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AEMC REVIEW OF ENERGY MARKET FRAMEWORKS IN LIGHT OF CLIMATE CHANGE POLICIES

MANAGING SHORT TERM RELIABILITY

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ABBREVIATIONS / GLOSSARY

AEMO	Australian Energy Market Operator
ANTS	Annual National Transmission Statement
ARC	advanced reserve contracting
committed DSP	A block of DSP with a very high probability of being dispatched in response to adverse market conditions during a high demand period.
CRR	Comprehensive Reliability Review
DNSP	Distribution Network Service Provider
DSP	demand-side participation
EG	embedded generation
ESAS	Electricity Sector Adjustment Scheme
FRMP	Financially Responsible Market Participant
MRL	minimum reserve level
native demand	The electricity demand supplied by both scheduled generating units and significant non-scheduled generating units.
NEM	National Electricity Market
NEMMCO	National Electricity Market Management Company
NER	National Electricity Rules
NSP	Network Service Provider
OCGT	open-cycle gas turbine
PoE	probability of exceedence
PPA	power purchase agreement
RERT	reliability and emergency reserve trader
SCO	Standing Committee of Officials
SR	standing reserve
Tier 1 Retailer	The default or franchise retailer for an area.
Tier 2 Retailer	Retailer who has taken settlement responsibility for an end-use customer following transfer of that customer from another Retailer.
VoLL	value of lost load – a price cap on regional reference prices

EXECUTIVE SUMMARY

This paper seeks to identify feasible options for addressing the problems identified in the AEMC's climate change review 1st interim report with respect to the management of short-term reliability.

If the market fails to deliver sufficient capacity to prevent the reliability standard from being breached, it is not necessarily the case that the market price cap – or other market framework settings – have been established at an inappropriate level. Failure to have adequate levels of reserve in place could be a result of transitory factors such as: changes to, or uncertainty about, government policy settings; or force majeure events (e.g. technical failure of major energy supply infrastructure). Further, appropriate long term responses to these problems can still leave short term problems that need to be addressed.

The risk of ineffective or inefficient response to actual or anticipated transitory shortfall of capacity creates a requirement for identifying feasible options for supplementing existing market frameworks, where appropriate, with new or amended tools that will aid the management of power system reliability over the next five years.

This report examines three broad options to more effectively manage the risks associated with a prospective (transitory) failure to manage power system reliability.

- developing more accurate assessments of DSP availability at times of system / regional peak demand;
- facilitating strategic use of existing under-utilised embedded generation; and
- contracting reserve outside existing intervention mechanisms – advanced reserve contracting.

Assessing DSP availability

There are two potential problems arising from the current approach to DSP estimation:

- The relevant provisions of the NER 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.
- The use by NEMMCO of only committed DSP and entirely discounting non-committed DSP is likely to produce conservatively low estimates of DSP.

What is proposed?

It is proposed that the NER be amended and appropriate reporting guidelines be introduced to make specific reference to the provision of DSP information, with the objective of providing a level of information sufficient for NEMMCO to make reasonable probabilistic assessments of DSP at times of peak demand.

How will proposals help manage reliability in the short term?

Mechanisms that deliver more accurate estimates of DSP likely to be available at times of peak demand will not deliver additional reserve, but do have the potential to more efficiently manage power system reliability through better informing the process by which market intervention is determined. With better information, where thresholds for intervention are approached the market can be more confident in the correctness of any decision by NEMMCO to intervene (or not).

Strategic use of embedded generation

Current arrangements do not seem to impose a substantial barrier to the strategic use of embedded generation (EG) as viable business models, which is leading to new business opportunities emerging within the existing market frameworks.

What is proposed?

Additional guidance should be provided to Distribution Network Service Providers (DNSPs) and the owners of small EG units with respect to the application of technical standards in order to lower the costs of negotiation and provide consistency across jurisdictions by providing fit-for-purpose standards.

Further, NEMMCO should be encouraged to proceed with its internal review of registration processes and to (at least) report annually on progress towards identifying and removing unreasonable barriers to registration of EG as market generating units.

How will proposals help manage reliability in the short term?

Given:

- identified reserve shortfalls represent in the order of only 1% of peak demand for affected regions; and
- there is likely to be a non-trivial volume of under-utilised EG,

actions that increase the strategic use of existing EG have the potential to make a substantial contribution to mitigating identified reserve shortfalls.

Current arrangements do not seem to impose a substantial barrier to the strategic use of EG as viable business models in this area are now emerging within the existing market frameworks. However, greater consistency in the application of technical standards is likely to provide additional certainty as to the outcomes of negotiations between EG unit managers and Network Service Providers (NSPs), thus encouraging more EG unit owners to make their facilities available for strategic deployment.

NEMMCO's internal review of registration processes are not expected to result in any substantial change to the operation of market frameworks, but the review will help retain a focus on minimising any barriers that may be identified.

Advanced reserve contracting

Intervention in normal market mechanisms to deliver additional reserve should only occur where the market has been deemed to have failed. In the absence of market failure, any capacity mechanism or express payment for additional reserve is inconsistent with the principles of an energy-only market.

If centrally managed mechanisms to make additional reserve available are considered, the prospect of these mechanisms distorting the existing market must also be taken into account. To ensure any chosen form of advanced reserve contracting (ARC) does not distort investment signals:

- contracted reserve would have to be quarantined from the energy-only market and, if dispatched, normal price signals would need to be preserved;
- care needs to be taken that capability presented to the ARC mechanisms would not otherwise have been offered to the energy market;
- contracted reserve must not be subject to capacity or availability payments; and
- there must be sufficient time for NEMMCO to undertake reasonable evaluation of dispatch options on the basis of final contractual conditions.

In addition to avoiding distortion of investment signals, any decision to procure additional reserve must carry with it a reasonable assurance that the likely value of lost load to be avoided as a result of having additional reserve in place is greater than the cost of procuring and delivering additional reserve.

There are divided views on the effectiveness of current arrangements. Although most parties generally accept the need for an intervention mechanism, generators and retailers in particular express strong views that the use of interventions such as reliability and emergency reserve trader (RERT) should be tightly proscribed and that in the absence of market failure, availability payments for additional reserve should not be contemplated. On the other hand, end-user representatives are of the view that the market has failed to deliver adequate assurance of reliability and that further opportunities for contracting energy reserve should be explored.

What is proposed?

- **NEMMCO should be allowed to adopt a panel arrangement for short-notice reserve** contracting via a modified RERT provided no payment for energy reserve availability be made prior to the time when NEMMCO agrees to pay for a firm option to commit the facility in question. However, consideration should be given to eventually migrating the short-notice reserve capability from the RERT mechanism to the directions mechanism.

- **A prolonged targeted reserve mechanism could be developed** that can be invoked up to 18 months ahead of dispatch, but only after policy makers have declared that the circumstances of a forecast reserve shortfall meet each of the following four threshold tests of seriousness:

  1. there has been failure to deliver adequate levels of reserve due to:

     - inappropriate settings for market parameters that have created systemic under-investment in capacity; or

     - uncertainty over future policy settings that have delayed decisions to invest in energy infrastructure; or

     - technical failure of major energy supply infrastructure (or other force majeure events) with consequences extending more than a year;

  2. anticipated reserve shortfall is highly likely to persist into dispatch time frames following:

     - assessment that the market is unlikely to be able to respond to emerging contract risks by recruiting sufficient alternative sources of energy at prices at or below the market price cap; and

     - re-examination of relevant up-to-date information (e.g. new demand forecasts that become available in June of each year) that either: confirm the extent of the forecast reserve shortfall; or revise the forecast reserve shortfall;

  3. the reserve shortfall is of a magnitude that the RERT mechanism is unlikely to cope with; and

  4. there is an expectation that, if load shedding were to occur to the extent forecast, the reliability standard would be breached.

  If invoked, a prolonged targeted reserve mechanism should have a clearly defined window for execution to allow time between it and possible contracting under the RERT when the extent of market response to the newly contracted reserve can be assessed.

  It is acknowledged that the threshold tests proposed present a substantial hurdle and that, if invoked, some level of market distortion is inevitable. Accordingly, a decision as to whether or not to proceed with this option is a matter of judgement. The option is presented for the sake of completeness as a targeted means of addressing concerns about reliability in Victoria and South Australia over the next three or so summers or the possibility of technical failure of substantive generation plant.

How will proposals help manage reliability in the short term?

The proposed options provide mechanisms to respond to reserve shortfalls that become apparent:

- as a result of inappropriate settings for market parameters that have created systemic under-investment in capacity; or
- as a result of uncertainty over future policy settings that have delayed decisions to invest in energy infrastructure; or
- as a result of technical failure of major energy supply infrastructure (or other force majeure events) with consequences extending more than a year; or
- in the few weeks or days prior to dispatch.

Each of the proposed options ensure that any investment in reserve over an above that brought forward by the market is targeted at addressing identified shortcomings in market outcomes.

Why is standing reserve not proposed?

A standing reserve arrangement is not considered to be an efficient, effective or necessary means to mitigate the effects of potential involuntary load shedding. The key problem with a standing reserve arrangement, whereby a set amount of additional capacity is procured for each market region, is that reserve is not targeted and would be procured regardless of whether market failure is likely to occur. Failure to target procurement to address an identified problem creates risks that: too little reserve was procured; too much reserve was procured; the reserve was of the wrong type; or reserve was in the wrong place.

Should there be an on-going or regular concern that an unacceptable level of unserved energy would arise from either reliability or security related events, the correct response would be to adjust market settings (e.g. the level of the market price cap) to provide the market with the signals and incentives to manage emerging risks in a targeted and cost-effective manner.

1. INTRODUCTION

1.1. Context of this paper

In the 1st Interim Report on the AEMC's *Review of energy market frameworks in light of climate change policies* (climate change review 1st interim report), it was noted that:

> There is a risk that the current energy market frameworks will not enable NEMMCO to manage an actual or anticipated transitory shortfall of capacity effectively or efficiently. The existing RERT mechanism and directions powers are important parts of the framework. The question is: is there a need for supplementary mechanisms, even if only for a transitional period?
>
> There is a potential need to amend the existing frameworks because:
>
> - in the period up to summer 2010-11, there is a risk of reserve shortfalls in the combined Victorian and South Australian market regions, and in the relevant timescales this risk cannot be mitigated by bringing forward planned investment;
> - while the risk of shortfall is significantly reduced as a result of the White Paper proposals on transitional assistance to coal-fired generators, there remains a risk of a further reserve shortfall emerging (e.g. resulting from a technical failure of an existing unit), and the frameworks should be resilient against this contingency; and
> - NEMMCO's RERT mechanism is not designed to manage a large or sustained reserve shortfall.[1]

This paper seeks to identify feasible options for addressing the problems identified above.

1.2. Background

In an energy-only market it is the frequency, duration and magnitude of high price events that signals the need for new capacity sufficient to meet established reliability standards. The National Electricity Market (NEM) is an energy-only market that sets a standard for reliable operation of the power system in terms of:

> The maximum permissible unserved energy (USE), or the maximum allowable level of electricity at risk of not being supplied to consumers, is 0.002% of the annual energy consumption for the associated region or regions per financial year.[2]

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[1] AEMC 2008, *Review of Energy Market Frameworks in light of Climate Change Policies, 1st Interim Report*. December 2008, Sydney. Available at: http://www.aemc.gov.au.

[2] AEMC Reliability Panel: NEM Reliability Standard – Generation and Bulk Supply (December 2007). Compliance with this Reliability Standard for Generation and Bulk Transmission should be measured over the long-term using a moving average of the actual observed levels of annual USE for the most recent 10 financial years. Operationally, this Reliability Standard for Generation and Bulk Transmission should be targeted to be achieved in each financial year, for each region and for the NEM as a whole. Standards also exist for the secure operation of the power system but they are not relevant in the context of this chapter.

In the NEM, the primary reliability management tool is the market price cap, or VoLL. Ideally, VoLL should be sufficiently high to attract the capacity required to deliver the established reliability standard, but not so high that market price volatility is considered excessive.[3] If VoLL is set too low, the consequence may be insufficient incentive for investment in generation or DSP options to meet the established reliability standard. However, if the market fails to deliver sufficient capacity and there is a risk that the reliability standard would be breached, it is not necessarily the case that VoLL has been set at an inappropriate level. The market could fail as a result of transitory factors such as:

- changes to, or uncertainty about, government policy settings; or
- technical failure of major energy supply infrastructure.

If the market fails to deliver adequate generation capacity, and the on-going ability of the market to meet the reliability standard is placed under threat, existing energy market frameworks provide for some intervention mechanisms to help correct anticipated transitory shortfall of capacity.

1.3. Assessment framework

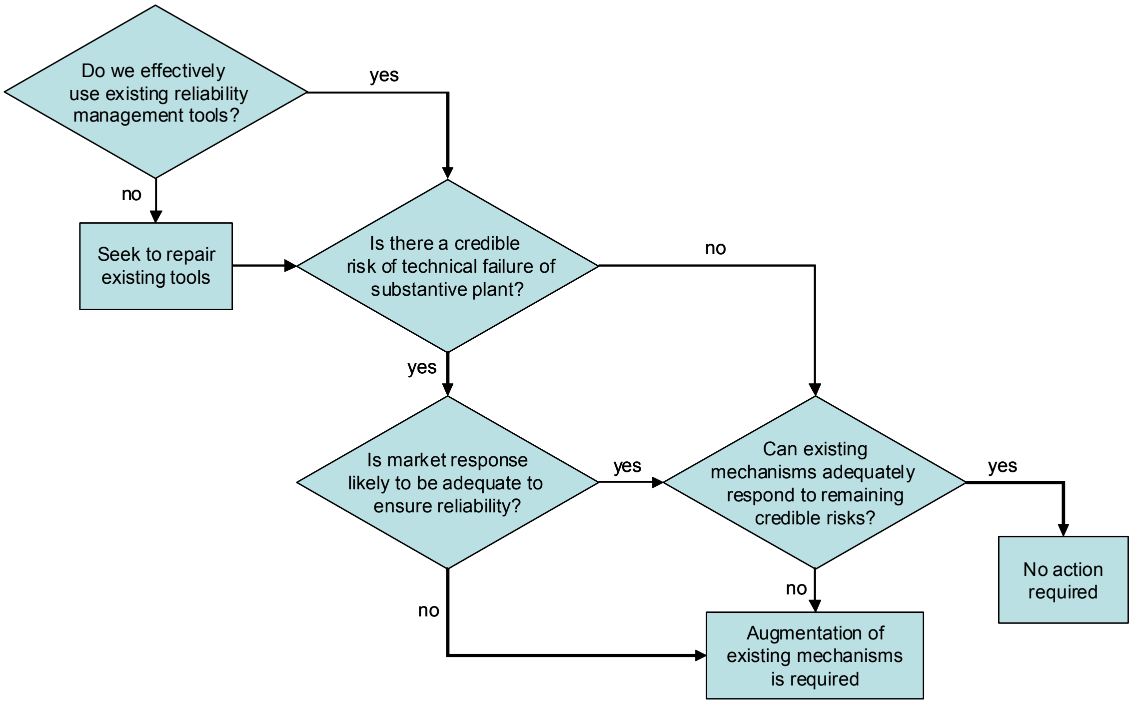
The framework for identifying and assessing options in the context of the climate change review employed herein is outlined in Figure 1. This framework reflects the problems identified in the climate change review 1st interim report.

The assessment framework to be used here considers the management of reserve shortfalls and the subsequent potential involuntary load shedding that might arise due to system reliability issues – that is, where there is a region-wide imbalance of supply and demand.[4] Unless otherwise stated, discussion herein expressly excludes consideration of strategies that might be used to mitigate involuntary load shedding that arise due to system security issues.

[3] Price volatility is partially managed via the cumulative price threshold.

[4] Also taking account of minimum reserve levels.

Figure 1: Framework for identifying and assessing options in the context of the climate change review



1.4. *Options to address identified problems*

Given the risk of ineffective or efficient response to actual or anticipated transitory shortfall of capacity, effort needs to be made to identify feasible options for supplementing existing market frameworks with new or amended tools that will aid the management of power system reliability over the next five years.

This report examines three options to more effectively manage the risks associated with a prospective (transitory) failure to manage power system reliability:

- developing more accurate assessments of DSP availability at times of system / regional peak demand;[5]
- facilitating strategic use of existing under-utilised embedded generation; and
- contracting reserve outside existing intervention mechanisms[6] – advanced reserve contracting.

5 This would not of itself deliver additional energy capability to the market, but it could contribute to more effective management of reliability by better informing NEMMCO's decision as to whether or not to invoke intervention mechanisms such as the reliability and emergency reserve trader (RERT).

6 Proposals in this area take account of, and are consistent with, options being pursued by the Reliability Panel to develop a modified RERT.

These options are not necessarily mutually exclusive.

Each of these options were also discussed in the context of the AEMC’s DSP review, although the framework for assessing the options in that case was quite different to the approach outlined in Figure 1. In the case of the DSP review the focus was identifying whether or not the options could efficiently and effectively contribute to the emergence of DSP (as either load reduction or embedded generation). In contrast, the focus of the climate change review is on whether existing energy market frameworks are robust to the issues emerging as result of climate change policies.

2. LIKELY MARKET RESPONSE TO SUBSTANTIVE PLANT FAILURE

2.1. The economics of high emission plant

In the absence of assistance under the Commonwealth's proposed Energy Sector Adjustment Scheme (ESAS), owners of high emission base-load plant could choose to withdraw some capacity from the market on the basis that plant is no longer economic to operate and properly maintain. Even though no submissions consider this to be a material short-term risk, modelling conducted by CRA International[7] indicates that, depending on the level at which a carbon price is introduced, utilisation of high emission plant could fall to levels that are not economically sustainable. The effect of the ESAS is to merely delay the timing of the decision to withdraw otherwise uneconomic plant.

The level of the carbon emissions target and the implied carbon price will dictate the effect on SRMC of all high emission generation and thus the position of plant in the generation merit order. High emission coal plant is not well suited to mid-merit or low merit operation. With a substantially changed merit order, utilisation levels of high emission plant could fall below a threshold whereby it is unable to economically sustain continuous operation. Given the high costs associated with frequent start-stop cycles and short-term running, permanent shutdown of affected plant might be the best option – it would not be viable to maintain this plant purely to operate for a couple of hours during short term demand peaks and high prices. Even if a plant was not shut down entirely, the incentive to carefully maintain the plant would diminish, with consequent adverse effects on its expected reliability. It is circumstances like these that create risks of plant technical failure and the potential for long term reserve shortfalls.

2.2. Market response to technical failure

If economically marginal large base-load generation experienced failure of critical components, and the otherwise remaining (assisted) life of the plant was not sufficiently long to warrant expenditure on repair to enable the plant to return to reliable service, there could be substantial overnight change in the supply-demand balance and the economics of the market. If the demand-supply balance was marginal to start with, any substantial change in that balance arising from the withdrawal of base-load plant would create a potentially large across-the-board upward shift in spot prices and contract values.

Overall system reliability outcomes resulting from this situation are unlikely to be significantly affected by where the contract exposure to higher spot prices happens to lie. If failed generation was heavily contracted to a fully hedged retailer, the generator operator would need to seek alternative sources of energy to cover its contracts. On the other hand, if failed generation was uncontracted, contracting options for retailers with short positions would reduce and retailers would then need to seek alternative sources of energy to cover their short position.

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7 CRA International, *Updating the Comprehensive Reliability Review quantitative analysis to account for CPRS and MRET*, December 2008. Available at: http://www.aemc.gov.au.

With a rise in the value of cap contracts, previously uneconomic energy reserve options (supply-side or demand-side) would now be "in the money". Marginal peaking generation might be safely committed and retailers would have a stronger incentive to contract with demand-side options in order to manage their higher value energy market exposures.

Although the increased revenues from higher spot prices should bring some new energy capacity to the energy market, there is no guarantee that additional capacity presented would be sufficient to match capacity withdrawn as a result of (assumed) technical failure of base-load plant. Generating capacity lost through technical failure may take several years to recover as replacement generating plant is committed, installed and commissioned. Given the loss of base-load capacity, rational market players with an eye to the long-term could seek to either: a) invest in <u>new</u> base-load or mid-merit plant; or b) bring forward a commitment to invest in base-load or mid-merit plant that was in the advanced planning stages. Investment in new peaking generation capability is not necessarily economic in these circumstances as higher revenue opportunities resulting from elevated spot prices may not be sustained for a sufficient time.

Depending on the opportunities to economically develop peaking generation capacity in the relatively short term, the market may have to rely on demand-side options to restore the demand-supply balance. Assuming there is no gaming in transferring capability between alternative forms of deployment, the choice of reserve providers to offer capacity to the energy market or the RERT could be a function of an appropriate trade-off between:

- revenue available from the frequency of deployment at prices no higher than the market price cap in the energy market (i.e. the value of a cap contract); and
- revenue available from opportunistic participation in the RERT mechanism at prices above the normal market price cap and up to the level approved by jurisdictions.

If the revenue available from the energy market is not sufficient, the party controlling reserve may only be prepared to offer capacity when the RERT mechanism is invoked and payment for availability as an intervention tool (i.e. at a price above VoLL) is sufficiently attractive.

2.3. Conclusion on market response to substantive plant failure

There are market signals that will be effective in bringing some new capacity to the energy market in response to technical failure of base-load generation. However, in the near-term, new capacity will be almost exclusively demand-side. The rate at which new generating capacity enters the energy market depends on the most economic long-term mix of peaking, mid-merit and base-load generation.

It is impossible to judge in advance of a failure event occurring whether or not sufficient capacity will be presented to avoid either: a reserve shortfall arising; or a pre-existing reserve shortfall being made worse. There is a possibility that reserve capacity otherwise available to the RERT mechanism (if invoked) would instead play an active role in the energy market, due to more favourable revenue opportunities, and thus reduce options to mitigate reserve shortfall via market intervention.

3. ASSESSING DSP AVAILABILITY

What is proposed?

It is proposed that the NER be amended and appropriate reporting guidelines be introduced to make specific reference to the provision of DSP information, with the objective of providing a level of information sufficient for NEMMCO to make reasonable probabilistic assessments of DSP at times of peak demand.

How will it help manage reliability in the short term?

Mechanisms that deliver more accurate estimates of DSP likely to be available at times of peak demand will not deliver additional reserve, but do have the potential to more efficiently manage power system reliability through better informing the process by which market intervention is determined. With better information, where thresholds for intervention are approached the market can be more confident in the correctness of any decision by NEMMCO to intervene (or not).

3.1. Current context

3.1.1. Current objectives

Accurate estimates of DSP availability help ensure that decisions on whether or not to intervene in the market are soundly based.

An important element in the secure and reliable management of the power system is the maintenance of minimum levels of reserve energy capability – that is, the margin of available energy capacity above expected peak demand. Peak demand itself must incorporate an assessment of the level of demand-side response that is likely to occur at such times. Where forward assessments of the margin of available energy capacity above expected peak demand fall below the regional minimum reserve level (MRL), NEMMCO must give consideration to invoking the reliability and emergency reserve trader (RERT) mechanism.

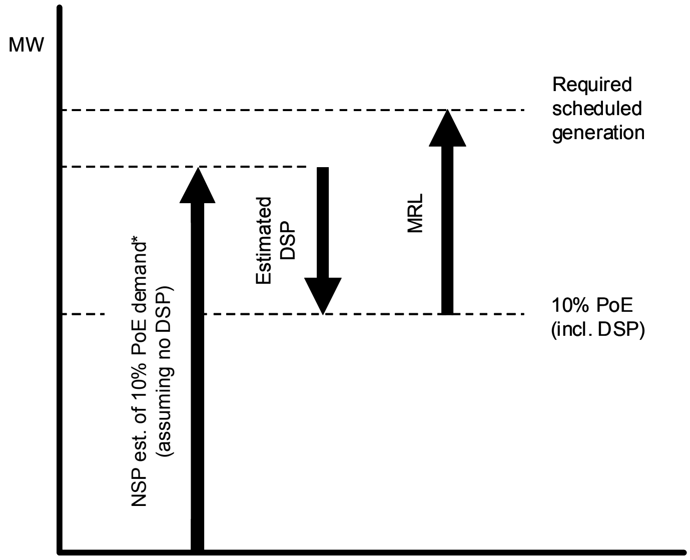
The objective of current arrangements is to provide as accurate as possible an estimate of DSP that would be deployed at times of system peak demand that, in turn, facilitates estimates of required scheduled generation and the adequacy of advised reserves. Figure 2 depicts the relationship between: 10% PoE demand as estimated by NSPs (see Box 1); DSP as estimated by NEMMCO; MRL; and required scheduled generation. If declared available scheduled generation (as advised to NEMMCO via participant bidding systems) equals or exceeds required scheduled generation, reserves will be declared adequate, otherwise a reserve shortfall is said to exist.

Box 1: Percentage probability of exceedence (% POE)

A percentage probability of exceedence (POE) for demand refers to the likelihood that a projection will be met or exceeded in a particular season of any given year. That is, 10% POE demand projections for a given season are expected to be met or exceeded, on average, one year in every 10. A forecast at this level is associated with atypical combinations of conditions (including temperature).

Similarly, 50% POE demand projections for a given season are expected to be met or exceeded, on average, five years in every 10. A forecast at this level is associated with average conditions.

Figure 2: DSP, MRL and required available generation – stylised representation



* NSP estimate of 10% PoE demand incorporates an estimate of **native demand**[8] less demand met by significant non-scheduled generating units and assumes zero DSP.

3.1.2. Current arrangements

The provisions of the NER currently provide for information to be gathered for the purposes of developing the Annual National Transmission Statement (ANTS), as follows:

5.6.5 Annual National Transmission Statement

…

(b) *NEMMCO* must, in the course of conducting the *ANTS review*, consult with *Registered Participants* and *interested parties* in relation to:

(1) the data and assumptions to be used as part of the *ANTS review*; and …

(c) In carrying out the *ANTS review*, *NEMMCO* must consider the following: …

(6) demand forecasts for the next 10 *financial years*; …

(f) *NEMMCO* may by written notice request an entity nominated under clause 5.6.3(b)(2) to provide *NEMMCO* with any additional information or documents reasonably available to it that *NEMMCO* reasonably requires for the purpose of the *ANTS review*.

(g) An entity nominated under clause 5.6.3(b)(2) must comply with a written notice from *NEMMCO* issued pursuant to clause 5.6.5(f).

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8 Native demand is the electricity demand supplied by both scheduled generating units and significant non-scheduled generating units.

These Rule provisions provide the basis for NEMMCO to conduct a survey of DSP within the NEM. The survey conducted by NEMMCO canvasses information from NSPs, retailers, market customers and aggregators with respect to:

- historical levels of active load reduction at times of peak demand;
- the nature of the process by which load reduction was or would be initiated;
- anticipated levels of DSP by type:
    - **price sensitive DSP** – dispatched when the spot price is high according to contracts between Retailers and their customers;
    - **network loading DSP** – used to reduce loading on certain parts of transmission / distribution network to manage network loading under system normal conditions;[9]
    - **security DSP** – load reduction schemes used to manage contingencies and maintain power system security (for example, the load reduction offered to NSPs for network support under contingencies);
    - **reliability DSP** – designed to maintain minimum reserve levels according to reserve trading contracts with NEMMCO;
    - **government initiative DSP –** dispatched in response to a government request to conserve electricity; and
- the degree of certainty associated with the availability of DSP for dispatch during periods of peak demand.

3.1.3. Current outcomes

The volume of DSP reported by NEMMCO and applied to this framework represents the total of individual contracts surveyed parties have indicated to be **committed (or firm) DSP**[10] – that is, a block of DSP with a very high probability of being dispatched in response to adverse market conditions during a high demand period. NEMMCO also gathers information on non-committed DSP, but this capability is entirely discounted in assessments of peak demand (and reserve).

[9] "System normal conditions" refers to a power system configuration where all network elements have a status that is considered typical – generally a "zero outage" configuration.

[10] DSP considered to be committed (or firm) is where controllers of DSP capability are able to attach a "high probability" that a block of DSP will be available to be dispatched in response to adverse market conditions during a high demand period – the nature of the DSP contract may impose limitations on when (or how often) the contract can be invoked.

3.2. Discussion of issues

Mechanisms that deliver more accurate estimates of DSP likely to be available at times of peak demand will not deliver additional reserve, but do have the potential to more efficiently manage power system reliability through better informing the process by which market intervention is determined.

3.2.1. Identified shortcomings of the current arrangements

Current forms of reporting DSP at times of peak demand are unlikely to be either complete or accurate. There are two potential problems arising from the current approach to DSP estimation:

- The relevant provisions of the NER 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.[11]

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

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

In one sense, under-estimation of the volume of available DSP at times of peak demand produces a desirable outcome in that reliability of the power system will be managed conservatively – actual reserves will be under-estimated. However, under-estimation of actual reserve creates the risk of NEMMCO intervening in the market prematurely, thus distorting the integrity of investment signals necessary for long term power system reliability in an energy-only market. Alternatively, should the volume of available DSP be over-estimated, actual reserves will also be over-estimated, thus creating the risk that NEMMCO will fail to intervene in the market when intervention is required to preserve power system reliability at times of peak demand. With better information, where thresholds for intervention are approached the market can be more confident in the correctness of any decision by NEMMCO to intervene (or not).

Participants in Advisory Committee and sub-group meetings agreed that it is desirable to improve the accuracy of DSP estimates at time of peak demand. However, in developing better estimates it is conceded that there will be many different forms of DSP, with varying contractual conditions and degrees of firmness associated with dispatch.

[11] AEMO submission to the climate change review 1st interim report (p.8) identifies likely proliferation of EG as a problem in demand forecasting.

3.2.2. Principles to be adopted in a modified approach

Given the need to take account of varying levels of firmness in DSP contracts, estimates of DSP availability at times of peak demand will need to incorporate estimates of dispatch availability probability if processes are to avoid entirely discounting non-firm DSP.

It is expected that any Registered Participant would view an obligation for additional reporting as unwelcome on the basis that potentially commercially sensitive information would have to be revealed. For this reason, Participants could seek to limit the amount of information they are required to divulge. However, a reasonably detailed level of DSP information would be required each year in order to inform development of the ANTS, and there seems to be little practical alternative other than for NEMMCO to conduct an information gathering process each year in response to a Rule requirement. Confidentiality of potentially sensitive Participant information could be maintained by requiring that NEMMCO only publish aggregated results.

Rather than specify in the NER the detailed DSP information that would be required, having the detail specified in guidelines provides an additional degree of flexibility on the form of survey that best meets the requirements of NEMMCO in managing power system reliability. In drafting relevant provisions of the NER and guidelines, allowance will need to be made for the fact that substantial judgement must be exercised on the part of survey respondents in order to translate highly variable DSP contract conditions into assessments of probability of dispatch at times of peak demand.[12]

3.3. Options and proposals

It is proposed that the NER be amended to make specific reference to the provision of DSP information incorporating Participant assessments of the firmness of contracted DSP. The NER would need to use terminology along the lines of:

> In accordance with guidelines that may be issued from time-to-time by the Reliability Panel, Participants must provide NEMMCO with information about the load reduction and non-registered embedded generation capability available under contract to the Participant. Information provided must be sufficiently detailed so as to allow NEMMCO to form reasonable probabilistic assessments of demand-side capability at times of high levels of power system loading.

Subject to the reporting guidelines matching the requirements of NEMMCO's assessment methodology, Box 2 represents a possible approach to making a probabilistic assessment of an individual Participant's contribution to demand-side capability.

[12] It would be difficult to enforce mandated reporting of (essentially) unverifiable information.

Box 2: Probabilistic assessment of DSP availability – an example

Participants in a region identify 500MW of demand-side facilities under contract spread over 100 sites. Based on an assessment of the limitations of the facility and the nature of the contract, the facilities have been categorised in "buckets" representing the probability of the facility being available for dispatch during a peak demand event. Categorisation yields the following:

- 95% < **100MW** ≤ 100% at times of peak demand;
- 75% < **150MW** ≤ 95% at times of peak demand;
- 50% < **100MW** ≤ 75% at times of peak demand; and
- 30% < **150MW** ≤ 50% at times of peak demand.

Having developed a form of probability distribution of the DSP capability within a region, there are many ways in which the information could then be translated into measures of likely DSP dispatch at time of peak demand.

An overall average level of DSP availability may be considered unsuitable, but the results could be used in a way that allows some weighted assessment of DSP availability such that there is at least an x% probability that a given volume of DSP is available for dispatch.

Alternatively, the following illustrates an unsophisticated, but nevertheless possible approach to an (arguably conservative) probabilistic assessment of demand-side capability …

(100 x 0.95) + (150 x 0.75) + (100 x 0.50) + (0 x 0.30) = **257.5MW**

Demand-side capability with < 50% probability of dispatch at peak demand has been entirely discounted, and all other capability has been discounted to a degree in accordance with the lower limit of the probability band in which it has been placed.

There will be other methodologies that are no less valid than this.

[Note that under the existing approach used by NEMMCO, it is likely that given the assessments above, only the 100MW of capability at > 95% probability would enter into the assessment of available DSP at times of peak demand.]

4. STRATEGIC USE OF EMBEDDED GENERATION

What is proposed?

Additional guidance should be provided to DNSPs and the owners of small embedded generation (EG) units with respect to the application of technical standards in order to lower the costs of negotiation and provide consistency across jurisdictions by providing fit-for-purpose standards.

NEMMCO should be encouraged to proceed with its internal review of registration processes and to (at least) report annually on progress towards identifying and removing unreasonable barriers to registration of EG as market generating units.

How will it help manage reliability in the short term?

Given:

- identified reserve shortfalls represent in the order of only 1% of peak demand for affected regions; and
- there is likely to be a non-trivial volume of under-utilised EG,

actions that increase the strategic use of existing EG have the potential to make a substantial contribution to mitigating identified reserve shortfalls.

Current arrangements do not seem to impose a substantial barrier to the strategic use of EG as viable business models in this area are now emerging within the existing market frameworks. However, greater consistency in the application of technical standards is likely to provide additional certainty as to the outcomes of negotiations between EG unit managers and NSPs, thus encouraging more EG unit owners to make their facilities available for strategic deployment.

NEMMCO's internal review of registration processes are not expected to result in any substantial change to the operation of market frameworks, but the review will help retain a focus on minimising any barriers that may be identified.

4.1. Current context

[NOTE: For the purposes of the following discussion a small embedded generator (small EG) is a unit with a power output capability of (generally) ≤ 5MW, although the discussion may still apply to many larger generating units.]

4.1.1. Current objectives

Arrangements for the deployment of energy within the market should be no more complex than is reasonably necessary to ensure the safe and secure operation of the power system and the prudentially sound management of the energy market. Subject to these objectives being met, the NER, guidelines and procedures should facilitate economic deployment of any generating unit that would create value in the NEM by:

- mitigating the effects of region- or NEM-wide generation shortage – as signalled through high spot prices; or
- assisting in the management of local network loading problems that, in the absence of local generation support, could lead to local load shedding (see Box 3).

For either of these applications to be commercially viable, the owner of the (generally) small EG unit in question needs access to a revenue stream dictated by either: the sale of energy on the spot market; or a power purchase agreement (PPA).

Box 3: Mitigating network congestion with embedded generating units

> Local network loading issues can arise in either transmission or distribution networks that do not necessarily coincide with high prices. Therefore, the spot market price signal is not always going to be effective in helping bring (potentially available) additional load management or generating capability into play.
>
> If local networks become congested (and prospectively overloaded), the short-term response could be:
>
> - involuntary load shedding; or
> - (if available) opportunistic deployment of demand-side capability or non-scheduled (embedded) generation.
>
> The long term response to prospectively persistent local network congestion could be:
>
> - network augmentation; or
> - (where available) use of long-term contracts for the timely deployment of demand-side capability or non-scheduled (embedded) generation to avoid or defer network augmentation.
>
> Strategically located and deployed generation of any size has the potential to offset or reverse otherwise problematic power flows if the capability is procured and deployed under the instruction of the NSP.

Where interpretation of the NER, guidelines and procedures is required to determine whether connection / registration of EG is to proceed, that interpretation should take account of the materiality of any risks to safety, security and prudential integrity.

4.1.2. Current arrangements

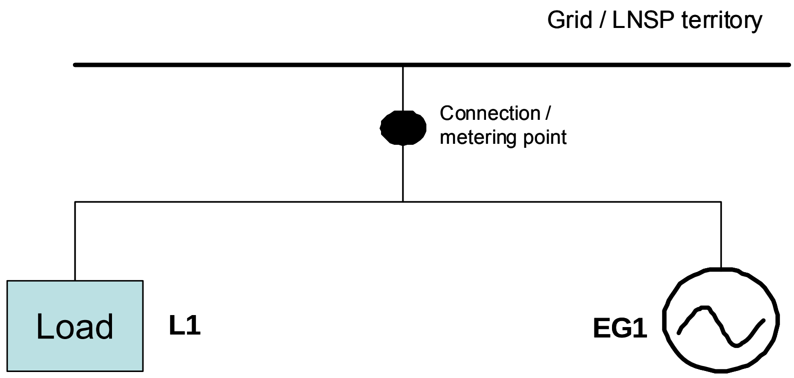
Many commercial operations embedded in distribution networks have on-site generation capability in the form of emergency / stand-by units or units specifically designed to offset their load and manage energy flows at their point of connection to the network – referred to hereafter as embedded generation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

Consider the stylised configuration for a small embedded generator (EG1) in Figure 3 that, to this point, has only ever been used to supplement energy delivered beyond the customer's connection point, or to provide emergency energy while the customer is disconnected from the grid. EG1 has never been used to export energy to the grid – that is, MWs supplied by EG1 ≤ MW consumed by L1. Many of these small EGs would be unable to operate in parallel (synchronised) with the grid – they are probably of a "break before make" configuration[13] – but

[13] "Break before make" refers to having to break the connection with the grid (open the circuit breaker) prior to starting the generator and supplying energy to the customer's equipment.

should the opportunity arise to strategically utilise energy from EG1 and to export energy to the grid, reconfiguration of the relevant connection may be an economically viable proposition.[14]

Figure 3: Stylised customer configuration with small embedded generator



Clause 2.2.4(a) of the NER states:

> A *generating unit* whose sent out generation is not purchased in its entirety by the *Local Retailer* [Tier 1 Retailer] or by a *Customer* located at the same *connection point* [Tier 2 Retailer] must be classified as a *market generating unit*.[15]

For an EG unit owner, sale of energy to either the Tier 1 or Tier 2 Retailers is the simplest option for yielding additional value from an existing facility and is equivalent to offsetting the energy settlement liability that would otherwise accrue at the relevant connection point. The more sophisticated approach of selling energy into the grid, where generation is greater than load at that connection point,[16] would require a different form of connection agreement and approval of that use by the local NSP.

Specialist skills are required to manage EG units selling energy into the grid. As there are likely to be economies of scale in managing EG units, having a portfolio of facilities is likely to lead to substantial savings in the per unit management cost. The suite of skills (and risks) for managing a portfolio of EG units range across:

- possessing the financial resources to procure, and the know-how to implement and operate systems, that can coordinate the deployment of several EG units;

[14] To separately measure energy used by L1 and energy delivered from EG1 (and prospectively exported to the grid) new connection and metering points may need to be established.

[15] Classification as a “market generating unit” requires the EG unit to have a Financially Responsible Market Participant (FRMP) who must register as a Market Generator for the generating unit. Tier 1 Retailer is the formal term given to the default of franchise retailer for an area. Tier 2 Retailer is any Retailer who has taken settlement responsibility for an end-use customer as a result of retail competition.

[16] For example, by temporarily cutting back production such that (per Figure 3) MWs from EG1 < MWs from L1. Under the terms of the Rules, an NSP is required to assess whether connection of a generator is likely to cause a material degradation in the quality of supply to other Network Users.

- building an EG unit "book" to be used to underwrite physical hedges, or other financial energy products; and

- entering into arrangements with NSPs to assist with mitigating network loading issues. Being able to respond to NSP instructions is likely to require establishment of communication, dispatch and maintenance protocols between the NSP and the aggregator, as well as agreeing on financial compensation. In turn, the aggregator would have to administer a pass through of the financial compensation in its PPA with the EG unit.

Given the specialisation required, the owner of an EG unit would seek to sell the capability of that unit on the basis of a PPA with a Financially Responsible Market Participant (FRMP) who would then accept the direct risks associated with trading the energy from the unit directly on the spot market. The FRMP would be any one of: Tier 1 Retailer; Tier 2 Retailer; or an intermediary that is a specialist in the management of small scale generation for strategic energy market purposes. If the terms of a PPA offered by either the Tier 1 or Tier 2 Retailers (as appropriate) are not sufficiently attractive, the next option for the owner of the EG (probably via an intermediary with the necessary specialist skills) is to:

- seek a connection agreement for the EG unit with the local NSP, which must be granted if the unit meets each of the automatic access standards in technical requirements laid down in Schedule 5.2 of the NER, but would otherwise require negotiation with the relevant NSP; and

- undertake the NEMMCO registration process (including payment of relevant registration fees) to have the unit classified as a market generating unit, a pre-condition for which would be some form of connection agreement with the local NSP.

4.1.3. Current outcomes

It is likely that a non-trivial proportion of this existing EG unit capability is not yet strategically managed from the perspective of dealing with an electricity market that could be under some stress.[17]

The owner of an individual (emergency or stand-by) EG unit, whose basic business model focuses on activities other than the electricity market, would not generally be well equipped to manage the operation of the EG unit for strategic energy market purposes. Owners of such

[17] There are no known reasonably accurate estimates of the volume of emergency generation capability that might be legitimate candidates for strategic management, although anecdotal information suggests that NEM-wide, under-utilised emergency generation capability is likely to be well in excess of 1,000 MW. NEMMCO conducts surveys of non-scheduled generation seeking information via NSPs. However, these surveys:

- expressly exclude consideration of emergency and stand-by generation; and
- seek to exclude generators larger than 1MW but whose export to the grid is less than 1MW, although there are known inconsistencies between jurisdictions as to how comprehensive is the coverage of generators between 1MW and 5MW in size.

generation facilities will wish to concentrate their efforts on their primary business operations. Direct participation by facility owners in the energy market could be administratively burdensome and managing an electricity generating facility is not where their expertise lies – owners may only be concerned about the facility when their individual supply is placed under some threat. For this reason, EG unit owners will probably benefit from access to the specialist skills outlined in Section 4.1.2.

Specialist aggregators seeking to build “books” of EG units for the above purposes are now emerging in the NEM.

4.2. Discussion of issues

Given:

- identified reserve shortfalls represent in the order of only 1% of peak demand for affected regions; and
- there is likely to be a non-trivial volume of under-utilised EG,

actions that increase the strategic use of existing EG have the potential to make a substantial contribution to mitigating identified reserve shortfalls.

An advantage of arrangements that encourage an intermediary to contract with small generating unit owners is that they are not necessarily interested in only looking for facilities when the demand-supply situation is known to be tight. Intermediaries who successfully negotiate a deal to manage an EG unit and act as the interface with the market on behalf of the unit owner become the FRMP for that unit. The ability to aggregate energy blocks over many facility owners provides an opportunity to sell larger blocks of energy to retailers to match hedge positions at all times. The more refined is the process of aggregation or strategic management of small EGs, the more likely it is that the intermediary will be able to offer attractive financial terms for the marginal facility owner to enter into a PPA. Clearly, the easier and more streamlined are registration and connection processes, the greater will be the opportunity to offer attractive PPAs and the more likely it will be that currently under-utilised EGs will become involved in the market.

Mixed signals are being provided as to how effective current arrangements are in effectively presenting opportunities to utilise existing EG.

4.2.1. Technical assessment and connection processes

The way in which technical matters are dealt with by the prospective FRMP of the EG unit and the local NSP is an important factor in the likely commercial success of a contract. Where operation of a small EG unit merely offsets load behind a customer connection point, connection agreements and adherence to the technical requirements of the NSP are unlikely to be an issue. It is where operation of a small EG unit leads to export of energy to the local network that the local NSP is likely to take a close interest in the technical parameters of the unit in question, with negotiation of a connection agreement between the prospective FRMP of the EG unit and the relevant NSP then becoming an important issue. The differences between automatic access standards and minimum access standards outlined in Schedule 5.2 of the NER reflect the matters on which NSPs and prospective FRMPs will negotiate. Inconsistency between NSPs in the manner in which technical standards are applied could create a barrier to successfully building an EG unit book, the efficient emergence of EG and its strategic use in the energy market.

Technical assessment and connection processes were subject to close examination in both the AEMC's DSP review and the Ministerial Council on Energy Standing Committee of Officials (SCO) Policy Response on the NERA and Allen Consulting Group report, *Network Planning and Connection Arrangements – National Frameworks for Distribution Networks*.

In respect of connection processes for EG the Commission was not persuaded that they represent a significant barrier, and that the proposed SCO framework:

> … appropriately balances the need for detailed arrangements for those generators where such arrangements are necessary while also allowing an appropriate level of flexibility for smaller generators where detailed arrangements would be unnecessary.[18]

In respect of assessment of EG against technical standards some refinement to existing approaches appears to warranted. The DSP review draft report findings noted:

> The jurisdictional arrangements have minimal guidance which allows a degree of flexibility for DNSPs with respect of the minimum technical standards they apply. The extent of flexibility, and therefore uncertainty in the minimum technical standards arrangements, means that embedded generators cannot be certain about the costs of meeting technical arrangements. This may deter embedded generators connecting when it otherwise would have been efficient to do so.[19]

4.2.2. Registration processes

The NER and NEMMCO's registration process confer an advantage on some parties in making strategic use of EG. The advantage exists because Tier 1 or Tier 2 Retailers wishing to make use of EG can do so without incurring the registration costs (both financial and administrative) that are faced by other Participants.

If formal registration of an EG unit is pursued in order to access spot market revenue, the FRMP must, at a minimum:

[18] AEMC 2009, *Review of Demand-Side Participation in the National Electricity Market*, Stage 2: Draft Report, 29 April 2009, Sydney (DSP review draft report), p.47.

[19] DSP review draft report, p.48.

- apply to NEMMCO to register in the categories of Generator, Non-Scheduled Generator and Market Generator;[20]
- gain approval of the relevant metering installation; and
- establish administrative processes sufficient to manage market settlement and other relevant compliance obligations.

To the extent that registration processes confer an unreasonable advantage on Tier 1 and Tier 2 Retailers and are harder to negotiate than they need to be, there will be diminished prospects of efficiently using small EG units in a strategic manner. Accordingly, more vigorous and even-handed competition may be achieved through modification and streamlining of the current registration process. Aside from imposing certain obligations, the registration process is subject to uncertainties associated with treatment of embedded networks and consequent assessment of metering and connection points. It is understood that NEMMCO is conducting an internal review of the processes required to be undertaken for registration of small EG units, with that review examining:

- interactions with AER guidelines for exemption from registration of embedded networks;
- location of formal connection points within an embedded network;
- metering requirements – how metering is assessed and where metering points need to be in an exempt embedded network;[21] and
- processes for the transfer of small EG units between FRMPs once the unit is initially registered.

4.3. *Options and proposals*

Given the potential for EG to offset forecast reserve shortfalls, it is worth pursuing actions that can reasonably be taken to reduce the barriers to development of PPAs for small EG units by ensuring the processes for both connection and registration are as smooth as they can reasonably be.

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[20] Including executing the application as a deed, providing evidence of legal status, regulatory compliance, financial viability and organisational capability. It may be possible to classify the unit as Scheduled, although this would carry substantial additional administrative and technical burden in relation to installing and managing the infrastructure necessary to respond to dispatch instructions from the National Electricity Market Dispatch Engine (NEMDE) operated by NEMMCO.

[21] There is a substantial administrative difference in the treatment of metering for loads as compared to the treatment of metering for (any) generation. NEMMCO and the FRMP share the responsibility of metering small EGS; so a large increase in EGs registering to participate in the market would result in a lot of (manual) metering work for NEMMCO – i.e. NEMMCO must manually assess every generator from a metering perspective, whereas load is assessed by the FRMP through an automated system.

Options for amending technical assessment processes have been outlined in the DSP review draft report. In noting the difficulties caused by the flexibility afforded when the NER provisions do not apply, and the inconsistency of their application across jurisdictions and DNSPs, the DSP review draft report suggested that:

> … there are likely to be benefits in providing additional guidance to smaller embedded generators about technical requirements on a national basis. Such an approach is likely to lower the costs of negotiation and provide consistency across jurisdictions by providing fit-for-purpose standards.[22]

NEMMCO should be encouraged to proceed with its internal review of registration processes and to (at least) report annually on progress towards identifying and removing unreasonable barriers to registration of EGs as market generating units.

[22] DSP review draft report, p.49.

5. ADVANCED RESERVE CONTRACTING

What is proposed?

- It is proposed that NEMMCO be allowed to adopt a panel arrangement for short-notice reserve contracting via a modified RERT provided no payment for energy reserve availability be made prior to the time when NEMMCO agrees to pay for a firm option to commit the facility in question.
- Consideration should be given to eventually migrating the short-notice reserve capability from the RERT mechanism to the directions mechanism.
- Consideration should be given to a prolonged targeted reserve mechanism that could to be invoked up to 18 months ahead of dispatch but only after policy makers have declared that the circumstances of a forecast reserve shortfall meet four threshold tests of seriousness.
- Contracting for standing reserve is not proposed.

How will it help manage reliability in the short term?

The proposed options provide mechanisms to respond to reserve shortfalls that become apparent:

- as a result of inappropriate settings for market parameters that have created systemic under-investment in capacity; or
- as a result of uncertainty over future policy settings that have delayed decisions to invest in energy infrastructure; or
- as a result of technical failure of major energy supply infrastructure (or other force majeure events) with consequences extending more than a year; or
- in the few weeks or days prior to dispatch.

Each of the proposed options ensure that any investment in reserve over and above that brought forward by the market is targeted at addressing identified shortcomings in market outcomes.

This section examines options for contracting reserve outside existing intervention mechanisms, generically referred to as **advanced reserve contracting** (ARC), which refers to any energy reserve capability managed under some form of contract entered into at any time prior to dispatch.

5.1. Current context

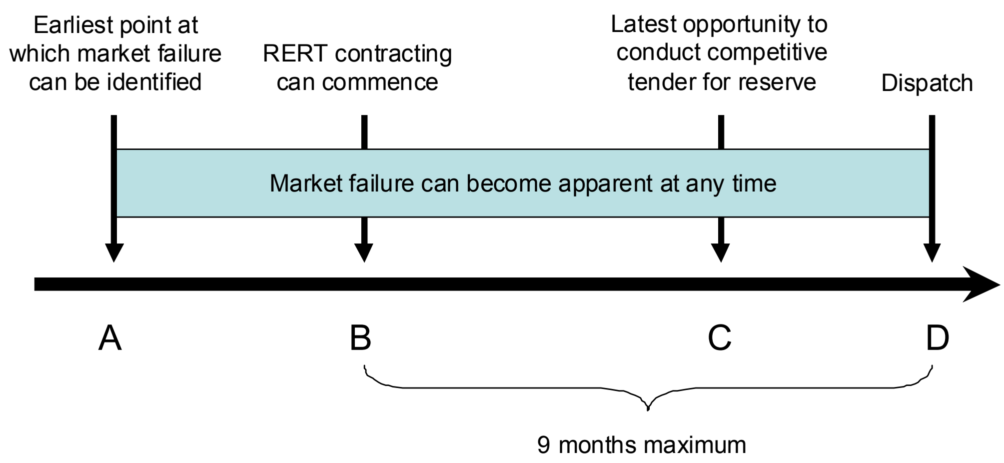
5.1.1. Current objectives

Primary reliability management tools such as the standard for unserved energy and the market price cap have been established with an expectation that, in combination with other market mechanisms, sufficient incentive is created for Participants to present adequate reserve. Intervention in normal market mechanisms to deliver additional reserve (via either RERT or formal directions) will only occur where the market has been deemed to have failed. In the absence of market failure, any capacity mechanism or express payment for additional reserve is inconsistent with the principles of an energy-only market.

5.1.2. Current arrangements

The existing RERT mechanism provides for market intervention in the event of the failure of the market to bring forth sufficient energy reserve to meet the established reliability standard. Under the RERT, contracting of reserve can occur no earlier than nine months prior to dispatch, but a practical limitation of the RERT is that the existing tendering process effectively imposes a sunset on contracting opportunities of several weeks prior to dispatch after which no additional reserve options can be considered (point C in Figure 4).

Figure 4: Time lines for reserve contracting



If a requirement for additional reserve becomes apparent in the time frame between:

- when the remaining time to dispatch makes conduct of further competitive tendering for energy reserve contracting impracticable (point C in Figure 4); and
- dispatch (point D in Figure 4),

the only remaining options for intervention by NEMMCO to maintain power system security is to issue a formal direction to appropriate plant or an instruction to NSPs to shed customer load.

The RERT is a short-term reliability mechanism designed for infrequent use to manage relatively small shortfalls in reserve capacity and to be used only when the market has failed to ensure reliable supply. Where a decision has been made that intervention in the market is required to overcome an identified market failure, NEMMCO consults the government in the affected jurisdiction(s) to determine an upper limit for the cost of reserve that may be contracted. This step ensures customers who would ultimately pay for the reserve are not liable for a cost of reserve above the value of customer reliability as nominated by the jurisdiction.

5.1.3. Current outcomes

The AEMC Reliability Panel summarised historical reliability performance in the NEM up to the end of the 2007-08 financial year as follows:

> Since market started in December 1998, averages for [unserved energy] due to shortfalls in available capacity indicate that New South Wales and Queensland remain within the Reliability Standard. Conversely, South Australia and Victoria fell outside the Standard in the year 2000, when there was a coincidence of industrial action, high demand and temporary unavailability of generating units in Victoria. In terms of the long term averages, Victoria remains outside the Standard due to that single event. In every year since 2000, South Australia and Victoria have met the Reliability Standard.[23]

Since the end of the 2007-08 financial year there have been events associated with the heat wave in Victoria and South Australia in late-January and early-February 2009 that contributed to unserved energy as a result of reliability issues. Further, on the basis of assessments in NEMMCO's 2008 *Statement of Opportunities*, capacity reserves in South Australia and Victoria are expected to be at or below minimum reserve levels until at least 2010-11.[24]

5.2. Discussion of issues

5.2.1. Identified shortcomings of the current arrangements

Neither RERT nor directions are mechanisms that can provide sufficient assurance of avoiding unserved energy (USE):

- The facility of directing plant in order to avoid unserved energy will be totally ineffective if there is no directable plant whose availability can be changed so as to supply energy for the intervals subject to direction.
- Notwithstanding the expectation that market settings are appropriate and should deliver adequate reserves, the RERT is a back-up and short-term reliability mechanism intended to deal with small demand-supply imbalances and is not designed for frequent use or to manage relatively large shortfalls in reserve capacity.
- Some reserve capability may need more lead time for development than is allowed through exercise of the RERT mechanism. If RERT remains the longest term option for accessing (substantial) additional reserve capability, potentially efficient reserve could remain unutilised.
- In some circumstances, market failure will be localised and apparent only very close to dispatch time frames – for example, when bush fires turn an otherwise non-credible failure of multiple transmission lines into a reality. To the extent that these circumstances can be reasonably characterised as a market failure, the failure is arguably not of the form for which services should have been procured in advance of the multiple contingency becoming credible.

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23 AEMC 2008, *Annual Electricity Market Performance Review 2008*, Final Report, 17 December 2008, Sydney, p.9. Available at: http://www.aemc.gov.au.

24 Assuming that all existing generation capacity remains in service, and no new constraints emerge on the operation of existing capacity (e.g. drought-related).

Should technical failure of major energy supply infrastructure occur, the extent of the possible reserve shortfall is expected to be such that the RERT mechanism will be ineffective in mitigating the shortfall because RERT has only a limited window in which to tender for, and contract with, reserve.

On the basis of feedback from both submissions and meetings with the Advisory Committee and sub-group, there are divided views on the effectiveness of current arrangements. Although most parties generally accept the need for an intervention mechanism, generators and retailers in particular express strong views that the use of interventions such as RERT should be tightly proscribed and that, in the absence of market failure, availability payments for additional reserve should not be contemplated. On the other hand, end-user representatives are of the view that the market has failed to deliver adequate assurance of reliability and that further opportunities for contracting energy reserve should be explored.[25] Although end-user criticism of reliability performance may not make a distinction between reliability and security related events, the lack of a distinction from their perspective is understandable – when the lights go out, it does not matter to users what the cause of supply failure happens to be, because in either case the consequence is that business has to stop.

The current approach to procurement of energy reserves, beyond that provided by the market, does present some gaps in the contracting opportunities as follows:

- at any time prior to point B in Figure 4 – contracting for either standing reserve or prolonged targeted reserve; and
- between point C and point D in Figure 4[26] – short-notice reserve contracting.

Therefore, it is worth examining whether or not mechanisms targeted at these gaps could be more efficient ways of helping to ensure the unserved energy standard is met, than is the current reliance on intervention via directions and/or RERT.

5.2.2. Principles to be adopted in a modified approach

If centrally managed mechanisms to make additional reserve available are to be considered, then the prospect of these mechanisms distorting the existing market must also be taken into account. To ensure any chosen form of ARC does not distort investment signals:

- Contracted reserve would have to be quarantined from the energy-only market for the period over which it is contracted and, if dispatched, normal price signals would need to

[25] For example, the EUAA submission to the climate change review 1st interim report expressed concern that unlikely events may become more frequent and the RERT may not efficiently prevent unacceptable levels of unserved energy. The EUAA suggested that the AEMC should develop a more comprehensive response to concerns about supply reliability, rather than focussing on RERT.

[26] In DSP Reference Group meetings, Energy Response has claimed that at times when involuntary load shedding has been imposed on the power system, reserve in the form of load reduction was available but was unutilised because of the absence of a mechanism by which they could be compensated.

be preserved if reserves were dispatched when involuntary load shedding was the remaining option to manage the security of the power system.

New centrally managed reserve that can participate in the market will dampen the frequency, duration and magnitude of high price events that signal the need for new capacity and, hence, such reserves would be replacing reserve that would otherwise appear through the market. Existing forms of market intervention preserve normal market signals through "what if" pricing (see Box 3).

- Care needs to be taken that capability presented to the ARC mechanisms would not otherwise have been offered to the energy market and that gaming is not inadvertently facilitated.

  Minimal distortion to the energy market will occur subject to NEMMCO being able to take effective action to allow it to be satisfied that the reserve to be contracted is not available to the market through any other arrangement in the period over which it is contracted.[27]

- Contracted reserve must not be subject to capacity or availability payments.

  Energy-only markets rely on the frequency, duration and magnitude of high price events to signal the need for new capacity. Any availability (or capacity) payment creates a risk of reserve that would otherwise be presented to the energy market, being withdrawn from the energy market in favour of more certain remuneration in a form of a capacity mechanism.

- On the presumption that NEMMCO is the party to manage any intervention mechanism,[28] there must be sufficient time for NEMMCO to undertake reasonable evaluation of dispatch options on the basis of final contractual conditions.

  In contracting with energy reserve providers (i.e. intervening in the market), NEMMCO needs to be sure that its choice of a portfolio of mitigation measures:

  - represents an effective means of mitigating involuntary load shedding;
  - represents good value – that is, there were no clearly more cost-effective options and the chosen portfolio can be delivered within acceptable cost parameters;
  - has been subject to reasonable due diligence with respect to avoiding concerns with respect to double-dipping;[29] and

[27] For a more fulsome discussion of gaming, see Appendix A.

[28] Other models for managing intervention do exist but, for the purpose of consistency in approach it is assumed NEMMCO (or AEMO) will continue to manage such functions.

[29] "Double dipping" in this context refers to a party seeking to yield income (or avoid costs) from two different sources as a result of delivering a single service. For example, reserve in the form of interruptible load secured for RERT would be double dipping if it was also:

- can be adequately audited post-dispatch to confirm the amount of energy provided under contract.

Box 3: Preservation of market signals during intervention – "what if" pricing

> Clause 3.9.3(e) of the NER requires that NEMMCO set the dispatch price and ancillary service prices for an intervention price dispatch interval at the value NEMMCO considers would have applied for that dispatch interval in the relevant region had the NEMMCO intervention event not occurred.
>
> For example, if NEMMCO exercises the RERT mechanism and deploys additional reserve, or issues a direction, and but for that intervention involuntary load shedding would have occurred, the price for affected intervals would be set at VoLL, thus preserving the investment signal presented to peaking generation.

In addition to avoiding distortion of market signals, any decision to procure additional reserve must carry with it a reasonable assurance that:

- the likely value of lost load to be avoided as a result of having additional reserve in place

is greater than

- the cost of procuring and delivering additional reserve.

The problematic nature of this type of assessment is acknowledged and available evidence as to likely values and costs is outlined in Box 4.

Box 4: Market evidence as to cost and value of reserve

> **Estimating the cost of standing reserve**
>
> It is difficult to estimate the likely costs of a hypothetical reserve arrangement without undertaking a formal tender. The best benchmark available is from the reserve trader exercise conducted by NEMMCO for the 2005-06 summer where the cost of 375MW of reserve to be available over an 8 week period was $1,450 / MW / week.[30] If these costs were indicative of those likely to be faced over the long term, it would equate to close to $75,000 / MW / year, with costs then to be multiplied by the amount of MWs of reserve to be procured for each region. By way of comparison, capital costs for new open-cycle gas turbine (OCGT) plant are currently in the order of $100,000 / MW / year.

- contracted as part of a DSP arrangement used by a retailer to hedge energy market exposure; or
- contracted to an NSP as part of an arrangement to manage local network loading; or
- subject to pool price pass through, whereby the manager of the facility chose whether or not to consume energy on the basis of the market price.

30 Total cost of $4.352 million for 375MW for 8 weeks.

NEMMCO has used its reserve trader powers twice since the start of the NEM:

- it contracted for 84 MW of additional reserves for the South Australian and Victorian regions for February 2005 based on forecasts in mid-late 2004 of a shortfall of 195 MW. The cost of acquiring those services was $1.035 million; and

In the Reliability Panel's Comprehensive Reliability Review (CRR),[31] volumes of standing reserve in each mainland market region were proposed as follows:

- 140MW in Queensland;
- 360MW in NSW;
- 150MW in Victoria; and
- 40MW in South Australia.

For the above volumes of standing reserve, the CRR estimated a total annual standing charge of $50 million based on an estimated cost of capacity (at the time) of $71,000 / MW / year.

Estimating the value of standing reserve

To put the above costs in perspective, the required load shedding attributable to reliability (as opposed to security) issues in Victoria and South Australia on 28 and 29 January 2009 was close to 2,500MWh (approximately 0.004% of total annual energy for Victoria and South Australia combined). If valued at $20,000 / MWh[32] this load shedding would have a total value of $50 million.

However, the CRR proposed volumes of standing reserve in Victoria and South Australia[33] was only around half the amount necessary to offset the load shedding that actually occurred in Victoria and South Australia. To offset all the January 2009 reliability load shedding, Victoria would have required 340MW of additional reserve and South Australia would have required 140MW of additional reserve. In other words, if the $50 million / year was spent on standing reserve in the proportions suggested in the CRR (with $13.5 million of that total spent on reserve for Victoria and South Australia), only around half of the actual reliability load shedding in January 2009 would have been avoided.

Value of standing reserve should be assessed over the long term (say, 10 years) taking account of the probability that procured reserve would be effectively deployed. See Section 5.3.2 for further discussion.

- it acquired an additional 375 MW of reserve at a cost of $4.352 million for those regions for the summer of 2005/06 based on delays in the commissioning of Basslink and a Laverton North power station.

In each case the reserves were contracted under the arrangements that applied prior to the commencement of the RERT on 26 June 2008.

31 AEMC Reliability Panel 2007, *Comprehensive Reliability Review, Final Report*, Sydney, December 2007, pp.63-64. The essential elements of the standing reserve were:

- the standing reserve would contract ongoing levels of reserve for periods of several years;
- the volume of reserve to be contracted would be set centrally and the price paid for the reserve would be determined from a tender or auction process;
- the reserve would be comprised of supply-side elements, or demand-side elements, or both; and
- the standing reserve would only be able to operate when a NEM Region wholesale dispatch price was at the level of VoLL and then only as a substitute for physical shedding of customer load.

32 No judgement is made as to whether $20,000 / MWh is the "correct" valuation of customer reliability. The figure is used for illustrative purposes only.

33 Volumes that contributed to the estimated $50 million standing annual charge for all procured standing reserve.

5.3. Options and proposals

5.3.1. Options

There are three types of advanced reserve contracting (in addition to existing intervention mechanisms) that could be considered:

- **short-notice reserve** – reserve chosen from a panel of providers contracted very close to dispatch time frames (days or weeks in advance of dispatch) should market failure be identified after it becomes impracticable to conduct a full competitive tender for the provision of reserve;
- **prolonged targeted reserve** – an amount of reserve to be contracted a year or more in advance of dispatch for any region in which a failure to deliver adequate reserve could be identified; and
- **standing reserve** – a predetermined amount of reserve to be contracted (potentially years in advance of dispatch) for each region regardless of whether or not a market failure has been identified.

Factors involved in the assessment of the merits of each of these options are discussed below.

Short-notice reserve

Where scheduled plant (generators, load or network services) and market generating units can be deployed to mitigate the effects of non-credible contingencies or otherwise unavoidable involuntary load shedding, NEMMCO may direct relevant units. NER-based mechanisms will subsequently ensure that parties are compensated for costs incurred in following that direction. However, there is currently no mechanism that would allow NEMMCO to compensate the voluntary deployment of non-scheduled load reduction in order to avoid involuntary load shedding following a market failure (or event) that becomes apparent in the few weeks or days prior to dispatch. The existing RERT mechanism for contracted reserve does not facilitate a response to any reserve shortfall that becomes apparent any closer to dispatch than around 2 months.[34]

A process of deploying and compensating load within these time frames could be found to advance the national electricity objective if it:

- contributes to the efficient achievement of the reliability standard without contributing to the standard being exceeded; and
- does not violate the principle that availability payments are only made when the market can be shown to have failed.

[34] Two months is around the minimum time required to conduct a competitive tender process.

It is therefore worth exploring options to manage market failures (or events) that become apparent between point C and point D in Figure 4. The only currently feasible option is to direct the dispatch of scheduled plant or market generating units known to be available given prospectively useful interruptible load is effectively prevented from making a contribution. An alternative to reliance on existing intervention mechanisms – each of which have limitations on recruitment options[35] – is to develop a process that would allow NEMMCO to compensate the voluntary deployment of non-scheduled load reduction. Such a mechanism would need to:

- be capable of operation (identification, contract completion and deployment) between point C and point D in Figure 4;
- be subject to minimum due diligence assessment (e.g. assurance of value; auditing of response); and
- minimise any restriction on competition for remunerated deployment while avoiding opportunistic shifting of capability from the energy market to the intervention mechanism.

A process of this nature must recognise that the closer to dispatch a market failure becomes apparent, the more certain will be the assessment of the probability for the need for additional energy reserve, but the fewer will be the practical options for efficiently mitigating any involuntary load shedding. Efficient mitigation options diminish with time because of:

- reduced flexibility of energy reserve deployment – some options may effectively expire if notice periods are too short;
- reduced time frames within which the technical and economic effectiveness of alternative options[36] can be analysed and, hence, a reduction in the extent of analysis that can be undertaken to identify the optimal portfolio of mitigation measures; and
- reduced opportunity for negotiating contractual terms.

Any assessment / negotiation process around short-notice reserve contracting will need to recognise these limitations and incorporate reasonable protections with regard to remuneration for, and assessment of the value of, feasible options. Accordingly, appropriate mechanism design will need to reflect a range of compromises. It would remain necessary to demonstrate that the market has actually failed and clearly defined thresholds for intervention have been reached before any direct payment for additional capacity could be justified.[37]

In a meeting with an Advisory Committee sub-group, options of this nature were discussed. Provided concerns over finalisation of contractual conditions associated with dispatch could be

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35 RERT has time-based limitations and directions has technology-based limitations.

36 Selected from those panel options deemed available for the period in which the reserve shortfall is to be managed.

37 For example, a forecast of lack of reserve level 2 (LOR2) – load shedding would immediately follow the occurrence a single credible contingency – in ST PASA.

resolved sufficiently far in advance (see Section 5.2.2), sub-group members (including those from retailers, generators, NEMMCO and end-users) expressed support for the concept of a panel of energy reserve providers. In discussing potentially viable arrangements for a panel of reserve providers, it was agreed that a panel could work effectively and allow NEMMCO to conduct essential due diligence tasks if the only contractual conditions needing confirmation were:

- availability for dispatch at a particular time;
- absence of any other market-based arrangement to deploy the facility in question;[38] and
- price.

The above characteristics could be incorporated into either:

- **increased flexibility of the RERT mechanism** via clarifying that NEMMCO may operate a RERT panel,[39] such that:
    - NEMMCO would assess expressions of interest from entities offering reserves to resolve any technical and legal issues;
    - entities on the RERT panel would be free to offer their capacity to the market, but would be requested to advise NEMMCO if they do so;
    - NEMMCO would not make payments to entities for being on the RERT panel; and
    - NEMMCO would use a full tendering process when contracting for reserves if time permits or, when there is insufficient time for such a tender process, select members of the RERT panel and then enter into reserve contracts; or
- **increased flexibility of the directions mechanism** via creation of a new participant category of "Directable Reserve", such that:
    - sources of energy other than scheduled plant and market generating units (e.g. non-scheduled but available interruptible load) could voluntarily register as Directable Reserve;
    - registered Directable Reserve would be voluntarily deployed following some standardised due diligence assessments by NEMMCO in relation to:

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38 Provisions against double-dipping may need to include a check for loads who are subject to pool price pass-through. End-users who actively manage their loads against exposure to the pool price should be considered to have a market arrangement, otherwise they could just pass on the opportunity to switch of at their usual threshold price in favour of remuneration via short-notice reserve contracts.

39 See: AEMC Reliability Panel, Exposure Draft, NEM Reliability Settings: Improved RERT Flexibility and Emergency Reserves Contracts, 1 May 2009, Sydney.

- o availability for deployment and confirmation that their energy response capability is not otherwise available to the market;
- o value of lost load likely to be avoided;
- o after the event auditing of response; and

- facilities deployed through this mechanism would not be subject to availability payments and would be remunerated on the basis of suitable provisions to be added to clause 3.15.7B(a3) of the NER.

Prolonged targeted reserve

A prolonged targeted reserve could be created that is capable of responding to a failure to deliver adequate reserve to specific regions of the NEM that is identified (say) 12 months or more ahead of dispatch. Circumstances that could give rise to shortfalls of this nature include:

- inappropriate settings for market parameters that lead to systemic under-investment in capacity – where the correct long term response to this situation is to adjust market settings so they deliver appropriate investment signals;
- uncertainty over future policy settings that directly impact decisions to invest in energy infrastructure (e.g. timing and level of emission trading scheme implementation) – where the correct long term response to this situation is clarification of policy; or
- technical failure of major energy supply infrastructure (see Section 2.1) – where the correct long term response to this situation is to maintain faith in the ability of the market to deliver appropriate capacity provided settings for market parameters deliver the correct investment signals.

Although an appropriate long term response to the likely failure can be identified, the probability of a reserve shortfall persisting at the time of dispatch can remain high. In this case, temporary measures may need to be invoked to deal with the problem if it is likely to be of a magnitude that the RERT mechanism[40] is unable to cope with. In exceptional circumstances, a reserve mechanism targeted at the specific reserve shortfall in specific regions may be the most effective response.

Subject to meeting the principles outlined in Section 5.2.2, in determining whether or not procurement of prolonged targeted reserve could be considered to represent good value, account needs to be taken of:

[40] A back-up and short-term mechanism intended to deal with small demand-supply imbalances.

- whether existing demand forecasts and/or notification of newly committed peaking plant in affected regions are likely to be maintained;[41]
- how effectively the market is likely to be able to respond by recruiting alternative sources of energy to offset emerging contract risks; and
- the level of risk that the reliability standard will be (further) breached.[42]

Standing reserve

The Reliability Panel, as part of its CRR made several recommendations to improve NEM reliability arrangements including consideration of, but no commitment to, a centrally managed standing reserve.[43]

If a standing reserve were to be implemented, with an appropriate amount to be procured for each market region and to be guaranteed to be available (potentially years) ahead of dispatch, the reserve service providers would be likely to require some form of availability or capacity payment. However, as noted in Section 5.1.1, availability (or capacity) payments are distortionary and inconsistent with the principles of an energy-only market. Even if there was a preparedness to compromise the basic principles of an energy-only market and make availability payments for reserve without requiring market failure to be demonstrated, clear efficiency gains to the market from doing so would need to be apparent.

In an examination of the principle of a standing reserve (SR), ROAM / Synergies[44] indicated:

> Our preliminary conclusions from the assessment of SR are as follows:
>
> - If reliability in the NEM remains very high, consistent with the past several years, with the reliability standard continuing to be met, SR would be called upon for very short periods, usually one or at most several 5 minute dispatch intervals, and SR (including DSP) will be relatively ineffective as the response time to VoLL events will be too great to contribute to reliability; furthermore, any effect would be to improve the network reliability beyond the standard;
> - On the other hand, if reliability is poor, owing to a failure of sufficient capacity to be developed to meet the reliability standard, the periods for which SR (and DSP) will be called upon will be lengthy, typically lasting for many hours in a day, and DSP may have difficulty in contributing to significant improvements in reliability; this is evidenced by the

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41 Noting that advice to the AEMC suggests the lead time for commitment of new OCGT peaking generation plant is currently 22 months.

42 Given that, in terms of the long term averages, Victoria remains outside the reliability standard (see Section 5.1.3).

43 See Footnote 31.

44 ROAM Consulting and Synergies Economic Consulting, *DSP Contribution to Standing Reserve for Reliability Purposes in the NEM*, July 2008. Available at: http://www.aemc.gov.au. For the purposes of the ROAM / Synergies analysis it was assumed that SR would be contracted on a 3 year rolling basis.

need, in emergency conditions, for standby plant to have sufficient fuel to manage up to a week at full output without additional supplies;

- Under intermediate conditions, where reliability is at borderline in meeting the standards, the benefits of SR and DSP may be the maximum, as the duration of SR may be consistent with the ability of DSP to contribute; under these circumstances the capacity of SR (and DSP) to be contracted will be a key factor to the success of the scheme; the contracted capacity of SR should then ideally be just sufficient to ensure meeting the reliability standard.

The most significant factors against SR to the NEM are:

- SR will be ineffective for VoLL events in many, if not most, situations where VoLL is not associated with a supply shortfall;
- SR will be contracted several years ahead across all regions, whereas VoLL events may be localised to a particular region; and
- DSP within SR has localised benefits and may even [worsen] reliability if actioned inappropriately.

The ROAM / Synergies report did not include any quantitative benefit-cost analysis of a standing reserve arrangement. However, the absence of such analysis is understandable as it would be extraordinarily difficult to estimate either:

- the likely cost of reserve; or
- the value of lost load likely to be avoided as a result of having the additional reserve available and the effect the avoided lost load would have on the achievement of the reliability standard of 0.002% USE.

Available evidence as to the likely values and costs of reserve is outlined in Box 4.

Subject to meeting the principles outlined in Section 5.2.2, in determining whether or not procurement of standing reserve could be considered to represent good value, account needs to be taken of:

- the expectation that reserve should be available to allow the system to meet, but not substantially better, the overall reliability standard;
- the expectation that the system be designed to meet minimum reserve levels and to operate securely and reliably in the face of 10% PoE demand events;
- whether failure of the system to meet either of the above expectations is best addressed through either:
    - systemic intervention via procurement of standing reserve; or
    - review of the reliability settings that would modify investment signals to the market; and

- how often a standing reserve is likely to be deployed to meet reserve shortfalls attributable to reliability (as opposed to security) events.

5.3.2. Proposal

It is too late now to deal with the reserve shortfalls identified for Victoria and South Australia in summer 2009-10 via anything other than the existing RERT mechanism or a new mechanism that facilitates response to a reserve shortfall that emerges sometime within a few weeks of dispatch. Assuming there are no practical market based mechanisms that could be effectively developed, the intervention mechanisms discussed below could, potentially, help address reserve shortfalls that may occur in summer 2010-11 or later.

Short-notice reserve has potential net benefit

There is a case for pursuing an short-notice reserve mechanism operated by NEMMCO that facilitates a targeted response to mitigating potential involuntary load shedding following a market failure (or event) that becomes apparent in the few weeks or days prior to dispatch. If implemented, the short-notice reserve mechanism should ensure appropriate due diligence assessment of availability of prospectively contracted facilities and optimum portfolio value, but expressly exclude payment for availability. Once NEMMCO agrees to pay for a firm option to include the relevant facility in the optimal portfolio of intervention measures, further payment may then be made as appropriate on the completion of necessary actions up to and including the time of physical dispatch.

Such a proposal takes account of, and is consistent with, options being pursued by the Reliability Panel to modify the existing RERT mechanism. Given the accelerated timetable in which the modifications to the RERT mechanism are being pursued, this option represents the best chance of having some form of additional reserve facility available for the coming summer.

However, it is noted that the RERT mechanism in the NER is subject to sunset provisions, yet the ability to call on some form of short-notice reserve is likely to have on-going value – there seems to be no question that the ability for NEMMCO to direct plant in certain circumstances is a valuable feature of the existing market framework. Accordingly, it is proposed that consideration be given to eventually migrating the short-notice reserve capability from the RERT mechanism to the directions mechanism. The most significant challenge in such a migration would be resolving the differences with respect to RERT being a “value-based” remuneration mechanism and directions being a “cost-based” remuneration mechanism. The fact that the RERT mechanism has a sunset of June 2012 provides a window for addressing these challenges prior to finalising a design for ongoing incorporation of Directable Reserve within the existing directions mechanism.

Prolonged targeted reserve may provide value under certain conditions

Advice to the AEMC suggests the lead time for commitment of new OCGT peaking generation plant is currently 22 months, in which case there could be legitimate concern about reserve shortfalls that become apparent 12 months or more ahead of dispatch. Accordingly, a prolonged targeted reserve may have value where there is identification of:

a) inappropriate settings for market parameters that have created systemic under-investment in capacity;

b) uncertainty over future policy settings that have delayed decisions to invest in energy infrastructure; or

c) technical failure of major energy supply infrastructure (or other force majeure events) with consequences extending more than a year.

In these circumstances failure is at the policy level (or higher) and, arguably, responsibility for the decision to correct for such failure lies with policy makers rather than NEMMCO. Even with appropriate long term responses the reserve shortfall may still persist in the short term. The appropriate short term response may be invocation of a facility that allows procurement of prolonged targeted reserve subject to policy makers declaring, on advice from NEMMCO:

1. there has been failure to deliver adequate levels of reserve due to the circumstances outlined in paragraphs a), b) or c) above;[45] and

2. anticipated reserve shortfall is highly likely to persist into dispatch time frames following:

    (i) re-examination of relevant up-to-date information (e.g. new demand forecasts that become available in June of each year) that either: confirm the extent of the forecast reserve shortfall; or revise the forecast reserve shortfall; and

    (ii) assessment that the market is unlikely to be able to respond to emerging contract risks by recruiting sufficient alternative sources of energy at prices at or below the market price cap; and

3. the reserve shortfall is of a magnitude that the RERT mechanism is unlikely to cope with; and

4. there is an expectation that, if load shedding were to occur to the extent forecast, the reliability standard would be breached.[46]

It is acknowledged that these tests place the threshold for invocation very high, but appropriately so. The tests ensure that any extraordinary reserve shortfall caused by factors outside an efficiently functioning market is subject to consideration at the policy level prior to

45 Or for similar reasons.

46 Supported by targeted modelling conducted by NEMMCO.

pre-emptive intervention taking place, rather than leaving a decision to invoke a prolonged targeted reserve mechanism to the discretion of NEMMCO.[47]

If invoked, a prolonged targeted reserve mechanism should have a clearly defined window for execution – say, between 21 and 15 months ahead of dispatch – to allow time between it and possible contracting under the RERT when the extent of market response to the newly contracted reserve can be assessed.

If a mechanism such as this was ever invoked some level of market distortion is inevitable. Arguably, the presence of such a mechanism, even if it was never invoked, may create some market distortion. Accordingly, a decision as to whether or not this option should be pursued is a matter of judgement. The option is presented for the sake of completeness as a targeted means of addressing concerns about reliability in Victoria and South Australia over the next three or so summers or the possibility of technical failure of substantive generation plant.

Standing reserve is not warranted

Standing reserve is not likely to represent value for money in avoiding lost load.

The key problem with a standing reserve arrangement, whereby a set amount of additional capacity is procured for each market region, is that reserve is not targeted and would be procured regardless of whether market failure is likely to occur. Decisions to invest in standing reserve capacity would be made years ahead of dispatch and prior to all relevant information with respect to market risks becoming known.

The factors contributing to inefficient outcomes are that, with the benefit of hindsight, for some or all of those years either: too little reserve was procured; too much reserve was procured; the reserve was of the wrong type; or reserve was in the wrong place. Standing reserve could not be effectively used sufficiently often in order for the investment in the reserve to be considered worthwhile.

Involuntary load shedding and VoLL pricing occurs as a result of either reliability related events, or security related events:

- Reliability (region-wide supply-demand) related events occur where either:

  a) regional demand exceeds 10% PoE levels; or

  b) regional demand is below 10% PoE levels but there is sufficient unanticipated restriction on generation or interconnector availability.

[47] Although reserve shortfalls have been flagged for Victoria and South Australia for the summer 2010-11, it is a matter of judgement as to whether this represents a failure sufficient to warrant invocation of a prolonged targeted reserve. Previous reserve trading exercises have proved the capability to bring forward reserves in excess of 300MW with only six months notice. Given the shortfall currently flagged for 2009-10 is between 250MW and 300MW it is arguable that, if the shortfall persists at this level, then RERT may be able to adequately deal with the issue.

By definition, events in category a) are expected to occur once in every ten years. Historically, events in category b) have occurred only three times in the past 10 years. If reliability settings and NEMMCO's operationalisation of the reliability standard is appropriate, over the long term unserved energy arising from these events should approach, but not exceed, 0.002%.

- Security related events occur two or three times a year as a result of (for example) intra-regional network failures that create involuntary load shedding and VoLL pricing.

If standing reserve were to be procured for deployment where involuntary load shedding and VoLL pricing were the only alternative to maintaining power system security, the reserve would inevitably be used to manage both reliability and security events. If reliability settings were maintained in a manner consistent with current objectives[48] and standing reserve was implemented, on the basis of expectations and experience, the outcomes are likely to be as follows:

- deployment of standing reserve for reliability related events would occur around three or four times over a ten year period;
- deployment of standing reserve for security related events would be desirable two or three times a year but there is no guarantee that reserve would be in the right location or of the right size to mitigate the effects of such an event;
- system reliability performance would be better than that required by the reliability standard;[49]
- given the number of times reserve would be effectively deployed, the avoided value of lost load would fall short of matching the long term cost of standing reserve.[50]

In the view of Newport Economics, the above represents sufficient reason not to implement a standing reserve.

If the operation of the power system and the market has maximum transparency, and reliability parameters such as the market price cap are set appropriately, there is little reason to believe

[48] Such that, in the absence of standing reserve, over the long term unserved energy arising from such events should approach, but not exceed, 0.002%.

[49] The only way to achieve a system reliability performance closer to 0.002% unserved energy where standing reserve was available would be to modify reliability settings (e.g. to reduce VoLL below where it should otherwise be).

[50] If the costs and volumes of standing reserve outlined in Box 4 were indicative of actual, over a ten year period expenditure on standing reserve for the mainland NEM would be $500 million. Although the MWhs of lost load that could have been avoided due to reliability related events can be calculated with reasonable accuracy – and a value applied to those MWhs – it is difficult to be clear about the MWhs of lost load that could have been avoided due to security related events because of the possibility that procured reserve was in the wrong place to be effective.

the AEMC[51] is in a better position than participants to determine the most appropriate mechanisms by which to manage market risks. On balance, a standing reserve arrangement is not considered to be an efficient, effective or necessary means to mitigate the effects of potential involuntary load shedding. Should there be a concern that an unacceptable level of unserved energy would arise from either or both of reliability and security related events, the correct response would be to adjust market settings (e.g. the level of the market price cap) to provide the market with the signals and incentives to manage emerging risks in a targeted and cost-effective manner.

[51] Or any other body that may be charged with the responsibility to determine the “right” amount of reserve to procure.

APPENDIX A: GAMING AND THE RERT

If long term investment signals and market outcomes are not to be skewed (or only minimally skewed) through invoking the RERT, care needs to be taken that contracted energy reserve would not otherwise have been offered to the energy market. Minimal distortion to the energy market will occur subject to NEMMCO being able to take effective action to allow it to be satisfied that the reserve to be contracted is not available to the market through any other arrangement.[52]

Ideally, all capacity that can be economically deployed within the energy market does actually participate in the energy market via either NEMMCO scheduling processes or self-dispatch in response to emerging market signals – market signals could be the spot price or contract with an NSP to manage network congestion. If remuneration of capacity to respond to such signals is sufficient to pay the opportunity costs of preparation for and actual deployment of the capacity, then participation in the energy market by demand-side capacity is the efficient outcome. It is only where energy market remuneration is not sufficient to cover opportunity costs, that deployment of capacity via an intervention mechanism is an economically efficient use of capacity.

While there is no evidence that formal intervention mechanisms have been subject to gaming in the past, the risk does exist, especially if the RERT process is to be used more often and for more MWs. Gaming could take the form of withdrawing energy or demand-side capability from the market (or under-reporting actual DSP) and subsequently re-offering it to the RERT mechanism where the remuneration may be higher than in the energy market. Such an outcome can be shown to create additional costs in the market.

With a choice of participating in either the energy market or intervention mechanisms, rational behaviour on the part of managers of existing energy capacity would be to chose the mode of participation with the highest expected revenue. As the probability of invoking the RERT mechanism rises, so to will the expected revenue from participating in the RERT and the relative attractiveness of withdrawing capacity from the energy market in favour of the RERT. This contrasts with the scenario described in Section 2.2 where the rising value of the energy market encourages demand-side capacity to enter the energy market, potentially at the expense of availability to intervention mechanisms.

Figure 5 shows the interaction of demand and supply for a peak demand dispatch interval where the horizontal portion of the demand curve reflects the availability within the energy market of a volume of DSP at price P_0 somewhere below the market price cap. At the market

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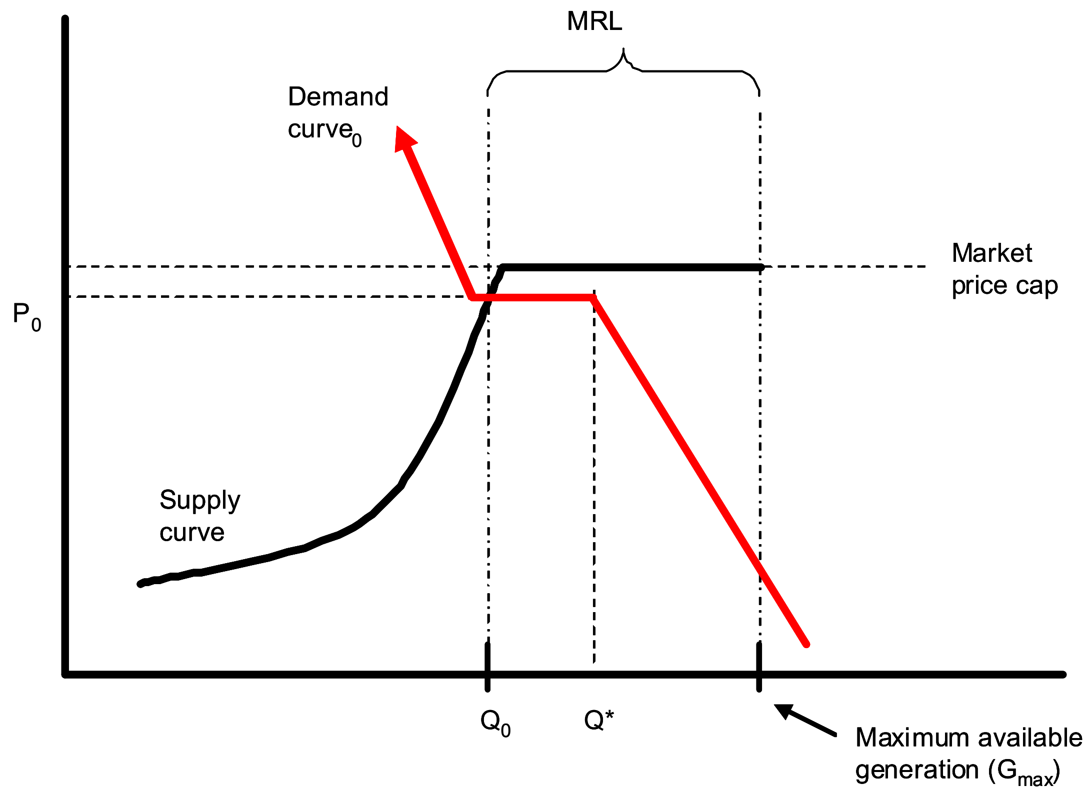
52 In accordance with AEMC 2008, *RERT Guidelines*, Final Report, 24 November 2008, Sydney. See also Section 5.2.2. Examples of market uses that would make demand-side capacity ineligible for participation in the RERT include: capacity within contracts for a DSP option made available for a retailer to exercise under specific market conditions; a load that is actively managed to control energy cost exposure through either a (partial) spot price pass through contract with a retailer or as a market Customer; or capacity that is contracted to an NSP to manage network congestion.

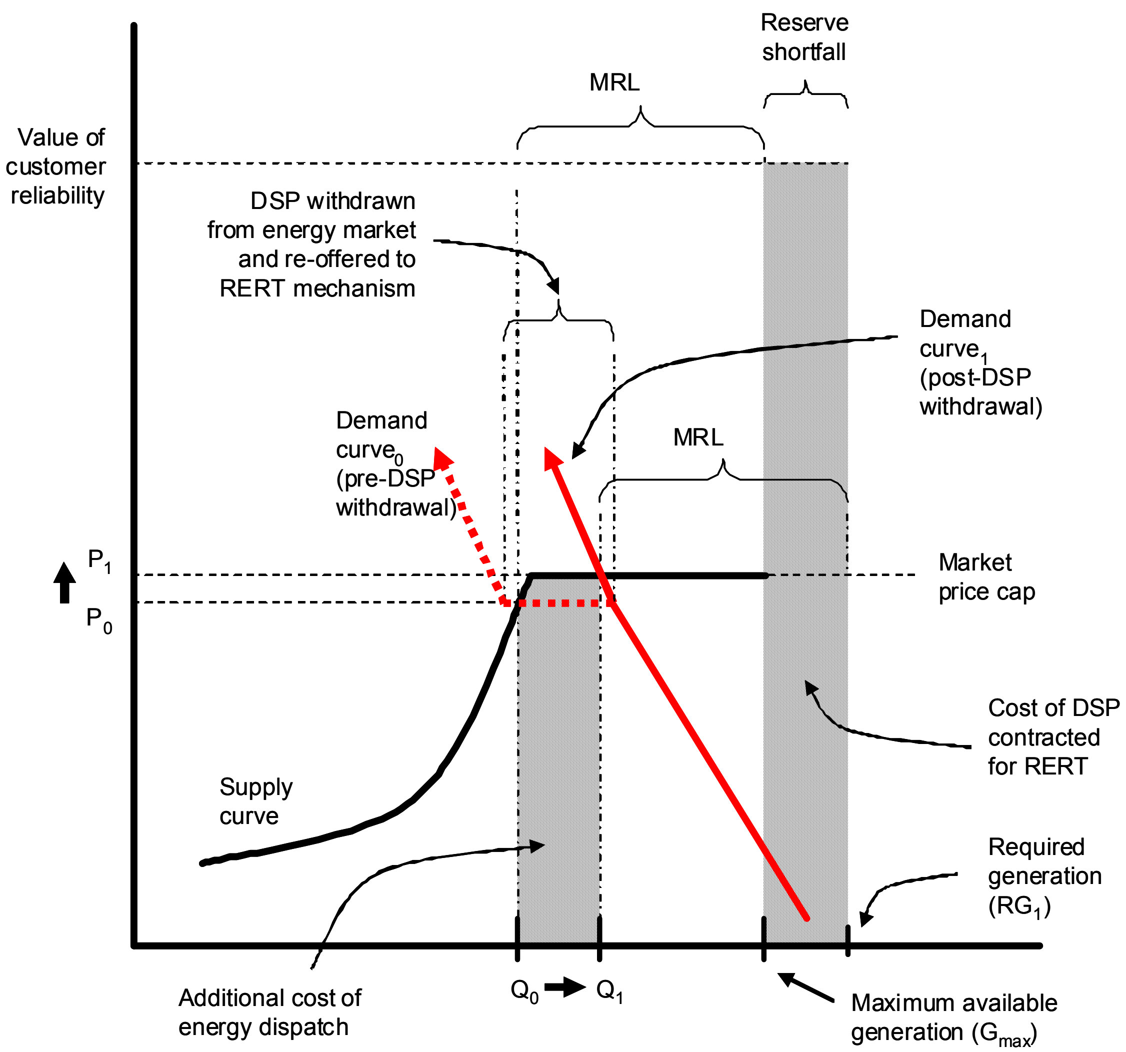
clearing price (P_0) and quanity (Q_0) an amount of DSP would be deployed ($Q^* – Q_0$) to ensure there is adequate additional generation available to meet the minimum reserve level ($MRL = G_{max} – Q_0$). In this scenario required generation matches available generation and the power system meets reliability requirements.

Figure 5: DSP role in delivering adequate reliability



If the probability of invoking the RERT were to rise sufficiently, a manager of DSP capability might be tempted to withdraw the capability from the energy market and instead offer the same capability to the RERT mechanism in the expectation of being remunerated at a price reflecting the jurisdictional value of customer reliability – see Figure 6. If all previously offered DSP was withdrawn from the energy market, the generation supply curve might be unaffected but part of the demand curve would shift outwards from demand curve$_0$ to demand curve$_1$ and the market clearing price and quantity would shift to P_1 Q_1. The maximum generation available (G_{max}) is unchanged but there is an increase in both generation dispatched (Q_1) and required generation (RG_1). With the same MRL, a reserve shortfall ($RG_1 – G_{max}$) is now apparent that would need to be corrected by invoking the RERT mechanism. Compared to the scenario where the DSP capacity was offered to the energy market, this alternative scenario has a higher cost of generation dispatched equal to the shaded area to the left in Figure 6, and additional costs of the RERT mechanism equal to the shaded area to the right in Figure 6.

Figure 6: Economic consequences of withdrawing DSP from the energy market



Although arrangements could be developed to minimise gaming of this nature (e.g. by requiring the formal registration of all demand-side capability), effective measures may run the risk that the cure is worse than the disease. On balance, additional arrangements of that nature are not considered necessary because, in the normal course of the market, RERT would be exercised infrequently and for small amounts, thus making it difficult for demand-side providers to rely on RERT as a form of income that makes gaming a viable strategy. Also, there are countervailing incentives to shift capacity to the energy market away from possible opportunistic availability to intervention mechanisms.