Australian Energy Market Commission

INTERIM REPORT

Reliability Frameworks Review

19 December 2017

REVIEW

Submissions due 6 February 2018. Reference: EPR0060
Interim Report

Inquiries

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AEMC 2017, Reliability Frameworks Review, Interim Report, 19 December 2017, Sydney

About the AEMC

The AEMC reports to the Council of Australian Governments (COAG) through the COAG Energy Council. We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the COAG Energy Council.

Executive summary

The Australian Energy Market Commission (AEMC) is undertaking a Review into the market and regulatory frameworks necessary to support the reliability of the electricity system in the National Energy Market (NEM). This interim report provides an update on the Commission's analysis and views to date. This Review includes consideration of several recommendations from the *Independent Review into the Future Security of the National Electricity Market* (Finkel Panel review) that relate to reliability.

What is reliability?

Reliability means having an adequate amount of capacity (both generation and demand response) to meet consumer needs. This involves longer-term considerations such as having the right amount of investment, as well as shorter-term considerations such as making appropriate operational decisions, to make sure an adequate supply is available at a particular point in time to meet demand. To deliver a reliable supply, the level of supply needs to include a buffer, known as reserves, so that supply is greater than expected demand. This allows demand and supply to balance, even in the face of unexpected changes.

Reliability is delivered in the NEM through efficient investment, retirement and operational decisions that are underpinned by various market structures. This is why the reliability framework in the NEM is referred to as being primarily market-based. The framework is however supplemented by a series of mechanisms that allow the system operator to intervene in the market in specific circumstances.

The design of the framework to deliver reliability in the NEM has been a deliberate one. Market-based solutions provide incentives to be innovative, benefiting consumers. This is because competitive pressures drive more cost-effective and efficient investment, operational and consumption decisions. Centrally-planned or mandated solutions can provide higher levels of certainty of having a reliable supply of energy but, compared to a well-functioning market, are unlikely to deliver an efficient level of reliability at efficient cost. Unlike market participants, central planners do not have the same financial incentives to make efficient decisions and do not have to bear the risk of poor decisions, and so their incentives are often to over-invest.

A reliable supply to consumers also requires a secure power system and reliable networks. This Review does not address security (that is, the technical performance of the power system itself) or network reliability as they are addressed through different frameworks. In particular, the Commission is considering system security issues through its *System security work program*.[1]

1 See http://www.aemc.gov.au/Major-Pages/AEMC-work-overview/System-security-review.

What is the context for this Review?

In the past decade the NEM has experienced high levels of reliability; however, over the past eighteen months a series of events (such as the load shedding in South Australia and NSW in February 2017), as well as numerous policy debates (for example, the Energy Security Board advice on the National Energy Guarantee (the Guarantee)) have led to a greater focus on reliability in the NEM.

Further, Australia's energy system is undergoing a revolution - driven by changing consumer choices and rapidly evolving technology. Various policy settings - including the lack of an emissions reduction mechanism that is integrated with the energy market - are having a profound influence on investment, operational and consumption decisions. This, combined with the considerable attention on reliability in recent times from both the mainstream media and various policy makers, is exacting pressure on the existing reliability framework.

One of the core objectives of this Review is therefore to provide a more holistic look at the reliability framework, with a view to proposing a coherent package for the future. Part of this task will necessarily involve 'stepping back' and examining the current arrangements and the various changes that have been proposed already, and then considering the detailed design of reforms that are likely to provide balanced solutions that will address the needs of the evolving system. These considerations and coordination of the various aspects of the reliability framework - including how this may interact with the National Energy Guarantee - will be considered further as this Review progresses.

What are the Commission's preliminary views?

The interim report assesses the following areas of the reliability framework, highlights issued raised by stakeholders and discusses the Commission's preliminary views in relation to the following areas:

- **Key concepts of dispatchability and flexibility:** Dispatchability and flexibility can be considered to already be valued and rewarded in the existing contract, spot and ancillary services markets, with these markets doing this in a way that reflects the inherent variabilities in these characteristics. For example, more flexible generating units are able to respond quickly to high prices in the market, and so get rewarded by earning higher revenues. However, we need to further consider whether the existing signals are "accurate" or "precise" enough. Conclusions on this question will lead to a better understanding of how definitions of 'dispatchability' and 'flexibility' could be created.

- **Forecasting and information processes**: Forecasts and information provision to the market are the foundation of the reliability framework. Australian Energy Market Operator (AEMO) is, and is committed to, improving its forecasting. However, as the electricity system evolves it is likely that there could be increased errors in forecasting. For example, a higher penetration of variable renewable generation, combined with more extreme weather days, will make it harder to forecast output from these resources. Increased variances may result in increased risks for participants (for example, knowing when to be available or to rebid), as well as making it more difficult for AEMO to manage reserves on tight demand-supply days. It will likely be worthwhile to explore whether there are ways these variances can be better managed through the forecasting process; or alternatively, whether there are ways to rely less on forecasts. Any changes to the existing processes should seek to make sure that incentives are created for variances to be minimised over time.

- **Market-based aspect of reliability, that is, the contract market:** Reliable supply in the NEM is supported by the inherent and symmetrical incentive for buyers and sellers to enter into contracts to have more certainty over costs and revenue over time. Alternatively, participants can invest in both retail and generation assets (vertical integration) to manage their risks. Contract markets not only smooth cash flows of market participants to manage their risk, but support reliability by informing participant investment and operational decisions. It is not evident that the level of trading in the contract market should be cause for concern. However, information on the contract market is not widely available. Such information is important for good investment and operational decisions, which is why the Commission is pleased the Australian Financial Markets Association is restarting its survey of the turnover of over-the-counter contracts.

- The following Finkel Panel recommendations:

  - **Strategic reserve:** Some form of a safety net, such as a limited and targeted ability for a system operator to pay a premium for capacity that is not otherwise being traded in the market, is appropriate in the event that the market is expected to fail to meet the reliability standard. Given the costs that can be associated with such safety nets, it is important to understand what the existing limitations are with the current safety net in the NEM, the Reliability and Emergency Reserve Trader (RERT), before a balanced solution to these limitations can be developed and assessed to make sure it is in the long-term interests of consumers.

  - **Wholesale demand response:** Demand response refers to participants, specifically loads, changing their level of consumption in response to signals to do so. It is hard to determine how much demand response there is in the NEM available at a value below the market price cap, due to it not being highly visible. If there is wholesale demand response that is currently being underutilised, then there are opportunities for new and existing parties to capture this value. But, it can be difficult for third parties to capture the value associated with wholesale demand response under the current framework, for example, where each customer can only have one party responsible for its consumption at its meter. The Commission is considering how best we can address such issues.

— **Day-ahead markets:** The NEM, despite not having a formalised day-ahead market, has many features that play a similar role to that of a day-ahead market e.g. pre-dispatch supported by a liquid financial derivatives market. In terms of an issue that a day-ahead market could address in the NEM, we consider that this has not yet been fully demonstrated. Identifying the problem, and the materiality of it, is crucial in order to work out what the best solution is to the issue. When looking at international examples of day-ahead markets, those found in US jurisdictions require the introduction of complementary reforms (such as nodal pricing and firm transmission rights) in order to achieve the intended outcome. Reforms of this nature take a considerable amount of time and resources to implement, and there may be more immediate actions that could be done to assist in the NEM.

How can you engage with us, and what are the next steps?

Submissions to this interim report are due on **6 February 2018**, with this date set based on the need to meet the COAG Energy Council's timeframes for its implementation plan for the *Independent Review into the Future Security of the National Electricity Market*.

We are conscious that this consultation period includes the holiday period, and so we encourage stakeholders to meet with us - please contact Sarah-Jane Derby on 02 8296 7823 or sarah.derby@aemc.gov.au.

Stakeholders will also have an opportunity to comment on a directions paper which is due in March. The final report including recommended actions will be published in mid-2018.

Contents

1 Introduction

On 11 July 2017, the Australian Energy Market Commission (AEMC or Commission) initiated a Review into the market and regulatory frameworks necessary to support the reliability of the electricity system.[2] The Commission published an issues paper on 22 August 2017. This interim report provides an update on the Commission's analysis and views to date. This Review includes consideration of several recommendations from the *Independent Review into the Future Security of the National Electricity Market* (Finkel Panel review) that relate to reliability.

1.1 Purpose of the Review

Over the past eighteen months, a number of events have led to a greater focus on reliability in the National Electricity Market (NEM):

- load shedding events on low reserve[3] days
- pre-emptive action and announcements from jurisdictional governments
- recommendations made by the Finkel Panel in the *Independent Review into the Future Security of the National Electricity Market* in March 2017
- Australian Energy Market Operator's (AEMO) Energy Supply Outlook, which noted the risk of electricity supply falling short of demand especially in extreme conditions.[4]

In initiating the Review in July 2017, the Commission considered that it is timely to assess whether the current market and regulatory reliability frameworks are appropriate given the above developments, as well as other current drivers of change that affect reliability. These others drivers of change include a changing generation mix with an increased penetration of variable renewable generation, batteries and distributed energy resources; as well as greater opportunities for demand-side participation.

Since the issues paper was published, reliability has continued to be at the forefront of policy debate. In September 2017, AEMO provided advice to the Commonwealth Government on dispatchable capability in the NEM, in which it highlighted its concerns about reliability, as the transition from traditional generation to variable renewable generation continues.[5] In October 2017, the Commonwealth Government

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2 The Review was initiated by the AEMC under section 45 of the National Electricity Law (NEL). The regulatory framework refers to the National Electricity Rules and the National Electricity Law.

3 Reserve levels are a key concept, and can broadly considered to be the balance of supply over demand in the market. These are discussed further in section 3.3.

4 AEMO, Energy Supply Outlook, June 2017, p. 3.

5 AEMO, Advice to Commonwealth Government on Dispatchable Capability, September 2017, p.1.

announced a National Energy Guarantee (the Guarantee), proposed by the Energy Security Board (ESB), which would require retailers to:[6]

- contract with or invest in generators or demand response to meet a minimum level of dispatchable on demand electricity and
- keep their emissions below an agreed level.

In November 2017, the COAG Energy Council agreed to the continued development of the design of the Guarantee.

In addition, state and Commonwealth governments are progressing with new generation and storage projects such as the 100 MW South Australian battery[7], the Queensland Government's 400 MW large-scale renewable energy reverse auction with 100 MW storage[8], and the proposed Snowy Hydro 2.0.[9]

The final report of the Review will provide recommendations to the COAG Energy Council on changes required to the regulatory and market frameworks to make sure that the existing high performance relating to reliability in the NEM continues to occur, as the electricity system transforms.

1.2 Purpose of the interim report

This interim report has been prepared to facilitate further consultation and feedback on a number of workstreams that were identified in the issues paper.

It provides an update on the Commission's progress to date, and discusses some of the Commission's preliminary analysis and views. It also provides an opportunity for stakeholders to provide input to this Review, ahead of the directions paper being published in March 2018.

1.3 Project scope

This Review is undertaking a holistic review of the existing reliability framework. This framework includes both longer-term aspects such as having the right amount of investment and retirement, as well as shorter-term operational aspects such as making sure an adequate supply is available at a particular point in time; all while balancing the cost of any likely intervention measures.

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6 See: http://www.coagenergycouncil.gov.au/publications/energy-security-board-update

7 Government of South Australia, Battery storage and renewable technology fund, accessed at http://ourenergyplan.sa.gov.au/battery.html, 24 October 2017.

8 Queensland Government, Renewables 400, accessed at: https://ww.dews.qld.gov.au/electricity/powering-queensland-plan/transition/renewables-400, 12 October 2017.

9 SnowyHydro, Snowy 2.0, accessed at: http://www.snowyhydro.com.au/our-scheme/snowy20, 24 October 2017.

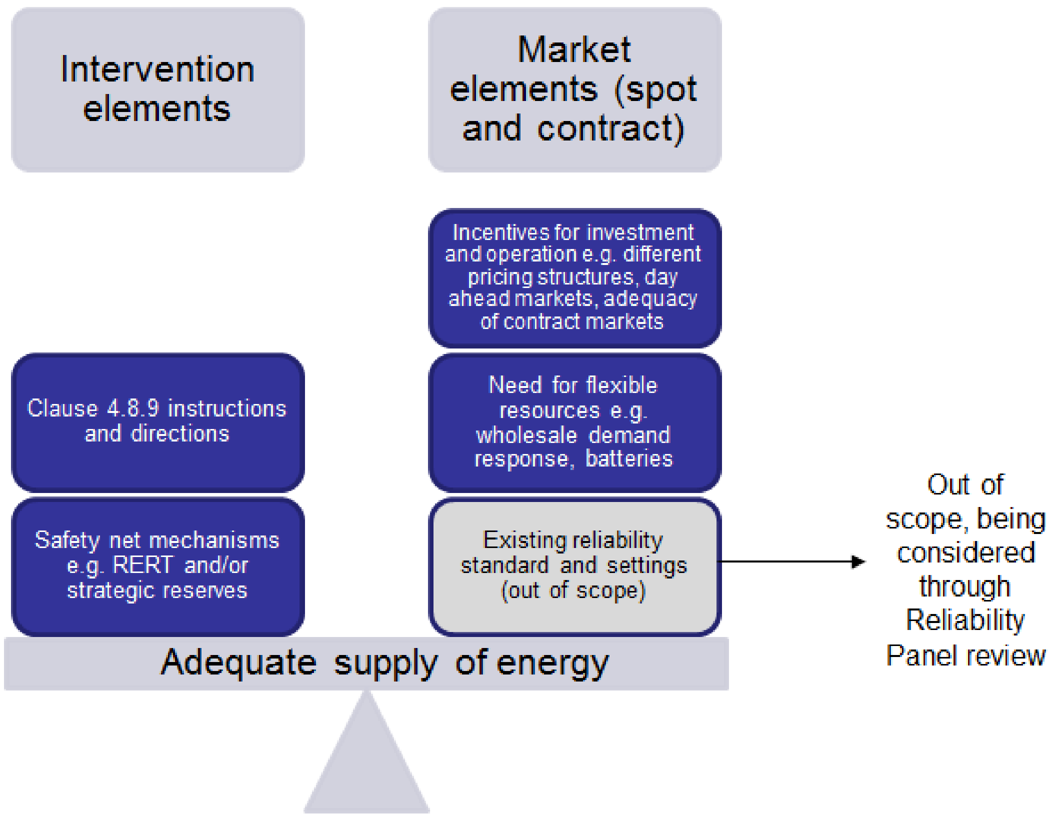
The Review is focussed on both the *supply-side* (generation) and the *demand-side* (demand response).

The reliability of transmission and distribution networks is outside of the scope of this Review.[10]

The *existing* reliability standard and settings are also outside of the scope of this Review since they are being considered in the Reliability Panel's *Reliability standard and settings review*, for which a draft determination was recently published and is discussed below.[11]

The scope of the Review is shown in Figure 1.1.

Figure 1.1 Scope of the Review



10 Each state and territory government retains control over how transmission and distribution reliability is regulated and the level of reliability that must be provided.

11 See: http://www.aemc.gov.au/Markets-Reviews-Advice/Reliability-Standard-and-Settings-Review-2018.

The Review also incorporates existing work or recommendations that relate to reliability, including recommendations from the Finkel Panel that are within the scope of the Review, such as:[12]

- the recommendation of a generator reliability obligation[13]
- assessing the need for a strategic reserve to act as a safety net in exceptional circumstances as an enhancement or replacement to the existing reliability and emergency reserve trader (RERT) mechanism
- assessing the suitability of a day-ahead market
- the recommendation of a mechanism that facilitates efficient demand response in the wholesale energy market.

These are four of the 49 recommendations from the Finkel Panel review that the COAG Energy Council has agreed to implement. The inclusion of these recommendations in this Review also takes into account the timeframes that the COAG Energy Council agreed to for the implementation of these recommendations.[14] The COAG Energy Council agreed that a strategic reserve and the RERT mechanism will also be considered as part of the AEMC's *Reliability Frameworks Review*, with the AEMC and AEMO continuing to work closely together on their reliability work programs.[15]

The Review also takes into account any relevant AEMO workstreams, including lessons from existing initiatives such as the demand response pilot program[16] being trialled by Australian Renewable Energy Agency (ARENA) and AEMO, and any other trials that ARENA and AEMO may undertake through their memorandum of understanding that are relevant to reliability.

Reliability (referring to having enough generation, demand response and network capacity to supply consumers) is different to security, which refers to being able to operate the system within defined technical limits, even if there is an incident such as the loss of a major transmission line or large generator. Therefore, security aspects,

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12 The Commission also notes that one of the other recommendations was a requirement for all large generators to provide at least three years' notice prior to closure. AEMO should also maintain and publish a register of long-term expected closure dates for large generators. The Commission notes that this recommendation is, in part, related to information requirements about reliability, and so will also consider this recommendation to the extent it has not otherwise been further progressed or implemented in other workstreams.

13 This consideration of this is discussed further in section 1.4.

14 On 25 August 2017, the COAG Energy Council wrote to COAG setting out an implementation plan for the *Independent Review into the Future Security of the National Electricity Market.*

15 See http://www.coagenergycouncil.gov.au/council-priorities/security-sustainability-and-stability-national-electricity-market and AEMC, *2017 Energy sector strategic priorities - detailed goals and initiatives*, accessed from http://www.aemc.gov.au/Markets-Reviews-Advice/2017-Energy-sector-strategic-priorities.

16 The initiative is a three-year pilot program seeking to provide 160 MW of reserve capacity through demand response. The trial is discussed further in appendix E.

including technical parameters such as voltage and frequency are outside the scope of this review.

The Commission has an extensive system security work program, which is discussed in Box 1.1.

Box 1.1 System security work program

The Commission's system security work program is focussed around finding new ways to provide inertia, respond to extreme frequency changes, and address issues around system strength.

Our power system security report,[17] published in June 2017, sets out a package of reforms to guard against technical failures that lead to cascading blackouts, and to deliver a more stable and secure power supply to Australian homes and businesses. This includes a number of new rules to deliver a stronger, more stable power system:

- In March 2017 we made a final rule to help protect the power system from emergencies through a new management framework for emergency frequency control schemes. These are ‘last line of defence’ mechanisms such as controlled load shedding, designed to protect against a major blackout if a sudden and unexpected loss of generation or load causes rapid changes in system frequency. The new rules require AEMO to regularly and transparently assess emerging risks caused by swapping out older synchronous generators, for non-synchronous generation technology like wind and solar.[18]
- In September 2017 we made final rules to:
  - manage the rate of change of power system frequency – enabling better frequency control by making networks provide minimum levels of inertia and, with AEMO approval, enabling networks to contract with suppliers to provide inertia substitutes[19]
  - manage power system fault levels – keeping the system stable by making networks provide minimum levels of system strength at key locations, and requiring new generators to pay for remedial action if they impact system stability[20]

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17 AEMC, System Security Market Frameworks Review, Final Report, 27 June 2017.

18 AEMC, National Electricity Amendment (Emergency frequency control schemes) Rule 2017, Rule Determination, 30 March 2017.

19 AEMC, National Electricity Amendment (Managing the rate of change of power system frequency) Rule 2017, 19 September 2017.

20 AEMC, National Electricity Amendment (Managing power system fault levels) Rule 2017, 19 September 2017.

— improve guidelines for generating system models – requiring generators and networks to provide more detailed information about how their equipment performs so AEMO and networks have the right data to efficiently plan and operate the system.[21]

Also in September 2017 we published a consultation paper on a proposal for new technical performance standards for connecting generators.[22] The rule change proponent, AEMO, considers that tighter generator technical standards are needed to help keep the system secure in the future as the changing generation mix makes the system weaker in some locations.

Finally, our *Frequency control frameworks review* is also underway, which is looking at ways to integrate new technologies and demand response to help keep the system secure.[23] A progress report was published on 19 December 2017. This review includes the consideration of the appropriate design of an inertia market mechanism, which is also the scope of a rule change request from AGL.[24]

1.4 Scope of the interim report

The interim report assesses the following areas of the reliability framework, highlights issues raised by stakeholders and discusses the Commission's preliminary views on the following matters in order to seek stakeholder feedback:

- key concepts underpinning the reliability frameworks, such as dispatchability and flexibility
- forecasting and information processes that are at the foundation of the reliability framework
- the market-based aspect of reliability, that is, the contract market and its incentives for investment and operational decisions
- Finkel Panel recommendations, namely:
  - assessing the need for strategic reserves
  - developing a mechanism for wholesale demand response
  - assessing the suitability of day-ahead markets.

21 AEMC, National Electricity Amendment (Generating System Model Guidelines) Rule 2017, 19 September 2017.

22 See: http://www.aemc.gov.au/News-Center/What-s-New/Announcements/Consultation-starts-on-proposal-for-new-technical

23 See: http://www.aemc.gov.au/News-Center/What-s-New/Announcements/Review-of-market-frameworks-for-better-frequency-c

24 See: http://www.aemc.gov.au/Rule-Changes/Inertia-Ancillary-Service-Market#

There are a number of other aspects of the reliability framework that are important in both the Commission and stakeholders minds, but which are not considered in this interim report. These aspects include: interventions (specifically, directions and clause 4.8.9 instructions), information provision, as well as how the regulatory investment test for transmission operates in respect of interconnectors. These aspects are not considered at this time because the Commission considers that more significant, threshold questions relating to the reliability frameworks need to be resolved first, before these other aspects can be considered.

The Finkel Panel recommendation of a generator reliability obligation is within the scope of the Review. However, following the Energy Security Board's advice on a National Energy Guarantee, the Commission has decided to, for the moment, put on hold any analysis regarding a generator reliability obligation. This is because the reliability component of the Guarantee aims to achieve similar outcomes to what a generator reliability obligation would. Once a COAG Energy Council decision is made on the Guarantee in 2018, the Commission will then decide how best to proceed in relation to the generator reliability obligation.

1.5 Related work

This Review forms part of a broader reliability work program being undertaken by the AEMC as discussed in this section. This section also discusses related Reliability Panel, Energy Security Board and AEMO work programs.

1.5.1 The *Reliability Standard and Settings* review

The Reliability Panel's work supports the national electricity system, and is comprised of members who represent a range of participants in the NEM, including AEMO, generators, network businesses, consumers and large end users. The Panel's core functions relate to the safety, security and reliability of the national electricity system.[25] The National Electricity Law sets out the key responsibilities of the Panel. These include:

- to monitor, review and report on the safety, security and reliability of the national electricity system and
- at the request of the AEMC, to provide advice in relation to the safety, security and reliability of the national electricity system.

The Panel’s work program is largely driven by specific requirements set out in the National Electricity Rules (NER). Generally, the focus of the Panel’s work is on determining standards and guidelines which are part of the framework for maintaining a secure and reliable power system.

25 For further information, see: http://www.aemc.gov.au/About-Us/Panels-committees/Reliability-panel

Every four years, the Panel is required to review the reliability standard and reliability settings. The Panel's current *Reliability standard and settings review*[26] is considering whether the reliability standard and settings remain suitable to guide efficient investment and operational decisions in the power system to meet consumer demand for energy, while protecting market participants from substantial risks that threaten the overall stability and integrity of the market.

On 21 November 2017, the Reliability Panel published a draft report that proposes to leave the reliability standard and settings unchanged for the period 1 July 2020 – 1 July 2024.

The Reliability Panel considers this appropriate as:

- The existing standard and settings are, in its view, still achieving their purpose and are likely to continue to do so out to 2023-24.
- Providing regulatory stability through no changes will benefit consumers and market participants, given the current impact of policy uncertainty on investor confidence, the rapid technological change underway in the NEM, and the absence of sufficient evidence in support of a change to the price settings.
- Matters relevant to other components of the broader market and regulatory frameworks for reliability in the NEM are being considered through other proposals and reviews being progressed by the market bodies.

The AEMC is working closely with the Reliability Panel and the outcomes from that piece of work, where relevant, are informing this Review.

1.5.2 *Declaration of Lack of Reserve conditions* rule change

On 1 August 2017, the AEMC received a rule change request from AEMO related to reliability in the NEM.[27] AEMO considers that the current lack of reserve (LOR) declaration framework, based on the concept of credible contingencies, is no longer appropriate for identifying risks in the power system. It wishes to replace them with a system triggered by a wider range of risks than those presently allowed for.

On 19 December 2017, the Commission made a final rule which reflects the rule proposed by AEMO, but has some amendments to improve the transparency of the new framework, including introducing a more robust consultation process than the one proposed by AEMO and a reporting requirement to support stakeholder education. The final rule removes the deterministic descriptions of lack of reserve from the NER, replacing them with a single high-level description for lack of reserve and so allows the system operator to move to a probabilistic framework. The final rule also places a requirement on AEMO to make guidelines that set out how AEMO will

26 See: http://www.aemc.gov.au/Markets-Reviews-Advice/Reliability-Standard-and-Settings-Review-2018.

27 See: http://www.aemc.gov.au/Rule-Changes/Declaration-of-lack-of-reserve-conditions.

determine lack of reserve conditions, so improving the transparency of the existing framework.

1.5.3 *Coordination of generation and transmission investment* review

The Commission recently commenced Stage 2 of the *Coordination of generation and transmission investment review*.[28] That review is considering what issues are associated with the coordination of generation and investment in the NEM, as well as options to address these. Addressing such issues can be considered to be an "enabler" of reliability outcomes in the NEM. That review is being progressed in coordination with this piece of work. An options paper is expected to be published in February 2018.

1.5.4 Energy Security Board advice on *National Energy Guarantee*

In October 2017, the Energy Security Board provided the COAG Energy Council with advice on a proposed National Energy Guarantee that aims to support the provision of reliable, secure and affordable electricity with a focus on ensuring:[29]

- the reliability of the system is maintained
- electricity sector emissions reductions needed to meet Australia's international commitments are achieved
- the above objectives are met at the lowest overall costs.

According to the Energy Security Board advice, the Guarantee will require retailers to contract with or directly invest in generation, storage or demand response so that:[30]

- there is a minimum amount of dispatchable energy available to meet consumer and system needs (set by the Reliability Panel and AEMO) and
- the average emissions level of the electricity they sell to consumers is in line with Australia's international commitments (set by the Commonwealth Government).

In other words, the Guarantee combines reliability outcomes and emissions targets to achieve a single energy price that guides investment and operation in the lowest cost resources. The guarantee is designed to integrate energy and emissions policy – both energy and emissions targets are reflected in a single energy price. That energy price will signal how much electricity the market needs and when it is needed, while also reflecting the cost of meeting Australia's emissions targets.

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28 See: http://www.aemc.gov.au/Markets-Reviews-Advice/Reporting-on-drivers-of-change-that-impact-transmi.

29 See: http://www.coagenergycouncil.gov.au/publications/energy-security-board-update.

30 Energy Security Board, Overview of Retailer Reliability and Emissions Guarantee, http://www.coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/Energy%20Security%20Board%20Overview%20of%20the%20National%20Energy%20Guarantee.pdf

On 24 November 2017, the COAG Energy Council[31] supported progressing further extensive work on the design, including consultation in early 2018. The COAG Energy Council noted that it will consider the design of the Guarantee following work undertaken by the Energy Security Board in 2018 and that the Energy Security Board will consult with stakeholders through this process.[32]

1.5.5 AEMO's related work

In September 2017, AEMO provided advice to the Commonwealth Government on dispatchable capability in the NEM.[33] AEMO noted that the NEM is not delivering enough investment in flexible dispatchable resources to maintain the defined target level of supply reliability, as it transitions from traditional generation to variable renewable generation proceeds.[34] AEMO noted the fact that it is pursuing around 1,000 MW of strategic reserves in its summer readiness plan.

AEMO recommended replacing the current RERT mechanism with a "strategic reserve" in the short-term, and in the long-term recommended developing another approach to retain and incentivise investment in dispatchable capability in the NEM.[35] AEMO stated that those mechanisms are required to ensure there is sufficient flexible dispatchable generation in the NEM to preserve supply reliability through the next decade of transition.[36]

Also in September 2017, AEMO announced the creation of an Expert Advisory Panel, comprised of leaders from across the energy industry to provide support to AEMO in delivering key initiatives and implementing the recently endorsed Finkel Panel recommendations. The expert advisory panel has met twice between September and the end of November and among other issues, have been providing feedback on a high-level design of strategic reserves. This is discussed further in chapter 7.

AEMO has recently been asked by the Commonwealth Government to provide advice on the suitability of the plan put forward by AGL to replace the Liddell Power Station, which follows on from AEMO's dispatchability advice.[37]

31 With the exception of South Australia and the Australian Capital Territory.

32 COAG Energy Council, Meeting Communique, Friday 24 November 2017.

33 AEMO, Advice to Commonwealth Government on Dispatchable Capability, September 2017.

34 Ibid.

35 Ibid.

36 Ibid.

37 The Hon Josh Frydenberg MP, Minister for the Environment and Energy, Experts to advise on best path to deliver affordable and reliable power with Liddell closure, media release, 11 December 2017.

1.6 Stakeholder consultation

1.6.1 Submissions to issues paper

Submissions to the issues paper were due on 19 September 2017. The Commission received 18 submissions from a wide range of stakeholders.[38]

Overall, stakeholders were supportive of the AEMC undertaking this Review and doing so in a balanced and considered way. Stakeholders expressed unanimous support for market-based mechanisms, and stated that interventions should only be used as a last resort. Stakeholders also overwhelming recognised the lack of a clear, consistent and integrated environmental and energy policy as a key aspect affecting reliability. Individual submissions and comments are discussed in each relevant chapter in more detail in this report.

1.6.2 Reference group and technical working group

A Reference Group comprising senior representatives of the AEMC, AEMO, the Reliability Panel, the Australian Energy Regulator (AER), the Senior Committee of Officials (SCO), ARENA, the Clean Energy Regulator (CER) and the Clean Energy Finance Corporation (CEFC) has been established by the AEMC to provide high-level input on related reliability matters. The reference group has met twice (August and November) and input from this group has been incorporated into this report.

The AEMC has also established a technical working group to provide technical advice, and to assist with the development of recommendations for this Review. The group comprises representatives from the market bodies (AEMO and the AER), ARENA, consumer groups, large energy users, conventional generators, renewable generators, retailers, demand response providers, and transmission and distribution network service providers.

The first technical working group meeting was held in November 2017 and focussed on discussion of the Commission's initial views with respect to the contract market, key concepts and demand response. Comments and feedback from the technical working group have been incorporated into this interim report.

1.6.3 Submissions to the interim report

The Commission invites comments from interested parties in response to this interim report by **6 February 2018**, with this date set based on the need to meet the COAG Energy Council's timeframes in its implementation plan for the *Independent Review into the Future Security of the National Electricity Market*. All submissions will be published on the Commission's website, subject to any claims of confidentiality.

38 The submissions can be found on our website.

We are conscious that this consultation period includes the holiday period, and so we encourage stakeholders to meet with us - please contact Sarah-Jane Derby at 02 8296 7823 or sarah.derby@aemc.gov.au.

Electronic submissions must be lodged online via the Commission's website, www.aemc.gov.au, using the "lodge a submission" function and selecting project reference code "EPR0060".

The submission must be on letterhead (if submitted on behalf of an organisation), signed and dated. Upon receipt of the electronic submission, the Commission will issue a confirmation email. If this confirmation email is not received within 3 business days, it is the submitter's responsibility to ensure the submission has been delivered successfully.

If choosing to make submissions by mail, the submission must be on letterhead (if submitted on behalf of an organisation), signed and dated. The submission should be sent by mail to:[39]

Australian Energy Market Commission

PO Box A2449

Sydney South NSW 1235

1.7 Review timeline

The structure of this Review is set out in the Table 1.1 below.

Table 1.1 Review timeline

Item	Date
Publication of issues paper	22 August 2017
Publication of interim report	19 December 2017
Close of submissions to interim report	6 February 2018
Publication of directions paper	March 2018
Publication of final report	June 2018

39 The envelope must be clearly marked with the relevant project reference code, as above. Except in circumstances where the submission has been received electronically, upon receipt of the hardcopy submission the Commission will issue a confirmation letter. If this confirmation letter is not received within 3 business days, it is the submitter's responsibility to ensure successful delivery of the submission has occurred.

1.8 Structure of interim report

The remainder of this report is structured as follows:

- chapter 2 sets out the context for this Review
- chapter 3 discusses the key concepts associated with reliability in the NEM
- chapter 4 examines the forecasting and information processes that underpin reliability
- chapter 5 discusses trends in the contract market
- chapter 6 discusses demand response in the NEM
- chapter 7 assesses the need for strategic reserves
- chapter 8 examines the suitability of day-ahead markets
- appendix A sets out the assessment framework used in this Review
- appendix B examines the theoretical spectrum for the reliability framework
- appendix C discusses operationalising the reliability standard
- appendix D provides a summary of the RERT framework
- appendix E summarises the ARENA-AEMO demand response RERT trial
- appendix F sets out examples of international markets
- appendix G provides a summary of submissions not discussed in the main report.

2 Context

This chapter sets out the context for this Review of the reliability frameworks, specifically:

- section 2.1 provides an overview of the existing reliability framework, which is predominately market-based but includes a limited set of interventions
- section 2.2 discusses how AEMO incorporates the reliability standard into its operations on a day-to-day basis, including its intervention mechanisms
- section 2.3 discusses the emerging challenges to the effective operation of the reliability framework and
- section 2.4 sets out the policy responses to date.

Further details on the existing framework, including more detail on how market participants and AEMO's operations occur in the reliability framework, can be found in appendices C and D.

2.1 Market-based framework

Reliability frameworks can be considered on a spectrum:

- One end is where desired levels of system reliability could be met by the government deciding when and where to build new generation capacity - pure 'central planning'. Indeed, this is precisely how such decisions in the electricity system in Australia were made prior to reforms of the 1990s prompted by the Hilmer report.[40]
- At the other end, reliability outcomes could be left solely to the market, with no limits on wholesale prices or additional regulatory mechanisms.

However, as explained further in appendix B, adopting either of these two approaches as the basis for a reliability framework would likely give rise to highly inefficient pricing, investment and operational outcomes throughout the electricity supply chain. Therefore, most reliability frameworks sit between these two extremes. The NEM is no exception and lies towards (but not at the end of) the market-based end of the spectrum.

The principal means of delivering the required reliability outcome in the NEM is through spot market price signals and, in turn, the prices of contracts that are used (in part) by participants to have more certain costs and revenue over time. Those market

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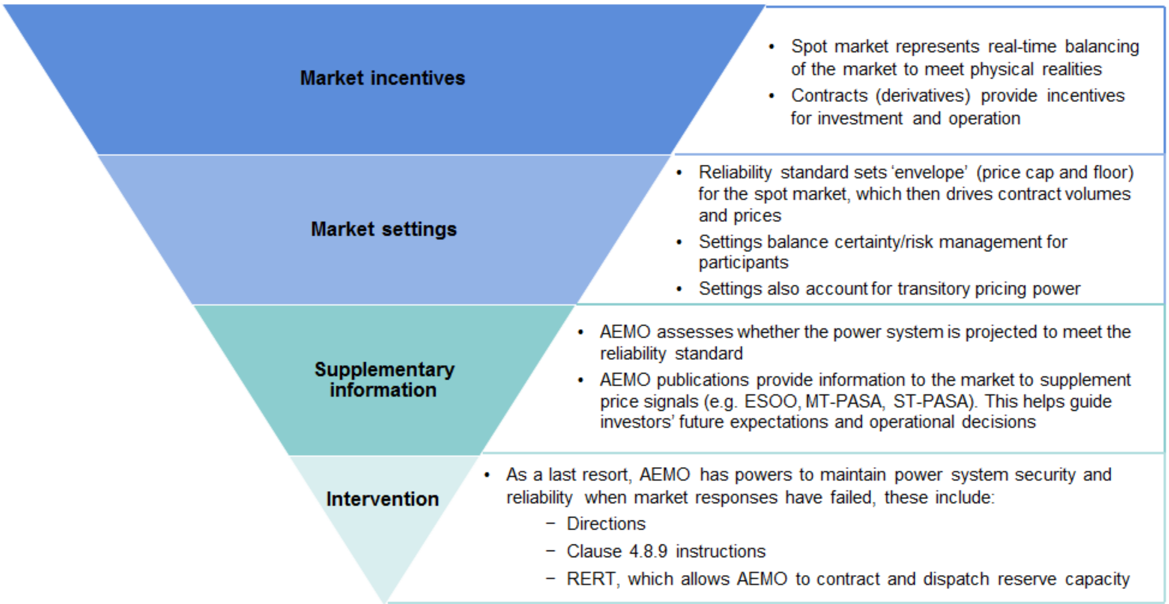
40 Hilmer, F., Rayner, M. & Taperell, B., 1993, *National Competition Policy: Report by the Independent Committee of Inquiry*, Australian Government Publishing Service, Canberra, available at http://ncp.ncc.gov.au/docs/National%20Competition%20Policy%20Review%20report,%20The%20Hilmer%20Report,%20August%201993.pdf

incentives are then supplemented by a series of mechanisms, with an increasing amount of intervention.

Figure 2.1 provides a summary of the existing reliability framework, including the reliability standard, the reliability settings and AEMO's intervention mechanisms.

Figure 2.1 Market-based approach with escalating series of interventions



2.1.1 The role of market incentives

The buying and selling of electricity, as well as associated financial products, via contract and spot markets is the main mechanism through which reliability is delivered in the NEM. Based on these market signals, market participants make investment and operational decisions. Prices in the spot and contract markets provide signals for adequate generation and demand-side resources to be built and dispatched, as well as information about the balance of supply and demand across different places and times.

Spot market

Like any market, the NEM was established with a particular pricing framework, in this case, a gross pool design with mandatory participation. Generators sell, and market customers buy, all of their electricity through the spot market, which matches supply and demand instantaneously, including an allowance for a sufficient quantity of reserves.

The market settings - the reliability standard, the market price cap, cumulative price threshold, administered price cap and market floor price - are an integral part of the reliability framework. They protect the long-term integrity of the market by limiting the extent to which wholesale prices can rise and fall. They are set at a level so as not to interfere with the price signals needed for efficient investment and operation. These reliability settings form the key price envelope within which the wholesale spot market seeks to balance supply and demand, and are discussed further below in section 2.1.1.

Scheduled and semi-scheduled generators and loads offer and bid into the market dispatch engine, operated by AEMO. Under competitive market conditions, generator offers will usually be based on their short run marginal costs (SRMC) such as fuel and the cost of operating plants. Load offers will usually be based on their value of customer reliability, that is, their willingness to pay for the reliable supply of electricity.

Once these offers are received, AEMO then forecasts the expected customer demand for electricity in each region for each 5-minute interval and, based on an optimisation process that attempts to maximise the value of trade given the physical limitations of the power system, dispatches as much generation as necessary to meet the demand. Each generator then receives revenue at the clearing price (known as the "regional reference price") for the electricity delivered – even when that clearing price is above the quantity it offers into the market. In this way, the spot market coordinates the physical dispatch of generation and all generators earn at least their offer for each unit of electricity delivered.

This stream of income from the spot market is used to cover a generator's variable operating costs, and to the extent prices are above its variable costs, a contribution to their capital costs. Revenue earned in the spot market, in conjunction with participants' contract positions, supports reliability in the short-term since it provides a financial incentive for generators to supply electricity when there is demand to meet it. Similarly, to the extent that spot prices are high, retailers or direct-connected customers will receive price signals to potentially engage in demand response, and so reduce their demand. This also assists with reliability.

In the long-term, when generators receive a clearing price higher than their SRMC, they also earn a "margin" on their energy, which funds their fixed costs. New generators enter the market when they expect the gross margin they can earn is sufficient to fund their fixed and capital costs. Absent new demand, the entry of new generators in turn, erodes the gross margin that a generator can make in the market by reducing the number of periods in the year where a margin is earned. Consequently, the contract market (discussed below) plays a key part in signalling market expectations of future prices, providing incentives for new generators to enter the market to make up any shortfall between supply and demand in the long-term.

Chapter 4 provides further detail on how central dispatch and the spot market works, and the importance of demand forecasting, both for AEMO in balancing supply and demand and for market participants in making business or process decisions (for example, generation levels, consumption levels, network planning). However, we have provided a simplified example of what happens in an operational timeframe in Box 2.1 below.

Box 2.1 Example of what happens in practice in the operational timeframe

In this simplified example, assume that today is a **Friday.**

On **Wednesday**, that is, day-2, Generator A, a scheduled gas-fired generator, provides AEMO detailed information about its capacity for the Friday. This includes its self-commitment and de-commitment times, capacity profile, energy availability, rates of changes etc. Bidding opens.

Generator A has to provide this information for every trading interval, that is, in half hourly blocks.

At 12:30 AEST on **Thursday**, that is, day-1, Generator A at **12:30 AEST** bidding closes. Generator A provides AEMO with its energy capacity offers for each price band and other information such as its ramp rates.

AEMO updates **pre-dispatch for Friday** soon after **12:30 AEST** on Thursday and publishes forecasts on a regional basis, including:

- total generation availability, by registration category (for example, scheduled, semi-scheduled)
- total demand
- price.

This information is available to all parties, including the public and is updated every 30 minutes.

In addition, Generator A gets told its own pre-dispatch quantity for its (and only its) generating units.

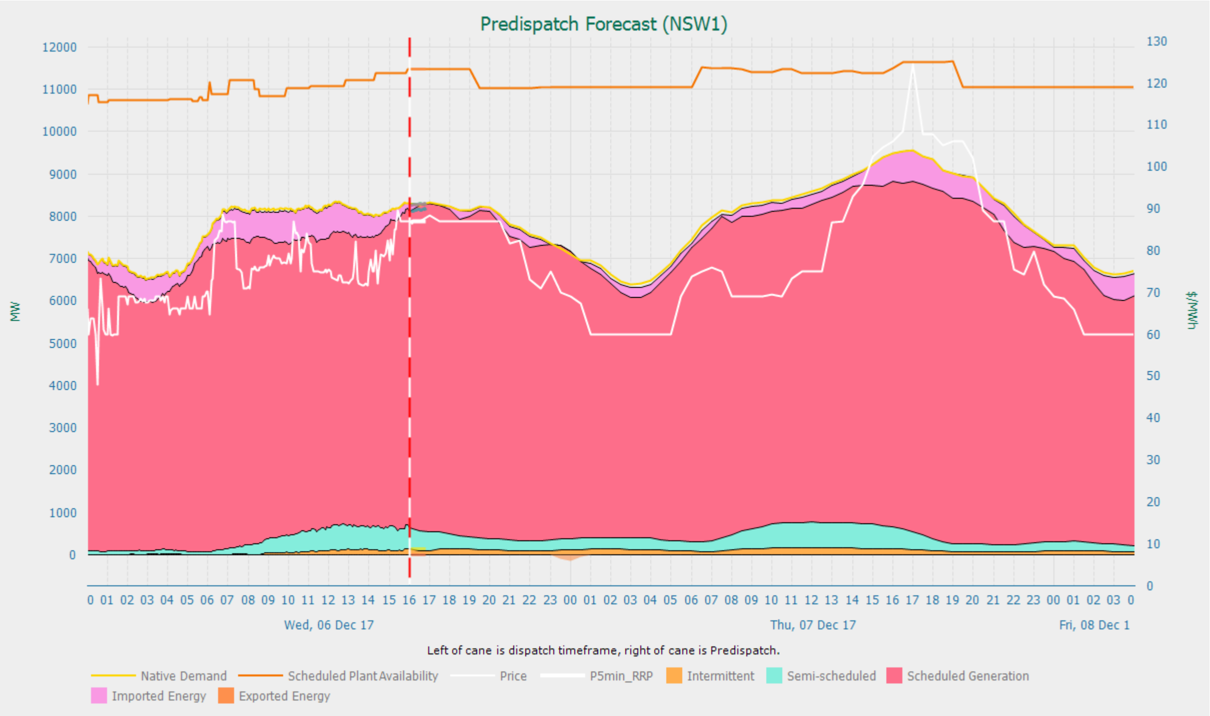
On **Thursday afternoon**, a technical problem arises at one of Generator A's units, creating a forced outage that it expects will last for 36 hours. Generator A rebids its energy capacity accordingly.

On **Thursday night,** AEMO revises its demand forecast for Friday upwards substantially, causing the forecast market price for Friday to rise. Generator A fixes its outage more quickly in response to the higher prices, and so revises its energy capacity offers within some of the price bands in light of the expectation of higher prices.

Generator A may re-bid up to just before the start of the next trading interval and must include a reason for rebidding.

Pre-dispatch for the spot market is run every 30 minutes for each trading interval, although participants also have access to a pre-dispatch process that is run every five minutes. Participants receive these files from AEMO and then, generally, would analyse it through their (or a third-party's) system. For example, an indicative snapshot of pre-dispatch for the NSW region at 16:00 AEST on 6 December 2017 is shown in Figure 2.2. Participants therefore have a detailed picture of what is occurring and likely to occur in the NEM over the next day.[41]

Figure 2.2 Indicative pre-dispatch



Source: NEOpoint.

Contract market

Reliable supply in the NEM is supported by the inherent and symmetrical incentive for buyers and sellers to obtain more certain revenues and costs. This incentive encourages buyers and sellers to agree to contracts[42] that swap spot prices of electricity for a fixed price to manage these risks. Alternatively, they can invest in both generation and retail assets (vertical integration). Contracts can be considered simply as another means of expressing the price of the same underlying product - electrical energy - meaning that spot and contract prices are intrinsically linked.[43]

41 Appendix C provides more detailed information about what AEMO is required to publish as part of pre-dispatch.

42 For example, cap and swap contracts.

43 The price of hedging contracts reflects the balance of expectations as to the level and volatility of future wholesale spot price outcomes, that is, if average spot prices are expected to increase in the future, contract prices will follow, and vice versa. If this were not the case – and the price of hedges was out of line with expectations of future market prices – then profitable arbitrage opportunities would arise to close the gap. Evidence of such trends is discussed in the chapter 5.

In the absence of such instruments, generators and market customers would be fully exposed to the spot market, which can fluctuate significantly on a 30-minute basis.[44] Hedging contracts offer a way for market participants to manage their exposure to these ebbs and flows, and provide more certainty around their future wholesale costs and revenues. The two most common types of contracts are swaps and caps, which are discussed more in chapter 5.

Because the parties to these hedging instruments do not have to physically deliver electricity,[45] some are financial intermediaries; that is, they are neither electricity generators nor retailers. This helps promote liquidity, which is essential, because contracts – such as swaps and caps – become considerably less useful as risk management tools if there are only a few counter-parties to buy them from or sell them to. A plentiful supply of financial hedging instruments and counter parties promotes reliability over both the short-term and long-term.

So, while its primary role is to smooth the cash flows of buyers and sellers to manage these risks, the contract market also supports reliability by informing both operational and investment decisions, specifically:

- On a short-term operational timescale, contracts provide certainty for participants and inform their decisions in the face of risky market conditions. For example, a generator that is protected from the adverse consequences of low spot prices through a swap contract is more likely to be operating when it is needed to meet demand as when prices are high it needs to be generating to receive those high prices that it will pay out to the buyer of its contact and when prices are lower it does not have an incentive to be available.
- In the longer-term, the contract supports reliability in three ways:
    - It provides market participants signals of market expectations of future spot prices, which support investment and retirement decisions.
    - It lowers the cost of financing of investment in generation capacity, which lowers the cost of achieving efficient levels of reliability.
    - It underwrites retailers' fixed-price offers to end-consumers, such as households and small businesses.

Further detail on how the contract market works, and its role in supporting reliability, can be found in chapter 5.

44 The Commission has recently made a final rule determination to move the NEM to 5-minute settlement from 2021.

45 Contracts in the NEM are traded on the ASX (they are 'exchange traded') or traded bilaterally ('over the counter' or 'OTC'). All energy traded through the NEM must be settled through the spot market, and so contracts represent a separate source of financial flows between market participants. In other words, financial contracts do not involve the physical delivery of electricity – it is a 'cash settled' market.

Objective of the market-based framework

The core objective of the existing reliability framework in the NEM is to deliver desired reliability outcomes through market mechanisms to the largest extent possible. As the expected supply/demand balance tightens, spot and contract prices will rise[46] which should inform operational decisions and provide an incentive for efficient entry and expansion, addressing any potential reliability problems as or before they arise.

Specifically, when a tight demand-supply balance causes spot prices to increase high enough, or frequently enough that the average spot price exceeds the long-run cost of constructing more capacity, then:

- firms already in the market have an incentive to retain and / or expand their generation capacity to take advantage of those periods of high prices
- new firms have a stronger incentive to enter the market and offer new generation capacity, chasing those high prices
- consumers and retailers have a stronger incentive to install equipment to enable them to reduce consumption to avoid those high prices.

Depending upon the circumstances, the most efficient expansion profile may involves a mix of investment decisions. For example, by both existing generators and new entrants; in a mix of generation, network and demand response technologies, for example, base-load, mid-merit and peaking plant; and, potentially, including transmission and interconnector capacity.

The most critical thing to recognise is that, in the NEM, it is generally left solely to private investors to make those decisions, motivated by the pursuit of profits (or economic rents), rather than a central planner with imperfect information about the 'least cost' or 'most efficient' outcome and potentially very different incentives. The framework provides incentives for the most efficient mix of technologies to be invested in – for example, expectations of highly volatile supply and demand conditions translates into expectations of highly volatile spot market prices. In turn, this provides incentives for investment/retention of plant best able to capitalise on that volatility, such as peaking plant and storage solutions.

2.1.2 The role of the reliability standard and settings

Reliability standard

The reliability standard is the maximum expected unserved energy (USE) in a region for a given financial year.[47] 'Unserved energy' means the amount of customer demand that cannot be supplied within a region of the NEM due to a shortage of generation or interconnector capacity.

46 Within the price envelope, as discussed in section 2.1.2.

Crucially, this is not set at zero per cent. The current reliability standard is 0.002 per cent expected unserved energy. In simple terms, the reliability standard requires there be sufficient generation and transmission interconnection in a region such that at least 99.998 per cent of forecast annual demand for electricity is expected to be supplied.

Importantly, setting the level of the reliability standard involves a trade-off, made on behalf of consumers, between the prices paid for electricity and the cost of not having energy when it is needed. A higher reliability standard (that is, expected unserved energy less than 0.002 per cent) would in turn derive a higher market price cap (all things equal) which in turn should incentivise a supply- or demand-side response such as investment and operational decisions in generation, improving reliability. However, a higher market price cap would expose consumers that participate directly in the market, and retailers, to higher average spot prices. In turn, in a competitive market, retailers will recover these higher average spot prices from end consumers. The trade-off is therefore between two sets of costs, both of which are ultimately borne by consumers.

The reliability standard underpins the reliability framework in the NEM, including AEMO's operation of the market as discussed in section 2.2.

Reliability settings

The reliability settings are closely linked to, and derived directly from, the 'reliability standard'. These form a price envelope for spot prices:

- The maximum price that a generator may bid during a dispatch interval is $14,200/MWh[48] – this is known as the 'market price cap' (or 'MPC'). The maximum price cap limits market participants' exposure to temporary high prices, being the maximum bid (and therefore settlement) price that can apply in the wholesale spot market. It should be set at such a level that prices over the long-term incentivise enough new investment in generation, as well as operational decisions, to achieve the reliability standard.

- The minimum price that a generator may bid during a dispatch interval is -$1,000/MWh – this is known as the 'market floor price'. The market floor price limits the amount of money a generator can lose in a single half hour, preventing market instability.[49]

- The cumulative price threshold limits participants' financial exposure to prolonged high prices, by capping the total market price that can occur over seven consecutive days. As with other reliability settings, it should be set at a level such that prices over the long-term incentivise enough new investment, as

47 Clause 3.9.3C of the NER.

48 This is indexed by CPI annually by the AEMC.

49 The AEMC recently made a final rule to change the settlement period for the electricity spot price from 30 minutes to five minutes, starting in 2021. See: http://www.aemc.gov.au/Rule-Changes/Five-Minute-Settlement.

well as efficient operational decisions, so the reliability standard is expected to be met. The administered price cap limits participants' financial exposure to prolonged high prices, being the price 'cap' that applies when the cumulative price threshold is exceeded.

- The administered price cap of $300/MWh applies when an administered pricing period is declared by AEMO whenever the sum of the spot price in the previous 336 consecutive trading intervals (that is, seven days) exceeds the cumulative price threshold, which is currently $212,800/MWh. Once invoked, the administered price cap remains in place until the end of the trading day during which the rolling sum of prices falls below the cumulative price threshold. To date, the administered price cap has rarely been triggered.

The market price cap

Of these price limits, the market price cap is of interest for present purposes. This constraint is intended (among other things) to address the two basic economic problems – namely, customers' inability to engage in wholesale demand-side bidding and their consequent susceptibility to the exercise of temporary pricing power by generators. Building on the objective as set out above, the market price cap is designed to:

- Provide a default bid for loads – small customers have not historically been active participants in the NEM and still have only an imperfect – albeit a steadily improving[50] – ability to alter their consumption to avoid high prices. The cap therefore serves as a proxy 'limit' on their bids.

- Limit market participants' exposure to extreme prices – notwithstanding the role of the market price cap as the default bid for loads, the cap also limits participants' exposure to very high prices.[51] It places an upper bound on the maximum possible price to which a participant can be exposed in any dispatch interval.

However, the market price cap is intended to fulfil these objectives while still allowing spot prices to rise above SRMC, as well as providing an efficient signal for investment and operational decisions.

50 The growing status of demand-side in the NEM is explored in more detail in section 3.3.1 and the potential for 'wholesale' demand response is explored in chapter 6.

51 Contracts also perform a similar role.

Reliability Panel's review of the reliability standard and settings

Every four years, the Reliability Panel must review the reliability standard and the reliability settings.[52] Indeed, the Panel is currently reviewing the reliability standard and settings. In November 2017, the Reliability Panel published a draft report that recommended leaving the reliability standard and settings unchanged. Box 2.2 discusses the Reliability Panel's reasoning for leaving the market price cap unchanged in its draft decision

Box 2.2 The Reliability Panel's draft reasoning on the market price cap

The Reliability Panel’s draft view is that the current market price cap of $14,200 ($2017, indexed annually by increases in CPI) should apply from 1 July 2020, for three reasons:

- The current level of the market price cap appears to be serving its purpose effectively – The level of the current market price cap is protecting market participants from high prices so as to maintain market integrity, and appears to be allowing price signals to incentivise sufficient generation to meet the reliability standard without use of AEMO’s intervention powers, and is likely to continue to do so through the review period.
- Modelling outcomes – The Reliability Panel examined the level of projected unserved energy with the current market settings unchanged, and tested the level of market price cap that would be needed to allow for sufficient investment under several alternate scenarios. The Panel considers the current market price cap is likely to be sufficiently low to maintain market integrity and sufficiently high to allow investment in enough generation so that the level of any unserved energy is consistent with the reliability standard.
- Benefits of maintaining policy stability, where warranted – The Reliability Panel has assessed changes in the market for impacts on the required level of the market price cap and on balance, holds the view that providing stable and predictable policy outcomes is appropriate.

Source: Reliability Panel, Review of the Reliability Standards and Settings, Draft Report, November 2017.

In conducting its review of the reliability standard, the Panel must:[53]

- comply with the *reliability standard and settings guidelines*[54]

52 Clause 3.9.3A of the NER.

53 Clause 3.9.3A(e) of the NER.

54 Reliability Panel, *Review of the reliability standard and settings guidelines*, Final guidelines, 1 December 2016.

- have regard to any terms of reference for the review provided by the AEMC
- have regard to the potential impact of any proposed change to a reliability setting on: spot prices, investment in the NEM, the reliability of the power system, and market participants
- have regard to any value of customer reliability determined by AEMO - see Box 2.3
- may take into account any other matters specified in the *reliability standards and settings guidelines* or which the Panel thinks are relevant e.g. the guidelines state that the Panel must consider any marked changes in the way consumers use electricity, particularly through the use of new technology, that suggests that a large number of consumers may face a lower value on a reliable supply of electricity from the NEM.[55]

Box 2.3 Value of customer reliability

Estimating the value of customer reliability is a complex and subjective process. Just as different customers might be prepared to pay a diverse array of prices to, say, attend a Bruce Springsteen concert, so too might they value the reliability of their electricity supply very differently.

The value of customer reliability will be influenced by many factors, including the type of customer, their access to alternative energy sources, their demographics and the extent to which they have experienced interruptions in the past. It will also be influenced by the duration, frequency, timing and location of an interruption. For example, a customer may place little value on avoiding a 10-minute outage that affects only her neighbourhood. But she may be prepared to pay much more on a per unit of energy basis to avoid an outage that plunges the entire state into darkness for five hours.[56]

In September 2014, AEMO released a report containing the first estimates of value of customer reliability undertaken at a national level.[57] It put the NEM-wide average value of customer reliability at $33,460/MWh.[58]

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55 Ibid. p. 5.

56 Because the actual costs to customers of supply interruptions cannot be observed, they must be estimated. One means of doing so is via ‘survey-based’ approaches, where data are gathered about the expected costs to customers of hypothetical events. The different approaches include estimating direct costs, estimating costs based on the economic cost of substitution, contingent valuation surveys and choice modelling. ‘Modelling-based’ approaches can also be used, which include considerations of gross national product per kWh of electricity consumed, wage income per kWh consumed or the costs of standby generation.

57 AEMO, Value of customer reliability review final report, September 2014.

58 Because this is an average, there will be customers who value reliability more highly, or by not as much.

In 2016, the Reliability Panel considered the implications of the value of customer reliability estimates for the level of the reliability standard. It concluded the existing standard (0.002 per cent USE) remained broadly consistent with the estimated value of customer reliability. In doing so, it had regard to ROAM's 2014 finding that the level of the current standard was equivalent to a value of customer reliability of approximately $30,000/MWh, which was close to the figure noted above ($33,460/MWh).[59] However, the Panel stressed at that time that these figures were only estimates of the true value of customer reliability and that other measures of reliability exist.[60]

Once the reliability standard has been determined in this fashion, the market price cap should be set at a level that achieves the reliability standard (no more, no less). Importantly, the market price cap does not need to be set equal to the estimated the value of customer reliability for the reliability standard to be met – indeed, the current $14,200/MWh cap is well below the current $33,460/MWh value of customer reliability estimate. Setting the market price cap at the maximum price an average customer is willing to pay for electricity (that is, at the value of customer reliability) would certainly provide strong incentives for new investment and operational decisions in generation, but other implications of this would need to be considered.

Theoretically, it is worth noting that there is an inverse relationship between the estimated value of customer reliability and the applicable reliability standard: the higher the estimated value of customer reliability, the lower the unserved energy should be, and vice versa. That is because, as the value that customers place on the reliability of the power system increases, the costs associated with each outage increases and the efficient level of unserved energy decreases. For example, if the NEM-wide average value of customer reliability was re-estimated today and found to be closer to, say, $60,000/MWh (using a hypothetical, round number) instead of the $33,460/MWh estimated in September 2014, it might be appropriate to reduce the unserved energy from 0.002 per cent to something lower – say, 0.001 per cent. But, this would need to recognise that the average prices that are eventually passed through to consumers would then be higher due to the higher required level of investment. This is discussed further in section 7.5 that provides indicative estimates of the costs that would be associated with a tighter standard.

2.1.3 The role of information processes

AEMO is required by the NER to publish various materials which provide additional information to market participants – and any other interested parties – on matters pertaining to the reliability standard; that is, over and above the information contained in contract and spot market prices. This information is provided in several formats and

59 See: AEMO, Value of customer reliability review final report, September 2014 and ROAM Consulting, Reliability standard and settings review, report to the AEMC, May 2014, p.64.

60 More recently, further doubts have emerged regarding the existing value of customer reliability estimates capture the full value to customers of avoiding widespread and prolonged disruptions – doubts precipitated in large part by the South Australian blackouts.

considers various time-frames. It helps guide market participants' expectations of the future, enabling more efficient investment and operational decisions. Some of these publications include:

- Electricity Statement of Opportunities (ESOO) – this document projects generation adequacy under a number of scenarios over a ten-year-period
- Projected Assessment of System Adequacy (PASA) – this publication assesses generation adequacy over various forward intervals (for example, over the next two years, six days or over the next day)
- Pre-dispatch schedules – AEMO provides two sets of pre-dispatch data; namely:
    - 30-minute pre-dispatch data by region to the end of the next trading day – which are updated half-hourly
    - 5-minute pre-dispatch data by region, showing short-term price and demand forecasts looking out one hour ahead – which are updated every five minutes
- Energy Adequacy Assessment Projection (EAAP) – this document provides information on the impact of potential energy constraints, particularly those relating to inputs to production, for example, water shortages or constraints on fuel supply.
- Low reserve conditions or lack of reserves (LOR) notices – AEMO may publish these notices to advise participants when reserves are already or projected to be below critical levels.

The purpose of these forms of supplementary information is to inform the market of prevailing and forecast conditions, and when reserves may be running low, in order to elicit a market response, if possible. For example, if the ESOO identifies a potential shortage of generation in a location in, say, five years' time, the intent is that revealing this information to the market will prompt new investment to alleviate that problem. Similarly, the medium-term PASA enables generators to plan or modify their maintenance schedules.

In a similar vein, AEMO's first step when publishing a low reserve condition or lack of reserve notice is to seek a market response, for example, any off-line generators that will come online in anticipation of the high spot prices which are likely to prevail during the identified period, or large loads that could reduce their demand.

As an example, a LOR2 was declared for Victoria in the short-term PASA on 10 December 2017 at 12:47 AEST for the period from 16:30 to 17:30 AEST on 13 December 2017, identifying a reserve shortfall of 118 MW. AEMO sought a market response. At 08:00 AEST on 11 December 2017, AEMO cancelled the LOR2 - in other words, the shortfall was no longer being forecast. Analysis of short-term PASA forecasts and availability showed that AEMO's demand forecast remained relatively unchanged from the time that the LOR2 was first declared to when it was cancelled. The LOR2 trigger level also remained unchanged. The forecast shortfall was addressed through a rise in the capacity being offered by scheduled generators as well as a small increase in forecast semi-scheduled plant availability.

2.2 Operationalising the reliability standard and intervention mechanisms

Another key role of the reliability standard is to guide various decisions made by AEMO in its role as the system operator. It is AEMO's responsibility to incorporate the reliability standard within its day-to-day operation of the market.

2.2.1 Obligations under the NER to implement the reliability standard

The NER does not give specific direction to AEMO on how to implement the reliability standard (0.002 per cent expected unserved energy), but it does require AEMO to perform the following functions in accordance with the *reliability standard implementation guidelines (RSIG):*

- In the medium-term, through the medium-term PASA, identify and quantify any projected failure to meet the reliability standard.
- In the short term, through the short-term PASA identify and quantify any projected failure to meet the reliability standard.
- To keep the system in a reliable operating state[61] in real time, assess whether the power system meets, and is projected to meet, the reliability standard.

In addition to monitoring the system using the information processes mentioned above, AEMO may declare:

- a low reserve condition when it considers that the balance of generation capacity and demand for the period being assessed does not meet the reliability standard as assessed in accordance with the *reliability standard implementation guidelines*; or
- a lack of reserve condition to advise market participants whenever it determines that the probability of involuntary load shedding is expected to be more than remote.[62]

The NER also obliges AEMO to publish the ESOO by 31 August each year. As mentioned above, the ESOO is an information tool providing information that can help stakeholders plan their operations over a ten-year outlook period, including information about the future supply demand balance. The intention of the ESOO is *not* a definitive guide to assess how much reserves should be procured, nor to inform

61 Defined in clause 4.2.7 of the NER.

62 The Commission has recently made a rule that removes the deterministic descriptions of lack of reserve from the NER, replacing them with a single high-level description for lack of reserve and so allowing the system operator to move to a more probabilistic framework. This is discussed in more detail in section 1.5.2.

governments about what actual outcomes in the market will be. Instead, the purpose is solely as a market information tool: signalling to the market ahead of time where there might be *potential* shortfalls to elicit a response from market participants.

2.2.2 Operationalisation of the reliability standard

AEMO operationalises the reliability standard using forecasts and projections over different timeframes.

Table 2.1 summarises the processes AEMO uses to operationalise the reliability standard.

Table 2.1 Operationalisation of the reliability standard

Process	Timeframe / frequency	Assumption for potential breach of reliability standard
ESOO	10 year / annually	Forecast unserved energy > 0.002% in any forecast year based on probabilistic modelling
EAAP	2 year / annually	Forecast unserved energy > 0.002% in any forecast year based on probabilistic modelling
Medium-term PASA	2 year / weekly	Until 15 February 2008, reserves fall short of the minimum reserve level[63] From 15 February 2018, forecast unserved energy > 0.002% in any forecast year based on probabilistic modelling
Short-term PASA	6 day / 2 hours	Forecast LOR2 or LOR3
Pre-dispatch	Day ahead / 30 minutes	Forecast LOR2 or LOR3
Dispatch	5 minutes / 5 minutes	Actual LOR2 or LOR3

Part of each of these processes involves AEMO calculating reserves in the NEM. This is done for different ways in each process. These different methods are summarised below, but for a more fulsome description see appendix C.

63 This is discussed further in appendix C.

2017 Electricity Statement of Opportunities

The ESOO is based on probabilistic, time-sequential modelling. It models each scenario's specific demand and generation assumptions and simulates hourly monte carlo simulations to determine potential future supply shortfalls. These simulations capture the impact of key uncertainties, such as generator outage patterns, weather sensitive demand, variable renewable generation availability, and coincidence of demand across regions.

The model performs optimised electricity dispatch for every hour in the modelled 10 year horizon, with the aim of minimising system costs incurred in meeting operational consumption across the NEM, subject to generation capability, fuel availability, and transmission constraints. In cases where there is insufficient generation or demand side participation to meet forecasts demand, it results in unserved energy. This is then reported to the market, informing investment and operational decisions of participants.

Medium-term timeframes

Until 15 February 2018, AEMO determines the level of reserves required in each region to meet the reliability standard deterministically. AEMO implements the reliability standard over a two-year timeframe by providing a capacity reserve assessment as part of the medium-term PASA process, which is run at least weekly. This component of the medium-term PASA process identifies low reserve conditions, and so the reliability standard is operationalised by identifying, disclosing and responding to periods of forecast low reserve conditions.

A low reserve condition is declared if capacity reserves are projected to be inadequate on any given day. Capacity reserves are the difference between the PASA availability participants have offered and expected demand estimated by AEMO. To assess supply adequacy, these capacity reserves are compared against deterministic minimum reserve levels,[64] avoiding the need to compute unserved energy explicitly using a large number of monte carlo simulations.

However, AEMO has recently changed the medium-term PASA process and so from 15 February 2018, the medium-term PASA will implement the reliability standard by assessing the level of unserved energy and evaluating the likelihood of reliability standard breaches through probabilistic modelling, using 200 monte carlo simulations on a set of predefined cases to assess variability in unserved energy outcomes.

Demand and variable renewable generation supply assumptions will vary for each case (ten per cent POE and 50 per cent POE), driven by different historical weather conditions. Within a case, the monte carlo simulations will vary with respect to unplanned outages based on historical forced outage rates.

64 Minimum reserve levels represent AEMO's implementation of the reliability standard into a required safety margin of surplus installed capacity that can be applied operationally. Minimum reserve levels are expressed relative to a region's 10 per cent probability of exceedance (POE) maximum demand, including any coordinated reduction in demand, known as demand side participation.

Short-term PASA and pre-dispatch

The reliability standard is operationalised through the lack of reserve framework in the short-term period that is six days into the future. The pre-dispatch process also follows a similar methodology. The differences are limited to assumptions made with regards to network constraints and energy limits.

At a high level, AEMO undertakes three steps:

- It forecasts total reserve levels in the NEM.
- It calculates the lack of reserve levels, currently based on a deterministic framework set out in the NEM, but from 16 January 2018 it will be a more probabilistic framework.[65]
- If the total reserve levels are forecast to or fall below the lack of reserve threshold, AEMO then issues lack of reserve notices to the market, for the purposes of seeking a market response to the event.

2.2.3 Intervention mechanisms

The above information processes help the market deliver reliable outcomes.[66] However, as effective as information processes can be in delivering the desired reliability outcomes through market incentives, they cannot be guaranteed to work. If the market fails to respond to the information it publishes, AEMO's next step is generally to engage in informal negotiations with market participants to alleviate any supply shortfalls. Furthermore, AEMO can use network support and control ancillary services to the extent that the projected reserve shortfall is affected by a network limitation that can be addressed by such services.

But if those options fail, AEMO may have no other choice but to intervene in the market more directly.

AEMO therefore has various 'last resort' intervention powers that enable it to deal with actual or potential shortages of varying degrees of severity. In each instance, the power in question is designed to be implemented in a way that results in the smallest disruption possible to the ongoing operation of the market. These intervention mechanisms include the following:

- AEMO has Reliability and Emergency Reserve Trader (RERT) obligations. These allow AEMO to contract for reserves ahead of a period where reserves are projected to be insufficient to meet the reliability standard. AEMO can dispatch these reserves to manage power system reliability and, where practicable, security. The current operation of the RERT is described in more detail in chapter 7.

65 See discussion in section 1.5.2.

66 The market also provides information to AEMO to assist AEMO in running these processes and preparing these publications, this is discussed further in chapter 4 and appendix C.

- In addition, if there is a risk to the secure or reliable operation of the power system, AEMO can use directions or instructions under NER clause 4.8.9 to:
  - Direct a generator to increase its output, if this is possible and can be done safely. To be effective, the generator must have enough time to 'ramp up'. If the generating unit is not already generating, it can take time for it to connect to the network and begin to ramp up.
  - Direct a large energy user, such as an aluminium smelter, to temporarily disconnect its load or reduce demand. This only applies to large users who are registered participants.

If there continues to be a shortfall in supply, even after these measures have been implemented, AEMO may require involuntary load shedding as a last resort to avoid the risk of a wider system blackout, or damage to generation or network assets.[67] These intervention mechanisms provide an important ultimate safety net when there is insufficient generation capacity to maintain adequate reserves above demand, to minimise the adverse impacts on customers of involuntary load shedding. Although AEMO would be expected to do all in its power to avoid load shedding using the above intervention mechanisms, there will be times when involuntary load shedding will be unavoidable because the level of investment and operational decisions are being driven by a reliability standard that is non-zero.

Impact of interventions on the market

Interventions can have the potential to distort outcomes in the market since it can lessen the incentives on participants to respond through the market processes, resulting in potentially negative effects on reliability and higher costs. Therefore, interventions in the NEM are designed to have as little distortionary impact on the market as possible. For example, the RERT principles as set out in clause 3.20.2(b) of the NER, state that when exercising the RERT:

- actions taken should be those which AEMO reasonably expects, acting reasonably, to have the least distortionary effect on the operation of the market
- actions taken should aim to maximise the effectiveness of reserve contracts at the least cost to end-use consumers of electricity.

In addition, intervention pricing occurs when AEMO intervenes in the market through either a direction issued in accordance with clause 4.8.9 of the NER or when the RERT is dispatched (each is termed an 'AEMO intervention event').[68] Clause 4.8.9 instructions to network service providers to shed customer load involuntarily are not an AEMO intervention event. Instead, the market price cap is automatically applied when involuntary load shedding occurs.

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67 Network businesses are required to shed load in accordance with schedules provided by the relevant state government.

68 See Chapter 10 of the NER for a description.

Intervention pricing is described in more detail in the appendix C. However, it is intended to preserve the market signals that would have existed had the intervention not taken place, and it is used for the purposes of spot price determination and settlements.

Under the NER, a registered participant must use its reasonable endeavours to comply with a direction or clause 4.8.9 instruction unless to do so would, in the registered participant's reasonable opinion, be a hazard to public safety, or materially risk damaging equipment, or contravene any other law.[69] This clause of the NER is classified as a civil penalty provision.

Generators must otherwise comply with directions regardless of the financial implications and they could incur losses as a result. However, following a direction, compensation may be payable to:

- Directed Participant:[70] for the generating units or services that were the subject of the direction.
- Affected Participants:[71] for scheduled generators or scheduled network service providers that were not the subject of the direction, but which had their dispatched quantity affected by the direction.[72]
- Eligible Persons:[73] for persons who have a right to receive a portion of net settlement residue from AEMO[74] (and ultimately consumers) where, as a result of the direction, there has been a change in flow of a directional interconnector, for which the eligible person holds settlement residue distribution units for the intervention price trading interval.

Compensation arrangements are discussed further in appendix C.

AEMO is currently reviewing its intervention pricing methodology, with the intention of submitting a rule change request to the AEMC to amend the existing arrangements. This work was commenced following the energy direction in South Australia on 9 February 2017, where the intervention pricing outcomes deviated significantly from the dispatch outcomes.

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69 Clause 4.8.9(c) of the NER.

70 A scheduled generator, semi-scheduled generator, market generator, market ancillary service provider, scheduled network service provider or market customer the subject of a direction.

71 See definition of 'affected participant' in Chapter 10 of the NER.

72 Or for scheduled generators or scheduled network service providers that were the subject of the direction, but which had other generating units or other services (which were not the subject of that direction) affected by that direction.

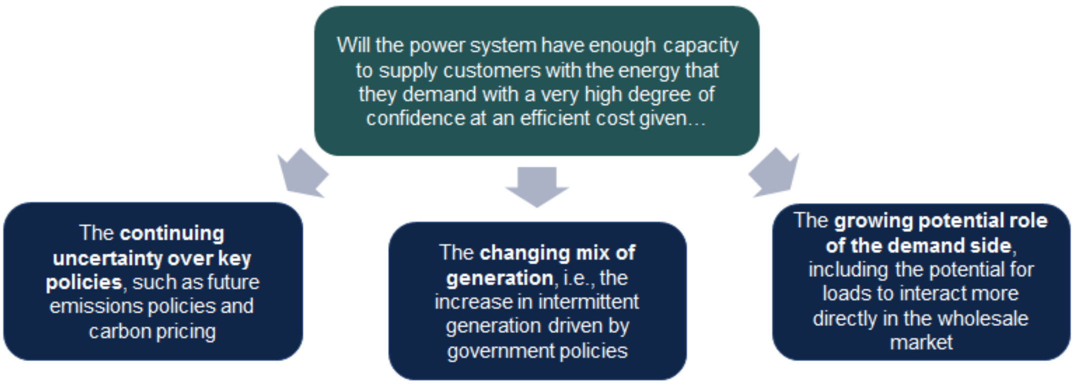
73 Clause 3.18.2(b) of the NER.

74 That is, the eligible person has a right to receive a portion of the net settlements residue because that eligible person has a settlements residue distribution agreement with AEMO in accordance with clause 3.18.1(b)(1) of the NER..

2.3 Emerging challenges to the existing framework

Australia's energy system is undergoing a revolution - driven by changing consumer choices and rapidly evolving technology. Meanwhile, various policy settings – including environmental policies – are having a profound influence on consumption, investment and operational decisions. As we explain in the following sections, these forces are having a significant influence on the reliability framework and raising legitimate questions about its ongoing suitability. Figure 2.3 summarises these potential drivers for change.

Figure 2.3 Summary of emerging challenges



The fundamental question is, when faced with these emerging challenges from various sources, will the power system have enough capacity to supply customers with the energy that they demand with a very high degree of confidence at an efficient cost, plus a sufficient level of reserves? In other words, is the existing reliability framework, which relies heavily upon a market based framework, sufficiently resilient to cope with these various influences? If the answer to this question is 'no' (or even 'maybe not'), the question then becomes: what needs to change – and how quickly?

2.3.1 The rise of the demand side

Historically, a 'reliable' power system invariably meant back-up generation, that is, the availability of additional generating units to ramp up if others failed. However, the emergence of new technologies and ensuing regulatory developments have meant that reliability is no longer the virtually exclusive dominion of 'supply-side' solutions. Rather, the demand-side – including residential customers – now has a potentially important role to play in delivering a reliable power system at the lowest possible cost. Indeed, consumers are now better-equipped than ever to manage and control their energy use and contribute to reliability and this will only improve in the future.

The emergence of distributed energy resources such as small-scale PV systems (of which there is now around 4,600MW in the NEM) – often assisted by heavily subsidised feed-in tariffs – and the steadily declining cost of battery storage means that these technologies may already be an efficient source of back-up capacity in some circumstances (furthermore, relatively broad geographic dispersion generally helps[75]). Those possibilities will expand in the future with AEMO estimating that, by 2036-37, nearly 20,000MW of roof-top solar PV will have been installed, together with more than 5,500MW of residential and commercial battery storage.[76]

Efficient, cost-reflective price signals can also encourage customers to shift energy use away from peak times, avoiding inefficient investments and load shedding events. These signals can be complemented by modern home energy management systems, which can provide a demand response that goes largely unnoticed by the customer. Voluntary load reductions by commercial and industrial users can also potentially be elicited as an alternative to involuntary load shedding. There is a growing body of evidence suggesting that the potential quantum of demand response available in the market is growing. For example, in October 2017, ARENA and AEMO announced that ten pilot projects had been awarded funding under their demand response initiative to manage electricity supply during extreme peaks. In total, the $35.7 million initiative will deliver 200MW of capacity by 2020, with 143 MW to be available for this summer.[77]

However, although demand response exists throughout much of the electricity supply chain, the NEM remains predominantly a generation-only wholesale market. While loads could opt to become scheduled, and be bid directly into the wholesale pool, to date, currently no loads are scheduled. In its submission on the issues paper, the PIAC noted that the continued absence of 'wholesale' demand response meant that, by definition, the energy system – and, by extension, the reliability framework – could not be operating at an acceptable level of efficiency. The feasibility and potential role of 'wholesale' demand response is therefore a particularly relevant topic to consider throughout this Review and is explored specifically in chapter 7.

More generally, it is abundantly clear that the demand-side will continue to be a key factor in driving the transformation of the energy sector – and the reliability framework is no exception. Whenever desired reliability outcomes can be most efficiently met through reduced demand instead of increased supply, the framework should facilitate that outcome. If it does not, consumers will be paying more to receive a higher level of reliability than they desire.

2.3.2 Changing mix of generation

For much of the history of the NEM, most of the installed generation capacity has been thermal (that is, coal and gas) and hydro-electric plants. These types of generation are 'synchronous', that is, spinning units driven by a steady fuel source – coal, gas or water. Synchronous generation provides system security benefits such as inertia and, most importantly for current purposes, it is dispatchable. Provided these generating

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75 In the absence of adequate storage capacity, solar PV that is clustered in a single geographic area can give rise to reliability problems. For example, it can result in sudden drops in supply during times of cloud cover when large numbers of plants stop producing all at the same time.

76 AEMC 2017, Reliability Frameworks Review, issues paper, 22 August 2017, Sydney, p. 26.

77 For further detail on this trial see appendix D.

units have sufficient fuel (that is, coal, gas, stored water) and their operational positions allow it – and assuming no unexpected outages or transmission constraints – they can be called upon by AEMO to increase or decrease their output at any time.

In other words, their output is controllable or, at least, manageable with a reasonably high degree of confidence. In 1998, nearly all of the registered generation in the NEM was dispatchable. The overarching market design and, in turn, the current reliability framework was consequently implemented against this backdrop. However, the mix of generation in the NEM has been changing rapidly in recent years, leading to a steadily declining percentage of dispatchable generation. These trends have been widely reported and include:

- Variable renewable generation in the NEM, including residential solar PV, has increased substantially since 2001. The capacity of variable renewable generation is expected to continue to increase with committed wind and utility solar projects. This has been incentivised by factors such as:
  - generous feed-in tariffs provided by state governments, which have provided strong financial incentives to install roof-top solar PV[78]
  - the large-scale renewable energy target (LRET), which has provided strong additional incentives for the private sector to invest in large-scale renewable generation, particularly wind farms
  - government grants through ARENA and long-term contracts under the ACT Government's reverse auction scheme.[79]
- There has been a strong trend of thermal (coal-fired) generation exiting, including Northern Power Station in South Australia (520MW in May 2016), Hazelwood Power Station in Victoria (1,600MW in March 2017). Moreover, the Liddell Power Station in New South Wales (2,000MW) is expected to close in 2022.[80]

78 For example, customers who applied for the Queensland government's Solar Bonus Scheme before 10 July 2012 and maintain their eligibility can continue to receive a feed-in tariff of 44 cents per kilowatt-hour for excess electricity exported to the grid. See: https://www.dews.qld.gov.au/electricity/solar/installing/benefits/solar-bonus-scheme

79 See: https://www.environment.act.gov.au/energy/cleaner-energy/how-do-the-acts-renewable-energy-reverse-auctions-work

80 See https://www.agl.com.au/about-agl/media-centre/asx-and-media-releases/2017/december/agl-announces-plans-for-liddell-power-station

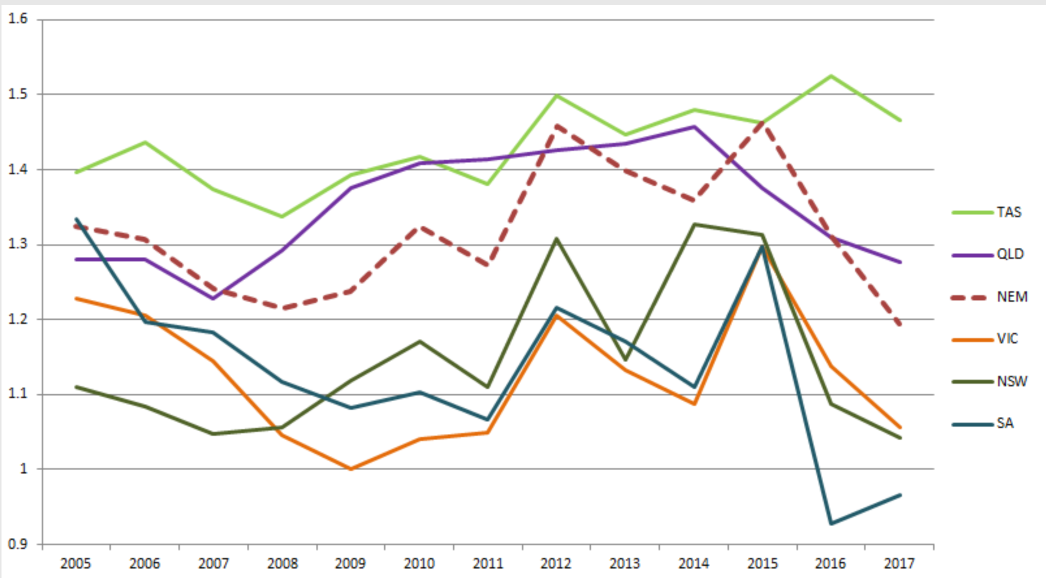
Box 2.4 Ratio of peak demand to dispatchable generation capacity

Figure 2.4 shows the ratio of regional and NEM wide peak demands to the level of dispatchable generation capacity. A ratio of one would exist if the peak demand in MW was equivalent to the capacity of dispatchable generation. Dispatchable generation capacity refers to installed generation excluding utility scale solar and wind. It does not include dispatchable demand side resources. However,, this may be partially accounted for in the level of peak demand.

This graph does not suggest that a certain level of dispatchable generation is necessary to meet peak demand. Peak demand can be meet through a combination of demand response, variable renewable generation, inter-regional power flows and dispatchable generation.

The changes in the ratio are driven in part by the withdrawal of dispatchable generation from the NEM. The falling ratio from 2015-17 was driven by the withdrawal of coal fired power capacity and the increase in NEM peak demand. The increase from 2011-12 was mostly the result of a sharp drop in NEM peak demand. Tasmania has the largest ratio of dispatchable generation capacity to peak demand and South Australia has the smallest with the ratio sitting below one. This chart suggests that in recent years the amount of dispatchable generation that can contribute to peak demand, has been declining.

Figure 2.4 Ratio of peak demand to dispatchable generation capacity



Source: AEMO, Generator information page; AEMO, Electricity statement of opportunities reports from 2005-16; AER, wholesale statistics.

In other words, the price signals provided by the market-based framework in the NEM have been overlaid with a *separate* set of incentives provided through various government subsidies for renewable generation. Not surprisingly, the result has been a large increase in the subsidised form of generation and a significant detrimental impact upon the returns of non-subsidised plants. Put simply, variable renewable generation appears to have driven out – and seems poised to continue to drive out – other, non-subsidised, forms of generation, including thermal plants that might otherwise have played a key role in ensuring continued resource adequacy.

In other words, these external factors – and the continued uncertainty over other key policies described below– may have resulted in significantly less investment in generation than might otherwise ideally have arisen under the market-based framework without those drivers. The proportion of dispatchable generation throughout the NEM now sits at 80 per cent and this is likely to shrink further in coming years. The rapid increase in the penetration of variable renewable generation creates several potential challenges from a reliability perspective. The confluence of these factors could result in perceived, or actual, reliability problems in the future.

The first challenge posed by the influx of variable renewable generation is that the intrinsic intermittency of wind and solar plants can make it considerably harder to forecast their output than other forms of generation, although advances in technology are making it easier to undertake this forecasting. For example, predicting accurately the output of wind farms depends critically upon the availability of reliable wind pattern forecasts. If these forecasts are wrong, this can have a pernicious impact throughout the entire framework. For that reason, there are several initiatives afoot that are exploring ways to improve the precision with which variable renewable generation output is forecast, as chapter 4 explains.

The second and arguably most fundamental challenge is that variable renewable generation is non-dispatchable (at least in the absence of adequate storage capacity, for example, large banks of batteries). This means that AEMO cannot depend upon those types of generation to ramp up when, say, a shortage is emerging, because their availability is at the mercy of the elements. If the wind is not blowing, or if there is cloud cover when these plants are needed, they will not be able to provide a reliability-firming response if called upon.

Third, the increase in variable renewable generation could result in reduced availability of hedging contracts, which need to be backed by 'firm' capacity. The basic contention is that variable renewable generators may be much less inclined than dispatchable forms to generation to participate in such activities and/or to invest in any firm back-up capacity (either by physical means – for example, installing batteries – or through a financial arrangement with a third-party dispatchable generator) due to:

- the financial exposure they may face if they are contracted during a ‘high price’ period, but unable to generate (due to the natural elements not being conducive), for example, they may have to procure the contracted capacity on the spot market at considerable expense
- the unique supplementary form of revenue that such plants can obtain from LRET certificates that, historically, have provided returns that have outstripped wholesale market revenues, potentially diminishing their appetite to hedge.

Either separately or collectively, these three factors could, in principle, potentially comprise reliability outcomes - although that is by no means guaranteed in practice. Whether this is, or will be, the case this is a key question for this Review. Indeed, the Reliability Panel's recent modelling shows that there is projected to be sufficient physical capacity in the electricity system to generate and transport power to meet consumer demand from 1 July 2020 to 1 July 2024.[81]

Moreover, the challenges described above have been exacerbated by the prolonged considerable uncertainty regarding not having an emissions reduction mechanism that is integrated with the energy market. Although these challenges are not 'emerging' per se – indeed, some of them have existed for some time – their potential impacts on the reliability framework may become more acute as time passes, as the following section explains.

2.3.3 General policy uncertainty

Many would agree that the continuing uncertainty around how any emissions reduction mechanism could be integrated with the energy market has had a significant impact upon investment in new generation – and that this is likely to continue until clarity is provided. This was recognised by all stakeholders submitting to our issues paper.

Indeed, an investor thinking of investing in solar, pumped hydro or gas plant may be unable to discern whether it will make money without a clear understanding of the emissions reduction mechanism that will be used to meet the 2030 and 2050 targets. Similarly, any prospective investors in new thermal plants will first wish to be cognisant of any obligations they will be subject to in relation to their emissions. This policy vacuum can potentially swamp the wholesale price signals, that is, investors may not respond to those signals due to uncertainty surrounding their future returns in the absence of those crucial policy details.

Potential investments in gas-fired plants would also almost certainly be aware of the potential for additional regulatory interventions that could affect the profitability of those ventures. For example, in April, Prime Minister Malcolm Turnbull indicated that the government would introduce a new gas security mechanism allowing the imposition of export controls on companies when there is a shortfall of gas supply in the domestic market. This prompted Santos, Shell and Origin to provide a guarantee that there would be no shortfall in 2018, staving off the introduction of formal regulations. However, this was merely a temporary measure – uncertainty remains as to the likely long-term outcome.

Finally, any prospective investor in new generation could well be disconcerted by the increasing role of the state and Commonwealth governments in funding, subsidising or studying the feasibility of additional dispatchable generation capacity. These

81 See http://www.aemc.gov.au/Markets-Reviews-Advice/Reliability-Standard-and-Settings-Review-2018

government initiatives (which were detailed in the issues paper) risk 'crowding out' investment by private investors. Specifically, private investors may be less inclined to invest in new generation for fear that their returns will subsequently be truncated by government-sponsored initiatives, for example, subsidised generation.

It is not the task of this Review to fix, or make recommendations in relation to these various areas of policy uncertainty. But their potential impacts upon the reliability framework cannot be ignored either. For example, although the potential negative effects on reliability of continued policy uncertainty would, naturally, be best addressed by providing clarity, it may be unwise to assume that will happen in a timely fashion. Rather, we have assumed that the reliability framework may need to adapt to accommodate that ongoing uncertainty (rather than wait for it to be resolved), unless there is clear evidence that a policy resolution is likely to be reached in a timely fashion.

2.4 Policy responses to date

The reliability framework for the NEM has attracted considerable attention in recent times from both the mainstream media and various policy makers. Several important developments have occurred over the last year – some since the publication of the issues paper in August, all of which are discussed in chapter 1.

These include:

- After the September 2016 state-wide blackout in South Australia, the COAG Energy Council commissioned Dr Alan Finkel to produce a blueprint for security and reliability in the NEM. The Finkel Panel report, released in June 2017, laid out an 'orderly transition' plan to give the market greater certainty on how emissions will be cut over time, and how the entry of new technologies and exit of old power stations will be managed.[82]

- AEMO was tasked with identifying the minimum acceptable level of dispatchable capacity in a region and reporting back to the Minister of the Environment and Energy on this. It supplied that advice in September. AEMO concluded that there were insufficient such resources to maintain the defined target level of supply reliability.

- On 17 October 2017, the Commonwealth government announced a National Energy Guarantee (the Guarantee) proposed by the Energy Security Board. The Guarantee combines reliability outcomes and emissions targets to achieve a single energy price that guides investment in the lowest cost resources - addressing one of the problems identified in section 2.3.3 and the challenges arising from the changing generation mix described in section 2.3. On 24 November 2017, the COAG Energy Council supported progressing further extensive work on the design, including consultation in early 2018.

82 Dr Alan Finkel, Ms Karen Moses, Ms Chloe Munro, Mr Terry Effeney, Professor Mary O'Kane, Independent Review into the Future Security of the National Electricity Market, June 2017.

Some of that new policy impacts directly upon the reliability framework and is consequently directly relevant to this Review. As is explained below, it is vital to be mindful of those changes to avoid needless duplication of policy initiatives, that is, introducing multiple costly solutions to a single perceived problem.

The previous sections have highlighted a series of emerging challenges that are exacting pressure on the existing reliability framework. These challenges have raised questions about whether the existing framework remains fit for its intended purpose. Since this Review began, the Energy Security Board has made important policy recommendations that would involve fundamental changes to the existing arrangements. Other parties have called for even more radical change, including the introduction of a capacity market.[83] More generally, scarcely a day passes when a story relating to the reliability framework does not feature somewhere in the media.

One of the core objectives of this Review is therefore to provide a more holistic look at the reliability frameworks, with a view to proposing a coherent package for the future. Part of this task will necessarily involve 'stepping back' and examining the current arrangements, and the various changes that have been proposed already, identifying problems with the frameworks and then considering the detailed design of reforms that are likely to be the most efficient. Therefore, how you might design one aspect of the reliability framework (for example, the strategic reserve) will depend on the detailed design of other aspects for example, how you might design a wholesale demand response mechanism. These considerations and coordination of the various aspects of the reliability framework - including how this may interact with the National Energy Guarantee - will be considered further as this Review progresses.

83 Grattan Institute, Next Generation: The long-term future of the National Electricity Market, September 2017.

3 Key Concepts

This chapter sets out the key concepts that underpin reliability in the NEM, and which are used throughout the rest of this report, specifically:

- section 3.1 discusses "reliability" and "security"
- section 3.2 discusses "dispatchability" and "flexibility"
- section 3.3 "reserves"
- section 3.4 discusses demand response, and the various types of demand response.

3.1 Reliability and security

3.1.1 What is a reliable power system?

A “reliable power system” has enough generation, demand response and network capacity to supply customers with the energy that they demand with a very high degree of confidence. This requires several elements:

- efficient investment, retirement and operational decisions by market participants resulting in an adequate supply of capacity to meet demand plus a sufficient level of reserves
- a reliable transmission network
- a reliable distribution network, as well as
- the system being in a secure operating state, that is, one where the power system is in, or will return to, a satisfactory operating state[84] within 30 minutes.

As a result, a reliable supply of electricity to customers requires adequate network planning, generation capacity availability, maintenance of all parts of the electricity supply chain and a properly functioning market (as investment, which is required to provide reliability, is driven by the market). The focus of this Review is on the first element of a reliable power system i.e. having efficient investment, retirement and operational decisions by market participants resulting in an adequate supply of generation capacity, including sufficient dispatchable capacity to maintain a balance of supply and demand.

84 Defined in chapter 10 of the NER as that described within clause 4.4.2.

3.1.2 How is reliability different from system security?

Reliability is distinct from **system security**, as set out below.

System security
A secure system is one that is able to operate within defined technical limits, even if there is an incident such as the loss of a major transmission line or large generator. Security events are mostly caused by sudden equipment failure (often associated with extreme weather or bushfires) that results in the system operating outside of defined technical limits, such as voltage and frequency.
Reliability
A reliable system is one with enough energy (generation and demand side participation) and network capacity to supply customers – this implies that there should be enough energy to meet demand, with a buffer known as reserves (defined in section 3.3).

While the two concepts are different, they are closely related operationally and it is not always so simple to separate the two concepts. A reliable power system is also a secure power system (indeed, as set out above a secure power system is one element of having a reliable system). However, the converse is not necessarily true; a power system can be secure even when it is not reliable. For example, the NER allows AEMO to undertake involuntary load shedding, potentially compromising reliability, in order to return the power system to a secure operating state.

It is also worth noting that typically reliability issues occur at peak times, that is, where the demand-supply balance in the system is tight. For example, when the RERT was exercised in Victoria on 30 November 2017 this occurred at peak time, in the middle of the afternoon.[85] In contrast, security issues can arise at any time, and more often than not occur at off-peak times, when there are low demand conditions. For example, AEMO has frequently directed on participants in South Australia for system security purposes recently, with these frequently occurring at off-peak times: on 2 December 2017, AEMO directed on a participant in South Australia to maintain the power system in a secure operating state, with the direction issued at 0000 hrs.[86]

The Commission is considering system security through its *System security work program*, which is further detailed on our website and in Box 1.1 in this report.[87]

85 AEMO activated reserve contracts to maintain the power system in a reliable operating state. The reserve contracts were activated at 1530 hr 30/11/2017. See: market notice 60142, 30 November 2017, 15:20, market intervention.

86 The direction was issued at 0000 hrs 02/12/2017, with effect from 0100 hrs 02/12/2017. See: market notice 60176, 2 December 2017, 0:02, market intervention.

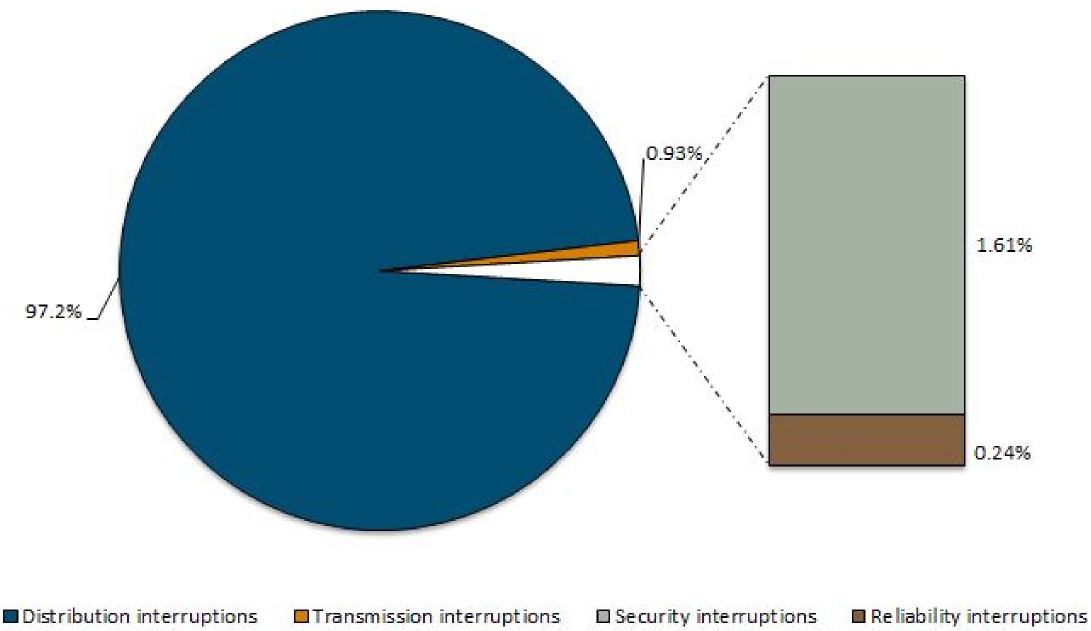
87 See: http://www.aemc.gov.au/Major-Pages/System-Security-Review

3.1.3 Supply interruptions

Consistent with the various elements of a reliable power system described above, there are a number of causes of supply interruptions to customers: reliability (e.g. having insufficient generation to meet demand); security (e.g. load being shed to manage frequency across the system); or network (e.g. a particular line being out driving a network outage). This Review is concerned with reliability related supply interruptions, which as shown in the brown area of the graph below only account for a small fraction of supply interruptions to consumers in the NEM.

Consumers who experience an interruption do not distinguish, nor are they likely to be concerned with the “type” of supply interruption: whether an outage is driven by a security event, a reliability event, or a network event. From a consumer’s perspective, the lights are either on or they are not. However, while the consumer may not be concerned with what is driving their interruption at a particular point in time, knowledge about what is driving the outages may affect their expectation in the long-term. For example, if a customer is aware that the outage is driven by a lack of reliability it may result in a higher expectation that there will be more outages in the future, rather than if it was a one-off security-related event.

Figure 3.1 Sources of supply interruptions in the NEM: 2007-08 to 2015-16



Source: AEMC analysis and estimates based on publicly available information from: AEMO's extreme weather event and incident reports and the AER's RIN economic benchmarking spreadsheets.

Figure 3.1 shows an indicative analysis of sources of supply interruptions in the NEM over the period 2007-08 to 2015-16. This shows that supply interruptions that stem from reliability issues (not having enough supply to meet demand), are relatively limited in number. Over the period, only about 0.24 per cent of total supply interruptions (in terms of GWh) was the result of inadequacy of supply. The vast majority was due to network interruptions, specifically from the distribution network.

3.1.4 Reliability in other jurisdictions

The definitions of 'system security' and 'reliability' that are used in Australia were developed prior to the commencement of the NEM. When the NEM and its roles and responsibilities were created this was done consistent with, and reinforcing of, these definitions. Specifically:

- "reliability" issues are typically resolved by the market; whereas
- "security" issues are operationally managed by the system operator.

Therefore, considering reliability and security issues in the NEM needs to be done in this context.

Other jurisdictions have different histories and drivers for their reliability and security frameworks, and so may have distinct definitions of what these terms mean. It is worth bearing this in mind when considering international examples, such as those discussed in appendix F. For example, in the United States, PJM defines reliability attributes as including frequency response, voltage control and ramping, which in the NEM would be considered 'security aspects'.[88] Another commonly used term in the United States that could be thought of as having a reliability connotation is "spinning reserve". As used in California, spinning reserve is the on-line reserve capacity that is synchronised to the grid, and ready to meet electricity demand within 10 minutes of a dispatch instruction by the independent system operator, with this used to maintain system frequency stability.[89] In the NEM, such services would be considered more analogous to the frequency control ancillary services (FCAS) regime and so a system security service.

3.2 Dispatchability and flexibility

For an electricity system to work properly and contribute to reliability, supply must equal demand plus reserves (near) instantaneously. As supply or demand changes, for example due to changing levels of consumption or output of generators, the rest of the system must respond to maintain the balance of supply and demand.

This Review was established to investigate what changes to existing regulatory and market frameworks are necessary to provide an adequate amount of capacity to meet consumer needs.

88 See: http://www.pjm.com/~/media/library/reports-notices/special-reports/20170330-pjms-evolving-resource-mix-and-system-reliability.ashx

89 See: https://www.caiso.com/Documents/SpinningReserveandNonSpinningReserve.pdf

'Dispatchability' and 'flexibility' are attributes of generators and load that are not currently defined in the NER.[90] Nevertheless, dispatchability and flexibility have always been important elements that are used to keep the NEM (or any electricity system) in balance.

3.2.1 Describing and measuring dispatchability and flexibility

The issues paper described the concepts of 'dispatchability' and 'flexibility' as below:[91]

- **Dispatchability** refers to sources of energy or load that can **respond to instructions** to increase or decrease output or usage. Resources that are dispatchable are valuable to maintaining the balance of supply and demand because their output can be instructed to be adjusted in response to changing supply and demand.

- **Flexibility** is the ability for generation or load to respond to changes in demand and supply in a **timely** manner. Resources that are more flexible are more valuable in maintaining the balance of supply and demand because they can adjust more rapidly to changes in supply and demand than less flexible generators and load.

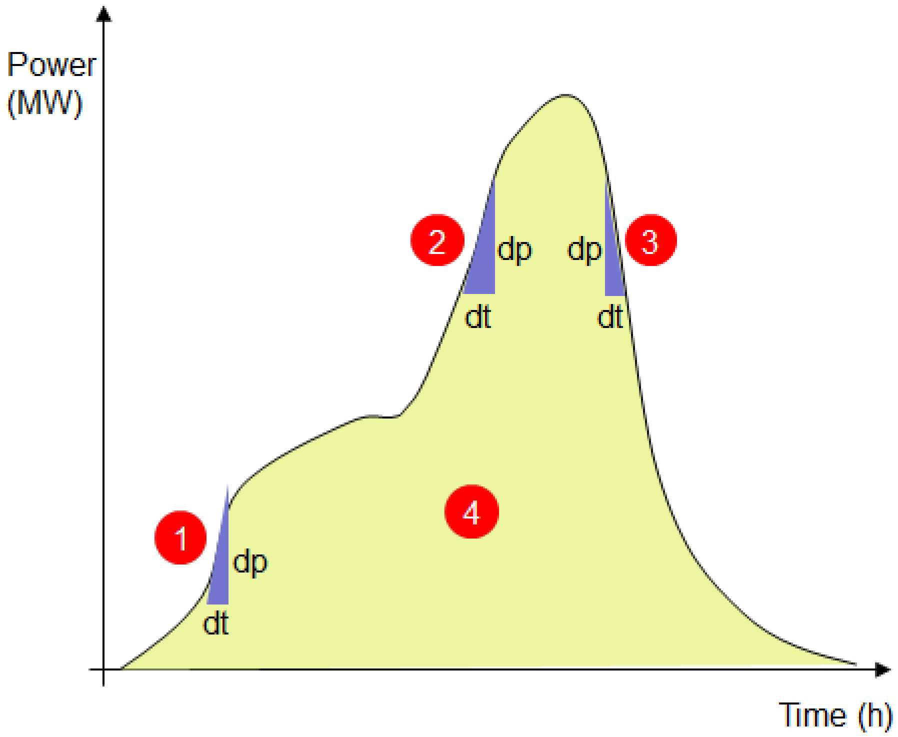
However, based on stakeholder feedback and our analysis, it is evident that defining these concepts is not as simple as set out above. For example, the above description would imply that dispatchability is a binary concept (it can either respond or it cannot) and does not take account of any element of timeliness. However, considering it this way is simplistic. For example, does a generator or load have to be available (that is, ready to respond) for it to be dispatchable?

An alternative construct would be to consider flexibility as a subset of dispatchability. However, defining whether a generator or load is flexible, or the extent of its flexibility, is arguably even more challenging than considering dispatchability. Figure 3.2 illustrates a small portion of the range of different ways by which a timely change to generation or load can be measured.

90 Although the concepts of "dispatch" (the act of initiating or enabling all or part of the response specified in a bid / offer in respect of a scheduled plant) and "rate of change" are defined.

91 See: AEMC, Issues Paper, Reliability Frameworks Review, August 2017, p. 8.

Figure 3.2 Flexibility metrics



The graph shows how power changes over time for a particular generator/load or collection of generators/loads. It highlights four potential measures of flexibility as examples:

- (1) maximum positive rate of change of power from start up[92]
- (2) maximum positive rate of change of power once operating
- (3) maximum negative rate of change
- (4) total energy available (area in green under graph).

As illustrated by the deliberately random shape of the graph, there are many other possible measures of flexibility.

There are many contradictions and trade-offs that exist in these concepts. For example:

- Batteries may be viewed as being flexible because they can be both generation and load, so can provide multiple services. However, their flexibility is limited by their capacity (approximately several hours' discharge).
- Solar can be considered flexible because it can be easily constrained off, but its flexibility is limited because the variable fuel source limits its ability to be turned on or increase its output.

92 Mathematically, the instantaneous rate of change of power (p) over time (t) is denoted as dp/dt.

- Coal plants can be flexible and dispatchable because they are predictable, but its flexibility may be limited by slow ramp rates.

Dispatchability and flexibility could be viewed as having common attributes. In this sense, we could think about "dispatchable and flexible" resources as being on a spectrum from those that are more of one thing, and less of another, to those that have qualities of both. However, this could also be problematic as there are likely to be other factors that may be relevant to these concepts and so to the electricity system, for example:

- predictability of the resource
- the capacity over time
- location of the resource
- the ability of the resource to match load and so on.

Creating definitions of flexibility and dispatchability that do not take into account the various trade-offs and complications is likely to result in too narrow definitions that could create perverse incentives.

For example, in California, there are three reliability mechanisms, each covering a different timeframe: the long-term procurement plan, considering long-term procurement with a ten year outlook; system and locational resource adequacy requirements to meet peak load plus a reserve margin requirement; and an out of market backstop reliability mechanism known as the capacity procurement mechanism. CAISO is currently looking to extend these reliability mechanisms to procure flexible resources in advance. Because of the fast development of solar PV, the daily demand profile has changed shape increasing the need for very fast ramping by thermal plants in the afternoon at sunset. Current proposals require load serving entities to also procure ramping capacity, in addition to energy capacity. We understand that one of the lessons from that effort is that it is extremely difficult to specify flexible capacity needs in a resource adequacy process and it is essential that these incentives be provided through the energy market. This is what CAISO has sought to do, implementing a flexible ramping product in real-time dispatch.

Similarly, in the UK, the capacity market was designed to exclude variable renewable generation – potentially resulting in higher costs to consumers, than would otherwise have been the case if a wider definition was adopted.[93]

In addition, we are of the view that the current framework already values these concepts in such a way that takes account of the overlaps and contradictions – as discussed below. The question is whether these mechanisms are sufficiently, and accurately, valuing these concepts.

93 Although we note that this would have to be weighed against the cost of having *too* wide a definition, and so potentially impacting on customer reliability outcomes.

3.2.2 Current framework for dispatchability and flexibility

The NEM currently already provides explicit incentives (or rewards) for generators and load to be flexible and/or dispatchable. This occurs through the combination of the ancillary services, spot and contract markets.

Ancillary services market

There are two types of ancillary services provided in the NEM: market and non-market ancillary services.[94]

Market ancillary services are concerned with the timely injection (or reduction) of active power to arrest a change in frequency. AEMO operates the wholesale electricity market, which dispatches electricity generation to meet the expected demand for electricity every five minutes. Some imbalance between supply and demand is expected to occur within the five minute dispatch process, which can cause frequency variations.

Market ancillary services are procured by AEMO to increase or decrease active power over a timeframe that maintains the technical performance of the power system. These services are collectively referred to as frequency control ancillary services (FCAS). 'Frequency' is a technical parameter in the power system, and so is therefore considered a security aspect (see section 3.1.2); however, it is still relevant to considering flexibility and so we discuss it here.

Box 3.1 Frequency control ancillary services

FCAS is sourced from markets operating in parallel to the wholesale energy market, with the energy and FCAS markets being optimised simultaneously so that total costs are minimised. There are eight markets in the NEM for FCAS, one for each type of regulating and contingency service.

There are two types of FCAS:

- regulation raise and lower services - used to correct a minor drop in frequency, with the operation of this co-ordinated by AEMO's automatic generation control system that monitors minor changes in the power system frequency and adjusts the output of regulating FCAS generating units accordingly
- contingency fast (6 second), slow (60 second) and delayed (5 minute) raise and lower services - procured by AEMO to respond to larger deviations in power system frequency that are usually the result of contingency events such as the tripping of a large generator or load.

94 Non-market ancillary services provide (black) system restart and network support (e.g. voltage control) services, and are provided by parties under contract with AEMO.

FCAS markets therefore value flexibility and dispatchability over a timeframe of seconds to five minutes. Resources that can respond "quickly enough" (i.e. they are controllable, and can respond in a timely manner) can benefit from receiving payments from participating in this market.

In addition, trends in prices in these markets incentivise participants to install equipment that enable them to participate in these markets. The cost of delivering ancillary services in the NEM (both market and non-market services) has increased significantly over recent years from roughly $100 million in 2012, to a year to date (40 weeks) total of over $180 million in 2017. To more easily compare these figures, the cost has increased from $2 million/week in 2012 to $4.45 million/week in 2017. The increased cost of market services can primarily be attributed to the increase in the cost of regulation services, which has increased by 16 times, or approximately $78 million over the period. As regulation services are provided through a market mechanism, this increase reflects the market clearing prices bid by generators to provide this service and, in the absence of significant market power, can be assumed to reflect the efficient cost of providing the service and to signal the opportunity for new entrants to participate in this market.

In response to the increased prices, we understand that more participants have, or are considering, registering to be FCAS providers in order to take advantage of the higher prices. Some of this has occurred since the Commission made a final rule to unbundle the provision of ancillary services from the purchase and sale of electricity, allowing new participants - market ancillary service providers - to enter FCAS markets.[95]

In timeframes greater than five minutes, flexibility and dispatchability are explicitly rewarded through the energy market and its associated contract market.

Wholesale spot market

Dispatchability and flexibility are also recognised in the spot market. For example, the profile and nature of output from variable renewable generation means that wind generation has, and can be expected to have, dispatch weighted prices that are less than the average spot price at its point of connection.[96] This "dispatch weighted price"[97] for wind generation as a percentage of the average spot price for 2015-16 varies across the NEM. For example, this discount is expected to be around 25 per cent in South Australia over the next 20 years. This reflects the fact that wind generation is not as "dispatchable" as other types of generation that can be more closely controlled and thus is not able to control output to catch the high value periods.

Consider what happens when there is a sudden and unexpected tightening of supply and demand, leading to a corresponding increase in prices in the energy market. Those generators that are able to adjust their supply upwards quickly will be rewarded for

95 See: http://www.aemc.gov.au/Rule-Changes/Demand-Response-Mechanism#

96 Regional spot price x marginal loss factor.

97 The dispatch weighted price is defined as generation revenue divided by generation quantity.

doing so through the high prices received for their generation output. Similarly, those generators that are able to adjust downwards are able to avoid incurring losses when prices suddenly and unexpectedly fall below their short run costs.

Conversely, generators that are less flexible bear a cost for this. Large-scale coal generators who ramp up and down slowly, or who have high minimum generation levels, face negative prices in the spot market in order to maintain their generation output at their minimum generation level in order to be "on" to respond to expected, higher spot prices later in the day. (It is not possible for large coal fired units to have a shutdown period of less than one hour in duration as the shutdown and start-up procedures would then overlap in time).

The incentives for both dispatchability and flexibility discussed above also inform efficient operation of plant - including matters such as plant maintenance, staffing and fuel resourcing.

The incentives provided through the wholesale spot market for the provision of dispatchability and flexibility are framed by the reliability settings. Rewards for being flexible and dispatchable generation are capped at the market price cap while losses for being inflexible or non-dispatchable are capped at the market floor price.

Contract market

The contract market also plays an important role in valuing these services. Variable renewable generators are unlikely to enter into firm derivative contracts to the same extent as dispatchable generators, because they cannot be confident they will be generating when prices are high, leading to potentially large payouts under the contract that are not covered through revenue from the spot market. In contrast, dispatchable generators are better able to offer these contracts, and so are rewarded through the contract market to the extent that demand for, and thus the value of, these contracts is high. Another benefit from participating in the contract market is that the price received for generation output is more certain, thus reducing risks. Similarly, load that is able to reduce its consumption can command a better price in the retail contract market because it reduces the risk to its counterparty of high spot prices.

The contract market also rewards flexible generation and load. To the extent that spot prices are becoming more volatile, retailers and other load-side market participants should place greater demand on contracts which manage their exposure to spot price spikes - in turn raising the price of these contracts. Inflexible or variable renewable generators typically do not offer contracts as they risk high payouts that are not covered by revenue generated through the spot market because they are unable to adjust their generation quickly enough in response to sudden and unexpected spot price rises. Flexible generators face less of this risk and are therefore more likely to enter into contracts, and so are rewarded in this market.

Furthermore, these incentives for both dispatchability and flexibility play into the investment timescales. High contract prices provide incentives for flexible and dispatchable generators/load to enter the market, and provide the mechanism by which investments can be bankable.

As discussed further in chapter 5 there are anecdotal examples of participants that have variable renewable generation investing in technology or equipment to "firm" up their capacity in order to respond to increasing contract prices that "value" dispatchability and flexibility.[98]

In addition, dispatchability and flexibility requires adequate plant maintenance, staffing, fuel resources. The market signals discussed above also incentivise the plant operator to manage these aspects as well.

Summary

Dispatchability and flexibility can therefore be considered to already be valued and rewarded in the existing market. Preliminary analysis shows that this is done in a way that takes into account the various contradictions and trade-offs that were set out above.

However, there are still several unresolved questions that we are considering further:

- Are the existing signals "accurate" or "precise" enough to fully reflect these concepts?
- Are there barriers that are limiting the market processes from driving the appropriate investment and operation decisions?
- Is there a lag between the signal for the need for dispatchable and flexible resources, and when investment in these resources actually occurs?

Conclusions on these questions would lead to a better understanding of whether, and if so how, definitions of 'dispatchability' and 'flexibility' could be created.[99]

3.3 Reserves in the NEM

Reserve levels are a concept defined in Chapter 10 of the NER and refer to the amount of spare capacity that is available giving consideration to amounts of generation, forecast demand, demand response and scheduled network service provider capability. In simple terms, reserves can be thought of as the amount of resources that

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98 Bloomberg New Energy Finance has recently undertaking some analysis on the cost of making onshore wind in Germany dispatchable. The costs can be as low as $52/MWh for a 25 per cent firming ratio and as high as $234/MWh for 100 per cent firming ratio. For utility scale PV, it was found that the cost of 'firming' is generally the same on a $/MWh basis but the size of the battery is smaller per MW of generating capacity, as is the amount of electricity firmed, due to PV's lower capacity factor. Source: Bloomberg New Energy Finance, The cost of making solar and wind dispatchable, the case of Germany, 5 December 2017.

99 We note that such questions will be important considerations when the Energy Security Board undertakes detailed design work on the National Energy Guarantee.

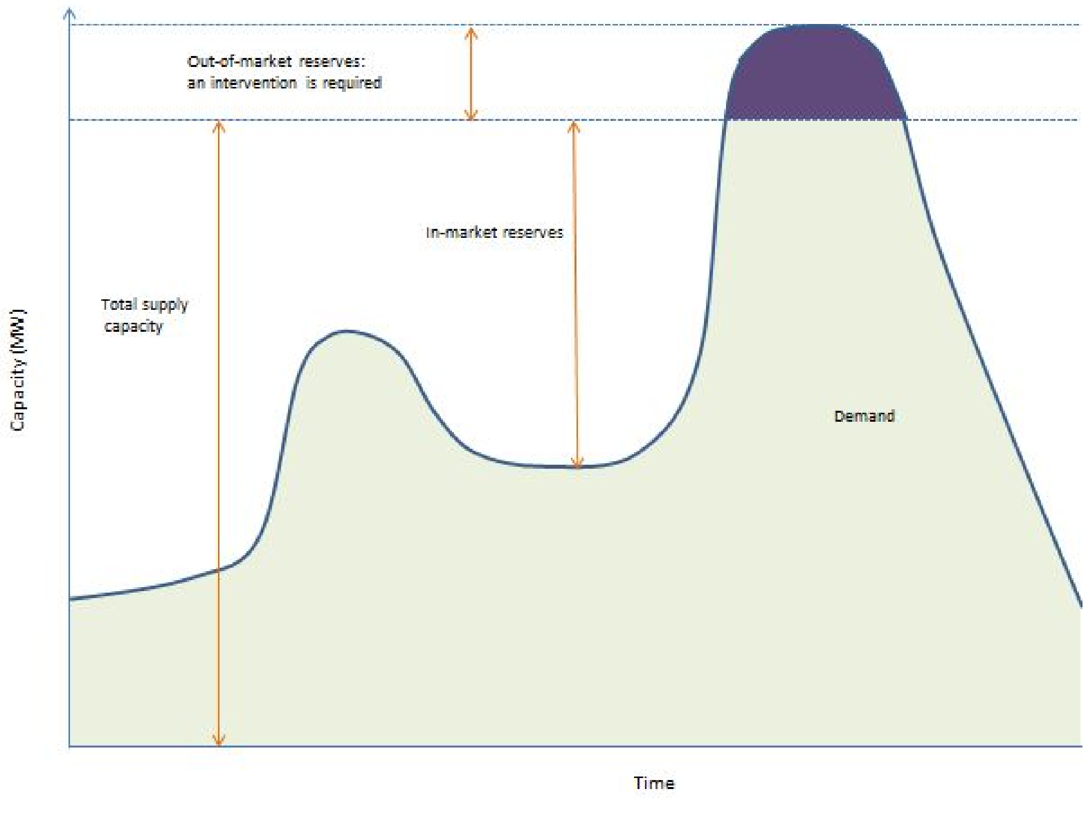
are available to supply the market, but that are not required to be used to meet demand at that point in time but may be required if demand or supply changes (for example due to generation equipment failure).

There are two types of reserves in the NEM:

Market reserves
Market reserves participate in the market and, at a high level, can be expressed as the balance of supply over demand.
Out-of-market reserves
Out-of-market reserves (for example, the reliability and emergency reserve trader (RERT)) are one of the available interventions permitted to be used by AEMO when it identifies, through a series of processes set out in the NER, that the market will not deliver enough market reserves to meet the reliability standard.

These are discussed in turn below with reference to Figure 3.3.

Figure 3.3 Reserves in the NEM



3.3.1 Market reserves

The level of market reserves indicates the difference between available resources provided by the market to meet demand for energy, and the level of energy demanded at a given time. In practice, market reserves also factor in inter-regional trading via interconnectors, that is, market reserves and generation can be shared across regions up to the capability of the interconnectors.

From a technical point of view, the power system is said to be reliable when the amount of available generation is enough to meet electricity demanded as well as a sufficient amount of reserves (to cover credible contingency events and forecast errors).

3.3.2 Out-of-market reserves

The Reliability and Emergency Reserve Trader (RERT) is an intervention mechanism that allows AEMO to contract for additional capacity (reserves) not otherwise available in the market for a period in advance of when AEMO projects there to be reserve shortfalls.

A projected reserve shortfall is where the amount of generation capacity is projected to be below the level consistent with the reliability standard. This means there is an increased probability of a shortfall of generation causing some consumers' supply to be interrupted.

The RERT is a strategic reserve and is used as a last resort to avoid involuntary load shedding – that is, consumers' supply being disrupted.[100] Reserves under the RERT are only available outside of the market (as shown in 3.3.2) and only procured after AEMO has forecast that the reliability standard is not likely to be met. The RERT is discussed in more detail in chapter 7.

3.4 Demand response

3.4.1 What is demand response?

Demand response is customers, specifically loads, changing their level of consumption in response to short-term signals to do so. These signals could be price signals from the wholesale market, or could be instructions coming from the market operator (e.g during an intervention event), a retailer or a third party.

Our definition of demand response focusses on *consumers* changing their consumption – in order to do so, consumers could employ on-site generation or batteries in order to manage changes to their amount of (grid) energy demanded.

100 There is a list of sensitive loads and priority loads that are maintained by the jurisdictional system security operators, typically for emergency services such as hospitals. Other than that, customers are typically disrupted at random without any regard to their actual value of reliability.

Demand response refers to dynamic and temporary changes to electricity consumption in response to short-term signals, as opposed to longer-term changes or trends in energy consumption. For example, if a consumer invested in energy efficient appliances to reduce the amount of energy consumed this would not be considered as demand response. However, if that consumer purchased appliances that allowed a consumption to be altered temporarily in response to, or in anticipation of, high prices this would be considered demand response.

Demand response would also be likely to contribute to the reliability of the power system. Without demand response and failing any other market response, AEMO manages periods of low reserves and restores the supply/demand balance by using the intervention mechanisms at its disposal, for example, by directing a generator on or using out-of-market reserves. If these are not available or effective, then involuntary, reductions in load are used. As a result, consumers do not have a choice in whether or not they are disconnected – it does not account for the willingness of individual consumers to pay for electricity (see Figure 3.3). A more responsive demand side would effectively reduce load in an orderly way, based on the value to consumers. This may reduce the amount of involuntary load shedding that is needed to restore the supply/demand balance, improving the reliability of the power system.

3.4.2 What are the four types of demand response?

By having consumers change their demand in response to signals, they are able to provide a number of services. Types of demand response can be defined by the service it is intended to provide. There are four types of demand response, disaggregated by the services it can provide:

- *Ancillary services demand response* – defined as demand response employed for providing ancillary services, for example, to respond quickly to brief, unexpected imbalances in supply and demand to return the grid to frequency utilised in the FCAS markets.

- *Network demand response* – defined as demand response employed to manage peak demand within a particular transmission or distribution network to help a network business to provide network services to consumers.

- *Wholesale demand response* – defined as market-driven demand response used to reduce the quantity of electricity bought in the wholesale market, either to reduce prices at times when wholesale spot prices are high, or to help market participants manage their positions in the contract market.

- *Emergency demand response* – defined as demand response employed as an emergency lever by the system operator during supply emergencies, the service being centrally dispatched or controlled to avoid involuntary load shedding. This can form part of out-of-market reserves, as discussed above.

The scope of the Review is confined to only considering wholesale demand response and emergency demand response. The Review does not consider demand response in the context of security related ancillary services (such as frequency control) or in relation to network support services. This is discussed further in chapter 6.

4 Forecasting and information provision

Key points

- In any electricity system, decisions need to be made for the future based on information forecasts made today - from decisions about the next five minutes, to investment decisions that will last years. This is unavoidable. As a market in the NEM, some of this information and forecasts is provided by market participants through investment and operational decisions, while some is provided by the system operator.
- Many stakeholders in this review consider that inaccurate forecasts are contributing to reliability issues in the NEM. However, analysis conducted to date does not definitively support this view. AEMO has also, and is committed to, making a number of improvements to its forecasting processes. In addition, many stakeholders have also suggested improvements that could be made to existing forecasting processes.
- The Commission agrees with AEMO that as the electricity system evolves it is likely that there could be increased errors in forecasting making it harder to for participants to participate in, and for the system operator to operate, the wholesale market. For example:
  - an increasing penetration of distributed energy resources, combined with a more responsive demand-side, will make it harder to forecast demand, particularly at a more granular level
  - a higher penetration of variable renewable generation, combined with more extreme weather days, will also likely increase variances and make it harder to forecast output from these resources.
- Increased variances may result in increased risks for participants (for example, knowing when to be available or to rebid), as well as for AEMO (for example, making it more difficult to manage reserve on tight demand-supply days and harder to work out when - or when not - to trigger the RERT).
- Therefore, the Commission considers it may be worthwhile exploring whether there are ways these variances can be better managed through the forecasting process; or alternatively, whether there are ways to rely less on forecasts. An example of the latter approach would be considering ways to get participants to reveal more information into market processes in order to better align risks and incentives.

A key aspect of the Review is considering forecasting arrangements and the information provision associated with this. Forecasting is an integral part of NEM operations, with forecasting occurring across:

- the long-term (e.g. the Electricity Statement of Opportunities which covers ten years in the future) to
- (very near) real-time (i.e. dispatch) timeframes.

Forecasting is undertaken by both the system operator (AEMO) as well as market participants. A key component of this aspect is the provision of this information (i.e. the forecasts) to the market. AEMO informs the market of these forecasts through a variety of mechanisms.

Forecasting is also related to many other workstreams that the Commission is considering as part of this Review, for example, day-ahead markets and strategic reserves.

This chapter is structured as follows:

- section 4.1 sets out a background to forecasting in the NEM
- section 4.2 summarises submissions in relation to the issue of forecasting
- section 4.3 draws together analysis on how accurate forecasts are and
- section 4.4 sets out the Commission's preliminary views.

4.1 Background to forecasting in the NEM

Forecasting affects all components of the NEM. Some forecasting is done by AEMO, while some is done by participants themselves. Appendix C provides further detail on forecasting in the NEM, but can be summarised as follows:

- AEMO provides a range of forecasts to the market over a range of timeframes, from ten-years out, through to real-time. The forecasting and information provision arrangements are an important feature of an efficient, reliable market.
- AEMO produces forecasts from its own analysis, but also uses information provided by participants as an input into its processes. . In some instances, it simply accepts what participants provide it and does not seek to cross-check this (for example, offers by scheduled generators and bids by scheduled loads into pre-dispatch). In other instances, it uses information from participants to inform its own forecasts, for example, information on wind turbine availability influences its forecasts of wind availability through the Australian Wind Energy Forecasting System (AWEFS).
- Participants also do their own forecasting in the NEM themselves, based on their own view of the future and their market position, with the outcomes from this

feeding into their investment and operational decisions. However, the process, input and assumptions that participants use is not always transparent. For example, generators have trading desks that monitor happenings in the market, which then drives their contract positions as well as operational decisions. Information based on their expectations is then submitted to AEMO for use in their information processes, for example, generators provide information to AEMO on when proposed generator outages may be for maintenance.

In this respect, forecasting is a key, foundational concept in the NEM and is self-reinforcing: participants have their own view of the future and make forecasts based on their expectations, which may get fed into AEMO’s processes. AEMO uses these inputs to refine its own forecasts, and then informs the market of these forecasts, for example, incorporating information on proposed network outages. In response to AEMO’s forecasts market participants will revise their own expectations of the future. The cycle continues.

Indeed, this was recognised by AEMO in its summer operations 2017-18 report, which noted that all AEMO forecasting relies on strong collaboration and the sharing of information across the energy industry and its customers.[101]

Broadly, forecasting can be broken into two timeframes – those used in central dispatch; and those used in the longer-term to drive investment and operational decisions. These are discussed in turn below.

4.1.1 Central dispatch

In balancing supply and demand in the NEM, AEMO must forecast for each trading interval:

- the amount of electricity demand that will occur in the market, (given the majority of demand is non-scheduled AEMO must forecast)
- the level of demand-side participation that occurs
- some of the sources of generation (for example, availability of semi-scheduled generation and output of non-scheduled generation).

AEMO uses this information, combined with availability bids and offers from scheduled loads and generation, to run central dispatch determining what generators will be required to generate electricity, and how much they will be required to generate in order to meet demand. The availability bids and offers from scheduled loads and generation are influenced by market participant expectations. Therefore, accurate forecasting - from both AEMO and market participant perspective - is an important feature of an efficient wholesale market.

101 AEMO, Summer operations 2017-18, November 2017.

In addition, market participants may also use the demand forecast information prepared by AEMO[102] in making business or process decisions (for example, generators in determining generation levels, consumers in determining how much to consume, and networks in deciding when to take maintenance) and so the accuracy of any demand forecasts may play an important role in achieving efficient market outcomes.

While there is more detail in appendix C, the below table summarises this information that is used in day-to-day operations of the NEM by AEMO. It is worth noting that being a scheduled load is optional for participants, and currently no participants have elected to become a scheduled load. Analysis of these inputs is in section 4.3 below.

Table 4.1 Central dispatch

Supply		Demand	
Scheduled generators	Participants are required to submit price/quantity offers over the pre-dispatch time horizon at a unit level, specifying their generation intentions at different market prices, and must comply with dispatch instructions from AEMO.	Scheduled load	Participants are required to submit price/quantity bids over the pre-dispatch time horizon specifying their consumption intentions at different market prices, and must comply with dispatch instructions from AEMO.
Semi-scheduled generators	AEMO forecasts generation via specific wind and solar forecasting models. The semi-scheduled generators then specify prices for their generation. AEMO can require these generators to limit their output to a specific level if required.	Semi-scheduled load	N/A
Non-scheduled generators	Generators are not required to provide information on their generation intentions. AEMO forecasts the output from this category. AEMO can impose conditions on registration under clause 2.2.3(c) or otherwise under clause 3.8.2(e) of the NER that would require such parties to comply with dispatch requirements that would normally only apply to scheduled or semi-scheduled generators.	Non-scheduled demand	Loads are not required to provide information on their consumption intentions. AEMO forecasts the demand from this category. AEMO can impose conditions on loads that are registered participants under clause 3.8.2(e) of the NER, which would require such parties to comply with specified dispatch requirements.

102 Or participants could use their own demand forecasts.

Participants can rebid their bids and offers. Rebidding by participants in the pre-dispatch scheduling period is an essential component of the NEM. Rebidding provides generators with the flexibility to adjust their positions to accommodate changes in market conditions and to respond to the offers or bids of other participants (see Box 4.1 below).

Box 4.1 Efficient price discovery process

Scheduled generators and loads are required to submit initial price/quantity offers for each 30 minute trading interval in up to ten price bands to AEMO by 12:30 the day before trading day. Rebids may be submitted up until the start of processing for the relevant five-minute dispatch interval by moving capacity between the nominated price bands, in response to changing market conditions.

Each generator’s initial offers submitted to AEMO are combined into a merit order and used to forecast the dispatch outcomes for the following day's trade. Initial offers that are based on a generator's genuine expectations of market conditions provide the best estimate that other participants can rely on to make their own commercial and availability decisions. As such, initial offers that are meaningful and broadly reflect the generator's market intentions can increase the predictability and efficiency of market outcomes.

As time progresses from the initial offers, rebidding provides the necessary flexibility to achieve an economically efficient dispatch of generation in the short-term. Rebidding facilitates an iterative process of price discovery as generators are provided with the necessary flexibility to adjust their position to accommodate changes in the market e.g. the actions of other generators.

Importantly, it is not the change in the market itself that triggers generators to adjust their position but rather the change in their expectations. The occurrence of a market event could be characterised as a change in market information that will impact on generators’ expectations as well as their expectations of other generators’ expectations.

While a change in the environment that is readily observable and objective may trigger a change in expectations, it could also occur in the absence of such a change. In practice, a generator’s offers will reflect its subjective expectations of any number of events occurring or not occurring.

While participants will generally have a good idea about the implications of the occurrence or non-occurrence of a given event on their relative position and costs, they are less likely to know the implications for other market participants and how they will react. As such, there is a process of learning that is typically undertaken following the occurrence or non-occurrence of a market event. The process may be quite short if participants are responding to a familiar event but could be substantially more protracted if the event is more complex.

Souce: AEMC, National Electricity Amendment (Bidding in Good Faith) Rule 2015, Final Rule Determination, 10 December 2015, p. 11-12.

4.1.2 Longer-term time frame

Beyond the central dispatch timeframe, market participants also do their own forecasting in order to make investment and operational decisions (for example, such as when to have their plant undergo maintenance). These forecasts, and decisions, are in part informed by a number of AEMO publications.

The publications produced by AEMO in relation to forecasting that are required under the NER:

- AEMO's Electricity Statement of Opportunities assesses supply adequacy across the NEM over ten years, taking into account any significant developments.[103]
- In the short- and medium-term, AEMO assesses supply adequacy through its PASA process, which involves collecting information and analysing if electricity supply can meet the reliability standard in the short-term (covering the period six days into the future, starting from the end of the trading day covered by the pre-dispatch schedule)[104] and medium-term (a two-year outlook),[105] and the very short-term, that is one day ahead via the pre-dispatch schedule.[106]
- AEMO's Energy Adequacy Assessment Projection is an information mechanism that provides the market with a two-year outlook on the effect of energy constraints in the NEM.[107]

In addition to these, until 2016, AEMO has also published the National Electricity Forecasting Report (NEFR), which has now been renamed the Electricity Forecasting Insights (EFI). The Electricity Forecasting Insights provides electricity consumption and maximum and minimum demand forecasts over a 20-year outlook period for the NEM regions. However, this is not a requirement under the NER.

4.1.3 Operationalising the reliability standard

Also relevant to forecasting, is how AEMO incorporates the reliability standard into its operations on a day-to-day basis. The NER does not give specific direction to AEMO on how to operationalise the reliability standard. Instead, it obliges AEMO to publish and amend the *reliability standard implementation guidelines,* which must explain how AEMO will operationalise the standard.[108] AEMO operationalise the standard through:

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103 Clause 3.13.3(q) of the NER.

104 Clause 3.7.3(h)(5)(ii) of the NER.

105 Clause 3.7.2(f)(6)(ii) of the NER.

106 AEMO also publishes 5-minute pre-dispatch (forecast) data by region, showing short term price and demand forecasts looking out one hour ahead. The information is updated every 5 minutes. This is not a requirement under the NER.

107 Clause 3.7C(a) of the NER.

108 Clause 3.9.3D(a) of the NER.

- six days ahead through short-term PASA
- two years ahead through medium-term PASA
- two years ahead through the Energy Adequacy Assessment Projection and
- ten years ahead through the ESOO.

The inputs and assumptions, as well as the calculation of reserves and reserve margins vary by process and timeframe. However, any errors that occur in relation to how reserves are calculated, and so the corresponding market notices of a lack of reserve condition, will necessarily inhibit market responses and so make it harder for AEMO to manage reserves. However, there have been recent improvements to these processes:

- From 15 February 2018, the medium-term PASA will operationalise the reliability standard by assessing the level of unserved energy and evaluating the likelihood of the reliability standard not being met through probabilistic modelling. This is a move away from the current process, whereby AEMO determines a minimum reserve level consistent with the reliability standard deterministically.
- The Commission made a final rule on 19 December 2017 to change the way that LOR levels are calculated by moving away from a deterministic framework to one that is probabilistic. Initially, the Commission understands that the LOR levels will still consist of the size of credible contingencies at a minimum, with an adjustment made for forecasting error (only when the error is larger than the credible contingency size), based on probabilistic modelling of reserves.

For further detail on how AEMO operationalises the reliability standard, refer to chapter 3 and appendix C.

4.2 Summary of submissions

The importance of forecasting to the reliability framework was recognised by many submissions to the issues paper.

A number of stakeholders (Snowy Hydro, Australian Energy Council, BlueScope, S&C Electric, Energy Networks Australia) consider that AEMO forecasting errors are potentially impacting on reliability in the NEM.[109]

Some stakeholders suggested specific improvements that could be made, for example:

- ENGIE suggested AEMO could assess the probabilistic output of each variable renewable generator individually instead of at a macro level across a region to better capture differences in the characteristics of each generator.[110]

109 See submissions to the issues paper: Snowy Hydro, p. 2; Australian Energy Council, p. 2; Bluescope, p. 2; S&C Electric, p. 2; Energy Networks Australia, p. 3.

110 ENGIE, submission to issues paper p. 2.

- S&C Electric considered that AEMO could improve its relationship with the bureau of meteorology in order to improve forecasting.[111]
- Clean Energy Council noted that there are alternative models for forecasting accuracy that could be used for example, the UK scheme for wind forecasting uses financial incentives to increase accuracy.[112]
- Snowy Hydro wanted more transparency into AEMO's forecasting processes and methods, as well as a better understanding of what AEMO intends to do to improve its forecasting accuracy.[113]
- Energy Networks Australia noted that good forecasting needs timely information from all appropriate sources, which involve a trade-off between the timing of such data and the accuracy of the forecast.[114]

In response, AEMO noted that it has a program of improvements to existing, as well as new modelling, approaches underway (discussed further in section 4.3). Further, AEMO noted that it is working with participants to incorporate forecast variances into more sophisticated risk management practices.[115]

4.3 Analysis of forecasting

In order to consider whether or not stakeholder concerns about forecasts affecting reliability outcomes in the NEM are true, or not, the Commission has analysed the accuracy of the different forms of AEMO's forecasts. These are discussed in turn below. (Obviously, since forecasts undertaken by market participants are commercial to that business, and likely, proprietary, we have been unable to analyse these).

It is worth noting that forecasts are always wrong – see Figure 4.3 below. While variances for forecasts were minimal from 2016 to 2017, the below chart shows that forecasts of demand have typically over estimated actual demand outcomes.

111 S&C Electric, submission to issues paper, p. 5.

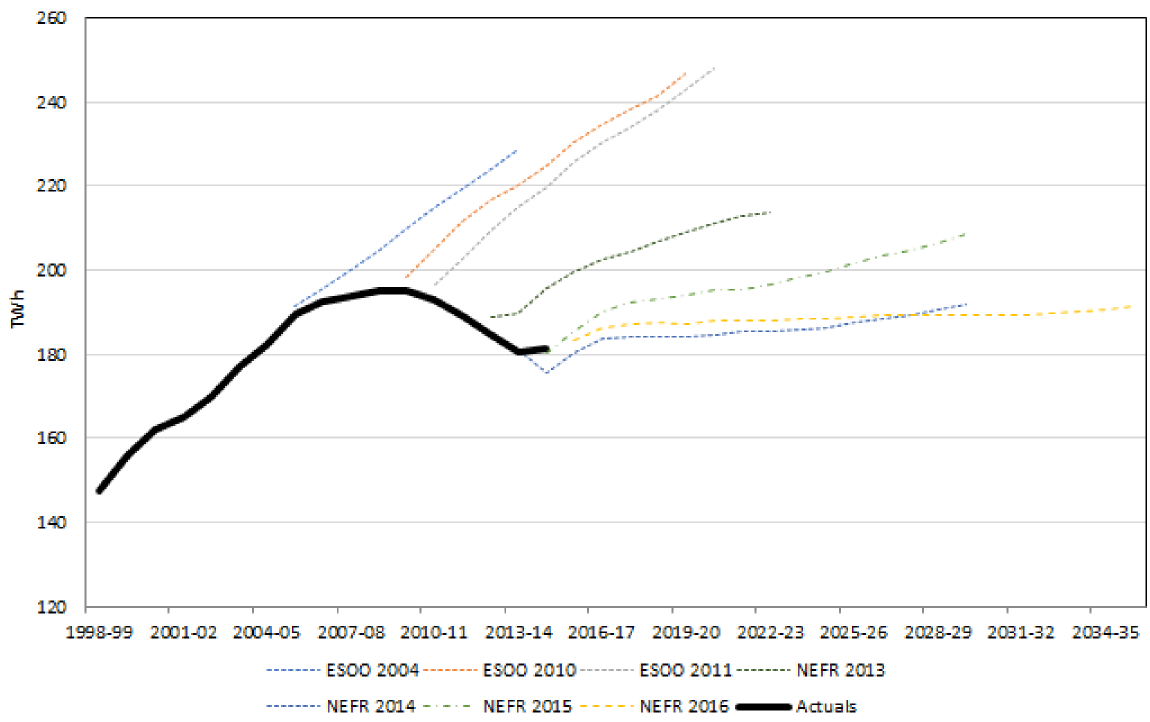
112 Clean Energy Council, submission to issues paper, p. 8.

113 Snowy Hydro, submission to issues paper, p. 2.

114 Energy Networks Australia, submission to issues paper, p. 3.

115 AEMO, submissions to issues paper, p. 6.

Figure 4.1 Demand forecasts - actual vs historical



Source: AEMO and AEMC analysis

4.3.1 Analysis of scheduled generation and load

Scheduled generation and load offers and bids are generated by market participants themselves, and so it is difficult to analyse these. We are considering how we can best analyse outcomes in pre-dispatch, as noted in chapter 8, and welcome stakeholder feedback on this. We will consider this further with our working group in early-2018, before this is then incorporated into the directions paper for this Review. Despite this, it is still useful to analyse the rationale for why participants provide this information to AEMO.

It is appropriate that these parties undertake their own forecasting. If generators or loads make the "wrong" offers or bids into dispatch then they bear the risks associated with that. However, there is reason to expect that scheduled generators or loads would provide better information than AEMO regarding their willingness to supply and the amount they are willing to supply. If the generator is wrong, then the incentives for future improvement would be stronger because they face a direct financial impact of the forecasts being wrong (for example, having too high an offer price and not being dispatched; or having a too low availability and missing out on revenue).

In addition, the Commission noted in the *Bidding in good faith* rule change request[116] that in the short term, participants make the best decisions they can in light of the available information and their capabilities, as discussed above. The resulting prices –

116 See: http://www.aemc.gov.au/Rule-Changes/Bidding-in-Good-Faith

reflective of short-term constraints – create signals for longer-term investment, retirement and operational decisions of both major consumers and generators. The dynamic process of participants learning and reacting to the actions of their competitors, and to the inherent volatility of the system, is an important part of a well-functioning market.

The work undertaken by Ernst & Young for the Commission indicated that deliberately late rebidding behaviour has had a significant consequential effect on the prices of financial hedge contracts.[117] In effect, some participants are paying a premium on contract market products in order to manage the price volatility that arose from deliberate late rebidding. This was estimated to have added around eight dollars per megawatt hour to the price of caps Queensland in the final quarter of 2014, and around seven dollars per megawatt hour in the first quarter of 2015. Across the market, this represented additional expenditure of approximately $170 million. The Ernst & Young report also provides quantitative support for the proposition that late rebidding impacts have differed between regions of the NEM.

Although late rebidding often has a role to play in responding to forecast price spikes and reducing anticipated market volatility, recent (at the time in 2015) behaviour in Queensland had resulted in price spikes, specifically towards the end of 30-minute trading intervals.

While offers apply to a whole 30-minute trading interval, rebids can be made during the trading interval and these affect the remaining 5-minute dispatch interval(s). Therefore, rebids made towards the end of a trading interval, to which other generators and consumers have difficulty in responding, can have the effect of significantly increasing the price in the final dispatch interval. Further, due to the settlement price being the average of that for the six dispatch intervals forming the trading interval, price changes in the final dispatch interval will apply to all energy consumed over the trading interval. Obviously, such an issue has recently been addressed through the final determination on *Five minute settlement*.[118]

The Commission also concluded in the *Bidding in good faith* rule change that rebidding is a tool that participants use to manage the risks of participating in the market. For example, rebidding may be used by a generator to manage an unplanned outage, or congestion-related dispatch risk. Consequently, a market that restricts rebidding may prevent participants from adequately managing their risks, dampening the signals for efficient investment and undermining the long-term efficient operation of the market in the interests of consumers.

There are also dispatch variances where scheduled participants do not precisely achieve its target - or, miss their target in a large way due to an unforeseen outage or tripping event. Under the current strict compliance obligation in clause 4.9.8(a) of the NER, a market participant is required to comply with a dispatch instruction unless to

117 E&Y, Non-scheduled generation and load in central dispatch rule change request, 5 September 2016.

118 See: http://www.aemc.gov.au/Rule-Changes/Five-Minute-Settlement

do so would, in that participant's reasonable opinion, be a hazard to public safety or materially risk damaging equipment. The AER is responsible for monitoring and enforcing compliance with these obligations. AEMO also monitors the extent to which generators comply with dispatch targets for the efficient operation of the market.

4.3.2 Analysis of semi-scheduled generation output

AEMO currently uses the Australian Solar Energy Forecasting Systems (ASEFS) and the Australian Wind Energy Forecasting Systems (AWEFS) to forecast the potential output of wind and solar generation. These systems cover the forecasting timeframe from five minutes to two years. The output from these systems are inputs into the unconstrained intermittent generation forecast (UIGF) with this used (amongst other things) in dispatch, five minute pre-dispatch and short-term PASA.[119]

While stakeholders (as noted above) are often critical of this output, there is little publicly available material on the accuracy of these forecasts. The two main sources are as described below.

AEMO is presently analysing the historical short-term accuracy of the Australian Wind Energy Forecasting Systems and Australian Solar Energy Forecasting Systems with the findings of this analysis leading directly into AEMO's development of the rule change request on the *Declaration of lack of reserve conditions* rule change request.[120] For example, on 8 February 2017 in South Australia, in the early afternoon, there was an unexpected fall in reserves that was not forecast by pre-dispatch early enough. This was partially due to an unexpected rapid decline in wind generation forecast by about 100MW.

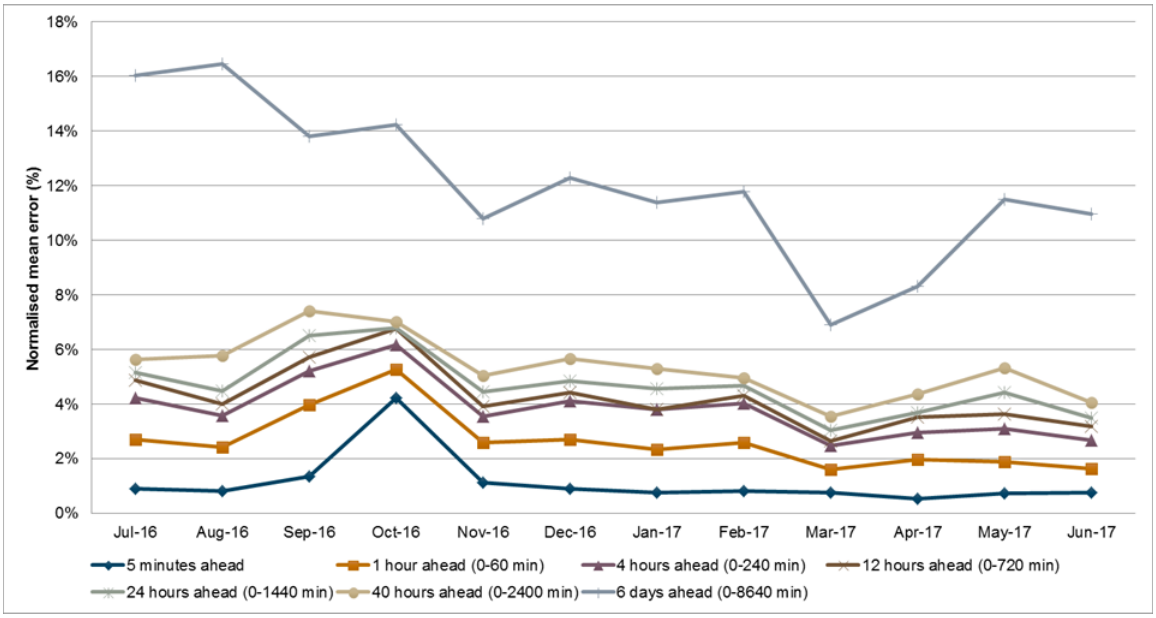
Forecast errors generally make it more difficult for AEMO to manage the system and for participants to respond. On that particular day, the wind forecast error contributed to a rapid decline in reserves. This meant that AEMO's ability to manage the system to a reliable operating state eroded. There was not enough time to inform the market that reserves were low, which could have provided a market response. Ultimately, involuntary load shedding was needed.

The Reliability Panel in its *Annual Market Performance Report* summarises the forecasting of variable renewable generation, in particular the performance of AWEFS based on the average percentage error across all regions in the NEM. The performance for 2016/17 is depicted below. As could be expected, the accuracy of the forecasts deteriorates as the forecast horizon increases. The highest normalised absolute error values correspond to situations when forecasting is difficult, for example, when there is high or low wind speed.

119 AEMO uses these forecasts to satisfy their obligation under clause 3.7B(a) of the NER to prepare a forecast of the available capacity of each semi-scheduled generating unit.

120 See: http://www.aemc.gov.au/Rule-Changes/Declaration-of-lack-of-reserve-conditions

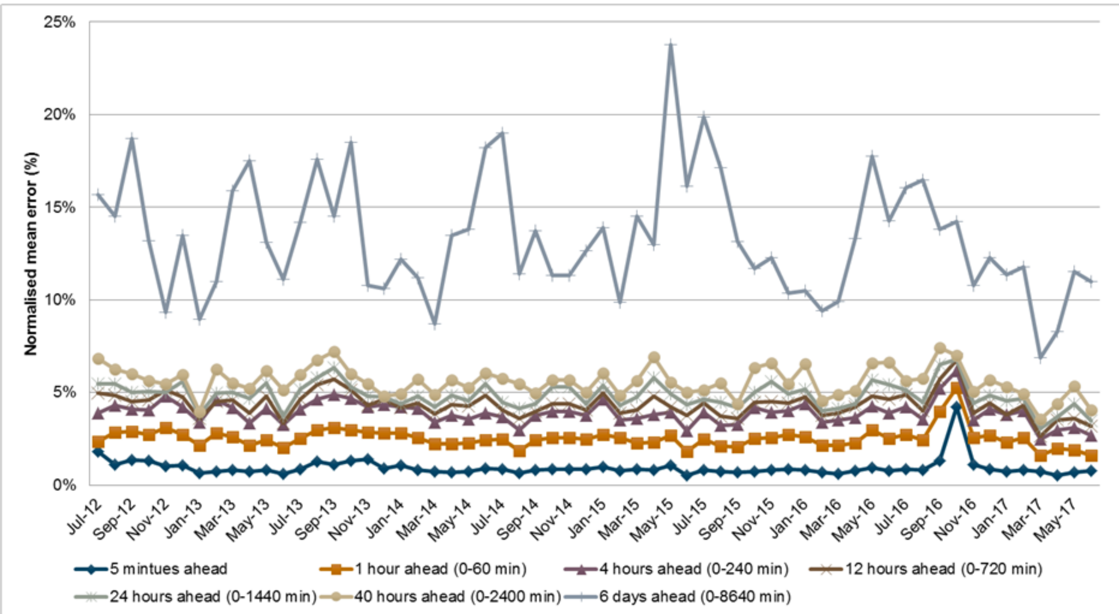
Figure 4.2 Australian energy wind forecasts 2016-17



Source: AEMO.

The figure below shows the performance of the system from 2012/13 to 2016/17. It shows that the forecast error of AWEFS has been relatively steady and increases in the amount of wind generation appear to have not significantly affected forecast performance.[121]

Figure 4.3 Australian energy wind forecasts 2012 - 2017



Source: AEMO.

121 The "spike" in errors in forecasts that can be seen in September 2016 can be explained by the system black event in South Australia.

4.3.3 Analysis of non-scheduled generation and demand and impacts on price

The effect to which non-scheduled generation and demand impact forecasts was recently considered by the Commission in the *Non-scheduled generation and load in central dispatch* rule change. In particular, the Commission considered whether the behaviour of non-scheduled generation and price-responsive load causes forecasting inaccuracies that leads to inefficiencies in the NEM.

To understand the materiality of the claims made by the rule change proponents the Commission undertook a detailed analysis of AEMO's demand and price forecasting inaccuracy, and it looked for evidence of causation related to any forecasting inaccuracy.

In relation to AEMO's demand and price forecast accuracy, the Commission found:[122]

- Demand forecasts are historically generally accurate at dispatch, which results in an efficient amount of generation being dispatched.

- While AEMO's price forecasts are not as accurate as the demand forecasts, this is to be expected as the price forecasts are a signalling mechanism to allow market participants to make and adjust their generation and consumption decisions ahead of dispatch. When spot prices are forecast to be above $300/MWh there is generally a market response that leads to actual spot prices being lower than forecast.

In relation to whether the forecast inaccuracy that does occur was caused by price responsive loads or non-scheduled generators, the Commission found (amongst other things) that the actions of non-scheduled generators and large price responsive loads were clearly not the only or necessarily the primary cause of forecast error and not all non-scheduled generators or load contribute to forecast inaccuracy, in particular price error. Other identifiable factors contributing to demand and price forecast inaccuracy included: the rebidding actions of scheduled generators, in particular in relation to price forecasting; and, general issues associated with forecasting models, and forecasting variable renewable and unregistered generation (that is, below the 5 MW registration threshold).

Therefore, the final determination concluded that the materiality of the issue raised by the rule change requests were insufficient to warrant making the proposed changes.[123] This includes the fact that the proposed changes would only apply to a limited number of generators and loads, and would therefore have limited impact on forecast accuracy.

However, the Commission also recognised the technological change that is currently occurring, which is likely to result in increased amounts of small generation and more

122 See: http://www.aemc.gov.au/Rule-Changes/Non-scheduled-generation-in-central-dispatch

123 The proposed changes were to mandate load be scheduled - this was deemed not be warranted given the limited number of new loads likely to connect. Further, the proposed changes to the non-scheduled category was not looking at non-scheduled participants less than 5MW, which is where the number of new connections is material.

responsive loads. In order to maintain a transparent market with accurate information for participants, the requirements to participate in central dispatch may also need to change. Any such change should take account of a broad range of factors and market design options, and be informed by the outcomes of the reviews and rule changes that are relevant to the central dispatch process and are currently underway (which would include this Review).

The Commission considered it was preferable for AEMO to continue to maintain and improve its forecasting and to manage system security issues, by means of its existing powers. To the extent AEMO considers its powers are inadequate to manage system security issues or to continue to forecast with reasonable accuracy, the Commission noted that it will work closely with AEMO to examine the issues and develop appropriate mechanisms to make sure AEMO has the necessary tools to operate the market.

As increased penetration of distributed energy resources occurs, AEMO considers that it needs more information about where distributed energy resources are in order to help manage the power system in a secure and reliable way. AEMO currently has a lack of visibility of a large number of distributed energy resources, which is impacting on its forecasting. Without proper visibility of distributed energy resources with current forecasting methodologies, AEMO cannot forecast the demand and supply balance as accurately as it could when energy was primarily supplied by thermal generators.[124]

AEMO is currently, or has recently considered, ways to improve its visibility of distributed energy resources:

- AEMO's demand-side participation guidelines will require registered participants to submit demand-side participation data annually at the national metering identifier (NMI) level from April 2018.[125]

- AEMO is also undertaking a range of work in the context of distributed energy resources and power system security, including its visibility of distributed energy resources project.

In addition, the COAG Energy Council has recently submitted a rule change request to the Commission to establish a national register for distributed energy resources (solar generation and batteries) to be administered by AEMO.[126]

124 See: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Reports/AEMO-FPSS-program----Visibility-of-DER.pdf.

125 This was the result of a recent rule change by the Commission. See: http://www.aemc.gov.au/Rule-Changes/AEMO-access-to-demand-forecasting-information

126 See: http://www.aemc.gov.au/Rule-Changes/Register-of-distributed-energy-resources

4.3.4 Analysis of forecasts on a longer-term timeframe

There has not been any detailed analysis by the Commission to date of the accuracy of forecasting done on a longer-term timeframe than central dispatch e.g. in the ESOO or the medium-term PASA.

However, every year, AEMO is required to produce a report, and provide this to the Reliability Panel, on the accuracy of demand forecasts to date in the Electricity Statement of Opportunities for the NEM. This report must also cover any improvements made by AEMO or other relevant parties to the forecasting process.

In the *2017 forecast accuracy report*, AEMO assessed its forecast accuracy by measuring the percentage difference between actual and forecast components of the published forecasts. It also compared actual maximum demand with published forecasts, as well as considering major forecast drivers, including weather (measured by heating degree days[127]and cooling degree days[128]).

This was the same method used in 2016. This method is simpler than was used in previous forecast accuracy reports and so it is difficult to compare with previous years.

In terms of forecasting accuracy for the 2016 NEFR forecasts, AEMO concluded that:

- Actual NSW operational consumption (GWh) in 2016-17 was 1.1 per cent above the 2016 NEFR prediction, due to the year being significantly warmer than normal resulting in more cooling degree days in NSW.
- Actual Queensland operational consumption (GWh) in 2016-17 was 0.7 per cent below the 2016 NEFR prediction, due to the overestimation of LNG consumption of electricity, due to a slower ramp-up of the LNG projects – although this was largely offset by actual consumption in other sectors being higher than forecast driven by significantly warmer weather than predicted.
- Actual South Australian operational consumption (GWh) in 2016-17 was 1.1 per cent below the 2016 NEFR prediction, with the 28 September 2016 blackout being a key contributor. Weather impact was closer to predictions.
- Actual Tasmanian operational consumption (GWh) in 2016-17 was 2.5 per cent below the 2016 NEFR prediction, due to significantly warmer weather than anticipated.
- Actual Victorian operational consumption (GWh) in 2016-17 was 5.0 per cent below the 2016 NEFR prediction, with the key reason being the outage of the Portland smelter in December 2016.

127 The number of degrees that a day's average temperature is below a critical temperature. It is used to account for deviation in weather from normal weather standards.

128 The number of degrees that a day's average temperature is above a critical temperature. It is used to account for deviation in weather from normal weather standards.

From these results we can see that the key variances in AEMO's forecasts were weather and changes in participant behaviour (for example, the Portland smelter being on an outage).

Box 4.2 Improvements to AEMO's forecasting methods

In the *2017 forecast accuracy report* AEMO set out a number of improvements they are currently making to forecasting.[129]

In particular, AEMO note that since 2016 it has:

- Added more detailed 'bottom up' models based on customer meter data to demand forecasts, which better reveals dynamics that originate beyond the grid, as well as putting more weight on recent historical data compared to using longer time series data where demand relationships can differ
- Updated PV and battery storage forecasts to account for lower prices during the "solar trough" (the period in the middle of the day when supply from rooftop and utility scale PV systems will meet an increasing share of the customer demand, causing wholesale prices to fall)
- Adopted updated electricity consumption forecasts for electric vehicles
- Undertaken climate change normalisation of historical weather input data and long-range climate forecasts, based on advice from CSIRO and Bureau of Meteorology.

Further, it sets out in this report that there are a number of other improvements currently underway:

- AEMO is developing a forecasting insights analytical platform, allowing for more regular updates to forecasts and tracking of the impact changes to any forecasting component make on overall forecasts
- AEMO is undertaking an analytics program, studying historical detailed meter data to observe consumption patterns down to individual consumer segments.

In addition to the forecast accuracy reporting, AEMO recently submitted the *Declaration of lack of reserve conditions* rule change request to the Commission, which sought to move to a more probabilistic assessment of lack of reserve conditions. The Commission has made a final rule that is largely as proposed by AEMO with some amendments to improve transparency. The Commission also notes that a new process for the medium-term PASA will apply from February 2018, which will improve the outputs of the medium-term PASA and more accurately reflect the implementation of the reliability standard.

129 AEMO, Forecast accuracy report 2017, for the 2016 National Electricity Forecasting Report, November 2017.

Finally, AEMO's recent summer operations 2017-18 report highlighted further improvements that AEMO is currently pursuing a number of improvements to its forecasting, largely related around weather:[130]

- Updating demand forecasting models to improve modelling of latent heat build-up and the modelling of micro-climate zones (such as the difference between coastal and inland city temperatures due to the strength of a sea breeze), leading to improved forecasting accuracy during extreme conditions.
- Collaborating with weather forecasting suppliers to obtain detailed alerts on weather-related events that could impact power system operation, such as heatwaves and sudden changes in wind or cloud conditions that affect the output of wind or solar generation.
- Developing tools and systems to provide real-time alerts when weather events cause forecasting uncertainty to increase. This will allow power system controllers to take pre-emptive action, such as reconfiguring the network and/or increasing the availability of reserves, in case actual events differ greatly from the forecasts.
- Engaging a resident meteorologist, seconded from the Bureau of Meteorology, to work out of the AEMO office and provide expert weather forecast advice directly to operational staff.
- Receiving monthly updates from the Bureau of Meteorology on its climate and weather forecasts.

4.4 Commission's preliminary views

In any electricity system, decisions need to be made in the future based on information and forecasts made today - from operational decisions about the next five minutes, to investment decisions that will last years. This is unavoidable. As a market, in the NEM, some of this information and forecasts is done by market participants through investment and operational decisions, while some is done by the system operator.

Many stakeholders in this review consider that inaccurate forecasts are contributing to reliability issues in the NEM. However, analysis conducted to date - as summarised above - does not definitively support this view. In addition, many stakeholders have also suggested improvements that could be made to existing forecasting processes. AEMO has a number of these already in train, as discussed above.

We agree with AEMO that as the electricity system evolves it is likely that there could be increased errors in forecasting making it harder for participants to participate in, and the system operator to operate the wholesale market. For example:

130 AEMO, summer operations 2017-18, November 2017.

- an increasing penetration of distributed energy resources, combined with a more responsive demand-side, will make it harder to forecast demand, particularly at a more granular level
- a higher penetration of variable renewable generation, combined with more extreme weather days, will also likely increase variances and make it harder to forecast output from these resources.

Increased variances may result in increased risks. Participants may find it harder to work out what to respond to, and so when to rebid. AEMO may find it more difficult to manage reserve on tight demand-supply days and harder to work out when - or when not - to trigger the RERT. Therefore, it may be worthwhile exploring whether there are ways these variances can be better managed through the forecasting process; or, alternatively, there are ways to rely less on forecasts. This is explored below.

In addition, AEMO has advocated in their submissions to the *Reliability Frameworks Review* and the *Five Minute Settlement* rule change the need for increased transparency, in particular the need for a day-ahead market. AEMO consider that a day-ahead market would increase the transparency and certainty for the operation, which has the potential to reduce the margin of error in forecasting and allow the system to be operated less conservatively. This is considered further in chapter 8.

4.4.1 Central dispatch

As discussed above, for scheduled generation and loads in the NEM, participants provide their own inputs into AEMO's central dispatch system based on their expectations of market conditions, while AEMO forecasts the output of semi-scheduled and non-scheduled generation as well as non-scheduled loads.

The NEM relies on forecasts of real-time energy prices and the financial derivatives market to provide incentives for market participants to co-optimise their energy availability across time *themselves* through their offers and rebids into the market.

This should result in efficient outcomes since it leaves forecasting demand and supply, and decisions regarding unit commitment, in the hands of market participants - who have a strong financial incentive to act efficiently and bear the risk of not doing so (rather than consumers).

For further explanation of the efficiencies associated with this, see Box 4.3 below.

Box 4.3 Risk allocation

One of the main elements in choosing a market design or form of regulation is deciding who takes responsibility for the various risks that are present. For the electricity system the most relevant risks are:

- demand for electricity and/or prices being more or less than anticipated
- supply-side costs changing (for example, changes in relative fuel costs), resulting in resource types becoming economically obsolete, or at least uncompetitive and
- project costs being higher than anticipated at the planning stage.

The placement of risk should lead to:

- Mitigation of risk: the consequences of that risk should it materialise (that is, the potential for loss - either in a financial or a physical sense) being avoided or lessened.
- Incentives to improve risk management: incentives being created for the risk management to improve over time. That involves allocating risk to a party who can, relative to others, better manage the consequences of that risk.

This can occur if the party holding the risk has:

- Incentives to manage the risk, because it stands to gain or lose from doing so, and there is a clear link between its actions and the outcomes of the risk.
- More information than other parties to manage the risk. It can use this information to better mitigate the impact of the associated loss.
- The ability to better manage risk than other parties, and so it can take actions to avoid or reduce the impact of the associated loss.
- The ability to improve risk management over time through experience. The party can learn and become more adept at risk management, meaning that it might make fewer errors in the future, or the likelihood of errors would become lower over time.

An efficient allocation of risk should enable parties to make better investment and operational decisions.

However, while scheduled generation and load make their own offers and bids, semi-scheduled generation nor on demand do not. The implications of better aligning the risks associated for these participant categories are set out below.

Semi-scheduled generation

AEMO has recently raised concerns about how the variances from variable renewable generation (that is, semi-scheduled generation) are becoming more significant. AEMO forecasts output of these types of resources through the AWEFS and ASEFS.

At the time the semi-scheduled generation category was introduced into the NER it was noted that these large, variable renewable generators cannot practically comply with some of the rule requirements for scheduled generators, such as following a dispatch target. This assumption could be questioned in today's environment of more sophisticated generator technology, as well as the increasing trend for variable renewable generation to install batteries to "firm" up their capacity.[131] It was also noted that there were scale efficiencies associated with AEMO doing the forecasting for these generation types on behalf of the generators themselves.

Given recent developments, such as more advanced cloud and wind monitoring resources (for example, geospatial mapping of solar and wind), some participants are of the view that they could do a better and more accurate job of forecasting than AEMO. Indeed, most renewable generators deploy their own meteorological equipment and their own forecasting.

In AEMO's final report for its consultation on amendments to the wind energy conversion model guidelines and the solar energy conversion model guidelines, it noted that it is considering the possibility of semi-scheduled generators offering their availability for dispatch and pre-dispatch through the dispatch engine.[132] We also understand that ARENA and AEMO are currently considering undertaking a trial on creating an open real-time geospatial platform for short-term weather forecasts.

Our preliminary view is that allowing semi-scheduled generators to offer their availability could be worthwhile exploring on a trial basis. It is likely that allowing semi-scheduled generation to provide their own 'offers' of their availability into AEMO's system could be relatively low-cost. One way to manage this, for example, would be for this to occur on an opt-in basis. Undertaking this on a trial basis would allow a better understanding of any technical (e.g. SCADA) challenges associated with this.

We also understand that there are issues associated with how offers are managed for semi-scheduled generation that seeks to install a battery at the same site (in order to

131 Bloomberg New Energy Finance has recently undertaking some analysis on the cost of making onshore wind in Germany dispatchable. The costs can be as low as $52/MWh for a 25 per cent firming ratio and as high as $234/MWh for 100 per cent firming ratio. For utility scale PV, it was found that the cost of 'firming' is generally the same on a $/MWh basis but the size of the battery is smaller per MW of generating capacity, as is the amount of electricity firmed, due to PV's lower capacity factor. Source: Bloomberg New Energy Finance, The cost of making solar and wind dispatchable, the case of Germany, 5 December 2017.

132 See: https://www.aemo.com.au/-/media/Files/Stakeholder_Consultation/Consultations/Electricity_Consultations/2016/Energy-Conversion-Model-Guidelines-Consultation---2016-Final-Report-and-Determination.pdf.

'firm' up its output). Under AEMO's interim arrangements for utility scale battery technology, AEMO has indicated that generators with a battery storage facility with a nameplate rating of more than 5MW but less than 30MW should consider applying to have their generating units classified as a scheduled generating unit. AEMO has noted that the situation becomes complicated if you are proposing to install battery storage within an existing semi-scheduled generating system. This would require a reconsideration of the classification of the whole site. AEMO notes it may consider that the combined installation could be reclassified as scheduled, but that it will make this determination on a case by case basis.

The above suggestion for semi-scheduled generators to submit offers into central dispatch would help to make this situation clearer.

Finally, the Clean Energy Council raised an example of what happens in the UK, where, as part of its system operator role and balancing function, National Grid has incentives placed on it to become better at forecasting. National Grid faces general incentives to improve its balancing operations, but also faces (or is about to face) specific incentives to improve its forecasts of short-term demand and wind generation. Ofgem noted that accurate forecasts allow better system operator planning of balancing actions, as well as helping market participants self-balance and respond effectively to price signals.[133] Imposing incentives on the system operator in the UK is possible since it is a for-profit entity. However, AEMO is not, and so we do not consider this example to be that relevant.

Non-scheduled generation

In relation to non-scheduled generation, these generally have a nameplate capacity between 5 MW and 30 MW. These generators are not required to provide information on their generation intentions. AEMO forecasts the output from this category, and generally does not constrain their generation output.

The Commission recently considered the issue of whether or not this class of generation could be scheduled, but concluded that a more preferable course of action is for AEMO to continue to maintain and improve forecast accuracy by means of its existing powers.[134] To the extent AEMO considers its powers are inadequate to manage system security issues or to continue to forecast with reasonable accuracy, the Commission will work closely with AEMO to examine the issues and develop appropriate mechanisms to ensure it has the necessary tools to operate the market.

133 See: https://www.ofgem.gov.uk/system/files/docs/2016/08/electricity_system_operator_incentives_from_2017.pdf

134 The Commission considers AEMO has various powers to seek information and manage system security that may be used to maintain and improve its forecasting accuracy – specifically AEMO has the power under clause 3.8.2(e) of the NER to require market participants to participate in the central dispatch process if it considers such participation is reasonably necessary for adequate system operation and the maintenance of power system security, and it has the power under clause 2.2.3(c) to impose any terms and conditions it considers reasonably necessary in respect of a generator at the time of registration.

Demand-side forecasting

Perhaps the biggest challenge in relation to forecasting and central dispatch, is that as the proportion of demand side participation increases, it is likely it will become harder for the system operator to forecast demand and so to follow that demand with flexible and dispatchable supply.

One potential solution that has been raised by some stakeholders is having the demand-side participate more directly in central dispatch. Currently, as there are increasing amounts of distributed energy resources, and responsive demand-side, this could result in what appears to AEMO as being an increase in load volatility, giving rise to larger five-minute forecasting errors in the dispatch process, and so an increased need for frequency control ancillary services to manage the resulting real-time supply-demand balances. In particular, the increasing variability of the demand side is likely to result in two potential problems for forecasting:

- the retailer or aggregators might dispatch controlled distributed energy resources (for example, virtual power plants), which creates forecasting errors, because they are not controlled by AEMO
- uncontrolled distributed energy resources may respond to short-run prices in way not predicted or predictable by AEMO.

One potential solution could be for AEMO to request more information from retailers or aggregators about any distributed energy resources (for example, virtual power plant) dispatch intentions and expectations. AEMO recently published the demand side participation information guidelines, which seeks to receive some of this information from participants. Such an option is also closely linked with considerations for a mechanism for demand response.

Using this information, AEMO could enhance its five-minute forecasting models in order to estimate the level of distributed energy resource response to wholesale energy price changes and include these estimated responses as notional bids in the dispatch calculation.

A logical extension of this would be for retailers themselves to do the forecasting, and submit bids into AEMO's system to then be "dispatched". You would expect that this would reduce errors in demand forecasts, since errors made by individual retailers would average out e.g. some would be “up” and some would be “down”. This can be considered an example of how we could reduce the reliance in the market on a particular set of forecasts. Obviously, such a change would be significant compared to the current regime and would involve high costs. We are interested in stakeholder views on whether this is an option worth exploring.

4.4.2 Longer-term forecasting

As discussed in Box 4.2 AEMO has recently made moved its medium-term PASA process, as well as lack of reserve framework, to a probabilistic methodology. These are positive improvements, and help market participants have more accurate information in order to make investment and operational decisions in the market.

4.4.3 Credible contingencies

As noted in the issues paper for this review, the concept of a credible contingency is a key concept in the NER, underpinning both the reliability, as well as the security framework. An example of the concept being used for one aspect of security is that AEMO is required to maintain the power system frequency within the operational frequency tolerance band when credible contingencies occur, and must return the frequency to the normal operating frequency band within a specified time period. Similarly, networks face a number of obligations to plan and operate their networks for credible contingency events.

Box 4.4 Credible contingency framework

NER clause 4.2.3(b) defines credible contingencies as a contingency event the occurrence of which AEMO considers to be reasonably possible in the surrounding circumstances, including the technical envelope. They may be caused by events such as the loss of a single generator, a single load or a single line in the network.

The NER therefore provides guidance to AEMO as to which contingencies should be regarded as credible but leaves AEMO with some discretion. AEMO has the discretion to reclassify contingency events from non-credible[135] to credible when it considers that the presence of abnormal conditions (for example, severe weather conditions) means that the non-credible contingency is now more likely to occur.

AEMO has recently raised concerns that the concept of credible contingency may no longer be appropriate in the context of reliability and security outcomes in the current environment, where variances from demand and variable renewable generation may be greater than the loss of a largest generator.

The credible contingency definition is a fundamental concept throughout the NER, and underpins security and reliability frameworks. Therefore, significant additional analysis will be required when considering any changes: to assess the potential impacts, any unforeseen consequences, and any flow-on effects relating to costs.

135 Clause 4.2.3A(g) of the NER.

However, the Commission has made several recent changes to the NER and Frequency Operating Standard that are relevant to this discussion:[136]

- In the final determination of the *Declaration of Lack of Reserve* rule change, the Commission made a final rule that removes the deterministic, credible contingency-based descriptions of lack of reserve from the NER and replaces them with a single high-level definition for lack of reserve, as well as a requirement for AEMO to make guidelines that set out how AEMO will determine, at least three, lack of reserve conditions. The final rule enables AEMO to declare lack of reserve conditions in a manner that takes into account forecast errors.[137]

- In the Reliability Panel's final stage one report for the Frequency Operating Standard, the Reliability Panel included a revised definition of a 'generator event' including the sudden, unexpected and significant change in output from one or more generating systems of 50 MW or more within a 30 second period. The standard still refers to the concept of credible contingency.[138]

We are still considering the broader implications of credible contingences further but would note that the issue seems to be heavily associated with the issue of forecasting. One interpretation of AEMO's concerns is that the variability of solar PV and wind generations are deviations from five minute forecasts or trajectories. It therefore follows that a rapid change in load of a wind farm or a solar PV field can be forecast (or output controlled to match the forecast) should the incentive be placed on the operator to do so, or if some of the changes flagged above were introduced. We will continue to analyse and consider these issues, but would welcome stakeholder views in relation to this.

136 In addition, in March 2017 the Commission made a final rule to help protect the power system from emergencies through a new management framework for emergency frequency control schemes. These are ‘last line of defence’ mechanisms such as controlled load shedding, designed to protect against a major blackout if a sudden and unexpected loss of generation or load causes rapid changes in system frequency. The new rules require AEMO to regularly and transparently assess emerging risks caused by swapping out older synchronous generators, for non-synchronous generation technology like wind and solar. For further information, see: http://www.aemc.gov.au/Rule-Changes/Emergency-frequency-control-schemes-for-excess-gen

137 See http://www.aemc.gov.au/Rule-Changes/Declaration-of-lack-of-reserve-conditions

138 See http://www.aemc.gov.au/Markets-Reviews-Advice/Review-of-the-Frequency-Operating-Standard

5 The contract market

Key points

- A reliable supply in the NEM is supported by the inherent and symmetrical incentive for buyers and sellers to enter into contracts to have more certainty over costs and revenue over time.
- It is not evident that the level of trading in the contract market should be cause for concern:
  - While some stakeholders indicated potential problems, others provided examples and healthy signs of adaptation to the spot prices signalled by the changing generation mix.
  - Our data on ASX futures trading does not confirm the results of charts we received from stakeholders that suggest liquidity in the contract market should be cause for concern.
- However, we are concerned that information on the contract market is not widely available, providing an advantage to the relatively few businesses that make the most trades and making it hard to evaluate the health of the market.
- The forward price curve is important information for making good investment and operational decisions. The Commission recommended in its *2017 Retail energy competition review* final report that industry should develop a credible survey to address the lack of data for electricity trading hedging products. We are therefore pleased the Australian Financial Markets Association (AFMA) is restarting its survey of the turnover of OTC contracts and intends backfilling missing data so the series will be unbroken. We understand that AFMA intends publishing the results sometime in the first quarter of 2018.

This chapter provides a summary of how the contract market supports the reliability framework, as well as analysis of recent and future trends in the contract market. It is structured as follows:

- section 5.1 discusses the background to the contract market
- section 5.2 presents a summary of stakeholder comments in submissions to the issues paper that relate to the contract market
- section 5.3 contains the Commission's preliminary views.

5.1 Background

5.1.1 The contract market supports reliability

Reliable supply in the NEM is supported by the inherent and symmetrical incentive for buyers and sellers to enter into contracts to have more certainty over costs and revenue over time.

For an electricity system to work properly and contribute to reliability, supply must equal demand plus reserves (near) instantaneously. Because of this need to co-ordinate supply and demand in real time, the mechanisms for buying and selling electricity at the wholesale level are divided into two parts:

- A formal spot market, governed by the NER and operated by AEMO, which co-ordinates the physical operation of the power system.
- A voluntary and informal financial hedge contract market, which provides parties with more certain revenues and costs over the term of their contracts.

All electricity traded in the NEM must be settled through the spot market (known as a gross pool). The variability of demand and supply conditions results in fluctuations in spot prices, which can range from the market price cap of $14,200/MWh to the market floor price of -$1,000/MWh.[139] Both buyers and sellers appreciate that large swings in spot prices have a similar but opposite effect on their costs and revenue and, consequently, their profits and share price. This encourages both buyers and sellers to agree to contracts that convert volatile spot revenues and costs for a more certain cashflows or to help underwrite further investment in both generation and retail assets (vertical integration).

While its primary role is to smooth the cash flows of buyers and sellers to manage these risks, the contract market also supports reliability by informing both investment and operational decisions.

5.1.2 Contracts support operational decisions

On a short-term operational timescale (e.g. hourly), contracts provide certainty for participants and inform their decisions in the face of risky market conditions. For instance, holding a swap contract incentivises generators to be available when needed (i.e. when demand and spot prices are high) in an operational timeframe, in order to earn revenues in the spot market to fund payouts on their contract positions.

Though a generator's contract is cash-settled (i.e. it is of a financial, rather than physical, nature), the existence of a contract prompts a physical response from the generator. This incentive to 'turn up' is heightened during tight demand-supply conditions, when the value of reliability is signalled by high prices and the system values the generator's output the most. In this way, contracts create a direct link

139 Both are currently under review, see section 1.5.1.

between the needs of the system for capacity and the financial rewards that accrue to generators from being available and dispatched, and the losses or penalties they incur if they are not.

For example, if a generator sells a firm hedge or cap contract then, when the market signals a need for more supply by the price approaching $14,200/MWh, the generator would face a high penalty for not supplying to the level of its contract cover.

5.1.3 Contract trading supports investment decisions

In the longer term, the contract market supports reliability in three ways:

- It provides market participants signals of market expectations of future spot prices (a forward price curve). These price signals support decisions to fund new generation projects (or retire existing ones), locate and fund a new energy-intensive industrial factory (or retire an existing one), or demand-side management capability (or retire an existing one).
- It lowers the cost of financing of investment in generation capacity, which lowers the cost of achieving efficient levels of reliability. By providing generators a steadier stream of income compared to taking spot price exposure, contracts reduce the risks to parties providing funding to generators, such as debt and equity holders, that the value of their investments may not be recouped. This lowers the overall cost of capital required to finance the project and lowers the cost of the new generation capacity.
- It underwrites retailers' fixed-price offers to end-consumers, such as households and small businesses. Like generators, retailers use the contract market to mitigate their exposure to the spot market. Contracts provide retailers with a consistent price for electricity, which in turn allows them to offer longer-term contracts, with stable prices, to their retail customers.

To illustrate how the forward price curve works, consider two contracts that provide an indication of future spot prices:

- forward-dated swap contract strike prices – to provide an indication of market expectations of future average spot prices
- forward-dated cap contract premia – to provide an indication of market expectations of the future magnitude and duration of spot prices in excess of the cap strike price (typically, $300/MWh).

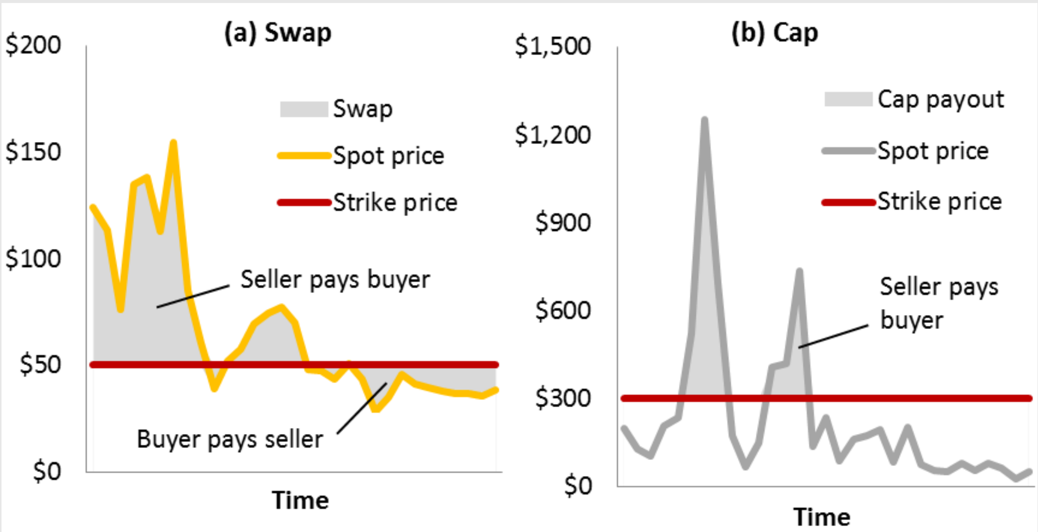
Box 5.1 Swap and cap contracts

Contracts in the NEM are currently traded on the ASX ("exchange-traded") or traded bilaterally ("over the counter" or "OTC"). Two common contract types that have proved useful to market participants to manage spot price risk are "swaps" and "caps":

- A **swap** contract swaps the spot price for a fixed price (strike price) for a fixed quantity over a fixed period. The contract is settled through payment between the counterparties, based on the difference between the spot price and the strike price.

- A **cap** contract requires the holder to pay a premium to the seller to swap the spot price for a fixed price when the spot price exceeds a specified price for a specified quantity over a fixed period. A cap contract provides electricity purchasers with insurance against high prices. The standard contract traded in the market is a "$300 cap". This means the seller of a cap is required to pay to the buyer the difference between the spot price and $300/MWh every time the spot price exceeds $300/MWh during the specified contract period:

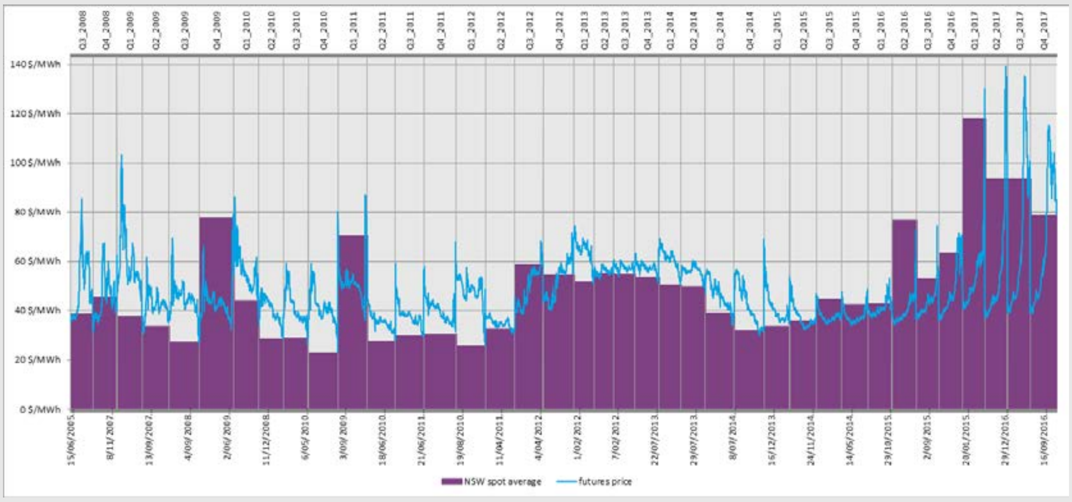
Figure 5.1 Swap and cap contracts



The price of caps and strike price of swaps also reflect a contract premium, or 'cost' of the contract itself. The sign and magnitude of contract premia are unobservable because expected future spot prices are equally unobservable.

Figure 5.2 illustrates the problem. It shows daily trading for each ASX quarterly base future swap (blue line) and the average spot price for the quarter (purple column) since the third quarter of 2008. In some quarters the blue lines show contract trading prices start above and fall toward the average spot price. However, since Q3 2015, you would have been better off signing a contract early (blue lines show contract trading prices start below and rise toward the average spot price). The width of the columns varies according to the number of days the swap was traded.

Figure 5.2 Quarterly ASX base futures swap prices and spot prices in New South Wales since Q3 2008



Together, the prices of these contracts help inform existing and prospective investors about what are likely to be profitable and unprofitable decisions. For example, if spot prices are expected to be elevated for a large proportion of the year, this would translate to swap strike prices being relatively high, which would provide a signal that new capacity is likely to be profitable and efficient. Similarly, a supermarket chain across the country, seeing electricity contract prices that suggest spot prices are expected to be high over the next year, might install new equipment that enables it to more easily engage in demand response in order to better manage its electricity costs.

Also, the forward prices for different products (e.g. swaps, caps, options), to the extent the market for them is liquid, provide an indication of the expectations of market participants. However, individual traders' expectations of trading conditions and prices vary and can affect a buyer's mix of products. For instance, if the swap strike price is increasing and a buyer expects this increase in expected spot prices for that period might be caused by greater volatility, it could induce the buyer to buy more caps.

Box 5.2 A futures exchange and open interest

A futures exchange or futures market is a central trading platform where people can trade standardised futures contracts; that is, a contract to buy or sell specific quantities of a financial instrument with delivery set at a specified time in the future. These types of contracts fall into the category of derivatives. The ASX is the primary futures exchange for trading electricity futures contracts. Futures trading on an exchange introduces financial terms for calculations of a trader's net position of a product on the exchange and open interest.

The **net position** of a trader in a futures market is a calculation that determines whether a trader is short or long (obligation to buy or sell) in a particular futures contract (e.g. cap for a particular quarter). For instance, a trader that buys ten contracts and later sell five contracts has a net short position of five contracts.

The **open interest** in a particular futures contract (e.g. swap for a particular quarter) is the number of open contracts (short or long) of all the traders. For instance, if the trading of contracts consists of three traders with net positions of six contracts short, four contracts long, and two contracts long, then the market has open interest of six contracts.[140]

5.1.4 The contract market must be liquid to support reliability

The contract market must be credible to traders and investors to provide the reliability benefits described and its credibility relies on the speed and ease with which trades can be made. For instance, the prices for each interval in the forward price curve need to be based on a reasonable number of trades. A high volume of trades and a large quantity of open interest (outstanding contract positions not closed or delivered[141]) provides confidence to investors and traders about the vibrancy of trading in the market. A liquid and effective market would also have many buyers and sellers.

The outcome of a liquid contract market is that parties are confident they can buy or sell in the market without significantly affecting the price. The benefits are that it reduces the cost to traders of changing their positions (increasing willingness to trade) and provides investors more confidence in the forward prices signalled by trades. In other words, a liquid contract market supports more efficient levels of reliability by lowering the cost of entry and exit.

140 You can find a short video on the internet that uses a simple example of how net positions, trading volume and open interest are calculated here: https://www.youtube.com/watch?v=AWi8gOM5TKo

141 For more information, this youtube video explains how to calculate net positions, trading volume, and open interest: https://www.youtube.com/watch?v=AWi8gOM5TKo

Key factors that negatively impact on contract market liquidity, include:

- uncertainties out into the future - the more uncertain the future, the higher the potential risk and greater the value there is in delaying a decision to trade
- large quantities of internal trading between retail and generation arms of a business (vertical integration) - this reduces the amount of trading by the remaining counter parties.

Financing new investments for generators, large loads or retailers can be difficult unless the party holds contracts to hedge its anticipated spot market exposure, at least in part. This, in turn, makes investors willing to provide funds to underwrite capacity.

The role of contracts in supporting investment is particularly important when conditions in the market are changing rapidly or otherwise more uncertain than usual. Observed or expected high spot prices cannot translate into new capacity without some degree of confidence that these prices will be sustained long enough for investors to recoup the value of their investment. Contracting provides confidence by (for example) enabling investors in new generation capacity to 'lock in' a particular price for their generation.

A major source of uncertainty that causes investors to delay investments and reduce their investment horizon is an unpredictable policy or regulatory environment. Therefore, in addition to a liquid and well-functioning contract market, investment decision making is also supported by a stable and predictable policy and regulatory environment.

In addition to considering concerns about vertical integration, the *2017 retail competition review* discussed the effect power purchase agreements (PPAs) signed under the Large-scale Renewable Energy Target (LRET) is having on the contract market. PPAs are a generation output-following fixed price contract between the generator (usually a wind farm or solar PV installation) and a counterparty (usually a retailer).

Generating capacity funded by a PPA does not have a financial incentive to be available when the physical system needs it the most because the contract includes the entire output whenever it is generated. Not only that, generation contracted under PPAs is replacing retiring thermal generation with greater potential to respond to spot prices and sell contracts to manage spot prices risks. While vertical integration and sale of PPAs are not of itself a cause for concern, taken to the extreme, a market where merging retail and generation businesses is the only viable way to manage spot price risks would create a high barrier for entry. A new independent generator or retailer, would become unviable without the acquisition of corresponding retailers or generators. In the long run, high barriers to entry reduces competition and increases the chance new investment does not occur when it is needed and reliability, at times, falls below efficient levels.

5.2 Submissions to the issues paper

5.2.1 Ten stakeholders responded to our questions on the contract market

Ten stakeholders responded to some or all of the questions posed in the issues paper.[142] We subsequently talked with some of them to clarify some items in their submissions. We also received advice from members of our technical working group.

While we received a variety of comments on the questions we posed, many stakeholders appear to share the view that investment and contract markets are supported by a stable and predictable political and regulatory environment. Other comments could be split into two categories:

- confidence the contract market would adapt to the changing generation mix
- concerns about whether the contract market is or will be resilient to the changing generation mix and continue to adequately support investment decisions and reliability.

5.2.2 Some stakeholders were confident the contract market would adapt to changing spot market conditions

Snowy Hydro expressed confidence the contract market would adapt to changing spot market conditions if it was supported by a stable policy and regulatory environment:[143]

> "Contract markets will evolve and new products will form. What is needed is stable policy and regulatory frameworks."

Meridian Energy Australia (Meridian) also expressed a view the contracts market would adapt to changes in the spot market:[144]

> "Contracts will continue to play a key role in managing risk and as is always the case in derivative markets, this will be achieved by the market matching parties with countervailing risk positions. It is the nature of financial markets that they develop relatively quickly in response to changing risk environments and often with the final outcome, while obvious in retrospect, not being predicted."

However, its confidence was also qualified:[145]

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142 AEMO, ARENA, Bluescope, The Clean Energy Council (CEC), The Grattan Institute (Grattan), Infigen, Meridian Energy Australia (Meridian), Origin Energy (Origin), Snowy Hydro, and Stanwell.

143 Ibid, p. 4.

144 Meridian Energy Australia, submission to the issues paper, p. 5.

145 Ibid.

> “…it is always difficult to predict how financial markets react to changing risk circumstances. In the long term, there should be no concern about the market developing an appropriate balance between those requiring certainty and those prepared to carry the risk of variability. It is possible that in a period of change there will be a temporary suppression of the financial market as new approaches and tools develop. This should not have a significant impact on reliability provided the conditions necessary for the development of the financial market responses are not inhibited. In particular, this requires clarity and certainty of market design decisions and sufficient time for the introduction of change to be accepted and accommodated within the financial markets.”

Bluescope suggested that "(a)s the capability of markets develop to be able to respond to shorter timeframes, it seems likely that there will be an increase in market efficiency, reducing prices and volatility, and as a consequence result in fewer contracts being required as risks reduce".[146] It was also confident that "(n)ew markets are likely to develop to efficiently manage demand side response and firming requirements, potentially increasing the number and types of contracts available". It suggested that retailers and other market participants which have bought PPAs for variable renewable energy projects are "likely to seek to contract for firming to manage their exposure or organise this within their own portfolio".[147]

5.2.3 Other stakeholders raised concerns that implied changes could be required to support reliability objectives

The Clean Energy Council (CEC) said the "(c)ore principles underpinning the NEM’s contract market include the expectation of stable market conditions over the near to long term".[148] It commented that "(p)olicy uncertainty and the looming threat of government intervention to prop up generation beyond its safe operating age or investing in pumped hydro introduces significant risk for new contracts". It felt that this and many other increasing uncertainties in the market have clearly had a "positive impact on contract prices and negative impact on liquidity" but it was not possible to isolate the introduction of variable renewable energy "as the driver of low liquidity in the contract market".

The Grattan Institute (Grattan) suggested the NEM might need to change in the face of an increasing share of variable renewable generation:[149]

> “Governments would have to accept the need for very high prices in times of short supply. Market participants would have to increase both short-term hedging activity to manage risk, and longer-term contracting to

146 Bluescope, submission to the issues paper, p. 3.

147 Ibid.

148 Clean Energy Council, submission to the issues paper, p. 5.

149 Grattan Institute, Next generation: the long-term future of the National Electricity Market, https://grattan.edu.au/report/next-generation-the-long-term-future-of-the-national-electricity-market/, September 2017, p. 16.

secure investment. And households and businesses would also need to be more flexible in their electricity use when supply is tight."

It considered "increased price volatility could be challenging for three reasons":[150]

- First, "(h)igher and more frequent price spikes may prove too risky for investors, retailers, consumers and/or governments". Grattan notes that solar and wind generation will reduce spot prices when the sun is shining and wind is blowing and increase spot prices when they are not. Grattan is concerned that "(a)s intermittent zero-marginal-cost generation is added, generators can only recover their costs if there are more high price events (and/or higher high price events) to counteract times when there are low, or even negative, prices". The report references a 2016 study that modelled an extreme scenario of 100 per cent renewables and no demand response.[151] Grattan notes this study estimated "a price cap of between $60,000 to $80,000 per megawatt hour would be required to ensure sufficient revenue in the market".[152] The report suggested any proposal to raise the price cap substantially would be "likely to meet community and political resistance". However, it noted that preventing the price cap from increasing sufficiently would artificially restrict the revenue generators could earn, leading to under investment.

- Second, "(t)here may be too few contracting opportunities to manage risk and bring on new supply". Grattan argued that businesses may increasingly opt to purchase their own generation rather than buy contracts, reducing the availability of contracts for other market participants. The report noted anecdotes and analysis to support the view that liquidity in the contract market is reducing and "may be limiting new investment in the NEM".[153] However, despite the points in support of its concerns, Grattan's says "(o)verall, it is hard to tell if contracting is sufficient to enable new investment". It notes that "extent of long-term contracting is unclear because ASX products are only available up to three-to-four years ahead and there is no visibility of direct bilateral agreements".

- Third, "(d)emand may prove to be insufficiently flexible to ensure resource adequacy".[154] While the report recognises that temporarily reducing demand can reduce the total amount of generation that needs to be built, it noted that most demand for electricity is currently inflexible.[155]

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150 Ibid.

151 Riesz, J., Gilmore, J. and MacGill, I., Assessing the viability of Energy-Only Markets with 100% Renewables, Economics of Energy & Environmental Policy 7.1, pp. 105–130.

152 Grattan Institute, Next generation: the long-term future of the National Electricity Market, https://grattan.edu.au/report/next-generation-the-long-term-future-of-the-national-electricity-market/, September 2017, p. 17.

153 Ibid, p. 20.

154 Ibid, p. 17.

155 Ibid, p. 22.

With respect to Grattan's second reason, we received comments from some stakeholders expressing concerns about the contract market and its resilience to changing spot market conditions, while others provided example that indicate it is already adapting.

Given the "physical characteristics of generation and demand are changing irreversibly" the CEC suggested the AEMC should examine the ongoing viability of "relying on an energy-only physical market".

Stanwell suggested that facilitating a "functioning and liquid financial market should be a key consideration in this review".[156] However, it went on to say:[157]

> “If the market moves to an environment with greater levels of non-dispatchable and/or energy limited resources, primary issuance may require an increase in horizontal integration in order to accommodate technology and geographical diversity. Alternatively, these players may not form part of the contract market but may sell their entire output through long-term deals. Both of these scenarios will challenge the traditional views of regulators and policy makers.”

Infigen agreed contracting "is an important part of the market".[158] In respect of variable renewable generation, it said "wind PPA contracts have not created incentives for large scale intermittent generation to develop firming options". It suggested this was because vertically integrated retailers "have been willing to accept the risk of intermittent generation given the firming capacity they have within their portfolios". It argued competition was a critical consideration, saying:

> “No matter what obligations may or may not be applied to the intermittent generator the contract market will only have sufficient liquidity if there is sufficient competition, i.e. there is risk in the market and numerous parties operating in it.”

Infigen also listed existing or potential rule changes that could positively or negatively impact the market for contracts, including five-minute settlement market, strategic reserve, day-ahead markets, contingency events.[159] It noted that the "contract market is an output of these market and policy design features".

While AEMO does not participate in the contract market, it is interested in its effect on reliability. In its submission, AEMO highlighted several potential problems in the contract market, including:[160]

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156 Stanwell, submission to the issues paper, p. 4.

157 Ibid.

158 Infigen, submission to the issues report, p. 6.

159 Infigen, submission to the issues report, p. 7.

160 AEMO, submission to the issues paper, p. 5.

- evidence of a reduction in liquidity in the derivative market which would seem to be at least partly responsible for the recent increase in wholesale prices
- specific areas where a lack of liquidity has long been a problem, such as South Australia
- little certainty from the forward market for investors in new dispatchable generation
- for gas powered generation, absence of a robust forward market and a contract market that is opaque and illiquid
- reduction in baseload generation is likely to reduce volume swaps being offered and an increase in their price
- changes in load shapes are likely to reduce demand for swaps but increase demand for caps.

It also said that electricity users had raised concerns with it about "the structural issues impacting on contract market liquidity".[161] In retail markets, AEMO "is concerned about anecdotal evidence of consumers being advised to accept spot price pass-through contracts". It suggested a customer that is fully or partly exposed to the spot price "would not be part of a retailer's risk profile, leading to a reduction in contracting and lower investment in the long term".[162]

ARENA provided examples of signs the contract market was evolving:[163]

> "Through ARENA's involvement with the financing of large scale renewable generation and storage projects we observe there is commercial innovation occurring in the structure of dispatch rights for projects. New ideas are emerging for financial contract structures that could be underwritten by stand-alone flexible capacity options, such as storage. One example could involve a supply-following power purchase agreement from a variable renewable energy facility, and sale of a cap or swap futures contract for the same energy volume. Facilities might also be financed as part of a larger portfolio rather than on a stand-alone basis underpinned by financial contracts."

161 Ibid.

162 Ibid, p. 6.

163 ARENA, submission to the issues paper, p. 7.

5.3 Commission's preliminary views

We have framed our discussion and initial views around questions raised by stakeholders:

- Should we be concerned about the resilience of the contract market in the face of the changing mix of generation in the NEM?
- Will the market price cap need to increase with the changing generation mix?

5.3.1 It is not evident that an increasing share of variable renewable energy is reducing contract market liquidity

Examples of resilience of the contract market

As noted in the last section, some submitters expressed concerns about the resilience of the contract market in the face of the changing mix of generation in the NEM. As explained in section 5.1.4, a liquid contract market is important because, at the other extreme, a market where merging retail and generation businesses is the only viable way to manage spot price risks would create a high barrier for entry. A new independent generator or retailer, would become unviable without the acquisition of corresponding retailers or generators. In the long run, high barriers to entry increases the chance that new investment does not occur when it is needed and reliability, at times, falls below efficient levels.

In response to the concerns raised by stakeholders in submissions, we took these concerns to the technical working group at its first meeting. The feedback from this group was that there did not appear to be cause for concern and some members offered examples of the changes in contracts being considered to combine different assets and contracts to provide a firmer hedge and command a higher price and value. We also met with a number of other stakeholders and financiers, who provided similar feedback - deals to finance variable renewable energy are taking account of the likely effect of the new resources on spot prices and are becoming more sophisticated to suit the needs of buyers.

For example, stakeholders noted that products being developed including solar-following and FCAS-following hedges. While such products take time to be developed (e.g. progressing these through internal risk management procedures), the fact that participants are thinking about developing these products is promising and shows the market is innovating.

In addition, many participants are also looking at developing "combined" variable renewable generation. For example, Kennedy Energy Park is a wind, solar and storage energy facility that is looking at locating in the Flinders Shire in central north Queensland.[164] The business proposition is that, as the sun is setting, the wind picks

164 See: http://www.kennedyenergypark.com.au/

up and continues to generate steady power throughout the night. In addition, the storage will allow the project to overcome any variable renewable challenges associated with a lack of wind or cloud cover.

Such examples show that the contract market, and in turn, investments and operations are adapting to changing conditions.

Empirical evidence on the contract market

While some stakeholders provided their concerns about the state of, or trends in, the contract market, only two provided charts of trading data in support of their concerns. We have reproduced these charts below and compiled similar charts of our own from ASX futures exchange trading data to try to reproduce similar results. The result is that we have not found evidence from ASX futures trading data that would confirm the concerns of some stakeholders that trading in the contract market is in significant decline. In fact, we have received signs and examples that suggest the contract market is adapting already (see section 5.3.2)

However, we are concerned that only information about contracts traded on the ASX electricity futures exchange are readily available to market bodies and participants. Without a public source of information about the trading of over-the-counter (OTC) contracts, the larger businesses regularly trading these contracts have an advantage over smaller and new participants. That is why, in the *2017 retail energy competition review*[165] we recommended that the industry develops a credible survey to address the lack of data for electricity trading hedging products. The Commission is therefore pleased to hear the Australian Financial Markets Association (AFMA) is restarting its survey of the turnover of over-the-counter contracts and will backfill missing data so the series will be unbroken by the end of the first quarter 2018.

Discussion on charts on state of, and trends in, the contract market

Figure 5.3 (Figure 3.3 in Grattan's report) suggests contract trading "is lower in South Australia and may be in decline across the board".[166]

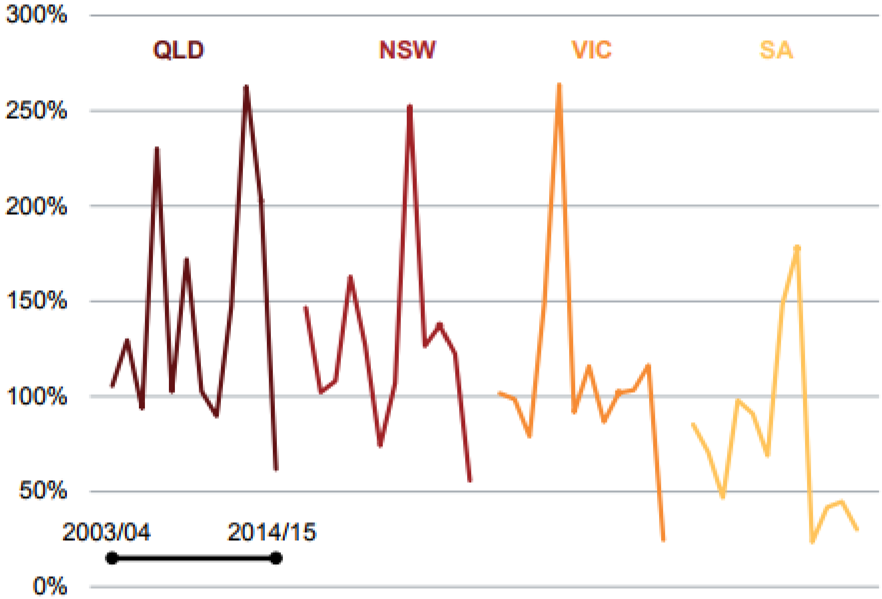
165 AEMC, *2017 Retail Energy Competition Review*, Final report, Sydney, 25 July 2017, viewed 16 November 2017.

166 Grattan Institute, Next generation: the long-term future of the National Electricity Market, https://grattan.edu.au/report/next-generation-the-long-term-future-of-the-national-electricity-market/, September 2017, p. 20.

Figure 5.3 Grattan chart showing contract trading activity as a share of regional consumption

Figure 3.3: Trading activity is lower in South Australia and may be in decline across the board

Volume of electricity traded as a share of regional consumption



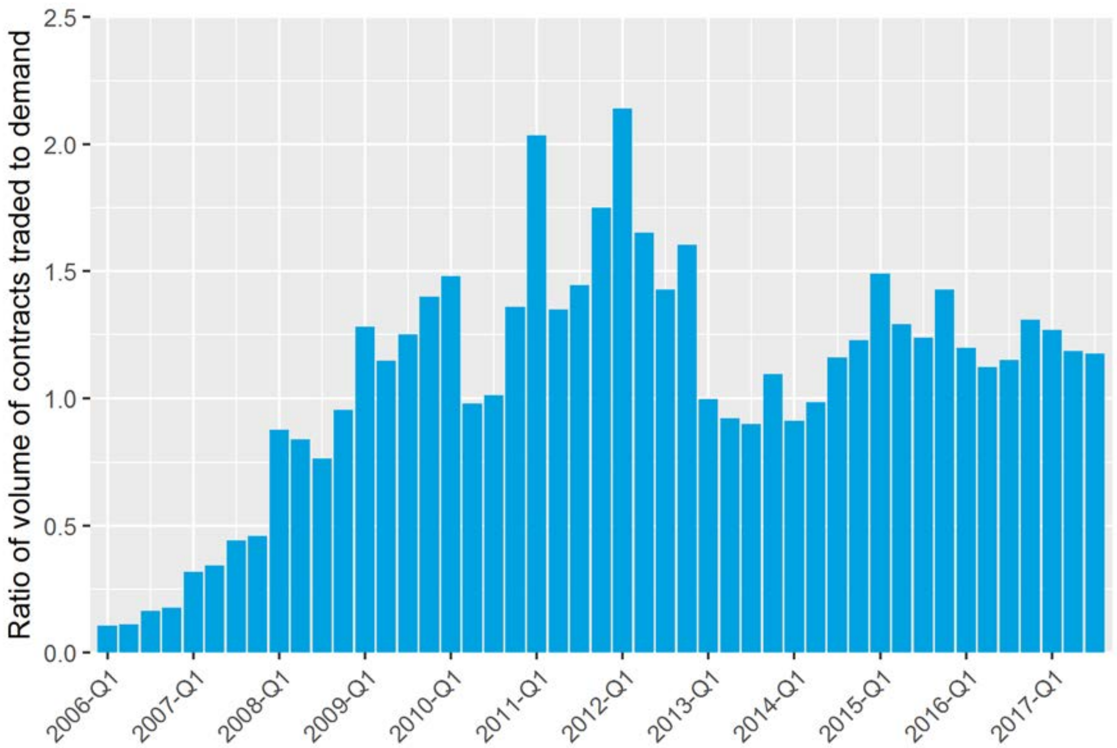
Notes: Data only available up to 2014-15. AFMA reporting changed from 2015-16, with previous data based on a survey that has now been discontinued.

Sources: Grattan analysis of AFMA (2015) and AER (2017e).

Grattan's chart uses the results of an AFMA survey of contract trades submitted by market participants, which was discontinued. To bring the view of contract trading up to date, we analysed trading of contracts on the ASX electricity futures exchange. This is a subset of the contracts traded by market participants as it omits the contracts traded by participants bilaterally or 'over the counter'. This is an unavoidable limitation of the analysis due to the lack of information available on the OTC contract market. Also, we have focussed on quarterly base futures, which consists of around three quarters of all contract trades on the ASX electricity futures exchange.

The resulting chart appears in Figure 5.4.

Figure 5.4 **ASX quarterly base futures – Volume traded as ratio of demand NEM-wide**



The chart in Figure 5.4 provides a different view of the contract market than the one suggested by the chart in Figure 5.3. While ASX quarterly base futures are only a sizeable fraction of the total contracts traded by market participants, they have still been trading at levels as high as more than two times demand in the NEM at times. More importantly, despite the decline since those highs in the first quarter of 2011 and 2012, recent levels of trading do not appear to be of significant concern, nor obviously trending downwards.

Figure 5.5 provides the same chart split into four regions: South Australia, Victoria, NSW, and Queensland.

Figure 5.5 ASX quarterly base futures – Volume traded as a ratio of demand by region

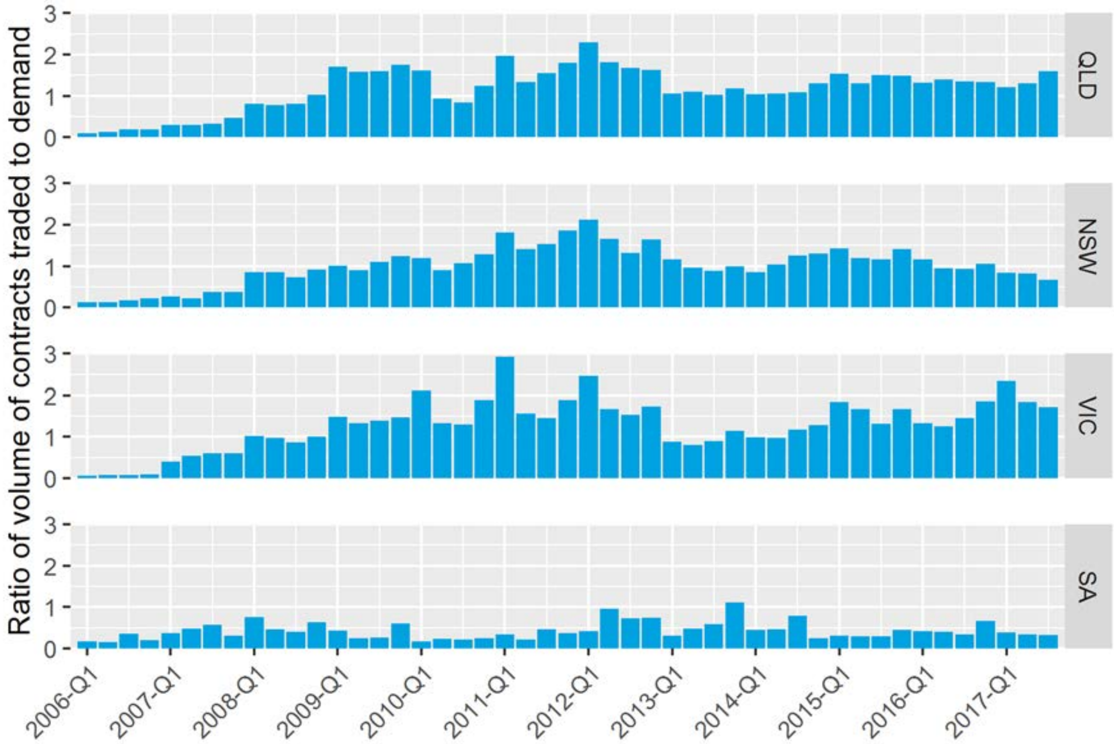
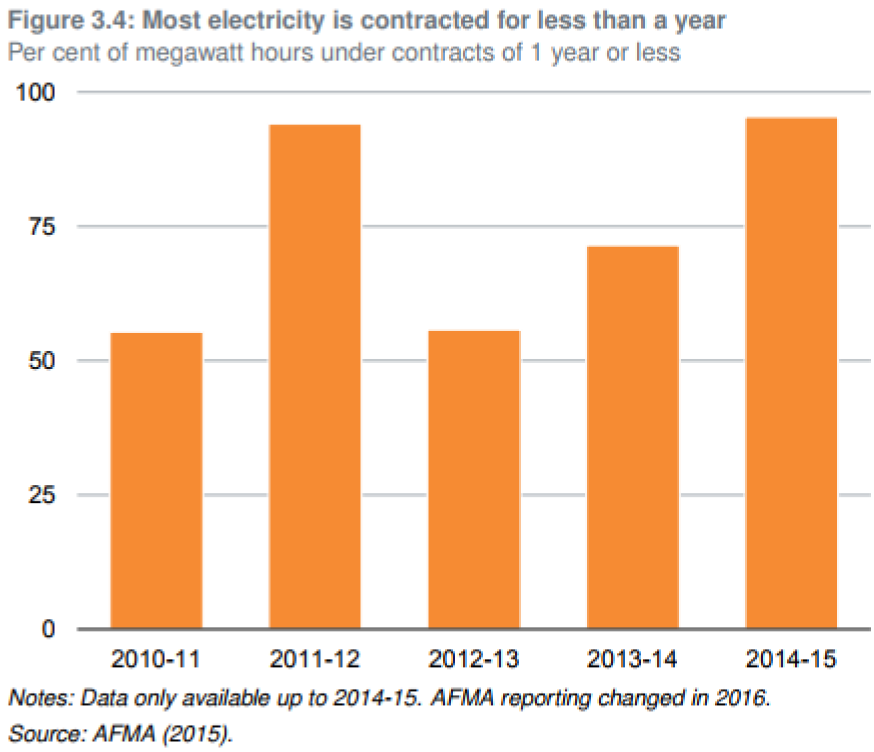


Figure 5.5 shows a mixture of results. ASX quarterly base futures in South Australia is (and has always been) thinly traded. Of the other three regions, it appears that only trading in NSW has been noticeably waning in the last two years.

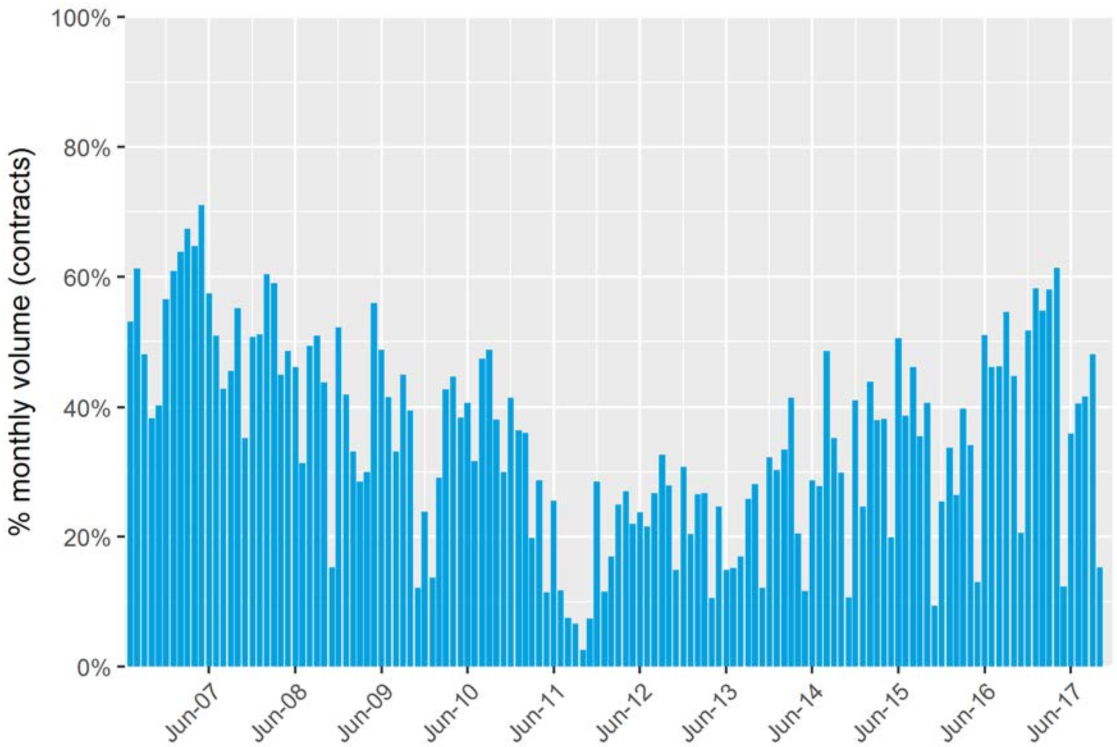
Grattan also presents a chart (figure 3.4 of its report) showing that most electricity is contracted for less than a year (see Figure 5.6 below).

Figure 5.6 Grattan chart showing the percentage of electricity under contract for less than one year



Again, we have had to use ASX trading data to bring the chart up to date. Also, rather than focus on the percentage of near-dated contract we have looked instead at its inverse - the percentage of long dated contracts (i.e. maturity of the contract is over year from the trading date). The result is the chart in Figure 5.7 below. The dips are caused by unusually high within-period trading and there are more of these in the latter years, but the underlying movement does not appear to be of special concern.

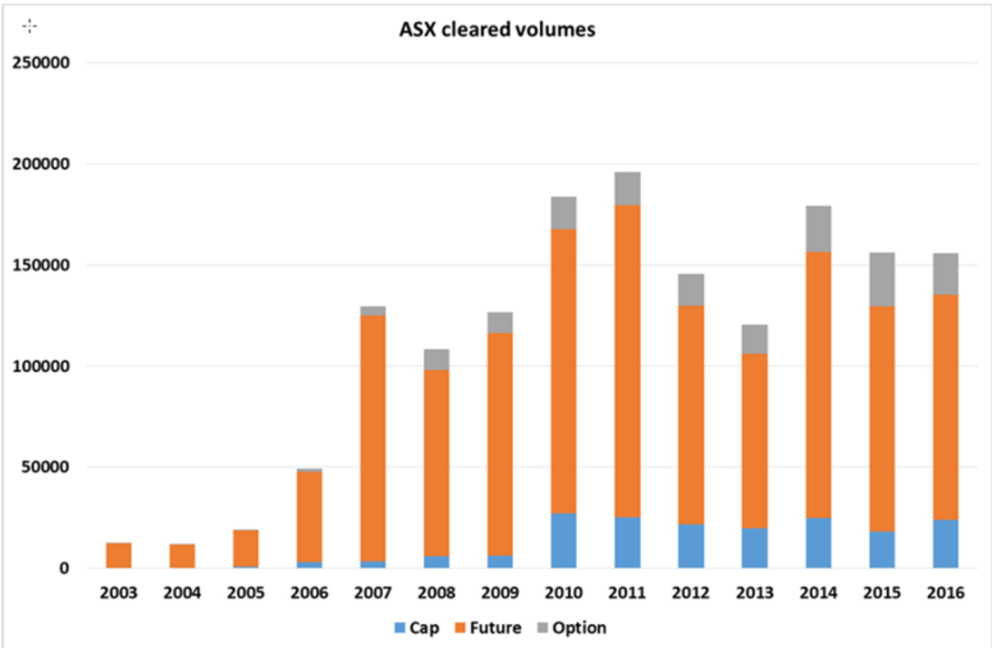
Figure 5.7 ASX quarterly base futures – Percentage of long traded contracts (over 1 year)



Finally, AEMO provided a chart in its submission to illustrate lower levels of trading in recent years (see Figure 5.8 below).

Figure 5.8 AEMO chart showing total volume of contracts traded on ASX from 2003 to 2016

Figure 1 shows ASX cleared volumes which show a lower level of trading recently compared to peak volumes in 2010 and 2011.



Again, while Figure 5.8 does show that trading of ASX futures in 2015 and 2016 is lower than in the three highest years in the period (2010, 2011, and 2014), it is still above levels in other years. Therefore, it is not evident to us that liquidity in the ASX electricity futures exchange should be a cause for concern from a reliability perspective.

5.3.2 The market price cap will not necessarily need to rise with increasing share of variable renewable energy

As noted section 5.3.1, Grattan was concerned that an increasing share of variable renewable energy would require the market price cap to increase and there was little community and political appetite for such a move. While this would appear to be a subject more suited to the Reliability Panel, we have a few observations that might mitigate concerns raised in the report. We also noted in chapter 1 that the Reliability Panel is conducting the *reliability standard and settings review 2018* and its draft determination recommends not making any changes to the reliability standard and reliability settings.

As Grattan notes, the market price cap in Australia[167] is already high by international standards. Grattan refers to a study suggesting the market price cap "may need to increase by a factor of six to eight", but it also suggests two alternatives that would mitigate the need to raise the market price cap:[168]

- "comprehensive demand side participation could allow each customer to select their preferred level of reliability and associated cost, removing the need for an administratively determined" market price cap
- a "liquid and well-functioning derivative contracts market, to allow generators and retailers to hedge significant market risks successfully".

The AEMC is interested in facilitating both increased efficient demand side participation and a liquid and well-functioning derivative contracts market. The former is discussed in chapter 6 and the latter was considered in the previous subsection.

There is also another consideration that might temper concerns about an increasing share of variable renewable energy disrupting the NEM. That is, the Grattan study does not consider the changes in the market that are likely to occur in transition. Over time, as the share of variable renewable energy generation increases, spot price volatility increases and raises the value of resources (e.g. storage) that can take advantage of the difference between high and low prices.

167 Currently $14,200/MWh.

168 Jenny Riesz, Iain MacGill, 100% Renewables in Australia - Will a Capacity Market be Required?, Centre for Energy and Environmental Markets, University of NSW, Sydney, Australia, 2 September 2013, p. 1.

We have noted anecdotes and other signs that businesses and governments are contemplating or already moving to take advantage of this opportunity, including:

- Snowy 2.0
- the Tesla battery in South Australia
- the Origin-Tempus trial in South Australia
- the EnergyAustralia and Consortium partners' feasibility study into pumped seawater hydro energy storage in South Australia and
- the Lincoln Gap project in South Australia.

Box 5.3 Examples of responses to spot market volatility

Snowy 2.0

On 16 March 2017, Snowy Hydro announced its proposal to carry out a feasibility study into the expansion of the pumped hydro-electric storage in the Snowy Mountains Scheme, also known as the Snowy 2.0 project. Snowy 2.0 is a pumped hydro project that will add an extra 2,000 MW of generating capacity and about 350,000 megawatt hours of energy storage to the existing Snowy hydro scheme. As its webpage says:[169]

> “ Snowy 2.0 will act like a giant battery, storing water which can be used as energy at times of high energy demand. As the economy decarbonises we are seeing more intermittent sources of electricity generation (like wind and solar) added to the energy mix while coal fired generation is retiring. This change in the energy market will make large-scale storage projects like Snowy 2.0 critical.”

The Tesla battery in South Australia

The Hornsdale power reserve is a South Australian Government project to construct 100 MW/129 MWh lithium battery provided by Tesla at Neoen’s 309 MW Hornsdale Wind Farm in South Australia. While ostensibly to provide reliability services:[170]

> “A portion of the battery will also be dedicated to trading on the electricity market. This capacity will be used to store power from the Hornsdale Wind Farm when demand is low and dispatch it when demand is high, reducing the need for expensive gas ‘peaking plants’ and placing downward pressure on power prices for South Australian consumers.”

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169 Snowy Hydro, Snowy 2.0 webpage, http://www.snowyhydro.com.au/our-scheme/snowy20/, accessed on 20 November 2017.

170 HPR, Hornsdale power reserve overview webpage, http://hornsdalepowerreserve.com.au/overview/, accessed on 20 November 2017.

Origin-Tempus flexible energy demand trial

On 11 October 2017, Origin announced it was working with UK-based startup Tempus Energy, which is part of the global Free Electrons accelerator co-founded by Origin and seven other utilities from around the world. According to Origin, "during the trial, Origin will use Tempus Energy's demand-side management platform to shift non-time critical load into cheaper periods or when renewables are plentiful, and test the potential savings that could be unlocked for the customer". It says the "technology can also help overcome the intermittency challenges of renewables, by helping energy to be used more efficiently and effectively".[171]

EnergyAustralia seawater pumped hydro energy storage feasibility study

In early 2017, EnergyAustralia and its Consortium partners Arup Group and Melbourne Energy Institute were awarded $453,000 by the Australian Renewable Energy Agency (ARENA) to partially fund a feasibility study for a new pumped hydro energy storage project using sea water. The potential site is located at Cultana on the Spencer Gulf near Port Augusta in South Australia.[172]

EnergyAustralia note the "core business model" for a storage asset like Cultana is "to maximise the arbitrage between buying energy when the price is low and selling it when the price is high".[173]

Lincoln Gap

Lincoln Gap Wind Farm is a 212 MW wind farm project with 10 MW grid scale battery storage, under development by Nexif Energy Australia Pty Ltd, located near Port August in South Australia. The project reached financial close in November 2017, with commissioning scheduled for late 2018.[174]

The CEFC committed $150 million in debt finance to stage one of the Lincoln Gap wind farm. The project is the first in Australia to secure debt finance for a grid connected large-scale battery component, on a non-subsidised basis. Nexif Energy Australia note that "with the scalable battery storage at Lincoln Gap we will be able to offer more flexibility to the national grid and improve the reliability of the system".[175]

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171 Origin, Media centre webpage, https://www.originenergy.com.au/about/investors-media/media-centre/origin-to-trial-demand-management-with-large-customers.html, accessed 20 November 2017.

172 EnergyAustralia, Cultana pumped hydro project webpage, https://www.energyaustralia.com.au/about-us/energy-generation/energy-projects/pumped-hydro, accessed on 22 November 2017.

173 EnergyAustralia, Cultana pumped hydro project, Knowledge sharing report, September 2017, p. 20.

174 See: http://lincolngapwindfarm.com.au/

175 See: http://www.ecogeneration.com.au/sa-wind-storage-project-wins-150m-cefc-debt-funding/

6 Wholesale demand response

Key points

- The Finkel Panel review recommended that the Commission should undertake a review to facilitate demand response in the wholesale energy market.
- Demand response refers to participants, specifically loads, changing their level of consumption in response to signals to do so.
- A more active demand side effectively increases the amount of reserves in the market. As the demand side becomes more and more active, it would be expected that larger amounts of demand response would be observed at high prices (which tend to accompany times when there are low reserves). Larger quantities of demand response would reduce the likelihood of needing to exercise interventions such as issuing directions, employing out-of-market reserves or involuntary load shedding to restore the supply-demand balance.
- For participants that face the real-time spot price for the purchase of electricity, wholesale demand response can offer a number of valuable services.
- For the NEM to have more firm and faster acting demand response, it will require more resources – both time and equipment – to develop. Such demand response needs to be offered by a portfolio of sufficient size. In contrast, there is demand response that can be achieved through simpler methods, but the extent of any demand response is likely to be less firm and more variable under these methods.
- Based on our analysis, as well as discussions with stakeholders, the Commission is not convinced that any of the potential limitations raised to the uptake of demand response indicate a regulatory barrier to wholesale demand response.
- If wholesale demand response is currently being underutilised, then there are opportunities for new and existing parties to capture this value. However, it can be difficult for third parties to capture the value associated with wholesale demand response under the current framework.
- Therefore, we are exploring ways in which this value could more easily be captured by parties. However, ways to do this require further consideration since they could have flow-on effects for a number of elements in the market, including potentially, prices for consumers.

Wholesale demand response can help to make the NEM more reliable. It can also provide a valuable service to assist parties to manage risk in the wholesale electricity market. This chapter provides a summary of how wholesale demand response fits into reliability frameworks.

This chapter is structured as follows:

- section 6.1 discusses the scope for considering demand response in this Review
- section 6.2 considers the current context for demand response in the NEM
- section 6.3 presents a summary of stakeholder comments in submissions to the issues paper that relate to demand response
- section 6.4 contains the Commission's preliminary analysis
- section 6.5 contains the Commission's preliminary views.

6.1 Demand response in this Review

The scope of this review is confined to only considering wholesale demand response and emergency demand response.[176] The review does not consider demand response in the context of security related ancillary services (such as frequency control) or in relation to network support services. The reason for not considering these services is twofold:

1. Wholesale demand response and emergency demand response could both contribute to the reliability of the power system by reducing demand under tight market conditions.
2. There are existing frameworks to support or incentivise demand response for ancillary services[177] and network support.[178] The Commission has already concluded in both the *Reliability frameworks review* issues paper, as well as in its *Strategic priorities for the Australian energy sector*,[179] that there are no regulatory barriers to the use of ancillary services and network demand response in the NEM.

As a result, only wholesale and emergency demand response will be considered in this Review.

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176 This concepts are defined in chapter 3.

177 Regulatory frameworks are established that allow demand response to participate in frequency control ancillary services. Third party aggregators are able to register as a market ancillary service provider and bid load into frequency control ancillary service markets. This is also being considered in the Commission’s *Frequency control frameworks review*. More detail is provided in Box 6.5.

178 Incentivising consumers to alter consumption to reduce impacts on networks. For example, demand response programs could alleviate local network peak demand to defer network upgrades.

179 AEMC, *Strategic priorities for the Australian energy sector - discussion paper*, September 2017.

While wholesale demand response may contribute to reliability, it is first and foremost a market-induced response to high wholesale prices to either reduce costs or better manage risk. Emergency demand response, on the other hand, is a change in consumption employed as an emergency lever during supply emergencies to avoid involuntary load shedding. This could take the form of contracted portion of load that, under extreme conditions, could be reduced to lower overall demand.

An increase in the amount of wholesale demand response should decrease the amount of emergency demand response needed. This is because under periods of low reserves and (typically) high wholesale prices, increased levels of wholesale demand response will reduce overall levels of demand and the likelihood of running out of market energy reserves and needing to rely on a mechanism external to the market (such as emergency demand response) to avoid involuntary load shedding. It may also reduce the amount of load that would be available to participate as emergency demand response, as price sensitive load would be increasingly participating in the market and providing wholesale demand response.

The interaction between emergency demand response, wholesale demand response and the market price cap is demonstrated in Figure 6.1.

Figure 6.1 Demand response in reliability frameworks

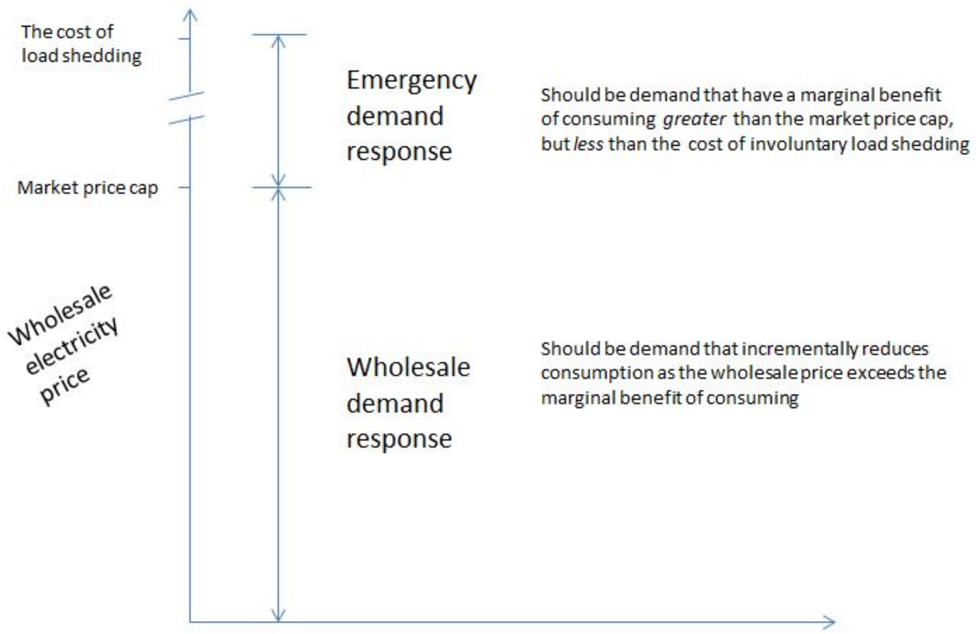

Figure 6.1 shows that there is a distinction between emergency demand response and wholesale demand response. Emergency demand response sits outside the current market settings and would therefore need to be procured through a separate market to the wholesale electricity market. If emergency demand response was used to maintain the balance between supply and demand, it would be considered a market intervention.

Wholesale demand response is responsive within the market (that is, it will respond to wholesale electricity prices between the market price floor and the market price cap) and to respond, would need to be exposed to some form of signal in order to change consumption. This signal may be wholesale electricity price, or some other signal provided by a retailer or third-party reflecting the wholesale electricity price. This chapter discusses wholesale demand response.

Emergency demand response is discussed in more detail in chapter 7.

6.2 Summary of issues

6.2.1 Context

Demand response has been receiving growing attention as a service that will increasingly play a role in the future of the NEM. This is being driven by technological advancements allowing loads to become more dynamic, as well as acknowledgement of the need for flexible and dispatchable resources to accommodate the increasing penetration of variable renewable generation.[180] Demand response is being used by a number of retailers and technology providers, as well as being considered by think tanks and academics. The value of demand response has been highlighted in:

- the Independent Review into the Future Security of the National Electricity Market ('Finkel Panel review')
- the Commission's *Strategic priorities for the Australian energy sector* discussion paper
- the Commission's *Power of choice* review
- Energy Networks Australia and CSIRO's *Electricity network transformation roadmap*
- the AER's demand management incentive scheme
- AEMO's *Advice to Commonwealth government on dispatchable capacity*
- AEMO's *Summer operations report 2017-18*.

The Finkel Panel review placed substantial emphasis on demand response as playing a pivotal role in the future of the NEM. The Finkel Panel review concluded:

- There is a need for adequate levels of dispatchable capacity in the NEM, which includes demand response.
- Price responsive demand has a role in reducing demand peaks when wholesale price are high.

180 This can been seen by observing demand response providers offering products for managing wholesale market volatility. For more information on these products, see chapter 5.

- The NEM currently does not have sufficient incentives for encouraging demand response. It may be a low-cost and under-developed opportunity for maintaining reliability.

Of particular relevance is the Finkel Panel recommendation 6.7:

"The COAG Energy Council should direct the [Commission] to undertake a review to recommend a mechanism that facilitates demand response in the wholesale energy market. This review should be completed by mid-2018 and include a draft rule change proposal for consideration by the COAG Energy Council."

Accordingly, when the Commission self-initiated this Review it committed to a consideration of methods to further engage demand response in the wholesale energy market.

6.2.2 Background

Demand response observed to date

A 2016 survey for the AEMC suggested that there is at least 235 MW of demand response capability under contract to retailers, mostly involving exposure to the wholesale market spot price, with more demand response contracted to specialist demand side-management companies.[181] This survey considered demand response procured by five retailers, and did not quantify the amount of demand response provided by other retailers or by customers who are not on a retail contract.

Figure 6.2 shows the level of demand side response that AEMO considered to be currently available in the NEM at the time of publishing its *Energy supply outlook* in June 2017. It considers the amount of demand response that would be expected at certain wholesale prices. For example, AEMO expects there to be approximately 50 MW of demand response in NSW when the price reaches $1,000/MWh.

Further, in the summer of 2017-18, AEMO considers that there is 512 MW of demand response across the NEM, which does not include anything that could be procured through the RERT. AEMO also notes that it expects the amount of demand response in the NEM to continue to increase over time.[182]

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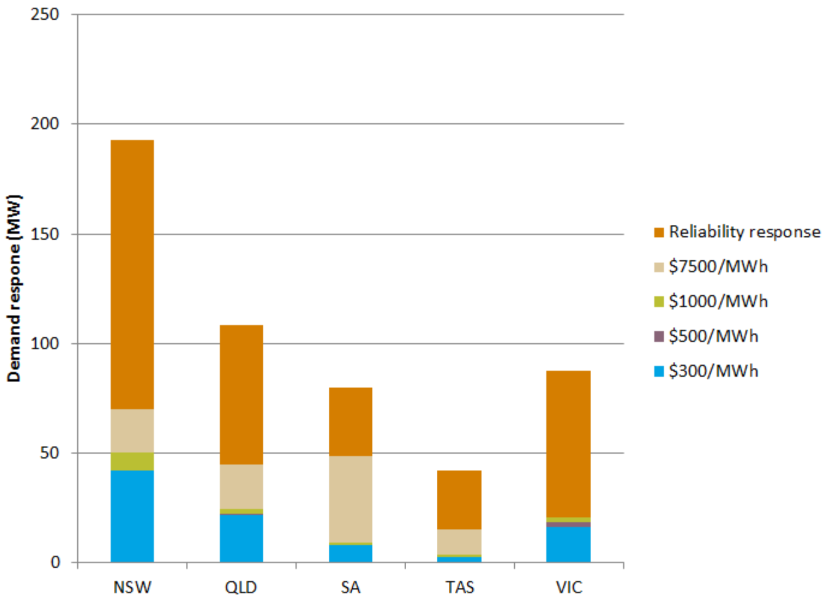
181 Oakley Greenwood, *Current status of DR in the NEM – Interviews with electricity retailers and DR specialist service providers*, June 2016, available at: http://www.aemc.gov.au/Rule-Changes/Demand-Response-Mechanism.

182 AEMO, *Energy supply outlook*, June 2017.

Figure 6.2 Amount of demand response in the NEM, per region



Note: For the purposes of this data, AEMO defines a reliability response as the expected demand response following the issuing of an LOR2 or LOR3 notice.

Source: AEMO, *Electricity Forecasting Insights*, June 2017.

The actual extent of demand response in the NEM is not readily apparent. As much of the demand response in the NEM arises from bilateral contracts or a reaction to wholesale prices (as opposed to being scheduled in the wholesale market), it is difficult to quantify exactly *how much* demand response occurs. Additionally, the amount of wholesale demand response is not static. It depends on the operating state and preferences of loads on a real time basis.

6.3 Stakeholder submissions to the issues paper

In submissions to the issues paper, stakeholders generally provided commentary on broader reliability frameworks rather than specific comments relating to demand response.

S&C Electric suggested that because domestic loads are not exposed to the wholesale spot price, this will diminish the amount of demand response.[183]

ARENA submitted that for better participation of demand response, a critical factor is the interaction of wholesale markets arrangements and retail contracts.[184] Energy Networks Australia noted that there may be value in allowing demand response currently procured by distribution businesses to be provided to the market, at least as

183 S&C Electric, submission to issues paper, p. 3.

184 ARENA, submission to issues paper, p. 9.

an interim measure until a demand response market has reached a sustainable level of maturity.[185]

Stanwell and Public Interest Advocacy Centre (PIAC) both advocated for arrangements that increase transparency of demand response. Stanwell supported measures to incorporate demand response into the operation of the market, suggesting that the lack of transparency regarding demand response (and other non-scheduled participants) potentially inhibits AEMO's ability to manage system reliability.[186]

PIAC maintained that allowing demand response to bid into the wholesale market is increasingly essential for the NEM to deliver efficient outcomes. PIAC noted that previously the Commission had suggested that retailers are incentivised to undertake demand response as they are exposed to spot prices. PIAC stated that high spot prices in South Australia have not delivered demand response, which indicates that high spot prices alone may not be sufficient for retailers to engage in demand response.[187] PIAC suggested that the only way for demand response to become effective in the NEM is for independent demand response aggregators to be able to participate in the wholesale spot market and for these aggregators to be able to contract with households without involving the retailer.[188]

PIAC also disagreed with the Commission’s statement in the issues paper that residential consumption can be difficult to shift from one period to another. PIAC suggested that many residential loads can be shifted and, when aggregated, would willingly be shifted to aid better price outcomes.[189]

BlueScope felt that large customers are limited in their influence on the contract market, suggesting that this is due to reliance on retailers and the absence of a demand side response mechanism. It suggested a well-functioning demand side market, could significantly reduce volatility and limit generator market power in the spot market which would consequently reduce prices in the forward market.[190]

BlueScope submitted that demand should be incentivised to turn on when supply is most plentiful and prices are lowest, where possible.[191]

6.4 Commission's preliminary analysis

The following section presents our preliminary analysis regarding wholesale demand response in reliability frameworks.

185 Energy Networks Australia, submission to issues paper, p. 5.

186 Stanwell, submission to issues paper, p. 3.

187 PIAC, submission to issues paper, p. 8.

188 Under the current regulatory frameworks, third party aggregators are not able to buy and sell electricity in the wholesale market on behalf on consumers without becoming a retailer.

189 Ibid.

190 BlueScope, submission to issues paper, pp. 3-4.

191 Ibid.

6.4.1 What is wholesale demand response?

As discussed in chapter 2, demand response is consumers, specifically loads, changing their level of consumption in response to short-term signals to do so. These signals could be price signals from the wholesale market, or could be instructions coming from the market operator, a retailer or a third party.

Our definition of demand response focusses on *consumers* changing their consumption – in order to do so, consumers could reduce load or employ on-site generation or batteries in order to manage their amount of (grid) energy demanded.

Wholesale demand response refers to the change in consumption of wholesale electricity in response to willingness to consume at certain wholesale price levels.

Box 6.1 What is not considered to be demand response?

Demand response refers to dynamic and temporary changes to electricity consumption in response to short-term signals. This does not include longer-term changes or trends in energy consumption. This fits under demand management, which is a more broad expression for how the demand side changes its consumption.

Demand management includes energy efficiency and installing non-controllable distributed energy resources behind the meter, such as solar PV. While these actions are a component of how customer might choose to manage its load, they are not dynamic changes in consumption in response to signals to do so, such as wholesale price signals. For this reason, they are not demand response as has been defined in this Review.

An active demand-side, characterised by the presence of wholesale demand response, promotes efficient consumption of electricity in the wholesale market. Where load is able to effectively respond to prices, it would be an efficient outcome it to “choose” its level of consumption based on its willingness to pay for consuming electricity. In other words, by responding to wholesale prices, the load is able to make the trade-off between the costs of consuming electricity and the opportunity cost of reducing its electricity consumption and so not being able to produce widgets or heat its home (for example).

The majority of consumers in the NEM are not directly exposed to the wholesale spot price,[192] instead purchasing electricity via the standard fixed price tariff offered by

192 Since the start of the market loads have not been required to schedule bids. Loads have the option of being scheduled in central dispatch; however to date, most loads have elected not to be scheduled, which indicates they do not see a business advantage in doing so. The Commission has recently considered requiring loads to bid into the market but decided that the upfront costs that would be imposed on loads would outweigh any benefits of doing so. For more information, see: http://www.aemc.gov.au/Rule-Changes/Non-scheduled-generation-in-central-dispatch

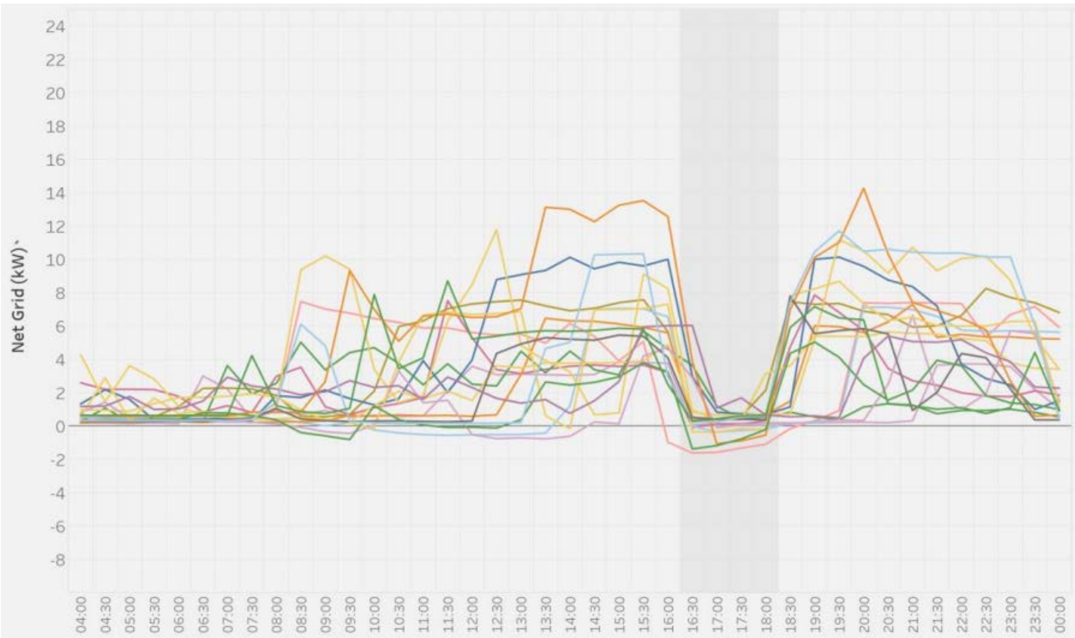
retailers and so they have no incentive to respond to wholesale prices, as discussed further below.[193]

Load that is not exposed to the wholesale price can still provide wholesale demand response but the signal which consumers respond to must come from a third party; for example, a retailer or a demand response aggregator.

Demand response can be used to reduce exposure to high wholesale prices and can be thought of as a physical hedge. To an extent, these demand response services would be able to substitute with other arrangements a retailer may have in place to hedge against wholesale spot market exposure, such as swap and cap contracts.

As an example, Mojo Power (an electricity retailer) offered its customers savings if they voluntarily reduced consumption during the February 2017 heatwave in NSW. This was during a period where wholesale prices were forecast to reach the price cap and AEMO had advised of a risk of involuntary load shedding. A high proportion of Mojo Power's customers responded positively and reduced consumption in exchange for a payment. The load profiles of the most responsive customers are shown in Figure 6.3. This shows a clear reduction in demand from these customers in response to a signal to change consumption.

Figure 6.3 Mojo Power demand response



Mojo Power, *Submission to the Independent Review into the Future Security of the National Electricity Market*, p. 7.

More recently, Origin Energy, in partnership with Tempus, announced a trial of a demand response program that would shift consumption for a group of commercial

193 Electricity retailers use contracts and other products to manage variable wholesale prices and underwrite fixed retail contracts. This is discussed in more detail in chapter 5.

customers in anticipation of future wholesale prices. This trial is discussed further in chapter 5.[194]

6.4.2 How can wholesale demand response contribute to reliability?

Reliability in the NEM is predicated on there being sufficient supply to meet demand, plus a sufficient amount of reserves. Demand response can contribute to reliability by altering the demand side to restore balance. A more active demand side effectively increases the amount of market reserves, with larger quantities of demand response reducing the likelihood of AEMO needing to exercise interventions in the market.[195]

Box 6.2 provides a demonstration of how wholesale demand response can help manage the reliability of the NEM.

Box 6.2 How wholesale demand response can contribute to power system reliability

Figure 6.4 and Figure 6.5 demonstrate a hypothetical situation in which a more active demand side, responding to signals to change consumption, could assist in managing the reliability of the power system. This example is only indicative of what occurs when supply-demand balance is tight and the market exhausts its reserves.

In Figure 6.4 there is no wholesale demand response. Demand peaks late in the day and exceeds the total supply capacity. At this point, there are no longer any reserves in the market that are able to meet the continued increase in demand. When this occurs, emergency reserves, if available, can be employed to maintain the balance of supply and demand.[196] If emergency reserves are not sufficient to maintain the supply/demand balance and there are no other options, it may become necessary for AEMO to commence involuntary load shedding.[197]

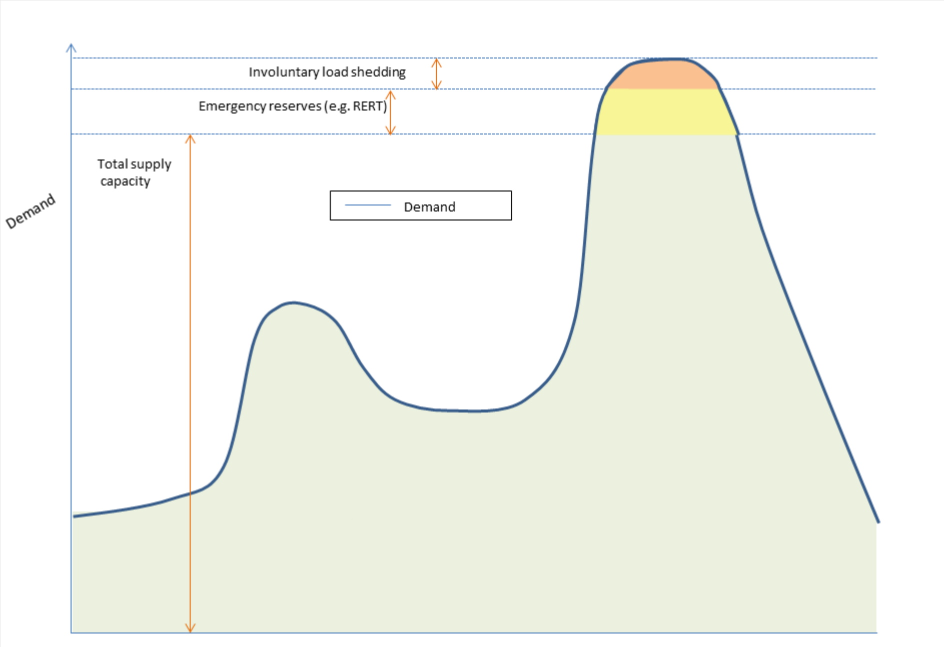
194 Origin Energy, *Origin to trial demand management with large customers*, October 2017. Accessed at: https://www.originenergy.com.au/about/investors-media/media-centre/origin-to-trial-demand-management-with-large-customers.html

195 For example, issuing directions, employing out-of-market reserves or involuntary load shedding to restore the supply-demand balance

196 In practice emergency reserves can be employed prior to demand exceeding total market supply. AEMO may also issue directions to generators to, for example, bring online a unit that was not available.

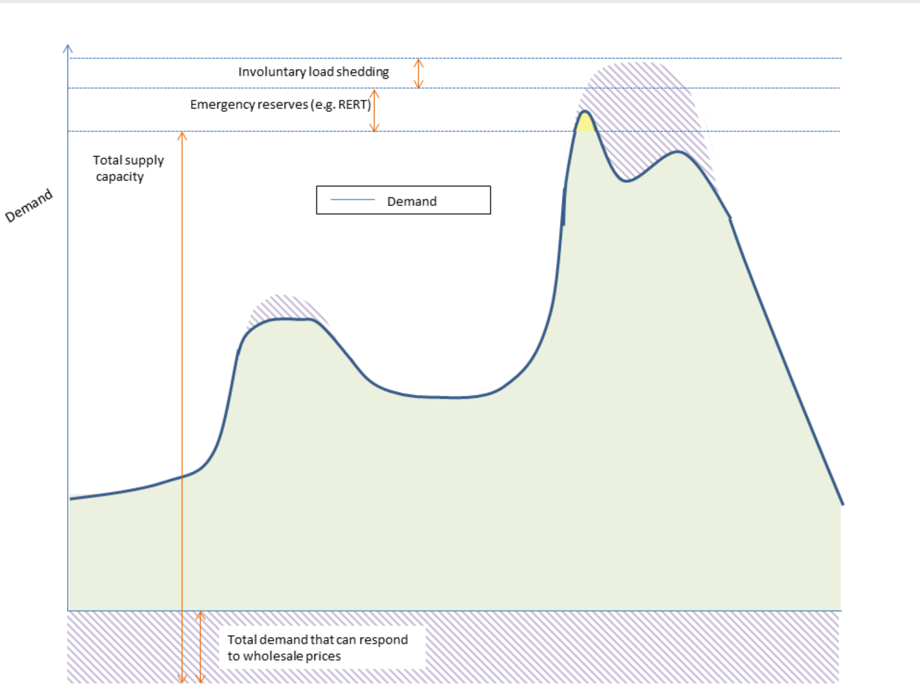
197 In practice, the actions are not necessarily additives – AEMO will monitor periods of low reserve and choose the appropriate action based on prevailing conditions. It may, for example, choose involuntary load shedding ahead of a direction based on costs and availability.

Figure 6.4 Tight supply-demand balance without wholesale demand response



In Figure 6.5 demand also peaks late in the day. However, this time there is a significant quantity of wholesale demand response. The demand may have changed directly in response to high wholesale prices or in response to a signal provided by a retailer or other third party. In this example, the combination of demand response and the deployment of emergency reserves is sufficient to prevent involuntary load shedding from occurring.

Figure 6.5 Tight supply-demand balance with significant wholesale demand response



6.4.3 Services offered by wholesale demand response

For participants that are exposed to the wholesale electricity market, demand response can offer a number of valuable services. Many of the services sought in contracts markets can be substituted for wholesale demand response, provided participants are confident that the demand response is expected to occur.[198]

Wholesale demand response assists participants to manage wholesale market price volatility as it provides a means to change the amount of electricity purchased in the wholesale market. The ability of wholesale demand response to assist with managing risk is dependent, in part, on the certainty of the response.

Some forms of demand response, like the example shown by Mojo Power above, are less certain in regards to quantity or timing. When demand response is less certain, it is less likely to be directly substitutable for financial hedging products. However, more certain demand response can replace or reduce the quantity of derivative products a participant may want to procure.

6.4.4 What's needed for demand response to operate?

For a consumer to be able to offer and provide demand response, a variety of equipment and information may be needed, depending on the type of demand response - see Table 6.1 below.

More firm and faster acting demand response will require more resources – both time and equipment – to develop. In contrast, there is demand response that can be achieved through simpler methods; however, the extent of any demand response is likely to be less firm and so more variable under these methods.

The time and effort that are necessary to set up a demand response portfolio of sufficient size is one reason several market participants have suggested there is not more wholesale demand response in the NEM.

198 This is similar to how vertical integration of retailers and generators can help participants manage wholesale electricity market exposure. The contract market is discussed in more detail in chapter 5.

Table 6.1 Various types of demand response

Type of demand response	Equipment required	Time required
Voluntary demand reduction in response to some form of signal - This demand response is not certain in terms of quantity or timing but it can reduce the extent of wholesale market exposure. It can occur over a customisable period of time. This can be offered by most loads and is suitable for residential loads.	Can be achieved with very limited technology. For example, Mojo Power sends customers an SMS offering to reward consumers for reducing consumption. This would require some form of interval metering to measure changes in consumption. Does not require any remotely controlled equipment to be on site.	This may not require a large amount of resources on behalf of the aggregator.[199] This would usually be operated by a retailer with their existing customers.
Remote controlled load - Consumption is altered by an external party. Due to the upfront costs, this appears to suit larger (commercial and industrial) loads.	This requires substantially more equipment to be installed on site. This includes remote monitoring communications devices and equipment that interacts with the load or process that will be interrupted. Conversations with stakeholders have indicated that these costs are substantial and can be time and resource consuming due to interactions site employees and equipment.	This also is substantially more time consuming and labour intensive. In addition to the time spent finding interested customers is the time spent determining which loads or processes can be interrupted, and developing contracts that the customers considers reflects the value of its demand response.
Remote controlled load that also responds to local measurements for participation in centralised market - This is also likely to be most suitable for large loads.	In addition to the equipment mentioned above, this requires equipment that monitors some local measurement. This could be a measurement of frequency or the trip of a generator. This would generally be used for providing market ancillary services.	In addition to the above, the time spent includes having to follow the administrative processes within AEMO such as registration and meeting the market ancillary service specification (MASS).

The equipment needed, or the time required, may change depending on who is procuring demand response and for what purpose. For example:

- Under the RERT,[200] AEMO would likely require communications equipment, either directly to the load or between the provider and its contracted load, allowing AEMO to dispatch the resource.

199 An aggregator could be either a retailer or a third party.

200 The RERT is discussed in more detail in chapter 7.

- If demand response is to be used to assist with maintaining system security (e.g. frequency control ancillary services), the resources have to comply with the market ancillary service specification. Stakeholders have suggested that equipment that provides this level of functionality has material costs, and requires a two-year payback period.

- In contrast, a retailer procuring wholesale demand response would be able to balance the costs of installing equipment against the value provided by more advanced technology. A retailer may opt to encourage demand response through text messages to customers, which would be relatively cheap but would result in a less firm quantity of demand response. One way to manage this would be to "over-procure" the level of demand to allow for dispersion in the level of response.

Some loads may also have the capability to offer demand response as an ancillary benefit to installing other equipment. For example, residential batteries may only require a small software change to be able to offer a range of demand response services.

6.4.5 How can wholesale demand response be provided in the NEM currently?

Under the current regulatory frameworks wholesale demand response can be provided in a number of ways, including:

- retailer procurement of demand response
- spot price pass through arrangements with a retail contract
- registering as a market customer and purchasing electricity directly from the wholesale electricity market.

These are discussed in more detail below.

Retailer procurement

A retailer may procure demand response services from loads to help it manage wholesale market risk. This is most likely an arrangement between the retailer and a customer, with which it has a retail contract agreeing to a set of arrangements in which the load will provide demand response.

Spot price pass through arrangements

A customer may opt to take a retail contract with some form of spot price pass through arrangement. This does not necessarily result in wholesale demand response. However, it would provide the load with the incentive to alter consumption in response to wholesale prices. A customer under such a contract would be able to observe the wholesale electricity price and change consumption accordingly. As long as the customer's willingness to pay was lower than the market price cap, she would be in control of making her own price/reliability trade off.[201] This customer may also form some sort of hedging arrangement.

Box 6.3 Flow Power

Flow Power is an electricity retailer that operates in all regions of the NEM. Flow Power is participating in the AEMO and ARENA RERT trial by offering automatic demand response from commercial and industrial customers. For more details on this, see appendix E.

Flow Power emerged from a company that offered energy management services (specialising in demand management) to medium and large energy users. It has since opted to register as a retailer and connect customers to the wholesale market.

Flow Power retail contracts pass on wholesale price signals to its customers, and it helps those customers manage consumption in a way that reduces costs. Flow Power's customers are typically medium to large energy users who are able to change consumption in response to wholesale spot prices. These customers can either do this manually or install a device that allows Flow Power to remotely adjust demand.

To help customers manage the amount of electricity they consume at different wholesale prices, Flow Power provides information advising of current prices as well as projections of future prices. It also has an alert system to warn of high price events. Customers use this information to inform the manner in which they consume electricity and make the trade-off between electricity consumption and avoided electricity costs. Flow Power's aggregate demand can be reduced by up to 45 per cent following notifying customers of a high price event.

In addition to providing customers with information regarding wholesale prices and assisting customers with load management, Flow Power can provide customers, who meet the definition of a wholesale customer, with financial products to help manage wholesale electricity risk with an Australian financial services licence, including swaps and caps. Flow Power also offers products that allow customers to sign a power purchase agreement with an variable renewable generator such as a solar or wind farm. This allows customers with flexible load to adjust consumption in line with output from variable renewable generation.

Source: https://flowpower.com.au/library/getting-power-use-under-control/

Registration as a market customer

A customer could opt to purchase electricity directly from the wholesale market (that is, without going through a retailer). As above, this would not necessarily result in

201 If the willingness to pay was higher than the market price cap, then she would be subject to the Reliability Panel's decision to limit reliability at the market price cap.

wholesale demand response, but the customer would be able to receive economic benefits by responding to the wholesale electricity price.

By registering as a market customer and taking the spot price, the customer would face strong incentives to both form some sort of hedging arrangement and to alter consumption in response to wholesale electricity prices.

6.4.6 Recent trends and developments

A number of recent developments have either increased the amount of demand response available in the NEM, or contributed to increased drivers for greater uptake of services provided by demand response over the past 12 months. These developments are discussed below.

We have been made aware in stakeholder meetings that there may be substantially more wholesale demand response present in the NEM that is not visible. This reinforces our view that the extent of wholesale demand response is difficult to observe because of the lack of visibility around demand response - to the extent it is occurring, it forms part of a suite of risk management tools and so participants do not report on it individually.

AEMO/ARENA RERT trial

This summer there will be 143 MW (from Victoria, South Australia and NSW) of RERT demand response resources through the joint AEMO and ARENA demand response trial. The three-year initiative, starting this summer, is to pilot demand response projects and encourage other market responses to provide firm capacity. It is discussed further in appendix E.

The demand response procured under the RERT trial is, by definition, **not** wholesale demand response. However, the subsidies provided through this scheme will contribute to increasing the capability of loads to become responsive to external signals. So, an outcome of the RERT trial may include increased capacity for loads to later provide wholesale demand response.

AER demand management incentive scheme

The AER has been developing a new mechanism to incentivise the efficient uptake of demand management to assist network businesses in providing network services. On 14 December 2017, the AER published its demand management incentive scheme. The scheme encourages network businesses to employ demand management to address network constraints. In particular, the AER will provide network businesses with a payment worth up to 50 per cent of the expected demand management costs when they invest in efficient demand management projects.[202] The AER estimates that the

202 AER, *Explanatory statement - demand management incentive scheme*, December 2017.

scheme may drive demand management investment of up to $1 billion over five years.[203]

While the scheme relates to network demand response, it is likely to increase the level of wholesale demand response available in the NEM. By rewarding efficient network demand response, participants with demand response capability are able to realise an additional demand response value stream, which promotes further investment in demand response technology.

Rewarding efficient network demand response is important, because it will affect the overall level of demand response that will occur in the NEM. This would be expected as providers will be able to better capture value in each element of the supply chain.

Increased consumer interest

The Australia Institute recently surveyed households to assess their appetite for providing demand response.[204] The key results from their survey included:

- The majority of households consider demand response to be the best solution for managing peak demand.
- The vast majority (81 per cent) suggested they would be interested in being paid to provide demand response.
- Respondents were interested in providing a range of services to reduce demand including reducing heating, cooling and appliance use.

This survey indicates that there is significant interest from households in being able to offer demand response. However, it does not account for how consumers may respond when actually faced with having to reduce or shift consumption. For example, consumers may undervalue using air conditioning until they are required to reduce their usage during high temperatures. When faced with having to endure higher temperatures, consumers may be less inclined to reduce consumption. Nonetheless, it is encouraging that consumers are increasingly interested in being able to offer demand response services.

This is consistent with our understanding that there are consumers who would like to engage in the demand response but are not being offered demand response products by their retailer.

203 See https://www.aer.gov.au/news-release/aer-incentive-scheme-to-drive-potential-1bn-in-demand-management-action.

204 The Australia Institute, *Polling - demand response*, October 2017.

AEMO demand side participation register

In April 2017, AEMO published its final demand side participation information guidelines following a final rule made by Commission in March 2015.[205] The guidelines specify the information that must be provided to AEMO by registered participants. The objective is to give AEMO better quality information to improve its current load forecasting.[206]

The information provided to AEMO should include:

- contractual arrangements between a registered participant and a person, in which they agree to the curtailment of non-scheduled load or the provision of unscheduled generation in specified circumstances.[207]
- non-contractual arrangements entered into between a registered participant and a person, or between two registered participants in relation to demand response.[208]

The information sought by AEMO is relatively detailed and should provide greater transparency regarding the extent of wholesale demand response in the NEM.

Changing market conditions

Over time, spot price volatility is expected to increase as the share of variable renewable generation increases, and this raises the value that more flexible resources, such demand response, can provide.

In submissions to the draft determination for the *Demand response mechanism and ancillary services unbundling* rule change, some stakeholders indicated that low wholesale electricity prices may result in relatively low levels of wholesale demand response.[209]As wholesale electricity prices increase, this should increase the value provided by wholesale demand response.

As noted in Box 6.3, there are a number of examples of businesses taking advantage of spot price variability and it is reasonable to expect that wholesale demand response will become increasingly valuable to market participants are market conditions change.

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205 For more information see: http://www.aemc.gov.au/Rule-Changes/Improving-Demand-Side-Participation-information-pr

206 AEMO, *Demand side participation information guidelines consultation - final report and determination*, April 2017.

207 AEMO, *Demand side participation information guidelines*, July 2017, p. 5.

208 Ibid.

209 EnergyAustralia, Submission to *Demand response mechanism and ancillary services unbundling* draft determination, pp. 1-2.

6.4.7 What limitations may exist?

Through feedback from stakeholders, including discussions with our technical working group, we have learned of a number of limitations to the uptake of services provided by wholesale demand response. Each of these potential limitations is discussed in more detail below, alongside our preliminary views in response to these.

High upfront costs

Stakeholders have suggested that developing a demand response portfolio able to offer services with sufficient scale and certainty has a large accompanying upfront cost. This can limit the offering of demand response products, particularly on behalf of residential consumers.[210]

The challenge of weighing upfront capital costs against uncertain future revenues is not unique to wholesale demand response. These challenges apply to other forms in investment in the NEM, where a commercial entity is able to make investment decisions with consideration of possible returns. For these reasons, we acknowledges the materiality of these limitations but do not consider them to constitute an inefficient *barrier* to wholesale demand response in the NEM. Instead, they are best addressed by commercial entities who bear the risk of making an upfront investment to provide wholesale demand response, compared to other investments (e.g. generation) that could be made.

The costs of compiling a demand response portfolio are likely to fall over time. Technological developments, such as increased penetration of advanced metering will assist with reducing costs. Consumers are gradually becoming more responsive as appliances become 'smarter', home energy management system are installed, and distributed energy resources continue to proliferate, assisting with the provision of wholesale demand response.

In addition, there are a number of incentives and temporary funding that have been introduced into the NEM that will contribute to the ability for parties to overcome the upfront capital costs of providing demand response, such as those discussed in section 6.4.6. While these mechanisms do not relate directly to wholesale demand response, they do contribute to the increase in capability and capacity of demand response in the NEM. This is because if a load achieves the functionality necessary to offer demand response for a particular purpose (e.g. network demand response), it is likely to be able to offer other demand response services as well, with the incremental cost of the other service being low.

Demand response is also able to offer services into ancillary service markets.[211] The capability of loads to provide ancillary services demand response may also contribute to the amount of load that is able to be remotely controlled, or respond to a signal, that may be able to offer wholesale demand response.

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210 This is discussed in more detail in section 6.4.4.

Wholesale price uncertainty

One area that some stakeholders remarked on was that the variability in spot prices for electricity may make it difficult for loads to respond efficiently. In part, this is currently driven by the fact that participants are settled on a 30 minute basis.[212] Unless the load was able to predict the extent of the sixth trading price in a settlement period, it may not have altered consumption in the earlier trading intervals. However, we do not consider this will be an issue on an enduring basis since the final rule on the *Five minute settlement* rule change will align dispatch and settlement outcomes which should reduce the extent of wholesale market price uncertainty for demand response providers.[213]

Technical barriers

As noted earlier, for demand response to be provided, there needs to be certain equipment installed on site. Even the most basic forms of voluntary demand response require some communications equipment and an interval meter to be available. If consumer premises do not have this capability, it may present an upfront cost that cannot be recovered in acceptable timeframes. While larger consumers will tend to have metering that is capable of measuring consumption on a five-minute basis, many residential consumers continue to have accumulation meters which make it difficult to assess the extent of any changes in consumption in response to a signal to do so.

These technical limitations may inhibit demand response, particularly from smaller consumers. However, the continued rollout of advanced metering under a competitive framework should reduce the extent of this limitation. Therefore, we do not consider the technical barriers associated with providing wholesale demand response need to be addressed as part of this Review.

The value of customer reliability exceeding the market price cap

In the issues paper, the Commission suggested that, if the value of customer reliability exceeded the market price cap (which is currently the case in the NEM), this may inhibit wholesale demand response.

If an individual customer has an individual value of customer reliability above the market price cap, theoretically, it would be inefficient for that load to reduce consumption in response to wholesale prices. That is because the customer values the supply of electricity more than it is priced in the wholesale market. If an individual customer values the supply of electricity less than the market price cap, then it would be efficient for that customer to change load in response to wholesale price signals.

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211 This is discussed more in Box 6.5.

212 The settlement price is the average of the six trading prices within a settlement period. This price applies to all wholesale consumption during that half hour.

213 See: http://www.aemc.gov.au/Rule-Changes/Five-Minute-Settlement

While a customer may have a value of customer reliability that is greater than the market price cap, it may have certain load components that are able to altered in response to wholesale prices. For example, a customer may value the electricity needed to power their Wi-Fi modem above the market price cap but value the electricity needed to power their fridge much less. In this case, the customer (if it received a signal to do so) would be able to offer wholesale demand response by turning off their fridge.

Further, where the value of customer reliability exceeds the market price cap a customer could offer out-of-market reserves by providing emergency demand response. This is discussed further in chapter 7.

Increased vertical integration and retailer hesitation

In the issues paper, the Commission noted that the presence of vertical integration may limit incentives on such companies to offer demand response.

Vertically integrated companies typically manage their wholesale electricity market exposure internally, and so, could be faced with conflicting incentives. For example, at times of high spot prices retailers would have an incentive to engage in demand response, but at the same time, their generation would have an incentive to offer capacity into the market to earn high prices. Since vertically integrated retailers have invested in generation (which has a long life) they may favour the revenue that can be earned by the generators, and so not engage in demand response.

The Commission has noted previously in the final report of *Stage 2 Review into Demand Side Participation* that even when retailers are vertically integrated, they should still face the same incentives to engage with demand response when it is commercially viable.[214] We have updated the example presented in that report in Box 6.4.

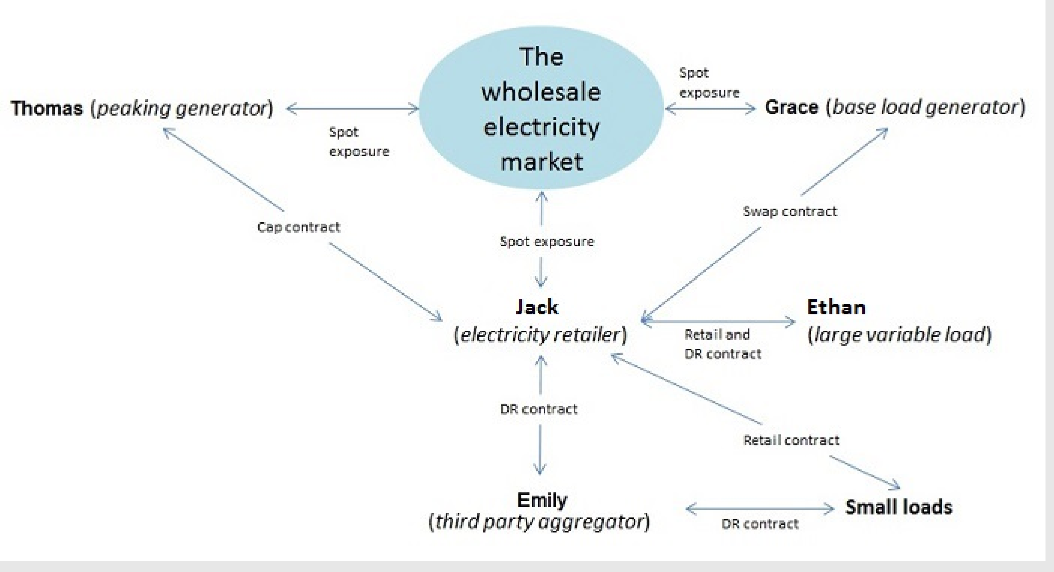
214 AEMC, *Stage 2 Review into Demand Side Participation - final report*, November 2009, pp. 64-65.

Box 6.4 Example of a retailer using wholesale demand response to manage wholesale risk

Jack is an electricity retailer that purchases electricity through the wholesale electricity market. In order to manage the risk and cash flows associated with participating in the wholesale market, Jack has set up a number of arrangements. These arrangements are shown figuratively in Figure 6.6:

- A swap contract with Grace, a 'baseload' generator. The swap is for 1,000MW at a strike price of $40/MWh.
- A cap contract with Thomas, a 'peaking' generator. The cap is for 100MW at $300/MWh.
- A demand response contract with Ethan. Ethan is a large load that has significant control over its consumption. Jack and Ethan have agreed that when high wholesale electricity prices are anticipated, Ethan will shift or reduce consumption in exchange for a payment. This will help Jack manage the quantity of electricity bought in the wholesale market during high price periods. Ethan is contracted to reduce its consumption by 100MW at a strike price of $500/MWh.
- A demand response contract with Emily. Emily is a demand response aggregator that can offer a fast reduction in load from consumers that have a retail contract with Jack. Jack and Emily agree that when the wholesale price exceeds a threshold level, Emily will reduce consumer loads, reducing the amount of electricity Jack has to buy from the wholesale market. Emily is also contracted to reduce its consumption by 100MW for $500/MWh when instructed by Jack.

Figure 6.6 Possible arrangement of hedging products



Exercising demand response contracts

If the wholesale electricity prices were $1,000/MWh for an hour, Jack's arrangements will minimise his exposure to these high prices. Jack can opt to exercise its contract with Emily. If he did not, the cash flows for Jack would be:

- Grace will settle the swap: 1,000MW x ($1,000 - $40)/MWh = $960,000.
- Thomas will settle the cap: 100MW x ($1,000 - $300)/MWh = $70,000.
- Ethan will reduce consumption by 100MW and be paid: 100MW x $500/MWh = $50,000.
- Jack will purchase 1,100MW from the wholesale electricity market = 1,100MW x $1,000/MWh = $1,100,000.

Overall, Jack's net cash flow will be: -$1.1M - $50,000 + $960,000 + $70,000 = -$120,000.

If Jack had also decided to exercise its contract with Emily there would be an additional cash flow and change in wholesale electricity consumption:

- Emily will reduce consumption by 100MW and be paid: 100MW x $500/MWh = $50,000.
- Jack will now purchase 1,000MW from the wholesale electricity market = 1,000MW x $1,000/MWh = $1,000,000.

Jack's new net cash flow will be: -$1.0M - $50,000 - $50,000 + $960,000 + $70,000 = -$70,000.

In this example, Jack exercised a demand response contract to improve its overall net cash flow. Regardless of Jack's other hedging arrangements (be they physical or financial), it makes no commercial sense not to exercise a demand response option if it is cheaper than consuming electricity in the wholesale market.

This example demonstrates how demand response can help parties exposed to the wholesale price manage associated risks. It also demonstrates that if a participant is exposed to the wholesale price for electricity and has the option to hedge against a high price by using demand response, they have the commercial incentives to do so.

Reluctance from retailers

We have also heard from stakeholders that there may be a reluctance from retailers to engage in demand response:

- Wholesale demand response is not a core function of retailers and they historically have limited experience in procuring these services.[215]

- Retailers may be wary of switching off loads, despite whatever commercial arrangement may be in place, because it may lead to a perception that the retailer's service is less reliable.

- Retailers may not make upfront investments in demand response capability with their customers because customer churn could result in the retailer not being able to recover upfront investments. For example, we understand that investing in demand response technology typically requires a return of investment in excess of eighteen months, whereas typically retail contracts in the NEM are rarely more than two years. There is obviously a disconnect between these timeframes.

However, these sentiments appear to be changing recently as retailers have been increasingly looking to engage in wholesale demand response.[216]

Smaller retailers, such as Flow Power and Mojo Power have also sought to use responsive demand to manage wholesale market exposure. If wholesale demand response is an efficient tool for retailers to manage risks in the wholesale market, retailers that use it have an advantage over others that do not.

Inability for third parties to benefit from wholesale demand response without the involvement of market customers

If retailers are hesitant to employ wholesale demand response, then you would expect to see other third parties offering wholesale demand response services. However, a response by third-party aggregators is limited because it is difficult to capture the benefit of developing a demand response portfolio without the engagement of a retailer.

Wholesale demand response provides economic benefit to parties by changing the level of consumption in the wholesale market. To benefit from wholesale demand response under the current arrangements, a participant must have some form of access to the wholesale price - either directly through wholesale market exposure, or indirectly through an arrangement with a participant exposed to the wholesale market. As wholesale demand response typically provides benefit in the form of reduction in consumption at high prices, to actually see the benefit, a participant must be actually purchasing the electricity (that is, be the financially responsible market participant (FRMP)) to benefit from a reduction. If that participant is not the FRMP at that connection point, it must then have some form of arrangement with the FRMP to share the benefits of providing wholesale demand response.

215 Recently, a number of retailers have offered to provide demand response in the AEMO and ARENA RERT trial, including Powershop, AGL and EnergyAustralia. Origin Energy has also announced a demand response trial.

216 Powershop, EnergyAustralia, Flow Power and AGL were awarded contracts under the RERT for offering emergency demand response. Origin Energy has also announced a demand response trial. This indicates that retailers are increasingly using demand response.

If a third party aggregator were to aggregate a number of consumer loads and reduce consumption during high wholesale prices, the benefit of doing so would be received by the FRMP[217] at the connection point for each of the loads. Unless the aggregator either becomes the FRMP at these connection points, or has a relationship with the FRMP, there is no way for the aggregator to accrue the economic benefits of wholesale demand response. This limits the ability for an aggregator to develop products that can assist other parties with managing wholesale risk.

6.5 Commission's preliminary views

The Commission's preliminary views are discussed in more detail below, but in summary are:

- Based on our analysis, as well as discussions with stakeholders, we are not convinced that any of the limitations previously discussed indicate a regulatory barrier to wholesale demand response.
- However, there is limited visibility regarding the extent of wholesale demand response in the NEM which makes it difficult to draw conclusions about how much “wholesale demand response” there is in the NEM.
- Wholesale demand response is more accessible to large energy consumers, either through a retailer or through registering as a market customer and purchase electricity from the wholesale market. But, small customers do not have as many opportunities to offer wholesale demand response.
- If there is wholesale demand response (that is, available in the market under the market price cap) that is currently being underutilised, then there are opportunities for new and existing parties to capture this value. However, it is difficult for aggregators to capture the value associated with wholesale demand response under the current framework.
- Therefore, we are exploring ways to make this value more easily captured. However, ways to do this would require further consideration as it would have flow-on effects for a number elements in the market, including potentially outcomes and prices for consumers.

6.5.1 Extent of wholesale demand response in the NEM currently

There is limited visibility regarding the **actual** extent of wholesale demand response present in the NEM. While some stakeholders have suggested that demand response has been limited in the NEM, others have suggested that it is present in substantial quantities that are not visible to the rest of the market. This makes it difficult to determine how much wholesale demand response occurs and where it occurs.

217 A FRMP at a connection point is the party that is responsible for paying for the electricity consumed behind that connection point in the wholesale electricity market. These FRMPs are typically retailers.

Under current arrangements, large energy consumers are able to either offer wholesale demand response to their retailer or take exposure to the wholesale electricity market. There are examples of loads registering as a market customer, which would allow them to capture the benefit of wholesale demand response. There are also examples of retailers offering large energy users retail contracts that either pass through price signals from the wholesale market or have a demand response component.

However, there may be limited opportunities for other consumers, particularly small customers, to offer wholesale demand response. Some of the retailers in the NEM may be hesitant to engage in wholesale demand response, for example, due to limitations in their billing systems or due to the upfront capital costs. In addition, smaller consumers may be less likely to be able to *offer* wholesale demand response to their retailer or to other participants due to limitations in the technology of their meter. The ability for smaller consumers to offer demand response should improve as metering equipment improves and consumer interest increases.[218]

6.5.2 Underutilised wholesale demand response is creating opportunities

To the extent that consumers are willing but unable to offer wholesale demand response, there should be an opportunity for new and existing participants. If consumers value being able to provide demand response, new retail contracts should develop to reflect this.

To gain a direct benefit from wholesale demand response, a party must be exposed to the wholesale market. If a customer signs a retail contract, its retailer is therefore the intermediary between the consumer and the wholesale market and acts on behalf of its customers in the wholesale market. The retailer will purchase electricity for its customers and can access the benefits of wholesale demand response on behalf of its customers.

To incentivise wholesale demand response, the retailer can share the benefits of doing so with the customers that have provided the service (either directly or through a third party aggregator). If the ability for a consumer to provide demand response is undervalued, there are opportunities for greater value to be gained by a separate party engaging that customer. This party would be able to share this value with its customers and deliver a better deal for both the customer and the retailer. This suggests that if demand response is being underutilised in the NEM, there are opportunities for new and existing participants to capture this value. To do so, a retailer would need to engage and win over customers.

For example, a retailer that procured wholesale demand response from its customers may be able to offer more attractive retail contracts to consumers who can change

218 In 2015 the AEMC made new rules to remove the networks' effective metering monopoly and give consumers more opportunities to access a wider range of energy services. The rules took effect on 1 December 2017. They were part of the Power of Choice reforms which have laid the foundation for consumers to make the choices that suit them best on what services they want and how they manage their bills.

consumption in response to a signal to do so. For this to occur, consumers would need to have an understanding of different retail offers.

However, as the Commission has noted in the final report for *Retail competition review 2017*, some consumers have limited awareness of different retail tariff structures. In addition, a significant number of consumers do not tend to shop around for a better retail deal. This may limit the ability of a new or existing retailer to offer retail contracts that consider demand response. Additionally, the value of the retail energy component of a retail contract would potentially largely outweigh the value of a demand response component, which would lead to consumers focussing on energy components when choosing a retailer.

6.5.3 Option of becoming a retailer to capture value of wholesale demand response

An option for a demand response aggregator to offer wholesale demand response is to register as a retailer. Under the current arrangements, a demand response aggregator (or another third party that is not a retailer) is not able to capture the value of wholesale demand response without also engaging the relevant retailer.

However, demand response aggregators and retailers may not necessarily have the same capabilities. Retailing typically requires expertise in risk management, marketing and IT systems administration. Whereas, demand response aggregation requires deep knowledge of load production processes, and dispatch / control technologies. Therefore, just as existing retailers may lack experience with demand response, demand response aggregators may not wish to engage in selling electricity, or lack expertise in doing so. Becoming a retailer also introduces more onerous requirements, such as the administrative costs of registration and meeting the prudential and consumer protection requirements set out in the NER.

In order to purchase electricity from the wholesale market, retailers must also comply with AEMO's prudential requirements. These requirements are designed to protect wholesale market participants from the risk of default of other market participants. In order to comply with these prudential requirements retailers must provide AEMO with an unconditional guarantee to cover their exposure to the spot market, for examples, bank guarantees. These requirements are similar to the collateral requirements of retail banks when they borrow from the central bank.

The prudential requirements in the NEM are set on a basis that considers various factors, including an estimation of load for each market participant and the relationship between average load and peak load for each market participant. This suggests that a retailer offering wholesale demand response on behalf of its customers should have lower prudential requirements under the current arrangements. These arrangements would adjust the prudential requirements of a retailer in an ex-ante fashion. The market participants' prudential settings are reviewed by AEMO at least annually and adjusted to reflect the prudential risk posed by the market participant. However, the current arrangements may not account for the ability for new retailers utilising wholesale demand response when setting the initial level of prudential requirements.

If becoming a retailer is too onerous, or the aggregator is not suited to selling electricity, a demand response aggregator, who may be able to better recognise and utilise demand response, may face barriers to registering as a retailer and capturing the benefits of wholesale demand response.[219]

6.5.4 Separation of wholesale electricity and wholesale demand response

If aggregators were to offer wholesale demand response services without becoming a retailer, there would need to be a framework for the provision of wholesale demand response separately to wholesale electricity.

Separating the two services - energy and wholesale demand response - would in a sense be trying to disaggregate energy from energy. The concept of unbundling the services of load being used for market ancillary service from the services of load in the energy market has been introduced into ancillary service market following a recent rule change that resulted in participants using demand response to offer frequency control ancillary services. This is discussed in more detail in Box 6.6.

It is easier to conceptually consider the unbundling of FCAS from energy. This is because it relates to allowing two different services to access the value attached to each respective service.

Box 6.5 Unbundling of FCAS from energy

In November 2016, the Commission made a rule to unbundle the provision of ancillary services from the provision of energy. The rule provides for a new type of market participant – a Market Ancillary Service Provider – who can offer appropriately classified ancillary services loads or aggregation of loads into FCAS markets without having to be the customer's retailer.

There is currently only one party, EnerNOC, registered as a Market Ancillary Service Provider in the NEM. We understand that other parties are intending to become registered soon.

By reducing the consumption of some demand-side loads, EnerNOC has been able to offer frequency raise services in the NEM FCAS markets. These demand-side electricity loads, typically commercial and industrial customers, are able to be communicated with remotely and if needed, turned down.

In contrast, wholesale demand response is, by definition, a change in electricity demanded in the wholesale market. Separating the two would necessitate significant changes to the current market design.

219 Flow Power is an example of a retailer that formerly offered demand management services and now offers retail products with a significant emphasis on demand response.

Previous changes have been made to the regulatory arrangements to allow for the aggregation of small generators to offer services at a wholesale level. The small generator aggregator framework, summarised in Box 6.6, is an example.

Box 6.6 Small generator aggregator framework

In November 2012 the AEMC made a final determination and final rule on the *Small generation aggregator framework* rule change.[220] The rule created a new category of market participant, the Small Generation Aggregator, who is able to sell the output of multiple small generating units through the NEM without the expense of individually registering each generating unit. The AEMC concluded that this would enable small generating units to have more direct exposure to market prices, and therefore create a more efficient wholesale market.

A Small Generator Aggregator must:

- sell all sent out generation through the spot market for all market connection points it is financially responsible for
- purchase all electricity supplied through the national grid to the market connection points it is financially responsible for.

As a result, this framework facilitates the aggregation of multiple small generating units but it does not allow for two different parties to offer services into the same market from behind one connection point. If wholesale demand response and electricity consumption from behind the same meter were settled by two different parties, there is the need for arrangements to be in place to split the provision of the two services.

If a consumer was to offer wholesale demand response without engaging the FRMP (e.g the retailer), there would need to be a change to the current market design. As the FRMP currently accrues the benefit of wholesale demand response, this benefit would need to be transferred to the party offering wholesale demand response services. So, one solution would be to create a small load aggregator framework, to mirror the small generator aggregator framework discussed above. However, as noted above there are a number of corresponding changes that would also have to be made in order to create such a framework.

Therefore, we are exploring ways to make this value more easily captured. However, ways to do this would require further consideration as it would have flow-on effects for a number elements in the market, including potentially outcomes and prices for consumers. We need to consider:

- the value that should be attributed to wholesale demand response services
- how to determine the extent of any demand response

220 See: http://www.aemc.gov.au/Rule-Changes/Small-Generation-Aggregator-Framework

- the interaction between any mechanism and the wholesale market
- the metering arrangements may be required
- the need for any new participant categories.

The issues raised are significantly complex and warrant further consideration, and so we are considering this further. We are interested in stakeholder views on our preliminary views set out above.

7 Strategic reserves

Key points

- The Finkel Panel review recommended that AEMO and the AEMC should assess the need for a strategic reserve to act as a safety net in exceptional circumstances as an enhancement of or replacement to the existing RERT.
- The RERT is an existing mechanism in the NEM which allows AEMO to contract for reserves (generation or demand-side capacity that is not otherwise being traded in the market), that it can use in the event that it projects that the market will not meet the reliability standard and, where practicable, to maintain power system security. It can be considered a form of strategic reserve.
- The RERT is governed by provisions in the NER and the Reliability Panel's RERT guidelines. AEMO is also required to develop and publish procedures for the exercise of the RERT. Subject to prescribed limitations, the NER give AEMO discretion as to how it should procure and exercise the RERT, including the amount of reserves it procures.
- For the purpose of the interim report, we have focussed our analysis on reviewing the existing strategic reserve mechanism in the NEM, the RERT, and considering the need for any enhancements to it, or an alternative mechanism consistent with the Finkel Panel recommendation in relation to this.
- Our preliminary views are that:
  - Some form of a safety net is appropriate in the event that the market is expected to fail to meet the reliability standard.
  - The need for a strategic reserve that is separate from the existing mechanism, the RERT, needs to be considered further, given the costs that can be associated with such reserves.
  - Alternatively, some enhancements to the RERT may be appropriate to improve its efficiency and lower the cost of additional reserves.
- In considering the need for changes to, or a replacement of, the RERT, it is important to be clear about the problem. For example, if the concern is that community or political expectations have changed such that load shedding is no longer acceptable, then this is unlikely to be best addressed through a strategic reserve. This concern would be more appropriately, and efficiently, addressed by considering whether or not the existing reliability standard is set at the appropriate level. If instead, a separate mechanism is created to procure extra reserves with a tighter trigger, this could result in distortions to the market.

- Therefore, having a clear understanding of the problem, existing gaps and potential need is crucial in terms of considering, and designing, either enhancements to or a replacement of the RERT. Some further lessons (for example, from the ARENA RERT trial with AEMO) may be available after this summer, which could inform any consideration of these issues and the least cost solution.

The structure of this chapter is as follows:

- section 7.1 provides a brief history of the RERT and summarises the framework for the RERT
- section 7.2 discusses the historical use of the RERT
- section 7.3 sets out considerations of strategic reserves
- section 7.4 summarises stakeholder submissions to the issues paper
- section 7.5 discusses the Commission's preliminary views.

7.1 The Reliability and Emergency Reserve Trader

The RERT is an existing mechanism in the NEM which allows AEMO to contract for reserves (generation or demand-side capacity that is not otherwise being traded in the market), that it can use in the event that it projects that the market will not meet the reliability standard (that is, 0.002 per cent expected unserved energy) and, where practicable, to maintain power system security. The RERT can therefore be considered a form of strategic reserve.

There are two types of RERT based on how much time AEMO has to procure the RERT prior to the shortfalls occurring:

- medium-notice RERT - between ten and one week's notice of a projected reserve shortfall
- short-notice RERT - between seven days' and three hours' notice of a projected reserve shortfall.

Typically, AEMO sets up a RERT panel of providers for both the medium-notice and short-notice RERT and only triggers the procurement contract when it has identified a potential shortfall and after seeking offers from RERT panel members.[221] Prior to 1 November 2017, AEMO could contract for reserves for up to nine months ahead of shortfalls through the long-notice RERT. There was no panel for the long-notice RERT; rather, contracts were signed following the close of the tender process.

221 AEMO has the discretion to use a tender process in addition to using panel members in the case of the medium-notice RERT.

The remainder of this section summarises the framework of the RERT. A comprehensive discussion of the framework is included in appendix D.

7.1.1 NER framework

The NER provide the high-level framework for the RERT,[222] including:

- setting out the RERT principles[223]
- requiring the Reliability Panel to publish RERT guidelines[224]
- requiring AEMO to publish procedures for the exercise of the RERT.[225]

Generally speaking, the NER give AEMO discretion as to how it should procure and dispatch the RERT. Within this discretion, AEMO is limited by a number of provisions, including the RERT principles, discussed next.

The RERT principles

When procuring and dispatching the RERT, AEMO must do so in accordance with the following RERT principles as set out in the NER:[226]

- actions taken are to be those which AEMO reasonably expects, acting reasonably, to have the least distortionary effect on the operation of the market
- actions taken should aim to maximise the effectiveness of reserve contracts at the least cost to end use consumers of electricity.

Procurement and dispatch of the RERT

Under the NER, AEMO may procure the RERT to ensure that the reliability of supply in a region meets the reliability standard for that region, and to maintain power system security if practicable.[227] AEMO must not enter into, or renegotiate, reserve contracts more than 10 weeks ahead of a projected shortfall.[228] The NER do not contain a specific limitation on the number of times that AEMO can procure the RERT.

The Commission's view is that there is a lack of clarity in the NER with regard to exactly how they calculate how *much* reserves it procures. The Commission is interested in stakeholder views on whether they agree there is a lack of clarity, and if so, whether more prescription around this issue is appropriate.

222 Rule 3.20 of the NER.

223 Clause 3.20.2(b) of the NER.

224 Clause 3.20.8 of the NER.

225 Clause 3.20.7(e) of the NER.

226 Clause 3.20.2(a)(3) and clause 3.20.2(b) of the NER.

227 Clause 3.20.3(b) of the NER.

228 Clause 3.20.3(d).

The NER state that AEMO may dispatch reserves to ensure that the reliability of supply meets the reliability standard, and where practicable, to maintain power system security.[229] The NER also state a sequence of events that AEMO must use its reasonable endeavours to act in accordance with during periods of supply scarcity, as discussed in appendix D.

Other aspects of the RERT

There is no restriction in the NER as to what type technologies can participate in the RERT. For example, demand-side participation can provide reserves. Reserves may be scheduled or unscheduled[230] and must not otherwise be available to the market.[231]

The NER require that AEMO's costs associated with contracting for the provision of reserves be met by fees imposed on market customers in the region where the RERT has been procured and/or dispatched.[232]

7.1.2 RERT guidelines

The Reliability Panel's RERT guidelines provide additional guidance to AEMO on the RERT principles[233] and to the cost effectiveness of the RERT.[234] AEMO is required to comply with the RERT guidelines. The RERT guidelines specify what AEMO may take into account when it is determining whether to enter into contracts for the RERT (that is, in procuring the RERT)[235] and in dispatching the RERT.[236] However, it is not prescriptive in doing so and gives AEMO an amount of discretion. The RERT guidelines provide some guidance to AEMO as to how it may contract for reserves.[237]

The RERT guidelines specify how much time AEMO has to procure the RERT prior to the shortfalls occurring, namely, between ten and one week for the medium-notice RERT and between seven days and three hours for the short-notice RERT.[238]

7.1.3 AEMO's procedures

AEMO publishes a procedure for the exercise of the RERT under clause 3.20.7(e) of the NER. That document is subject to the rules consultation procedures. AEMO also makes

229 Clause 3.20.7(a) of the NER.

230 Clause 3.20.3(a) of the NER

231 Clause 3.20.3(j) of the NER.

232 Clause 3.15.9(a) of the NER.

233 See section 5 of the RERT guidelines.

234 See section 5 of the RERT guidelines.

235 Section 4 of the RERT guidelines.

236 Ibid.

237 Section 8 of the RERT guidelines.

238 Reliability Panel, RERT Guidelines, 2016.

and publishes an operating procedure for the dispatch and activation of reserve contract.[239]

AEMO typically procures the RERT when, in the medium-term PASA that is run weekly, AEMO identifies low reserve conditions. It may also procure the RERT when it identifies lack of reserve conditions (LOR), in the short-term PASA, pre-dispatch and / or dispatch. AEMO may also use any other information it thinks is relevant. As far as the Commission is aware, AEMO does not publish any methodology as to how exactly it calculates how much reserves to procure. The Commission is also interested in stakeholders' views on whether there needs to be more clarity and transparency around the procurement process.

Once AEMO has procured reserves, AEMO may then dispatch such reserves in an operational timeframe when it identifies that reserves are running low, typically through LOR2 or LOR3 declarations, typically after it has sought a market response and one has not been forthcoming.

7.2 The RERT in practice

Prior to 2017, the RERT had only been procured three times and had never been dispatched. In 2017, AEMO procured reserves through the long-notice RERT, introduced new panel members to the short-notice RERT panel through the ARENA-AEMO demand response trial and dispatched the RERT for the first time in November 2017.

7.2.1 History of RERT use

Prior to this year, the RERT had only been **procured** three times:

- 33 days from 31 January 2005 to 4 March 2005 (84 MW of capacity)
- 54 days from 16 January 2006 to 10 March 2006 (375 MW of capacity)
- three days from 15 January 2014 to 17 January 2014 (650 MW of capacity).

It is worth noting that the RERT had **never been dispatched** prior to 2017:

- From 31 January 2005 to 4 March 2005: These reserves were contracted to address a reserve shortfall that did not eventuate due to lower than expected temperatures reducing demand
- From 16 January 2006 to 10 March 2006: The forecast shortfall reflected the impact of delays in the commissioning of Basslink and Laverton North power station

239 See: AEMO's SO_OP3717

- From 15 January 2014 to 17 January 2014: AEMO contracted for reserves under the short-notice RERT to address a forecast LOR2 condition. The Commission understands that this was due to a forced outage of Basslink. The reserves did not need to be dispatched as Basslink returned to service earlier than expected.

Even when the RERT is not dispatched, **costs were still incurred** as in some instances, the contracts included an availability-type payment which was paid to reserve providers to be made available for the duration of the contract. The Commission understands that the availability payments in each of the three instances where reserve contracts were entered into were:[240]

- $1.035m ($12,321 per MW) for the 31 January 2005 to 4 March 2005
- $4.352m ($11,605 per MW) for the 16 January 2006 to 10 March 2006 period
- zero for the 15-17 January 2014 period.[241]

7.2.2 Use of the RERT in 2017

In July 2017, following a number of consecutive low reserve condition notices[242] via the medium-term PASA process for summer 2017-18, AEMO triggered the procurement of the long-notice RERT.[243] It went to tender twice, once in July and once in September for reserve contracts for the period of January to March 2018.

At the same time, AEMO also issued an expression of interest for the RERT Panel, seeking expressions of interest for the short-notice and medium-notice RERT panel. The original expression of interest closed in July 2017, after which AEMO issued a further expression of interest which was due to close in September 2017 but was extended to 17 November 2017. AEMO is currently seeking expressions of interest from entities in Victoria, South Australia, Tasmania, Queensland, NSW and the ACT.[244] This will close on 1 March 2018 or as notified earlier.

In addition, recipients of ARENA funding through the ARENA and AEMO trial (discussed in appendix E), are also short-notice RERT panel members. The trial is running for a period of three years.

On 30 November 2017, the RERT was dispatched for the first time, as discussed in Box 7.1.

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240 AEMC, Extension of the Reliability and Emergency Reserve Trader - Consultation paper, 14 June 2016, p. 16.

241 This was through the short-notice RERT which does not have availability payments.

242 AEMO sought a market response when issuing each of these notices.

243 The long-notice RERT is no longer available. It expired on 1 November 2017. It allowed AEMO to contract for reserves up to nine months ahead of a projected shortfall.

244 See http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Emergency-Management/RERT-panel-expressions-of-interest

Box 7.1 November 2017 RERT activation

The RERT has only ever been exercised once in the history of the NEM. On 30 November 2017, AEMO dispatched reserves for six hours in Victoria.

On the day in question, AEMO first issued a LOR2 notice for Victoria on the day at 04:51 when pre-dispatch PASA identified a reserve shortfall of 187 MW for the time period starting from 15:30 that afternoon and lasting until 17:00. It sought a market response.

The second LOR2 notice was issued at 11:10 for the same time period. The shortfall had fallen to 88 MW, due to a market response or revisions in forecasts. In the market notice, AEMO noted that it had determined the latest time at which it would need to intervene through an AEMO intervention event was 12:30.

At 13:53, AEMO issued a market notice to inform the market that it had entered into a reserve contract and may implement an AEMO intervention event by activating the RERT to maintain the power system in a reliable operating state for the time period starting 15:30 until 21:30.

Demand appeared to be falling from just after 15:00 onwards. At 15:20, AEMO issued another notice informing the market that the RERT had been activated (which is the term used for dispatching unscheduled reserves) to maintain the power system in a reliable operating state.

AEMO implemented an AEMO intervention event for the duration the reserve contract is activated (that is, all dispatch intervals from 15:30 to 21:30).

Note: please note that all times are AEST. Information based on market notices issued by AEMO on the day.

For the 2018-19 summer, AEMO states that it expects a total of 1,150 MW of RERT (884 MW of demand response resources and 266 MW of generation) capacity NEM to be available:[245]

- generation capacity: this includes the South Australian government's emergency generators
- demand response: this includes the ARENA and AEMO demand response trial.

With regards to the ARENA and AEMO trial,[246] while this capacity is available to AEMO, the trial is being run through the short-notice RERT. This means that the successful demand response providers through this trial are now short-notice panel members. Technically, the resources have not yet been "procured" as such. AEMO will still need to meet the hurdle of identifying a reserve shortfall (in this case, via

245 AEMO, summer operations 2017-18, https://www.aemo.com.au/-/media/Files/Media_Centre/2017/AEMO_Summer-operations-2017-18-report_FINAL.pdf

declaration of LORs) before it executes any contract with members of the short-notice RERT panel. The availability payment being paid to providers is being done through the ARENA and NSW Government funding.

7.3 Consideration of strategic reserves

7.3.1 The Finkel Panel's strategic reserve

The Finkel Panel's recommendation 3.4 states that:[247]

> "By mid-2018, the Australian Energy Market Operator and the Australian Energy Market Commission should assess:
>
> - The need for a Strategic Reserve to act as a safety net in exceptional circumstances as an enhancement or replacement to the existing Reliability and Emergency Reserve Trader mechanism."

The Finkel Panel noted that a strategic reserve would have the purpose of increasing available measures to maintain a reliable system. It commented that a strategic reserve is a type of targeted mechanism that compensates surplus capacity for being available at times of scarcity – that is, to address short-term reliability.[248]

In describing a potential out-of-market strategic reserve for the NEM, the Finkel Panel noted the following:[249]

- A strategic reserve could involve equipping AEMO with the power to contract for a targeted level of capacity that would be held in reserve outside the market.
- If implemented, this policy should be designed as an enhancement or replacement to the Reliability and Emergency Reserve Trader (RERT) to avoid adding additional complexity and uncertainty
- Making better use of demand response in the NEM represents a low cost and as yet under-developed opportunity to maintain reliability.
- To avoid interventions crowding out private sector investment or creating other perverse outcomes, there would need to be a clear and transparent set of criteria under which the reserve could be called upon. For example, where the reliability standard is expected to not be met.

The COAG Energy Council has agreed that a strategic reserve and the Reliability and Emergency Reserve Trader mechanism will also be considered as part of the AEMC's

246 Discussed in more detail in appendix E.

247 Finkel Panel, Independent Review into the Future Security of the National Electricity Market: Blueprint for the Future, June 2017, p.103.

248 Ibid., p.85.

249 Ibid., pp. 100-101.

Reliability Frameworks Review, with the AEMC and AEMO continuing to work closely together on their reliability work programs.[250]

7.3.2 AEMO's views on the strategic reserves

In its advice to the Commonwealth Government on dispatchable capacity, AEMO noted that it is pursuing around 1,000 MW of strategic reserves in its summer readiness plan (which is described above).[251]

AEMO also recommended the development of a strategic reserve. In this advice, AEMO made the following comments about the design of the mechanism:[252]

- Demand response and peaking generation (such as diesel generators) would be procured ahead of time and used to avoid load shedding, but would only be enabled during periods of scarcity pricing.[253]
- The mechanism would be used from summer 2018-19 to summer 2020-21, after which time a longer term mechanism would need to be in place.
- Strategic reserve requirements depend on a number of factors; requirements need to be assessed on at least an annual basis, and the requirement may go up and down each year.
- Strategic reserves are only used as a last resort to avoid load shedding.

AEMO also noted that since strategic reserves are procured outside of the market and are only used for emergencies, they do not distort investment signals.[254] AEMO reinforced its recommendation of a strategic reserve mechanism in its submission to the issues paper for this Review, as discussed in section 7.4.

In August 2017, AEMO set up an expert advisory panel of senior energy leaders to help AEMO deliver key initiatives and implement the Finkel Panel recommendations. The expert advisory panel has met twice to date and discussed, among other things, the design of a strategic reserve mechanism.

In addition, AEMO staff have discussed a working paper on a high-level design for strategic reserves with AEMC staff and the Reliability Panel. We understand that this working paper has been discussed with a number of other industry participants.

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250 See http://www.coagenergycouncil.gov.au/council-priorities/security-sustainability-and-stability-national-electricity-market and AEMC, 2017 Energy sector strategic priorities - detailed goals and initiatives, accessed from http://www.aemc.gov.au/Markets-Reviews-Advice/2017-Energy-sector-strategic-priorities.

251 AEMO, Advice to Commonwealth Government on Dispatchable Capability, September 2017, p.3.

252 Ibid. pp. 18-20.

253 AEMO does not provide any additional guidance as to what scarcity pricing is but we understand that they mean prices close to or at the market price cap.

254 Ibid. p. 18.

However, this working paper is yet to be made public. Therefore, it is difficult to gauge stakeholder reaction on the proposal. According to the minutes of an expert panel meeting, the primary feedback has been around the cost of such a mechanism, including:[255]

- the impact on consumers and affordability
- general concerns around costs and transparency.

Expert panel members also suggested a sunset clause for the mechanism or a trigger designed carefully if the mechanism is to be permanent, and noted risks associated with enforcing contracted reserves, including whether there would be penalties associated with failure to deliver.[256]

7.3.3 International examples

International examples are increasingly being referred to as comparisons to the NEM. Care should be taken when comparing mechanisms available in other jurisdictions with those available in Australia. First, there is no single market in the world that works exactly the same as Australia's NEM. Even comparing similar markets (e.g. Texas), there are a number of significant differences in structure, naming convention and mechanisms. As a result, direct comparisons are not encouraged. However, from an assessment point of view, overseas mechanisms and experiences can prove to be useful.

The two most relevant strategic reserve examples are discussed in detail in appendix F, since they can be considered opposite ends of the spectrum. In particular:

- The Electric Reliability Council of Texas (ERCOT)'s Emergency Response Service which provides out-of-market demand response and distributed energy resources response for reserve purposes. This effectively sets a 'budget' for reserves and procures as much as it can to meet that budget.
- Belgium's strategic reserves which are used to avoid a capacity shortfall and maintain reliability, similar to the Reliability and Reserve Trader (RERT). In other words, the system operator procures some capacity that is used only during supply shortfall. This effectively sets an 'amount' of reserves and spends whatever it needs to obtain this amount.

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255 See October 2017 meeting minutes at https://www.aemo.com.au/-/media/Files/About_AEMO/Expert-Panel/171101---AEMO-Expert-Panel-Minutes.pdf

256 Ibid.

7.4 Stakeholder submissions to the issues paper

On interventions, including the RERT, stakeholders are primarily of the view that:

- interventions should only be used as a last resort or for emergency
- only be used when the market has failed to deliver reliability
- mechanisms should be designed so as to minimise market distortions
- interventions should, however, be balanced against the cost of load shedding
- lessons from the ARENA-AEMO RERT trial should be factored into the Commission's decision.

Intervention mechanisms should be used as a last resort and designed so as to minimise market distortions

Infigen acknowledged the role and importance of intervention mechanisms (including the RERT) as a last resort or safety net in the event that the market has failed to deliver reliability.[257] Infigen also noted that these mechanisms need not be enshrined permanently in the NEM, but acknowledged that some intervention mechanisms may be needed more in the short-term.[258] EnergyAustralia was of the view that intervention mechanisms should be well designed so as to minimise market distortions.[259]

EnergyAustralia noted that transparency, consistency and accountability are important in intervention mechanisms to balance the potential market distortions against the preference of intervention to load shedding when the cost is not excessive.[260] Meridian Energy also highlighted the importance of a well designed and implemented mechanism to make sure that market distortions (for example, acting as a barrier to investment in new supply) are minimised.[261] This is echoed by ENGIE - it noted that interventions may inhibit market responses leading to underinvestment in additional reserve capacity provided within the market.[262]

BlueScope noted however that, for many large energy users, the cost of the RERT may be dwarfed by the cost of unserved energy - the cost of extended outages brought about by involuntary load shedding may far outweigh the short-term costs associated with interventions.[263]

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257 Infigen, submission to issues paper, p.8.

258 Ibid. p.8.

259 Energy Australia, submission to issues paper, p.3.

260 Ibid. p.3.

261 Meridian Energy, submission to issues paper, p.7.

262 ENGIE, submission to issues paper, p.5.

263 BlueScope, submission to issues paper, p.5.

Meridian Energy noted that given that the market is only now recognising the value of demand response, the implementation of demand response within the RERT may undermine the development of efficient long-term demand response approaches.[264]

While not specifically referring to demand response, Stanwell noted that the Commission should consider whether resources that are outside of the market could be incorporated into the market at a lower cost to consumers.[265] They also suggested reviewing compensation arrangements to assess trade-offs; for example, it would be perverse if resources were incentivised to participate in the out-of-market RERT rather than participate in the market (where the compensation may be that associated with directions).[266]

There was general support for the RERT, although a number of stakeholders suggested changes

Stakeholders primarily commented on interventions more broadly but there were a few comments about the current RERT mechanism.

Stanwell stated its support for the retention of the short-notice and medium-notice RERT.[267]

Meridian Energy noted that there may be merit in the long-notice RERT. It said that the long-notice RERT enables more efficient investment and response timelines and when combined with capacity payments, may have the ability to produce much lower costs of intervention.[268]

S&C Electric noted that if the RERT is being used more often, then it suggests that a new service may be needed that operates within the market.[269]

AEMO's submission on strategic reserves

On interventions and the RERT, AEMO notes that although operationally it takes every opportunity to manage shortfalls, issues arise as the RERT is linked to the reliability standard, which it says is a planning standard that is unclear as to use for operating reserves, while its power to issue directions are linked to maintaining a reliable operating state, which it says appear to encourage intervention to avoid involuntary load shedding.[270]

264 Meridian Energy, submission to issues paper, p.8.

265 Stanwell, submission to issues paper, p.3.

266 Ibid. p.3.

267 Ibid. p. 3.

268 Meridian Energy, submission to issues paper, p.8.

269 S&C Electric, submission to issues paper, p.10.

270 AEMO, submission to issues paper, p.4.

AEMO states that:[271]

> "Both these mechanisms [RERT and directions] operate in the same operational timeframe but with different triggers. To the extent that intervention can't be avoided, the trigger should be consistent and the objectives of interventions should be clearly defined as part of the design of the market intervention mechanism. The current framework is deficient in this regard."

AEMO also provided an update on its view of strategic reserves. Specifically, AEMO said that:[272]

> "Strategic reserves would also be likely to replace RERT with:
>
> - An operational trigger based on achieving a reliable operating state rather than the reliability standard, but also minimising the gap between unserved energy under the standard and zero.
> - Generalised procurement to be permanent rather than triggered and sized to meet operational rather than planning requirements.
> - Providing for recovery of some initial capital expenditure, and a commercial approach that allows some involuntary load shedding to be converted into a service.
> - An extension of the AEMO/ARENA initiative."

7.5 Commission's preliminary views

For the purpose of this interim report, we have focussed our analysis on assessing the existing permanent strategic reserve in the NEM, the RERT, and considering the *need* and desirability for *either* enhancements to the RERT *or* an alternative mechanism as per the Finkel Panel recommendation to do so; as well as focussing on how the need could be determined. As identified by the Finkel Panel, this is a threshold issue, the determination of which would then inform any subsequent changes to existing frameworks.

The following section, therefore, does not seek to make recommendations around the detailed design of a replacement to the RERT, but rather to set out our preliminary views on the need for changes to the existing RERT mechanism. AEMO's work on the high-level design for a strategic reserve will be informative input for future assessment of these issues.

271 Ibid. p.4.

272 AEMO, submission to issues paper, p.7.

7.5.1 What is the theoretical rationale for strategic reserves?

Strategic reserves (which are typically out-of-market reserves, that is, interventions) are designed as a last resort mechanism that AEMO may use should a market response fail to eventuate. In other words, they are based on the premise that the market, through contract and spot market signals, should deliver the *right* level of reliability both in the investment and operational sense as determined against the reliability standard.

In a perfect world with perfect information, the reliability standard (that is, maximum expected unserved energy amounting to 0.002 per cent of total energy demanded in a region per financial year) would be expected to always be met through the investment and operational decisions made by participants. However, in practice, it is true that investment in, and operation of capacity may not be "perfect".

However, over time there is a natural tendency for sub-optimal market outcomes caused by uncertainty to self-correct, particularly if risks are placed with the party best able to manage them and so they are appropriately aligned. For example, if retailers under-contract relative to the 'efficient' level, they will be left exposed to high actual spot price events that will incentivise them to contract more in future.

In other words, in practice, the market can never "guarantee" that the reliability standard will always be met. This means that some sort of out-of-market reserves such as RERT helps provide a safety net in the long-term interests of consumers *if* the market fails to deliver the expected level of reliability.

As mentioned, AEMO can only trigger the procurement of the RERT when it expects that the reliability standard (that is, 0.002 per cent unserved energy) may not be met and, if practicable, to maintain power system security.

In extending the RERT indefinitely last year, the Commission noted that it is preserving a "safety net" in the event that market responses are, or are likely to be, insufficient to service the electricity needs of consumers in a manner consistent with the reliability standard.[273] The Commission also noted that the indefinite extension of the RERT provides regulatory certainty about the range of intervention tools available to manage reliability in the NEM.[274]

We therefore consider there needs to be some form of reserve mechanism in the NEM.

Economic efficiency and the RERT

There is also an economic efficiency argument for having out-of-market reserves in the context of the NEM and existing reliability framework.[275]

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273 AEMC, Extension of the Reliability and Emergency Reserve Trader, Final Determination, 23 June 2016.

274 Ibid.

275 Ibid.

The RERT complements the suite of permanent intervention tools available to manage reliability (directions and clause 4.8.9 instructions), in the event that market responses are, or are likely to be, insufficient to service the electricity needs of consumers in a manner consistent with the reliability standard. These intervention tools help AEMO manage reliability in the short term.

As noted in the issues paper, the RERT is more economically efficient than directions and clause 4.8.9 instructions - stakeholders also agree with that view. As noted above, in the case of demand response, this is because the RERT is *voluntary* and so reflects the value that *consumers* place on reliability, including where this may be above the level of the market price cap. In contrast, load shedding under clause 4.8.9 is based on load shedding schedules set by governments, which involve the government making an assessment of areas that have higher values for reliability (e.g. those with hospitals). This is not as granular as it could be if each customer could express their own value.

For some consumers, their value of customer reliability exceeds the market price cap. It is economically efficient for these consumers to participate in an out-of-reserve market should they choose to do so - they are unlikely to participate in the wholesale market since their value of reliability is higher than any benefits they may get in response to wholesale prices. The same argument could apply, in theory, to generation. Generation that cannot recover their costs in the wholesale market could theoretically benefit from participating outside of the market where prices are expected to be higher than the market price cap. However, it is unlikely that investors would invest in generation simply to participate in such a market as it would not make sense financially.

In Australia, typically, diesel generators are the ones that tend to have participated in the RERT. In other markets, typically, only mothballed plants have participated - however, their participation is problematic as allowing mothballed plants to participate in out-of-market reserves may create a perverse incentive for these plants to retire early in order to benefit from prices that are expected to be higher than the market price cap.

However, as set out above, the existing RERT is already a strategic reserve in place in the NEM, and so enhancements to the NEM or alternative mechanisms should be considered with this in mind.

7.5.2 Does the RERT need to be enhanced or replaced?

In addition to the concerns raised by AEMO in its submission, as discussed in section 7.4, stakeholders are of the view that the following are shortcomings of the RERT:

- the RERT is bespoke in nature and tends to be driven and procured through complex and lengthy bilateral negotiations, which limits price discovery
- the lack of availability payments has been a barrier to RERT participation
- the lead times for procuring reserves are too short (up to 10 weeks)

- the RERT can only be procured in response to a potential shortfall and therefore cannot be used for unexpected shortfalls i.e. AEMO must forecast or project that there will be a shortfall first before it can enter into contracts. If the shortfall is imminent and is not expected by AEMO, then the RERT cannot be procured.

These points are discussed in turn below.

As noted in section 7.4, stakeholders were overwhelming of the view that intervention mechanisms, which includes the RERT, should be used as a last resort and should be designed so as to minimise market distortions. We agree with this view.

RERT triggers

In its submission, AEMO noted that the RERT is linked to the reliability standard, which it says is a planning standard that is unclear as to its use for operating reserves, while directions are linked to the reliable operating state, which appear to encourage AEMO to intervene to avoid involuntary load shedding.[276]

As noted in sections 7.1.1 and 7.1.2, the regulatory framework for the RERT provides AEMO with a level of discretion, subject to certain constraints (such as having to consider the RERT principles and reliability standard), to enter into reserve contracts and exercise the RERT to ensure reliability of supply and maintain power system security.

Based on the above mentioned framework AEMO takes the following steps in triggering the RERT:

- AEMO issues market notices to signal to the market when reserves are expected to not be sufficient to deliver the reliability standard.

- If its processes continue to project insufficient reserves to meet the reliability standard, then AEMO may procure reserves for up to ten weeks ahead of its projected shortfall.

- In the operational timeframe, AEMO's responsibilities are to minimise unserved energy using its NER-provided intervention mechanisms.

However, even if AEMO should manage the system to minimise unserved energy, the *expectation*, as set by the reliability standard, is of some unserved energy (a maximum of 0.002 per cent to be precise). AEMO would not be *expected* to always have zero unserved energy in an operational timeframe. In fact, implicit in the reliability standard is an expectation that it will not be zero. To the extent that this is considered to be unclear, it could be worth amending the NER to clarify this.

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276 AEMO, submission to issues paper, p.4

Lead time for procurement

The lead time for procurement in the RERT is short by design. In 2016, the Commission reduced the lead time for procurement, since this will:[277]

- Give market participants greater time and opportunity to respond to a projected reserve shortfall, before AEMO seeks to enter into RERT contracts. A market response is a more economically efficient outcome than reserve contracting.
- Minimise the likelihood that, in contracting for reserves, AEMO crowds out potential market-based arrangements (such as retailers seeking to engage with their customers to reduce load).
- By only being able to act closer to real time, allow AEMO to utilise new and more up-to-date information to inform both its assessments of capacity adequacy, and its decisions on whether to enter reserve contract. This can reduce the risk that reserve contracts are unnecessarily entered into and not dispatched.

The longer the lead time, the more distortionary the impact on the market is - the long-notice RERT was removed for that reason. If AEMO identifies a shortfall a year or two years out through its PASA process, this sends a signal to the market - either to increase investment or shift maintenance. If the PASA processes regularly identify potential shortfalls, that also serves as a signal to the market that there may be a reliability problem and, again, sends a signal to invest in capacity.

Procuring reserves too far ahead of a potential shortfall can be distortionary and preclude a potential market response. In other words, may incentivise capacity that may be participating in the market to shift their availability to participate in the out-of-market reserve mechanism instead of through the market, meaning that reliability would be met at a higher cost.

Therefore, we consider that increasing the lead time could lead to higher costs. Having a longer lead time could result in the perverse outcome of paying participants to sit there, out of the market, when they might not be needed, increasing costs as well as distorting the efficient operation of the market. However, given the changes in market dynamics since the final determination on this was made, we are interested in stakeholder views on whether the lead time could be longer.

Procurement trigger

The current procurement trigger for the RERT involves AEMO expecting that the reliability standard, as set by the Reliability Panel, may not be met.

The fact that AEMO can only procure the RERT in response to a potential shortfall that is referenced against the reliability standard is by design - in fact, AEMO can procure

277 AEMC, Extension of the Reliability and Emergency Reserve Trader, Final Determination, 23 June 2016.

the short-notice RERT with only three hours of notice (as a minimum up to seven days in advance).[278]

The procurement trigger is essentially a proxy for the expected level of reliability. It is appropriate for such a trigger to continue to be set by the Reliability Panel, not another party. If, for example, AEMO, as system operator, were to determine alone what the trigger should be, it would likely err on the more conservative side. Even if it could still be required to take into account the cost-benefit trade-offs of providing reliability, it is likely that its decisions would also implicitly take into account other considerations, such as its ability to more easily operate the system.

However, we have examined two possible options when it comes to the procurement trigger - it could either be changed (presumably, tightened) or it could be removed altogether.

Changing the procurement trigger

Changing the procurement trigger would likely be inconsistent with the reliability standard and could involve significant costs. In effect, there would be two standards, one that drives both investment and operational decisions in the market and set by the Reliability Panel following a cost trade-off assessment. Another, presumably a tighter standard, that would relate to procuring reserves in the operational timeframe. Having two standards would create conflicting signals for participants.

The reliability standard and settings underpin the investment and operational decisions that market participants make, as well as AEMO's day-to-day operations. Having a separate, distinct standard solely on the operational timeframe that is tighter than the reliability standard could mean that the market would never be expected to invest to meet this level of reliability. In essence, the tighter standard for reserves would always be triggered.

Removing the procurement trigger

In a case with no threshold to trigger procurement, that is, a system whereby the operator would seek to procure reserves, say, annually, independent of an assessment the need for reserves, the system operator could be given the task of working out the procurement amount to be on stand-by all the time. The procurement amount may use a metric such as 0.002 per cent unserved energy (or some other metric) and the system operator would then work out what this translates to in terms of MW and procure this amount of reserves every year, or it could be based on a maximum budget.

This is similar to ERCOT's strategic reserves (discussed in more detail in appendix F), whereby reserves are procured annually based on a set, maximum budget regardless of any assessment of need. ERCOT then procures an amount of reserves up to the budget.

278 To the extent that shortfalls unanticipated due to forecasting error, improvements to AEMO's forecasting processes, as discussed in chapter 4 would go some way in improving outcomes for identifying a potential shortfall.

This would likely be highly distortionary as discussed above when assessing the lead time for procurement. If market participants know that there are reserves on stand-by all the time, there would be little incentives to invest in peak capacity.

Summary

As a number of stakeholders noted in submissions, if the market expects that the system operator has access to reserves, procured outside of the market, that it could use, this may inhibit market responses, including investment in capacity. However, if the resources that will be in the strategic reserve would not participate in the market today (consider demand response with a value of customer reliability that is greater than the market price cap) then distortions may not be as severe.

Our preliminary view is that the current procurement trigger should be retained - the procurement trigger should remain an identified potential breach of the reliability standard so as not to distort investment signals. The market should remain the primary mechanism by which reliability, including tight demand-supply balances, is met. However, to the extent that stakeholders consider it should be changed, we would welcome feedback in this regard.

Procurement amount

Once AEMO has identified the need for procurement, it is up to it to work out how much reserves it needs to ensure a reliable supply of energy, that is, enough reserves to meet the reliability standard. There is discretion as to how AEMO does that.

Our view is that there could be a lack of clarity in the NER with regard to exactly how much reserves AEMO may procure. We are interested in stakeholder views on whether they agree there is a lack of clarity, and if so, whether more prescription around this issue is appropriate.

At present, the procurement amount is linked to the reliability standard, as set by the Reliability Panel. Our preliminary view, as set out above, is that it is still appropriate for AEMO to assess the needs of the system, within the constraints of meeting the reliability standard.

Cost of the RERT

Due to the infrequent use of the RERT to date,[279] the modest size of the associated availability payments, and the requirement that capacity procured under the RERT must not otherwise be available to the market, we consider the distortions to the market associated with the RERT to be minimal. Further, that the infrequent use of the RERT is unlikely to provide sufficient incentive to withhold reserves (on either the supply or demand side) in order to contract with AEMO.

279 The RERT has only been procured five times, including the most recent procurement process for this summer and has only been dispatched once, on 30 November 2017.

The size and infrequent use of the RERT is consistent with the mechanism being a safety net to be used only when the market is expected to fail to meet the reliability standard, which incorporates the trade-off between increased reliability and the costs associated with that.

When considering whether the RERT be redesigned or replaced, the costs associated with that would need to be revisited and balanced against the benefits of higher reliability.

Payment structure

Currently, the NER do not specify a structure for how payments under reserves contracts are calculated; they are privately negotiated bilateral contracts between AEMO and the provider.

Stakeholders noted that the lack of availability payments[280] has inhibited participation in the RERT. Any changes to the payment structure of the RERT would require careful assessment due to the costs associated with a more comprehensive availability payment structure, against the benefit of additional or more efficient participation in the RERT.

Having an availability payment that applies all the time would potentially be costly. In the case of the ARENA-AEMO trial, availability payments are funded through grants that are outside of the energy market. If availability payments were to become a permanent feature of the RERT, the costs would have to be paid through the energy market and ultimately recovered from consumers. The structure of the availability payment would also impact on incentives of parties to participate or not. The cost of the mechanism would need to be carefully assessed. We understand, based on comments from the minutes of the last AEMO expert advisory panel meeting, that stakeholders are indeed concerned about the cost of such mechanisms on consumers. Until now, the RERT has been used so rarely (and can only be triggered and dispatched in extenuating circumstances), that costs have not been excessive.

As discussed in appendix A, balancing the costs of higher reliability on consumers against the costs of unserved energy will be crucial in assessing any reliability mechanism.

Product design

The RERT is highly bespoke and requires bilateral negotiations with AEMO. We note stakeholders' concerns around the cost and complexity associated with such a mechanism and is considering whether the RERT could be simplified. To that end, we consider that introducing specific, standardised products into the RERT may be beneficial. Therefore, we are interested in the lessons from the ARENA – AEMO trial to see if that has been helpful.

280 Availability payments are only available for the duration of a medium-notice RERT contract.

As previously noted, we are of the view that more comprehensive lessons from the trial will be available after the summer. It may, therefore, be useful to wait until any lessons from that trial are evident before finalising any recommendations on detailed design of the changes - there are many more threshold level questions that can be considered before then.

7.5.3 Potential improvements to the RERT

We consider that the need for a strategic reserve that is separate to the RERT needs to be further considered, given the costs associated with such reserves.

Our initial view is that the existing strategic reserve in the NEM – the RERT - could benefit from some enhancements to reduce the complexity and associated cost of participating in the mechanism. For example, there may be benefit in simplifying the RERT through the use of standardised products and, in particular, exploring the role of demand response in participating in the RERT. As noted, there may be an economic argument for some consumers to participate in out-of-market reserve mechanisms, while the argument is not necessarily present for other types of resources.

Further, certain aspects of the legal framework for the RERT may lack clarity and could be amended to provide sufficient certainty - for example, in terms of the quantities of reserves that may be contracted once a shortfall has been identified.

AEMO has developed a working paper on a high-level design for a strategic reserve. AEMO considers the need for a strategic reserve to be informed by its September advice on dispatchable capacity to Minister Frydenberg. The need for a strategic reserve mechanism of the kind envisaged by AEMO seems primarily to be that community or political expectations have changed such that load shedding or the probability of load shedding is no longer acceptable.

Understanding wider stakeholder views on this articulation of the need is necessary before drawing conclusions on what alternative mechanism may be required. This is because a need of this kind may be better and more readily addressed through other mechanisms or changes to the framework. The reliability standard takes into account not just community expectations through the value of customer reliability into account when it is assessed, but other factors such as market participant risk exposure. Ultimately, the reliability standard balances the cost and benefits trade-offs of providing additional reliability.

Further, identifying the need for an alternative mechanism, requires a better understanding of the inadequacies of the RERT or what other gaps there are in the existing reliability framework that may mean it is no longer fit for purpose. It may in fact be very costly to have an alternative mechanism. These costs should be clearly assessed against any benefits that may be achieved in order to make sure that the introduction of such a mechanism (or amendments to the RERT) would be in the long-term interests of consumers, consistent with the National Electricity Objective (NEO). Some of the concerns around the absence of the long-notice RERT that have been raised by stakeholders, and problems with the existing RERT framework could be better specified and consulted upon before a decision to create a completely new mechanism is made.

We welcome stakeholder views on what potential improvements to the RERT could be.

ARENA-AEMO demand response trial

In addition, we are of the view that more comprehensive lessons from the ARENA-AEMO trial will be available after the summer.[281] It may, therefore, be useful to wait until any lessons from that trial are evident, given they may highlight the very gaps that need to be addressed, particularly in terms of the simplification of the RERT process by introducing two standardised products and the impact of the availability payment on participation in the program.

We agree with AEMO that having specific products is simpler and may promote participation in the RERT. This would promote competition and may deliver reserves at a lower cost. However, the design of the products would be crucial - for example, a 10-minute response time is likely to exclude most non-flexible resources, while a 24-hour notice product is likely to result in distortions to the market.

Stakeholders raised this point in submissions, particularly given that demand response in the NEM, while occurring and growing, is not particularly visible. If demand response is to be specifically incentivised to participate in out-of-market reserves, it will be important that this does not shift demand response which would have participated in the wholesale market in the absence of the RERT from the market to the RERT. In other words, from the market which would have delivered reliability at a lower cost to consumers to the RERT, which is arguably a more costly option.

We note that given the wide range of the value of customer reliability for different loads, out-of-market demand response participation may be appropriate. If the value of reliability for a particular customer is higher than the market price cap, that particular customer would have little incentive to respond to price signals when prices are below or at the market price cap (i.e. within the market). However, they may be willing to do so when prices are higher than the market price cap.

Commission's preliminary views

In considering the need for such a strategic reserve mechanism that is separate from the RERT, it is important to be clear about the problem. For example, if the concern is that community or political expectations have changed such that load shedding or the probability of load shedding is no longer acceptable, then creating a new mechanism may not be the best way to address this problem. Any such concern would be appropriately addressed by reconsidering whether or not the existing reliability standard is set at the appropriate level - that is, whether the community now expects lower levels of unserved energy.

281 The trial will be running for three years.

Changing the reliability standard could likely be a more efficient outcome, since it may more directly address the problem. When setting and assessing the standard, the Reliability Panel considers the cost-benefit trade-offs of providing reliability. For example, they take a number of factors into account, including the value of customer reliability, the risk associated with the market and the costs of providing additional reliability. The outcome, the maximum expected unserved energy, efficiently balances those factors.

If the problem is community expectations, consider two approaches to address the problem:

- Option one, that is, leaving the reliability standard unchanged (that is, expecting the market to deliver 99.998 per cent reliability) and creating a separate mechanism to procure for additional capacity with a tighter trigger in the operational timeframe (that is, an intervention mechanism to deliver a level of reliability that is higher than the standard). This would be at odds with the reliability framework - the market would be expected to deliver a level of reliability that is lower than the one expected through the intervention mechanism.

- Option two, that is, a tighter reliability standard, say, say 0.001 per cent expected unserved energy instead of the 0.002 per cent. This would then result in a higher market price cap and associated changes in the reliability settings, which in turn sends signals to the market about what appropriate investment and operational decisions may be required from market participants.

Both options would have the purpose of achieving a similar outcome (lower unserved energy) to address the problem. However, option two would be approaching the problem consistent with the current market-based framework whereby the trade-offs between reliability and costs would have been made efficiently. This option would arguably deliver reliability at a lower cost to consumers than an option with two conflicting standards.

In any case, regardless of the option used, any tightening of the standard will carry costs - the case would still have to be made that the benefits to consumers in terms of higher reliability outweigh the cost of the market providing additional reliability through the market.

For example, in its draft report of the *Reliability standard and settings* review, the Reliability Panel noted that there here appears to be some public and/or political interest in reducing the amount of unserved energy expressed in the reliability standard to less than 0.002 per cent of expected demand in a region in a year, for instance to 0.001 per cent or even to zero per cent. At the same time the contrary view is held in some quarters; given rising electricity bills and affordability concerns, the reliability standard should be loosened to allow for more expected unserved energy to reduce costs to consumers.[282]

If stakeholders think that the current level of reliability standard is no longer appropriate, it will be important to make the case for why that is so and also recognise that this will come with a cost.[283] As discussed in Box 7.2, the Reliability Panel has carried out some indicative modelling of the potentially costs of having a tighter standard, that is, expected unserved energy being close to zero and found that the costs associated with that are likely to be significant.

Box 7.2 Indicative costs of tightening the reliability standard

The following provides some indicative costs associated with the reduction of unserved energy to zero in the Reliability Panel's modelling being carried out for its review of the *Reliability standard and settings*.

While it is impossible to reduce expected unserved energy to zero under base scenario conditions in Victoria (where there is virtually no estimated unserved energy at 0.000003 per cent in 2020-21), EY indicated that an estimated additional 1,000MW of capacity would be required to be in place in Victoria in 2020-21 to avoid any unserved energy under the modelling assumptions (including the impact of forced outages).The additional cost of moving to (close to) zero expected unserved energy under the base scenario would increase wholesale energy costs by nearly 7 per cent ($200 million per annum) in that region, as measured against current market outcomes in Victoria.

EY also modelled an alternative scenario where unserved energy exceeds the reliability standard (0.002 per cent unserved energy) in Victoria through early coal fired generation retirement. Under this scenario, EY indicated there is a peak unserved capacity of approximately 3,000 MW, or three times the amount under the base scenario. This implies a threefold increase in costs to achieve an expected outcome of zero unserved energy compared to the base scenario. That is around $600 million per annum, or a 20 per cent increase in wholesale energy costs, compared to current Victorian wholesale energy costs.

Source: Reliability Panel 2017, Reliability standard and settings review 2018, draft report.

282 Reliability Panel 2017, Reliability standard and settings review 2018, draft report, 21 November 2017, Sydney, p. 47.

283 When the Reliability Panel set the standard, it has regard to the cost trade-offs of providing reliability and the cost of unserved energy. The standard is set at the efficient level when balancing those costs. Any mechanism that would go beyond the standard implies that the standard is no longer appropriate - that is the expectation is of a higher level of reliability.

8 Day-ahead markets

Key points

- The Finkel Panel review recommended that "[b]y mid-2018, the Australian Energy Market Operator and the Australian Energy Market Commission should assess: [...] the suitability of a 'day-ahead' market to assist in maintaining system reliability.[284]
- The NEM, despite not having a formalised day-ahead market, has many features which play a similar role to that of a day-ahead market. These features include information that is provided to AEMO as part of the pre-dispatch process, supported by a liquid financial derivatives market with rebidding down to five minutes before real time. Rebidding allows participants with the flexibility to adjust their bidding position to respond to new information as it becomes available including changes in market conditions as well as responding to offers or bids of other participants.
- In terms of problems that a day-ahead market may address in the NEM, the Commission does not consider this has been fully demonstrated. To the extent that problems have been discussed, they generally relate to information provision and / or security-related matters (e.g. not being sure whether or not there will be enough synchronous generators running in the system at a particular point in time), as distinct from reliability (having sufficient supply to meet demand). Clearly identifying the problem, and articulating the materiality of it, is important in order to work out what the best solution is to the problem.
- Notwithstanding this, we have considered a number of options for the design and implementation of day-ahead markets. This chapter discusses two widely used day-ahead market designs: a European-style day-ahead market that facilitates participant-to-participant trades ahead of real-time; and a US-style day-ahead market that facilitates participant-to-system operator actions as a tool to schedule reliable operations.
- A European-style day-ahead market that facilitates participant-to-participant trading ahead of real time is more similar to the current NEM arrangements than US-style day-ahead markets. Consequently, our preliminary view is that the benefits of introducing a European-style day-ahead market in the NEM are not likely to be significant. This is because many of the potential reliability benefits from this type of option seem to be indirect, as well as this form of day-ahead market not appearing to be markedly different to the current NEM arrangements.

284 Finkel Panel, Independent Review into the Future Security of the National Electricity Market: Blueprint for the Future, June 2017, p. 23.

- A US-style day-ahead market facilitates participant-to-system operator trading. The main difference in the US-style approach compared to the current NEM arrangements is that through the day-ahead market, the system operator acquires firm financially binding information from participants which it then co-optimises over a period of time (typically, a day-ahead of real time) in order to physically operate the system. Participants settle a day-ahead, and then deviation quantities are settled between participants in the real-time balancing market (paid for by consumers).
- While the US-style approach could be beneficial in improving reliability outcomes if evidence was found that the contract market was not driving these outcomes, its implementation in the NEM would require the introduction of complementary reforms (such as nodal pricing and firm transmission rights) in order to achieve its intended outcome. Reforms of this nature also take a considerable amount of time and resources to implement. In Texas it took around seven years to implement a nodal day-ahead market. There may be more immediate actions that could be done to assist with addressing issues with reliability in the NEM.

This chapter discusses the principles behind day-ahead markets and the potential options for the implementation of a day-ahead market in the NEM. Specifically:

- section 8.1 discusses background to day-ahead markets
- section 8.2 discusses how we might approach assessing the suitability of a day-ahead market
- section 8.3 provides a comparison of day-ahead markets with the current NEM framework
- section 8.4 presents the Commission's preliminary views.

8.1 Background to day-ahead markets

This section first provides background to why we are considering day-ahead markets, then describes what a day-ahead electricity market is and introduces two distinct models for day-ahead markets:

- a European-style participant trading model which primarily assists participants with trading
- a US-style model where market participants provide information to the system operator ahead of real time to inform the system operator's dispatch decisions.

Finally, case studies of international examples of day-ahead markets are provided. These case studies illustrate that there are a number of different forms of day-ahead markets in existence, with each market design developing to suit local market conditions and issues.[285]

8.1.1 The Finkel Panel's day-ahead market

The Finkel Panel's recommendation 3.4 states that:[286]

> “By mid-2018, the Australian Energy Market Operator and the Australian Energy Market Commission should assess: [...]
>
> - The suitability of a 'day-ahead' market to assist in maintaining system reliability.”

The Finkel Panel noted that the ability for both AEMO and NEM participants to contribute to short-term reliability could be enhanced through greater forward transparency of supply conditions. It recognised that while the NEM already has mechanisms that provide forward transparency, another approach that is used in other countries is a 'day-ahead market'.

In describing a potential day-ahead market for the NEM, the Finkel Panel noted the following:[287]

- Internationally, facilitated day-ahead markets are widespread, existing in most European power markets and in the majority of North American power markets.
- Day-ahead markets uses a 'two settlement' system (as described below), whereas the NEM uses a 'single settlement' approach. In the NEM there is a pre-dispatch process that has similarities to a day-ahead market, but it is not financially binding to the system operator:[288] up until the start of the relevant five-minute dispatch interval, generators are allowed to rebid to shift volumes between price bands nominated in the original bid. The accuracy and validity of the pre-dispatch process depends on factors such as the demand forecasts, wind and solar forecasts, changes to constraints, unplanned outages, and the level of rebidding. Aside from rebidding, the same factors also affect the accuracy and validity of scheduling in day-ahead markets.
- Day-ahead markets could be a more effective means for the system operator to manage reliability than a pre-dispatch process, to the extent that a pre-dispatch process may be subject to strategic capacity withholding or disorderly bids. This is because day-ahead positions are financially binding at the day-ahead stage, whereas generators have the ability to rebid right up to dispatch in the NEM.

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285 The discussion in this chapter has been informed by analysis prepared by FTI Consulting on behalf of the AEMC.

286 Finkel Panel, Independent Review into the Future Security of the National Electricity Market: Blueprint for the Future, June 2017, p. 23.

287 Ibid., p. 102.

- However, there is also recognition of the efficiency benefits from the flexibility of unit commitment through bidding closer to real-time (as occurs in a single settlement system such as in the NEM). Indeed, in some existing day-ahead markets there is consideration of moving the gate closure (the time by which bidding closes) closer to real-time.

- The forward nature of day-ahead markets also enables generators and loads to hedge against exposure to pricing and scheduling risks, and in doing so, can reduce price volatility in the real-time market. The financial markets in the NEM provide a similar function, but in a less transparent way to the system operator.

Before we consider such issues further, we first spend some time explaining what a day-ahead market is commonly understood to be.

8.1.2 What is a day-ahead market

A day-ahead market is a common feature in other electricity wholesale market designs. In practice there are many variants of a day-ahead market and the market can serve a number of different purposes. Common to nearly all day-ahead markets however is that they allow generators to bid to sell electricity to meet some quantum of demand over a 24-hour period that commences at some point the following day.[289]

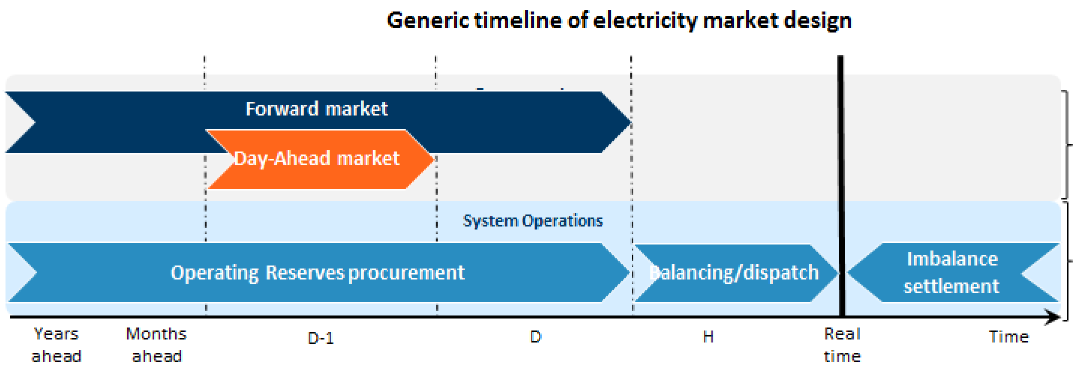
A day-ahead market can therefore be considered to be multi-settlement where participants settle day ahead and subsequent deviations are settled in the real time balancing market. While this is the most recognised form of multi-settlement system, some spot markets settle day ahead, and subsequent deviations are settled one hour ahead, and any differences after that are settled in the real time (balancing) market (with these ultimately paid for by consumers). Given the recommendation made by the Finkel Panel, this chapter concentrates on day-ahead markets as a particular type of multi-settlement market.

A stylised timeline of a day-ahead market is given in the figure below.

288 Although generators may have entered into forward contracts which are financially binding to its counterparty.

289 Some electricity market 'days' start at midnight of the day-ahead (for example most European markets) whereas other markets allow bids any-time from up to seven days in advance (for example California). In the NEM, through pre-dispatch generators must submit their bids by 12.30pm on the day-ahead.

Figure 8.1 Timeline of actions in a day-ahead market



For the purposes of this discussion we examine two key broad designs of a day-ahead market which each cover a different set of objectives. These designs will then be considered by comparison to the existing reliability frameworks in the NEM, with a view to providing some preliminary views on whether such designs are likely to provide a greater benefit in being able to maintain system reliability.

European-style markets

A European-style day-ahead market involves facilitating participant-to-participant trades of contracts ahead of real-time. This type of market is common in Europe and for the purposes of this discussion will be termed "European-style" day-ahead markets. As this design facilitates participant-to-participant trades of contracts, it is intended to meet the following objectives:

- To concentrate trading liquidity at a certain point in time. This is because trading is defined around a specific period, the day-ahead, rather than the contract market in the NEM which is continuous and has no defined time period. This potential for greater liquidity may provide greater confidence to market participants that the price signal observed reflects the underlying demand-supply balance. In turn, because there may be greater confidence in prices observed in the market, this might provide better investment and operational signals to participants.

- To allow market participants to fine tune previous traded positions ahead of real time and/or to hedge against volatility in the real time market.

- To provide information to the market ahead of the real time market as to the likely scarcity of generation relative to expected demand over the coming 24 hour period. In turn, this may influence individual plant operating decisions.

In essence, this European-style, participant-to-participant market is a '"trading tool" that provides price signals and a risk management facility to market participants. Importantly, the system operator does not rely on the information from the day-ahead market to operate the system. The Commission notes that there are few barriers to the establishment of such a day-ahead market in the NEM if it was thought to be beneficial to market participants.

US-style markets

By contrast, the second type of day-ahead market facilitates participants-to-system operator actions as a tool for the system operator to better schedule efficient and reliable operations. It has the following objectives:

- To provide technical and cost information to the system operator in the form of financially binding operating schedules and physical resource operating parameters for the day. This allows the system operator to schedule plant to meet expected demand of the system the following day and evaluate operational conditions on high stress days.
- To provide market participants with financially binding schedules to support physical unit commitment and gas scheduling
- To provide a way for market participants to provide information to system operators to schedule cross-border flows between different regional markets for the following day (which is obviously not a relevant consideration in the NEM)

Summary

To be clear, with regard to reliability, the key difference between the two styles of day-ahead market is that:

- the US-style, market participant-to-system operator approach aims to provide sufficient and binding information to aid the system operator to physically operate the system, whereas
- the European-style, market participant-to-market participant approach aids market participants to enter into contracts. Reliable outcomes are a consequence of financial incentives on market participants to fulfil contractual positions in real time, as discussed in chapter 5.

Box 8.1 The difference between trading types in a day-ahead market

This box explains the difference between participant-to-participant trades, which are common in European-style day-ahead markets, and participant-to-system operator trades, which is a common feature of US-style day-ahead markets.

In participant-to-participant trading:

- generators and retailers and other market customers optimise their own portfolios

- generators submit bids and retailers and other market customers submit offers reflecting cost of deviation (i.e. the cost that they would be willing to pay or receive to move away from their positions in the market)
- the trading between market participants allow then to minimise the costs of self-dispatch and meeting expected demand.

The participant-to-participant trade therefore do not directly inform the dispatch process. This is because market participants trade with each other to optimise their own portfolios rather than to make decisions on unit commitment. After the day-ahead market clears generators will re-optimise their portfolio to produce the committed volume, with financial incentives to do so that arise as a consequence of their contractual positions. They will then nominate the unit-level production to the system operator, which will inform dispatch decisions. Therefore, under this type of market day-ahead trading and real-time dispatch are two separate processes.

In participant-to-system operator trading:

- generators submit unit-level bids for their entire portfolio to the system operator in the day-ahead market[290]
- these bids are often multi-part and incorporate details of the plants dynamic constraints (start-up costs, minimum load, incremental energy cost etc.)
- the system operator takes all the bids from generators and determines generator schedules for the whole day based on their unit-level bids
- a financially and physically binding unit-level schedule is produced for each generator in the day-ahead market.

In these markets the trading is done between the system operator and generators. These trades form the basis of the centralised day-ahead schedule by the system operator and is much more closely related to actual dispatch outcomes than participant-to-participant trading. This is because the bids received by the system operator are at the unit level and are sufficiently granular for the system operator to create a schedule that would meet expected demand, and system security and reliability requirements the day-ahead of dispatch. Any deviations from this schedule are traded in the real-time or imbalance market, the costs of which are borne by consumers.

290 Variable renewable generation may find it difficult to commit their plant a day-ahead. To address this issue there are numerous arrangements in place in different markets, for example, in some markets only plant with longer start times participate in the day-ahead market.

8.1.3 International examples of day-ahead markets

Stakeholder submissions noted that the Commission should consider day-ahead markets in other jurisdictions in our analysis of this issue. We have considered two international examples of day-ahead markets, Texas and Great Britain, which are described in detail in appendix F.

We have chosen these two examples to provide insights into how these different styles of day-ahead markets operate in practice, and the decisions that were made on design features of these markets in response to local conditions and issues:

- Electric Reliability Council of Texas (ERCOT) was chosen as a case study because ERCOT is often mentioned as a good comparator for the NEM because its market is also considered to be "energy only"[291] and the day-ahead market that was introduced was voluntary in nature. This is an example of a US-style market as described above. However, the experience of Texas illustrates that there are a number of features of the ERCOT market that are very different to the NEM and that the development of this market was done in a way that responded to local market conditions and issues.
- The Great Britain example is a European-style power exchange independent of the system operator. In contrast to American markets, including ERCOT, European energy markets have a greater partition between energy trading by market participants and procuring reserves by the system operator. This means that generators are required to optimise and allocate their capacities between the energy and reserves markets based on their own expectations of the spot price.

8.1.4 Stakeholder submissions

There was relatively little discussion of day-ahead markets in stakeholder submissions to the issues paper, with only three submissions from ENGIE, AEMO and BlueScope Steel addressing the issue in detail.

ENGIE agreed with the statement in the issues paper that "it is particularly important to be clear on what the objective is that is trying to be met, prior to thinking about what the best mechanism is to address it". ENGIE is of the view that the recent discussion of day-ahead markets has emerged relatively quickly and "feels somewhat like a solution looking for a problem".[292]

ENGIE further note that the Commission should bear in mind that a day-ahead market was comprehensively evaluated prior to the commencement of the NEM and it was decided not to introduce a day-ahead and rely instead on financial hedges between parties. Since this time the financial derivatives markets have developed and could be

291 While the wholesale market run by AEMO is energy only, the NEM also encompasses a number of arrangements, such as the contract market, that does support the entry of capacity into the system.

292 ENGIE, submission to issues paper, p. 3.

detrimentally impacted if a day-ahead market was introduced, including potential financial losses for some participants.[293]

Finally, the submission from ENGIE noted that there may be some potential benefits if the day-ahead market is not applied to energy but rather to the additional services that may be necessary for a secure and reliable supply of electricity. There may be scope to consider the need for inertia in a day-ahead forecast, and have a day-ahead market for the provision of inertia services. ENGIE suggested that if such a day-ahead market for inertia has merit, then it would be preferable to extend the idea beyond just inertia, and have a day-ahead market for a range of flexible services that rely on the commitment status of synchronous generators.

The submission from AEMO stated that contract markets can provide hedges, but do not provide the necessary transparency to the system operator to operate a secure and reliable system, while ensuring the optimal amount of reserves are procured. In addition, contract markets will not provide hedging or reliability for spot-price exposed customers.[294]

It is further noted by AEMO that the Finkel Panel review identified a day-ahead market as a way of providing forward transparency to contribute to short-term reliability. The submission stated that increasing transparency and certainty for the operator has the potential to reduce the margin of error and allow the system to be operated less conservatively.[295]

The example of the Texas market was given as an energy-only market that uses a day-ahead market to provide a platform to hedge congestion and instruments to mitigate the risk of price volatility in real-time.[296] It noted that in this market willing buyers and sellers are matched and energy is co-optimised with ancillary services and congestion rights. AEMO noted that ancillary reserves in Texas are broader than the concept of the NEM's market ancillary services as they include regulation, non-spinning reserve and responsive reserve.[297]

The submission from AEMO also noted that day-ahead markets have the potential to promote demand-side participation. This is because increased transparency on system requirements may give customers more time to prepare and put alternative arrangements in place.[298]

AEMO made similar comments on the need to further examine the suitability of a day-ahead market in its submission to the Commission's *Five minute settlement* rule

293 ENGIE, submission to issues paper, p. 3.

294 AEMO, submission to issues paper, p. 6.

295 AEMO, submission to issues paper, p. 6.

296 It should be noted that the day-ahead market itself does not provide a platform to hedge congestion risk but rather the existence of a day-ahead market along with nodal pricing and firm transmission rights.

297 AEMO, submission to issues paper, p. 6.

298 AEMO, submission to issues paper, p. 6.

change draft determination.[299] It further noted in this submission that the design and implementation of day-ahead markets and improved markets for demand response, as well as consideration of better markets for fast frequency response and load following should be pursued in a timeframe that further ensures the success of the five minute settlement.

BlueScope Steel also noted that consideration of the suitability of a day-ahead market was one of the Finkel Panel's recommendations. The submission stated that given the potential for a day-ahead market to contribute to enhancing short term reliability through greater forward transparency of supply conditions relative to the status quo and facilitating market competition, this is an area that could have been included and considered in greater detail within the Issues Paper. BlueScope supported the Finkel Panel's recommendation to assess its suitability, and to draw on international experience in assessing its potential benefit within the NEM.[300]

8.2 Assessing the problem

The Finkel Review recommended that the suitability of a day-ahead market be examined. This recommendation was motivated by the assertion that short-term reliability in the NEM could be enhanced through greater forward transparency of supply conditions to the system operator and market participants.

We consider that the source of any problem with the current market frameworks needs to be clearly identified. At this point in time we are not aware that there has been detailed consideration of whether there are sufficient issues with the current market design in the NEM such that the introduction of a day-ahead market, and the related reforms necessary to implement it, would be in the long-term interests of consumers. Having noted above that the current NEM framework already has many features which are intended to produce similar outcomes to day-ahead markets internationally, it seems appropriate that attention is focussed on the effectiveness of these features in the NEM at present, namely:

- pre-dispatch
- contracts market
- the current market-led process by which market participants, through their bids, co-optimise energy and reserves over time (through their rebidding).

It will also be important to identify whether the problems identified are related to reliability concerns or system security concerns (or both). For example, concerns about not having sufficient synchronous generation in a particular region are motivated by *security* concerns, and so, consistent with the framework in Australia are managed by the system operator. Indeed, this is what the Commission's *System security work program* and related rule changes are seeking to address. The Commission's work on

299 AEMO, submission to the *Five minute settlement* draft determination, p. 3-4

300 BlueScope Steel, submission to the issues paper, p. 3.

system security is described in more detail in chapter 1. Or, perhaps some stakeholders have different interpretations of what information must be provided into pre-dispatch, and so this may be impacting on the ability of the market to deliver a reliable outcome. This could be resolved by more clarity about what information should be provided.

Where problems are identified, the scale and materiality of the issues with the current framework must also be assessed before a decision on what changes could be beneficial and therefore contribute to the National Electricity Objective. In other words, the solution developed has to address the problem and be proportionate to the size of the problem. There are a number of other changes that could be made to the NEM, including but not limited to the introduction of a day-ahead market, that could improve the current arrangements, depending on the problem identified.

These potential options may range from incremental changes to the current framework to fundamental changes to the wholesale market design of the NEM. The complexity and costs related to changes in market design therefore vary greatly. For example, if a problem was identified that related to needing to improve transparency on forward supply conditions, then, as identified in the Commission's recent *Five minute settlement* rule change there are a range of options to address this, ranging from improvements to the accuracy of forecasting inputs to introducing administrative options to reduce the freedom of market participants to change their offers as dispatch approaches (e.g. gate closure) through to a US-style day-ahead market.[301] Other options could include improving the transparency of market participants' contract positions.

The Commission is considering ways in which it can analyse outcomes from (e.g. dispatch targets), and information provided through, pre-dispatch for the purpose of seeking to better understand and assess the problem that a day-ahead market could potentially solve. For example, we may analyse pre-dispatch as compared to real-time outcomes. We would welcome evidence from stakeholders on this, or suggestions on how this data could be analysed.

Therefore, the Commission considers that in order to better evaluate the suitability of a day-ahead market, this problem needs to be more clearly articulated. However, notwithstanding that, the Commission has considered the applicability of European-style and US-style day-ahead markets, as per the below.

8.3 Comparison of the NEM with day-ahead markets

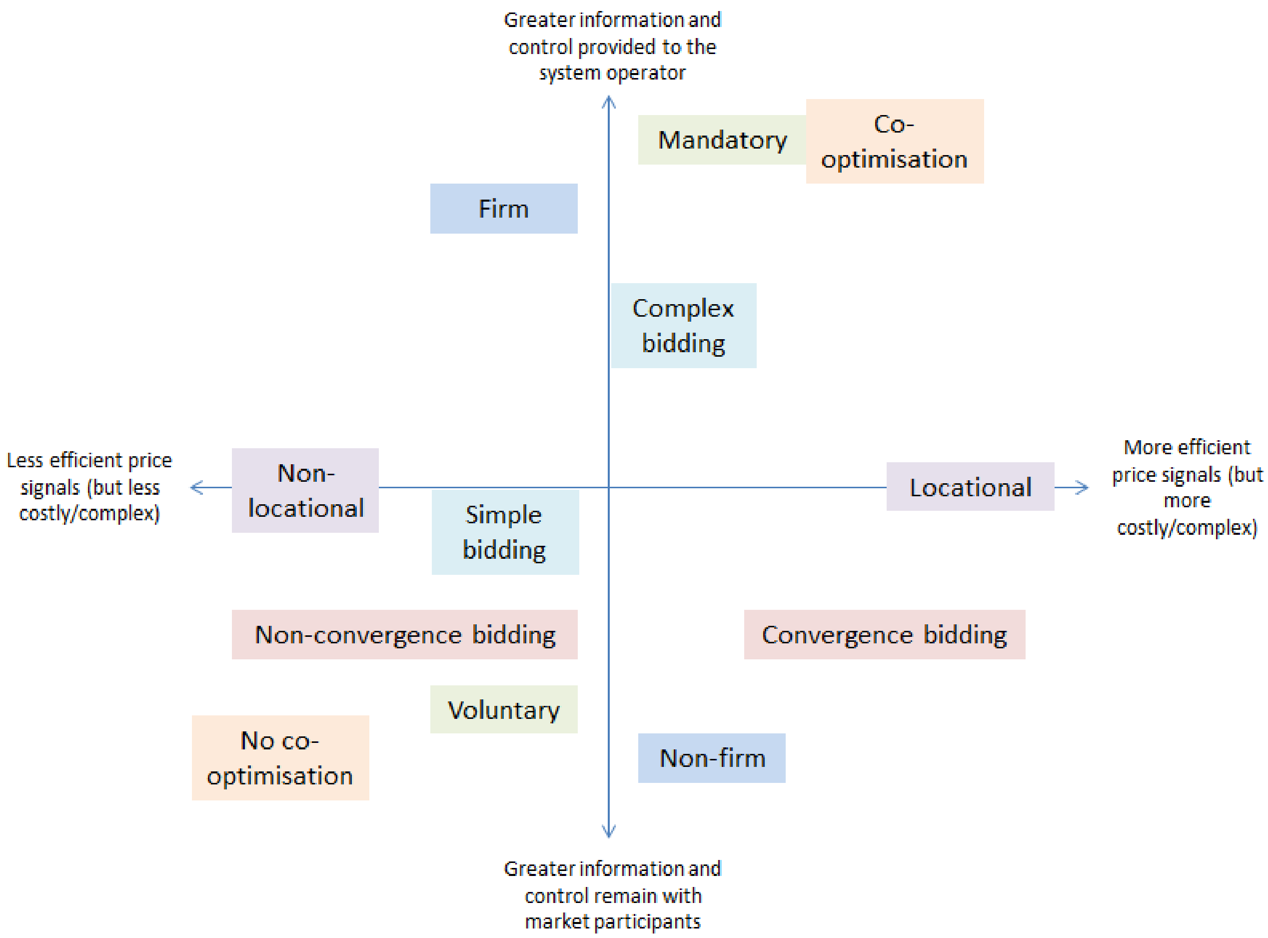
Each day-ahead market design must decide on a number of key design criteria to suit the conditions in the market in question and the issues the day-ahead market is seeking to address. This section discusses the key design criteria, as well as implications of these criteria. It then compares these features to what we have in the NEM. It is useful to undertake this task in order to be able to compare "apples" with "apples".

301 AEMC *Five minute settlement: draft determination* September 2017, pp. 78-80

8.3.1 Features of a day-ahead market

The below diagram illustrates a number of design features of a day-ahead market, each of which will be discussed in this section.

Figure 8.2 Design features of a day-ahead market



Each of these design features has pros and cons presenting trade-offs on wholesale market design. These trade-offs can be summarised as:

- whether the day-ahead market design features chosen are used to provide greater information and control to the system operator to optimise schedules or whether this optimisation is done by market-participants
- whether the day-ahead market design feature provides more theoretically efficient price signals but at greater cost and complexity.

The overall impact of these trade-offs depend on the existing structure and issues the market is facing. These trade-offs between these key-design parameters are shown in Figure 8.2. These trade-offs in designing a day-ahead market are often driven by local market conditions; both the physical characteristics of the system (meshed versus long network), the market design in place before the introduction of the day-ahead market and the market structure (level of competition etc.).

Key features of a day-ahead market are described below. The choice of these design features is in large part informed by the role that the day-ahead market serves – in European markets, the design tends to aid participant-to-participant trading, whereas in US markets, the design tends to facilitate the system operator.

Mandatory or voluntary participation

This design feature relates to whether participation in a day-ahead market is voluntary or mandatory.[302]

Mandatory day-ahead markets are used mostly in market designs that aim to facilitate scheduling by the system operator, that is, the US-style markets as described above. They are typically mandatory so that the system operator has information from the entire market in order to help it operate the system.

The typical key features of a mandatory day-ahead market are:

- generators that participate in the day-ahead market must submit unit-level bids for their entire portfolio of generation
- typically, the system operator uses these bids to determine a generator schedule, based on all the unit level bids and forecasts of demand
- generators are dispatched against this schedule.

Typically, only those generators that are part of the 'capacity' market are required to bid into the day-ahead market. Therefore, if wind is not part of the capacity resource requirements, it is not required to participate in the day-ahead market.[303]

A voluntary day-ahead market is more common in a participant-to-participant activity, such as the European-style markets described above. As these markets are not relied upon by the system operator to physically operate the system, they do not need to be mandatory.

The typical key features of a voluntary day-ahead market are:

- participants choose to optimise their own portfolio to meet their own commitments ("self-scheduling") without necessarily participating in the day-ahead market
- participants are required to notify the system operator ahead of real time about their production (or in some case consumption) intentions in the forthcoming period on a per-unit basis (but this is not financially or physically binding).

302 The distinction between mandatory and voluntary may be arbitrary in reality. In some "voluntary" markets such as ERCOT the financial incentives to participate in the day-ahead market are so strong as to make it functionally identical to a mandatory market.

Theoretically, a mandatory day-ahead market provides for a more liquid day-ahead market than a voluntary market since all generators must participate, which would provide more efficient price signals to market participants and also more information for the system operator.

A voluntary day-ahead market however, is simpler to implement, and might be considered to be less restrictive to market participants by allowing them to participate only if they consider it to be beneficial. This is more effective for a market that relies predominantly on self-scheduling and/or self-dispatching (for example Great Britain[304]).

Firm or non-firm scheduling

Most day-ahead markets have firm schedules where participants are financially or physically bound to the awarded schedules. In the case of financially binding schedules, participants are able to adapt their financial position with virtual bids[305] or other financial derivatives.

Firm scheduling 'locks-in' bids and offers made in the day-ahead market which provides the system operator more control in scheduling the residual demand closer to real-time.

However, non-firm scheduling allows market participants to 'fine-tune' their positions from the day-ahead market to optimise their own portfolio.

The previous England and Wales gross pool market[306] is an example of a non-firm day-ahead market where there was no penalty for non-delivery.

Locational or non-locational

This feature of day-ahead markets relates to the degree to which the day-ahead market takes into account locational elements of the electricity system.

A day-ahead market which fully takes into account location is a nodal day-ahead market. In such a market, transmission system limits are taken into account such that the schedules produced by the day-ahead market are operationally feasible and are

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303 See: http://www.pjm.com/~/media/training/nerc-certifications/gen-exam-materials/gof/20160104-day-ahead-energy-market.ashx

304 The Great British market relies predominantly on a self-dispatch system where buyers and sellers contract their position ahead of time either through bilateral contracts or the futures market. This market is the described in more detail in a case study below.

305 Discussed in more detail below.

306 A gross pool market is used in the NEM. It refers to a market where generators are required to sell all of the energy they produce through the spot market. A gross pool market differs from a net pool market where generators only sell energy that they have not already sold through bilateral contracts.

consistent with the physical characteristics of the transmission network. Prices at each location (node) differ as a consequence of transmission constraints between nodes.

In the short-term locational markets improve bidding incentives and the optimisation of dispatch. Over the longer term locational prices may provide market signals for further investment either through more generating capacity or more transmission investment at a given location. Finally, in theory locational pricing may reduce market power as market participants cannot take advantage of real physical constraints.

Locational day-ahead markets are typically used in US-style participant-to-system operator day-ahead markets, because it provides the system operator with granular, locational data to inform scheduling.

From a generator perspective, nodal pricing and firm transmission rights are a necessary feature of US-style day-ahead markets because they provide the generator with a means of managing congestion risk. Generators can therefore hedge against risks that their day-ahead positions, which are physically and financially binding, may not come to pass because of transmission outages or congestion. Without such a means of managing these risks, generators may not be willing to provide as much capacity as they could in the day-ahead market. If such an outcome occurred (i.e. participants did not provide as much capacity in a day-ahead sense), the benefits of a day-ahead market would need to be questioned.

However, such an approach may be costly to implement. Furthermore, inadvertently, while locational pricing might result in overall more efficient price signals in the system, it would create ‘winners’ and ‘losers’ between market participants.

An example of the implementation of a locational day-ahead market is Ontario, where the system operator is seeking to implement this kind of market as part of a wider "Market Renewal" process.[307] The introduction of a day-ahead market has been considered in Ontario since 2003 but is not expected to start until 2021. This is because a number of intermediate reforms were considered necessary as part of the market renewal process in advance of the introduction of a day-ahead market.[308]

A non-locational day-ahead market optimises a nominal schedule which does not take into account the physical capabilities of the transmission system. The resolution of congestion in the transmission system is then undertaken by the system operator in a separate set of processes, nearer to or at real-time. An advantage of this approach is that the non-locational market creates a more generic energy product that can be traded by a larger number of participants. This is thought to create a more liquid market and therefore greater price discovery – most useful in European style participant-to-participant day-ahead markets.

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307 IESO. Market renewal process: introduction to day-ahead market", 2017

308 IESO, The future of Ontario's Electricity Market: A benefits case assessment of the Market Renewal Project, 2017.

Simple or complex bidding

Another design feature of day-ahead markets is how bids into the market are structured in order to support unit commitment decisions. Options for how bids could be structured include simple bids, block bids or multi-part bids.

Generators tend to have a non-linear cost profile – that is, their costs do not rise linearly with power output. Rather, generators typically face fixed start-up and shut-down costs in addition to volume-based and operational hours-based costs.

A simple bidding structure means that generators bid a simple price-quantity bid that is accepted whenever the market clearing price is above the level of the generator's bid. Under this approach, generators must incorporate all features of their cost profile in a single bid. The features of a generator's cost profile include start-up costs and different costs of production at different levels of operation. This requires generators to have a view as to the likely levels of prices over multiple time periods.

An example of this is that a generator may set its bid at a level that would recover its start-up costs over a number of trading periods. The level of its bid would depend on the number of trading periods it expected to recover its start-up costs over (bids would be higher the smaller the number of periods the generators expected to recover its costs over and lower the larger the number of periods over which it expected to recover its costs).

Under a block bidding structure, generators or load-serving entities (such as retailers) have the option to bid or offer into the market a constant amount of energy over a period of consecutive hours. These bids are either entirely accepted or entirely rejected. Another way to consider this is that each individual dispatch interval bid is conditional on all the other individual dispatch interval bids within the block also being accepted. The structure of these bids allow generators to submit a bid price that includes start-up costs and other dynamic considerations.

Box 8.2 Example of block bidding

In a block bid a generator would bid into a day-ahead market specific price-quantity volumes for a number of consecutive 30 minute settlement periods. The “block” element of it is simply that the offer to sell this power (by generating) is contingent on all of the bids in each of the consecutive settlement periods (i.e. the “block bid”) being accepted in the day-ahead market auction. This is helpful for generators that do not wish to incur significant start-up costs without the guarantee that they will run for a period of time to recover the costs incurred in start-up. It might also be helpful for demand side that if they wish to shut down would only prefer to do so for a longer period of time.

For example a generator could submit the following price quantity bids:

Time period	Quantity	Price
1	100MWh	$50/MWh
2	130MWh	$60/MWh

The auction can only accept the period 1 bid if it also accepts the period 2 bid. Therefore, if successful the generator will supply 100MWh at $50/MWh in period 1 and 130MWh at $60/MWh in period 2. The revenue earned as a result of these bids should be sufficient to cover all the generators costs, including start-up costs. If unsuccessful the generator does not supply any electricity in either period.

Another form of block bid is that in some markets a generator can stipulate a minimum revenue that needs to be recovered over a number of periods.

In markets where block bidding occurs the calculation of the clearing price may be difficult as it must take a number of factors, including generators bids in all other periods into account. It may require a lot of effort to create algorithms that can calculate the clearing price for each period in such markets.

Multi-part bidding requires that generators submit bids detailing their cost structure. Three-part bids are the most common type of multi-part bidding and include start-up costs, incremental energy costs and no-load cost (or minimum load costs, the cost to generators of just being online or to be at its minimum generation level).

Multi-part bidding appears to only be used in markets that facilitate participant-to-system operator trades. In essence, it allows for the provision of a greater level of information to the system operator regarding the characteristics of particular generation plant. This allows the system operator to optimise the operation of plant more effectively over the course of the following day. Such an approach is most prevalent in the US markets.

Complex bidding provides more information to the system operator rather than being managed internally by market participants and allows the system operator to optimise to overcome dynamic constraints. This however is costly to implement as it requires significant information to be submitted and processed by the system operator.

Co-optimisation of energy and reserves through the scheduling algorithm

Typically, day-ahead markets in other jurisdictions talk about "co-optimising energy and reserves" through the scheduling algorithm. This means that a simultaneous schedule and prices for energy and reserves are produced and that both energy and reserve prices are taken into account when the scheduling algorithm selects generators to meet expected demand. However, care should be taken when comparing this feature with the NEM since the term "reserves" in other markets may not be analogous to the term reserves as used in the NEM. In some markets the term reserves also includes ancillary services, which we would consider as FCAS, a security aspect in the NEM.

Without co-optimisation of energy and reserves, the day-ahead energy market would clear first while only taking into account expected supply and demand for energy. The reserves market would then be cleared based on the remaining supply.

Such co-optimisation is a common feature of day-ahead markets that are designed to facilitate participant-to-system operator actions. Co-optimisation allows for more accurate price signals when incorporating the reserve requirement. With co-optimisation, the energy price reflects the marginal value of energy taking into account the reserve scarcity as compared to the reserve requirement.

Co-optimisation of energy and reserves in the day-ahead market enables the system operator to optimise based on the technical and operating constraints of the plant.

Consistency of real-time markets

Another key design feature of day-ahead markets is whether there are incentives and mechanisms to allow prices and schedules in the day-ahead market to converge with expected prices and schedules in the real time market. Both settlement systems should incentivise loads and generation to participate in the day-ahead market.

An issue for day-ahead markets is the potential for inefficient and diverging prices between the day-ahead and real time market schedules and the real time power flow. This occurs if not all resources and consumers are incentivised to participate in the day-ahead market. An illiquid day-ahead market might give rise to market power and for market participants to take advantage of the divergent prices in the day-ahead and real-time markets.

Convergence bidding (also called virtual trading) enhances price signals by allowing market participants (including third-party intermediaries) to trade on bids made in the day-ahead market. Virtual bidding allows parties to profit from differences between the day-ahead and real-time markets. For example a party could sell energy in the day-ahead market at the day-ahead price and buys replacement energy in the real-time market at the real-time price (such that the supply-demand for energy is not affected). When the day-ahead price is higher than the real-time price the virtual trader will make a profit.[309]

Convergence bidding is generally regarded as a necessary feature in a mandatory and firm day-ahead market, where there is potential for market manipulation from participants with excessive market power.

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309 Similarly a virtual trader can buy energy a day-ahead and sell those MW of energy back into the real-time market. When day-ahead prices are lower than real-time prices the trader will make a profit on this trade.

8.3.2 How the NEM compares to a day-ahead market

In order to consider whether or not a day-ahead market would be suitable for the NEM or not, it is useful to first set out how arrangements in the NEM compare to day-ahead market arrangements elsewhere.

The below table compares the current NEM framework to the design features of a day-ahead market discussed in section 8.1. As the NEM has a different market design not all of the design features are directly relevant to the NEM and care must be taken when comparing across jurisdictions as terminology may differ. This is discussed in more detail in this section.

Table 8.1 Comparison of market design in the NEM against day-ahead markets

Design feature	NEM	US-style market	European-style market
Mandatory or voluntary[310]	Mandatory (but not financially binding) pre-dispatch	Mandatory	Voluntary
Locational or non-locational	While participants are not exposed to locational prices, pre-dispatch and dispatch is done on the basis of locational constraints	Locational	Non-locational
Simple or complex bidding	Simple	Multi-part	Typically block-bidding
Co-optimisation of energy and reserves	Energy and reliability reserves co-optimised across time by market participants through their bids. Energy and frequency control ancillary services co-optimised by AEMO in real-time dispatch and pre-dispatch.	Yes	No
Consistency with real-time market	Combination of rebidding and information provision that occurs up to real-time dispatch, means that over time the closer you get to dispatch prices will converge	Yes	No

AEMO does not run a formal day-ahead market, but the NEM has processes in place that are similar to a day-ahead market in three respects. These are:

- information provision to the system operator in advance of dispatch

310 As noted above this feature refers to whether participation in the market is deemed to be "mandatory". However, the distinction between mandatory and voluntary may be arbitrary in reality and can refer to cases where there are strong financial incentives to participate in the day-ahead market.

- co-optimisation of energy and reserves through market participants' bids, as well as co-optimisation between energy and frequency control ancillary services by AEMO
- a liquid contract market.

Each of these features of the NEM will be discussed in turn.

Information provision in advance of dispatch

Despite (or because) there is not a formal day-ahead market in place, AEMO receives substantial information (including information on the physical operation of plant and indicative bids) from market participants in the lead-up to dispatch (from two years out) through to real time.

An integral part of information provided to market participants by AEMO is the pre-dispatch schedule - which is particularly relevant to a discussion of day-ahead markets given that the pre-dispatch timeframes are also in the day-ahead time horizon. Through pre-dispatch and non-binding offers and bids made from day-minus-2, market participants are required to provide information including: energy (and FCAS) bids, capacity notification (including self-commitment/de-commitment times and capacity profile), energy availability, ramp-rates etc. The pre-dispatch process calculates projected market outcomes on a trading interval basis from the next trading interval to the final trading interval of the day for which all dispatch bids and offers have been received.

On the basis of this pre-dispatch information (and other information), AEMO publishes various information, including forecast price, demand, available and dispatched generation, and whether AEMO is forecasting any lack of reserve conditions and determines the need for any out-of-market actions it must undertake if there is insufficient response to notices provided to the market.

Rebidding is a key tool that participants use to manage the risks of participating in the market. Rebidding provides generators with the flexibility to adjust their bidding positions to accommodate changes in market conditions and to respond to the offers or bids of other participants. For example, rebidding may be used by a generator to manage an unplanned outage, or congestion-related dispatch risk. This is discussed further in chapter 4.

Uncertainties are inherent to the spot market - there are unexpected events, and one (or a few) generators may make the last rebid for any given dispatch interval. In the short term, participants make the best decisions they can in light of the available information and their capabilities. The resulting prices – reflective of short-term constraints – create signals for longer-term operational, investment and disinvestment decisions of both major consumers and generators. The dynamic process of participants learning and reacting to the actions of their competitors, and to the inherent volatility of elements of the power system, is a deliberate and important feature of the NEM’s design.

An objective of the pre-dispatch process is therefore to provide market participants with projections of spot prices and expected dispatch schedules to assist them to determine when to commit their generating units. As generators are required to self-commit, pre-dispatch forecasts are essential for generators to determine whether to be online and to bring plant into the market.

NEM customers, primarily retailers, also rely on pre-dispatch forecasts to manage their pricing risk. Pre-dispatch forecasts assist customers to determine whether they need to consider forward contracting or to prepare for demand-side response. Therefore, reliable and accurate information is key to determining meaningful pre-dispatch forecasts and allowing competitive demand and supply side responses - in turn driving reliability outcomes. The purpose of informing the market that there could be a lack of reserves is to seek a market response from participants to either increase the availability of their generation, or from demand-side participants to reduce their consumption of electricity.

There are obligations imposed on participants with regard to the accuracy of the information they provide for the pre-dispatch schedule. For example, under clause 3.8.22A(a) of the NER participants must not make a dispatch offer, dispatch bid or rebid that is false, misleading or likely to mislead.[311]

Co-optimisation across time periods

The NEM does not have a formal, system operator-run process through which energy and market reserves[312] are co-optimised across time, utilising complex bidding, like in some day-ahead markets such as Texas. However, there is a market-based co-optimisation process of energy (and FCAS services) *across* time periods whereby market participants' bids to sell energy in any individual time period, and their physical state (that is, whether they are ready and able to generate) reflect their expectations of future prices over the coming period.

For example, a market participant's expectations of high prices (owing to an expected tight supply/demand situation) will incentivise it to be physically ready to generate, and to structure its bids in the lead-up to and after the expected high price time in a profit maximising manner. In turn, this drives reliability outcomes - times of expected tight supply/demand are coincident with (and drive) expected high prices, which provide incentives for generators to be physically ready (that is, in reserve). This is discussed further in chapter 3.

Market participants are therefore incentivised to structure their own bids on the basis of their expectations of the market price, which in turn is a function of their expectations of both demand and all other market participants' bids (in a continuous

311 For the purposes of this obligation, the making of such offers, bids or rebids is deemed to represent to other participants through the pre-dispatch schedules that the offer, bid or rebid will not be changed, unless the relevant Generator or Market Participant becomes aware of a change in the material conditions and circumstances on which the offer, bid or rebid is based.

312 The balance of supply over demand in the market.

feedback loop). Market participants are also allowed to rebid - as set out above - in order to respond to changing expectations over time.

Of course, market participants could be incorrect in their expectations of the market price and so structure their bids in such a way that the least-cost outcome is not achieved with the benefit of hindsight. However, in getting their forecasts (and hence bidding structures) "wrong", market participants are financially penalised through lower profits, providing them incentives to forecast accurately - including forecasting the response of other market participants operating under the same incentives. It is this competitive process of continuous adjustment and readjustment of bids through pre-dispatch which drives reliability outcomes and leads to a least-cost equilibrium over time.

In comparison, it is not clear that complex bidding and centralised commitment of units at a day-ahead stage would result in systematically superior outcomes, as it relies on the forecasts of the system operator, as opposed to the collective and financially incentivised forecasts of market participants. To the extent that the system operator gets its forecasts wrong (and, for example, commits a unit unnecessarily) it is consumers, rather than market participants, which bear the cost. Particularly, because while participants settle a day-ahead, deviation quantities are settled between participants in the real-time balancing market, the costs of which are likely borne by consumers.

Furthermore, while the NEM’s single bid structure may appear to be simpler that the complex bidding seen in day-ahead markets in other jurisdictions, in fact the complexity of generators' non-linear cost profiles is internalised within market participants' bids. Given that market participants are able to take account of the precise cost structure of their individual plants (i.e, start-up costs, ramp rates, minimum run rates), this system could be considered to be as or more sophisticated that the two or three part bidding structure seen elsewhere.

Finally, it should be noted that AEMO's dispatch engine does co-optimise security services - frequency control ancillary services - with the energy market *within* each dispatch interval to deliver electricity at the lowest cost. AEMO's dispatch engine may move the energy target of a scheduled generator or load in order to minimise the total cost (of energy plus FCAS) to the market. This process is named co-optimisation and is inherent in the dispatch algorithm. The co-optimisation process allows potential providers of both energy and FCAS to submit their full capacity for each and have the market select the optimum combination and for the provider to be commercially indifferent to the mix of services that they are scheduled for.

Contract market

The third feature of the NEM that performs a function similar to that which would occur in a day-ahead market is the contract market. This separate financial derivatives market is used by market participants to manage their exposure to the spot market with their hedging position informing their offers and bids to AEMO, with this in turn driving investment, retirement and operational decisions by participants. This is discussed further in chapter 5.

Without being contracted, failure to be ready to produce energy at times of high prices represents an opportunity cost for the generator – foregone profit which would otherwise have been received. In contrast, generators with contractual positions to generate suffer losses for not generating (receiving zero revenue from the spot market and paying large payments to meet their contractual obligations). Risk-averse generators which are contracted are incentivised to be available at times of likely high prices to avoid these losses. This in turn provides reserves at times of tight supply/demand conditions, and so drives operational decisions.

8.4 Commission's preliminary views

Leaving to one side whether the problem that a day-ahead market would solve has been fully identified, the Commission has considered the relative costs and benefits of European-style and US-style day-ahead markets in the context of the NEM.

8.4.1 European-style day-ahead markets

Potential reliability benefits

Many of the potential reliability benefits from this type of market design are indirect and rely on the potential improvements in market transparency and incentives on market participants to provide more accurate forecasts through their bids in the day-ahead market. To the extent that this day-ahead market were to become a focal point for the market with a large number of trades undertaken through it, then this may have the effect of aiding price discovery and providing greater confidence to market participants as to the accuracy of the price reflecting the best expectations of outturn prices. However, improved transparency in the contracts market might otherwise be addressed through more targeted regulatory changes. Furthermore, increased transparency in contracts may be a consequence of the National Energy Guarantee, depending on how this is to be designed.

There are limited direct reliability benefits to the system operator in operational timescales as this form of day-ahead market does not require any changes in how AEMO schedules generation dispatch. The trading between participants in such day-ahead markets is often undertaken at a portfolio-level and would not provide information on what generating units the energy is expect to come from. This would not be helpful to AEMO because it already has this level of granularity through what participants submit into its pre-dispatch process.

There are also unlikely to be substantial reliability benefits to market participants as a result of improved investment efficiency. First, as discussed in chapter 5, contracts between participants are already an important mechanism through which investment and operational decisions are facilitated. Second, there is no reason to expect that prices in the day-ahead market will systematically diverge from those in the real-time market (given that the any systematic difference would create arbitrage opportunities between them markets.[313] If the real-time price provides sufficient returns to investors then it may be the case that a highly liquid but voluntary trading hub might conceivably provide greater investor certainty and hence provide better investment signals. However, the caveat is an important one – if the real-time prices are not determined in a way that provides sufficient returns to investors then, given that day-ahead prices will not deviate systematically from the real time prices, the implementation of a voluntary day-ahead market will have minimal impact on investment relative to the current arrangements.

Implementation

A European-style day-ahead market would be relatively straightforward to implement by developing a power exchange that runs a day-ahead transaction platform. This could be done independently by a power exchange operator or within AEMO itself. The day-ahead market in its simplest form would be voluntary and designed for the purpose of centralising trades (with simple quantity-price bids) to increase liquidity at the day-ahead stage.

However, it is worth noting, that there is currently no impediment under the current arrangements in the NEM for such a day-ahead power exchange to operate - that is, an organisation such as the Australian Securities Exchange could operate such a market.[314] It may follow, therefore, that given there has not been sufficient demand for such a power exchange to date, the likely usefulness of such a market is questionable: if market participants had wanted one, then the market should have provided one.

Summary

The Commission therefore considers that the benefits of introducing a European-style day-ahead market relative to the status quo in the NEM are unclear and are not likely to be significant to any party (either participants or the system operator). This is because many of the potential reliability benefits from this type of option are indirect, and this form of day-ahead market is not markedly different to the current arrangements.

The NEM already has a liquid financial derivatives market that performs most (if not all) of the functions of European-style day-ahead market. The Commission notes that no such type of market has developed in the NEM to date and that there are limited barriers to the establishment of such a participant-to-participant trading platform if it was judged to be of benefits to market participants.

313 Some systematic deviations might occur if there are differences in risk aversion. It may be that one side of the market might be prepared to pay a premium or sell at a discount in the day-ahead market relative to the real time market if it is more risk averse than the other.

314 Changes may need to be made to the current arrangements for AEMO to operate this power exchange.

8.4.2 US-style day-ahead markets

Potential reliability benefits

A US-style mandatory day-ahead market run by the system operator could be more likely to have an impact on reliability in the NEM than a European-style day-ahead market from a system operator perspective. This is because:

- The system operator could have the ability to schedule the market, based on bids that incorporate information on generators' start-up, energy and other relevant costs, a day ahead. For non-variable renewable generators, financially binding day-ahead schedules could aid in unit commitment and gas delivery decisions.
- The system operator may have better information to examine market conditions on high-stress days where the supply-demand balance is expected to be tight, as it has a firm, financially binding schedule a day-ahead.
- If locational pricing is used, the price signal to market participants is enhanced and reflects the physical characteristics of the power system (by including transmission constraints).

However, it is not clear whether this impact would be positive or negative compared to current arrangements in the NEM as discussed above. As discussed in section 8.4.1, the extent of the reliability benefits derived from the introduction of a day-ahead market is dependent on the extent of the "problem" associated with the current market arrangements. Specifically, the following matters need more consideration:

- The accuracy of the information provided to AEMO and the efficacy of the pre-dispatch process. If the information that AEMO receives as part of pre-dispatch is accurate then the benefits to be derived from the introduction of a day-ahead market may be limited or result in a less-efficient outcome than that provided by the NEM's current market-based processes. As discussed in chapter 4 there is value in allowing market participants the flexibility to rebid. A market that restricts rebidding may prevent participants from adequately managing their risks, dampening signals for efficient investment and undermining the long-term efficient operation of the market in the interests of consumers.
- Whether the current market-led co-optimisation of energy (and FCAS) across time periods is effective, or whether a process by which the system operator co-optimises energy and FCAS (as occurs in markets such as ERCOT) would be more appropriate.

For market participants, the introduction of such a market would limit the existing efficiency benefits that are obtained from the rebidding process, which allows participants to adjust their offers and bids in response to changing expectations.

In addition, the intra-day trading that occurs through a day-ahead market adds another factor that market participants have to consider when making their offers and bids. Generators need to be able to hedge against risks that their day-ahead positions, which are physically and financially binding, may not come to pass because of transmission outages or congestion. Therefore, typically, nodal pricing and firm transmission rights are needed alongside the day-ahead market in order to help participants manage the financial consequences of intra-day network variations.[315]

Without such a means of managing these risks, generators may not be willing to provide as much capacity as they could in the day-ahead market. If such an outcome occurred (i.e. participants did not provide as much capacity in a day-ahead sense), the benefits of a day-ahead market compared to the current NEM arrangements would need to be questioned

Implementation

Putting aside the issue of whether or not there is a problem that would be solved by a US-style day-ahead market, the suitability of a US-style day-ahead market in an Australian context would need further consideration given that it would require the introduction of complementary reforms (such as nodal pricing and firm transmission rights) in order to achieve its intended outcome.

The introduction of a US-style day-ahead market would involve implementing a day-ahead market run by the system operator with mandatory participation and, at the same time, the implementation of locational signals with firm transmission rights (similar to most US markets). Any day-ahead market with multi-part bidding and nodal pricing would need to be introduced in a multi-stage comprehensive reform. This implies that the implementation of a US-style day-ahead market in the NEM would take a number of years and would impose significant implementation costs on AEMO and market participants.

Conversely, nodal pricing could be introduced first before a full day-ahead market. This was the case with the Southwest Power Pool in the US where it introduced nodal pricing in 2007 before implementing a day-ahead market in 2014. As discussed above, Ontario also delayed the introduction of a day-ahead market until a number of other intermediate reforms could be implemented as part of its market renewal process.

As noted above, locational pricing is widely considered to be a necessary feature of these types of day-ahead markets. In order to provide signals to market participants, as well as the system operator, about real-time operations, participants would need to be exposed to locational prices. Furthermore, firm transmission rights are considered to be required as they provide a hedge for differences in locational prices and allow traders at one location to contract with another location. Firm transmission rights are also needed in order to provide generators with a means of hedging risks related to transmission congestion, which causes prices to differ between nodes, therefore for them to participate fully in the day-ahead market.

315 Therefore, such a package of reforms may result in more efficient investment decisions in both generation plant and transmission infrastructure, and more efficient congestion management. However, these would likely not be a direct benefit of the day-ahead market as they would otherwise arise if the current regional market was reformed to be nodal.

The above discussion shows that in order to derive benefit from a system-operator run day-ahead market a number of other, related reforms would be required. This would involve a long reform and transition process that would include changes to:

- AEMO's dispatch engine to accommodate information from complex bids from generators
- the pre-dispatch process, as schedules made from generators' bids a day ahead would be financially and physically binding
- how congestion in the transmission network is managed the associated flow-on effects to current transmission frameworks.

Summary

While the US-style approach could be beneficial in improving reliability outcomes if evidence was found that the contract market was not driving these outcomes. The introduction of a day-ahead market would require careful consideration since:

- Such a reform is likely to take a significant amount of time. International experience suggests that the introduction of a day-ahead market is a multi-year process.
- In order to implement an efficient day-ahead market a number of complementary reforms would be required. These other separate but related reforms would include nodal pricing and changes to transmission access arrangements (firm transmission rights).
- Depending on the scale of any issues identified with the current market design, it may be more beneficial to improve the current arrangements rather than undertake a long and costly change to the current market.

8.5 Summary

The Commission is not yet convinced that there are significant problems with the current market design that would be addressed in an efficient manner by the introduction of a day-ahead market. To the extent that problems have been discussed, they generally relate to information provision and / or security-related aspects (e.g. not being sure whether or not there will be enough synchronous generators running in the system at a particular point in time). Therefore, identifying the problem, and the materiality of it, is crucial in order to work out what the best solution is to the problem. More work is required in this regard. The Commission is doing some of this, but would welcome input from participants on this.

Notwithstanding this view, we have considered a number of options for the design and implementation of day-ahead markets. This chapter discusses two widely used market designs for a day-ahead market: a European-style day-ahead market that facilitates participant-to-participant trades ahead of real-time; and a US-style day-ahead market that facilitates participants-to-system operator actions as a tool to schedule reliable operations.

A European-style day-ahead market that facilitates participant-to-participant trading ahead of real time is more similar to the current NEM arrangements than US-style day-ahead markets. Consequently, the benefits of the introduction of a European-style day-ahead market relative to the status quo in the NEM are unclear and are not likely to be significant. This is because many of the potential reliability benefits from this type of option are indirect and this form of day-ahead market is not markedly different to the current arrangements.

A US-style day-ahead market, which facilitated market participant-to-system operator trades, could conceivably result in more significant reliability benefits - although only to the extent that there is a relevant problem in the current arrangements. Further, to the extent a problem is identified, reforms targeted to the problem might be more appropriate. But, introducing a US-style day ahead market would require the introduction of complementary reforms (such as nodal pricing and firm transmission rights) in order to achieve its intended outcome. Reforms of this nature take a considerable amount of time and resources to implement, and there may be more immediate actions that could be done to assist in the NEM.

Overseas examples of day-ahead markets are instructive in understanding how such markets can be designed. However, we understand many jurisdictions (both with and without day ahead markets) are also grappling with similar challenges to the NEM, although in many instances (for example, the penetration of variable renewable generation) the NEM is more advanced than elsewhere. This is why we think it is important to understand the issues within the NEM context. It is likely to be faster and more beneficial to address any issues by implementing solutions that speak to the particular problem and that are informed by the NEM's specific circumstances.

Abbreviations

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AFMA	Australian Financial Markets Association
ARENA	Australian Renewable Energy Agency
ASEFS	Australian Solar Energy Forecasting Systems
AWEFS	Australian Wind Energy Forecasting System
CEFC	Clean Energy Finance Corporation
CER	Clean Energy Regulator
DMIS	Demand management incentive scheme
EAAP	Energy Adequacy Assessment Projection
ERCOT	Electric Reliability Council of Texas
ESOO	Electricity Statement of Opportunities
FCAS	Frequency control ancillary services
FRMP	Financially responsible market participant
LOR	Lack of reserve
LRET	Large-scale renewable energy target
NEL	National Electricity Law
NEM	National Energy Market
NEO	National Electricity Objective
NER	National Electricity Rules
NSPs	Network service providers
OTC	Over-the-counter

PASA	Projected Assessment of System Adequacy
POE	Probability of exceedance
PPAs	Power purchase agreements
RERT	Reliability and Emergency Reserve Trader
SCO	Senior Committee of Officials
SRMC	Short run marginal costs
USE	Unserved energy
VCR	Value of customer reliability

A Assessment framework

This appendix sets out the assessment framework for how the AEMC is conducting this Review, specifically:

- section A.1 discusses the National Electricity Objective
- section A.2 discusses the trade-offs inherent in the frameworks for reliability
- section A.3 discusses the principles the Commission will consider
- section A.4 discusses our assessment approach.

A.1 The National Electricity Objective

The overarching objective guiding the Commission's approach to this Review is the National Electricity Objective. The Commission's assessment of any recommendations must consider whether the proposed recommendations promote the National Electricity Objective. Similarly, with any related rule changes, the Commission must consider whether the proposed rules promote the National Electricity Objective. The National Electricity Objective is set out in section 7 of the National Electricity Law (NEL), which states:

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

The Commission considers that the relevant aspects of the National Electricity Objective for further consideration are the efficient investment in, and operation of electricity with respect to the **price** and **reliability** of supply of electricity, as well as the **reliability** of the national electricity system.

A.2 Trade-offs inherent in the reliability framework

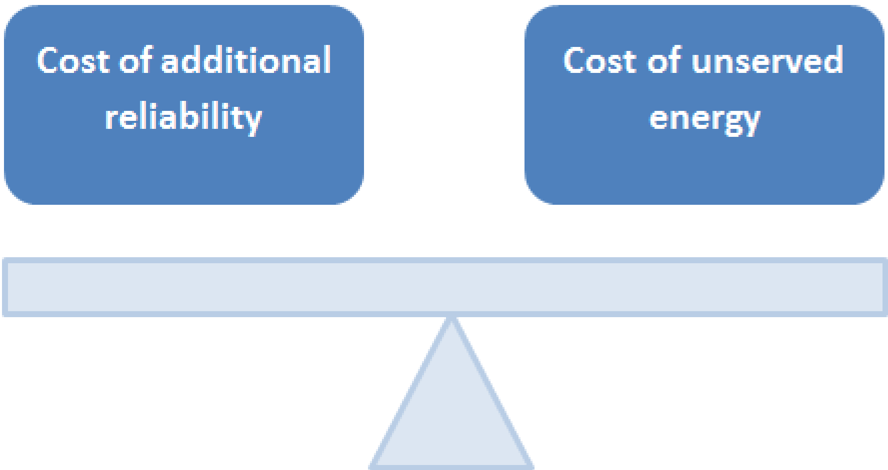
Consistent with the relevant aspects of the National Electricity Objective identified above, there are two costs that need to be balanced in considering the reliability framework:

- Cost of additional reliability - higher levels of reliability require more investment in energy capacity, or more stringent operating conditions, and so a higher cost per unit of energy supplied to achieve financial viability. These costs will be reflected in consumer prices.

- Cost of unserved energy - the alternative is not to supply the energy, that is, to allow a higher expected level of supply interruptions to consumers. This too has costs, which are the costs of not having energy when consumers want it (known as the value of customer reliability).

As Figure A.1 illustrates, a reliability framework embodies a trade-off, made on behalf of consumers, between the prices paid for electricity and the cost of not having energy when it is needed. The need to balance these costs illustrates that the most efficient level of reliability is not having zero per cent unserved energy. Such an approach would be inefficient: the cost of the provision of a guaranteed supply of energy would exceed the value placed on it by consumers.

Figure A.1 The trade-off inherent to a reliability framework



The key question for this Review is therefore how to create a reliability framework that efficiently balance the costs set out above, given the uncertainties.

Broadly there are two types of mechanisms to that contribute towards this balance:

- market-based mechanisms
- intervention mechanisms.

The existing reliability framework, as discussed in chapter 2 is largely market-based, but does have some elements of intervention intrinsic in its design (for example, the reliability settings) and allows for other interventions in specific circumstances (for example, the RERT).[316]

We consider that, intervention-based approaches, however well designed are likely to be a second-best alternative to well-functioning markets at promoting economic efficiency in the long-term interests of consumers. Markets put consumers at the heart

316 Origin Energy noted that it strongly believes the regulatory framework should support market-led solutions that aim to meet the reliability standard over time. See: Origin Energy, submission to issues paper, p. 1.

of decision making. Through markets, technologies and business models that promote value to consumers (as indicated by their individual consumption, investment and operational decisions) will thrive, while those that do not will fail. Markets also provide incentives for companies to innovate, to the benefit of consumers. By allocating risks to market participants, markets provide financial incentives for market participants to make efficient decisions.

However, not all markets are well functioning. For markets to deliver least cost outcomes it requires a reasonably competitive market. Poorly functioning markets are unlikely to provide an efficient level of reliability at efficient cost. The ACCC is currently considering market power issues in the NEM, focussing on South Australia. We will therefore take into account such issues in our assessment approach, as discussed further below.

Intervention-based approaches, on the other hand, tend to provide higher levels of certainty of reliable supply of energy, but, compared to a well-functioning market, are unlikely to deliver an efficient level of reliability at efficient cost. Agencies making interventions do not have the same financial incentives to make efficient decisions compared to market participants, and the risk of poor decisions is borne by consumers. Interventions also distort the functioning of the market, resulting in unintended consequences, including the perceived or actual need for greater intervention. Agencies would naturally be risk averse and, as a consequence, this will likely add costs. There may therefore be long-term negative implications from intervention.

Therefore, there are different costs and benefits for market-based or intervention-based mechanisms. For example, centralised control over reliability provides a high degree of certainty that a reliable supply of electricity will be produced. However, such an approach will likely foreclose the considerable potential benefits of a well-functioning market, imposing costs and risks on consumers. But, in some instances (for example, where reliability concerns are manifesting in operational timescales or where the risk external to the energy market prevents it from being well-functioning), intervention mechanisms are likely to be appropriate in order to maintain the integrity of the electricity system.

A.3 Principles

In order to articulate how we will consider balancing the criteria outlined above, we have set out a number of principles to guide the development of recommendations on potential changes to market and regulatory arrangements that affect reliability in the NEM. These principles will be used to guide our assessment of the existing framework, as well as any potential modifications to, or additional, mechanisms that will be considered through this Review:

1. **Appropriate risk allocation:** Regulatory and market arrangements should be designed to explicitly take into consideration the trade-off between the risks and costs of providing a reliable supply of electricity. Risk allocation and the accountability for investment and operational decisions should rest with those parties best placed to manage them. High risk to consumers is likely to be borne

by consumers through higher prices while risk to market participants will only be passed on to consumers in terms of higher prices where competition permits. Under a centralised planning arrangement, risks are more likely to be borne by consumers.[317] Solutions that are better able to allocate risks to market participants, such as commercial businesses, who are better able to manage them are preferred, where practicable.

2. **Efficient investment in, and operation of, energy resources to promote a reliable supply**: Any framework for reliability should result in efficient investment in, and operation of, energy resources to promote a reliable supply of electricity for consumers. However, there are costs associated with provision of energy resources, which should be assessed against the value to consumers of having a reliable supply. The reliability framework should also seek to minimise distortions in order to promote the effective functioning of the market.

3. **Technology neutral:** Regulatory arrangements should be designed to take into account the full range of potential market and network solutions, as well as taking account of all possible technologies that could provide such solutions (e.g. generation or demand-side). They should not be targeted at a particular technology, or be designed with a particular set of technologies in mind. Technologies are changing rapidly, and, to the extent possible, a change in technology should not require a change in regulatory arrangements.

4. **Flexible:** Regulatory arrangements must be flexible to changing market and external conditions. They must be able to remain effective in achieving reliability outcomes over the long-term in a changing market environment. Regulatory or policy changes should not be implemented to address issues that arise at a specific point in time. Further, NEM-wide solutions should not be put in place to address issues that have arisen in a specific jurisdiction only. Solutions should be flexible enough to accommodate different circumstances in different jurisdictions. They should be effective in facilitating reliable outcomes where it is needed, while not imposing undue market or compliance costs on other areas.[318]

5. **Transparent, predictable and simple:** Reliability frameworks should promote transparency as well as being predictable, so that market participants are informed about aspects that affect reliability, and so can make efficient investment and operational decisions. Simple frameworks tend to result in more

317 For example, in Western Australia, which has such an arrangement for reserve capacity, in 2016-17, there was an estimated 23 per cent (1061 MW) of excess capacity, which translates to $116 million. The costs of this are borne by electricity consumers and taxpayers. This translates to being one-fifth of the capacity in the WEM. Source: Government of Western Australia, Department of Finance, *Final Report: Reforms to the Reserve Capacity Mechanism*, 7 April 2016, p.3.

318 This principle was supported by a number of submitters to the issues paper. See: submissions to the issues paper: ARENA, p. 9; Snowy Hydro, p. 2; Hydro Tasmania, p. 2.

predictable outcomes and are lower cost to implement, administer and participate in.[319]

In submissions to our issues paper stakeholders supported the proposed principles, but ask that we also consider other principles. Table A.1 sets out the additional principles proposed by stakeholders to be included in our assessment framework and our response to these issues.

Table A.1 Stakeholder comments on assessment principle

Stakeholder	Additional principle	Commission response
Infigen[320]	Propose an additional principle providing explicit recognition of the need to meet community and customer expectations.	We do not propose to include an additional principle on this aspect. This is because these broader points about customer expectations are captured through consideration of the value of customer reliability, when considering the long-term interests of consumers, which, as set out in the NEO, must guide any recommendations that the Commission makes in this Review.[321]
Meridian Energy Australia[322]	Consider the focus of the issues is too industry-focussed and may not play the ultimate long-term customer benefit at its core.	We do not propose to include an additional principle on this aspect. The long-term interests of consumers is the foundational principle of the NEO and is therefore central to our assessment.
Infigen[323]	Propose that the AEMC consider the effect of competition on any future market re-design.	It is important to consider the impact of any new or revised regulatory or market arrangements on competition in the NEM. In general, the greater extent of competition amongst market participants, the lower the likely costs to consumers of achieving policy objectives. Therefore, consideration of the level of competition (or market power) is an important consideration for us. Further, we note that the ACCC is currently examining this matter.

319 This principle was explicitly supported by ARENA who noted that a transparent, predictable and simple framework will reduce the forecast price at which investors will come forward, particularly in larger-scale capital intensive projects such as pumped hydro or concentrating solar thermal. See: ARENA, submission to issues paper, p. 10.

320 Infigen, submission to issues paper, p. 2.

321 PIAC made a similar point, noting that if full regard to the cost impacts and consumer expectations is not given in developing new reliability measures, a gold-plated wholesale market will result. As noted above, the Commission is considering the trade-offs inherent in the reliability framework through this Review.

322 Meridian Energy Australia, submission to issues paper, p. 2.

323 Infigen, submission to issues paper, p. 2.

Stakeholder	Additional principle	Commission response
		However, competition is not an end in itself, rather it is a process through which efficient outcomes (and hence the NEO) can be met. Therefore, we do not propose to include it as an additional assessment principle, but do recognise below that it will be a key aspect informing our assessment of options.[324]
PIAC[325]	Propose that in addition to considering technology neutrality, the AEMC should also consider service neutrality. This would imply, for example, not favouring network based over market based solutions, or generator based solutions over demand response.	We agree that it is important for the regulatory arrangements not to favour network based over market based solutions, or generator based solutions over demand response. Our interpretation of technological neutrality already includes these concepts, but for the avoidance of doubt have clarified the definition of technological neutrality above.
S&C Electric[326]	Propose that the impact of climate change policies at the Federal and State level cannot be ignored, and while there is no sustainability component to the NEO, these policies will impact on investment and delivery.	We do not propose to include an additional principle on this aspect. As noted in section 2.3, it is not the task of this Review to fix, or make recommendations in relation to the integration of energy and emissions reduction mechanisms. But their potential impacts upon the reliability framework cannot be ignored either. Rather, we have assumed that the reliability framework may need to adapt to accommodate that ongoing uncertainty (rather than wait for it to be resolved), unless there is clear evidence that a policy resolution is likely to be reached in a timely fashion.

A.4 Assessment approach

We intend to adopt the following approach to assessing the market and regulatory arrangements that underpin reliability, and developing recommendations as part of this Review.

324 Bluescope noted a similar concern that implicit in a reliance on market-based mechanisms is that the market is functioning both efficiently and competitively in practice. See: submission to issues paper, p. 2.

325 PIAC, submission to issues paper, p. 4.

326 S&C Electric, submission to issues paper, p. 5.

- **Define the issues**

  The first step in our assessment framework is to define the problem or issues that have been identified in relation to reliability frameworks in the NEM, as well as the materiality of these issues.[327]

  As chapters 1 and 2 note there are a number of recent documents that provide a good starting point for articulation of these issues, including: AEMO's latest *Energy Supply Outlook;* AEMO's *Electricity Statement of Opportunities 2017;* AEMO's *Advice to Commonwealth Government on Dispatchable Capacity;* the Reliability Panel's issues paper and draft report for the *Reliability Standard and Settings review;* the Energy Security Board's *Advice on the National Energy Guarantee* as well as the analysis contained in the Finkel Panel's *Independent Review into Future Security of the National Electricity Market.*

  Chapters 4 through 8 of this report articulates our work and analysis on the issues, to date. These chapters incorporate analysis from the above reports, where relevant. Our views are preliminary, and in a number of instances we have highlighted where we are still assessing these issues.

- **Determine the options available**

  Our Review will identify the changes to market and regulatory frameworks that will be required to address the issues identified through the above process. The Review will consider both modifications to existing, as well as potentially new, mechanisms relating to the market- and intervention-based frameworks. It will also consider how these elements could address reliability in both the short- and long-term. In this regard, we note the recent Energy Security Board advice on the National Energy Guarantee. Developments on this will be taken into account for this Review. We anticipate that this stage will be contained within our directions paper.

- **Assess the range of options against the NEO and guiding principles**

  Any recommendations for potential changes to market and regulatory frameworks developed by the Commission will need to result in net benefits to the market and promote the long-term interests of consumers, consistent with the National Electricity Objective. The Commission's assessment of the options, and the development of recommendations in this Review will also be guided by the framework principles set out above. This will also include consideration of any market power issues, including work to understand the underlying causes and effects of any concentration of market power that could exist in the NEM.

327 Snowy Hydro noted that the assessment approach should define the issues and/or problem and determine if the problem is material. The materiality determination is important as there will inherently be trade-offs in costs and implementation from a range of options to address the defined issue. (See: Snowy Hydro, submission to issues paper, p. 2) We agree with this.

B Theoretical spectrum for reliability frameworks

From a theoretical point of view, there are two extreme alternatives that could underpin a reliability framework:

- First, the desired levels of system reliability could be met by the government deciding when and where to build new generation capacity - pure 'central planning'. Indeed, this is how such decisions were made prior to the Hilmer reforms of the 1990s, and the creation of the NEM.
- Second, reliability outcomes could be left solely to the market, with no limits on wholesale prices or additional regulatory mechanisms.

Figure B.1 illustrates the disparate positions these approaches occupy on the spectrum of possibilities.

Figure B.1 Spectrum of potential approaches

As explained below, adopting either of these two extreme approaches as the basis for the reliability framework would likely to give rise to highly inefficient pricing and investment outcomes throughout the electricity supply chain, resulting in higher costs for consumers. Understanding the source of these efficiency problems can consequently assist in understanding the origins of and the rationales for the current, predominantly market-based reliability framework that exists in the NEM.

B.1 Pure central planning

Historically, it has been common for governments around the world to own and operate electricity infrastructure – including generation assets. Australia was no exception. Prior to the start of the NEM, central planners (that is, governments or their agencies) would decide when to invest in new generation, what types of plants to build (for example, base-load, mid-merit or peaking) and where they would be located. The chief advantage of this pure central planning approach is that it can generally be expected to deliver a reliable power system. Put simply, public funds can be allocated directly to try and make sure that this desired level of reliability is met, i.e. it is a simple way to make sure that there is enough generation to ‘keep the lights on’ for an acceptable amount of the time.

However, the problem with this approach is the associated with high cost to consumers. It is generally accepted that central planners perform this capital investment function far less effectively than private firms and individuals. Private investors pursuing profits invariably have superior information about their own forward-looking costs and are subject also to important capital and take-over market disciplines. They will consequently be striving to produce their output at lower a cost than their competitors and to maximise their returns. In contrast, central planners generally:

- have access to only highly imperfect information, i.e. much like an economic regulator, they face an asymmetric information problem, in that they cannot estimate accurately the respective costs and benefits of different investment options
- do not have very strong incentives to ensure that the industry is operating at least cost, i.e. they are not subject to the same market disciplines and may be motivated primarily by 'keeping the lights on' at whatever the cost, for reasons of political expediency.

Centrally planned electricity generation consequently tends to be significantly more expensive to consumers than market-based investments since it passes the risk of "getting it wrong" onto consumers. For example, if central planning builds "too much", then consumers will be the consequences of that through higher prices.[328] Conversely, if central planning builds "too little", then consumers will face costs through potential reliability shortfalls. Over time, it has been increasingly recognised that market-forces can play a vital role in driving more efficient investments in electricity generation markets. There has consequently been a distinct international trend away from central planning in generation markets and, again, Australia is no exception. However, whilst market forces are undoubtedly an essential ingredient into most reliability frameworks, they are generally not allowed a completely free reign, for the reasons set out below.

B.2 Pure market forces

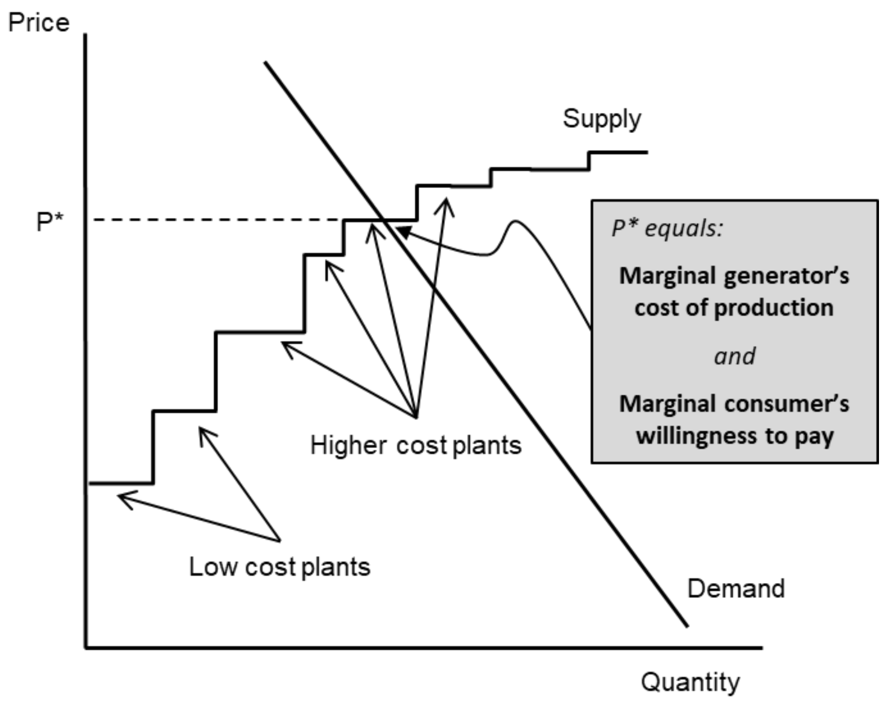
In the NEM today, decisions about where and when to invest in new generation capacity are made predominantly by non-government entities,[329] in response to wholesale price signals. Prices in the wholesale pool are determined through the interactions of supply and demand. Scheduled generators can submit offer prices for their capacity for every 5-minutes of the day. From those offers, AEMO uses a optimisation process that attempts to maximise the value of trade, determines the

328 Or indirectly in the form of higher taxes or lower spending on other government services.

329 Although, as section 3.3.3 explains, in recent times, both the state and Commonwealth governments are taking an increasing role in funding, subsidising or studying the feasibility of additional dispatchable generation capacity.

generators that will be called upon to produce electricity to meet demand, i.e. generators are dispatched in 'merit order'.[330]

Figure B.2 Wholesale price when supply is plentiful



As Figure B.2 illustrates, in times of plentiful supply, a competitive wholesale electricity market functions in the same way as any other competitive market. Competition between generators to supply the limited available demand should mean that they lodge bids that reflect the short-run marginal cost (SRMC) of running each type of plant.[331] The supply curve should therefore correspond to those plants' economic merit order, i.e. it will 'stack' them from lowest to highest cost. The market-clearing or 'equilibrium' price will then reflect simultaneously:

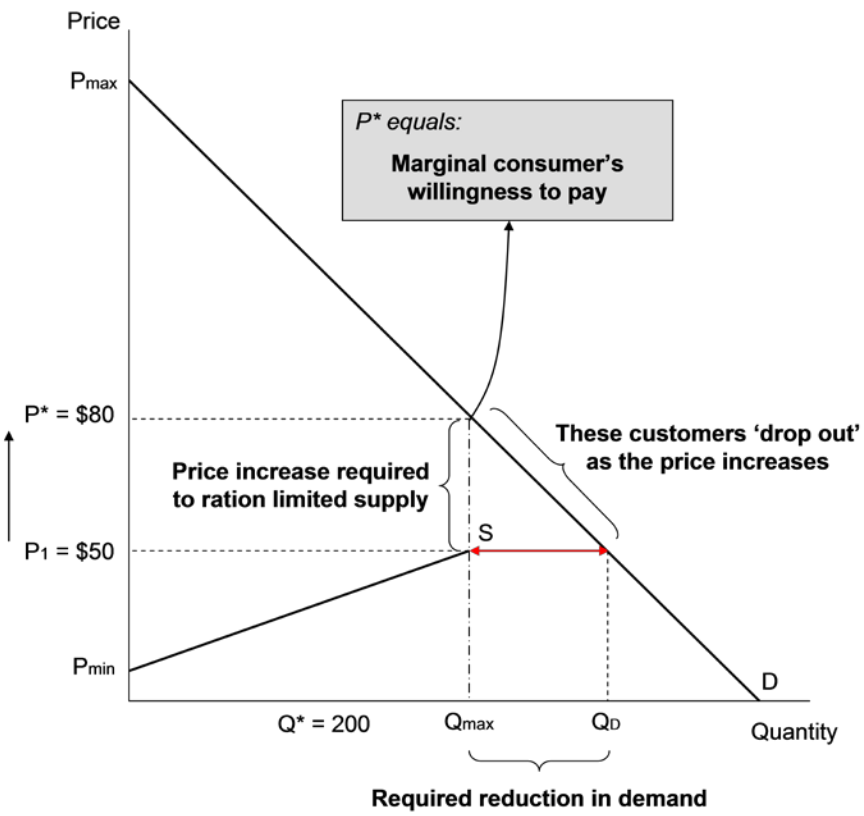
- the cost incurred by the 'marginal generator' to supply the unit that 'clears the market', i.e. its SRMC
- the willingness to pay of the 'marginal consumer' who purchases (i.e. demands) that unit of output.

330 A 'dispatch price' is determined every five minutes, calculated by a market clearing algorithm as the price of the highest generator bid required to meet forecast demand in that five minute period at that node on the system. Currently, six dispatch prices are averaged every 30-minutes to determine the 'spot price' for each trading interval for each of the five regions of the NEM, i.e., the spot price is determined 48 times per day. However, the Commission recently made a final determination to align settlement timeframes with dispatch timeframes, which will result in a move to five minute pricing.

331 For example, a base load plant that bids substantially above its operating and maintenance costs risks not being dispatched and being forced to incur the expense of shutting down and restarting its plant.

However, the more relevant scenario from a reliability perspective occurs when *shortages* emerge and there is potentially *not enough capacity* to meet demand and provide reserves. When this situation arises in a typical competitive market this gives rise to 'demand-side bidding' (or 'price rationing'). Figure B.3 illustrates that this occurs through customers competing against one another for the limited supply by bidding up prices. As would-be buyers offer higher prices, other buyers who do not value the product that much 'drop out' and choose not to purchase it. This continues until the quantity of the product demanded by those fewer remaining customers is equal to the available supply.

Figure B.3 Shortages in a typical competitive market



The resulting market price (P* in Figure B.3) reflects the willingness to pay of the marginal consumer who buys the unit that clears the market. Crucially, this price is not influenced in any way by the cost incurred by the firm that supplied that unit e.g. an $80 market price exceeds the underlying $50 production cost. Such shortages therefore provide signals for new entry and expansion by firms chasing those 'above cost' prices which, in time, should serve to reduce the regularity with which excess demand arises, resulting in a 'more reliable' supply of steel. In typical competitive markets, pure market forces will therefore provide incentives to firms:

- to supply consumers with the products that they want to buy at competitive prices and at the desired level of quality/reliability, i.e. to achieve static efficiency

- to invest in new and innovative offerings and explore techniques to continually reduce their production costs over time, i.e. to strive for dynamic efficiency.

However, the atypical characteristics of competitive wholesale electricity markets mean that unencumbered interactions between demand and supply (i.e. pure market forces) cannot be relied upon in the same way to produce efficient wholesale price and reliability outcomes. Most notably, when a shortage emerges in a 5-minute dispatch interval, the price rationing process cannot occur in the same way that is described above or, at least, not without the same effect. There are two key reasons for this:

- in 'typical' competitive markets, this rationing process usually takes time, whereas prices in wholesale electricity markets are set in near real-time, and so unless this demand-side reaction occurs almost instantaneously, the market will not clear

- although emerging technologies are making it increasingly feasible for consumers to respond rapidly to price increases, fully-fledged demand-side bidding is still not possible – at least not at the speed and on the scale required.[332]

This creates a potentially significant problem if market forces are left to operate completely unchecked. If a generator foresees that there will not be enough capacity available to meet projected demand during a period or, alternatively, if it surmises that its own capacity is 'pivotal' to demand being met, its bidding incentives may alter dramatically. Specifically, it will have a strong incentive to increase its offer prices well above its SRMC and, potentially, well above the price that most customers would be willing to pay, since it will know that most will not be able to curtail their demand. In other words, the price could exceed substantially the level that would prevail under demand-side bidding in a 'typical' competitive market.

The potential for the exploitation of temporary pricing power is exacerbated by the fact that most smaller customers would be unlikely to even be aware of any price spikes, since they would be insulated from them through the 'risk aggregation' function performed by their retailers. Nonetheless, if generators exercise this temporary pricing power with sufficient regularity, the effects will eventually filter through to final customers' bills, as retailers pass-on those higher wholesale costs. This would give rise to several potential adverse flow-on impacts, including (but not limited to):

- Distortions to the prices of hedge contracts, since these are determined primarily by the balance of expectations as to the level and volatility of future wholesale spot price outcomes, i.e. if spot prices are affected, then so too will be contract prices.[333]

- Inefficient over-investment in transmission-connected and embedded (distribution-connected) generation, as investors chase the economic rents that

332 The current and potential future role of demand response in the reliability framework – including the possibility of 'wholesale' demand response – is discussed in more detail in chapter 7.

333 The relationship between spot prices and contract prices is explored in more detail in section 2.1.

can be earned from the high spot prices prevailing during windows of excess demand.

- Inefficient over-investment in demand-side management initiatives by consumers looking to avoid the adverse consequences of the higher retail prices that would arise from the price spikes in the wholesale market.

In other words, those distorted wholesale price signals would risk compromising investment incentives throughout the entire electricity supply chain. That would serve to undermine the basic purpose of introducing market forces in the first place, i.e. the total cost to consumers to achieve a desired reliability outcome could be even greater than it would have been with a central planning approach. For that reason, the existing reliability framework relies on neither pure central planning nor pure market forces to deliver desired outcomes. Rather, it sits in between these two extremes, as is explained below.

B.3 Potential sources of failure

The basic idea of the existing reliability framework in the NEM is to deliver the desired reliability outcomes through the market mechanism as much as possible, albeit within the specified price limits. As the supply/demand balance tightens this should manifest in higher spot and contract prices that should provide a spur for efficient entry and expansion that addresses any potential problems before they transpire. Those market-based initiatives are assisted by further information provided by AEMO in various publications and it is only after all else has failed that direct interventions are used as a last resort to minimise the likelihood of involuntary load shedding.

The existing reliability framework is therefore multi-dimensional and that of its elements are interrelated. For example, estimates of the value of customer reliability inform the reliability standard, which then informs the market price cap and so on. Similarly, AEMO's information affects participants' forecasts and expectations, which in turn affects participant investment and operational decisions, which are then used as an input into AEMO's forecasts. This interdependence means that there are many ways in which the framework could face pressures from the emerging challenges. Indeed, a shortcoming in one element of the framework can have cascading effects throughout all the others. For example:

- If the estimated value of customer reliability is too low (say, because the costs of widespread outages are understated or not adequately captured), this may lead to the reliability target being set too high (i.e. the unserved energy target may be higher than it should be) and, in turn, the market price cap being set too low (and vice versa if the value of customer reliability estimate is too high).

- The value of customer reliability estimates and the reliability target might be set appropriately, but the market price cap might nevertheless be set at the wrong level, e.g. it may be lower than is necessary to elicit the new investment needed to meet the reliability standard, or higher than necessary, resulting in higher prices and wasteful over-investment.

- Forecasting errors – which are inevitable on some level – might cause AEMO to provide inaccurate information to market participants in the various supplementary materials it publishes, potentially resulting in insufficient generation being available in the short-term and/or long-term – this issue is explored in chapter 4.

This also emphasises the need to consider the reliability framework in a holistic manner.

These potential pitfalls apply at the best of times yet, despite their existence, the framework outlined above have been reasonably successful over the life of the NEM to date. We understand that on only three occasions has the reliability standard not been met. Two occurred in January 2009, in Victoria and South Australia, during the height of the heatwave that contributed to Victoria's 'Black Saturday' bushfires. The third one occurred in Victoria during one event in December 2016 whereby the Alcoa Portland Aluminium Smelter lost supply.

Despite the impressive track-record of the existing arrangements, in recent years concern has grown about whether the arrangements are the right ones to have in place in 2017 and beyond. A series of emerging new challenges, such as the closure of large thermal plants and the increasing penetration of subsidised variable renewable generation, has prompted several commentators[334] to call for a holistic review of the existing reliability framework to examine whether it remains fit for purpose. These potential drivers of change have provided a key impetus for this Review, as is explained in chapter 2.

334 Grattan Institute, Next Generation, The long-term future of the National Electricity Market, September 2017.

C Operationalising the reliability standard

AEMO's incorporates the reliability standard into its day-to-day operations, as explained in this appendix.

This appendix is structured as follows:

- section C.1 outlines the role of information processes in the NEM
- section C.2 summarises AEMO's NER requirements with regards to the operationalisation of the reliability standard
- section C.3 explains how AEMO operationalises the reliability standard
- section C.4 discusses AEMO's intervention mechanisms.

C.1 The role of information processes

AEMO is required by the NER to publish various materials which provide additional information to market participants – and any other interested parties – on matters pertaining to the reliability standard, i.e. over and above the information contained in contract and spot market prices. This information is provided in several formats and considers various time-frames. This helps guide market participants' expectations of the future, enabling more efficient investment and operational decisions. Some of these publications include:

- Electricity Statement of Opportunities (ESOO) – this document projects whether there will be an adequate supply of electricity over a ten year-period to meet the applicable reliability requirement.
- Projected Assessment of System Adequacy (PASA) – this publication forecasts whether there will be sufficient supply to meet projected demand over various forward intervals (e.g. over the next two years, six days or over the next day).
- Pre-dispatch schedules – AEMO provides two sets of pre-dispatch data; namely:
  - 30-minute pre-dispatch data by region to the end of the next trading day – which are updated half-hourly
  - 5-minute pre-dispatch data by region, showing short-term price and demand forecasts looking out one hour ahead – which are updated every 5 minutes
- Energy Adequacy Assessment Projection (EAAP) – this document provides information on the impact of potential energy constraints, particularly those relating to inputs to production, e.g. water shortages or constraints on fuel supply.

- Low reserve conditions or lack of reserves (LOR) notices – AEMO may publish these notices to advise participants when the probability of involuntary load shedding is or is forecast to be more than remote, that is, when reserves are running low.[335]

The purpose of all these forms of supplementary information is to inform the market of prevailing and expected conditions, and when reserves may be running low, entice a market response, if possible. For example, if the ESOO identifies a potential shortage of generation in a location in, say, five years' time, the expectation is that revealing this information to the market will prompt new investment to alleviate that problem. In a similar vein, AEMO's first step when publishing a low reserve condition or LOR notice is to seek a market response, for example, ideally, generators will come online in anticipation of the high spot prices that are likely to prevail during the identified period.

C.1.1 How information is provided

The below section discusses in detail how information is provided through the medium-term and short-term PASA processes, as well as pre-dispatch.

Medium-term PASA process

Medium-term PASA assesses the adequacy of expected electricity supply to meet demand across a two-year horizon through regular assessment of any projected failure to meet the reliability standard.

Each week, scheduled market participants (e.g. generators) must submit forecasts of their availability (total MW capacity available for dispatch) to AEMO for the period covering the next 24 months, commencing eight days (i.e. Sunday) after the publication date of the medium-term PASA report.

The report is published every week as a minimum. AEMO publishes the medium-term PASA every Tuesday at 16:00 AEST with outcomes of the PASA process as well as input variables.

Scheduled generators or market participants are required to submit PASA availability of each scheduled generating unit, load or network service and energy constraints for each scheduled generating unit or load.[336] Network service providers must provide planned network outage information.[337]

Specifically, market participants submit the following availability data as frequently as changes occur, with this being used as an input into the medium-term PASA:

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335 Following the Commission making a final rule on 19 December 2017 on the *Declaration of Lack of Reserve conditions*, on and from 16 January 2018, LOR notices will be declared on a probabilistic basis, whereas prior to the rule change, LOR notices were declared on a deterministic basis,

336 In accordance with clause 3.7.2(d) of the NER. This clause is classified as a civil penalty clause.

337 In accordance with clause 3.7.2(e). This clause is classified as a civil penalty clause.

- Scheduled generators and scheduled loads[338] provide the expected capacity of each scheduled unit, with this typically varying over the period on a daily basis.
- Scheduled generators with energy constraints (hydro) provide their weekly energy limit.
- Semi-scheduled generators (solar and wind) submit wind turbine availability.
- Network service providers (both distribution and transmission) provide an outline of planned network outages and other information.

In addition to using the above information, AEMO also uses its own processes and inputs to forecast the following information through the medium-term PASA process:

- Network constraints - based on both network businesses, as well as generator inputs, AEMO forecasts what constraints are likely to bind at a particular point of time, with this in turn influencing the forecasts of generation output.
- Demand forecasts for each region for each day.
- Demand-side participation, which includes short-term reductions in demand in response to price increases, either by turning off equipment to reduce electricity consumption or using on-site generators.
- Based on the network constraints and demand forecasts:
  - Forecasts of semi-scheduled wind and solar generation output – AEMO uses inputs from generators (e.g. turbine/inverter availability) and AEMO inputs (historical data on wind/temperature/solar irradiation) to create forecasts for how many MW semi-scheduled generating units will produce.
  - Forecasts of non-scheduled (generators less than 30MW in size) generation output – AEMO forecasts how much MW these generators will produce.
- Future generation based on committed generation projects under development with a dispatch type of scheduled or semi-scheduled. Before the unit is registered, it is modelled as future generation which has the PASA availabilities as its seasonal capacity and is available from the start date of commercial operation, based on ESOO information. Once the unit is registered, the generator is responsible for submitting data.

Short-term PASA process

Short-term PASA is a six-day half-hourly reserve outlook.

338 Currently there are no scheduled loads in the NEM.

Market participants must submit forecasts of half-hourly availability to AEMO for the six trading days from the end of the trading day covered by the most recent pre-dispatch schedule.

AEMO publishes the outputs of short-term PASA every day at 14:00 AEST although it is updated every two hours thereafter. Participants provide updates as frequently as changes occur. Scheduled market participants (e.g. generators) submit the following availability data as frequently as changes occur, with this being used as an input into the short-term PASA:

- For each trading interval (30 minutes) over the short-term PASA period available capacity of each scheduled generating unit, scheduled load or scheduled network service. Generator outages are reflected in the available capacity.
- For each trading interval over the short-term PASA period, the PASA availability of each scheduled generating unit, scheduled load or scheduled network service for each trading interval. PASA availability is physical plant capability taking into account ambient weather conditions, that can be made available on 24 hours' notice.
- If applicable, daily energy availability forecasts for energy-constrained scheduled generating units (hydro) and energy constrained scheduled loads.

As with medium-term PASA, the NER require the relevant participants to provide particular inputs to AEMO. Furthermore, the NER require that these inputs represent the participant's current intentions and best estimates.[339]

In addition to using the above information, AEMO also uses its own processes and inputs to forecast the following through the short-term PASA:

- For each trading interval, what the demand level in each region will be.
- Based on the forecast demand level, as well as the availability information from generators, what the reserve level requirement is.
- Based on the forecast demand level, as well as the availability information from generators, what the projected constraints on the network will be.

The short-term PASA process outputs, which are published by AEMO from 14:00 AEST the day before the trading day, and updated every two hours after that, include:

- The demand forecast for each region.
- Information on what constraints on the network are likely to bind.
- Forecast reserve levels and reserve conditions, including lack of reserve notices.
- Aggregate unit availability and PASA availability for each individual generator.

339 Clause 3.7.3(e) of the NER. This clause is classified as a civil penalty provision.

- Interconnector transfer capabilities.

In terms of generator unit availability, generators do not see information on other units but see information on their own units. The market (and the general public) sees the aggregate unit availability. Individual unit availability information is only available to AEMO for confidentiality reasons, primarily.

Pre-dispatch

The pre-dispatch process provides projections of the prices and generation dispatch based on market participant bids and offers, and AEMO forecasts of demand and other system conditions. Pre-dispatch data of an aggregate nature (both inputs and outputs) is published to the whole market, with data relating to a specific market participant only available to that participant.

Market participants with market ancillary service offers must submit energy and frequency control ancillary services (FCAS) dispatch offers and bids and registration data to AEMO for the following day in half-hourly intervals.

The report is published the day before typically just after 12:30 AEST and no later than 16:00 AEST for the following day, with AEMO updating the file every 30 minutes thereafter.

AEMO publishes a range of information within pre-dispatch, for each trading (30-minute) interval, as set out in Table C.1.

Offers and bids

Market participants must make 30-minute offers and bids in relation to day 0 starting from 2 days from day 0. These refer to both energy and FCAS and the data is used in pre-dispatch and for dispatch.

Market participants are responsible for the following actions:

- On day-2 at 12:30 AEST participants provide a capacity notification or day 0 including self-commitment/de-commitment times, capacity profile, energy availability, rates of changes.

- On day-1 at 12:30 AEST bidding closes for day 0. Bids and offers made by participants include quantities and prices for each band, ramp rates etc.

- On day 0, participants can re-bid up to just before the start of the next trading interval and must include a reason for rebidding.[340]

340 The prices for each price band specified in the bids and offers are firm and cannot be changed with a rebid. A participant may only submit a rebid to vary those aspects of its bid or offer set out in clause 3.8.22(b) of the NER.

Dispatch

AEMO publishes dispatch information every five minutes for the next dispatch interval (five minutes).

Dispatch is according to current bids, offers and rebids made by participants. AEMO publishes a range of information as set out in the table below.

C.1.2 Inputs to information processes

The below table summarises the various information processes provided by AEMO, as well as the various inputs associated with them. This table is not an exhaustive list of all the information provided by AEMO but highlights the main variables and outputs for each process and document.

Table C.1 AEMO's information processes

Variables	ESOO	EAAP	Medium-term PASA (from 15 February 2018)	Short-term PASA	Pre-dispatch	Dispatch
Timeframe	Ten years Clause 3.13.3(q)	Two-year Rule 3.7C(b)(1)	Two-year Clause 3.7.2(a)	Six-day Clause 3.7.3(b)	One day Clauses 3.13.4(e), 3.8.20(a) and 3.8.20(h) Note: AEMO also publishes a five-minute pre-dispatch	Two-day rolling window/5 minute Clause 3.14.4(l) Note: AEMO must operate the spot market according to the approved timetable Clause 3.4.3(a)
Frequency of publication	Annually (by 31 August) Clause 3.13.3(q)	At least annually Rules 3.7C(b)(2) and 3.7C(d) Note: clause 3.9.3D(b1) requires the RSIG to set out the factors AEMO will consider in determining whether it has an obligation to publish an EAAP under 3.7C(d)(2)	Weekly Clauses 3.7.2(a) and 3.13.4(a)	Two-hourly Note: clause 3.7.3(a) requires publication at least daily, but AEMO publishes it every two hours	30 minutes Note: clause 3.8.20(a) requires a pre-dispatch schedule covering each trading interval	5 minutes

Variables	ESOO	EAAP	Medium-term PASA (from 15 February 2018)	Short-term PASA	Pre-dispatch	Dispatch
Resolution of forecast	Annually Note: However, modelling determines the regional USE itself at an hourly resolution	30-minute traces	Daily Clause 3.7.2(a)	30 minutes Note: clause 3.13.4(c) requires publication for each trading interval	30 minutes Note: clause 3.8.20(b) requires the pre-dispatch process to have a resolution of one trading interval	5 minutes
Purpose	Provides technical and market data that informs the decision-making processes of existing and potential market participants, as they assess opportunities in the NEM over a 10-year outlook period. Clause 3.13.3(q)(5)	Provides an analysis to market participants and other interested persons that quantifies the impact of energy constraints on energy availability over the 24 month period, such as water storages during drought conditions or constraints on fuel supply for thermal generation, or supply adequacy in the NEM. Rule 3.7C(a)	Provides an analysis of power system security and reliability of supply prospects to inform participants and enable them to make decisions about supply, demand and transmission network outages in respect of periods up to two years in advanced. Clause 3.7.1(b)	Provides an analysis of power system security and reliability of supply prospects to inform participants and enable them to make decisions about supply, demand and transmission network outages in respect of a six day half-hourly reserve outlook. Clause 3.7.1(b)	Provides projections of the prices and generation dispatch based on market participants' bids and offers, and AEMO forecasts of demand and other system conditions Clause 3.13.4(f)	Publishes dispatch information every five minutes, for the next dispatch intervals Note: some of this information is published at the start of the 5-minute interval, some immediately after - generally, information in the dispatch timeframe or relating to the dispatch timeframe is published according to a timetable.

Variables	ESOO	EAAP	Medium-term PASA (from 15 February 2018)	Short-term PASA	Pre-dispatch	Dispatch
Assumption for potential breach of reliability standard Note: These assumptions are specified in AEMO's *reliability standard implementation guidelines*.	Directly assesses USE expectations based on probabilistic modelling	Directly assesses USE expectations based on probabilistic modelling	Directly assesses USE expectations based on probabilistic modelling Clause 3.7.2(f)(6)(ii) obliges AEMO to identify any projected failure to meet the reliability standard in accordance with the RSIG Clause 4.8.4(a) identifies the trigger for low reserve conditions	Is any region in forecast LOR2 or LOR3? Clause 3.7.3(h)(5) obliges AEMO to identify any projected failure to meet the reliability standard in accordance with the RSIG Clauses 4.8.4(c) and 4.8.4(d) identify the triggers for lack of reserve level 2 and 3 declarations. From 16 January 2018, the triggers will be identified through Clause 4.8.4(b) in accordance with the reserve level declaration guidelines.	Is any region in forecast LOR2 or LOR3? Clauses 4.8.4(c) and 4.8.4(d) identify the triggers for lack of reserve level 2 and 3 declarations. From 16 January 2018, the triggers will be identified through Clause 4.8.4(b) in accordance with the reserve level declaration guidelines.	Is any region in actual LOR2 or LOR3? Clauses 4.8.4(c) and 4.8.4(d) identify the triggers for lack of reserve level 2 and 3 declarations. From 16 January 2018, the triggers will be identified through Clause 4.8.4(b) in accordance with the reserve level declaration guidelines.

Variables	ESOO	EAAP	Medium-term PASA (from 15 February 2018)	Short-term PASA	Pre-dispatch	Dispatch
Input assumption: Forecast demand	Based on National Electricity Forecasting Report (now Electricity Forecasting Insights) , historical 30 minute operational demand traces and historical weather patterns RSIG based on Cl. 3.13.3(q) output requirement	Based on National Electricity Forecasting Report (now Electricity Forecasting Insights), historical 30 minute operational demand traces and historical weather patterns Clause 3.7C(b)(6)(A)	Based on National Electricity Forecasting Report (now Electricity Forecasting Insights) , historical 30 minute operational demand traces and historical weather patterns Clause 3.7.2(c)(1) specifies input and RSIG details assumptions and methodology	50% and 10% POE half-hour demand based on expected weather patterns Clause 3.7.3(d)	50% POE half-hour demand based on expected weather patterns Note: Clause 3.8.20(c)(2) requires AEMO to forecast load for each region for each trading interval.	5-minute forecast of demand regional changes
Input assumption: Intermittent generation Note: Rule 3.7B requires AEMO to forecast intermittent generation but only for PASA processes, pre-dispatch and dispatch	Generation profiles based on historical performance or weather patterns for new or committed generation. RSIG based on clause 3.13.3(q) output requirement	Based on historic weather patterns – hourly profiles. Generator outage rates calculated based on historical performance data Clause 3.7C(b)(6)(A)	Using historically-observed generation outputs for wind and solar units for at least eight reference years. Half-hourly profiles used. Clause 3.7.2(c)(4) specifies input and RSIG details assumptions and methodology	Australian Wind Energy Forecasting. System (AWEFS) and Australian Solar Energy Forecasting System (ASEFS) Clause 3.7.3(d)(4) specifies input and RSIG details assumptions and methodology	AWEFS and ASEFS, with participants submitting price offers Clause 3.8.20(c)(3)	AWEFS and ASEFS, with participants submitting price offers Clause 3.8.6(g)

Variables	ESOO	EAAP	Medium-term PASA (from 15 February 2018)	Short-term PASA	Pre-dispatch	Dispatch
Input assumption: Scheduled generation capacity and outages	Based on annual survey of participants Generator outage rates calculated based on historical performance data RSIG based on clause 3.13.3(q) output requirement	Medium-term PASA offers Clause 3.7C(b)(6)(A)	Scheduled generators and loads provide the expected availability of each scheduled unit Clause 3.7.2(d)(1)	Scheduled generators and loads submit available capacity and PASA availability data to AEMO Clause 3.7.3(e)(1)-(2)	Pre-dispatch offers and bids (price and quantity) made by market participants Clause 3.8.20(c)(1)	Dispatch offers and bids made by market participants Clause 3.8.6
Input assumption: Energy constraints	Based on historical observations RSIG based on clause 3.13.3(q) output requirement	Provided through Generator Energy Limitation Framework (GELF) Clause 3.7C(b)(6)(C)	Scheduled generators and loads with energy constraints (e.g. hydro) submit weekly energy limits Clause 3.7.2(d)(2)	Scheduled generators and loads with energy constraints (e.g. hydro) provide their daily energy availability forecasts Clause 3.7.3(e)(4)	N/A	N/A
Input assumption: Network constraints	System normal transmission network constraints affecting interconnector flows RSIG based on clause 3.13.3(q) output requirement	System normal transmission network constraints affecting interconnector flows Clause 3.7C(b)(6)(B)	Networks provide an outline of planned network outages and availability of interconnectors Clause 3.7.2(c)(3) specifies input and RSIG details assumptions and	Networks provide an outline of planned network outages and availability of interconnectors Clauses 3.7.3(d)(3) and 3.7.3 (g)	Network constraints invoked by the AEMO control room to reflect system conditions Clauses 3.6.4 and 3.8.10	Network constraints invoked by the AEMO control room to reflect system conditions Clauses 3.6.4 and 3.8.10

Variables	ESOO	EAAP	Medium-term PASA (from 15 February 2018)	Short-term PASA	Pre-dispatch	Dispatch
			methodology; Clause 3.7.2(e)			
Basis of participant information	Participant surveys. Capacity based on evidence of project status (existing, committed etc) Must provide information to AEMO as soon as practicable after participant becomes aware of any information required for publication by AEMO Clause 3.13.3(t)	Generator must provide updated GELF if there has been a material change that impacts the energy constraints associated with that GELF Clause 3.7C(i)	Generator must provide the information in accordance with the timetable Clauses 3.7.2(d) and 3.7.2(e)	Scheduled generators must provide the information in accordance with the timetable, based on current intentions and best estimates Clauses 3.7.3(e) and 3.7.3(g)	A generator must not make a dispatch offer that is false, misleading or likely to mislead. This includes if it: 1) does not have a genuine intention to honour; or 2) does not have a reasonable basis to make; the offer Clauses 3.8.22A(a) and (b) Re-bidding is required when the participant becomes aware of changes to the basis of the offer Clause 3.8.22A(d) Participants must ensure that they are able to dispatch relevant plant required under the	Current offer used. Offers, bids and rebids must not be false or misleading. Clause 3.8.22A

Variables	ESOO	EAAP	Medium-term PASA (from 15 February 2018)	Short-term PASA	Pre-dispatch	Dispatch
					schedule Clause 3.8.20(g)	
Information provided to the market	Taking the above inputs into account, AEMO forecasts the unserved energy over the next 10 years. As a minimum, the ESOO has to include the following: Demand and energy requirements projections; generation capabilities of existing generators; generation capabilities of generation for which formal commitments have been made for construction or installation planned plant retirements; network capabilities and constraints; operational and economic information	Taking all of the above into account, AEMO forecasts the following: Projected annual unserved energy for each region; probabilistic assessment of projected energy availability for each region; adequacy of energy availability by scenario identified in EAAP guidelines. Clause 3.7C(b) AEMO publishes a public version of the EAAP with the following information over 2 years unless otherwise	Taking all of the above into account, AEMO forecasts and/or publishes the following: Network constraints; demand forecasts for each region (10% POE and most probable); demand-side participation; semi-scheduled wind and solar output; non-scheduled generation output; scheduled generation availability; capacity taking into account network constraints and energy constraints See, for example, clause 3.7.2(f) (1) to (5B) AEMO also publishes future generation projects	Taking all of the above into account, AEMO forecasts and/or publishes the following: Demand forecast; network constraints; forecast reserve levels; forecast aggregate generator availability See, for example, clause 3.7.3(h)(1) to (4C) Generators also see availability for each generator (generators do not see information on other units) AEMO also identifies and	Taking all of the above into account, AEMO forecasts and/or publishes the following: Demand forecasts; forecast projected RRN price; forecast FCAS requirements; projected FCAS prices; forecast aggregate available generation and load, per region; forecast aggregate dispatched generation and load, per region; forecast interconnector flows and inter-regional loss factors; forecast aggregate semi-scheduled dispatch and availability information, by region; forecast binding network	Information published includes: Dispatch price for each RRN; the ancillary service price for each RRN; actual interconnector flows; actual constraints binding; actual regional reference price; actual demand; amount of dispatchable generation; amount of dispatchable load; amount of FCAS; actual FCAS prices See, for example, clauses 3.2.2(c1), 3.4.3(a) and

Variables	ESOO	EAAP	Medium-term PASA (from 15 February 2018)	Short-term PASA	Pre-dispatch	Dispatch
	about the market to assist planning See, for example, clause 3.13.3(q)	specified: monthly unserved energy; unserved energy for the first 12 months and second 12 months; monthly energy generation reductions, capacity reduction and generation contribution for each scenario EAAP guidelines but complies with NER requirements The confidential version covers individual scheduled generating units or hydro power schemes and is only made available to the relevant generator. EAAP guidelines and clause 3.7C (r)	AEMO also identifies and quantifies: Any violation of power system security; failure to meet the reliability standard; forecast interconnector transfer; when and where network constraints may bind See, for example, clause 3.7.2(f)(6)	quantifies: Any violation of power system security; failure to meet the reliability standard; forecast interconnector transfer; when and where network constraints may bind See, for example, clause 3.7.3(h)(5)	constraints; forecast lack of reserve or low reserve conditions. See, for example, clauses 3.8.20(a), 3.13.4(f) and 3.13.4(g) AEMO makes the following information available to the relevant participant for a specific unit on a confidential basis: Scheduled times of commitment and de-commitment of individual slow start generating units; half hourly loading level; provision of ancillary services and related constraints; provision of constraints due to network limitations; intermittent generation forecast See, for example, clause 3.8.20(j)	3.13.4(l)

C.2 Obligations under the NER to operationalise the reliability standard

The NER does not give specific direction to AEMO on how to operationalise the reliability standard (0.002 per cent unserved energy (USE)), but it does require AEMO to perform the following functions in accordance with the *reliability standard implementation guidelines* (RSIG):

- In the medium-term, through the medium-term PASA, identify and quantify any projected failure to meet the reliability standard.[341]
- In the short term, through the short-term PASA, identify and quantify any projected failure to meet the reliability standard.[342]
- To keep the system in a reliable operating state in real time, assess whether the power system meets, and is projected to meet, the reliability standard.[343]

In addition to monitoring the system using the information processes mentioned above, AEMO may declare:

- a low reserve condition when it considers that the balance of generation capacity and demand for the period being assessed does not meet the reliability standard as assessed in accordance with the *reliability standard implementation guidelines*[344]
- a lack of reserve condition when it determines, in accordance with the reserve level declaration guidelines, that the probability of load shedding (other than the disconnection of interruptible load) is, or is forecast to be, more than remote.[345]

The NER also require AEMO to publish the ESOO by 31 August each year. The ESOO provides information which can help stakeholders plan their operations over a ten-year outlook period, including information about the future supply demand balance. The purpose of the ESOO is not to be used as a definitive guide to assess how much reserves should be procured, nor to inform governments about what actual outcomes in the market will be. Instead, the purpose is solely as a market information tool:

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341 Clause 3.7.2(f)(6)(ii) of the NER.

342 Clause 3.7.3(h)(5)(ii) of the NER.

343 Clause 4.2.7(c) of the NER.

344 Clause 4.8.4(a) of the NER.

345 On 19 December 2017, the Commission made a final rule which, from 16 January 2018, removes the deterministic descriptions of lack of reserve from clause 4.8.4(b) – (d) of the NER, replacing them with a single high-level description for lack of reserve and so allows the system operator to move to a probabilistic framework. The final rule places a requirement on AEMO to make guidelines (the reserve level declaration guidelines) that set out how AEMO will determine lack of reserve conditions, so improving the transparency of the existing framework. See: AEMC, National Electricity Amendment (Declaration of Lack of Reserve Conditions) Rule 2017, Final Determination, 19 December 2017.

signalling to the market ahead of time where there might be potential shortfalls in order to elicit a response from market participants.

C.3 Operationalisation of the reliability standard

AEMO applies the reliability standard using forecasts and projections over different timeframes:

- In the long term (over the next ten years), AEMO uses the ESOO to provide market information over a ten-year horizon to assist market participants in making investment and operational decisions.
- In the medium term (for the time period covering the next two years), AEMO operationalises the reliability standard though the identification of low reserve conditions via the medium-term PASA process.[346]
- AEMO also uses the Energy Adequacy Assessment Projection (EAAP) to forecast unserved energy (USE) for energy-constrained scenarios (e.g. drought affect hydro stations) over a two-year horizon, similar to the medium-term PASA process
- In the short term (for a time period covering six days in the future from the end of the pre-dispatch period), AEMO manages reserves through the identification of lack of reserve (LOR) conditions via the short-term PASA process. Short-term PASA identifies capacity reserves over this period. LORs can also be identified in pre-dispatch and real time.

C.3.1 ESOO versus medium-term PASA

The ESOO and the medium-term PASA processes are similar but have typically been seen by AEMO to fulfil different purposes:

- Medium-term PASA is used for near-term operations and assessment of generator preventative maintenance planning and other medium term decisions. Medium-term PASA uses more granular, short-term generator availability information. The purpose is to assess the adequacy of expected electricity supply to meet demand across a two-year horizon.
- ESOO compares longer term supply adequacy against a planning standard. ESOO uses longer-term advice provided by generators. The purpose of the ESOO is to provide technical and market data that informs the decision-making processes of market participants, new investors and jurisdictional bodies as they assess opportunities in the NEM over a 10-year outlook period.

346 Medium-term PASA forecasts peak capacity reserve conditions over a two year horizon. The current, deterministic process is only expected to be in place until 15 February 2018. From 15 February 2018, it will be replaced with a probabilistic process.

While ESOO analysis is based on multiple statistical simulations that produce a probability distribution function for USE, AEMO currently backs up these results with the medium-term PASA outlook, which indicates the risk of low reserve conditions in the medium term.

The inputs into these processes also tend to be different given the timeframes. For example, generation availability in the ESOO is based on an annual survey of generators (longer term advice provided by scheduled participants) and a number of assumptions are made as to new builds.

Availability in the medium-term PASA is based on medium-term PASA offers made by scheduled participants. PASA availability is defined in Chapter 10 of the NER as:

> "The physical plant capability (taking ambient weather conditions into account in the manner described in the procedure prepared under clause 3.7.2(g)) of a scheduled generating unit, scheduled load or scheduled network service available in a particular period, including any physical plant capability that can be made available during that period, on 24 hours' notice."

Medium-term PASA offers, as a result, tend to be more granular and reflect short-term scheduled participant availability information.

C.3.2 Medium-term PASA changes

Changes to the medium-term PASA process, set to be implemented on 15 February 2018, will re-align it more closely with the reliability standard. The process that will be used from 15 February 2018 onwards is termed the "2018 medium-term PASA process" throughout the rest of this appendix.

By way of background, AEMO engaged Ernst & Young (EY) to recommend improvements to the medium-term PASA methodology in 2016. In proposing the changes, EY noted that a more probabilistic approach would assess reliability against forecast USE better than an outdated, deterministic approach. A probabilistic approach would more accurately reflect the purpose of the medium-term PASA process, including to:[347]

- Improve the usefulness of information to market participants through the supply and demand summary.
- More accurately reflect whether the reliability standard is being met and improve its usefulness as an information provision tool for participants to make decisions and for AEMO as an intervention trigger.

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347 EY's report is available at http://www.aemo.com.au/-/media/Files/Electricity/NEM/Data/MMS/2016/EY-MTPASA-Final-Report-2016-11-23C.pdf.

In order to implement these changes, AEMO went through consultation on the *reliability standard implementation guideline,* which combines all of AEMO's processes on incorporating the reliability standard into its day-to-day operations into a single document.[348]

C.3.3 Calculating reserve margins in medium-term PASA: current methodology

Current medium-term process

Until 15 February 2018, AEMO determines the level of reserves required in each region to meet the reliability standard deterministically.

AEMO applies the reliability standard over a two-year timeframe by providing a capacity reserve assessment as part of the medium-term PASA process, which is run at least weekly. This component of the broader medium-term PASA process identifies potential capacity shortfalls known as low reserve conditions.

The reliability standard is operationalised by identifying, disclosing and responding to periods of forecast low reserve conditions

AEMO declares a low reserve conditions if capacity reserves are projected to be inadequate on any given day. Capacity reserves are the difference between the PASA availability participants have offered and expected demand estimated by AEMO according to the PASA processes.

To assess supply adequacy, these capacity reserves are compared against minimum reserve levels. This provides a fast and timely assessment of supply adequacy without needing to compute unserved energy explicitly using a large number of monte carlo simulations.

Minimum reserve levels represent AEMO’s operationalisation of the reliability standard into a required safety margin of surplus installed capacity that can be applied operationally. A minimum reserve level is expressed relative to a region’s 10 per cent POE maximum demand, including any coordinated reduction in demand, known as demand-side participation.

Minimum reserve levels

Minimum reserve levels represent the minimum level of capacity reserves that must be carried in each region to avoid exceeding 0.002 per cent unserved energy in a given financial year.

348 See: https://www.aemo.com.au/Stakeholder-Consultation/Consultations/Reliability-Standard-Implementation-Guidelines

They are calculated by AEMO through market modelling, taking into account inter-regional reserve sharing capability, network system normal constraints, and generation forced outage probabilities. Due to the time-consuming nature of the minimum reserve level analysis, they are only updated occasionally. The last time minimum reserve levels were updated was in 2010. As from February 2018, minimum reserve levels will no longer be required since AEMO is moving to a probabilistic assessment of unserved energy.

The minimum reserve level that is used in medium-term PASA for each region is derived from a series of probabilistic monte carlo studies that aim to determine the minimum local generation required in each region to target 0.002 per cent unserved energy in all regions. In other words, the reliability standard is translated into an operational trigger in the form of minimum reserve level equations.

The minimum reserve level is expressed relative to 10 per cent POE maximum demand conditions. Currently static minimum reserve level equations are applied in medium-term PASA for Queensland, NSW, and Tasmania regions while shared minimum reserve level equations are applied to Victoria and South Australia regions.

AEMO constructs system normal and outage constraint equations for the medium-term PASA time frame based on the capabilities of the medium-term PASA process and the data available for this time frame.

For example, no FCAS constraints are included and constraints are formulated on a daily resolution using peak forecast data. Many constraint equations are simplified versions of their dispatch counterparts or a single static value (e.g. Vic-SA <= 250 MW). Thus a more simplified version of the network is represented in medium-term PASA, providing a high level approximation of power transfer capabilities.

Calculating minimum reserve levels

The below section sets out our understanding of how minimum reserve levels are calculated, based on the ROAM Consulting report that assisted with the recalculation of minimum reserve levels in 2010 (last time they were set).[349]

Step 1 determine the generation capacity required to meet the reliability standard

The simulation aims to reflect the levels of generation, forced outage rates, transmission constraints, and demand that will occur in the simulation years. The levels of generation are adjusted so that the expected estimated unserved energy is exactly (in practice, very close to) 0.002 per cent in each region simultaneously, that is, in order to just meet the reliability standard.

Levels of generation are generally adjusted by removing whole units from the generation available, rather than by scaling the generation available in each region.

349 ROAM Consulting's report is available at https://www.aemo.com.au/media/Files/Other/electricityops/0249-0002%20pdf.pdf

The 0.002 per cent regional unserved energy target is based on an assessment of a range of probabilistic peak demand forecasts. In the 2010 minimum reserve level simulation studies, 100 monte carlo iteration simulations of the system have been completed for demand POE load traces corresponding with 5 per cent, 10 per cent, 50 per cent and 90 per cent POE. The unserved outcomes from these four simulations are then weighted[350] against certain probabilities to calculate an expected unserved energy. This simulation uses medium-term PASA inputs and assumptions.

The simulations work out the minimum level of generation needed to meet that target, given transmission constraints, probabilistic assumptions for forced outage rates and demand-side participation, given the various demand levels. It should be noted that FCAS is not explicitly taken into account. This yields the expected unserved energy, which is a weighted average rather than 10 per cent POE unserved energy.

Step 2 – establish the minimum reserve level by comparing the generation capacity derived in step 1 with the 10 per cent POE maximum demand

The minimum reserve level is calculated by comparing the generation capacity derived in step 1 against the 10 per cent POE peak demand, taking into account interconnection flows and regional committed demand-side participation.

minimum reserve level = generation capacity to meet the reliability standard + interconnector support + demand-side participation – 10 per cent POE demand

Minimum reserve levels can actually be negative within a region – this implies that local generation within the region can be below demand without USE occurring as a result of interconnection. For example, the -50 MW minimum reserve level in NSW means that the NSW region requires a minimum level of available local generation plus demand-side participation equal to its 10 per cent POE peak demand minus 50 MW.

Minimum reserve levels can also be shared as in currently the case with Victoria and South Australia. When there is little diversity between regional demands, they will tend to experience generation shortfalls at the same time and therefore the interconnector between those regions will tend to be unconstrained. In this situation, as was the case with the Victoria and South Australia regions, there is then available headroom on the interconnection between the regions to move away from the baseline minimum reserve levels and allow for reserve sharing.

Minimum reserve levels are published and the current levels are as below.

350 We understand that the weightings are: 16 per cent for 90 per cent POE; 67 per cent for 50 per cent POE; and 16 per cent for 10 per cent POE.

Table C.2 Minimum reserve levels (MW)

Region	Minimum reserve levels
Queensland	913
NSW	-1564
Tasmania	144
Victoria and South Australia (shared)	Vic reserve ≥ 205.00 5.88 x Vic reserve + SA reserve ≥ 1237.88 1.33 x Vic reserve + SA reserve ≥ 228.00 0.43 x Vic reserve + SA reserve ≥ -40.53 0.23 x Vic reserve + SA reserve ≥ -147.55 SA reserve ≥ -368.00

In order to remain consistent with the calculation of the minimum reserve level equations, the following interconnector headroom constraints (net import and export limit constraints) are applied:

- Queensland's minimum reserve level is assessed with 0 MW of maximum net import into Queensland
- NSW's minimum reserve level is assessed with 330 MW of minimum net export from NSW
- Victoria's minimum reserve level is assessed with 940MW of maximum net import into Victoria
- South Australia's minimum reserve level is assessed with 0 MW of maximum net import into South Australia.

Step 3 – declaring low reserve conditions

Medium-term PASA analyses minimum reserve levels against capacity reserves, and declares an low reserve condition if capacity reserves are insufficient to meet the minimum reserve level.

For this assessment a capacity adequacy linear programming model is used.

This capacity adequacy linear programming model maximises spare generation capacity (medium-term PASA considers scheduled and semi-scheduled generation only) in the NEM above the summation of 10 per cent POE regional demand forecasts and regional minimum reserve requirements subject to:

- PASA availability of generation and weekly energy limits (includes committed future generation)
- Power transfer capability of the power system with no planned network outages.

Where medium-term capacity reserves do not meet the required level, the deficit is shared on a pro-rata basis among regions subject to applicable interconnector constraints.

The outcome is an indication of the supply reliability in NEM over the medium-term PASA period (a low reserve condition is triggered) and is used as a key input to decide whether or not to procure the RERT.

C.3.4 Calculating reserve margins in medium-term PASA: from 15 February 2018

From 15 February 2018, the medium-term PASA assessment will be carried out at least weekly using two different model runs:

- Reliability run - to identify and quantify potential reliability standard breaches, and assess aggregate constrained and unconstrained capacity in each region, system performance and network capability
- Loss of load probability run- to assess days most at risk of load shedding.

The 2018 medium-term PASA reliability run will operationalise the reliability standard by assessing the level of unserved energy and evaluating the likelihood of reliability standard is being met through probabilistic modelling. The Reliability Run will be conducted weekly.

The 2018 medium-term PASA reliability run will use 200 monte carlo simulations on a set of predefined cases to assess variability in unserved energy outcomes. Demand and intermittent generation supply assumptions will vary for each case (10 per cent POE and 50 per cent POE), driven by different historical weather conditions. Within a case, the monte carlo simulations will vary with respect to unplanned generation outages based on historical forced outage rates.

The reliability run will be conducted in three phases:

1. Generate random patterns of forced outages and determine any other stochastic parameters required for each simulation run.
2. Split the two-year medium-term PASA horizon into two one-year periods that are solved at a reduced level of time detail to allow long-term energy constraints to be optimised so that resources subject to constraints are deployed at the most appropriate time. Inter-temporal constraints are decomposed into a set of ending targets for each weekly time frame selected for use in phase three.
3. Solve the entire horizon in shorter weekly steps with full half-hourly detail, using the weekly allocation targets determined in phase two. Medium-term PASA weekly energy limits are co-optimised with dispatch of other resources, including intermittent generation, to maximise the value of the energy limited resource.

Each simulation will produce an estimate of annual unserved energy, with the total 3,200 simulations providing insight into the distribution of annual unserved energy. AEMO will use a minimum of 50 per cent POE and 10 per cent POE demand levels, weighted appropriately, to assess the expected unserved energy as a weighted average across all simulations. Unserved energy results from 50 per cent POE and 10 per cent POE runs will be aggregated with 69.6 per cent weighting for 50 per cent POE and 30.4 per cent weighting for 10 per cent POE.

C.3.5 Calculating reserves in 2017 ESOO

The ESOO is based on probabilistic, time-sequential modelling. It models each scenario's specific demand and generation assumptions, and simulates hourly monte carlo simulations to determine potential future supply shortfalls.

These simulations capture the impact of key uncertainties, such as generator outage patterns, weather sensitive demand, intermittent generation availability, and coincidence of demand across regions.

The model performs an optimal electricity dispatch for every hour in the modelled 10-year horizon, with the aim of minimising system costs incurred in meeting operational consumption across the NEM, subject to generation capability, fuel availability, and transmission constraints. In cases where there is insufficient generation or demand-side participation to meet forecast demand, it results in USE.

For the 2017 ESOO, the following parameters were simulated for each NEM region:[351]

- The availability of generation capacity, accounting for planned and unplanned outages, and storage capabilities.
- The intermittent nature of wind and solar generation.
- Demand side participation.
- Transmission network limitations.
- Electricity demand projections under a range of weather conditions, including the impact of rooftop photovoltaic (PV) systems.

In total, 210 probabilistic simulations were run for each year in the modelled horizon for each scenario, representing the variable nature of forced generator outages, intermittent generation, and demand patterns across regions.

The breakdown of simulations was as follows:[352]

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351 AEMO, 2017 ESOO Methodology, https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2017/2017-NEM-ESOO-Methodology.pdf

352 Ibid.

- Demand under extreme weather conditions (10 per cent POE):
  - Seven historical reference years to represent variable patterns of intermittent generation and demand.
  - 20 generator forced outage patterns per reference year (monte carlo).
- Demand under moderate weather conditions (50 per cent POE):
  - Seven historical reference years to represent variable patterns of intermittent generation and demand.
  - 10 generator forced outage patterns per reference year (monte carlo).

The key output of the model is regional unserved energy, enabling assessment of whether the current reliability standard is expected to be met.

Expected unserved energy was derived by applying the following weightings to results from the moderate and extreme demand scenarios:[353]

- 30.4 per cent for 10 per cent POE
- 69.6 per cent for 50 per cent POE.

Where the expected unserved energy is above the reliability standard, the ESOO flags that the standard is not expected to be met. The year that happens is referred to as the low reserve condition point.

C.3.6 Calculating reserves in short-term PASA

The reliability standard is operationalised through the lack of reserve framework in the short-term period, i.e. six days into the future.

The pre-dispatch process also follows a similar methodology. The differences are limited to assumptions made with regards to network constraints and energy limits.

Step 1: Forecasting total reserve levels

At a high level, AEMO calculates a region's reserves as follows:

- amount of scheduled generation that has offered in its availability; plus
- forecast semi-scheduled generation and large non-scheduled generation; plus
- surplus reserve available from adjacent regions; less
- operational demand (which refers to electricity used by residential, commercial and large industrial consumers, as well as including non-scheduled generation).

353 Ibid.

Short-term PASA uses the following assumptions for demand and supply:

- demand forecasts use a 50 per cent POE half-hour demand based on expected weather patterns
- intermittent generation forecasts based on the Australian Wind Energy Forecasting System and Australian Solar Energy Forecasting System
- scheduled generation capacity and outages based on available capacity within the PASA availability.

Short-term PASA uses a series of linear programmes modelled as security-constrained linear programme problems to be solved by the short-term PASA solver.

Step 2: Calculating LOR level

The Commission made a final rule on 19 December 2017 to change the way that lack of reserve levels are calculated so that they more accurately reflect the risk of involuntary load shedding. According to AEMO's new methodology which is set out in its guidelines, initially, the lack of reserve levels will still consist of the size of credible contingencies at a minimum, with an adjustment made for forecasting error (only when the error is larger than the credible contingency size), based on probabilistic modelling of reserves.[354]

Step 3: Declaring a lack of reserve

AEMO declares the relevant lack of reserve when reserve levels in step out fall below the trigger levels in step 2. Lack of reserve levels are forecast in the short-term PASA and pre-dispatch. Actual lack of reserve may also be declared in real time.

C.4 Intervention mechanisms

There are various ‘last resort’ intervention mechanisms available to AEMO that enable it to deal with actual or potential supply shortages of varying degrees of severity, typically to be used as a safety net should the market fail or be expected to fail to meet the reliability standard. In each instance, the mechanism in question is designed to be operationalised in a way that results in the smallest disruption possible to the ongoing operation of the market. These intervention mechanisms include the following:

- AEMO has Reliability and Emergency Reserve Trader (RERT) obligations. These allow AEMO to contract for reserves ahead of a period where reserves are projected to be insufficient to meet the reliability standard. AEMO may also contract reserves to maintain power system security where practicable.
- In addition, if there is a risk to the secure or reliable operation of the power system, AEMO can issue directions or instructions under NER clause 4.8.9 to:

— Direct a generator to increase its output, but only if this is possible and can be done safely. To be effective, the generator must have enough time to 'ramp up'. If the generating unit is not already generating, it can take time for it to begin to ramp up.

— Direct a large energy user, such as an aluminium smelter, to temporarily disconnect its load or reduce demand. This only applies to large users who are registered participants.

If there continues to be a shortfall in supply, even after these measures have been operationalised, AEMO may require involuntary load shedding as a last resort to avoid the risk of a wider system blackout, or damage to generation or network assets.[355] These intervention mechanisms provide an important ultimate safety net when there is insufficient generation capacity to maintain adequate reserves above demand, to minimise the adverse impacts on customers of involuntary load shedding.

The section below discusses directions and clause 4.8.9 instructions in more detail. Chapter 7 and appendix D of this report discusses the RERT.

C.4.1 AEMO's powers to issue directions and clause 4.8.9 instructions

Clause 4.8.9 of the NER gives AEMO the power to issue both directions and clause 4.8.9 instructions to registered participants where it is necessary to do so to maintain or return the power system to a secure, satisfactory or reliable operating state.

The NER specify high-level conditions under which AEMO can issue a direction or instruction:

- if there has been a failure of the market to deliver sufficient reserves
- or if the secure and safe operation of the system is under threat.

AEMO may also issue directions or instructions if it is satisfied that it is necessary to do so for reasons of public safety or to maintain power system security under section 116 of the NEL.

Directions are issued when AEMO[356] requires a registered participant to take action for the above reasons in relation to scheduled plant or a market generating unit (i.e. plants with controllable output). For example, AEMO can direct a scheduled plant to reduce load or a generator to increase production.

354 For further information on this, see chapter 1.

355 Network businesses are required to shed load in accordance with schedules provided by the relevant state government.

356 Or a person authorised by AEMO.

Instructions are issued when AEMO[357] requires a registered participant to take some other action for the above reasons. For example, a clause 4.8.9 instruction to a network service provider to disconnect load.

Under clause 4.8.9(c) of the NER, a registered participant must use its reasonable endeavours to comply with a direction or clause 4.8.9 instruction unless to do so would, in the registered participant's reasonable opinion, be a hazard to public safety, or materially risk damaging equipment, or contravene any other law. This clause is classified as a civil penalty provision.

Generators must comply with directions regardless of the financial implications and they could incur losses as a result. Where a direction affects a whole region, intervention or 'what if' pricing would be required. Under 'what if' price, the spot price is determined as if the direction had not occurred. Directions also have a direct cost for consumers since both directed participants, as well as other participants affected by a direction, may be eligible to seek compensation, the costs of which are ultimately recovered from consumers.

Participants issued with clause 4.8.9 instructions are not entitled to compensation.

How directions operate in practice

In practice, AEMO issues directions for either security reasons (to keep the system operating to a secure operating state) or reliability reasons (to keep the system operating to a reliable operating state) most often.

Reliability

AEMO undertakes a number of planning and forecasting processes that seek to assess whether the power system meets, and is projected to meet, the reliability standard, as discussed above.

If a shortfall of reserves is projected, AEMO uses a variety of ways to inform the market to try and elicit a market response, for example, through market information reports and by issuing low reserve condition and lack of reserve notices.

AEMO may also use informal methods such as phoning generators or large loads to get a response. If these fail to elicit a market response, then AEMO can exercise one of the intervention mechanism (using the RERT, directions or instructions), at its discretion.

The NER also require AEMO to minimise the market impact of its intervention, including in terms of the number of affected participants, and the cost/compensation to affected and directed participants, which it also considers when deciding which mechanism to use.

357 Or a person authorised by AEMO.

The typical course of actions is as follows. AEMO first forecasts a reserve shortfall, informs the market through a lack of reserve notice and seeks a response. If the market does not respond to a lack of reserve notice (typically a LOR2), AEMO may choose to intervene. It may choose any of the options available to it, depending on the circumstances and keeping cost impacts in mind.

This process is similar to how AEMO would approach the RERT.

Security

While outside the scope of this Review, it is still useful to understand how AEMO uses directions to manage security events. Clause 4.2.4 of the NER states that the power system is defined to be in a secure operating state if, in AEMO's reasonable opinion, taking into consideration the appropriate power system security principles described in clause 4.2.6:

- the power system is in a satisfactory operating state
- the power system will return to a satisfactory operating state following the occurrence of any credible contingency event or protected event in accordance with the power system security standards.

AEMO has a maximum of 30 minutes to return the power system to a secure operating state.

It should be noted that reliability events will often turn into security events if not alleviated early enough.

AEMO will issue a direction for system security purposes, if, for example:

- There is not enough FCAS available to handle any credible contingency event.
- There is a violation of a system security requirement such as the requirement to maintain a certain number of thermal synchronous generating units online at all times.

Similar to reliability events, AEMO will issue a market notice when its processes, typically pre-dispatch, forecast a power system security violation. AEMO then issues a market notice advising the market of the forecast violation and seeking a market response that would address the violation.

C.4.2 Processes that AEMO follows when issuing a direction

According to AEMO's operating procedures and to comply with the NER, when AEMO considers that it might have to intervene in the market by issuing a direction, it will:

- publish a market notice of the possibility that AEMO might have to issue a direction so that there is an opportunity for a market response to alleviate that need
- determine and publish the latest time for intervention
- determine which registered participant should be the subject of a direction or clause 4.8.9 instruction
- issue a direction or clause 4.8.9 instruction verbally to the relevant registered participant, confirming whether it is a direction or clause 4.8.9 instruction
- issue a participant notice confirming the direction or instruction
- issue a market notice advising of the event
- revoke the direction or instruction as soon as no longer required.

Reliability versus security directions

The efficacy of reliability directions is influenced by the physical and technical limits of the plant. This is a known limitation. For example, the effectiveness of directions to wind generators to increase generation may be limited by the intermittent nature of that plant and the effectiveness of directions to thermal generators may be limited by the time it takes for offline thermal generating units to come online.

Reliability directions typically occur at very tight demand-supply balance periods where, presumably, the prevailing price is close to the market price cap. It could therefore be argued that most generating units, if online and functioning properly, would already be in the market, or if not, would most likely recover their costs.

On the other hand, security directions can occur when the system is reliable and there is a lot of generation. Prices may actually be quite low at that point in time. Analysis of recent interventions, and the 'drivers' for these interventions are discussed below.

The AEMC's frameworks for inertia and system strength commence on 1 July 2018 and place an obligation on TNSPs to make minimum levels of both these services available from 1 July 2019. However, in relation to system strength, AEMO has declared an NSCAS gap in South Australia which, under the transitional arrangements in the rules, will bring forward the timeframe for the TNSP to meet the obligation under the AEMC's frameworks.

ElectraNet has agreed to provide the minimum level of system strength by 30 March 2018. It is expected that the minimum level of system strength to be provided by ElectraNet will mean that AEMO will no longer be required to provide directions to generators to maintain system security.

C.4.3 Nature of recent interventions

We have had a look at what has occurred in relation to interventions over the period 9 October 2016 and 19 October 2017. In this period there were 15 interventions (see Table C.3), each of which involved one or more directions.

Table C.3 Intervention events between 9 October 2016 and 19 October 2017

Date	Region of direction(s)	Reason for intervention	Intervention pricing?
9 October 2016	SA	Requirement for synchronous generation in SA	No
11 October 2016	SA	Requirement for synchronous generation in SA	No
1 December 2016	SA	Management of FCAS requirements.	Yes
1 December 2016	VIC	Unexpected system configuration requiring intervention to invoke a system security constraint.	No
8 February 2017	SA	Scarcity of energy requiring load shedding.	Yes
9 February 2017	SA	Requirement for additional available capacity to address forecast Lack of Reserve 2 condition.	Yes
10 February 2017	NSW	Scarcity of energy requiring load shedding.	Yes
1 March 2017	SA	Requirement for additional available capacity to address forecast Lack of Reserve 2 condition.	Yes
28-29 March 2017	QLD	Directions to maintain secure system given the credible loss of multiple transmission lines during cyclone in Queensland.	No
25 April 2017	SA	Requirement for synchronous generation in SA.	Yes
26 April 2017	SA	Requirement for synchronous generation in SA.	Yes
2-4 September 2017	SA	Requirement for synchronous generation in SA.	Yes
17 September 2017	SA	Requirement for synchronous generation in SA.	Yes

Date	Region of direction(s)	Reason for intervention	Intervention pricing?
22-24 September 2017	SA	Requirement for synchronous generation in SA.	TBC
7-8 October 2017	SA	Requirement for synchronous generation in SA.	TBC

Source: Endgame Economics analysis of AEMO event reports and market notices.

Most of these interventions have been for system security concerns and are unrelated to the scarcity of energy or frequency control ancillary services (FCAS). We note that:

- eight of the interventions related to a requirement for synchronous generation in South Australia; and
- two of the interventions (i.e. on 1 December 2016 in Victoria, and on 28-29 March 2017 in Queensland) were for other reasons that are unrelated to a scarcity of energy or FCAS.[358]

Historically there have been few events of intervention pricing. However, in the past 12 - 18 months the number of intervention events has increased considerably, with around 15 intervention events with 25 or so directions. There has been eight direction events for system strength since July this year. The nature of the directions are such that it involves many units and some of them are occurring over multiple days.

C.4.4 Impact of interventions on the market

Interventions are designed to have as little distortionary effect on the operation of the market as possible.[359] Furthermore, to further minimise market distortions, pricing during an intervention event is set by 'what-if' pricing, discussed next.

Pricing during interventions

Intervention pricing occurs when AEMO intervenes in the market through either a direction issued in accordance with clause 4.8.9 or when the RERT is dispatched (each an "AEMO intervention event").[360] Clause 4.8.9 instructions to network service providers to shed customer load involuntarily are not an AEMO intervention event.

358 The intervention on 28-29 March 2017 required a direction to a generator in northern Queensland to maintain security in the event of a separation of the northern Queensland. Clause 3.9.7 of the Rules establishes that in the event of such a separation, the generator's offer would not affect the determination of the dispatch price. It follows that altering the market price cap and cumulative price threshold would not change the incentives to generators of providing energy under these circumstances.

359 See, for example, RERT principles as set out in clause 3.20.2(b) of the NER.

360 See Chapter 10 of the NER for a description.

Instead, the market price cap is automatically applied when involuntary load shedding occurs.

For intervention events, AEMO uses 'what if' pricing. Under ‘what if’ price, the dispatch price is determined as if the intervention had not occurred. If there is a direction, then AEMO goes through a process to work out whether the NER 'what if' pricing applies (see Box C.1). If the RERT is dispatched, then 'what if' pricing applies automatically.

Box C.1 'What if' pricing in practice

An intervention price dispatch interval is declared when AEMO intervenes in the market to direct a participant to operate plant other than in accordance with dispatch instructions (i.e. issues a direction), or activates a reserve contract (i.e. the RERT).

AEMO is provided some time (of up to two dispatch intervals) to commence intervention pricing after the intervention takes effect, but must use reasonable endeavours to do so as soon as practicable.

The Regional Reference Node (RRN) test

Where a direction affects a **whole region** (i.e. if the RRN test below is passed), intervention or 'what if' pricing is required. Under 'what if' pricing, the dispatch price is determined as if the direction had not occurred.

AEMO will only initiate ‘intervention’ or ‘what if’ pricing if the RRN test is passed. The RRN test only applies to directions and not to the RERT. The RRN test is met when a direction in respect of plant at the RRN would have avoided the need for the direction. If it is not met, then normal price settings continue.

The test is as such: The RRN test is met, i.e. intervention pricing applies in situations where equivalent intervention in respect of plant located at the RRN would have removed the need for the intervention actually given.

If a generator is directed to operate its generating plant to address a supply deficiency that is confined to a part of the network that does not include the regional reference node, then intervention pricing is **not** invoked. This might occur for example if a network constraint was restricting supply to a remote area near the directed generator. In this instance, normal pricing occurs.

If the direction affects the entire region, i.e. if being directed at the RRN would have avoided the need for the actual direction given, then intervention pricing does occur.

AEMO is currently reviewing its intervention pricing methodology, with the intention of submitting a rule change request to the AEMC to amend the existing arrangements. This work was commenced following the energy direction in South Australia on 9

February 2017, where the intervention pricing outcomes deviated significantly from the dispatch outcomes.

Box C.2 explains how intervention pricing currently works in the national electricity market dispatch engine (NEMDE).

Box C.2 NEMDE runs for intervention pricing

Intervention pricing is meant to preserve the market signals that would have existed had the intervention not taken place, and it is used as the dispatch price and market ancillary services prices for the purposes of spot price determination and settlements.

Two special constraint equations (known as what-if and intervention) are invoked in NEMDE to determine the pre-intervention dispatch (i.e. what if the intervention had not occurred) of the scheduled plant subject to the intervention and the required intervention dispatch level.

Market prices and dispatch targets of generation and interconnectors are calculated twice for each dispatch interval:

- The first calculation takes into account all of the constraint equations, including the intervention and what-if constraint equations. This first calculation sets dispatch outcomes for all scheduled plants. In other words, the dispatch targets from this run are used to dispatch the market a way that is consistent with AEMO’s intervention.
- The second calculation ignores the intervention constraint equation, so that the what-if constraint can take effect. The dispatch targets from this run are published but can be ignored for practical purposes. The important information from this run is the regional energy and ancillary service prices which are published as the official market prices for the dispatch interval.

To be clear, the second run simulates a hypothetical scenario whereby the initial MW (actual output at the beginning of a dispatch interval) of each generator and interconnector is assumed to be the same as the dispatch instruction issued in the previous dispatch interval, with all other inputs being retained from the dispatch run. The price is, therefore, set for the quantity that would have been dispatched if the intervention had not occurred.

Simply put:

- The first run includes the intervention in the form of a constraint and is used to determine **dispatch targets**.
- The second run is used to determine **prices** had the intervention not occurred.

Compensation

As mentioned previously, generators must comply with directions regardless of the financial implications and they could incur losses as a result. However, following a direction, compensation may be payable to:

- Directed Participant:[361] for the generating units or services that were the subject of the direction.
- Affected Participants:[362] for scheduled generators or scheduled network service providers that were not the subject of the direction, but which had their dispatched quantity affected by the direction.[363]
- Eligible Persons:[364] for persons who have a right to receive a portion of net settlement residue from AEMO[365] (and ultimately consumers) where, as a result of the direction, there has been a change in flow of a directional interconnector, for which the eligible person holds settlement residue distribution units for the intervention price trading interval.

AEMO calculates the amount of compensation the directed participants are entitled to receive based on the 90th percentile spot price level for the 12 months prior and the quantity of energy dispatched during the directed dispatch intervals. Participants may also be entitled to additional compensation, e.g. a directed participant may be entitled to compensation to cover loss of revenue and net direct costs minus trading amounts for energy and market ancillary services and minus any compensation for directed services that has been determined. Additional compensation claims are subject to different calculations based on the type of claim made.

The compensation amount, interest, and an independent expert fee if applicable (i.e. AEMO may ask an independent expert to assess participants' compensation entitlements), are recovered from market participants.

Affected participants are entitled to receive compensation from AEMO following an AEMO intervention event (e.g. if the RERT is dispatched).[366]

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361 A scheduled generator, semi-scheduled generator, market generator, market ancillary service provider, scheduled network service provider or market customer the subject of a direction.

362 See definition of 'affected participant' in Chapter 10 of the NER.

363 Or for scheduled generators or scheduled network service providers that were the subject of the direction, but which had other generating units or other services (which were not the subject of that direction) affected by that direction.

364 Clause 3.18.2(b) of the NER.

365 That is, the eligible person has a right to receive a portion of the net settlements residue because that eligible person has a settlements residue distribution agreement with AEMO in accordance with clause 3.18.1(b)(1) of the NER..

366 Clause 3.12.2(a)(1) of the NER.

D The Reliability and Emergency Reserve Trader

This appendix is structured as follows:

- section D.1 provides a brief history of the RERT
- section D.2 sets out the NER framework for the RERT
- section D.3 sets out the RERT guidelines
- section D.4 summarises operational procedures and processes with respect to the RERT.

D.1 The RERT

The RERT is an existing mechanism in the NEM that allows AEMO to contract for additional reserves not otherwise available in the market for a period ahead of when AEMO projects there to be reserve shortfalls. A projected reserve shortfall is where the amount of generation capacity is projected to be below the level consistent with the reliability standard (0.002 per cent expected unserved energy).The RERT is a safety net that AEMO can use in the event that it projects that the market will not meet the reliability standard, and where practicable, to maintain power system security.

D.1.1 History of a reserve safety net in the NEM

Some form of mechanism (reserve trader provisions) for the market operator to contract for reserves, has been a feature of the NEM since its commencement in December 1998. At the time, such a mechanism was deemed to be necessary due to uncertainty around how the market would respond to price signals, but the intention was that it would be removed after a period of time. Consequently, at the start of the NEM, the reserve trader mechanism had a sunset clause of 30 June 2003.

Over time, periodic reviews of the reserve trader provisions have led to various amendments of the mechanism, including postponing its expiry date, as well as changes to its scope and operation. The current mechanism, the Reliability and Emergency Reserve Trader (RERT), discussed in more detail below, built on the prevailing mechanism at the time and was developed as part of the Reliability Panel's 2007 *Comprehensive Reliability Review*.

In its final report, the Reliability Panel concluded that, although the operation of the reserve trader leads to market distortion that would not be necessary under ideal conditions, the prevailing market conditions were such that a revised form of the provisions needs to be maintained for a defined period of time. It noted that, ideally, in the longer-term, the market should be able to operate without the need for a distortionary intervention mechanism. The Panel also noted that although it is a market distortion, on balance the costs are minimal when compared to the costs in the market overall and that if better specified, the mechanism could lead to less of a distortion.[367]

The Reliability Panel therefore submitted a rule change request to the Commission to give effect to a redesigned Reserve Trader (the Reliability Emergency Reserve Trader (RERT)) mechanism to be implemented in the short-term to assist maintaining the future reliability of the NEM.

When considering the rule change request, the Commission agreed that with the Panel's conclusion that such a mechanism has a role in the market given the expected tightening of the demand-supply balance (at the time), despite the potential distortionary effects on the market.[368] The Commission also agreed that proposed modifications would minimise the distortionary effects of the mechanism.

The RERT was therefore incorporated into the NER in June 2008, and replaced the reserve trader provisions. The RERT was specifically designed to impose minimal distortion on the operation of the NEM. However, it still had a sunset clause – with the Commission noting this would provide a signal to the market that the mechanism would not be necessary under ideal conditions.[369]

In March 2012, the Commission extended the RERT sunset clause to 30 June 2016. In December 2015, the COAG Energy Council submitted a rule change request to extend the RERT to 2019.[370] As part of that rule change, in 2016, the Commission decided to extend the RERT indefinitely as a result of continued uncertainty in the market. In its decision, the Commission noted that ongoing uncertainty raised the likelihood that future electricity demand may not be adequately met, and that the market responses to address these projected shortfalls may be insufficient.[371]The Commission also noted in that the RERT is more efficient than the other forms of interventions (that is, directions and clause 4.8.9 instructions) to manage potential shortfalls.[372]

The RERT is now a permanent feature[373] of the NEM's reliability frameworks and falls under the intervention umbrella of the reliability frameworks.

D.2 NER framework for the RERT

The NER provide the high-level framework for the RERT,[374] including setting out the RERT principles[375] and requiring the following:

367 AEMC, Comprehensive Reliability Review, Final Report, 21 December 2007.

368 AEMC, NEM Reliability Settings: Information, Safety Net and Directions, Final Determination, 1 July 2008.

369 Ibid.

370 AEMC, Extension of the Reliability and Emergency Reserve Trader, Final Determination, 23 June 2016.

371 Ibid.

372 Ibid.

373 Albeit subject to rule change requests.

- The Reliability Panel to develop and publish RERT guidelines to provide guidance to AEMO as to what it must take into account when procuring and exercising the RERT.[376]
- AEMO to develop, publish and amend procedures for the exercise of the RERT.[377]

Additional details regarding the detailed design and operational parameters of the RERT are contained in the NER, RERT guidelines and procedures.

Box D.1 RERT terminology

The terminology used in each of the NER, RERT guidelines and AEMO's procedures with regards to the RERT have some overlap and may cause some confusion. In order to more clearly explain how the current framework operates, the Commission has minimised the use of the word "exercise" except when referring to particular clause of the NER or the RERT guidelines. The Commission, instead, uses the following terminology:

- when referring to AEMO entering into RERT contracts, this is referred to as procuring the RERT or the procurement trigger
- when referring to AEMO actually dispatching scheduled reserves or activating unscheduled reserves under reserve contracts, that is, when the reserves are actually used in real time, this is referred to simply as dispatching the RERT or the dispatch trigger.

Triggering the RERT or exercising the RERT may refer to either one (or both) of these two conditions depending on the context and on the particular stakeholder. For example, the NER use exercise in the context of "dispatch " or "activate" but the RERT Guidelines and AEMO's procedures use the term in the context of both "procure" and "dispatch"/"activate" under RERT.

Box D.1 explains the terminology used by the Commission in this interim report.

D.2.1 RERT principles

When procuring and dispatching the RERT, AEMO must do so in accordance with the following RERT principles as set out in the NER:[378]

- actions taken are to be those which AEMO reasonably expects, acting reasonably, to have the least distortionary effect on the operation of the market

374 Rule 3.20 of the NER.

375 Clause 3.20.2(b) of the NER.

376 Clause 3.20.8 of the NER.

377 Clause 3.20.7(e) of the NER.

378 Clause 3.20.2(a)(3) and 3.20.2(b) of the NER.

- actions taken should aim to maximise the effectiveness of reserve contracts at the least cost to end use consumers of electricity.

These highlight two core principles of the NEM:

- If the market is functioning well, investment and operational signals should be sufficient to meet reliability. Contracting for additional reserves, even when outside of the market, can have distortionary effects on investment and operations. This could lead to a situation whereby reliability is met at a higher cost then it would if left to the market alone. As a result, minimising the distortionary effect of any intervention mechanism is crucial.

- Any intervention mechanism must have regard to the national electricity objective - the long-term interest of consumers is preserved by making sure that reserves procured through an intervention are done at the least-cost.

D.2.2 Procurement trigger

Under the NER,[379] AEMO may determine to enter into reserve contracts to ensure that the reliability of supply in a region meets the reliability standard for that region, and if practicable, to maintain power system security.[380]

The NER do not contain a specific limitation on the number of times that AEMO can procure the RERT. However, AEMO's discretion to procure the RERT is limited by a number of factors, including:

- that the entry into reserve contracts must be done for the purposes of ensuring that the reliability of supply in a region meets the reliability standard for that region *and* where practicable, to maintain power system security[381]

- AEMO must have regard to the RERT principles, RERT guidelines and the NEO when determining whether to procure reserves and the quantity of those reserves[382]

- AEMO must consult with relevant participating jurisdictions with respect to its determination of whether to procure and how much to procure.[383]

D.2.3 Procurement lead time

Under the NER[384], AEMO must not enter into a reserve contract, or renegotiate, more than 10 weeks prior to when AEMO reasonably expects the reserves to be needed.

379 Clause 3.20.3(b) of the NER.

380 Ibid.

381 Clause 3.20.3(b) of the NER.

382 Clause 3.20.2(a); 3.20.2(c) of the NER and section 49(3) of the NEL.

383 Clause 3.20.3(c) of the NER.

D.2.4 Procurement amount

The NER do not prescribe the amount that AEMO should procure once it has identified a potential shortfall.

In relation to reliability, the NER *imply* that AEMO can only procure so much as would be reasonably necessary to ensure that the reliability standard is met.[385] However, given that there is an element of discretion in how AEMO operationalises the standard and there are certain subjective assessments it makes in operationalising the standard, there remains a fair degree of discretion in the level of reserves it may procure under the framework. In other words, how AEMO operationalises the reliability standard in an operational timeframe may influence how much reserves it procures.

Further, determining the procurement amount becomes more complicated when considering that AEMO may also procure reserves to maintain power system security. Therefore, there may be some discretion for the system operator to procure in excess of reserves needed to meet the reliability standard in order to maintain power system security.

D.2.5 Not otherwise available to the market

To minimise distortions, reserves contracted under the RERT must not otherwise be available in the market. Under the NER, AEMO must not contract for scheduled reserves if such reserves are otherwise available for dispatch in the trading interval to which the contract would relate.[386] The NER also specify that any reserve contracts entered into must contain a provision that provides that the other party to the contract has not and will not otherwise offer the reserve which is the subject of the contract in the market for the trading intervals to which the contract relates.[387]

In other words, the capacity must not otherwise be made available to the market for the relevant trading intervals for the duration of the contract.

D.2.6 Type of reserves

The NER specify that AEMO may enter into one or more contracts with any person in relation to the capacity of:[388]

- scheduled generating units, scheduled network services or scheduled loads (being scheduled reserve contracts)
- unscheduled reserves (being unscheduled reserve contracts).

384 Clause 3.20.3(d) of the NER.

385 Clauses 3.20.2(a) and 3.20.2(b) of the NER.

386 Clause 3.20.3(h) of the NER.

387 Clause 3.20.3(j) of the NER.

388 Clause 3.20.3(a) of the NER.

As such, the NER currently allows for all types of technologies, including demand-side participation, to participate in the RERT. The NER is not prescriptive about exactly how the RERT products and contracts should be structured, other than they should not be otherwise available to the market, as discussed above.[389]

D.2.7 Payment structure

The NER do not prescribe any particular structure of payments under the reserve contracts.

D.2.8 Who pays for the RERT

The NER require that AEMO's costs associated with contracting for the provision of reserves be met by fees imposed on market customers in the region where the RERT has been procured and/or dispatched.[390]

D.2.9 Information provided to the market

If the RERT is dispatched, the NER require AEMO to, as soon as practicable thereafter, publish a report detailing a number of things, including:[391]

- the circumstances giving rise to the need to dispatch reserves
- the basis on which it determined the latest time for that dispatch and on what basis it determined that a market response would not have avoided the need for dispatch
- the changes in dispatch outcomes as a result of the dispatch of reserves
- the process implemented by AEMO to dispatch reserves.

The remainder of clause 3.20.6 of the NER requires AEMO to provide more information to the market, including reporting on the cost and recovery of the cost of the RERT.

D.2.10 Dispatching the RERT

In the first instance, AEMO must determine the latest time for exercising the RERT.[392] Once such time has arrived, the NER state that AEMO may dispatch reserves to ensure that the reliability of supply meets the reliability standard, and where practicable, to

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389 The NER does, however, prescribe that the Reliability Panel develops the RERT guidelines that should set out certain requirements with regard to contracting, for example, the process for tendering of the contracts.

390 Clause 3.15.9(a) of the NER.

391 Clause 3.20.6(a) of the NER.

392 Clause 4.8.5A and clause 4.8.5B of the NER.

maintain power system security.[393] AEMO must also take into account the RERT guidelines before dispatching the RERT.[394]

Further, during periods of supply scarcity, AEMO must use its reasonable endeavours to act in accordance with the following sequence:

- all valid dispatch bids and offers submitted by scheduled generators, semi-scheduled generators or market participants are dispatched (including those priced at the market price cap)[395]
- then, after all such bids and offers are exhausted, AEMO may exercise the RERT under rule 3.20, and[396]
- finally, if necessary, implement any further corrective action under clauses 4.8.5B and 4.8.9 (namely, issue directions and clause 4.8.9 instructions).

D.2.11 Dispatch prices when the RERT is dispatched

The RERT is an AEMO intervention event under the NER, which requires AEMO to use intervention pricing.[397]

The purpose of the intervention pricing regime is to restore price signals, that is, to preserve the market signals that would have existed had the intervention not taken place. This is to minimise the distortions created by the RERT. Intervention pricing is discussed in more detail in appendix C.

D.3 RERT guidelines

As mentioned, the NER require the Reliability Panel to develop the RERT guidelines, which must include:

- what information AEMO must take into account when deciding whether to exercise the RERT[398]
- the actions that AEMO may take to be satisfied that reserves contracted under the RERT are out of market[399]

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393 Clause 3.20.7(a) of the NER.

394 Clause 3.20.7(f) of the NER.

395 Clause 3.8.14(a) of the NER. This is subject to any plant operating restrictions associated with the relevant AEMO intervention event and any adjustments that may be necessary in order to take any further corrective action under clause 3.8.14(c).

396 Clause 3.8.14(b) of the NER. This is subject to any plant operating restrictions associated with the relevant AEMO intervention event and any adjustments that may be necessary in order to take any further corrective action under clause 3.8.14(c).

397 Clause 3.9.3 of the NER.

398 Clause 3.20.8(a)(1) of the NER.

399 Clause 3.20.8(a)(3) of the NER.

- any additional assumptions about key parameters that AEMO must take into account in assessing cost effectiveness[400]
- additional forecasts that AEMO should take into account prior to exercising the RERT.[401]

The RERT guidelines[402] were last updated in 2016 following the Commission's decision to remove the long-notice RERT in the NER without any sunset clauses.[403]

D.3.1 RERT principles

Under the NER, the RERT guidelines must provide guidance on the relevance of the RERT principles to the exercise of the RERT.[404]

Least distortionary

The RERT guidelines state that when exercising the RERT, actions should be taken that AEMO reasonably expects to have the least distortionary effect on the operation of the market, both in relation to the short term impact on the spot prices and the long term impact on investment signals. In determining the action to take, AEMO must consider:[405]

- how it seeks offers and how it contracts for reserves
- in relation to scheduled reserve contracts, setting the dispatch price and ancillary service prices for an AEMO intervention price dispatch interval at a value which AEMO, in its reasonable opinion, considers would have applied had the AEMO intervention event not occurred (that is, 'what if pricing').

Cost of the RERT

The RERT guidelines provide additional guidance as to the cost effectiveness of the RERT, and in particular, require AEMO to consult with the relevant participating jurisdictions when considering the cost effectiveness of the RERT.[406] The guidelines

400 Clause 3.20.8(a)(5) of the NER.

401 Clause 3.20.8(a)(7) of the NER.

402 Reliability Panel, Reliability Standard and Settings Guidelines, 1 December 2017. Hereafter, these are referred to as the "RERT guidelines".

403 AEMC, Extension of the Reliability and Emergency Reserve Trader - Consultation paper, 14 June 2016, p. 16

404 Clause 3.20.8(a)(2) of the NER.

405 See section 5 of the RERT guidelines.

406 Noting that clause 3.20.3(c) of the NER also requires AEMO to consult with jurisdictions when entering into contracts.

specify the following factors as being relevant to this consideration and consultation:[407]

- the cost of the reserve contracts for the amount of reserves to be contracted
- payment to be made when reserves are dispatched
- penalties accruing to AEMO should AEMO cancel a reserve contract early
- the nature of the reserves being offered (for example, how firm the capacity is)
- the duration of the projected capacity shortfall
- the size of the projected capacity shortfall in MW
- the likelihood of the proposed capacity shortfall being resolved.

In addition, for the short-notice RERT, the RERT guidelines suggest that AEMO should, when entering into contracts:[408]

- consult in advance with the jurisdictions to determine a maximum average price threshold (in $/MWh) that AEMO should pay to dispatch reserve contracts in the relevant region (reflecting the opportunity cost of shedding customer load in that region)
- exclude in advance entities from the RERT panel that have an average cost (in $/MWh) that is greater than the maximum average price threshold approved by the respective jurisdiction.

D.3.2 Procurement of the RERT

The RERT guidelines specify what AEMO may take into account when it is determining whether to enter into contracts for the RERT (procurement triggers):[409]

- To procure the medium-notice RERT, AEMO may take into account the outcomes of medium-term PASA, Energy Adequacy Assessment Projections and any other information it thinks is necessary, for example, confidential information received from a generator warning of a potential reduction in capacity
- For the short-notice RERT, AEMO may take into account the outcomes of the short-term PASA and pre-dispatch process and any other information it thinks is relevant.

The guidelines do not limit the number of times that AEMO can procure the RERT.

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407 See section 5 of the RERT guidelines.

408 See section 8.2 of the RERT guidelines.

409 See section 4.1 of the RERT guidelines.

D.3.3 Procurement lead time

The RERT guidelines provide further guidance on this point, specifying two types of RERT based on how much time AEMO has to procure the RERT prior to the shortfalls occurring:[410]

- medium-notice RERT - between ten and one week's notice of a projected reserve shortfall
- short-notice RERT - between seven days' and three hours' notice of a projected reserve shortfall.

D.3.4 Not otherwise available to the market

The RERT guidelines specify the actions that AEMO may take to be satisfied that RERT reserves are not being offered into the market, including:[411]

- for medium-notice situations, AEMO may, for example, enter into an undertaking to that effect with the relevant counterparty or making enquiries in the market to that effect
- for short-notice situations, confirm with the RERT panel that reserves they are offering are not available to the market as a result of another arrangement.

D.3.5 Contracting for the RERT

The RERT guidelines provide some guidance to AEMO as to how it may contract for reserves. The guidelines state that AEMO may form a RERT panel of entities that may be called upon to make reserve offers, and enter into, a contract for reserves for medium-notice situations where there is between ten weeks and seven days of notice and short-notice situations of between three hours and seven days of notice of a projected shortfall in reserves.

The guidelines provide guidance (but does not go so far as to require) as to what AEMO should do with regards to setting up the RERT panel (e.g. inform the market) and in conducting contract negotiations. The guidelines state that members of the RERT panel:[412]

- would negotiate and agree with AEMO on technical and legal requirements in sufficient detail for them to be able to enter into reserve contracts if AEMO uses the RERT with less than ten weeks' notice of a projected shortfall in reserves
- do not recover any payments from AEMO for being a member of the RERT panel

410 See the RERT guidelines.

411 See section 7 of RERT guidelines.

412 See section 6 of the RERT guidelines.

- are free to contract their capacity with other parties, including market participants
- should advise AEMO if their reserves are not available to be contracted under the RERT at any time over the next twelve months, including due to the fact that it is already contracted to other parties.

The RERT guidelines also outline the process that AEMO may use to contract for reserves under the RERT.[413] The process differs for medium-notice and short-notice RERT:

- Under medium-notice situations, AEMO may secure reserve contracts by seeking offers from the RERT panel, or offers from the RERT panel and from other potential reserve providers. In the case of other reserve providers, it may do so through a tender process and it may determine whether a tender process is open to the public or limited to specific potential reserve providers.
- Under short-notice situations, AEMO may use a RERT panel arrangement to identify which panel members are technically able, on the basis of their expressions of interest, to provide reserves within the applicable notice period and in the required regions or in some circumstances, combined regions;

D.3.6 Use of the RERT Panel

The RERT guidelines provide the following guidance with regards to the RERT Panel. AEMO should:[414]

- inform the market before it forms the RERT panel and when it commences negotiations for reserves contracts
- operate the RERT panel on a continuous basis and periodically open the RERT panel for new members
- subject to any decision by AEMO to publish relevant details following contracting of reserves, treat information on the RERT panel membership as confidential information.

D.3.7 Dispatch of the RERT

The RERT guidelines state that when deciding whether or not to dispatch the RERT, AEMO may review any information it took into account when it was deciding whether or not to procure the RERT. It also states that AEMO may consider for the period

413 See section 8 of the RERT guidelines.

414 See section 6 of the RERT guidelines.

where reserves may be required to ensure reliability of supply and where practical, maintain power system security:[415]

- the details of the outcome of the short-term PASA
- the details of the pre-dispatch schedule in terms of the anticipated available reserves
- any other information that AEMO considers relevant.

The guidelines do not provide any other information as to exactly how AEMO should dispatch the RERT.

D.4 AEMO's procedures and RERT processes

Under the framework provided by the NER and the RERT guidelines, AEMO creates guidelines and procedures to operationalise the exercise of the RERT. In particular, under clause 3.20.7(e) of the NER AEMO must develop and publish a procedure for the exercise of the RERT in accordance with the rules consultation procedures. AEMO also makes and publishes an operating procedure on the procedure for the dispatch and activation of reserve contracts.[416]

This section summarises AEMO's procedures and what the Commission understands to be the processes for exercising the RERT. Given that the RERT has only been dispatched once and only very recently, the amount of information available on this process was limited at the time of publication.

D.4.1 Procurement of the RERT

The procurement trigger for the RERT involves AEMO identifying a potential breach of the reliability standard; in other words, when the market is not expected to deliver reliability to a level that is consistent with the reliability standard. Specifically, the RERT may be triggered when AEMO identifies potential or actual shortfall in reserves as follows:

- In the medium-term PASA which is run weekly, AEMO identifies low reserve conditions. It identifies these conditions through a deterministic approach, although from 15 February 2018, it will do so by probabilistically assessing a potential breach of the standard.
- In the short-term PASA, pre-dispatch and dispatch, through the identification of lack of reserve conditions. These are identified through a combination of deterministic and probabilistic modelling.[417]

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415 See section 4.2 of the RERT guidelines.

416 See AEMO's SO_OP3717.

417 The Commission made a final rule on 19 December 2017 to change the LOR declaration framework from a deterministic one to one which is more probabilistic in nature. In particular, the new

D.4.2 Procurement amount

AEMO does not publish any methodology as to how exactly it calculates how much reserves to procure.

D.4.3 Dispatch of the RERT

The Commission understands that the summary below is an example of what could happen in the operational timeframe.

Once AEMO has procured reserves, AEMO may then dispatch such reserves during an operational timeframe when it identifies that reserves are running low, typically through LOR2 or LOR3 declarations.

Typically, AEMO will first seek a market response. AEMO will also estimate and publish the latest time at which AEMO would need to intervene through an AEMO intervention event[418] should there be an inadequate response from the market. If one is not forthcoming, AEMO may informally attempt to get a response[419] or intervene through the use of the RERT or directions.[420] The Commission understands that AEMO currently does not prioritise any of these options but, rather, assesses each situation uniquely. When AEMO decides to intervene, it will publish a notice advising the market that it intends to implement an AEMO intervention event.

If all these options fail, AEMO will then use involuntary load shedding through clause 4.8.9 instructions.[421]

Figure D.1 shows a simple scenario with no interconnectors or demand response and assuming a fixed (that is, horizontal) total supply capacity.[422] Specifically:

- The demand curve shows demand at various times of the day.

probabilistic approach will enable AEMO to take into account all the relevant risk factors that could affect reserve levels, without limiting it to the singular concept of a credible contingency. See: AEMC, National Electricity Amendment (Declaration of Lack of Reserve Conditions) Rule 2017, Final Determination, 19 December 2017.

418 A direction or the RERT.

419 For example, by calling generators informally rather than through a direction.

420 Directions are one of the mechanisms available to AEMO to use to maintain power system security or, in this case, for reliability purposes. It typically involves directing a generator to increase its output. A generator must comply with a direction unless it is not safe to do so. See clause 4.8.9 of the NER.

421 Clause 4.8.9 instructions enables AEMO to instruct network service providers to shed customer loads.

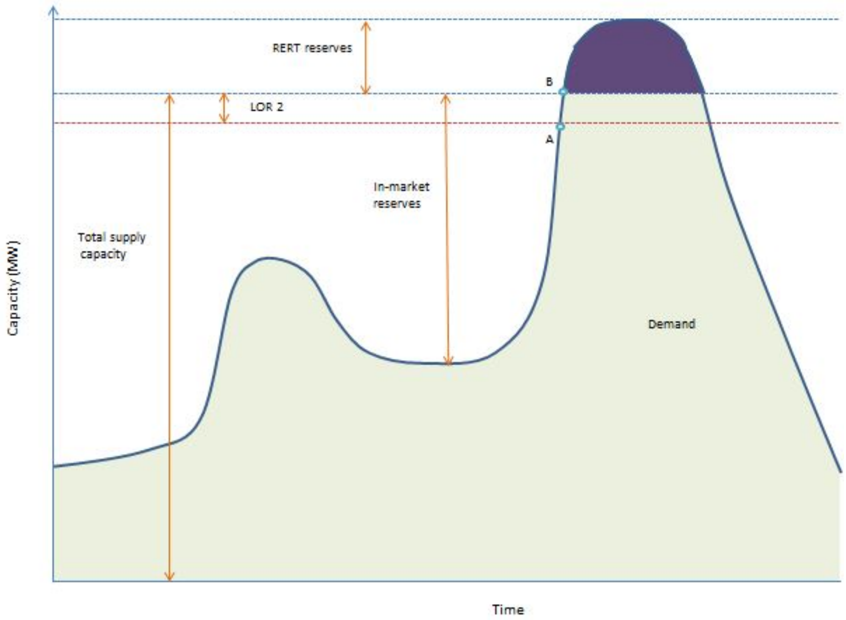
422 This example also excludes frequency control ancillary services (FCAS) as it is not used for reliability purposes. However, FCAS will be used if a tight supply-demand balance (i.e. a reliability problem) keeps worsening to the point that system security is compromised (e.g. frequency starts dropping), at which point FCAS may be triggered.

- Total availability, shown on the figure as total supply capacity, refers to all the generation made available in dispatch, including supply currently dispatched to meet demand.

- The difference between the horizontal total supply capacity line and the demand curve is the size of market reserves available.

- Lack of reserve level 2 (LOR 2) shows the reserve margin - if reserves fall below that margin, then the likelihood of involuntary load shedding rises to a point sufficiently high for AEMO to seek a market response, as required under the NER.

Figure D.1 Out-of-market reserves in the NEM



Assume that AEMO has already procured the RERT ahead of a forecast shortfall, which is now occurring, and has decided to use the RERT and not any other intervention mechanisms. Once an LOR 2 is triggered at point A,[423] AEMO informs the market of a potential shortfall. In this instance, assume that the market fails to respond, perhaps because there was no additional supply capacity available to respond. Before the market is out of reserves at point B,[424] but demand continues to grow, AEMO dispatches the RERT and meets that demand (and the minimum level of reserve required to keep the system secure).

Prices are not included on the graph. However, from a theoretical standpoint, prices should be at the market price cap at point B. In practice, this does not always happen, although prices are generally high when the demand-supply balance is tight. Once the

423 Typically, LOR2s are declared before real time in short-term PASA or pre-dispatch ("forecast LORs" but can also be declared in real time ("actual LORs"). For the purpose of this example, we assume everything is happening in real time.

424 Generally, AEMO will intervene before point B but after point A.

RERT is used, AEMO declares an intervention event and prices are set based on a "what-if" approach,[425] that is, what if the intervention had not occurred. This occurs automatically every time the RERT is dispatched.

D.4.4 Payment structure

The Commission understands from AEMO that generally, there is no availability payment, except in the case of the medium notice RERT where one may be paid for the duration of the contract (a maximum of 10 weeks), if the contract is triggered. In practice, the payment structure typically includes: availability payment (medium-notice only), usage payment, pre-activation payment for unscheduled reserves, early termination payment. There may also be penalties for not being available when required.

425 Intervention pricing is discussed in more detail in Appendix C.

E ARENA-AEMO RERT trial

This appendix provides a summary of the current ARENA & AEMO trial on a demand response initiative to manage electricity supply during extreme peaks. Specifically, this appendix:

- section E.1 summarises the trial and
- section E.2 sets out those providers that were chosen under the trial.

E.1 Background to ARENA & AEMO trial

In May 2017, ARENA and AEMO announced they were partnering to run a pilot program to incentivise demand response for reliability purposes. The trial's dual aim is to:[426]

- provide reserves for the upcoming summer as part of RERT
- trial a strategic reserve model for reliability or emergency demand response to inform future market design.

The three-year pilot program aims to provide 160 MW of reserve capacity which AEMO can call upon when reserves are low to prevent involuntary load shedding.[427] Total funding for the trial amounts to $37.5 million - $22.5 million of which is from ARENA to be used for about 100 MW across the NEM (mainly Victoria and South Australia) and the rest is from the NSW Government and ARENA ($7.5 million each) to be used in NSW for about 70 MW of demand response. Participants compete for this money through a competitive funding round, which received 24 applications.

The ARENA-AEMO trial supplements the existing RERT (which was discussed in more detail in chapter 7) and is specifically aimed at making this a more attractive mechanism for demand response providers.

Under the program, energy users or their service providers (for example, aggregators and energy retailers) who are successful with their funding application will receive a grant from ARENA as an incentive, or availability payment, to provide standby capacity during emergency or reserve shortfall events. This upfront payment will assist participants to install equipment / technology to allow it be ready to provide this capacity – this is a feature that, anecdotally, participants have expressed as a positive feature of the trial.

The compensation structure of ARENA's incentive has the following features:[428]

426 AEMO, summer operations 2017-18 report, p. 15.

427 ARENA, Demand response program, https://arena.gov.au/funding/programs/advancing-renewables-program/demandresponse/

428 ARENA, https://arena.gov.au/assets/2017/06/Demand-Response-FAQ%E2%80%99s_2nd-Release-1.pdf

- a one-off up-front payment when the contract is signed
- a one-off performance amount linked to initial testing results
- an activation performance and a knowledge sharing amount paid in six month instalments and in arrears.

The last component has associated penalties if performance is not achieved. Successful participants will also sit on the short-notice RERT panel and will receive payment from AEMO via the short-notice RERT panel if they are called upon to dispatch reserves, at a fixed, pre-agreed $/MWh rate. The AEMO payment is through the RERT and ultimately recovered from consumers.

Performance will be measured as the difference between a baseline and energy actually used. The baseline calculation uses the method proposed in AEMO's demand response mechanism[429] and can be adjusted up or down depending on prevailing conditions.[430] The difficulties associated with the baseline methodology was noted by the Commission during the consideration of a demand response mechanism rule change request.[431]

When a demand response event occurs, the response calculated for payment is the difference between the metered quantity of the resource and the baseline energy for the resource, where the baseline energy is an estimate of what demand would have been had there been no demand response.[432] In other words, it could be the case that participants have an incentive to "stay on" (when they would have otherwise reduced consumption in response to high prices) in order to be able to be dispatched by AEMO and receive payments through the RERT.

The pilot is being trialled in Victoria, South Australia and NSW, and demand response capacity was made available from 1 December 2017.

Unlike the RERT, ARENA is offering two standard products as shown in Table E.1.

429 AEMO, Demand Response Mechanism and Ancillary Services Unbundling - High Level Market Design, June 2013 Available at: https://www.aemo.com.au/-/media/Files/PDF/DRM_High_Level_Market_Design_Final.pdf

430 ARENA, https://arena.gov.au/assets/2017/06/20170628_2nd-UpdatedFundingAnnouncement-30MW-20MW-NSW-amendment_PUBLIC.pdf

431 AEMC, Demand Response Mechanism and Ancillary Services Unbundling, Final Determination, 24 November 2016.

432 Ibid. p. 38

Table E.1 ARENA-AEMO products

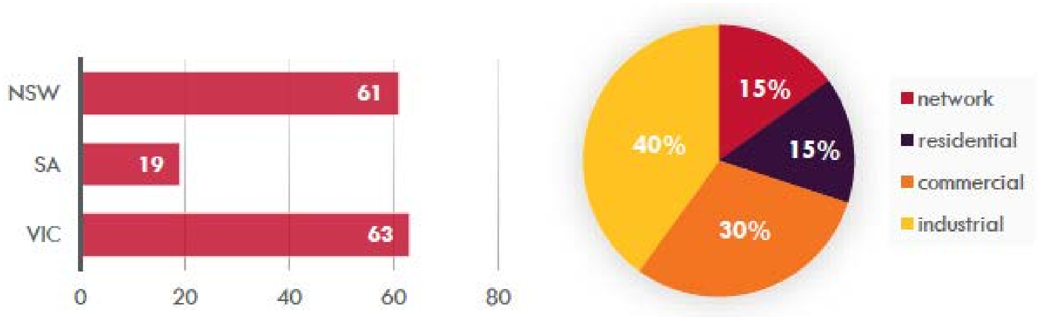
Feature	Product 1	Product 2
Notification period	60 minutes	10 minutes
Activation duration	four hours	four hours
Activation trigger	LOR2, LOR3, system security	LOR2, LOR3, system security
Availability	10am to 10pm business days	10am to 10pm business days
Activation frequency	10 per year (i.e. 40 hours)	10 per year (i.e. 40 hours)

Source: AEMO-ARENA, RERT Information session, 20 June 2017.

E.2 Participants in the program

In October 2017, ARENA and AEMO announced that ten demand response projects would be participating in the program following a successful tender process. In total, the projects are expected to deliver 143 MW of reserve capacity for the 2017-18 summer, rising to 200 MW by 2020.[433]

Figure E.1 AEMO/ARENA demand response trial for this summer, by region and sector



Project recipients include gentailers, demand response aggregators, retailers, large energy users and networks. Capacity ranges from 5 MW to 30 MW each and the type of demand response include behavioural changes of customers, remotely controlling and curtailing load and using voltage control devices.[434] The projects are summarised below.

433 Ibid.

434 Ibid.

Table E.2 Demand response projects - NSW

Funding recipient	Max capacity	Capacity in 2017-18	NSW Government & ARENA funding	Type of project
AGL	20 MW	18 MW	$5.2 million	AGL will provide 17 MW of capacity from large commercial and industry customers, and 3 MW from 10,000 NSW residential households with smart meters using a combination of behavioural demand response and controllable load/storage.
EnergyAustralia	20 MW	18 MW	$2.9 million	Energy Australia will sign up commercial and industrial businesses and residential customers. Energy Australia will use WattWatchers' remote monitoring and load curtailment devices and GreenSync's VPP technology for aggregation along with Redback Technology's smart battery storage systems.
EnerNOC	20 MW	20 MW	$3.6 million	EnerNOC will install their own hardware to automatically and remotely control and curtail energy use in 20 large commercial and industrial businesses, with approximately 1 MW available per site. The demand response will be 100 per cent generated by curtailment of loads. EnerNOC will also provide FCAS services demonstrating how customers can receive multiple revenue streams from their reserves.
Flow Power	20 MW	5 MW	$2.6 million	Flow Power will create a program called Energy Under Control which involves roll out of their own kWatch Intelligent Controller (designed and manufactured in Victoria) to 100 commercial and industrial energy customers across NSW. This will target manufacturing, agricultural businesses and cool storage.

See: https://www.aemo.com.au/-/media/Files/Media_Centre/2017/Media-release---AEMO-ARENA-demand-response-announcement.pdf

Table E.3 Demand response projects - Victoria and South Australia

Funding recipient	Max capacity	Capacity in 2017-18	Total ARENA Funding ($)	Type of project
EnergyAustralia	30 MW	11 MW (Vic) 9 MW (SA)	$6.9 million	Energy Australia will sign up commercial and industrial businesses and residential customers. Energy Australia will use WattWatchers' remote monitoring and load curtailment devices and GreenSync's VPP technology for aggregation along with Redback Technology's smart battery storage systems.
EnerNOC	30 MW (Vic only)	30 MW	$5.4 million	EnerNOC, one of the world's leading demand response aggregators, will install its own hardware to automatically and remotely control and curtail energy use in 30 large commercial and industrial businesses, with 1 MW available per site. These businesses will include cold storage facilities, manufacturing plants, metalworkers, water pumps, gas production facilities, commercial buildings, mills, paper/timber/forest mills and glass manufacturers. The demand response will be 100 per cent generated by curtailment of loads. EnerNOC will also provide FCAS services demonstrating how customers can receive multiple revenue streams from their reserves.
Zen Ecosystems	15 MW	5 MW	$2 million	Zen Ecosystems is a Victorian smart thermostat developer which has previously exported its innovative technology in the United States. Zen Ecosystems will deploy its smart, connected and controllable network of Zen thermostats. The demand response capacity will be delivered by controlling air conditioning, heating and ventilation. Zen Ecosystems will roll this out at business customers, and through a combination of voluntary and load control programs aimed at residential customers run in partnership with the RACV.
Powershop	5 MW (Vic only)	5 MW	$1 million	Powershop plans to run a behavioural demand response program called Curb Your Power using a mobile notification system for its Victorian retail customers. It will invite customers to reduce energy consumption in exchange for a financial incentive. By reducing energy usage for 1-4 hours, customers may receive the equivalent of a weekend of free electricity. Powershop will also be able to draw on 1 MW of Reposit enabled batteries installed in Powershop customers' homes and on a 1 MW co-generation facility at Monash University as a backup.

Funding recipient	Max capacity	Capacity in 2017-18	Total ARENA Funding ($)	Type of project
United Energy	30 MW (Vic only)	12 MW	$5.8 million	United Energy intend to use voltage control devices installed at substations across its entire distribution network in Melbourne and Mornington Peninsula to deliver demand response. During a peak event, United Energy will slightly lower the voltage across its whole network of 600,000 households and businesses, and will use smart meters to ensure the voltage remains at a safe allowable limit.
Intercast & Forge	10 MW (SA only)	10 MW	$323,654	Intercast & Forge is a South Australian metal foundry which manufactures metal castings. This local business has installed sophisticated energy systems that allows it to provide dispatchable demand response by powering down furnaces during peak events.

See: https://www.aemo.com.au/-/media/Files/Media_Centre/2017/Media-release---AEMO-ARENA-demand-response-announcement.pdf

F International examples

This appendix summarises various other jurisdictions and their reliability frameworks, specifically:

- section F.1 discusses the Texas energy market
- section F.2 sets out the Great Britain market, including its day-ahead market
- section F.3 discusses strategic reserves in Belgium.

F.1 Texas market

This section discusses the Texas's market, the Electric Reliability Council of Texas (ERCOT), in detail. ERCOT is the closest international example to the NEM in terms of frameworks. Even then, there are a number of significant differences in structure, naming convention and mechanisms. As a result, direct comparisons are not encouraged. However, from an assessment point of view, overseas mechanisms and experiences can prove to be useful.

The Public Utility Commission (PUC) of Texas regulates ERCOT, with oversight by the Governor and the Texas Legislature. The Texas Legislature restructured the Texas electricity market in 1999 and assigned ERCOT four primary responsibilities: maintain system reliability; facilitate a competitive wholesale market; ensure open access to transmission; and facilitate a competitive retail market.

An overview of the Texas wholesale market is:

- Market participants may submit offers to buy and sell energy on an hourly basis in the voluntary day-ahead market. Results help ERCOT operators and market participants plan for real-time operations the following day.
- In the real-time market, market participants submit offers to provide generation output and bring generation on-line as needed. ERCOT may request additional generation if needed to maintain system reliability.
- Every five minutes, ERCOT’s security-constrained economic dispatch system selects the most efficient generation resource options to serve customer demand effectively within the limits of the transmission system.
- Energy prices reflect the availability of resources during each interval, adjusting as needed to reflect the value of energy during scarcity conditions.
- The real-time market is settled every 15 minutes. Generators are paid settlement point prices, which reflect locational prices. Load-serving entities pay load zone prices, which can include costs associated with transmission congestion.

ERCOT's peak demand in 2016 was 71,110 MW - an all-time high; however, average wholesale energy prices in the ERCOT real-time market hit an all-time low in 2016 (US$24.62/MWh). ERCOT supplies 24 million consumers in its region, with more than 1,800 active market participants.[435] Its generation mix is predominantly gas (43.7 per cent), with coal (28.8 per cent), wind (15.1 per cent) and nuclear (12 per cent) comprising the rest.[436] Similar to the NEM, the majority of new generation is wind and solar projects.

F.1.1 ERCOT's day-ahead market

When ERCOT began its role as an independent system operator in 1996, the market focussed on bilateral trades with zonal congestion management and retail competition. However, because of increasing cost of real-time re-dispatch for transmission congestion management and volatile zonal prices, ERCOT began planning to move to a nodal market from 2003.

After seven years of planning, in 2010 the market reformed into a nodal market where prices are set at each node and prices diverge between nodes due to transmission constraints. This market features congestion revenue rights to manage the risk of price differences between nodes, a co-optimised day-ahead and ancillary services[437] market, and a day-ahead and hourly reliability unit commitment mechanism. Reform to the market is still ongoing.

Multi-part bidding is allowed in the day-ahead market. Generators submit either an energy-only bid or a three-part bids setting out the incremental energy cost, the no-load cost and the start-up cost.

Although participation in the day-ahead is voluntary, the day-ahead market has no price cap (but has an offer cap at US$9,000), thus it can be very expensive if congestion in the real-time market occurs with the risk of US$9,000 prices. This provides strong incentives for all market participants to participate.

ERCOT uses the granular information relevant to the physical operation of the system (locational, unit-based bids and bids which reflect the cost structure of the plants) in system dispatch - co-optimising energy and ancillary services on a daily basis.

Market participants with load are financially obligated to procure ancillary services. Awarded ancillary services are also physically binding.

While energy offers made through the day-ahead market are financially-firm (if accepted), ERCOT does not physically commit the plant. As there is no centralised, mandatory unit commitment process, the Reliability Unit-Commitment (RUC) process is used to ensure sufficient capacity is committed to serve forecasted load at the right

435 ERCOT, 2016 state of the grid report, 2017.

436 Ibid.

437 Noting that the definition of ancillary services in the Texan market may not be the same as what are termed ancillary services in the NEM.

locations. It allows ERCOT to examine the transmission system, identify security concerns, and determine the resource commitments required to reliably serve load. It relies on offers submitted but not awarded in the day-ahead market and will apply 'make-whole' payments or clawbacks if actual revenues are different from the guaranteed revenue under the RUC.

The adjustment period allows ERCOT and market participants to prepare and modify ancillary services offers, and to plan for any outages in preparation of the real-time market. This relates to the actions and reporting required to meet obligations set by the day-ahead market and/or day-ahead RUC (as financial settlements can occur at any time bilaterally).

Because it is a nodal market, congestion revenue rights are available. These are financial instruments which hedge against transmission congestion in the day-ahead market (that is, they provide optional firm access to the transmission network). This allows participants to hedge congestion charges on forward contracts between generators and loads at different locations on the grid, but they do not form a right to deliver physical electricity.

ERCOT's real-time market is more of a 'process' rather than a 'market' because the dispatch model does not co-optimise energy and ancillary services. All imbalances in financial positions from the day-ahead positions are typically settled in the real time market.

Reliability mechanisms in ERCOT

To enhance market signals, ERCOT applies a scarcity pricing mechanism that adds a price adder to meet energy demand and a reserve target. ERCOT's operating reserve demand curve is based on a loss of load probability function. This mechanism is intended to sustain both short- and long-term signals of short-term scarcity, which must guide investment decisions in flexible generation capacity and demand-side resources.

Note that the scarcity pricing mechanism in ERCOT applies the adder across the region and has no locational element. This has raised some concerns that the impact on market signals to ensure sufficient reliability at the appropriate location is still muted.

ERCOT also has the ability to undertake four out of market actions:

- First, because the ERCOT day-ahead market is voluntary and much load and generation is hedged by point to point bids, rather than physical generation schedules, ERCOT requires market participants to submit daily resource plans which are included in the day-ahead schedule.

- Second, as discussed above, ERCOT carries out day-ahead and hourly RUCs. The RUC provides ERCOT an opportunity to check if there are sufficient resources that could be committed if the need arises.

- Third, ERCOT has a mechanism known as the Emergency Response Service (ERS) which is designed to allow demand-side response providers (including aggregators) to be deployed during emergencies to prevent load-shedding. This is procured through a clearing-price auction on the expected MWh required. It is paid on the basis of the amount of load reduction provided when ERS is deployed. This is discussed in more detail below.
- Fourth, ERCOT is able to procure bespoke contracts known as reliability-must-run (RMR) contracts. These contracts allow ERCOT to resolve short-term, specific and localised reliability issues. Generally, RMR contracts are procured when a generator announces retirement because it is no longer economic but is identified as a necessity to maintain reliability while transmission upgrades are in place. Hence RMR typically address timing mismatches when a high-cost resource wants to retire and when a transmission upgrade is needed.

Emergency Response Service

As noted above, ERCOT has an Emergency Response Service (ERS) which calls upon demand response and distributed energy resources in response to emergencies. The ERS's procurement mechanism involves generating a demand curve based on an annual expenditure limit of US $50 million, rather than by estimating the total capacity required. This effectively sets a 'budget' for reserves and procures as much as it can to meet that budget.

Box F.1 ERCOT's emergency response service

ERCOT introduced an emergency product called the Emergency Interruptible Load Service (EILS), which could be deployed in an emergency prior to shedding firm load, following an event in 2006 where it was forced to shed load for the first time since the market opened.

Under the EILS, in the event of an emergency, demand response resources (excluding distributed energy resources) could be called upon by ERCOT to curtail within 10 minutes. Participants could choose to be available during one of three business day time periods or during non-business days.

In 2012, the program was expanded to allow participation by distributed energy resources (DER - or an integrated system of energy equipment that is connected to the distribution network.) and the program was renamed the Emergency Response Service (ERS). ERCOT has made several changes to the program since, including introducing a 30-minute curtailment product.

The ERS's procurement mechanism involves generating a demand curve based on an annual expenditure limit of US $50 million. The total available funds are distributed across three annual auctions according to an assessment of the relative risk of an emergency event occurring in each of these three periods.

Participants of the EILS program, and its successor, the ERS, program are paid for their "availability" to be curtailed in the event of an emergency, typically supply scarcity. This availability payment is similar to the payment received by loads participating in capacity market demand response programs.

The ERS includes several availability periods (not just in summer) in which participants can register. In each one, resources can be activated in response to generation and transmission outages or extreme weather events.

ERCOT's ERS introduces a type of capacity mechanism for demand response reliability reserves in an energy-only market through an availability payment. Participants of the ERS do not receive further payments when load is curtailed while under the ERS.[438]

Source: Brattle Group, *International review of demand response mechanisms report* and ERCOT website.

Comparison of the strategic reserve with the NEM

As mentioned in Box F.1, unlike the NEM where reserves are procured through a tender process, ERCOT reserves are procured through an auction three times per year, for four-month contract terms.[439] Resources are procured across six availability periods that cover the entire four-month period - this means that different loads with different profiles can participate at different times.[440]

To limit loads from consuming less prior to curtailment (to limit their exposure to high prices), the ERS includes a hefty penalty system for those that consume less than their baseline prior to being asked to curtail.[441] In that sense, demand response via the ERS cannot respond to high prices in the market, meaning that they are effectively out-of-market reserves, similar to what we have in the NEM.

The ARENA-AEMO trial is similar to ERCOT's ERS program. Both target demand response only and both have specific products - however, the procurement structure differs.

F.2 Great Britain market

The Great Britain market has some physical similarities to the NEM, namely an ageing coal fleet and increasing penetration of renewable generation technologies. Despite these similarities, this section illustrates the different approach taken in Great Britain in terms of wholesale electricity market design, including a day-ahead market.

In March 2001, the electricity market in England and Wales was reformed as the New Electricity Trading Arrangements (NETA), replacing the GB gross pool system. In

438 Brattle Group, *International review of demand response mechanisms report*, October 2015.

439 Brattle Group, *International review of demand response mechanisms report*, October 2015, p.7

440 Ibid.

441 Ibid.

April 2005, NETA was expanded to include Scotland and was renamed as the British Electricity Transmission Trading Arrangements ("BETTA").

NETA was designed as a self-dispatch wholesale electricity market as opposed to a centrally-dispatched gross pool system. NETA was introduced to promote effective competition under a prevailing ethos at that the time of 'competition by individual participants is good' in that it would be preferable if market participants self-scheduled in competition with other market participants rather than being instructed to operate by all overseeing centralised system operator. This was underpinned by the perception that the gross pool was unable to facilitate competition. Additionally, the gross pool was considered to be susceptible to market manipulation by generators and was insufficiently cost-reflective.

The Great Britain energy market relies predominantly on self-dispatch system where buyers and sellers contract their positions ahead of time either through bilateral contracts or the futures market. Approximately 90 per cent of trades are conducted in this way.

Market participants in the Great Britain energy market have access to day-ahead power exchanges (which actually begin 48 hours before dispatch). There are two power exchanges run by APX and N2EX. Through the EU Third Energy Package, these exchanges are also coupled with North-Western Europe, South-Western Europe, and the Baltic energy markets. Over 40 per cent of electricity produced is traded through these exchanges.

Market participants are also able to continuously amend their positions through the APX exchange until an hour before dispatch.

At an hour before dispatch (known as 'gate closure'), the market is closed. At this point in time, market participants are required to submit their final positions of their expected generation production and demand consumption profiles over the forthcoming period. Also at this time, they can also submit bids and offers to vary their positions to the system operator into the so called Balancing Mechanism (BM), which the system operator can use to instruct participants to deviate from their intended generation of consumption decisions. The net imbalance which the system operator is required to balance through the BM represents around two per cent of energy demand.

F.3 Belgium market

Energy policy responsibility in Belgium is divided between the federal government and the three regions. Belgium power production that is connected to the system operator (Elia's) grid is 14,765 MW. Between September 2014 and mid-October 2014, four nuclear units in the Belgian system were retired from service simultaneously due to technical malfunctions, amounting to a total unplanned outage of approximately 4,000 MW. In light of these events and the retirement and mothballing of flexible capacity in Belgium, the Belgium Regulatory Commission for Electricity and Gas issued an investigation about whether adequate incentives are in place in order to attract investment in flexible power generation in the country.

Belgium also has strategic reserve in its energy-only market to avoid a capacity shortfall and maintain reliability, similar to the Reliability and Reserve Trader (RERT). In other words, the system operator procures some capacity that is used only during supply shortfalls.[442]

F.3.1 Strategic reserve mechanism

In 2014, Elia, Belgium's system operator, introduced a strategic reserve mechanism to help manage reliability during the winter months. In particular, the mechanism aims to address structural shortage of generation from 1 November to 31 March of each year. Belgium introduced the mechanism following concerns about reliability of the power system as power stations retired. In particular, at the time Belgium experienced a lack of generation capacity (several nuclear units, totally a capacity of up to 4,000 MW, were out of the market for several reasons) and some CCGT were announced to be mothballed.[443] Therefore, part of the driver for the strategic reserve was in relation to mothballed capacity that has been re-commissioned in order to address supply shortages.[444]

Each year, by 15 November, Elia must calculate the strategic reserve requirement using probabilistic modelling to identify the quantity required for winter. If a requirement is identified, reserves are procured through a competitive tender process.

Reserves are only triggered if a structural shortfall is identified - that is, if Elia forecasts that demand will not be met with existing supply and imports from other countries.

There are two types of reserves under Elia's strategic reserve mechanism:

- Reserves delivered by generation - a strategic generation reserve (SGR).
- Reserves delivered by demand response - a strategic demand reserve (SDR).

In the case of the former, in order to minimise market distortions, SGR is limited to generators that are mothballed or completed shut down. In other words, they would be offering out-of-market reserves.

The SDR offers two types of demand response, which both require demand to curtail to a power level known as the target:

- The drop by target means that demand must be reduced by a specified amount.
- The drop to target means that demand must reduce to a specified amount.

442 Brattle Group, Near-term reliability auctions in the NEM, p. 4.

443 COMMISSION DE REGULATION DE L'ELECTRICITE ET DU GAZ, Note (Z)160512-CDC-1527 on Scarcity pricing applied to Belgium, 12 May 2016, can be found here: http://www.creg.info/pdf/Divers/Z1527EN.pdf.

444 Ibid.

For the SGR, providers are paid to cover expenses incurred for keeping generating units available as well as for energy dispatched. For the SDR, providers are paid an availability payment and an activation payment. The cost depends on the outcome of the tender process. There are penalties associated with failure to provide the response.

Comparison of the strategic reserve to the NEM

Elia's strategic reserve mechanism is very similar to that of the RERT - it is only dispatched when there is an identified shortfall. However, unlike the RERT, the requirement for procurement is assessed on an annual basis, one year ahead, and even for more than one year ahead.[445] In the NEM, this is done on a regular basis through the PASA processes but only for a lead time of up to ten weeks.[446]

Like the RERT, Elia's strategic reserves promote out-of-market reserves in order to minimise distortions. However, in terms of product offerings, it is more like ERCOT's ERS and the ARENA-AEMO demand response trial. Finally, Elia's strategic reserve can be activated either in the (non-mandatory) day-ahead market or in real time.[447]

445 Brattle Group, *International review of demand response mechanisms report*, October 2015.

446 See clause 3.20.3(d) of the NER.

447 Brattle Group, *International review of demand response mechanisms report*, October 2015, p. 4

G Summary of submissions

This appendix sets out the issues raised in the first round of consultation. If an issue raised in a submission has been discussed in the main body of this document, it has not been included in this table.

Stakeholder	Comment	Commission response
Accommodating intermittent generation		
Infigen Energy	Reliability and security challenges are being driven less by the emergence of new entrant technologies but more by the retirement of coal plant (p. 2.)	The Commission is exploring the emerging challenges to the existing reliability frameworks, as set out in section 2.3.
Merdian Energy Australia	It is important that changes that are made are not biased in favour of existing, but potentially soon to be extinct generation (p. 3.)	The Commission agrees with this, and as such has proposed an assessment principle of technology neutrality for this review, as discussed in appendix A.
BlueScope	By identifying where additional dispatchable generation should be paired with new variable renewable resources to maintain reliability, rather applying the requirement for all new investments, costs will be minimised. (p. 2.)	The Commission is considering the co-ordination of generation and transmission investment in a separate process.[448] It will take such considerations into account when we consider how best to proceed with the generator reliability obligation or related outcomes.
ARENA	The wind regime in different locations also has differing correlation with demand. Siting decisions can therefore affect the contribution of an individual facility to overall system reliability. (p. 4.)	
S & C Electric	It is entirely appropriate that variable generation	The Commission agrees that renewable resources

448 See: http://www.aemc.gov.au/Markets-Reviews-Advice/Reporting-on-drivers-of-change-that-impact-transmi

Stakeholder	Comment	Commission response
	should have some role in mitigating the nature of its variability. Currently renewable generation is very "plug and play" and has no need to contribute to the costs or implications of the variable nature of the generation. (p. 6.)	can contribute to reliability, although their ability to do so fully depends on whether there are complementary, dispatchable resources co-located with the renewables; or whether the renewable resources are sufficiently geographically dispersed.
EnergyAustralia	While renewable resources such as solar and wind are inherently variable, in the context of an overall system they can nevertheless contribute to reliability (p. 3.)	
Clean Energy Council	Enabling increasing contribution from flexible renewable energy sources will have long-term benefits of reducing system-wide fuel costs and exposure to volatility in both fuel (mainly gas and coal) prices and supply (p. 3.)	
ARENA	Energy assets specifically focused on flexible capacity can complement variable renewables. (p. 4.)	The Commission agrees with this view, and has observed that there is an increasing trend for this to occur in the market as set out in chapter 5.
The Grattan Institute	All generators – including wind and solar – may struggle to recover their full costs in the NEM as the proportion of intermittent renewables grows (p. 6.)	The Commission notes this view and is seeking to assess whether or not this is the case, and if so, its materiality.
Clean Energy Council	The Clean Energy Council does not see a need to adjust the current reliability frameworks at this point in time, and requests that the AEMC demonstrate any perceived issues (in line with the assessment framework). (p. 8.)	The *Reliability frameworks review* is considering whether there are issues arising from the current reliability frameworks, in accordance with our assessment framework set out in appendix A. The Commission agrees with the Clean Energy Council that any solution needs to be commensurate with the problem.

Stakeholder	Comment	Commission response
PIAC	The paper states the wind energy is non-synchronous, however this is not entirely correct – many modern wind turbines have full power conversion and are synchronous, and some even support improved power quality in the grid. (p. 9.)	The Commission acknowledges that some wind turbines can be synchronised to the rest of the grid. However, the majority of wind turbines in Australia are not synchronised. Further the issue of synchronisation is relevant to security issues rather than reliability ones.
Energy Networks Australia	An AEMO rule change on generator performance standards and the potential wider adoption of the Essential Services Commission of South Australia arrangements (advised by AEMO) for inverter generation will clearly need to be taken into account when considering options to accommodate intermittent generation (p. 3.)	The Commission acknowledges the ongoing *Generator technical performance standards* rule change and to the extent that there are any interactions, these will be considered.
PIAC	The benefit of the well-connected energy system we have today would be better acknowledged by instead considering 'how the intermittency of variable generation can be balanced in the future'. This would give consideration to distributed solutions, rather than the narrower and more restrictive 'making generation firmer' (p. 4.)	Making generation more firm is just one of many options for increasing the supply of flexible and dispatchable energy resources in the NEM explored in this review.
Scope of the review		
The Grattan Institute	The review appears to have too narrow a focus, thereby failing to explicitly address broad concerns about the ability of the market to deliver reliability in the current policy environment (p. 3.)	This review is a holistic review of the reliability framework, considering both existing and new mechanisms.
Day-ahead market		
Australian Energy Council	It is inappropriate and premature for the Reliability	The Commission's consideration of day-ahead

Stakeholder	Comment	Commission response
	Frameworks Review to conduct its assessment of day ahead markets and make a recommendation without considering how it will change once Five Minute Settlement comes into effect. (p. 2.)	markets is presented in chapter 8. The Commission is aware that its determination of *Five minute settlement* will need to be considered.
Clean Energy Council	An option could be to implement a day-ahead market that balances uncertainty in the market's forecasting with flexible capacity (p. 6.)	Such a model would be similar to the Great Britain day-ahead market, that is discussed in more detail in appendix F.
Demand response		
S & C Electric	We need to move away from demand response as a "last resort" and it needs to be a standard approach to providing flexibility in the NEM. (p. 3.)	The Commission considers demand response will play an important role in contributing to the reliability of the power system. More detail on this is presented in chapter 6.
S & C Electric	Network Service Providers will need to have visibility of assets providing system services or just connected to the system. The AEMO, COAG-endorsed, register will be critical for supporting forecasting and management of distributed resources that impact on both the distribution and transmission system. (p. 3.)	The Commission is considering this issue in the *Register of distributed energy resources* rule change request. The project page is available at: http://www.aemc.gov.au/Rule-Changes/Register-of-distributed-energy-resources. Relevant interactions will be considered in this Review.
Clean Energy Council	A market design to take advantage of demand response should emphasise performance criteria, such as ramp rates, accuracy and notification periods (p. 4.)	The Commission agrees that such considerations would need to be taken into account any mechanism for wholesale demand response.
PIAC	Procuring contracts for the RERT would have been made easier, or potentially entirely unnecessary, if a pool of active demand response was in place, as would be the case if the huge potential for demand response to respond to high wholesale prices was	The Commission agrees that the more wholesale demand response there is in the market, the less need for reliability demand response.

Stakeholder	Comment	Commission response
	realised through a demand response mechanism. (p. 8.)	
ARENA	Low transaction costs are particularly important for efficient participation of distributed energy resource in markets. At high shares of distributed resources, it may be appropriate to require market participation of smaller resources than is currently the case - whether directly in wholesale markets or through intermediary parties or platforms. (p. 6.)	The Commission agrees that there can be value in aggregation of smaller resources to provide services to the system. For demand response, the aggregation of small resources such as residential household may come with more significant capital costs. However, the Commission notes that some market participants are using these resources to participate in the AEMO and ARENA RERT trial. See appendix E for more information.
Information/forecasting		
Meridian Energy Australia	Stakeholders rely on a range of information including forecasts provided by networks, internal and external party forecasts of price and demand, general economic forecasts and forecasts of generation and fuel costs. (p. 6.)	The Commission agrees that this is an important part of the reliability framework.
BlueScope	While there is a number of reports in the market about coal stocks driving prices in NSW, there is little factual data to assist market participants. Improved granularity and timeliness of fuel supply and security issues would improve analysis by participants. (p. 4.)	The Commission notes this view, and will consider this in the later stages of the review where our attention will turn to the issue of information provision.
ENGIE	One of the challenges that has emerged in recent years is how to treat variable generation sources when assessing the reserve capacity across the different timeframes. The importance of this issue will continue to increase as the proportion of generation obtained from variable sources	The Commission is aware of this issue and is considering this through this review.

Stakeholder	Comment	Commission response
	increases (p. 4.)	
ENGIE	In the case where generation capacity decides to commercially withdraw from the market for a period of time, then it would be desirable that the requirements for such participants are made clear in the NEM, to reduce the likelihood of confusion and uncertainty. (p. 5.)	The Commission notes that one of the Finkel recommendations was to put in place a three year closure rule, which would assist with providing certainty in relation to this. The Commission will bear these comments in mind when considering such a mechanism and any rule change request that is submitted in relation to a three year closure rule.
Stanwell	Stanwell encourages the Commission to consider whether the closure notification proposal could be implemented through minor changes to the existing AEMO processes such as Medium Term Projected Assessment of System Adequacy (MT PASA) (p. 3.)	
	Stanwell notes that no transparency mechanism will be sufficient to overcome external interventions, whether they be forced acceleration of closure or pressure to delay well telegraphed closure. The process must also be flexible enough to account for genuinely unforeseeable events (p. 3.)	
Interventions		
Australian Energy Council	The AEMC should also consider whether the absence of compensation for market participants so directed is equitable, particularly if such services are to be called upon more frequently in the future. (p. 1.)	The Commission notes these views on interventions, and will consider these views when it considers interventions once threshold questions on the reliability framework are resolved.
Merdian Energy Australia	AEMO should aim to give the maximum notice possible in all the circumstances including alerting	

Stakeholder	Comment	Commission response
	specific generators that a direction is being considered. However, due to the nature of directions and the requirement to maintain system security and reliability, the ability to give substantial advance notice is often limited (p. 9.)	
Merdian Energy Australia	There appears to be value in AEMO developing capabilities which reduce the overall cost of the provision of reserves for the benefits of customers. This would include enhancing the ability of retailers and other to involve retail customers in responding to signals to change consumption. (p. 8)	
EnergyAustralia	There needs to be transparency, consistency and accountability built into the intervention mechanisms to ensure that there can be assessment on an ongoing basis on the appropriateness of their use (p. 3.)	
Origin Energy	High levels of market intervention will lead to greater investment uncertainty (p. 1.)	
ENGIE	ENGIE believes that there is reasonable transparency regarding the triggers for AEMO to intervene, whether by using the Reliability and Reserve Trader (RERT), direction or instruction (p. 5.)	
BlueScope	The concerns expressed in the Issues Paper that suggest that if long term ARENA/AEMO contracts become more common, it could impact on the operation of retailers in this area are unfounded. Demand response should be an option owned and controlled by the consumer, who ultimately bears	

Stakeholder	Comment	Commission response
	the risks of any commitment. Where retailers suggest that are being undercut, this could indicate that they are not providing fair value to the customer or are creating an inefficiency in the process that should be removed. In addition, retailers that own generation have a split incentive that may inhibit efficient functioning of the demand response market (p. 5.)	
ENGIE	It is possible that generator participants will decide to withdraw from the market, rather than have to pay high prices for fuel whilst not having the certainty of an electricity contract. The rules do not currently provide sufficient clarity on how such capacity should be declared to the market. This may impact AEMO's ability to direct participants (p. 6.)	
AEMO	Limited intervention mechanisms do not bridge the gap between the reliability standard and an expectation that a reliable operating state (that is, no unserved energy) needs to be maintained as (much as practicable and reasonable) in real-time by AEMO. This is consistent with consumer expectations of a reliable supply at reasonable cost. (p. 3.)	
AEMO	The concepts of reliable operating state, reliability standard, RERT, directions and clause 4.8.9 instructions imply a mix of planning and operational objectives that do not come together into a comprehensive framework that can meet consumer expectations of supply reliability. (p. 7.)	

Stakeholder	Comment	Commission response
AEMO	AEMO has described a potential strategic reserve, similar to the existing RERT and AEMO/ARENA demand response mechanism. It would use demand response and peaking generation that would be enabled during periods of scarcity pricing. (p. 7.)	
Stanwell	Stanwell does consider that the compensation arrangements warrant review so as to align the impacts on similar resources with different registration status. It would be perverse if there was an incentive for resources to remain out of the market in RERT in order to obtain a better price compared with entering the market and receiving compensation through Directions. (p. 3.)	
Interconnectors		
S & C Electric	It is highly unlikely that RIT-T would support the investment needed for new interconnectors. (p. 7.)	The Commission notes these views on how interconnectors contribute to reliability in the NEM, and will consider these views when it considers how the regulatory investment test for transmission operates in respect of interconnectors once threshold questions on the reliability framework are resolved.
Infigen Energy	A further matter the AEMC may consider is what amendments could be made to the RIT-T and RIT-D tests reflect the new norm - a more distributed rather than centralised energy system. (p. 5.)	
ENGIE	The long and thin nature of the Australian transmission network, with limited duplication of interconnectors, means that we should take a cautious approach to increasing the level of dependence placed on the interconnectors in the NEM. (p. 3.)	

Stakeholder	Comment	Commission response
Hydro Tasmania	In considering the future reliability framework, the AEMC should consider the role of interconnectors in the NEM and how their value to the market can be correctly identified. Appropriate changes to the RiT-T will be of particular importance in this regard. (p. 2.)	
Energy Networks Australia	Energy Networks Australia recommends that the AEMC particularly examine whether the current Australian Energy Regulator (AER's) Regulatory Investment Test – Transmission (RIT-T) adequately enables Transmission Network Service Providers (TNSPs) to undertake system reliability related assessments or estimating the value of sharing reserves. (p. 2.)	
Energy Networks Australia	New drivers need to be considered when assessing the value of transmission investment., including access to low-cost energy, capturing renewable energy, meeting regional economic and public policy needs, efficiencies from better inter-regional coordination and option value to address future uncertainties and mitigate risks. (p. 5.)	
Generator reliability obligation		
S & C Electric	By creating a new service, a new provider, such as a third party battery operator, may deploy and offer the service to generators, as well as providing other system services (p. 6.)	As noted the Finkel Panel recommendation of a generator reliability obligation is still within scope of the Review. However, following the Energy Security Board's advice on a National Energy Guarantee, the Commission has decided to , for the moment, put on hold any analysis regarding a
Infigen Energy	Infigen's strong view is that reliability is a system	

Stakeholder	Comment	Commission response
	issue that should be sourced and paid for on a system wide basis (p. 3.)	generator reliability obligation. This is because the reliability component of the Guarantee aims to achieve a similar outcome to what a generator reliability obligation would. Once a COAG Energy Council decision is made about the Guarantee in 2018, the Commission will then decide how best to proceed in relation to the generator reliability obligation.
Australian Energy Council	The Energy Council fully supports arrangements which maintain the reliability of the power system, however the reliability of the NEM is best assessed dynamically, and on a regional or market-wide basis. While individual generators contribute to the power system's reliability, it is not appropriate to attribute changes in reliability to particular generators, and particularly not to new renewable energy generators, since reliability can be affected by matters outside their control, such as the retirement of thermal generation (p. 1.)	
Merdian Energy Australia	Our initial assessment of these factors suggests that a Generator Reliability Obligation may not be necessary and if deemed necessary, should not only be imposed on new intermittent generation and the costs should be borne by all the beneficiaries of maintaining reliability (p. 4.)	
EnergyAustralia	A key recommendation from the Finkel review was the Generator Reliability Obligation. We support consideration of this recommendation as part of the Review (p. 2.)	
Clean Energy Council	A key recommendation from the Finkel review was the Generator Reliability Obligation. We support consideration of this recommendation as part of the Review (p. 2.)	
Origin Energy	the AEMC should closely scrutinise what impact the additional costs of complying with a GRO will	

Stakeholder	Comment	Commission response
	have on the level of future intermittent developments. The assessment should also consider not only the capital requirements but also fuel and transport contracts that may be required (e.g. gas fired generators) to satisfy a GRO (p. 2.) The AEMC should also consider whether different intermittent generation technologies should have different obligations (p. 3.)	
Snowy Hydro	Snowy supports the Finkel Generator Reliability Obligation approach in principle. Where possible this should be achieved through a market based mechanism. (p. 3.)	
Energy Networks Australia	Energy Networks Australia thinks it is just as crucial that requiring generators to have storage does not solve the reliability problem if the transmission network cannot deliver the capacity due to current and potential constraints. (p. 4.)	
ARENA	Market design options requiring more complex deals, such as design options requiring contracts between multiple project developers, are also likely to impose higher transaction costs on new investment. (p. 10.)	
ENGIE	The first concern is that approaching the problem incrementally as each new investment is proposed, with a 'spot' assessment at that time of the firming obligation to be imposed, seems an inefficient method. Further, imposing these costs onto the investor at the time of investment introduces a barrier to entry for some renewable energy	

Stakeholder	Comment	Commission response
	projects. (p. 1.) ENGIE would prefer to see an arrangement introduced where flexible services are defined and the requirement for these services is determined in advance, and competitively sourced by AEMO. (p. 1.)	
	Competitive procurement open to a wide range of potential suppliers is likely to be more efficient than a mandated obligation on an individual renewable energy investor who may or may not be willing or able to procure GRO services. (p. 1.)	
	If we are to ensure that there is sufficient dispatchable capacity available to balance out variable renewable energy, there needs to be consideration given to both the investment and operational timeframes. Only then can we be confident that the necessary investments will be made, and that the dispatchable capacity will be incentivised to operate when required. (p. 2.)	
AEMO	AEMO has undertaken to begin development of a longer-term approach to retain and incentivise investment in dispatchable capability, which includes covering approaches to compensate for dispatch flexibility that would include the articulation of a Generator Reliability Obligation. (p. 7.)	
	A feature of this articulation would be in establishing specific flexibility services relating to different operational timeframes. For instance, the services could relate to dispatchable response available within 5 minutes, 15 minutes and 1 hour.	

Stakeholder	Comment	Commission response
	(p. 7.)	
Review governance		
EnergyAustralia	We note that the interaction between this review and recommendations made in the Finkel review will require a high level of coordination with other related topics being looked at through other processes and by other market bodies (p. 1.)	The Commission is conscious that there are a number of related work programs on similar issues and is working closely with the other market bodies (that is, AEMO and the AER), the Reliability Panel, the Energy Security Board and stakeholders on these matters. We note the letter from the COAG Energy Council to the COAG Energy Ministers that set out the market bodies' implementation plan for the Independent Review into the Future Security of the National Electricity Market.
	Having multiple processes, overseen by separate organisations, creates a risk of inconsistent findings or diverging approaches to similar issues. We consider that there needs to be much more clarity in terms of the governance of these related projects. (p. 1.)	
The Grattan Institute	An integrated work plan should be developed by the Energy Security Board, identifying the individual focus of each workstream and how they complement each other (p. 2.)	
	The Review should work closely with the Reliability Panel to understand their assessment of the value placed on reliability and any potential changes to the reliability standard. How the two reviews will work together needs better explanation (p. 4.)	
Energy Networks Australia	There may be benefit in the AEMC clarifying the issues that this particular review will address in summary form as well as those inter-related issues that will be covered in other reviews. (p. 1.)	

Stakeholder	Comment	Commission response
Hydro Tasmania	It is unclear how AEMO's proposed consideration of these issues will be coordinated or integrated into the *Reliability frameworks review*. (p. 2.)	
Other issues		
ARENA	Changes in electricity market design to improve reliability may not be the appropriate response to issues more closely associated with external factors such policy settings and market conditions (p. 6.)	The Commission agrees that it is important to understand what the issues and/or problems are, and their materiality, before considering what the solution to these may be.
Origin Energy	All policies considered by the AEMC should assess the interaction between climate and energy policy to achieve outcomes that balance reducing emissions, with retaining reliable energy supply at an affordable cost to consumers (p. 2).	The Commission recognises that the lack of an emissions reduction mechanism that is integrated into the energy market is impacting on investment, and so the reliability framework in the NEM, and is taking that into account in this review.
ENGIE	Consideration of the effectiveness of the market and regulatory framework needs to be carried out within the current political context, which is characterised by governments that are unable to agree on a clear, long term energy and emissions policies, and have shown a willingness to intervene regularly in an uncoordinated manner (p. 4).	
S & C Electric	The lack of clear direction from the Federal Government is critically hampering the operation and future development of the NEM (p. 9).	
EnergyAustralia	Government interventions remain a key concern for private investors and create a real risk of unnecessarily high costs for consumers (p. 3).	The Commission has recognises this as an emerging challenging in the reliability framework, as discussed in chapter 2.

Stakeholder	Comment	Commission response
Infigen Energy	Bringing certainty within a sensible set of market and policy settings provides the framework in which entities can balance investment decisions. It places back in the entities hands things which the entity rather than Government or Regulators are better able to control and risk manage (p. 8).	The Commission agrees that the allocation of risk is an important principle to consider, as set out in appendix A.
Australian Energy Council	Flexible generation sources are able to increase or decrease output based on variable market fluctuations. Adequate consideration should be given to valuing flexible generation appropriately, as these sources will be increasingly relied upon as the market changes (p. 2).	The Commission has considered ways that flexibility can be valued in section 3.2.
EnergyAustralia	In developing new reliability mechanisms, the Commission should consider whether they adequately cater for jurisdictional differences in the generation mix or ownership structures, and will reduce the incentive for further government intervention (p. 2).	The Commission considers that market power issues are an important consideration in our assessment framework, as reflected in appendix A.
Stanwell	Stanwell considers that it is important to incentivise investment in dispatchable resources prior to a shortfall occurring, not just when a reliability assessment indicates an additional need (p. 4).	The Commission is considering the timing of investment and operational signals (e.g. whether or not there is a lag between when the signal is provided and when it is responded to), as flagged in chapter 3.
ARENA	A key question for the review is whether changes to the reliability settings will continue to be a sufficient tool for providing for reliability in the NEM (p. 8).	The Reliability Panel is currently considering this question through its reliability standard and settings review, for which a draft report was recently published.

Stakeholder	Comment	Commission response
AEMO	AEMO suggests the NEM needs multiple reliability standards to address planning and operational reliability, in addition to the services already in place (such as frequency control, network control, system restart) or being considered (p. 2).	The Commission would welcome further information from AEMO on what these additional services may need to be.
ARENA	Given potential value from geographic diversity, a beneficial feature of market designs is to signal the relative benefit of generation investment in different locations - and for that signal to change as conditions change over time. It will also be important the review's recommended market design changes are balanced with the regulatory incentives for transmission to access resources either at the edges of a region (p. 9).	The coordination between generation and transmission investment is being considered by the Commission through a separate review. It considers this issue is an "enabler" for a reliability framework.