for the reliability and security of operation flowing from the scheduling process.

  Facility owners whose opportunity costs of avoided load are greater than the market price cap will never see a signal sufficient to provide an economically viable opportunity to allow them to participate as a scheduled load. Prima facie the level of the market price cap could therefore have an influence on participation. However, it is not clear that a higher market price cap would necessarily being more demand-side resources into the market in the longer term. This is because a higher market price cap would also be likely to bring additional generation to the market and there would be considerable additional DSP that could come forward at prices less than $10,000/MWh provided the mechanisms were more aligned with the characteristics of demand-side resources.

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9 The level of financial guarantee that a Market Customer must provide is based on maximum credit limits and prudential margins. In combination, this adds up to several weeks of "*reasonable worst case* estimate of the aggregate payments for *trading amounts* (after *reallocation*) to be made by the *Market Participant* to *NEMMCO*". To the extent that having demand-side resources available, diminishes the size of possible settlement outstandings to NEMMCO, the level of financial guarantee to be provide will diminish.

It is notable that participants who control potential demand-side resources have greater flexibility than equivalent sized generators. Demand-side resource owners have a choice to: participate as a scheduled load; register as a Market Customer without registering as a scheduled load; or simply to respond to the published price and negotiate a pass-through tariff with a Retailer. On this basis we see little justification for loosening the Rules for participation as a scheduled load, which could otherwise compromise the central dispatch process.

- **Flexibility of participation**

  The formal central dispatch process [NER clause 3.8] presumes all scheduled units are facilities with infinitely variable loading characteristics. All scheduled units are assumed to be able to exactly follow a dispatch instruction issued by NEMMCO, even if the facility is dispatched part way through a bid / offer band. A dispatch instruction from NEMMCO can be for any whole number of MWs in any bid band and, for scheduled loads, will be a target level of MW consumption to be achieved by the end of that dispatch interval – there is no inter-temporal optimisation that will allow consideration of target quantities for time frames other than the immediate 5-minute dispatch interval. Accordingly, if a facility can only be dispatched in discrete quantities (rather than single MWs) the relevant party will need to ensure that dispatched bid bands are not marginal (i.e. dispatched part way through a bid band) in order to avoid the consequences of being declared non-conforming [NER clause 3.8.23][10]. Generators with similar restrictions are required to use the rebidding system to "force" NEMDE to issue dispatch instructions consistent with their operating limitations. The same applies to DSP.

  Even if a load could be controlled such that only a proportion of it is turned "on" or "off" as required, NEMMCO's registration would prevent only part of a load being classified as scheduled – each dispatchable unit is required to have its own metering.

  Although deployment of a large number of small loads may be simplified if they are aggregated and dispatched as a single load, approval of aggregation can only be guaranteed if the loads are connected at a single site with a common intra-regional loss factor. However, NEMMCO may approve aggregation provided such aggregation would not materially distort central dispatch [NER clause 3.8.3]. For a Market Customer, subject to being able to overcome load aggregation and control / communication issues, having a diversity of loads under management will provide a valued flexibility of demand-side resources – an ability to respond more accurately to dispatch signals and to mitigate the effects of non-conformance by discrete loads.

10 Conformance to dispatch instruction is necessary to ensure NEMMCO is able to adequately manage perturbations around forecast and actual load within the dispatch interval, with the objective of ensuring all network equipment loadings remain within rated values.

- **Transparency of demand-side resources**

  Demand-side resources deployed as scheduled load are clearly signalled to all relevant parties in the dispatch process for each 5-minute period, however, there is no mechanism or requirement for a demand-side resource to indicate its intentions to rebid to manage inter-temporal operating constraints.

- **Firmness of demand-side resources**

  The relevant Market Customer is responsible for ensuring that bid quantities are managed in accordance with dispatch instructions within a tolerable time and accuracy [NER clause 3.8.23]. All changes in availability of scheduled loads are required to be signalled via the rebidding process [NER clause 3.8.22; 3.8.22A] – for example, if a discrete load was given a signal to dispatch only part of its load, it would be exposed to non-conformance provisions and, to mitigate the effect of this issue, would be required to "rebid" its demand-side resources in subsequent intervals in order to achieve conformance[11].

- **Managing interactions with other parties**

  All interactions between relevant parties (facility operator, Market Customer and NEMMCO) are managed via signals from NEMDE and communication (telemetry) between the demand-side resource and NEMMCO's energy management system. The communication arrangements are specifically designed to ensure power system security can be effectively managed and that parties subject to a dispatch instruction can be audited in real time as having responded within tolerable degrees of accuracy.

Summary of effectiveness

The effectiveness of current arrangements in facilitating utilisation of demand-side resources as a scheduled load is low because incentives to participate are low and disincentives to participate are high – opportunities are characterised by:

- lack of financial reward from participation;
- potentially high cost of control systems required to participate;
- onerous administrative requirements to be registered / classified as a scheduled load;
- inability for specialised aggregation service to play a direct role in the formal registration / classification process;
- the risk of mismatch between opportunity cost of load and the pool price at the time a dispatch signal is received;

11 Rebidding is allowable under NER clause 3.8.22.

- challenges created by the prospect of marginal dispatch of a discrete load; and
- no loss of ability to respond to pool price movements if the resource does not participate.

2.2. DSP AS A MARKET ANCILLARY SERVICE (AKA FCAS)

Service description

Loads with suitable control capabilities are able to participate in the provision of market (frequency control) ancillary services (FCAS) in a manner similar to scheduled loads in the energy market. The types of FCAS are:

- "**regulation**" raise or lower – requirement is being able to respond continuously (every 4 seconds) with small movements up or down as required;
- "**fast**" raise or lower – requirement to respond between zero and 6 seconds post-contingency;
- "**slow**" raise or lower – requirement to respond between 6 seconds and 60 seconds post-contingency; and
- "**delayed**" raise or lower – requirement to respond between 60 seconds and 5 minutes post-contingency.

However, in some respects, the control requirements on loads (or generation) dispatched in the FCAS markets could be more onerous than the requirements for participation in the energy market (see Section 2.1) – it depends on which category of FCAS the facility in question is providing.

Remuneration for FCAS is on the basis of being *enabled* and *available* for use, rather than necessarily being *dispatched* and *used*. While the regulation services are often dispatched and used, the contingency services (fast, slow, delayed) are only used when there is a contingency. FCAS prices are always greater than or equal to zero. Therefore, provided a load is capable of accurately responding to a dispatch instruction for the delivery of FCAS, it will be eligible for remuneration if it is selected for duty.

Smelters are candidate loads to provide FCAS contingency services. To this point in the NEM's history, Victorian smelters are the only loads that have participated in the FCAS market.

Effectiveness of current Rules & processes

Market ancillary services are currently limited to services that provide rapid increase or decrease in supply or demand in response to a contingency. The Rules for market ancillary services are structured around service providers regardless of technology, although the standards for frequency and the central dispatch process that the ancillary services must participate in have been developed around generation technologies. The rules for the accuracy of response and ability to comply with dispatch instructions are broadly aligned with those for energy dispatch and, accordingly, require relatively high levels of accuracy. It is not clear that high accuracy for contingency FCAS is necessary, as it may only be necessary to ensure response from at least the amount scheduled to be enabled. Provided there is not an over provision to the point where frequency rebounds in the opposite direction, provision of more than is scheduled will simply return the frequency to normal faster than required.

The requirements for an ancillary services load are similar to those for a scheduled load.

- **Incentive to participate**

  A load classified as a scheduled load is required to be capable of complying with dispatch instructions [NER clause 2.3.4(e) and (g); 4.9.3(d)]. It seems impracticable for an end-user to manage all market interactions themselves as this would involve substantial transactions costs with respect to managing the administrative (NEMMCO registration) challenges of:

  - registering as a market customer;
  - the establishment of suitable telemetry communication facilities to be able to respond to dispatch instructions from NEMMCO; and
  - classifying the facility as an ancillary services load.

  The service that is being remunerated is the ability to respond within specified times regardless of whether it is called on to respond or not. Participants providing ancillary services may also receive or pay for energy supplied or taken at the prevailing energy price. Prices must be greater than or equal to zero [NER clause 3.9.2A].

  The fact that loads are likely to offer discrete quantities of service still creates a potential conformance issue, in that an ancillary services load may be selected for duty with respect to a part of the offered service – that is, the facility could be "marginal". Rebidding provisions [NER clause 3.8.22] would then need to be applied to ensure the load was capable of responding to dispatched targets. Measurement of conformance would only ever be an issue on the rare occasions where a facility selected for duty was actually required to provide the service in response to a contingency that moved frequency beyond the relevant threshold.

- **Opportunity to participate**

  Participation as a scheduled load is limited only to the extent that a facility is prepared to submit to and pass NEMMCO's formal classification process [NER clause 2.3.5 and related clauses] – that is, a load with:

  - suitable control characteristics (ability to respond accurately and within the time frame relevant to the contingency service the facility has been selected to provide)
  - adequate communication / telemetry;
  - control facilities capable of automatically responding to change in frequency; and
  - an arrangement via a Market Customer.

  Under the current Rules, strict compliance with dispatch instructions is assumed, and registration procedures are designed to confirm that this is likely.

- **Flexibility of participation**

  It seems likely that ancillary service loads would participate only in provision of contingency FCAS because the probable discrete nature of the demand-side resources makes it more amenable to respond as a block to more occasional usage when frequency deviates beyond the normal operating band, rather than as part of regulation FCAS that needs to be controlled with (small) movements up and down in response to automated control signals from NEMMCO.

  The NER does allow part of a load to be offered as a market ancillary service. As with participation as a scheduled load, even if a load could be controlled such that only a proportion of it is turned "on" or "off" as required, NEMMCO's registration process is likely to prevent only part of a load being classified as a market ancillary services load – each dispatchable unit would be required to have its own metering.

  Load aggregation challenges similar to those applying to scheduled loads are also likely to apply to market ancillary services load. Although deployment of a large number of small loads may be simplified if they are aggregated and dispatched as a single load, unless loads are connected at a single site with a common intra-regional loss factor, approval of aggregation is not guaranteed. However, NEMMCO may approve aggregation provided such aggregation would not materially distort central dispatch [NER clause 3.8.3]. For a Market Customer, subject to being able to overcome load aggregation and control / communication issues, having a diversity of loads under management will provide a valued flexibility of demand-side resources – an ability to respond more accurately to dispatch signals and to mitigate the effects of non conformance by discrete loads.

- **Transparency of demand-side resources**

  Demand-side resources deployed as market ancillary services load are clearly signalled to all relevant parties in the dispatch process.

- **Firmness of demand-side resources**

  The relevant Market Customer is responsible for ensuring that the ancillary services load is able to respond in the manner contemplated by the market ancillary services specification. All changes in availability of scheduled loads are required to be signalled via the rebidding process [NER clause 3.8.22; 3.8.22A] – for example, if a discrete load was given a signal to dispatch only part of its load, it would be exposed to non-conformance provisions [NER clause 3.8.23(f)] and, to mitigate this issue, would be required to "rebid" its demand-side resources in subsequent intervals in order to achieve conformance. Provided a participant is diligent in quickly rebidding if dispatched to a level that cannot be accurately delivered, then the consequences of non-conformance in the provision of contingency FCAS are zero or negligible.

  Whether or not this represents an insurmountable burden to prospective service providers would need to be assessed on a case-by-case basis. However, given that some smelter loads do participate in the FCAS markets – and CRA is not aware of any conformance problems[12] – participation on this basis is apparently quite feasible.

- **Managing interactions with other parties**

  All interactions between relevant parties (facility operator, Market Customer and NEMMCO) are managed via signals from NEMDE and communication (telemetry) between the manager of the demand-side resource and NEMMCO. Should an ancillary service load be participating in FCAS regulation markets, it will be subject to signals via NEMMCO's automatic generation / load control (AGC) system.

Summary of effectiveness

Although there are clear revenue opportunities to be derived from participation, the effectiveness of current arrangements in facilitating utilisation of demand-side resources as a market ancillary service is low – opportunities are characterised by:

- difficulty for loads to respond quickly to signals to make small adjustments to consumption as required by regulation services makes the pool of suitable services very small;
- potentially high cost of control systems required to participate;

12 Given FCAS contingency services are rarely dispatched, the requirement to check conformance is also rare. It is likely that conformance would only be checked *if* there was a problem identified in the aggregate response to a contingency by dispatchable units selected for duty.

- onerous administrative requirements to be registered / classified as a scheduled load[13];
- inability for specialised aggregation service to play a direct role in the formal registration / classification process;
- challenges created by the prospect of marginal dispatch of a discrete load.

2.3. DSP AS AN ANCILLARY SERVICE TO ENHANCE THE VALUE OF SPOT MARKET TRADING

Service description

Assisting in the management of network capability is a service that suitably configured loads are quite capable of providing. However, there are several potential rationales for managing network capability and, although the nature of the facility used and the *outcomes* of the alternative service deployment rationales may be similar[14], it is the specific *rationale* for deployment that is of interest here as this has a significant impact on the effectiveness of the Rules relating to each.

NEMMCO's obligations with respect to increasing the benefits of trade from the spot market are mentioned only in the ill defined[15] NER clause 3.11.4(b)(2) – whereby NEMMCO is required:

> ***where practicable*** *to enhance network transfer capability whilst still maintaining a secure operating state when,* ***in NEMMCO's reasonable opinion****, the resultant* ***expected*** *increase in non-market ancillary service costs will not exceed the resultant* ***expected*** *increase in benefits of trade from the spot market. [Emphasis added.]*

The degree of qualification in this clause gives a large amount of discretion to NEMMCO as to how the requirements of the clause are to be met.

Conceptually, DSP could be procured as NCAS and deployed specifically for this purpose – for example, by enabling (arming) a load tripping scheme, short-term ratings on interconnectors can be accessed thereby providing an opportunity for NEMDE to increase the dispatch of energy flows from a low price to a high price region to beyond a level that would otherwise be non-secure.

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13 Market ancillary services can only be provided by Market Participants that meet the relevant ancillary service specification and are appropriately registered *Non*-market ancillary services may be provided by any Registered Participant that wins a contract to do so.

14 Management of the network to a point where secure power flows over a set of network elements is higher than it would otherwise be.

15 Thus creating a requirement for substantial interpretation of the requirement by the market operator – a situation that is usually expressly avoided with respect to other aspects of market operator responsibility.

However, NEMMCO has not found a practical way to identify, then optimally procure and dispatch a service whose sole purpose is to enhance the benefits of trade in the spot market. The on/off nature of many sources of DSP is a major limitation on the ability to use DSP within the scheduling process to enhance spot market trading as this cannot be assessed using the current form of linear programming in the NEMDE and would require the use of mixed integer software[16]. The approach used currently is that where NCAS has been procured for security and reliability reasons [NER clause 3.11.3 and 3.11.4(b)(1)], NEMMCO reserves the right to deploy the service to enhance the benefits of trade in the spot market. As the services currently available to NEMMCO require advance notice of deployment, the decision as to whether a service is deployed (and the cost of that service is incurred) can be made in pre-dispatch time frames using an off-line "what-if" run of the dispatch engine rather than relying on mixed-integer programming[17].

Notwithstanding the fact that any DSP that reduces network congestion has the ability to reduce the economic cost of dispatched generation[18], NEMMCO procured services have thus far been limited to those that increase inter-regional transfer capability via the use of short-term line ratings to a level higher than it would otherwise have been. Although DSP that reduces intra-regional congestion could also enhance the value of spot market trade, TNSPs have an express responsibility for maintenance and development of the intra-regional transmission network.

Effectiveness of current Rules & processes

- **Incentive to participate**

  Impediments to greater use of demand-side resources to enhance the value of spot market trade arise from the difficulty faced by NEMMCO in making optimal procurement and deployment decisions. The ill defined nature of NER clause 3.11.4(b)(2) means that procurement decisions, and hence NCAS tender structures, are far from straightforward.

16 The current linear program used in NEMDE assumes all schedulable units can be controlled to any level and cannot assess on/off decisions that are involved in switching a block of load. It is notable that similar on/off decisions relating to minimum loads on generators must be made by participants through the self commitment (or self-dispatch) process [e.g. 3.8.2 (b)].

17 As part of a consultation process conducted in 2004 and 2005, NEMMCO engaged CRA to investigate the feasibility of automatically dispatching on/off NCAS to facilitate real-time optimisation of the service. Given the number of relevant services available to NEMMCO (at the time) was limited, the consultation concluded: "none of the options identified for automating the dispatch of NCAS within NEMDE were both viable and clearly superior to the [existing] manual process". For further information see: http://www.nemmco.com.au/powersystemops/169-0044.pdf.

18 … and increase the value of spot market trade subject to the cost of DSP deployment being less than the saving in the cost of dispatched generation.

In order to encourage demand-side resource owner participation in a tender for NCAS, availability, enablement and usage payments need to be offered, yet this combination of payments makes optimal procurement and deployment of appropriate services impossible to guarantee[19].

With these constraints in mind, NEMMCO will only deploy services to enhance the value of spot market trade if those services have already been contracted as security / reliability NCAS capable of being enabled (or "armed") and available to be tripped within the required time frame in response to a signal that a defined contingency has occurred[20]. Alternative approaches to procurement and deployment of NCAS to enhance the value of spot market trade have, so far as CRA understands, not been considered by NEMMCO to be viable[21].

19 Optimal procurement/deployment decisions require the combination of enablement and usage payments *in each instance* to be less than the increase in the value of spot market trade facilitated by deployment. However, given an availability payment is likely to be involved in the payment for NCAS, the availability payment would have to be amortised over each individual deployment over the life of the NCAS contract. Given the number of optimal deployments cannot be known in advance, absolute guarantees of lifetime optimal deployment cannot be made. See Section 6.2.2 for further discussion.

Further, making an availability payment for demand-side resources deployed *only* to enhance the value of spot market trade could be seen as inconsistent with the current market design – an availability payment for DSP in such circumstances might be equivalent to a capacity payment for a generator. If an alternative perspective is taken along the lines that availability payment for DSP in these circumstances is equivalent to payment for transmission capacity, then one would wonder why such a payment is being made by NEMMCO rather than a TNSP.

20 The time frame for tripping of load is determined by the nature of the short-term network rating NEMMCO is seeking to manage. Decisions to deploy such services must (usually) be made in pre-dispatch time frames and take account of:

- the cost of enabling (and possibly using a service);

compared to:

- the additional value of spot market trade that is available as a result of deploying the facility.

Even if only 30-minutes notice of deployment was required by a customer, there is a risk that market conditions could change – the pre-dispatch deployment decision that appeared optimal (taking account of enablement + usage payments) could become sub-optimal by the time the dispatch time frame arrives. The decision as to whether there is benefit to the market in contracting the service, would be further complicated should the facility require an availability payment – the value of the availability + enablement + usage payments risks never being recovered through increased value of spot market trade.

21 Possible alternatives involving a probabilistic approach to procurement and deployment are discussed in Sections 5.2.2 and 6.2.2.

The lack of clarity in the Rules as to the dividing line of responsibility between NSPs and NEMMCO for managing network capability adds a dimension of confusion and uncertainty as to the type and extent of services NEMMCO should be pursuing in this context. Both TNSPs and NEMMCO have a responsibility to supply / procure services that will assist in the management of network capability – TNSPs via the regulatory test; and NEMMCO via obligations to procure NCAS. The lack of clarity relate to distinctions between the respective ultimate objectives for the service – the network locations that are being influenced; the level of security that NSPs are obliged to provide; and the time frames for which the services should be procured.

Given restrictions on the type of service NEMMCO is able to deploy, and the restrictions on the nature of the contract it is likely to offer for the service, the incentives for end-users and Market Customers to participate of this part of the market will also be restricted. However, if the service is already contracted for other reasons, by allowing the service to also be used to enhance the benefits of spot market trade, additional revenue for the end-user and the managing market customer can be earned.

- **Opportunity to participate**

  The opportunity for demand-side resources to participate in the delivery of this service is limited by NEMMCO's operation of the NCAS tender process and the ability to marry DSP with access of short-term line ratings managed by NSPs – not all network elements are yet able to be securely operated at levels consistent with short-term ratings. Under present arrangements, participation in this service is not possible unless the demand-side resources are already contracted as a security / reliability NCAS.

- **Flexibility of participation**

  Flexibility of participation in the service is limited to the parameters provided by the terms of NCAS contracts offered by NEMMCO. The nature of the service is such that NSPs will rely on the delivery of specific DSP in order that network equipment ratings are not breached.

- **Transparency / firmness of demand-side resources – managing communication with others**

  The transparency and firmness of the demand-side resources offered and deployed is a condition of contract by the end-user, the managing Market Customer, the NSP whose equipment ratings are being managed, and NEMMCO. Each party involved needs, and is provided, clear signals as to the volume of demand-side resources that is required and deployed at any given time.

Summary of effectiveness

The combination of the Rules by which the obligation to procure DSP for the purpose of enhancing spot market trade, and the approach so far taken by NEMMCO to fulfilling its obligations under the Rules, means that existing arrangements are far from effective – they are, at best, ambiguous and difficult to manage. Minimal involvement of demand-side resource in this form of deployment is, therefore, not surprising.

3. DSP INDEPENDENT OF CENTRAL DISPATCH

3.1. DSP AS A SYSTEM RELIABILITY TOOL

Service description

Under the proposed Reliability and Emergency Reserve Trader (RERT), NEMMCO is able to contract additional reserve in the form of DSP (if available) up to 9 months in advance of a projected reserve shortfall. Prospective providers of capacity under the RERT will be required to give undertakings that the offered reserve capacity is not contracted to another entity, such as a market participant. Remuneration for contracted demand-side resources could be on the basis of availability or usage and would be negotiated with NEMMCO.

Dispatch of contracted demand-side resources would be on the basis of arrangements negotiated with NEMMCO – depending on the circumstances, a dispatch instruction could be issued in advance of 24 hours ahead of the time the service was required, with auditing of delivered reserve also being the subject of negotiation with NEMMCO. It is unlikely that communication requirements for DSP subject to dispatch under the RERT would be anywhere near as onerous as those required for services dispatched as scheduled loads in the energy market or as market ancillary services (see Section 2).

Effectiveness of current Rules & processes

- **Incentive to participate**

  Participation under contract to NEMMCO as part of a Reserve Trader (or in the future RERT) intervention, can be a more attractive commercial proposition to a demand-side resource owner than provision of DSP to provide hedging services to Retailers or network loading services to NSPs. Depending on the balance of availability and enablement/ usage payments, demand-side resource owners could be encouraged to stand out of the normal market, in favour of duty in the Reserve Trade (or RERT) market.

- **Opportunity to participate**

  The opportunity to participate is limited to the times when NEMMCO exercises its authority to intervene in the market. Once this point has been reached, the Rules provide guidance to NEMMCO about how it is to arrange contracts [NER clause 3.20]. A maximum of 9 months is the time separation between: when a need for intervention is identified; and the time intervention may be necessary – under previous reliability safety net arrangements, the separation time is 6 months. Single load blocks are more likely to be able to respond and arrange the logistics in this time than distributed demand-side resources. Unlike other forms of service procured by NEMMCO, there is no requirement that RERT services are procured via a Market Customer.

- **Flexibility of participation**

  Subject to any guidelines issued by the Reliability Panel (see above) the Rules afford NEMMCO significant flexibility about the detailed terms and conditions it requires of respondents but the nature of reserve shortfalls that are likely to trigger the use of demand-side resources under RERT or Reserve Trader contract are likely to allow for at most 24 hours' notice and we would expect less would be desirable.

- **Transparency / firmness of demand-side resources – managing communication with others**

  DSP will generally be as firm as the contract terms require.

Summary of effectiveness

Existing arrangements do provide a reasonable opportunity for NEMMCO to procure all available reserve in the form of DSP. However, the manner in which the RERT scheme is administered by NEMMCO – in particular, the expected structure of payment for RERT services – could have an influence on whether or not demand-side resources choose to stand out of the standard market mechanisms in favour of guaranteed higher returns from the RERT process. All effort should be taken in the development of the remuneration regime for RERT to ensure that services procured under RERT are in fact *in addition to* services that would otherwise be made available to standard market mechanisms.

3.2. DSP TO ASSIST IN THE MANAGEMENT OF NETWORK LOADING

Service description

DSP can be used as a tool specifically to manage network loading within safe limits[22]. This form could be procured by any of the following market actors:

- DNSPs to manage local network loading – for example, use of direct load control of air-conditioners[23];

- TNSPs to manage reliability on an intra-regional basis – for example, industrial load placed on standby under certain (forecast) network / system conditions[24].

22 Facilities with similar capabilities could be procured and deployed by NEMMCO for reasons other than maintaining power system security and reliability, such as for managing congestion within the transmission network and enhancing the value of spot market trading – which have a very similar outcome. See Section 2.3.

23 The costs of which will be recovered via DUoS.

24 The costs of which will be recovered via TUoS.

- NEMMCO to manage power system security and reliability on an inter-regional basis – for example, by using load tripping schemes to access short-term ratings on interconnectors with the objective of avoiding involuntary load shedding[25]. This form of deployment would also provide economic benefit in the spot market.

Although separate examples of deployments used by each of DNSPs, TNSPs and NEMMCO have been provided above, any deployment could be used by any of the three actors to achieve their objective.

Effectiveness of current Rules & processes

- **Incentive to participate**

  At the transmission level, the dividing line between TNSPs and NEMMCO for responsibility to manage network loading is unclear. TNSPs have a responsibility under the regulatory test to examine network augmentations and non-network solutions (e.g. DSP) as a means to improving the ability of the network to facilitate economically efficient outcomes *by reducing network congestion*. On the other hand, NEMMCO has a responsibility to procure NCAS under contract [NER clause 3.11] in order to manage power system security and reliability – an outcome it achieves *by reducing network congestion*.

  Although the ultimate service objectives of NSPs and NEMMCO are similar, the cost of the services procured will be allocated differently according to whether the service is contracted to:

  - TNSPs – paid for within a jurisdiction via TUoS; or

  - NEMMCO – paid for by Market Customers with the cost smeared across the NEM.

  Although DNSPs are the only party with a direct incentive to manage congestion in the distribution network, they are seeking to procure the services of similar facilities as both TNSPs and NEMMCO. It is possible that all three parties could compete to win the services of the same facility. There are already requirements in the rules for joint planning and there are some joint planning reports published – NEMMCO's review of network support and control services is looking at this point in more detail.

25 The costs of which are smeared across the NEM.

The arrangements in the NEM inherently favour network solutions to non-network solutions for two primary reasons, one technical and one commercial. The technical reason is that network solutions, which are under the control of the network, offer greater reliability and availability as compared to DSP, a large proportion of which may not be under direct dispatch control of the NSP and may have restrictions on when, how often and for how long it can be used. The commercial reason is that NSPs are permitted to earn a return on network solutions. DSP by contrast is virtually always treated as opex, so that the NSP receives the return *of* the money it spends, but not a return *on* the money it spends on DSP.

- **Opportunity to participate**

  While there may be opportunities to more effectively manage network congestion, it seems necessary that either a DNSP, a TNSP or NEMMCO must recognise the responsibility in that instance as their own, and to then actively pursue the opportunity in the hope that suitable demand-side resources can be identified and contracted. Where the demand-side resources are contracted to NSPs, no intermediary is necessary, although a Market Customer or a Facility Agent can act on behalf of the facility owner if required. However, if the facility is to be contracted to NEMMCO as NCAS, it must be done through a Market Customer [NER clause 3.11.3].

- **Flexibility / firmness / transparency and communication**

  The form of participation is dependent on the requirements of either the DNSP, the TNSP or NEMMCO. Each is likely to have situationally dependent needs with respect to:

  - flexibility of deployment requirements – whether response could be manual or must be automated;
  - firmness of demand-side resources – whether an approximate or exact response is required; and
  - verification of response – whether after-the-event metering data is sufficient or whether SCADA-type systems are necessary.

  The transparency of the demand-side resources will also vary by situation. NEMMCO may be unaware of demand-side resources managed by a DNSP and is not necessarily made aware of demand-side resources managed by a TNSP.

Summary of effectiveness

The most substantive issue in the Rules framework regarding the utilisation of demand-side resources to manage network loading is the lack of clarity between TNSPs and NEMMCO as to where the dividing line of responsibility for procurement happens to lie. From the perspective of a demand-side resource owner, this could mean increased competition for their services, but it is more likely to create inefficiencies in the procurement and deployment of otherwise potentially effective resources.

3.3. DSP AS A HEDGING TOOL

DSP can be used in several ways as a hedging tool, as described below. What all of these mechanisms have in common is that the Retailer (or a Facility Agent acting on behalf of a Retailer) must:

- identify customers with the ability to reduce their consumption upon request; and
- enter into commercial arrangements with those customers that:
  - are acceptable to those customers; and
  - specify the conditions under which each of those customers will reduce its consumption.

We would expect that, at a minimum, these contractual conditions will include:

- the specific amount of demand reduction to be provided by each customer;
- the period for which the demand reduction is to be provided (which may differ from one demand reduction event to another);
- the amount of lead time the Retailer will provide the customer with respect to the need to deliver the demand reduction on each event; and
- how delivery of the amount and duration of the demand reduction will be verified.

Other conditions that may be specified include:

- the minimum pool price at which the demand reduction can be requested;
- the total number of times the demand response can be called upon over a given period of time (e.g., week, season, year);
- the maximum and expected duration of each demand response event; and
- any penalties that the customer may incur for non-delivery of the contracted demand reduction in terms of amount or duration.

These contractual conditions are likely to vary depending upon how the Retailer is planning to use DSP, and that the changes in those conditions will have an impact on both:

- the types of DSP that are more and less suited to participation; and
- the willingness of end-users to enter the various contractual conditions.

As a result, the different contractual conditions are likely to affect the aggregate DSP potential likely to be available. For example, as will be discussed further in the sections below, the contract conditions for DSP to capitalise on pool price arbitrage opportunities are generally far more flexible than those used where DSP is used as a physical hedge or as a substitute for a financial hedge against high pool prices. This flexibility will, in turn, generally result in there being more DSP available when the Retailer's objective is to use DSP for price arbitrage, than when it is used to provide a physical hedge or to supplant the need for a financial hedge.

The use of DSP for wholesale market price arbitrage, substitution for a physical or financial hedge, or even to reduce the pool price can be seen as different points on a continuum in which DSP is used to exploit price differences between the wholesale and retail markets. However, these uses are, in fact, very different in terms of the commercial terms that are likely to be required[26], and the level of DSP likely to eventuate. It is therefore important that each deployment objective be considered separately.

The opportunities to deploy demand-side resources noted in Section 3.3 are all managed via over-the-counter bi-lateral contracting that is not governed by the operation of the National Electricity Rules. Hence, none of the advantages or impediments to utilisation of demand-side resources that are discussed in the following sub-sections are attributable to the construction of the Rules.

3.3.1. DSP by Retailers to create arbitrage opportunities

Service description

The Retailer can readily use DSP to exploit arbitrage opportunities between its contract position and the pool price, and this is in fact the manner in which most Retailer-engendered DSP is used. This opportunity arises where the Retailer is adequately hedged, but reducing the volume it purchases from the pool at times of high pool price represents an avoided outgoing, thereby making the payment from its financial hedge a net income rather than a compensatory payment to offset the pool price. That net income is then shared between the Retailer and the customer.

Consider the set of market arrangements outlined in Figure 1.

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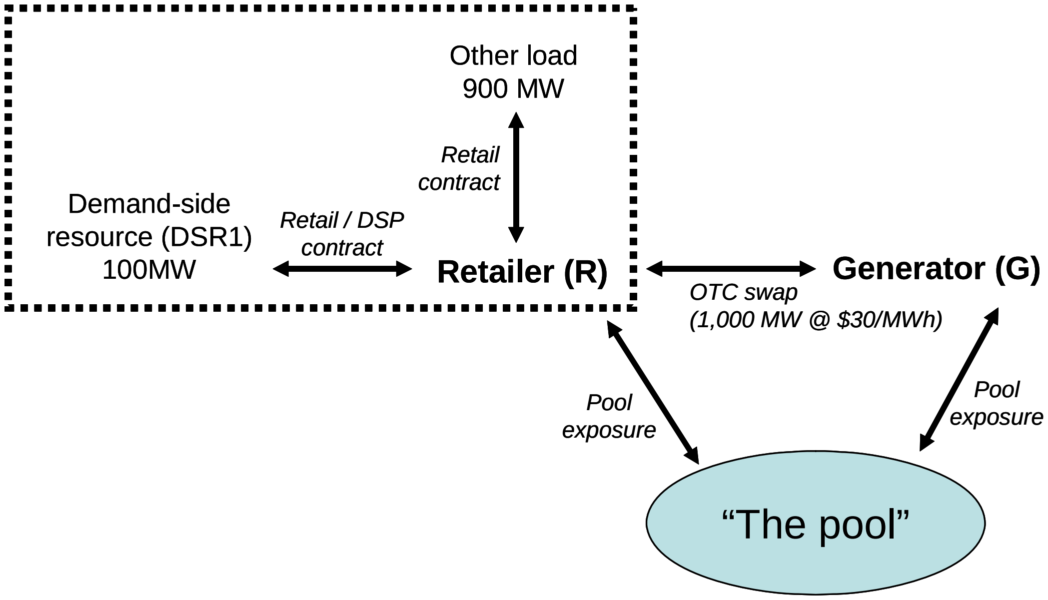
26 Most simply, and as explained in further detail in each of the sections that follow, where the purpose of the DSP is to substitute for a physical or financial hedge, or to reduce pool price, there will be a specific quantum of DSP that is required every time it is called. This means the Retailer would be required to either reduce the ability of DSP providers to opt out of calls, or contract with a larger pool of providers in order to ensure it can meet the required quantum. The former case would represent a significant change to the commercial terms of the contract, at least in the perception of DSP providers, who are significantly less willing, in aggregate, to provide firm than non-firm interruptibility. The latter case will increase the Retailer's transaction costs.

Figure 1: Illustrative set of contractual arrangements



Scenario A

Market / system conditions force pool price to $5,000 for one hour.

In the absence of DSP, R's customers (DSR1 + other load) consume 1,000 MW.

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

- *R → "The pool" as settlement for load = 1,000 x $5,000 / MWh = $5M.*
- *G → R as settlement of hedge = 1,000 x ($5,000 - $30) = $4.97M*
- *R's net outlay = $5M - $4.97M = $30,000*

Scenario B

Market / system conditions force pool price to $5,000 for one hour and R wishes to take advantage of arbitrage opportunity.

R's contract with DSR1 is deployed and remaining customers (other load) consume 900 MW. R's cash flows for this hour would be as follows:

- *R → NEMMCO as settlement for load = 900 x $5,000 / MWh = $4.5M.*
- *G → R as settlement of hedge = 1,000 x ($5,000 - $30) = $4.97M*
- *R net outlay (income) = $4.5M - $4.97M = ($470,000)*

Conclusion

Under Scenario B (R takes advantage of arbitrage opportunity), R is $500,000 better off than under Scenario A ($470,000 income from the hedge + $30,000 avoided outlay on energy). Under Scenario B, R is in a position to profitably share some of its gains with the demand-side resource owner.[27]

This sort of arrangement does not need to achieve any specific level of demand reduction on any particular event, though it is likely that the Retailer would want to have some minimum amount of demand-side resources in order to make the income stream large enough to offset the initial transaction costs of the required prospecting and commercial arrangements (e.g. development of the contracts, communications and measurement and payment procedures that are required to administer this type of arrangement).

As a result, the commercial terms employed generally provide a fair amount of flexibility for demand-side resource owners with respect to the requirements regarding the frequency, duration and volume of their demand reductions. Correspondingly, the commercial arrangements often provide payments on dispatch only, and the Retailer generally seeks to split the arbitrage earnings with the demand-side resource owner[28].

These commercial arrangements will often have a stated or de facto demand reduction level in order to ensure that the anticipated annual arbitrage revenue will be sufficient to justify the transaction costs incurred by both the Retailer and the end-user.

Effectiveness of current Rules & processes

- **Incentive to participate**

  There is nothing in the Rules that acts as a particular incentive for participation in this type of demand-side resource deployment by Retailers, end-users, or Facility Agents.

  The eligibility of end-users to participate is only limited by their ability to: a) reduce demand upon notification from the Retailer or Aggregator; and b) document that load reduction. Customer sovereignty (the right of the end-user to reduce demand without notice or penalty) underpins the ability for the Retailer to create arbitrage opportunities through customer demand reductions.

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27 Note that this example abstracts from the problems of price uncertainty and the opportunity cost of load not taken by DSR1. The issue of price uncertainty and the opportunity cost of load not taken will be addressed in the consideration of forward markets in Section 6.1.2.

28 Retailers have typically retained 50% of the arbitrage value, although (on occasion) end-users with substantial and/or very flexible demand reduction capabilities have been able to secure a higher proportion of the arbitrage. Aggregators sometimes urge retailers to require less of the arbitrage in order to provide both higher DSP payments and ‘room’ for the aggregator’s share of the revenue stream.

End-users could exercise this form of DSP on their own and garner the full benefit of the arbitrage. Doing so requires that they have an interval meter, take pool price exposure for at least a designated part of their load, and obtain a hedge contract for that load either directly or through their Retailer. In practice very few end-users have been willing to do this to date, and virtually all of the DSP for arbitrage has been undertaken under the auspices of Retailers. This may be a function of a lack of awareness on the part of end-users that education could address over time, but there are other considerations which could be expected to serve as a limit to the degree to which such arrangements are likely to be taken up even with greater awareness. The most important of these include:

- End-users are generally focussed on their core business activities, do not have the management bandwidth or technical capability to assess their potential to manage their load in response to price signals, and do not stand to gain enough from it to employ dedicated staff or accept the perceived risk of failing to respond to prices when they are very high. Therefore, until a low-cost turnkey solution[29] can be provided for such users, participation is likely to be effectively limited to large, technically competent end-users who consume significant amounts of electricity.

- The core capability of the Retailer is to package and re-sell risk. Prior to the development of the type of turnkey solution mentioned above, the Retailer will only have an incentive to help the customers described above where general market conditions have imposed risks that the Retailer cannot manage or hedge, and for which he cannot pass-along the price. Once a turnkey solution is developed, effective competition could be expected to drive Retailers to offering it as a means to protect market share.

Other constraints that can act as disincentives include:

- The NEM's real-time price determination, which can pose a mild to moderate disincentive to end-user participation because the anticipated arbitrage that serves as the trigger for deployment of the DSP may not eventuate.

- Related to this is the potential for an over-supply of DSP to reduce or even crash pool prices and thereby correspondingly reduce the arbitrage value of each unit of DSP.

- The fact that the occurrence and extent of arbitrage opportunities are highly variable tends to act as a disincentive to capital investment to enable DSP capability. This can therefore reduce the total quantum of DSP.

29 The turnkey solution could be a black box programmable load controller, or an outsourced energy manager.

From the Retailer's perspective, the incentives to participate in this form of DSP are: a) the ability to earn arbitrage revenues at low risk and relatively low transaction costs; and b) the ability to share that arbitrage revenue with customers, thereby providing a strong case for customer acquisition, satisfaction and retention.

As in the case of the end-user, the only disincentive posed by the Rules is the potential for out turn results to reduce or negate the anticipated arbitrage. This disincentive is possibly stronger for the Retailer than the end-user, as the erosion of expected payments can significantly reduce end-user satisfaction with the DSP arrangement, in addition to exposing the Retailer's costs to non-recovery. Further disincentives to Retailer participation are the fact that: a) the occurrence and extent of arbitrage opportunities are highly variable; and b) setting up these arrangements is not a core skill of the Retailer.

A Facility Agent, unless registered as a Market Participant, can only participate in this form of DSP on behalf of a Market Participant, most likely on behalf of a Retailer.

While there is nothing in the Rules that acts as a particular incentive for a Facility Agent to participate in this type of DSP, there are other incentives, including:

- end-user and Retailer interest, but lack of expertise in the technical and commercial arrangements required by this form of DSP deployment; and
- the ability to earn fees by taking a portion of the arbitrage that leaves acceptable income opportunities or other benefits for the other parties to the arrangement.

Provisions of the Rules that preclude the combination of other DSP-derived revenue streams with arbitrage-derived revenues, serve as a disincentive to the Facility Agent to participate in this form of DSP (and possibly other forms of DSP deployment being considered as well).

Commercial returns to Aggregators may also be constrained by: a) the potential for anticipated arbitrage levels to be reduced or negated by real-time price determination; b) the variability of the occurrence and extent of arbitrage opportunities from year to year; and c) the need for the other parties to the arrangement to receive acceptable returns.

The Rules preclude NSPs participating in the energy market. In any case, NSPs are likely to be indifferent regarding deployment of DSP for wholesale market arbitrage except to the extent that the variability of these loads can impact network loading. Revenue loss (due to the reduced throughput) is likely to be only a minor concern, and remains the right of the customer in any case.

However, where NSPs have control over loads, they may be able to exercise those loads on behalf of a Market Participant. It might also be possible for the NSP to act as an Aggregator on behalf of one or more Retailers. This could be particularly valuable at the small end of the market where investment in communications and control gear could make significantly more DSP available. Although asset investment ownership and operation tend to be core skills and capabilities of NSPs, current regulatory practice does not allow NSP ownership of capital equipment on the customer side of the meter.

- **Opportunity to participate**

  The Rules do not address the use of DSP for arbitrage, but the requirement that all energy be bought from the pool creates the opportunity for arbitrage against the strike price of swap contracts. Because this arbitrage flows from a contract position, the opportunity for participating in this form of DSP begins with those who participate in the contract market – namely Retailers and, to a lesser extent, generators.

- **Flexibility of participation**

  Because the Rules are silent on this form of DSP, the level of flexibility characterising end-user participation is left to the parties to the arrangement to determine. This will most often be a Retailer, but can also be a Facility Agent or an NSP acting on behalf of the Retailer.

  Generally, the more flexibility provided to end-users within the arrangement, the greater the nameplate amount of DSP that can be recruited. Areas where flexibility is most important include:

  - the ability of the end-user to choose whether to deploy its demand-side resource on a case by case basis; and

  - the ability of the end-user to decide how much demand reduction to provide and over what time period.

- **Transparency of capability**

  There will be little or no transparency of this DSP capability to NEMMCO or the market except where Market Participants reveal the capability they hold in responses to NEMMCO surveys, or where NEMMCO monitors demand as a function of price by Retailer to determine by observation the amount of demand response that can be expected as a function of price.

  Sponsors of DSP arbitrage efforts (i.e. Retailers and their agents) will be interested in transparency at the demand-side resource owner level in order to allow accurate measurement of and payment for contribution to the group demand reduction.

However, all participants in arbitrage DSP have an interest in that capability and its deployment being non-transparent, to the extent that transparency to the market can potentially reduce arbitrage value through re-bidding or other actions.

- **Firmness of capability**

  This form of DSP does not need to be firm from the perspective of either the Rules or commercial gain. Any amount of DSP that is measurable will create arbitrage value when there is a price difference between the contract strike and wholesale pool prices. From the perspective of the end-user, the lack of a requirement regarding firmness is likely to be an attractive bit of flexibility that reduces risk and motivates participation. On the other hand, Retailers and their agents are likely to have transactions costs that require at least a threshold amount of DSP to repay; this is true on a program as well as an event basis.

- **Managing interactions with other parties**

  All parties to the arrangements needed to deploy DSP for arbitrage – end-users, Retailers and their agents – are essentially commercial and consensual in nature.

Summary of effectiveness

The Rules do not, in and of themselves, limit the efficiency or effectiveness of DSP deployed to create arbitrage opportunities. However, Retailers that are vertically integrated into generation will have significantly less motivation to participate in this form of DSP as it essentially constitutes a partial wealth transfer from the generation side of the business to the Retail side of the business and its customers. The other limitation presented by current market arrangements is the inability for the end user to ‘sell’ its DSP capability for this form of deployment to anyone other than the serving Retailer.

Despite these constraints, this form of deployment was the original motivation that activated DSP in the market and still probably accounts for one of the largest if not the largest activation factors of DSP.

3.3.2. DSP by Retailers to reduce the pool price

Service description

The arrangements whereby the Retailer would use demand response to reduce pool price would be largely the same as those described with reference to taking advantage of an arbitrage opportunity. Under such arrangements, the Retailer would be seeking to achieve a sufficient aggregate level of demand response so as to change the pool price. While this would reduce the Retailer's financial obligation for settlement in the pool it would also reduce its compensatory payments from its contract position, and also deliver the benefit of reduced settlement charges to its competitors. As a result, reducing the pool price is likely to only be of particular interest to the Retailer in the short term if the Retailer has a significant unhedged position[30]. In such a case, the benefit of the reduced pool price would be equal to the amount of unhedged load multiplied by the amount by which the pool price was reduced. While this would result in avoided pool payments, it would not provide a revenue stream with which to pay the demand-side resource owners, and would therefore still constitute a cash outlay from the Retailer[31]. We are not aware of any Retailers that have initiated DSP programs with the express purpose of reducing the pool price.

In the longer term, the value of demand response that can be used to reduce the pool price probably competes with a vertically integrated capability. In such a case, the vertically integrated position is likely to be more highly valued by the Retailer for its flexibility and ability to earn income as well as to avoid outgoing payments. More importantly, the vertically integrated position provides the Retailer with a benefit stream that its competitors may not be able to access, as compared to the reduction in pool price which delivers benefits to all Retailers[32].

30 An alternative would be to use demand-side resources as a physical hedge against the short position, as discussed in Section 3.3.3. Such a strategy would provide a known level of demand-side resources requirement and would avoid providing a benefit to the retailer's competitors.

31 A form of this problem also occurs in DSP programs that focus on arbitrage opportunities that dispatch enough demand-side resources to (inadvertently) reduce the spot price.

32 More generally, the deployment of DSP to reduce pool price could be seen as a form of organisational downstream vertical integration, while financial contracting can be seen as a form of upstream contractual vertical integration, and ownership of or by a generator can be seen as organisational upstream vertical integration. *Organisational* vertical integration has been and is logically preferred by the supply industry to upstream contractual vertical integration and organisational downstream vertical integration because it locks in benefits not accessible to others.

Commercial arrangements for this form of DSP, if they existed, would seek to ensure that 'enough' DSP could be provided to effect a reduction in the pool price each time pool prices exceeded a certain level. This would imply that commercial arrangements would put a premium on demand response that could be seen as firm (that is, deliverable any time it is called) or possibly a penalty on demand response which was not delivered when called. A premium for firm demand-side resources could take the form of either availability payments, some form of guaranteed minimum annual revenue or premium payment level for dispatch, each of which would increase the certainty if not the level of cash outlay from the Retailer. The latter approach – penalties for non- or under-delivery of demand-side resources – would be likely to significantly erode the available potential of DSP[33]. A further complication is the fact that the amount of demand reduction required in each instance cannot be known with precision before the event.

Effectiveness of current Rules & processes

[**Note:** All comments made in the discussion of *Effectiveness of rules and processes* in Section 3.3.1 also apply to DSP by Retailers to reduce pool price, unless discussed below. The information presented below is limited to points that provide additional information that uniquely applies to DSP deployed to reduce pool price.]

- **Incentive to participate**

  Where the Retailer is adequately hedged there is no financial advantage to reducing the pool price except perhaps to place a moderating influence on future contract prices[34].

  In periods when the Retailer is under-hedged and pool prices are high, and the Retailer has not already contracted DSP to be available, the Retailer will have a very significant financial incentive to deploy DSP on an emergency basis as a means of both (a) reducing exposure to the high pool price or (b) reducing the pool price itself, if possible. In those instances, the Retailer is likely to be prepared to significantly increase the level of incentive paid to end-users for DSP.

- **Opportunity to participate**

  As in Section 3.3.1.

33 Although we are not aware of any programs structured this way or attempting to reduce the pool price, our own customer research and experience in designing and implementing DSP programs demonstrates that very few end-users are willing to enter into arrangements that include penalties for under- or non-delivery. Foregoing of anticipated benefits can be incorporated without significant reduction in participation, but penalties drastically reduce participation. This is not surprising given that demand reduction is not a core business activity for virtually any end-user while reduced electricity consumption is likely to constrain core, revenue producing activities.

34 In the event that the Retailer is over-hedged, reducing the pool price will be counter-productive as it will reduce income on the total volume of load hedged, while reducing pool payment obligations only on the volume of DSP deployed.

- **Flexibility of participation**

  Retailers wanting to use DSP to reduce exposure to pool prices may seek less flexible arrangements with end-users (in order to ensure availability of sufficient DSR to affect pool price) or may over-recruit.

  Where less flexibility regarding participation is provided, end-users will likely require higher incentives to provide the same quantum of DSP.

- **Transparency of capability**

  As in Section 3.3.1.

- **Firmness of capability**

  If the objective of DSP is to reduce the pool price, the Retailer will need access to firm DSP in the amount required to do so, although this amount is likely to be somewhat case-specific, and therefore the amount of capability to be contracted may not be known with precision. It is also the case, however, that any amount of DSP will reduce the Retailer's exposure to its short position.

  If the Retailer is motivated to reduce pool price, end-users may be able to achieve higher incentive payments for firm demand reductions.

- **Managing interaction between parties**

  As in Section 3.3.1.

Summary of effectiveness

There is nothing in the Rules that limits the use of DSP for the purpose of reducing pool price. However, as in the case of DSP for arbitrage, Retailers with vertical integration into generation have no real motivation to reduce the pool price. More generally, even Retailers without vertical integration have little motivation to reduce pool price when they are adequately hedged. Compared to DSP deployed for arbitrage which confers benefits on the Retailer and its customers, DSP deployed to reduce pool price will provide the same benefit to the Retailer's competitors as it confers to the Retailer itself.

These commercial limitations may be a significant part of the reason why virtually no Retailers we are aware of deploy DSP for this purpose.

3.3.3. DSP by Retailers as physical hedge or alternative to a financial hedge

Service description

The Retailer can use DSP as a physical hedge against pool price, or as a substitute for a financial hedge if the aggregate volume of demand-side resources available is suitably firm or has sufficient over capacity as to make delivery of the required quantum of demand reduction possible at any time the physical or financial hedge would be needed.

Where demand-side resources are used as a physical hedge, the aggregate demand reduction required must equal or exceed the Retailer's foreseeable maximum volume risk above its contracted position[35]. Although any amount of DSP reduces a Retailer's risk with regard to unhedged volumes at times of high price, all prudent Retailers have strict risk management policies that require that volume and price risks are addressed at specific levels by calendar year quarter. Therefore, from the perspective of the Retailer's risk management policy, for DSP to be considered a substitute for a physical hedge, it will need to provide the same risk cover as a physical hedge. It will only be seen as providing risk cover for the volume, frequency and durations for which it can realistically be expected to be dispatched. DSP volumes that may be available (i.e., non-firm from an aggregate dispatch perspective) will not be seen as meeting risk management policy criteria, but will be useful as either:

- possible insurance, should other mechanisms not be available; or
- additional volumes available for arbitrage.

The same reasoning applies where demand-side resources are used as a substitute for a financial hedge. The Retailer's risk management policy will require the aggregate demand reduction dispatchable from the DSP to equal or exceed the volume of the hedge that would have been required in the absence of the DSP. However, because cap contracts (the types of financial hedges for which DSP would most readily substitute) are generally available at a minimum size of 10MW, DSP of less than 10MW can avoid the cost of a minimum size contract if the marginal hedge required to be purchased is needed for a risk position smaller than the minimum block size.

35 Where the DSP volume equals the physical hedge volume to be substituted for, the DSP will need to be firm from a dispatch point of view. This can be achieved by contracting for firm interruptibility of load that is certain to be on when the load reduction is needed, or to over-contract with loads that individually are very likely to be on during times when load reductions are needed but may not all be able to be curtailed every time needed. In this case the over-contracting makes the demand side resource firm in aggregate, rather than firm on an individual facility basis. Based on the volumes offered by individual demand-side resource owners, and their availability in specific events, the Retailer can meet different levels of demand reduction need. DSP available during a specific event that exceeds the physical or financial hedge being substituted for can then be dispatched as an arbitrage play between the Retailer's pool price obligations and its other hedge volumes.

Using demand-side resources for these purposes requires a high degree of firmness: the demand-side resources must be available in the amount needed every time it is needed. The consequences of failing to achieve the required quantum of DSP when demand-side resources are used as a physical hedge are exactly the same as being under hedged in the contract market: pool price multiplied by the volume of energy that is unhedged (i.e., the undelivered DSP). In the case where DSP has been used to offset a cap, the consequence would be similar: the amount of unhedged energy times the pool price. As a result, a Retailer entering into DSP contracts for these purposes is likely to either require firmness or over contracting (or both). A requirement for firmness will lead to commercial arrangements – and impacts on the amount of available demand-side resources – similar to those discussed above with regard to DSP to reduce pool price. Over contracting, on the other hand, is likely to reduce the price that can be offered for availability payments on a per MWh basis, as these availability payments will need to be spread over a larger demand-side resources pool. Over contracting would not necessarily constrain dispatch payments as long as dispatch could reliably be limited to the volume of DSP required in any instance.

Demand-side resources used either as a physical hedge or as a substitute for a financial hedge will also reduce the volume of load the Retailer must settle in the pool. In addition, the ability of the customer to reduce its load at times of high price effectively reduces the volume risk those customers present to the Retailer. This may allow a Retailer that enters into DSP arrangements with its customers the ability to serve those customers at lower cost, and thereby improve the Retailer's ability to offer these customers a lower price, leading to enhanced customer acquisition and retention.

However, for demand-side resources as a substitute for a financial hedge to be cost-effective for the Retailer, the cost of the financial hedge (e.g. the premium to be paid on a cap contract) would have to exceed:

- the transaction costs involved in identifying those customers with demand response capabilities and forging the required commercial arrangements with them, plus
- any payments that would be required by the participating customers.

It should be noted that the transaction costs are one-off costs which act as a barrier to the initiation of a DSP strategy on the part of the Retailer. However, once those costs have been incurred, they are largely non-recurring[36], such that the average cost of this strategy to the Retailer should decline over time.

36 Once identified and signed up, it is likely that a significant proportion of these customers will be likely to continue in the arrangement in subsequent years, thereby reducing the cost of the strategy. Some leakage will occur, however (through customers switching retailers or becoming unwilling or unable to continue offering to reduce their demand).

Where DSP is used as a physical hedge, its costs and benefits would still need to be compared to the alternatives, which could be a vertical integration strategy or the use of a financial hedge. Vertical integration provides an additional revenue stream as well as risk management in the wholesale market. Demand-side resources, as discussed above, can provide benefits in terms of more favourable pricing or DSP payments to end-use customers, which could provide the Retailer with a competitive advantage in attracting or retaining customers.

Effectiveness of current Rules & processes

[**Note:** All comments made in the discussion of *Effectiveness of rules and processes* in Section 3.3.1 also apply to DSP deployed by Retailers as physical hedge or alternative to a financial hedge, unless discussed below. The information presented below is limited to points that provide additional information that uniquely applies to DSP deployed as physical hedge or alternative to a financial hedge.]

- **Incentive to participate**

  The incentive to the Retailer to deploy DSP for these purposes is to avoid the cost of a financial hedge (typically a cap contract), which could be an issue when cap contract premia are very high-priced, or when caps are unavailable or unavailable on suitable terms and volumes. As a result, the value of the DSP for these circumstances can easily vary widely between Retailers and over time.

  Incentives provided by the Retailer to the end-user may increase where the Retailer is seeking to reduce an under-hedged position or to avoid the cost of a financial hedge.

- **Opportunity to participate**

  As in Section 3.3.1.

- **Flexibility of participation**

  Retailers wanting to use DSP to reduce exposure to pool prices when under-hedged or to avoid the cost of a financial hedge may seek less flexible arrangements with end-users (in order to ensure availability of sufficient DSR to affect pool price or offset their unhedged volume) or over-recruit.

  This in turn is likely to reduce flexibility to end-users (unless over-recruitment is pursued).

- **Transparency of capability**

  As in Section 3.3.1.

- **Firmness of capability**

  Firmness will be of significant interest to Retailers seeking to substitute DSR for a financial hedge. It is also the case, however, that any amount of DSP deployment will reduce the Retailer's exposure to an under-hedged position.

  As a result, end-users may be able to achieve higher incentive payments for firm demand reductions.

- **Managing interaction between parties**

  As in Section 3.3.1.

Summary of effectiveness

There is nothing in the Rules that limits the use of DSP by Retailers as a physical hedge or as an alternative to a financial hedge. However, these forms of deployment are significantly more demanding than deployment for arbitrage, and have seldom been used to our knowledge. A related form of DSP deployment – DSP to reduce a short position – has been used, but differs from the use of DSP as a substitute for a physical or financial hedge, as it is a reactive rather than a proactive deployment strategy. As the Retailer is generally already in a difficult position, DSP deployed to reduce a short position does not have the same firmness associated with its target volume as does DSP deployed to substitute for a physical or financial hedge.

3.4. VOLUNTARY RESPONSE FROM END-USER TO RETAIL / NETWORK TARIFFS

Service description

Pricing mechanisms from Retailers or distributors can motivate demand response, and essentially serve as a baseline condition for DSP that is initiated by the customer without the intervention or assistance of the Retailer or a Facility Agent. These pricing mechanisms, unlike the approaches discussed in the previous sections, are not in the first instance seeking to motivate a specific aggregation of DSP, but rather seeking to provide pricing signals to customers that customers can respond to as suits their own perceptions of value. Where customers do not respond, they pay a price that is more cost-reflective than do customers who do not participate in the DSP deployment forms discussed above.

The ability to provide these price signals depends on the type of metrology that is in place. Where interval metering is present such pricing arrangements can include:

- ***Real-time pricing or pool price pass through*** – Under either of these arrangements, the customer is exposed to half-hourly fluctuations in the price of energy in the spot market, thereby providing a very accurate price signal to the customer about the cost of using energy and therefore the avoided cost of not doing so[37]. Where the cost of using the energy exceeds the end-user's opportunity cost of not using it plus the transaction costs associated with responding to such a price signal, the rational end-user will cease (or at least reduce) its consumption. Relevant transaction costs include:

    - the need to determine whether there is sufficient flexibility in the use of end-use energy such that the facility stands to gain from such a pricing arrangement;
    - the need to pay attention to the fluctuating cost of energy and make managerial and operational decisions as the price changes, or
    - the costs of determining in advance the opportunity costs of the operation and of implementing a communications and control strategy that either notifies operators of the need to reduce specified end-uses in response to price fluctuations or automatically controls end-use equipment in these instances.

- ***Critical peak pricing (CPP)*** – Under this approach the price of electricity is almost always a set, pre-established amount known to the end-user, but can rise by a significant amount – in most cases by a factor of 5 to 7 times – when specified supply/demand conditions, or pool price levels are reached. The number of occasions on which critical peak prices can be declared is sometimes subject to a maximum number of times per season or per year.

    In exchange for the exposure during times of high price, the cost of electricity at non-critical times is generally reduced marginally from the flat price that would normally be charged. Because the vast number of hours in most systems that use CPP are non-critical, the end-user makes savings during most of the year. Those savings can then be locked in or somewhat eroded based how often and by how much the facility is able to reduce consumption during peak price time periods.

    The time of day in which the critical peak price will apply is generally also pre-established, and some forward notice of the applicability of the critical peak price is generally provided. In some cases this may be only a matter of hours; in others, notice may be given the day before the price is to pertain.

37 The fact that the price signal comes from the spot market makes the use of these approaches inapplicable to distributors, however.

CPP can be used by either Retailers or distributors. However, use by distributors faces some constraints. The first is that at the small end of the market, Retailers typically bundle network charges and energy charges into a single price or tariff for end-use customers. In such cases, the fluctuation in the network price may not be passed along in a visible way to customers, particularly where the Retailer is comfortable that it will be able to manage the volume risk on the network critical peak price by offering a flat price that includes a premium for anticipated consumption at the critical peak price.

Compounding this is the fact that, in most jurisdictions, networks are required to offer a uniform price throughout the service territory for customers within a given customer class. As a result, area-specific pricing is not permitted which means customers within an area facing the need for network augmentation will not see that cost in their network tariff, but rather the average system-wide cost of augmentation allocated to that class. This averaging effect blunts the signal in those areas in which demand response is needed, potentially jeopardising the ability to motivate sufficient demand response to effect the deferral.

The fact that no Retailers have offered CPP to date to interval metered customers, and that very few customers have opted for pool price pass through, suggests that significant barriers to these pricing structures – or indifference or opposition to them on the part of end-use customers – is likely to exist[38].

It is also important to note that these approaches use the avoidance of an increased price as the inducement to undertake demand response. In that aspect they are more like DSP as a scheduled load than DSP used as a hedging tool in the deployment options discussed in this section, where the customer continues to receive its familiar (and generally flat) price signal except when responding to a DSP call.

38 This is likely to persist for some time. A study conducted by KPMG for the MCE that assessed the potential demand response benefits of a mandatory roll-out of smart meters in the small end of the electricity market revealed that the majority of retailers would be unlikely to pass through network pricing signals to end-use customers, due to concerns regarding the complexity of those tariffs, unless the nature and extent of those network tariffs posed risks the retailers felt to be unmanageable (see KPMG, *Cost Benefit Analysis of Smart Metering and Direct Load Control, Workstream 3: Retailer Impacts – Phase 2 Consultation Report*, March 2008, Section 6.4, pp 62 – 64). Given the fact that wholesale market volatility has not spurred retailers to abandon flat pricing structures it would seem unlikely that the level of volatility imposed by network CPP would be likely to do so.

By contrast, under CPP or real-time pricing, the customer would be comparing these new price structures to flat prices or relatively simply on-peak/off-peak prices. In the case of real-time pricing, there is virtually no price stability, requiring the customer to monitor price virtually continually (at least to the extent to be aware of any time prices are expected to exceed a certain level for a certain time and to be prepared to respond accordingly such that the annual bill will be equal to or less than what it would have been on the previous price structure. The customer could also enter into a financial hedge (presumably with the retailer, due to its small size) and then be free to treat the real-time price like the arbitrage opportunity available through the retailer. While the end-user would reap all the benefit of this arbitrage, it would require a significant amount of set-up and monitoring and the arbitrage itself would be reduced because of the almost certain higher cost of the hedge.

In the case of CPP, the price offered in non-CPP periods is reduced, while the CPP price is increased. However, because of the difference in the number of hours in the two periods, the reduction (generally only a few percent as compared to the flat price) is much less than the increase (which is likely to be five times the flat price). The magnitude of the increased price and the lack of knowledge of most customers about how much energy various end-uses consume and how to control them, generally makes the downside risk of the CPP a far more powerful deterrent than the attraction of the price reduction in other periods. As a result virtually all of the CPP tariffs trialled and offered to date have required incentives and guarantees to recruit customers.

So, although these pricing schemes effectively expose the end user to price signals that can motivate DSP, the end user is likely to perceive those schemes as inherently riskier than the arbitrage deployment form in which there is no risk, but only upside when a call comes. Retailers may also feel that the arbitrage form offers them more benefits: not only does it allow them to share in the benefits, but it may also give them more control over and knowledge of the demand response that is likely to eventuate and greater kudos from the customer for delivering benefits (rather than simply allowing the customer to obtain them.

Where interval metering is not present, pricing options are severely constrained, and are effectively limited to much blunter signals, such as interruptible service arrangements and time-of-use and ascending block pricing. Of these, interruptible service arrangements are likely to make the greatest impact from a demand response perspective. However, it should be noted that interruptible service arrangements:

- Are most often offered to large commercial and industrial customers. These offers share some features with DSP offers for arbitrage, and in that sense would compete with those offers within the eligible market.

- When they have been offered to residential and other small volume users, they have generally taken the form of controlled hot water tariffs. While useful, these tariffs have historically been controlled by networks. Some arrangements have been made whereby Retailers have contracted with networks to exercise this capability for a fee for the benefit of the Retailer[39], but this has primarily been the case where a single Retailer enjoys a very high market share within the network area as the control technology currently in place generally switches these loads in banks of customers and is not addressable at the level of the individual customer. As a result, this strategy is likely to be of decreasing value until more addressable control technology is widely in place. Even so, other factors such as greenhouse emission reduction policies are serving to decrease the penetration of controlled hot water service.

By contrast, time of use (ToU) and inverted block pricing are very likely to have limited affect on the absolute peak demand. These pricing mechanisms are designed to affect the overall proportions of energy used in peak, shoulder and off-peak periods and to reduce overall energy consumption, respectively. The peak, shoulder and off-peak levels of these tariffs are designed to apply for extended periods – such as over a season – hence the differences in price levels under such tariffs is much less than the differences in levels that customers would be exposed to under more dynamic structures (such as CPP).

The shift of energy from peak to shoulder and off-peak periods, that ToU tariffs are designed to induce, can help achieve many of the goals of DSP. This is particularly the case where the ToU tariff is combined with load control such as controlled water heating. However, in those cases, where control is exercised continually – as has historically been the case – it will become part of the load forecast. This will provide general load profile smoothing benefits to the electricity supply value chain and a lower price for the end-user. The capability will not be available for arbitrage or other forms of DSP deployment. Those forms could be accommodated where the dispatch is irregular and only in response to, say, price in the case of the arbitrage form. However, this requires significantly more flexibility in the control of these loads as individual points than has been deployed to date, thereby increasing costs.

Inverted tariffs, because they offer an even blunter signal, will tend to have less beneficial effects from the electricity supply value chain as it will encourage energy conservation at any time. This is likely to be least readily accomplished by most end-users during periods of high demand and/or congestion.

39 AGL Energy SA had such an arrangement with ETSA for some time, for example.

Effectiveness of current Rules & processes

- **Incentive to participate**

  There is nothing in the Rules that precludes a Market Customer from offering any of the types of tariffs discussed above. In a competitive environment Retailers will offer tariff structures in response to customer demand. To date, tariff structures have been relatively simple for all but a very small set of customers that are either very sophisticated or have a high degree of control over when and how they use electricity. As noted earlier, some pricing structures require interval or other types of advanced metering functionality. Should interest in the different pricing arrangements that reward load flexibility increase among customers, it would be likely that we would see an increased offering using these concepts.

  From the end-user's perspective, there are significant differences in the incentive to participate in the various types of voluntary pricing arrangements for different classes of customers, as well as for customers within the same class that have different load characteristics. Several of the most relevant between- and within-class factors that will influence the relative attractiveness of the various pricing arrangements are discussed below.

  - Real-time pricing and/or pool price pass through – requires interval metering and is most likely of interest to relatively large and sophisticated customers that have the ability to turn off relatively significant proportions of their loads in response to high prices for the duration of typical high price events. The incentive for the end-user is to use the flexibility in its load and its technical capability to exercise that flexibility and commercial ability to monitor prices, to reduce total electricity bill. The customer will also need to be able to manage, if needed, significant changes in electricity costs from month to month in the event that it is not always able to respond to price events.

  - Critical peak pricing (CPP) – requires interval metering and has generally been offered to residential and very small business customers, probably because it is significantly simpler that either real-time pricing or pool price pass through. Experience in Australia and elsewhere indicates that initial recruitment to the tariff requires special arrangements that protect customers, at least for a year, from higher bills than they would have paid if they hadn't taken up the CPP arrangement, but that (a) CPP is generally successful in reducing peak demand, and (b) a relatively high proportion of customers elect to stay on the tariff after the trial period, indicating that are able to respond to the price signal without undue hardship. Given these positive experiences, it may be that recruitment in later years will succeed on a word-of-mouth basis, and that the provision of insurance will not be needed.

- Interruptible service arrangements – can be implemented without any advanced metering functionality. For larger commercial and industrial customers the motivation to participate is the ability to be charged a lower per-unit price in exchange for being able to be turned off (either in whole or in part) for a specified duration on no more than a specified number of times per season or year. The only version of this type of arrangement generally made available for residential and small business customers tends to focus on allowing the Retailer or distributor to control when certain end-use devices or circuits are energised, as is the case in controlled water heating. The motivation for the customer is a lower per-unit price.

- Time of use (ToU) and inverted block tariffs – charge customers lower per-unit prices for either using energy at certain times (ToU) or using less energy (inverted block). ToU arrangements have been developed for all customer classes, though will generally appeal most strongly to those that either already use a significant proportion (i.e., more than the average) of their electricity in off-peak periods, or can readily get into that position by permanently shifting one of more end-uses to a controlled arrangement[40]. Inverted tariffs have also been offered to all customer classes but most often on a mandatory rather than voluntary basis. Experience in Australia and elsewhere has shown that these arrangements generally have a much more significant impact on end-users' total consumption rather than peak demand.

Networks can also offer these types of pricing structures, though a number of the jurisdictional regulators have stressed that networks should not develop prices based on end-user customer classes, but rather should price either to Retailers (as the actual customers of the network), or with regard to usage characteristics as they drive network costs. This would include primarily coincident peak demand, load factor and power factor. Other aspects of network price regulation can pose constraints to innovative pricing. For example, the general prohibition against area-specific pricing tends to blunt the price signal that could be delivered through CPP.

40 In some cases, including residential water heating, the tariff is provided just for the end-use that can be controlled and which is supplied through a separate meter, while the rest of the customer's usage is charged on the standard arrangement. Where this is the case, it essentially constitutes interruptible service.

- **Opportunity to participate**

  There is nothing in the Rules that preclude Retailers from offering any of these pricing arrangements of that constrain end-users from taking them up. As noted above, current regulatory practice that does not allow networks to price on an area-specific basis tend to blunt the price signals that could be provided by a CPP tariff. Possibly more importantly, there are no Rules that require that the network tariff be passed along to the customer in a form whereby the customer must ‘see’ the network pricing structure. Rather, Retailers are allowed to re-wrap a CPP from a DNSP into a flat price. Presumably, if this were to impose an acceptable risk to the Retailer, it would be passed along to the end-use customer. However, given the blunting of these price signals described above, this may be able to be absorbed by the Retailer. Although Retailers are willing to manage the much higher risk posed by the wholesale energy market and still offer customers flat energy prices, it must be remembered that Retailers can hedge their volume and price risks with financial instruments. No such instruments exist for hedging exposure to network CPP arrangements.

- **Flexibility of participation**

  These arrangements generally include relatively little flexibility, other than their voluntary nature. Customers are generally free to enter and leave these arrangements, though some conditions may be applied, particularly where an investment has been made on the customer’s behalf. For example, where a special meter or control gear has been installed, there may be penalties for early exit.

  The only other form of flexibility other than exit is when an offer of insurance has been made that protects the customers for an initial period against increased bills as a result of taking up the tariff.

  In general, however, while the end-user is on any of these tariffs they will be subject to pricing and/or control features of the tariff.

- **Transparency and firmness of demand-side resources**

  Interruptible service arrangements are firm, as the control of the load generally rests with the Retailer or, more typically, the network operator offering the arrangement, and therefore their impact on load can be fully transparent. This transparency is not required to be disclosed to NEMMCO under any current Rules, however.

The remainder of the arrangements under consideration – real-time and pool price pass through, CPP, ToU and inverted block tariffs – all rely on customers' responses to each event. In this sense they are essentially non-firm, except where they are hard-wired to a load control strategy, as is the case in controlled water heating[41]. It would be possible, however, to analyse the response to different events under each type of pricing arrangement (assuming they are offered and taken up) and to develop a model for estimating response based on relevant independent variable. It should be noted that there is no requirement for any one in the market to develop such a model, or for models developed by different parties to be reconciled in any way, or for their results to be provided to NEMMCO. Furthermore, there is no obligation under the current Rules on any party using these arrangements to notify NEMMCO that they will be using those demand-side resources on any particular day. To this extent, the impacts of these capabilities are likely to be highly non-transparent to NEMMCO and the market.

- **Managing interaction with other parties**

Virtually all of these arrangements will be bi-lateral arrangements between the Retailer and the end-user. The exception is those network tariffs that are offered to end-users or that are simply put in place by a DNSP in which the Retailer may choose whether or not to pass along the price signal. There could also be occasions where a Retailer or a DNSP that enlists a customer onto a pricing arrangement that provides a set number of times a price or a load interruption can be invoked, determines that it is not going to need to use the full number of events allowed and therefore on-sells the right of interruption to another party. In practical terms, this would most likely happen where a DNSP was not going to use the allotment and so on-sells the right to the serving Retailer for use in the energy market.

41 This is least likely to be undertaken with inverted block tariffs. In addition, where such control is applied regularly, as is the case in controlled water heating, it will be captured in load forecasts thereby reducing the value in certain hedging applications, such as arbitrage deployment.

Summary of effectiveness

Again, there is nothing in the Rules that limits the Retailer's ability to provide the types of price signals that can assist end-use customers in assessing the value of DSP from their individual perspective and acting as suits their individual perceptions of value. However, the ability of the Retailer to provide certain types of price signals – particularly critical peak prices, real-time prices or pool price pass through – will depend on whether or not interval metering is available. Interestingly, even where such metering is available, Retailers have not offered these pricing structures. This is likely to reflect customer preferences for simpler and flatter pricing structures in which they perceive less risk, and the fact that both of these types of pricing reduce, to some degree, the risk packaging that is the core value-add of the Retail function in the market. Additional education of customers and the emergence of turnkey means for helping customers respond to varying price signals may increase customers' willingness to engage in these pricing structures. Where this is coupled with significant levels of competition in the Retail market, there will also be significantly greater propensity on the part of Retailers to offer these products.

4. LESSONS FROM PREVIOUS REVIEWS OF DSP MECHANISMS

Over the past 10 years a number of separate consultations and reviews of DSP mechanisms have been undertaken, with the broad objective of identifying potential benefits, the barriers to realising them, and the initiatives required to overcoming the barriers, which could include information/awareness development, Rules changes and/or policy and regulatory initiatives[42]. The focus of the reviews / consultations has ranged widely with specific topics, or variants thereof, as follows:

- DSP as a counter-balance to generator market power;
- the merits of interval metering and real time pricing signals for end-users;
- identification of the types and volumes of load that might be suitable for market-based deployment in some form;
- the incentives to use DSP as an alternative to network augmentation and how those incentives are best incorporated in NSP regulated revenue resets;
- alternative load control mechanisms:
    - direct load control by NSPs; or
    - contracted response as a reaction to a signal from a market player (Retailer or Facility Agent);
- refinement of existing market Rules to facilitate dispatch of scheduled loads;
- direct payment for DSP in a manner analogous to payment for generation; and
- development of short-term settlement markets to lock in the value of DSP.

The outcomes of previous reviews of DSP provide some valuable lessons and insights into how the structure of the NEM Rules and processes can influence the effectiveness of measures to deal with the above topics. These lessons, backed up by CRA's experience, are outlined below.

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42 Energy Futures Australia identified 40 separate reports on DSM issues undertaken or commissioned by NEM stakeholders (State and Commonwealth government agencies and regulators; NEM-based statutory bodies; network service providers and lobby groups) from market start in December 1998 up to December 2004). See http://www.efa.com.au/dsmdocs.html.

- In the absence of remuneration, the current arrangements for scheduled load have been unsuccessful in encouraging demand-side participation in the central dispatch process – aside from hydro pumping loads, there are no loads registered with NEMMCO for participation in the energy market.

- Forward markets have been proposed as a means by which demand-side resource owners can lock-in value. Existing financial market arrangements provide the capability, but the liquidity of those markets is claimed to be insufficient to guarantee that demand-side resources can be rewarded.

- Even with (modest) remuneration available, the current arrangements for FCAS markets have been unsuccessful in encouraging demand-side participation – aside from Victorian smelters, there are no loads registered with NEMMCO for participation in the FCAS market.

- Identification of DSP potential and network opportunities (for example, the location of network constraints that could be alleviated via DSP) are probably necessary but not sufficient conditions for successful demand-side resource recruitment and deployment – targeted programs are required to encourage the potential DSP into the market in some way. It is important to note that DSP potential is *not* assessed by networks when noting opportunities for DSP to defer network augmentation. The fact that the identification of the potential must be done on a speculative basis by an aggregator and that there is significant cost and effort in doing so is indeed a barrier in and of itself.

  Despite efforts to promote DSP, there is little transparency in the market for demand-side resources – officially reported levels of exercisable demand-side resources remain low, with NEMMCO's *2007 Energy and Demand Projections* reporting 132 MW of committed NEM-wide DSP[43], although anecdotal evidence suggests that actual demand-side resources exercised on a regular basis is several times the officially reported level.

  Maintaining the accuracy of NEMMCO's demand forecasting is still problematic despite Rule/Code-based efforts to improve forecasting – for example NECA's Code Change Panel proposed (in late 2000) changes to the Code to improve the accuracy of demand forecasts; and make the arrangements for demand-side bidding, which already exist in the Code, more attractive to end-use customers.

  In the absence of mandated reporting of demand-side resources, it cannot be known how much of the discrepancy between actual and forecast load is a consequence of:

  - purely random decisions by end-users to switch load on and off; or

43 By "committed" NEMMCO is referring to DSP that is highly likely to be dispatched at times of peak demand.

- some programmed control over load in response to market signals that are invisible to NEMMCO's systems.

- Efforts by regulators to encourage NSP consideration of DSP as an alternative to network augmentation have, thus far, yielded limited success only – even the introduction of specific demand management codes of practice in both NSW and SA has not been accompanied by an increase in DSP[44]. In CRA's experience, DSP is more likely to occur when a NSP actively facilitates DSP compared to passively advertising an opportunity. The recent Total Environment Centre Rule change proposal is a further effort to increase the propensity of NSPs to embrace DSP as an alternative to network augmentation.

- Direct and targeted government intervention can be effective in bringing new demand-side resources to the market – for example:

  - SA Government encouragement for ETSA utilities to find a solution to SA's peak loading problems resulted in a successful trial of direct load control over air-conditioner compressors[45], although to date there has not been a single program from ETSA either internally or contracted to a third party to actually try to defer augmentation; and

  - Western Power (WA) was able to find 100 MW of load available to be shed within seconds of receiving the signal, although actual review and test dispatch revealed that only a portion of this load was available to be shed at any given time.

- Proposals to encourage DSP via radically different market structures have yet to gain industry acceptance as a viable way forward. The COAG (Parer) report suggestion for a 'pay-as-bid' mechanism to encourage DSP was not pursued on the basis that it would be extremely complicated, particularly in terms of: trading-off notice periods, shutdown periods and bid price; and in auditing energy curtailment. The pay-as-bid proposal also left unanswered a number of major market design questions in that it created an unhedgeable uplift.

- The cost benefit analysis of mandatory interval metering as a means to support larger scale end-user involvement in DSP programs suggests a stronger case for roll-out in more densely populated areas. Although smart meter infrastructure would be likely to result in additional demand-side resources being available to the market, the value of that DSP represented a very small proportion of the total benefits (or costs) of a roll-out.

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44 There was a review of the code in SA about around 2 years ago initiated by the fact that no DSP projects had emerged from ETSA despite the code being in place for over 4 years at that point. In NSW, significant effort did not emerge until the d-factor was introduced.

45 In this particular case, ETSA specifically noted that interval metering was not required in order to implement an effective DSP program. This was also supported by the results of the Commonwealth's cost-benefit analysis of smart meters

- Critical peak pricing (CPP) trials may have had some success when run as a retail tool, but have thus far failed to translate into an effective network management tool. CPP tariffs are unlikely to be successful as a means of managing local network loading unless NSPs (as opposed to Retailers) are able to offer locationally specific tariffs. Current network tariff structures are required to be uniform across a jurisdiction.

5. LIMITATIONS AND APPROACHES TO RESOLUTION

Sections 2, 3 and 4 provide discussion of the nature of the various forms of DSP and the effectiveness with which the current Rules facilitate their deployment. In the context of that discussion, attention now turns to identification of specific issues that, if addressed, could represent the removal of limitations of the impact of DSP on market outcomes.

5.1. AEMC AREAS OF SPECIFIC INTEREST

The terms of reference provided by the AEMC required CRA to consider the following:

> *Recognising the variety of ways in which demand-side resources can participate in the NEM wholesale market, are the Rules limiting opportunities for some types of demand-side resources to impact on the wholesale price of electricity, having regard to:*
>
> - *the implications of incorporating the variability of DSP in the dispatch engine;*
> - *the accuracy of NEMMCO's load forecasts and its impact on supply and consumption decisions;*
> - *the impact of a market price cap (VoLL) in the wholesale market;*
> - *the transaction costs of participating in the wholesale electricity market;*
> - *the transaction costs for retailers and demand-side resources in contracting; and*
> - *the need for knowledge and detailed understanding on the behalf of potential demand-side resources of the operation of the wholesale spot market.*

The links between these areas, the previous discussion and the identified issues are discussed below:

5.1.1. Incorporating the variability of DSP in the dispatch engine

Subject to arrangements to manage power system control and accuracy and verification of the level of response, CRA sees no adverse implications arising from incorporation of further DSP into central dispatch processes as either scheduled load or market ancillary services. The major challenge with respect to the management of dispatch processes will be faced by the demand-side resources themselves, as under current arrangements they would need to incorporate appropriate control mechanisms to allow them to respond to dispatch instructions.

Market efficiency is likely to be enhanced if a greater proportion of otherwise unpredictable load participates in central dispatch. As well as helping to improve the accuracy of demand forecasts (see Section 5.1.2), increased participation of load provides more scope for the dispatch engine to allow it to minimise the objective function. However, under current arrangements, there is no incentive for DSP in the form of scheduled load to participate. Possible mechanisms by which non-centrally dispatched DSP could be increased are discussed below (see Section 5.2.4).

5.1.2. Load forecasts and impact on supply and consumption decisions

Accurate demand forecasts:

- allow operating margins on network constraints to be reduced and, hence, more efficient use of existing network infrastructure;
- allow more accurate dispatch of scheduled units to meet non-scheduled demand, thus reducing the cost of dispatch; and
- lead to more accurate pricing of energy, thus improving the allocative efficiency decisions of parties determining their level of electricity supply and consumption.

However, developing commercial opportunities and current market arrangements have features that contribute to the inaccuracy of centralised demand forecasts – for example:

- freedom of load to respond in any way it likes to emerging market conditions;
- development of systems that make it possible to have coordinated control over multiple dispersed loads;
- commercial value in having hidden capability to deploy demand-side resources; and
- increasing sophistication of control systems for (non-scheduled) embedded generation, allowing them greater freedom to respond to market conditions in a way that NEMMCO finds it difficult (or impossible) to anticipate;

Possible mechanisms by which demand forecasts can be improved are discussed below (see Sections 5.2.3, 5.2.5 and 6.2.4).

5.1.3. Impact of a market price cap in the wholesale market

A market price cap will provide some limitation on the volume of demand-side resources available to the market in some form – either within or independent of central dispatch.

With a market price cap in the order of $10,000/MWh there is very low chance of inducing DSP from a load with an opportunity cost of load not taken greater than $10,000/MWh[46]. Although raising the market price cap may increase the incentives for buyers to seek additional DSP, in our experience, virtually all of the DSP that currently makes itself available in the market does so at prices significantly below the current market price cap. While a higher market price cap might result in some additional volume of DSP, our view is that the increment will be small notwithstanding that there may be more motivation for parties to seek out DSP. Better gains in terms of the amount of DSP available to participate in the market would probably come from increasing the likelihood that DSP capability will be used, removing barriers to the use of DSP in more than one 'market', and establishing means by which the capital investment required to activate DSP (particularly in communications and controls at the small end of the market) does not act as a barrier.

5.1.4. Transaction costs of participating in the wholesale electricity market

The transactions costs (previously discussed in Sections 2.1 and 2.2 and outlined below) to establish the mechanisms that allow the participation of demand-side resources in central dispatch (i.e. the energy or FCAS markets) are non-trivial and, in many cases, prohibitive:

- For end-users, there is:
  - the opportunity cost of interruption and load not taken;
  - the installation cost of (potentially expensive) communication / telemetry mechanisms;
  - the choice of either:
    - incurring the costs of registration with NEMMCO as a Market Customer; or
    - ceding a degree of control of end-use systems and processes to a Retailer or some other Market Customer.
- For Market Customers (Retailers) there is:
  - the initial registration as a Market Customer with NEMMCO and administrative requirements associated with classifying additional loads;
  - the administrative burden of managing the dispatch of a demand-side resource.

Possible mechanisms by which demand forecasts can be improved are discussed below.

46 The supply curve of potential demand-side resources is quite inelastic and there is a finite set of discretionary loads that are affected. Loads that are affected are those with an opportunity cost of less than $10,000/MWh.

5.1.5. Transaction costs for Retailers and demand-side resources in contracting

Transactions costs arise in the process of contracting between demand-side resources and parties that will act on their behalf, either Market Customers (Retailers) or Facility Agents, as a result difficulties arise in finding suitable counter-parties:

- owners of demand-side resources willing to sell their load reduction capability but unable to find a willing buyer (Retailer, NSP or NEMMCO); or
- willing buyers of demand-side resources (hedge counter-party, NSP or NEMMCO) but unable to find an owner of suitable demand-side resources willing to sell their load reduction capability.

The level of transaction cost in entering such contracts is likely to vary greatly and will depend on:

- the scarcity and uncertainty of the opportunities to economically deploy demand-side resources;
- the extent of the negotiations required to reach agreement on the nature and terms of the deployment; and
- the (im)maturity of the market for DSP – our experience is that it is much easier to get an end-use customer who has participated in a demand-side initiative to participate *again*, than it is to convince another end-use customer with the same DSP capability to play in the first instance. Transaction costs are high in part because it is a new type of transaction.

Nevertheless, in theory, transaction costs could be reduced if more effective market information mechanisms existed for bringing the parties together – for example, a bulletin board or some form of forward market as discussed below. Stronger regulatory incentives to undertake demand-side resource contracting is unlikely to reduce the transactions costs of contracting, but would instead raise the transaction cost threshold beyond which DSP contracting is not attractive.

5.1.6. Need for knowledge of the wholesale spot market

Even if demand-side resource owners understand their load has potential strategic value, and there is an opportunity to deploy the resource to manage costs, revenues and risks, access to detailed knowledge of electricity market mechanisms is required in order for them to make the most of the opportunities. However, for most demand-side resource owners, energy management is not their central focus, and a clear understanding of DSP opportunities cannot be expected

In order to be an effective player in DSP, the requirement for knowledge extends to understanding:

- the resource owner's business and how electricity can be used to manage costs, revenues and risks;
- the roles played by all stakeholders in the market and their specific interests and motivations in taking advantage of the deployment (or not) of demand-side resources;
- the market Rules and the constraints and opportunities they present to all stakeholders in the market

The parties for whom the DSP has operational value and the reason for their interest in the operation of central dispatch and the potential impact DSP will have on the spot price are:

- a Market Customer trying to manage a hedge position – for example:
    - if a Market Customer is involved in an arbitrage play (see Section 3.3.1) its interest will be in deploying as much demand-side resource as possible without reducing the spot price (too much), because reducing the spot price will reduce the value of the arbitrage; or
    - if a Market Customer is attempting to offset a short contract position and is short by an extent greater than available DSP, its interest will be to reduce the pool price by as much as possible (see Section 3.3.2).
- a TNSP trying to manage network loading either pre- or post-contingency – TNSP interest in the effect of DSP on spot market outcomes is very diluted as interest arises only to the extent that the NSP perceives its 'at risk revenue' to be affected through market impact transparency measures recently implemented by the AER[47]; and
- NEMMCO trying to manage network loading either pre- or post-contingency.

In each of these cases, access to and understanding of pre-dispatch information is essential. A Facility Agent seeking to act on behalf of the owners of demand-side resources needs to understand the motivations and mechanisms that are at play for all parties in order to be able to extract maximum value from the capability offered by a demand-side resource.

47 We are not aware of any situations where DNSPs have exposure to spot market prices.

To the extent that lack of understanding creates a limitation for DSP, CRA does not believe it is something that can be addressed through changes in the Rules. Education and experience is the only thing that can effectively overcome limited understanding[48].

5.2. LIMITATIONS AND POSSIBLE SOLUTIONS

CRA has identified potential limitations associated with current arrangements for DSP in the following areas:

- transactions costs, uncertainty and lack of rewards and uncertainty;
- inflexibility of existing procurement and dispatch mechanisms;
- inefficient central dispatch of generation and load;
- failure to procure / deploy available demand-side resources when economic to do so;
- inaccurate assessment of the need for exercise of RERT; and
- lack of clarity in roles between NSPs and NEMMCO.

The remainder of this section will discuss the nature of the limitations that arise in each of these areas and the *possible* broad solutions to those limitations. The merits of each of the possible solutions are discussed in Section 6.

5.2.1. Transactions costs, uncertainty and lack of rewards

The limitation

A reluctance to offer demand-side resources into central dispatch processes may arise because of the transactions costs, uncertainty or lack of rewards that impact on DSP:

- transactions costs for DSP are high:
  - registration as a Market Customer carries potentially substantial prudential obligations;
  - aggregation of multiple distributed loads is complicated;
  - communication and telemetry requirements to participate as a scheduled load or as a market ancillary service provider may be perceived as too onerous;

48 As commented in Section 5.1.5, the fact that this education is needed is in part a product of the immaturity of the use of DSP in the market. However, the fact that fairly arcane things have to be explained – such as how we might call you but then the price might dip below the price that you said was your minimum, or the price was above your minimum but we didn't call you because we thought there was a very good chance that it was going to turn out below your minimum – make the education process much harder and reduces participation.

- rewards for DSP are too low – there is no formal market provided remuneration for scheduled loads and no formalised market for the provision of short-term reserve;
- lack of certainty the demand-side resource owner will capture value from DSP;
  - no obvious opportunity for facility provider to forward trade on the value of DSP;
  - dispatch price is not necessarily reflective of opportunity cost of load because of approximations in the dispatch and pricing process associated with:
    - 5-minute dispatch and 30-minute settlement; and
    - dispatch on the basis of the value of energy at a node, but settlement for energy at a regional reference price; and
  - a load deemed capable of providing a service to enhance the value of spot market trading cannot be paid on an availability basis for that service and is not guaranteed to be enabled / used.

A possible solution

In addressing the limitations associated with transactions costs, uncertainty and lack of rewards, Rule changes could be contemplated in the following areas:

- modification of registration categories and requirements:
  - creation of a new participant registration category, say “Facility Agent”; and
  - simplification of load aggregation processes and communication / telemetry requirements for smaller blocks of load.
- inclusion of uplift for scheduled loads in current market design;
- creation of a market for standing reserve;
- development of a forward market or bulletin board for DSP trading opportunities; and
- re-consideration of those aspects of market design that create approximations in pricing and, hence, value risks for scheduled loads.

5.2.2. Inflexibility of existing procurement and dispatch mechanisms

The limitation

The fact that load has only limited participation in central dispatch processes is symptomatic of the lack of flexibility. Recently active DSP in central dispatch processes is restricted to:

- contingency FCAS; and

- "legacy" NCAS arrangements to enhance spot market trading[49].

At present on/off loads must manage potential non-conformance to infinitely variable dispatch targets if they are marginal in the dispatch process.

An additional concern for loads participating in central dispatch is the need to manage the time frame over which the load can be switched – an inter-temporal optimisation problem. Depending on the type of load, varying lead times for turning off are required and the length of time the load can stay off will be limited.

NEMMCO's approach to procurement of services to enhance the value of spot market trade, by requiring procurement and deployment to be consistent with full optimisation of the dispatch process is an impediment to more comprehensive utilisation of demand-side resources.

A possible solution

The Rules do not prescribe the nature of the dispatch engine with respect to whether or not it must be capable of making integer decisions. Requiring a capability for (mixed) integer programming may be one way of more effectively facilitating the participation of discrete loads in central dispatch processes. Integer programming could also play a role in inter-temporal optimisation of dispatch.

Consideration of probabilistic approaches to procurement and deployment of demand-side resources could be seen to be a feasible approach to meeting expectations of enhancing the value of spot market trade.

5.2.3. Inefficient central dispatch of generation and load

The limitation

As discussed previously, a discrepancy between actual and forecast load can arise due to:

- purely random decisions by end-users to switch load on and off; or
- some programmed control over load in response to market signals that are invisible to NEMMCO's systems.

To the extent of the inaccuracy in demand forecasts, the efficiency of central dispatch is compromised:

49 CRA understands that the only service NEMMCO is able to deploy to enhance the value of spot market trading is an arrangement that is a carry-over from market start whereby a system security based contract between VPX and a market stakeholder was novated to NEMMCO.

- operational margins, as reflected in constraint equations, are larger than they would otherwise have to be, resulting in sub-optimal use of the transmission network; and
- higher levels of FCAS need to be procured and deployed than would otherwise be the case.

There is no Rule that expressly requires any party to provide NEMMCO with accurate information with respect to the level of demand-side resources that may be under contract[50].

A possible solution

The current invisibility of programmed control over load in response to market signals could be addressed in a couple of ways:

- mandated reporting of demand-side resources – for example, in the PJM market in the US, retailers and other load response providers are required to advise the system operator of the amount of load response that would be exercised at specific price levels;
- require Market Customers to be responsible and accountable for forecasting their load through the establishment of some compulsory form of forward market.

5.2.4. Failure to procure/deploy demand-side resources when viable

The limitation

Ineffective use of *available* DSP can be manifested in the following ways:

- NSP failure to properly consider DSP as a means to address network congestion – this may be due to:
    - possible bias against DSP in regulated revenue assessments that can limit NSP ability to recover demand-side resource development costs and foregone revenue due to DSP, and reduce the size of the asset base from what it otherwise would have been thereby reducing commercial returns to shareholders; and
    - NSP default position to construct network assets, given infrastructure under NSP control may be considered a more reliable means of dealing with network loading problems than contracted DSP[51];

50 Some information on demand-side resources is sought by NEMMCO in order to assist with the compilation of the SOO / ANTS (see Section 5.2.5).

- Once procured and contracted for a specific purpose – say, for NSP management of network loading – demand-side resources are often precluded from being made available for other forms of DSP.

- NSPs lack the incentive to adopt CPP programs following apparently successful trials of such programs by Retailers.

  For example, both Country Energy and Energy Australia have completed (apparently successful) trials of CPP programs[52]. However, a DNSP's ability to effectively utilise such programs is limited by its inability to:

  a) ensure that end-users will see its price signal (as the Retailer can re-wrap the network charge in an all-in price to the end-user); and

  b) charge locationally specific network tariffs (which would increase the price signal possibly to levels that would motivate the Retailer to reduce its risk by passing the signal through to the end-use customer, thereby making it visible)

  as a result of jurisdictional regulatory approaches that force network charges to be postage stamped.

- Notification to the market of deployment opportunity that is either too early or too late:

  - early notice of firm requirement may be inefficient in the sense that it could either commit the NSP to expenditures that might not be needed (if demand slows), or could be addressed at less cost (should demand alter in such a way as to make a network solution more cost-effective); and

  - late notice may be ineffective – for example, a 9-month advance notice if needed for RERT may be too short to maximise DSP, particularly in the current market environment when very little DSP has been activated.

- Retailer disinterest in additional demand-side resources.

51 In order to be effective in avoiding new investment in network infrastructure, DSP procured for network loading purposes must be guaranteed to be available in 100% of instances it is required. A demand-side resource owner would not be able to opt-in and opt-out of such an arrangement at will.

52 Country Energy's trial was initiated by its retail business; EnergyAustralia's was initiated by the network side of the business.

In principal the customer will talk to different retailers to find the retailer offering the best deal, and the customer's competitors will do the same. Competitive pressures between Retailers will result in the Retailers competing to provide a better share of the available arbitrage to the demand-side resource owner. This will result in higher returns to demand-side resource owners and therefore more providers entering the market. The greater volume of DSP will in turn tend to reduce arbitrage as it reduces load to be met and therefore bid prices. This continues until arbitrage is reduced to break-even (i.e. where arbitrage equals demand-side resource owner opportunity costs) and there is no further economically feasible DSP.

Assuming the customer is interested in reducing the overall long-term average cost of electricity he will see that the reduction in arbitrage reflects the fact that the DSP that has been dispatched is effective in exercising discipline on pool price and that this will translate into lower electricity prices for all users.

In practice, however, a key consideration is the fact that Retailers have little interest in changing the pool price when they are adequately hedged. Rather, they generally offer DSP as a means for providing a customer benefit and for covering the costs of that benefit and perhaps providing a modest additional source of revenue by sharing in the arbitrage that eventuates when the demand-side resources of their customers are deployed – the higher the pool price the higher the arbitrage in total dollars, and the more there is to share between Retailer and end-user. The greater the number of players on the DSP side – and the greater volume of DSP in play – the greater the risk of depressing pool price and thus reducing the arbitrage pay-out and the satisfaction of the Retailer's customers.

A possible solution

NSP inclination to prefer network solutions and Retailer disinterest in additional demand-side resources could be addressed by:

- specific bias in the Rules in favour of demand-side technologies that may result in both NSPs and Retailers seeking greater quantities of DSP;
- stronger regulatory incentives for NSPs to seek DSP as an alternative to network augmentation; and
- removal of inability of DNSPs to charge locationally-specific network tariffs.

5.2.5. Inaccurate assessment of need for exercise of RERT

The limitation

Lack of transparency of demand-side resources in the NEM creates a risk of inaccurate assessment of reserve at forecast levels of 10% PoE demand, with the subsequent possibility of NEMMCO either:

- failing to intervene in the market through the exercise of the RERT when NEMMCO's estimates of exercisable demand-side resources at 10% PoE demand are too high; or

- unnecessarily intervening in the market through the exercise of the RERT when NEMMCO's estimates of exercisable demand-side resources at 10% PoE demand are too low.

NEMMCO's ability to secure information on the level of contracted demand-side resources is limited by accuracy of the responses to annual surveys of NEM stakeholders conducted for the purposes of compiling the SOO / ANTS. It is understood that NEMMCO relies on the authority provided by Rule 5.6.5 [sub-clauses (b)(1), (c)(6), (f) and (g)] to request information by way of survey of NSPs, Retailers and parties known to be involved in the aggregation of small loads. However, the terms of the relevant Rules are not sufficiently clear to guarantee that NEMMCO is provided with full and accurate information with respect to the level of contracted demand-side resources. Information complied for the purpose of the SOO / ANTS is understood to be aggregated for the purpose of deriving a regional demand off-set against 10% PoE demand and the subsequent assessment of reserve adequacy.

The possible solution

Mandated reporting of demand-side resources to ensure accuracy of MT PASA forecasts at 10% PoE demand.

5.2.6. Lack of clarity in roles between NSPs and NEMMCO

The limitation

A lack of clarity in responsibility between TNSPs and NEMMCO with respect to the management of network capability creates a risk that either:

- TNSPs and NEMMCO will inefficiently compete for the same demand-side resources; or

- TNSPs and NEMMCO will each stand aside from an opportunity to efficiently procure demand-side resources in the belief that it is the other's responsibility.

A possible solution

This matter is part of NEMMCO's "Review of network support and control services"[53] – we have not assessed it for the purposes of this review.

53 Refer: http://www.nemmco.com.au/powersystemops/168-0089.html.

6. AMENDED RULES: OPTIONS AND THEIR VIABILITY

The terms of reference provided by the AEMC required CRA to consider the following:

> *If the Rules are limiting opportunities for some types of demand-side resources to impact on the wholesale price of electricity, what changes to the Rules would remove or reduce these limitations, having regard to:*
>
> - *the existing single settlement market design;*
> - *alternative market designs;*
> - *opportunities for up-lift payments;*
> - *opportunities for reducing the transaction costs for financial contracting between demand-side resources and retailers, such as a central exchange or bulletin board; and*
> - *opportunities for improved load forecasts.*

Each of the changes mentioned in the AEMC terms of reference has the potential to impact on the spot market price for electricity. However, as discussed in Section 5.2, other possibilities also exist for amending Rules that, through facilitation of higher levels of DSP, could also impact on the spot market price for electricity and the broader financial contracting environment for such services.

CRA has identified several candidate areas for amending existing Rules in a manner that would either:

- remove an impediment to the emergence of DSP; or
- facilitate the more efficient utilisation of existing demand-side resources.

DSP can provide benefits to many parts of the value chain and a number of the separate markets within the NEM. However, we also note that a significant barrier to DSP in the current market structure is the fact that each beneficiary, when considering the benefits it may obtain, confronts the full transaction costs and implementation costs of DSP. As a result, in examining opportunities to facilitate greater utilisation of demand-side resources, we should be taking a comprehensive view of deployment potential rather than limiting consideration to a subset of deployments, such as those directly involved in central dispatch.

The analysis that follows considers each of the possible changes to the Rules in isolation, rather than trying to propose an optimal package of measures[54]. This approach has been adopted because there are several parallel streams of work being conducted as part of the AEMC's review of DSP (Stage 2) – each of which could result in proposals to make changes that could be variously sympathetic or inconsistent with the Rule changes being discussed here. Accordingly, CRA is not advocating any particular solution, but we discus the range of features and considerations that should be taken into account when deciding whether or not to incorporate a mechanism within the ultimately chosen market design.

There are two broad categories of change and several sub-categories as follows:

1. change to market design:
    - development of a bulletin board for trading under-utilised capability;
    - development of forward markets to lock-in resource value;
    - the development of uplift arrangements for scheduled load;
    - development of a market for the provision of standing reserve;
    - addressing the disconnect between price and the opportunity cost of dispatched units that is created by:
        - 5-minute dispatch and 30-minute settlement; and
        - dispatch on the basis of nodal value and settlement on the basis of a zonal price;
2. administrative measures:
    - modification of participant registration categories and requirements;
    - providing for integer decisions in the dispatch process;
    - wider tolerances for demand-side response; and
    - mandated reporting of contracted demand-side resources.

54 Some of the alternative mechanisms may be incompatible with each other.

As well as the parallel work streams being managed by the AEMC as part of the review of DSP (Stage 2), CRA is aware that NEMMCO is in the process of conducting a review of network support and control services[55]. Given the range of work that is being done elsewhere, it is inevitable that some common issues will arise. On those common issues where CRA believes it is more properly left to an alternative work stream to make detailed comments, CRA's own comments will be brief.

In Section 5.2.4, it was suggested that DSP could be encouraged by addressing the following matters:

- specific bias in the Rules in favour of demand-side technologies that may result in both NSPs and Retailers seeking greater quantities of DSP;
- stronger regulatory incentives for NSPs to seek DSP as an alternative to network augmentation; and
- removal of inability of DNSPs to charge locationally-specific network tariffs.

These matters are more appropriately discussed in other work streams more directly concerned with these areas: no further comment is offered here.

6.1. CHANGE TO MARKET DESIGN

CRA has identified five forms of market design change that could facilitate increased levels of demand-side resource utilisation in the NEM:

- development of a bulletin board for trading under-utilised capability;
- development of forward markets to lock-in resource value;
- the development of uplift arrangements for scheduled load;
- development of a market for the provision of standing reserve; and
- addressing the disconnect between price and the opportunity cost of dispatched units that is created by:
  - 5-minute dispatch and 30-minute settlement; and
  - dispatch on the basis of nodal value and settlement on the basis of a zonal price.

55 See http://www.nemmco.com.au/powersystemops/168-0089.html.

Sections 6.1.1 to 6.1.4 outline entirely new market features for which no Rules currently exist. If the AEMC was to pursue any of the changes outlined below, there will be a multitude of variations to such arrangements, with each variation potentially requiring consequential impact elsewhere within the Rules. Accordingly we have provided high level functional descriptions of the changes that would be required.

6.1.1. Bulletin board for demand-side resources

The objective of a central bulletin board (BB) would be to match buyers and sellers of the capability of demand-side resources. However, there is no single model for the management of a BB – for example:

- The BB could be used to advise opportunities for increased utilisation of demand-side resources only, or also include opportunities to make better use of embedded generation.
- The role of the manager of the BB could merely be BB host, or it could also extend to a clearing house for contact exchange, or broker (and even market maker) for contracts.

  The chances of success of a BB could be affected by whether or not the identity of those posting information was protected – anonymity is likely to have value, thus requiring a centralised entity (probably NEMMCO) to be the broker of any deals, in which case price would need to be one of the reported parameters.

If the operator of the BB was to be NEMMCO, consideration would have to be given as to whether a conflict of interest could arise if NEMMCO was also competing with other parties for DSP contracts from opportunities posted on the BB. The type of model to be initially adopted would need to be based on judgements as to the degree of contract facilitation that is required, although the structure of the BB could be such that its role is an evolving one.

For both un-contracted / under-utilised resources and buyers of DSP with un-contracted needs, the following parameters would be relevant:

- location / region;
- capability – MW load able to be reduced;
- price;
- availability:
  - time of day / season;
  - notice time required to switch off;
  - minimum and maximum run times;

In order for a trade to be effected, both buyers and sellers of capability would need to reach agreement on every parameter. Therefore the number of parameters needed to define a resource is likely to represent an impediment to successful trade.

Success of a BB as a trading mechanism would be dependent on the liquidity of the market – in the absence of robust (and high volume) competition between buyers and sellers, the propensity of buyers and sellers to participate in the BB might be limited. Some commodity markets can only succeed if there is a market maker, someone prepared and able to buy all resource offered at a reasonable price – a Facility Agent[56] perhaps – and to then repackage that capability in a form that is attractive as a sale to a third party.

6.1.2. Forward markets

A step further on from the creation of a BB as a means to facilitate trade in demand-side resources, would be the creation of a formalised forward market – a mechanism that could create opportunities for demand-side resources to lock-in the value of their capability. However, before a centrally managed forward market is considered, the effectiveness of existing forward contracting opportunities needs to be examined.

Existing forward market

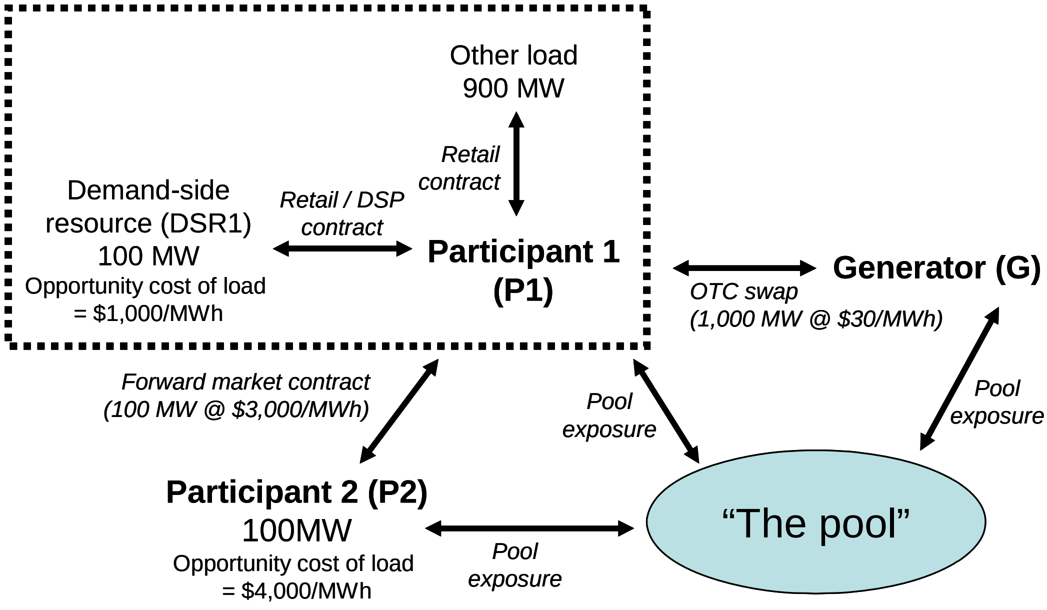
A forward market already exists in the form of OTC contracting. There is no technical or Rule-based reason why this forward market cannot facilitate trades that would lock-in value of demand-side resources.

The example of arbitrage presented in Figure 1 (Section 3.3.1) provides much of the framework, although it is noted that this earlier example abstracted from the complications of price uncertainty and the opportunity cost of load not taken.

Consider the set of arrangements outlined in Figure 2 and the example (Scenario C and Scenario D) below.

56 See Section 6.2.1.

Figure 2: Illustrative set of (forward) market arrangements



The situation

In this example the opportunity cost of energy not taken is:

- *$1,000/MWh for DSR1; and*
- *$4,000/MWh for P2 (e.g. transmission connected smelter with direct exposure to the pool).*

P1 and G have a long standing OTC arrangement for a 1,000MW swap at $30/MWh.

The pre-dispatch schedule at 4pm Wednesday forecasts a market price for the hour commencing 4pm Thursday of $5,000/MWh due to hot weather and generator unavailability.

- *As P2 has an opportunity cost of energy not taken of $4,000/MWh, P2 would be happy to lock-in an energy cost of anything less than $400,000 for the hour commencing 4pm Thursday (100MW load x $4,000/MWh).*
- *As DSR1 has an opportunity cost of energy not taken of $1,000/MWh, DSR1 would be happy to switch-off for the hour commencing 4pm Thursday if it could be guaranteed payment of over $100,000 for that hour (100MW load x $1,000/MWh).*

An OTC-based day-ahead market exists.

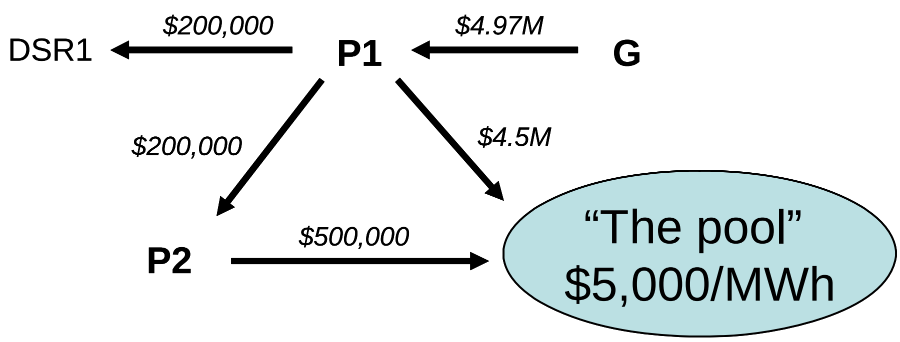
P1 and DSR1 have a DSP contract and agree to deploy the demand-side resources for the hour commencing 4pm Thursday in return for P1 paying DSR1 an amount of $200,000.

P1 and P2 enter into a forward market swap contract of 100MW at a price of $3,000/MWh for the hour commencing 4pm Thursday.

Scenario C

Hot weather and generator unavailability comes to pass and out-turn price for the hour commencing 4pm Thursday is $5,000/MWh.

Cash flows between relevant parties are as follows:



- *P1 ➔ "The pool" as settlement for load = 900 x $5,000/MWh = $4.5M*
- *P2 ➔ "The pool" as settlement for load = 100 x $5,000/MWh = $500,000*
- *G ➔ P1 as settlement of hedge = 1,000 x ($5,000 - $30) = $4.97M*
- *P1 ➔ DSR1 for deployment of demand-side resources = $200,000*
- *P1 ➔ P2 as settlement of hedge = 100 x ($5,000 - $3,000) = $200,000*

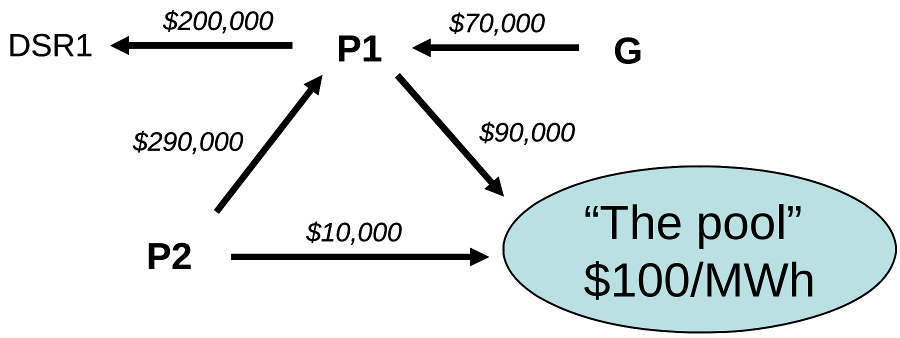
Net position of parties involved in forward market transactions are as follows:

- *P1: -$4.5M + $4.97M - $200,000 - $200,000 = $70,000*
- *DSR1: -$100,000 (opportunity cost of load not taken) + $200,000 = $100,000*
- *P2: -$500,000 + $200,000 + $400,000 (value of load taken) = $100,000*

Scenario D

A cool change comes in early and the out-turn price for the hour commencing 4pm Thursday is $100/MWh.

Cash flows between relevant parties are as follows:



- *P1 ➔ "The pool" as settlement for load = 900 x $100/MWh = $90,000*
- *P2 ➔ "The pool" as settlement for load = 100 x $100/MWh = $10,000*
- *G ➔ P1 as settlement of hedge = 1,000 x ($100 - $30) = $70,000*
- *P1 ➔ DSR1 for deployment of demand-side resources = $200,000*
- *P2 ➔ P1 as settlement of hedge = 100 x ($3,000 - $100) = $290,000*

Net position of parties involved in forward market transactions are as follows:

- *P1: -$90,000 + $70,00 - $200,000 + $290,000 = $70,000*
- *DSR1: -$100,000 (opportunity cost of load not taken) + $200,000 = $100,000*
- *P2: -$10,000 - $290,000 + $400,000 (value of load taken) = $100,000*

Conclusion

Under both Scenario C and Scenario D the net position for each of P1, DSR1 and P2 is identical, despite the fact that the pool price under each scenario was very different – that is, $5,000/MWh and $100/MWh.

Note that although the above example is written in terms of a Retailer managing the contract with the demand-side resource, it would be open for a Facility Agent to play that role. There is nothing in the Rules that prevent the set of arrangements described above from taking place.

Centrally managed forward market

As noted above, existing voluntary financial markets can already facilitate trading of DSP and the subsequent ability to lock-in the value of demand-side resources. It is not clear that the lack of liquidity in the trading of such contracts would be addressed simply by centrally managing an electricity specific forward market and thus whether the depth of DSP would be increased materially.

On the other hand, a centrally managed mandatory forward market could be a mechanism to hold participants financially accountable for their forward positions – for example, making Retailers financially accountable for forecasting the demand of their customers. If Retailers were to be accountable for demand forecasts, then it is logical that generators would also have to be accountable for planned dispatch. The spot market would then be effectively a balancing market. Such a proposal is equivalent to changing from the current gross-pool arrangements to some form of net pool arrangement.

International market arrangements with mandatory forward settlement, balancing settlement and ex post settlement are commonly termed “multi-settlement”. Both single-settlement and multi-settlement arrangements have advantages and disadvantages – Retailers typically have different incentives under the different market structures to manage the accuracy of their forecasts. In a multi-settlement arrangement with Retailer accountability for forecast accuracy, a Retailer has a strong incentive to contract with demand-side resources to help in the management of their position against the forecast – although existing arrangements under contracts could do this to some extent now. Any resultant improvements in forecasting accuracy would bring benefits in the dispatch process (see Section 5.1.2).

Before a centralised forward market is created, whether it be voluntary in the form of simple facilitation of existing opportunities or a mandatory arrangement, it would be necessary to examine the benefits and costs that might be achieved. Although a multi-settlement market would improve the prospects for DSP, the changes could be profound and it is not intuitively obvious that the dislocation would be warranted if facilitation of DSP was the primary motivation.

6.1.3. Development of uplift arrangements for scheduled load

Uplift is the term for an amount paid or received in settlement for a service or commodity that is in addition to amounts at the common clearing price (e.g. the spot price). Uplift can often be a problematic area of market design. Uplift is used in the current settlement for energy to pay and fund payments for plant contracted to the Reserve Trader and when “what if” pricing is invoked, and for compensation payments when the Administered Price Cap applies. These payments are all special cases that apply only under particular circumstances.

In the NEM, charges for market and non-market ancillary services are also, in essence, uplifts. However, market ancillary services have represented a relatively low percentage of energy turnover and are, therefore, not much of a problem. In addition, non-market services costs are reasonably predictable because they are contracted and can be reasonably budgeted for.

Uplift could, in principle, be paid to DSP as scheduled load. Changes would be required to the provisions for determining:

- the volume of scheduled load that would be entitled to an uplift payment taking into account both the instruction and metered amount of response – NER Chapter 3 and possibly also Chapter 7 (in relation to the nature of metering for small scheduled loads and for validation and substitution algorithms).

- the price at which the payment is made (presumably the prevailing spot price).

- the amount of uplift payment – subject to the design of drafting by amending Rules 3.15.4, 3.15.5 and 3.15.5A in relation to the calculation of Adjusted Gross Energy (other approaches would be possible also, for example by establishing a new series of clauses specifically dealing with scheduled load uplift).

- recovery of uplift payments from participants – presumably new clauses that operate in a similar way to recovery of compensation to directed parties in clause 3.15.8 (but again other approaches may be possible and should be a matter for the AEMC to determine).

- potentially, additional monitoring of compliance with rebidding provisions and dispatch instructions.

While uplift would undoubtedly be attractive to demand-side resource owners, its use to fund payments for DSP has been reviewed a number of times (e.g. the Parer Review). In each of these reviews it has been decided not to introduce uplift in the spot market settlement in the light of the economic implications and complexity of design and compliance requirements.

The energy market concept on which the NEM is based treats energy as a commodity. It pays for energy dispatched by generators but not for the provision of capacity or availability in readiness for dispatch. Similarly, the NEM charges customers for energy consumed, not for energy that may be consumed (e.g. over a peak), nor energy that has not been consumed, such as when demand-side resources are deployed in line with a scheduled load bid.

Were generators paid for provision of capacity, customers would be expected to fund that payment – instead generators are expected to recover all costs at the time of dispatch and thus the cost of providing capacity is reflected in the spot price and paid by customers in proportion to their contribution to the demand at the time.

The NEM, however, does make payments for availability of generators and demand-side resources to respond rapidly when used as an ancillary service. The payment is, in reality, for the speed of response. The NEM design relies on the operation of commercial relationships between stakeholders – for example, to manage financial risk in the wholesale market and also to arrange for DSP where there is a benefit and payment for not consuming. Any payments that are made for reduction in consumption are expected to come from those contracts – for example, where a Retailer holds a hedge contract with a generator and by reducing its demand pays less to NEMMCO but receives the same contract payment from the generator[57].

Introduction of a payment for not consuming would introduce considerable complexity to settlement as it would be necessary to determine the level of "non-consumption" responding to the dispatch signal that would be entitled to receive a payment and to determine an efficient charging mechanism to recover the payment.

However, in an environment of less than perfect competition, *and* where supply side of market power is present, *and* this is distorting price outcomes, increased elasticity of demand could be a valuable countervailing force. Separate investigation would be required to determine whether the costs of funding uplift would be less than the benefits of the reduced prices outcomes – if this was the case, customers may be prepared to pay uplift.

It would be a significant and contentious task to establish the overall cost customers would face in practice. In particular, to recover fixed costs, generators are dependent on prices above their short run costs. Any measure that, for instance, depressed peak price may simply be reflected in higher off-peak and shoulder prices. On the other hand, sustained reduction in peak demand may reduce the level of capacity that is required to be built and thus reduce the overall cost of the power system. In principle, contracting mechanisms that would achieve these outcomes are already available, but apparently not being fully utilised. An uplift payment may be considered as a means to overcome this barrier.

6.1.4. Development of a market for the provision of energy reserve

Only market ancillary services receive a specific payment for the provision of reserve to control power system frequency. Reserves for energy production do not receive a specific reserve payment – parties providing that reserve are expected to recover their full fixed and variable costs via payment for energy production at times when they are dispatched, or via the terms of contracts with market participants.

There have been a number of suggestions that payment for reserve should be introduced – for example:

57 This arbitrage mechanism is described in more detail in Section 3.3.1.

- **Reliability ancillary service** – During the CRR, the Reliability Panel considered a form of reserve payment termed a *reliability ancillary service* (RAS) that would have made a payment to resources available to provide reserve with a response time of up to 30-minutes, with an ability to sustain that response for a number of hours.

  The Panel gave consideration to the RAS as a means to make more stable and less risky payments to plant that provide reserve and was only dispatched occasionally when it would seek very high prices and receive a very volatile revenue stream. The RAS payment would have reduced the risk of marginal investments crucial for the provision of reserve. The RAS price was to be determined in the NEMDE in the same way as other ancillary services.

  Ultimately, the Panel decided that the RAS would not make a material difference to the revenue position for reserve plant and would also add unnecessary complexity to the market, thus the Panel did not pursue the concept. It would also have introduced a discriminatory reserve payment to only those parties providing reserve when all other plant received revenue only on dispatch. Although demand-side resources were to have been entitled to bid for dispatch as RAS, it is unlikely it would have led to a large increase in DSP. This is because of the proposed requirement to be accepted in dispatch (interruption with effectively no notice and to remain off for many hours) would be unattractive to many demand-side resources.

- **Standing reserve contracted to NEMMCO** – An alternative form of reserve payment would be for a standing reserve contracted to NEMMCO on a long-term contract outside of the central dispatch process. This form of reserve would be dispatched as the last resort before involuntary interruption. It would be more attractive to demand-side resources as dispatch would be rare but payment regular.

  However, this form of reserve also introduces a discriminatory payment for capacity that is not available to other plant; it would also require a mechanism to audit entitlement to the reserve payment. If such an arrangement is justified it will most likely be on the basis of its ability to ensure reserve rather than a means to facilitate DSP, the reason being that, although some advance notice of emerging low reserve conditions can often be given, actual dispatch may occur without advance notice.

6.1.5. Addressing 5/30 and nodal/zonal anomalies

In concept, the “dispatch price” / “opportunity cost” imbalance risk faced by those in a position to deploy demand-side resources could be addressed by: aligning the time frames for dispatch and settlement intervals; and moving toward more granular pricing. However, these dispatch price / opportunity cost imbalance risks are no greater than those faced by scheduled generators under existing arrangements, and it is hard to make a case for fundamental structural change to the market in order to address a relatively minor value-based risk associated with DSP.

One way of addressing the nodal/zonal anomalies, briefly mentioned for the sake of completeness, would be an amendment to the Rules to facilitate DSP as a means of reducing congestion via introduction of some form of constraint-based congestion payment/contracting regime – a variation on CSP/CSC regimes. It is understood that proposals of this nature are discussed in some detail in other work commissioned for the AEMC but the case for its use was not made.

6.2. ADMINISTRATIVE MEASURES

CRA has identified four administrative measures that could be taken within the current market design change that could facilitate increased levels of demand-side resource utilisation in the NEM, and more efficient dispatch of the NEM in consideration of existing levels of contracted demand-side resource:

- modification of participant registration categories and requirements;
- providing for greater flexibility in procurement and dispatch processes;
- wider tolerances for demand-side response; and
- mandated reporting of contracted demand-side resources.

6.2.1. Modification of registration categories and requirements

A new category of registered participant, say "Facility Agent", could be created with less onerous registration and communication requirements than for a Market Customer provided:

- the activities of such participants were fundamentally different to those of a Market Customer or a Generator; and
- the activities of such participants do not give rise to a need to manage obligations with respect to system security or market prudential factors.

As a new category of Registered Participant, a Facility Agent could:

- manage the deployment of scheduled loads and ancillary service (FCAS) loads; and
- be the counter party for contracts with NEMMCO with respect to NCAS.

If an aggregator is not a Registered Participant, existing Rules prevent the aggregator from acting as the formal agent for scheduled loads and ancillary service loads [NER clause 2.3.3; 2.3.4; 2.3.5], and also from contracting for NCAS with NEMMCO [NER clause 3.11.5(j)].

In order to justify less onerous registration conditions, the nature of the activities of Facility Agent would have to be restricted to providing intermediary functions with respect to the management and dispatch of scheduled load. In order to avoid the requirements associated with obligations regarding market prudential factors, the Facility Agent could not be the financially responsible market participant for any load. Any changes to the definition of a financially responsible market participant will impact on the Rules relevant to settlements [NER clause 3.15] and metering [NER Chapter 7].

If uplift was to be implemented for scheduled loads (see Section 6.1.3), a case could be made for introducing a form of 'telemetry-lite' for smaller loads to ease their participation as a scheduled load or a regulation FCAS provider. Even if uplift was available for scheduled loads, current telemetry requirements are likely to prove to be prohibitively expensive for smaller loads. Some mechanism to facilitate the aggregation and telemetry on smaller loads under the management of a Facility Agent, with an ability to control the dispatch of distributed loads within "reasonable" bounds[58] may prove to be sufficient to ensure power system security would not be degraded. If this path was taken, there would also be merit in reviewing the appropriateness of existing limits to aggregation of loads [NER clause 3.8.3].

6.2.2. Flexibility of procurement and dispatch processes

This section considers two amendments to the procurement and dispatch processes that might facilitate increased utilisation of demand-side resources:

- adoption of integer programming in the central dispatch process; and
- adoption of a probabilistic approach to procurement of NCAS to enhance the value of spot market trade.

Integer programming in central dispatch

One barrier to the further use of the DSP within the central dispatch process is that NEMDE is currently a linear program and cannot handle integer, or on/off, decisions. Many DSP facilities require such decisions for deployment because they involve switching load blocks, whereas NEMDE currently assumes all dispatchable units can be adjusted one MW at a time. There is the prospect of enhancing NEMDE to allow it to make decisions about block loads using integer programming. This would remove the NEMDE algorithm as a barrier in this respect, but it would not of itself affect other barriers that we have discussed elsewhere.

58 Further analysis would need to be conducted to determine what "reasonable" bounds would mean. Because the loads are scheduled, and therefore volumes of dispatchable load would be known to NEMMCO, a case could be made that NEMMCO's ability to optimise dispatch would be greater than at present notwithstanding the fact that non-conformance thresholds for such units would have to be wider than is the case for existing generation (see also Section 6.2.3).

It is worth noting that while NEMDE is restricted by its inability to consider load blocks, there is no rule that would prevent a load block from bidding into the NEM as if it could respond linearly but, in practice, responding more or less than the resultant instruction – this is considered in the following section is discussion of tolerances to dispatch instruction. It is possible to reconfigure NEMDE to use integer programming that can assess block decisions, although it would still be restricted to considering only 5-minute by 5 minute decisions[59].

decision to introduce some form of integer programming to help avoid potential non-conformance of scheduled loads and market ancillary services, suggests an adjustment to market design – that is, moving away from the principle that all scheduled units (including generators) are responsible for managing their own dispatch through appropriate use of rebidding. We note that the fast start provisions of the Rules and central dispatch were introduced to ensure the principle of self management was adhered to.

Probabilistic approach to procurement

A second option, that tackles a different barrier, is to:

- require that NEMMCO can contract with DSP (or generators) and pay an availability fee and then dispatch (within either the current linear program format or integer programming algorithm);

but

- accept that NEMMCO will have entered the contract on the basis of a probabilistic analysis of increasing the value of spot market trading.

This would be a subtle but important shift from the current philosophy employed by NEMMCO of not utilising resources to achieve an enhancement of spot market trading unless enhancement can be guaranteed.

6.2.3. Wider tolerances on dispatch accuracy

Current arrangements in the Rules require tight compliance with dispatch instructions. This is to enable a close alignment between dispatch price and dispatch. If compliance obligations were relaxed, additional demand-side resources may enter the market.

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59 It is worth noting that procuring DSP with an objective of enhancing the value of spot market trade via integer programming in dispatch time frames is, effectively, no different to a decision to dispatch generation. Were either NSPs or NEMMCO to engage in the former activity – procuring DSP with an objective of enhancing the value of spot market trade – for all intents and purposes they would be competing with scheduled generation. Although this report is considering possible changes to market design that could facilitate more effective utilisation of demand-side resources, creation of an environment where regulated NSPs and the independent system/market operator were expected to compete with scheduled generation, seems to be ‘a bridge too far’.

Although widening the tolerance band for response may remove a barrier to entry for some demand-side resources, it may also come at the expense of accurate dispatch – for example:

> *If 100MW of DSP was scheduled, but the scheduled resource may deliver somewhere between 70MW and 130MW, it would mean some other resource would need to be ready to provide any shortfall, or too much would have been scheduled.*

Nevertheless the loss of efficiency (if any) *may* be offset by higher participation of DSP and thus a reduced need for other resources.

Alternatively, if contingency FCAS could be provided from resources that offered no less than the scheduled amount (instead of exactly the scheduled amount), a wider range of participants may be encouraged to provide services. In such a case, it is likely that there would also need to be provision to ensure that FCAS was not over-provided with a risk of overshooting frequency response. Provisions of this nature may also improve the opportunity for aggregations of load to participate in central dispatch subject to any other limitations on aggregated loads.

A series of changes would be required to implement this change across:

- registration in Chapter 2;
- details of bids/offers;
- central dispatch;
- central dispatch in Chapter 3; and
- specification of required ancillary service amounts in Chapter 4.

6.2.4. Mandated reporting of contracted demand-side resources

A threshold issue to consider with respect to the development of any mandated reporting regime is whether or not the inaccuracy of demand forecasting has reached a level whereby it is determined to be a problem that requires a solution.

On the assumption that inaccuracy of demand forecasts is of concern, then some level of mandated information disclosure with respect to contracted demand-side resources is warranted. Mandated reporting of contracted demand-side resource parameters – perhaps all or a subset of those indicated as required for trades under a bulletin board (see Section 6.1.1) – could be in the form of:

- a requirement to respond fully and accurately to periodic (regular) surveys by NEMMCO of demand-side resources that take account of the probability of dispatch at certain thresholds[60]; or
- a requirement for Retailers and load controlling entities to advise NEMMCO of the volume of DSP that would be exercised at particular price points.

While neither of these mechanisms could guarantee 100% accuracy demand forecasting, the increased information would, at least, offer the opportunity for improved demand forecasting. Depending on which forecasting time frames are determined to in need of more accuracy, the surveys and reporting requirements would need to be appropriately tailored.

As noted in Section 5.2.5, NEMMCO's ability to secure information on the level of contracted demand-side resources is currently limited by accuracy of the responses to annual surveys of NEM stakeholders conducted for the purposes of compiling the SOO / ANTS. Specific Rule provisions would be developed to ensure NEMMCO has a clear power to seek the necessary information from relevant Market Participants.

60 NEMMCO's current reporting is of "committed DSP" – that is, DSP that is highly likely to be available when called. It is apparently up to the survey respondent to determine the meaning of "highly likely". Non-committed DSP is not reported by NEMMCO. The survey conducted by NEMMCO also focuses on MT PASA time frames.