AEMC

REVIEW

Australian Energy Market Commission

DIRECTIONS PAPER

Reliability Frameworks Review

17 April 2018

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Directions Paper
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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

Australia's energy system is undergoing a transformation - driven by changing consumer choices and rapidly evolving technology. The generation mix is moving from a centralised system supported mostly by synchronous generation to more a more decentralised system, with greater volumes of variable renewable generation, customer-connected distributed energy resources as well as demand response and storage capability.

This transformation also includes changing electricity demand patterns and the impact of weather events. Reflecting this, AEMO, the system operator, has recently identified and highlighted where security and reliability needs are shifting across the national electricity market (NEM), including how these factors are impacting on the operation of the system.[1] Further, the reliability and security of the NEM has attracted considerable attention in recent times from both the mainstream media and various policy makers.

This fundamental step change in power system technologies is occurring against a backdrop of uncertainty over nationally consistent, long-term policy settings on emissions reductions and the mechanisms that will be used to achieve those reductions.

Uncertainty over an emissions reduction mechanism is to be addressed through the Energy Security Board's proposed National Energy Guarantee (Guarantee), which seeks to integrate energy and climate change policy instruments in the NEM to provide investors with the certainty they need to make long-term investments.[2]

The Guarantee is a foundational component of a broader work program to support this transition of Australia's energy system. As part of that broader work program, the AEMC's reliability frameworks review is considering complementary changes to energy market design to support the Guarantee's objective in delivering long term reliability at least cost. As part of this review a number of Finkel Panel recommendations in relation to reliability that were directed to the AEMC have also been progressed.

For the purposes of getting stakeholder input to inform the Commission's recommendations, this paper sets out progress to date on the key streams of work undertaken as part of this review:

- the foundational aspect of the reliability frameworks - **forecasting and information processes**

1 AEMO, submission to the interim report, p. 3. See below for definitions of security and reliability.

2 Energy Security Board, Call for public submissions on National Energy Guarantee, Media Release, 15 Feb 2018.

- assessing the suitability of a **day-ahead market** in the context of the NEM[3]
- developing a mechanism that can facilitate **wholesale demand response**[4]
- assessing the need for a **strategic reserve**, including as a replacement to or enhancement of, the existing Reliability and Emergency Reserve Trader (RERT).[5]

The table at the end of this Executive Summary maps out progress to date on this Review.

Prior to highlighting how these four streams of work have been progressed so far, it is important to reinforce what reliability means in the Australian context and how reliability is currently delivered. Understanding reliability performance to date is also important, particularly when viewed against power system security performance.

What is reliability?

Reliability means that the power system has an adequate amount of capacity (both generation and demand response) to meet consumer needs. It therefore requires there to be an adequate pattern of investment and disinvestment as well as appropriate operational decisions, so that supply and demand are in balance at a particular point in time. In a reliable power system the expected level of supply will include a buffer, known as reserves. Expected supply will be greater than expected demand. This allows the actual demand and supply to be kept in balance, even in the face of shocks to the system, known as "credible contingencies".

Reliability is currently delivered in the NEM through investment, retirement and operational decisions that are underpinned by various market structures. The framework is supplemented by a series of mechanisms that allow the system operator to intervene in the market in specific circumstances.

The National Electricity Rules (NER) contains the reliability standard for the NEM, currently at 0.002 per cent expected unserved energy. As system operator, AEMO incorporates the reliability standard within its day-to-day operation of the market.

The concept of reliability is distinct from that of security. A reliable supply to consumers also requires a secure power system and reliable networks. A secure power system is one that operates within defined technical limits. This Review does not seek to address power system security. The latest annual review of the security, reliability and safety of the NEM found that while we have a reliable supply, it has become harder to keep the power system stable, that is, in a secure operating state.[6] The Commission is considering system security issues through its *System security work*

3 Finkel recommendation 3.4.

4 Finkel recommendation 6.7.

5 Finkel recommendation 3.4.

6 See: https://www.aemc.gov.au/markets-reviews-advice/annual-market-performance-review-2017

program. Network reliability is addressed through different, jurisdictionally based frameworks.

We are conscious of the interactions between this review and other pieces of work.

Reliability performance

Recently, the Reliability Panel found that the NEM performed well in terms of reliability for the 2016/17 time frame, which is consistent with conclusions for previous years.[7] In 2016/17, at a wholesale level, 0.00036 per cent unserved energy came from one reliability event that occurred in South Australia on 8 February 2017, where demand was higher than forecast, wind generation was lower than forecast, and thermal generation capacity was reduced due to a few forced outages. This is within the reliability standard.[8] At a wholesale level, there was no other unserved energy recorded due to reliability events for any other region in the NEM.

Recent analysis undertaken by the Reliability Panel suggests that the current reliability standard will be met in all regions of the NEM in the near to medium term.[9]

Some projections show that some unserved energy, although not close to breaching the reliability standard, is forecast over the medium term (2018/19 to 2026/27).[10]

System security

Whilst currently the reliability standard is being met across the NEM, it is becoming harder for AEMO to manage power system security. The Reliability Panel has found that the security performance of the power system has been mixed, resulting in a less secure power system and also load being shed i.e. blackouts.[11]

For example, in 2016/17 there were 11 instances of the system being outside its secure limits for greater than 30 minutes, the target limit. This represents an increase on the previous year, 2015/16, when there were seven instances. The year before that there

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7 See: https://www.aemc.gov.au/markets-reviews-advice/annual-market-performance-review-2017

8 An expectation that no more than 0.002 per cent of demand for energy will be unmet in any region of the NEM.

9 Reliability Panel 2017, *Reliability standard and settings review 2018*, draft report

10 AEMO projects unserved energy over the medium- and long-term through its forecasting processes, namely the medium-term PASA in over the next two years and the ESOO and the EAAP over the two-to-ten year timeframe. With respect to the recent projections of some unserved energy within the reliability standard, AEMO has, for example, projected that the probability of some unserved energy in NSW post-Liddell closing rises to 35 per cent in 2026-27 assuming no additional capacity. It is important to note that, despite this, AEMO's processes are forecasting that the reliability standard will be met. The projected unserved energy is within the reliability standard (i.e. 0.002 per cent unserved energy).

11 The Panel also recognised the significant body of work underway that is currently considering how to maintain the resilience of the NEM.

were four instances of the system being outside its secure limits for greater than 30 minutes.[12]

The most significant system security event in 2016/17 was the South Australian black system event which occurred on 28 September 2016. This incident saw a total loss of supply to the region, close to 850,000 customers. It is estimated that South Australian businesses suffered costs of $450 million as result of the blackout.[13] This incident demonstrated both the importance and difficulty in maintaining system security in a changing technological environment.

The challenges in managing power system security are being addressed by the AEMC through its system security work stream; another critical component of broader work program to support the transition of the power system. To date the AEMC has made seven rule changes to assist in meeting the security needs of the transforming system. The AEMC continues to work closely with AEMO to identify further system security challenges so that the market and system operator is equipped to manage, and market participants contribute adequately to, power system security in the most effective and least cost ways. Most recently this is through the AEMC's *Frequency control frameworks review* and the *Generator technical performance standards* rule change request from AEMO.

Update on key streams of work in the Review

Against this background, this paper provides an update on the key streams of work for this Reliability Frameworks Review, highlighting issues raised by stakeholders, as well as setting further questions and matters for consultation with stakeholders.

Forecasting and information provision

In any electricity system, decisions need to be made today based on information and forecasts of the future - from decisions about how much power to dispatch in the next five minutes, to investment decisions that will last for decades. This is unavoidable. With this in mind, the purpose of forecasting is not necessarily to predict the future per se, but to provide market participants and AEMO with information that influences their decisions today.

In the NEM, some forecasting is undertaken by market participants in the course of making investment and operational decisions. Other forecasts are undertaken by AEMO, which are then used in participant and AEMO's own decision-making. The Commission considers that forecasting activities will be most effective when:

12 Under the National Electricity Rules (Rules) AEMO is required take all reasonable actions to adjust, wherever possible, the system's operating conditions with a view to returning the power system to a secure operating state as soon as it is practical to do so, and, in any event, within thirty minutes.

13 Parliament of South Australia, Report of the select committee on the state-wide electricity blackout and subsequent power outages, 28 November 2017.

- Centralised forecasts are well-understood via the publication of details on how they are produced and the risks associated with how accurate they are – this informs decisions on how the forecasts are used and, if necessary, where improvements can be made.

- Entities other that the system operator have the opportunity to provide their own forecasts, since by disaggregating the provision of forecasts, risks associated with the forecasts can be shared between multiple parties that may be better placed to manage them.

Stakeholders have raised concerns about the accuracy of forecasts, and the impacts that this may have had on reliability outcomes in the NEM. In response, the Commission has undertaken indicative analysis of the accuracy of demand forecasts produced for the medium-term projected assessment of system adequacy (PASA), short-term PASA and 30-minute pre-despatch forecast. In most cases, the analysis shows that while the forecasts contain a degree of inaccuracy (as to be expected since forecasts, by definition, are always incorrect) the size of the error has not increased over time. However, in a tighter demand-supply balance with the changing characteristics of the system, the differences between forecasts and actual outcomes may have more significant consequences. Transparency and systematic regular reporting of these differences will become increasingly important.

Forecasting is likely to become more difficult due to the growth in distributed energy resources, deployment of variable renewable energy resources and more extreme weather days. Consequently, it is appropriate to explore changes to the forecasting framework that can reduce and diversify the risks associated with the centralised forecast process. For consultation and feedback, the Commission has proposed three potential improvements that could be implemented in the short- to long-term:

- In the short-term, there would likely be benefit in an entity undertaking greater reporting of the differences between forecast and actual outcomes, especially in relation to the 30-minute pre-dispatch, short-term PASA and medium-term PASA forecasts. The existing reporting under the NER is somewhat limited. The transparency that a common source of reporting could provide would be conducive to industry participants and AEMO in their decision making, risk management and, if necessary, point to how to improve the forecasts.

- There is currently work being undertaken by Australian Energy Market Operator (AEMO) and Australian Renewable Energy Agency (ARENA) to enable five-minute ahead self-forecasting by utility-scale wind and solar projects on a voluntary basis, as a "trial". Self-forecasting for a longer horizon could provide a tangible reliability benefit by better informing AEMO and the market of the likely future output of wind and solar generators. In the medium-term, depending on the results of the trial, there could be benefits from embedding this in the regulatory framework.

- In the long-term, an option to deal with greater volumes of distributed energy resources could involve retailers forecasting their own load, and submitting this information into AEMO's systems. This could occur through the submission of individual forecasts, or by retailers appointing a third-party forecast provider (e.g. a DNSP bearing in mind that DNSPs forecast for their own purposes) to produce an aggregate forecast. The design of such an arrangement would seek to promote accurate forecasting and efficient demand response decisions. Providing entities with the opportunity to provide their own forecasts should increase the efficiency of forecasts by placing the risks with parties that may be better placed to manage them. The Commission acknowledges that this obligation would be a substantial change and not be without costs.

Day-ahead markets

Despite not having a formalised day-ahead market, the NEM 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 the flexibility to adjust their position in response to new information as it becomes available including changes in market conditions as well as responding to offers or bids of other participants.

In this review to date the Commission sought stakeholder feedback on what existing ahead features of the NEM may require change. To date little feedback has been forthcoming and deficiencies in existing market design generally relate to information provision and / or security-related matters (e.g. not being sure whether there will be enough synchronous generators running in the system at a particular point in time), as distinct from reliability (having sufficient capacity or supply to meet demand).

The Commission understands that AEMO is currently identifying the existing ahead features of the NEM that may require change and compiling the evidence of the deficiencies that AEMO considers need to be addressed, either through targeted improvements to existing arrangements or through a centrally facilitated ahead market design. The AEMC welcomes this. AEMO’s contribution is important to understand what part of the existing market design is inadequate or needs to be improved, as well as the materiality of these matters. This is to help determine the most targeted solution and least cost solutions, whatever those solutions might be.

Any deficiencies or potential improvements identified will help determine the objectives of any solution hence help further the assessment of this area, in line with the Finkel recommendation. The Commission has identified three high-level objectives an ahead market could be designed to achieve. These are:

- To provide market participants (both demand and supply side) with more, or better quality, information so that they can incorporate this information into their unit commitment or demand response decisions and bids/offers and therefore increase the efficiency of outcomes in the NEM wholesale market, including reliability and security outcomes.

- To provide the system operator with more, or better quality, information so that the system operator can use this information to more efficiently manage the system in relation to reliability and security outcomes, while maintaining the current generator self-commitment arrangements.
- To provide the system operator (rather than participants) with a schedule that centrally coordinates unit commitment decisions, the intent being to increase the efficiency of outcomes in the NEM wholesale market, including in relation to reliability and security outcomes.

These objectives exist on a spectrum from the first objective, which is similar to the current NEM arrangements through to the third objective which would change responsibility for unit commitment decisions from market participants to the system operator - a fundamental change to the competitive underpinnings of the market design. Each of these objectives would require different changes to the current market design.

The Commission is interested in stakeholder feedback on the objectives generally and on any deficiencies of the current market arrangements and how they can potentially be addressed by a formalised ahead market in the NEM.

The Commission is working with AEMO and other stakeholders to identify problems or improvements, and from that to develop solutions that are effective and least cost.

Demand response

The Finkel Panel recommended that the Commission should undertake a review to recommend a mechanism that facilitates demand response in the wholesale energy market.

Demand response is a source of reliability that can be used to support the Guarantee. Demand response can help to keep costs down in situations where the value consumers place on electricity services is less than the efficient costs of supply.

Due to the lack of transparency around how much wholesale demand response is currently being utilised, it is very difficult to draw firm conclusions about how much demand response is occurring in the NEM, or whether the level of demand response is efficient.

Some consumers want more opportunities to offer wholesale demand response – and consider that in many instances wholesale demand response can more efficiently contribute to reliability than building new generation.

Of the factors influencing wholesale demand response in the NEM, the Commission has identified two issues that could be addressed through changes to the regulatory frameworks:

- the requirements for there to be a single financially responsible market participant at a connection point

- the difficulties faced by retailers offering demand response products that are valued by consumers such as acquiring customers for demand response programs and recovery of costs associated with investments in demand response capability.

The Commission has also identified for consultation three options that could be progressed to address these issues. They are:

- two options that could allow multiple parties, for instance a specialist demand response aggregator and a retailer, to engage a single consumer behind a connection point without that being contingent on the original financially responsible market participant
- providing additional incentives for retailers to offer demand response products.

The ways these options are developed have flow-on effects for a number of elements in the market, and hence potentially prices for consumers.

Strategic Reserve

The Finkel Panel recommended that 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 should be assessed.

The Commission considers that it remains appropriate for the NEM to have some form of strategic reserves to act as a safety net and as one of the last resort alternatives to involuntary load shedding.

AEMO has recently submitted two rule change requests with the Commission with regards to the RERT.[14] The first rule change requests that the Commission reinstates the long-notice RERT as a short-term measure for the upcoming summer of 2018/19. The second asks the Commission to consider AEMO's proposal for an enhanced RERT as a longer-term solution. As a result the Commission will explore the potential improvements to the RERT that are within the scope of the rule change requests, through the rule change processes rather than through the next stage of this Review. AEMO's proposal for an enhanced RERT addresses the Finkel Panel recommendation. These rule changes will form part of the Commission's Reliability work program, alongside this Review.

14 See: https://www.aemc.gov.au/rule-changes/enhancement-reliability-and-emergency-reserve-trader and https://www.aemc.gov.au/rule-changes/reinstatement-long-notice-reliability-and-emergency-reserve-trader

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

Submissions on this paper are due by **18 May 2018**, with this date set based on the need to meet the Council of Australian Governments (COAG) Energy Council's timeframes for its implementation plan for the *Independent Review into the Future Security of the National Electricity Market.*

We encourage stakeholders to meet with us - please contact Sarah-Jane Derby on 02 8296 7823 or sarah.derby@aemc.gov.au.

The final report including recommended actions will be published in mid-2018.

Table 1 Where we are and next steps

Milestone	
Issues paper	An issues paper was published in August 2017 seeking stakeholder feedback on the issues that the Review will cover. 18 submissions were received.
Interim report	An interim report was published in December 2017 providing an update on our thinking. 31 submissions were received. Stakeholder feedback to those reports demonstrated strong support for maintaining the existing market-based approach to reliability, with interventions only being used as a last resort. Stakeholders also overwhelmingly recognised the lack of a clear, consistent and integrated environmental and energy policy as a key aspect affecting reliability.
Directions paper	The directions paper sets out the Commission's proposed approach to four of the key streams of work to facilitate further consultation and feedback on these streams of work.
Submissions due to Directions paper	Submissions are due on 18 May 2018.
Final report	A final report, including recommendations, will be published mid 2018. This will present our findings in relation to the four key streams of work in this report, as well as other aspects of the reliability framework (e.g. interventions).

Contents

1 Introduction

On 11 July 2017, the Australian Energy Market Commission (AEMC or Commission) commenced a Review into the market and regulatory frameworks necessary to support the reliability of the electricity system.[15] This Review also includes consideration of several recommendations that were subsequently directed to the AEMC 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 (such as load shedding on low reserve[16] days) have led to a greater focus on reliability in the National Electricity Market (NEM). In commencing the Review, the Commission considered that it is timely to assess whether the current market and regulatory reliability frameworks are still appropriate given the 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 Review commenced, 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.[17] In March 2018, AEMO provided advice in response to a request from the Federal Energy Minister assessing AGL's plan to replace the energy and capacity currently delivered by the Liddell Power Station following its retirement in 2022.[18]

The Energy Security Board proposed a National Energy Guarantee, which would require retailers to:

- contract with or invest in generators or demand response to meet a minimum level of dispatchable on demand electricity in the event of a material expected reliability gap and
- source electricity with an average emissions below an agreed level.

In addition, State and Commonwealth governments are progressing with new generation and storage (both chemical batteries as well as pumped hydro), the most

15 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.

16 Reserve levels are a key concept in the NEM, and can broadly be considered to be the balance of expected supply over demand in the market.

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

18 AEMO, Advice to the Commonwealth relating to AGL's proposal to replace Liddell, 16 March 2018.

notable examples being the proposed Snowy Hydro 2.0[19] and South Australia's 100 MW battery.[20]

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.[21]

Table 1.1 Review timeline

Item	Date
Publication of issues paper	22 August 2017
Publication of interim report	19 December 2017
Publication of directions paper	17 April 2018
Close of submissions to directions paper	18 May 2018
Publication of final report	mid 2018

1.2 Initial stakeholder feedback and purpose of the Directions Paper

The Commission has previously released an issues paper and an interim report for this Review. Stakeholder feedback to those reports demonstrated strong support for maintaining the existing market-based approach to reliability, with interventions only being used as a last resort.[22] Stakeholders also overwhelming recognised the lack of a clear, consistent and integrated environmental and energy policy as a key aspect affecting reliability.[23]

This directions paper sets out the Commission's next iteration of thinking to four of the key streams of work in this Review, namely:

- the foundational aspect of reliability frameworks of forecasting

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

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

21 In addition, our *Frequency Control Frameworks Review* has recently made a series of draft recommendations that aim to address risks to power system security (in this case, frequency performance) as the electricity sector changes. See: https://www.aemc.gov.au/markets-reviews-advice/frequency-control-frameworks-review

22 See for example the following submissions to the interim report: AGL, Energy Networks Australia, Hydro Tasmania, Flow Power.

23 Sixteen of the eighteen submissions to the issues paper recognised this.

- assessing the suitability of a day-ahead market (Finkel Panel recommendation 3.4)
- development of a mechanism to facilitate wholesale demand response (Finkel recommendation 6.7)
- assessing the need for a strategic reserve to enhance or replace the RERT (Finkel recommendation 3.4).

The purpose of this paper is to facilitate further consultation and feedback on these streams of work.[24] It also provides stakeholders an opportunity to provide input into this Review, ahead of the final report being published in mid-2018. The final report will also progress other aspects that are in scope of the Review, such as assessing intervention mechanisms including directions (that require generators to increase output, for example) and clause 4.8.9 instructions (that result in involuntary load shedding).

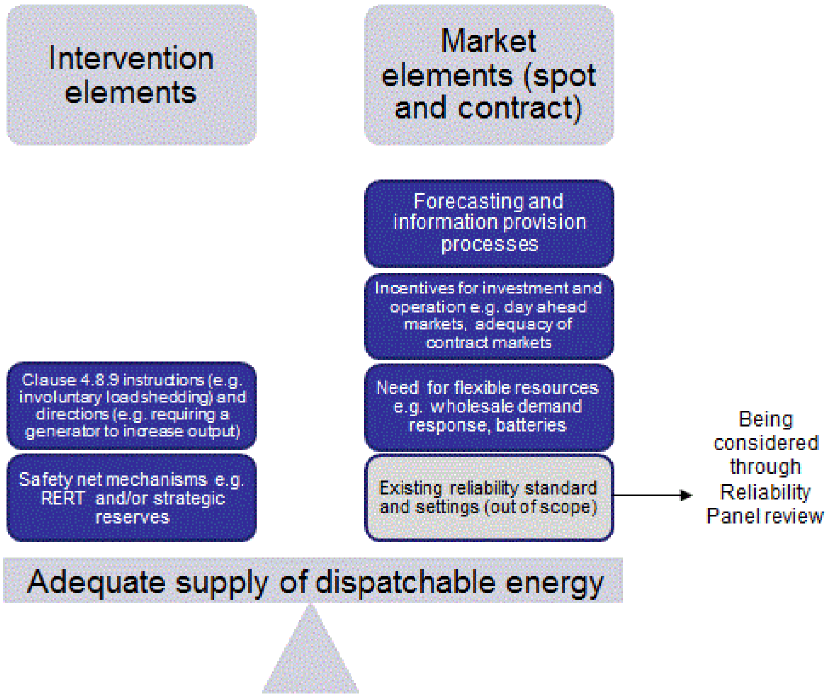
1.3 Project scope

This Review is undertaking a holistic review of the existing reliability framework. This framework includes both longer-term aspects such as the appropriate pattern 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 intervention measures. This Review looks at this from both the supply-side (generation) as well as the demand-side (demand response).

The scope of the Review is shown in Figure 1.1 below.

24 Noting that the strategic reserve aspect, as set out in the relevant chapter of this directions paper, will be progressed through rule change processes going forward since AEMO submitted two rule changes with regards to the RERT. See https://www.aemc.gov.au/rule-changes/enhancement-reliability-and-emergency-reserve-trader and https://www.aemc.gov.au/rule-changes/reinstatement-long-notice-reliability-and-emergency-reserve-trader.

Figure 1.1 Scope of the review



The Review also incorporates existing work or recommendations that relate to reliability, including recommendations directed to the AEMC from the Finkel Panel:[25]

- 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 (recommendation 3.4)
- assessing the suitability of a day-ahead market (recommendation 3.4)
- the recommendation of a mechanism that facilitates efficient demand response in the wholesale energy market (recommendation 6.7).

These are three 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 is consistent with the timeframes that the COAG Energy Council agreed to for the implementation of these recommendations.[26]

25 The Commission also notes that one of the other Finkel Panel recommendations was a requirement for all large generators to provide at least three years' notice prior to closure. Under the proposal, 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. The Commission has recently received this rule change request from Dr Kerry Schott AO regarding notice of generator closure, and this will be progressed alongside this Review, as part of the Commission's reliability work program.

26 On 31 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. See http://www.coagenergycouncil.gov.au/publications/report-coag-leaders-finkel-review-implementation. The Energy Security Board's annual Health of the NEM report tracks progress against this.

The scope of the Review also originally included the Finkel Panel recommendation of developing a generator reliability obligation. However, the reliability requirement proposed by the Energy Security Board as part of the National Energy Guarantee is intended to address the same underlying issues as the generator reliability obligation. Details of the Guarantee are being developed and will be considered by the COAG Energy Council at its April 2018 meeting.

The Review also takes into account relevant AEMO workstreams. This includes the demand response emergency reserve program being trialled by Australian Renewable Energy Agency (ARENA) and AEMO,[27] as well as their self-forecasting project.[28] It will take account of any other trials that ARENA and AEMO undertake through their memorandum of understanding.

The reliability of transmission and distribution networks is outside the scope of this Review.[29] The security of the power system is also outside the scope of this Review, since this is being addressed through the AEMC's comprehensive system security work program detailed in section 1.4 below.

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 published late 2017 and is discussed in appendix A.[30] A final report is due by the end of April 2018.

1.4 AEMC's system security work program and its interaction with this Review

Reliability (referring to having enough generation, demand response and network capacity to supply consumers) is different from 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. Security aspects, including technical parameters such as voltage and frequency are outside the scope of this Review.

“Secure” has a particular meaning under the NER. Specifically, 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, defined under the NER

27 The initiative is a three-year pilot program seeking to provide 160 MW of reserve capacity through demand response.

28 Discussed in chapter 3.

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

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

- 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.

Following a contingency event or significant change in power system conditions, AEMO must use its reasonable endeavours to return the power system to a secure operating state within 30 minutes.[31] AEMO may authorise a person to do any of the things contemplated by section 116 of the National Electricity Law if AEMO is satisfied that it is necessary to do so for reasons of public safety or the security of the electricity system.[32]

It is important to recognise that a reliable power system will also be a secure power system. However, the converse is not necessarily true; a power system can be secure even when it is not reliable. For example, one of the ways in which AEMO can maintain power system security is to undertake involuntary load shedding, potentially compromising reliability, in order to return the power system to a secure operating state.

The AEMC has a separate, comprehensive system security work program that is focussed on having a secure power system. In particular this focusses on developing market frameworks which allow continued take-up of new generating technologies while keeping the lights on. Projects completed under this work program include:

- 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 the Australian Energy Market Operator (AEMO) to regularly and transparently assess emerging risks caused by swapping out older synchronous generators, for non-synchronous generation technology like wind and solar.

- 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

31 Under cl. 4.3.2(a), AEMO must use its reasonable endeavours, as permitted under the Rules, to achieve the AEMO power system security responsibilities (which are set out in clause 4.3.1) in accordance with the power system security principles set out in clause 4.2.6. One of those principles is that following a contingency event (whether or not a credible contingency event) or a significant change in power system conditions, AEMO should take all reasonable actions to adjust, wherever possible, the operating conditions with a view to returning the power system to a secure operating state as soon as it is practical to do so, and, in any event, within 30 minutes.

32 Clause 4.8.9(a)(2) of the NER.

- 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
- 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[33]

- Also in September 2017 we published a consultation paper on a proposal for new technical performance standards for connecting generators. 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 more difficult to manage in some locations. A draft determination is due in June 2018.
- Our *Frequency control frameworks review* is underway, which is looking at ways to integrate new technologies and demand response to help keep the system secure, as well as considering new ways to deliver more inertia where this provides additional benefits to the system. A draft report was published in late March 2018, ahead of a final report in mid 2018.

Given that having both a reliable and secure electricity system results in the best possible outcomes for consumers, the Commission is coordinating these two work programs.

Relevant to the above is the Reliability Panel's *Annual Market Performance Review* which reviews the performance of the national electricity market (NEM) in terms of reliability, security and safety. In 2016/17, the security performance of the NEM has been mixed. In 2016/17 there were 11 instances of the system being operated outside its secure limits for greater than 30 minutes.

In contrast, the Reliability Panel found that the NEM performed well in terms of reliability for the 2016/17 time frame.[34] In 2016/17, at a wholesale level, 0.00036 per cent unserved energy came from one reliability event that occurred in South Australia on 8 February 2017, where demand was higher than forecast, wind generation was lower than forecast, and thermal generation capacity was reduced due to a few forced outages. This is within the reliability standard.[35] At a wholesale level, there was no other unserved energy recorded due to reliability events for any other region in the NEM. Projections show that some unserved energy, although nowhere close to

33 This rule change was proposed by AEMO.

34 See: https://www.aemc.gov.au/markets-reviews-advice/annual-market-performance-review-2017

35 An expectation that no more than 0.002 per cent of demand for energy will be unmet in any region of the NEM.

breaching the reliability standard, is forecast over the medium term (2018/19 to 2026/27).[36]

1.5 Related work

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

1.6 Stakeholder consultation

1.6.1 Submissions to issues paper and interim report

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

Submissions to the interim report were due on 6 February 2018. The Commission received 31 submissions from a wide range of stakeholders.[37]

Overall, stakeholders were supportive of the AEMC undertaking this Review and doing so in a balanced and considered way.[38] Stakeholders generally expressed support for market-based mechanisms, and stated that interventions should only be used as a last resort.[39] As previously mentioned, stakeholders also overwhelming recognised the lack of a clear, consistent and integrated environmental and energy policy as a key aspect affecting reliability.[40] Stakeholders also wanted more detail on the interaction between the Guarantee and this Review.[41] Individual submissions to the interim report and comments are discussed in each relevant chapter in more detail in this report.

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36 AEMO projects unserved energy over the medium- and long-term through its forecasting processes, namely the medium-term PASA in over the next two years and the ESOO and the EAAP over the two-to-ten year timeframe. With respect to the recent projections of some unserved energy within the reliability standard, AEMO has, for example, projected that the probability of *some* unserved energy in NSW post-Liddell closing rises to 35 per cent in 2026-27 assuming no additional capacity. It is important to note that, despite this, AEMO's processes are forecasting that the reliability standard will be met. The projected unserved energy is within the reliability standard (i.e. 0.002 per cent unserved energy). Modelling for the Reliability Panel carried out by EY also projects that the reliability standard will be met after Liddell closes.

37 The submissions themselves, as well as a summary of them, can be found on our website, see: https://www.aemc.gov.au/news-centre/media-releases/summary-stakeholder-submissions-aemcs-reliability-frameworks-review

38 See for example the following submissions to the interim report: Snowy Hydro, PIAC, Bluescope, Clean Energy Council, AEMO, Infigen, Origin.

39 See for example the following submissions to the interim report: AGL, Energy Networks Australia, Hydro Tasmania, Flow Power.

40 Sixteen of the eighteen submissions to the issues paper recognised this.

41 See for example the following submissions to the interim report: Hydro Tasmania, Australian Energy Council, Energy Networks Australia, TransGrid, Origin, EnerNoc, Major Energy Users.

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 three times (August and November 2017 and March 2018) and input from this group has been incorporated into this paper.

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 AEMO, the AER, ARENA, consumer groups, large energy users, conventional generators, renewable generators, retailers, demand response providers, and transmission and distribution network service providers. The technical working group has met twice:

- first in November 2017, with the discussion focussing on initial views with respect to the contract market, key concepts and demand response
- then in February 2018, with the discussion focussing on forecasting, demand response and day-ahead markets.

Comments and feedback from the technical working group have been incorporated into this report.

1.6.3 Submissions to the directions paper

The Commission invites comments from interested parties in response to this directions paper by **18 May 2018**, set based 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.[42] All submissions will be published on the Commission's website, subject to any claims of confidentiality.

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".[43]

42 See: http://www.coagenergycouncil.gov.au/publications/report-coag-leaders-finkel-review-implementation

43 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.

1.7 Structure of directions paper

The remainder of the directions paper is structured as follows:

- chapter 2 sets out the context for this Review
- chapter 3 discusses forecasting and information provision
- chapter 4 discusses the suitability of a day-ahead market in the NEM
- chapter 5 examines options for facilitating wholesale demand response
- chapter 6 provides an update on strategic reserves
- appendix A summarises related work to this Review
- appendix B provides more detail on our forecasting analysis
- appendix C provides some further detail on day-ahead markets
- appendix D provides a mapping of the timeframes involved in participating in the NEM
- appendix E summarises submissions not discussed in the main body of this paper.

The submission should be sent by mail to: Australian Energy Market Commission, PO Box A2449, Sydney South NSW 1235. 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.

2 Context

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

- section 2.1 discusses what reliability is and consumer experiences of reliability
- section 2.2 provides an overview of the existing reliability framework
- section 2.3 discusses challenges to this framework and
- section 2.4 discusses policy and market responses to these challenges.

2.1 Reliability and consumer experiences of reliability

2.1.1 Reliability and security

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, the NER requirement of a satisfactory operating state within 30 minutes.[44]

The focus of this Review is on the first element of a reliable power system.

As noted in chapter 1, reliability is distinct from 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.

However, the two concepts are closely related operationally and it is not always simple to separate the two concepts. A reliable power system will also be 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

44 The "satisfactory operating state" is a defined term under the NER, which is set out in clause 4.2.2.

even when it is not reliable. One of the ways in which AEMO can do this is 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 are expected to occur at times of peak demand for electricity, generally on very hot days, 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.[45] Similarly, when the RERT was again exercised in January 2018, it was in the middle of the afternoon with the temperature exceeding 40 degrees Celsius in Victoria.[46]

In contrast, security issues can be expected to arise at any time, and, at present, more often than not tend to occur at off-peak times, when there are low demand conditions. Recently, AEMO has frequently directed on participants in South Australia for system security purposes, with these generally occurring at off-peak times. For example, 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 00:00.[47] Between 1 July 2017 and 31 March 2018, AEMO has issued 20 directions to generators in South Australia to manages system strength (security) outcomes.[48] In contrast, in order to manage reliability AEMO only intervened twice (exercising the RERT two times in Victoria).

2.1.2 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.

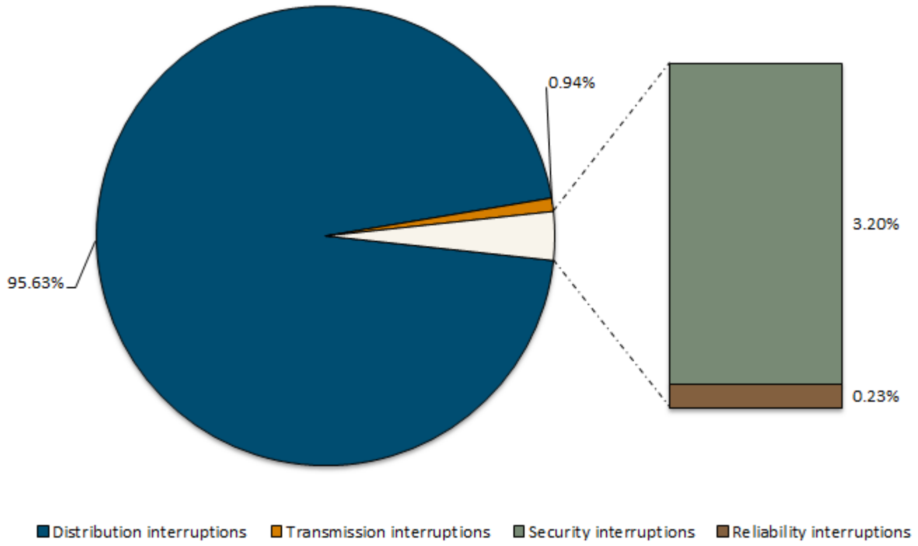
45 AEMO activated reserve contracts to maintain the power system in a reliable operating state. The reserve contracts were activated at 1530 hr 30/11/2017. See: market notice 60142, 30 November 2017, 15:20, market intervention.

46 AEMO activated reserve contracts to maintain the power system in a reliable operating state. The contracts were activated at 14:00 AEST on 19/01/2018. See: market notice 60843, 19 January 2018, 13:43, market intervention.

47 The direction was issued at 00:00 02/12/2017, with effect from 01:00 hrs 02/12/2017. See: market notice 60176, 2 December 2017, 0:02, market intervention.

48 Noting that directions are counted per event and that some events span a number of days. There was also an instruction in NSW for power system security reasons.

Figure 2.1 Sources of supply interruptions in the NEM: 2007-08 to 2016-17



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 2.1 shows an indicative analysis of sources of supply interruptions in the NEM over the period 2007-08 to 2016-17. This chart includes an extra year compared to that included the interim report, incorporating 2016-17 and so the system black event in South Australia.[49] 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 0.23 per cent of total supply interruptions (in terms of GWh) was the result of inadequacy of supply, noting that this is well below the reliability standard.[50] This is much smaller than the amount of security interruptions that have occurred: over the past 10 years there have been 3.20 per cent (nearly 10 times more) supply interruptions for security.

The vast majority was due to network interruptions, specifically from the distribution network.

These trends in supply interruptions have been relatively stable for the past ten years.[51] There have only been two instances of reliability interruptions, in 2008-09 where reliability interruptions accounted for 1.4 per cent of total supply interruptions and 2016-17 (0.05 per cent of total supply interruptions).

49 The figure therefore includes an estimation of unserved energy associated with the black system event which occurred on 28 September 2016 in South Australia as security.

50 The reliability standard is unserved energy of no more than 0.002 per cent of demand. The amount of unserved energy associated with the reliability interruptions in the chart is well below 0.002 per cent of demand. The only year whereby there was unserved energy in excess of the standard was in 2008-09.

51 And beyond that.

2.1.3 Recent performance of reliability and security

Every year, the Reliability Panel reviews the performance of the NEM in terms of reliability, security and safety in its *Annual Market Performance Review* report. Of relevance here is the performance of reliability and security in the most recent report.

During 2016/17, the security performance of the NEM was mixed. In 2016/17 there were 11 instances of the system being outside its secure limits for greater than 30 minutes, an increase on 2015/16 when there were seven instances, which was an increase again on 2014/15 with four instances.

There were some major security events witnessed in 2016/17, chiefly, the South Australian black system event which occurred on 28 September 2016. This incident saw a total loss of supply to the region, close to 850,000 customers. It is estimated that South Australian businesses suffered costs of $450 million as result of the blackout.[52] This incident demonstrated both the importance and difficulty in maintaining system security in a changing environment.

In relation to reliability, in 2016/17, at a wholesale level, there was only 0.00036 per cent unserved energy recorded from one reliability event that occurred in South Australia. This event featured extreme temperatures that led to high demand conditions and coincided with factors including outages of thermal generation and inaccurate forecasts.

This measure of unserved energy is well within the reliability standard (an expectation that no more than 0.002 per cent of demand for energy will be unmet in any region of the NEM). There was no other unserved energy recorded due to wholesale reliability events for any other region in the NEM.

While the NEM has performed well over the last decade in terms of reliability, projections show that some unserved energy, within the reliability standard, is forecast over the medium term (2018/19 to 2026/27). AEMO projects unserved energy over the medium- and long-term through its forecasting processes, namely the medium-term PASA in over the next two years and the ESOO and the EAAP over the two-to-ten year timeframe. With respect to the recent projections of some unserved energy within the reliability standard, AEMO has, for example, projected that the probability of some unserved energy in NSW post-Liddell closing rises to 35 per cent in 2026-27 assuming no additional capacity is built. It is important to note that, despite this, AEMO's processes are forecasting that the reliability standard will be met.[53] The projected unserved energy is within the reliability standard (i.e. 0.002 per cent unserved energy). Modelling for the Reliability Panel carried out by EY also projects that the reliability standard will be met after Liddell closes.

52 Parliament of South Australia, Report of the select committee on the statewide electricity blackout and subsequent power outages, 28 November 2017, p. 12.

53 AEMO, advice to the Commonwealth relating to AGL's proposal to replace Liddell, accessed from http://www.aemo.com.au/Media-Centre/AEMO-observations---operational-and-market-challeng es/AEMOs-liddell-response.

Views on reliability performance

On 23 March 2018, AEMO published its advice to the Commonwealth Government in relation to AGL's proposal to replace Liddell.[54] In its advice, AEMO noted that approximately 850 MW of additional dispatchable resources are needed by 2026-27.[55]

As noted above AEMO is not forecasting that the reliability standard will be breached without an additional 850 MW of capacity. When AEMO evaluated AGL's plan against the reliability standard, its conclusion was that the reliability standard is forecast to be met.[56] AEMO's analysis is, instead, based on a Loss of Load Probability (LoLP) metric, which is different from the reliability standard, and includes consideration of worst case scenarios. The metric takes into account the probability of *any* involuntary load shedding, including unserved energy that is within the reliability standard.[57] The reliability standard is discussed in more detail in section 2.2.2.

2.1.4 Consumer expectations

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, responding to information provided by the system operator;[58] whereas ‘security’ issues are operationally directly managed by the system operator. Therefore, considering reliability and security issues in the NEM needs to be done in this context.

Under current market and regulatory frameworks, the obligations in relation to the delivery of reliability and security, and the tools available to AEMO to maintain a 'secure operating state'[59] and a 'reliable operating state'[60] are therefore different and tailored to meet either the security or reliability outcomes necessary for the power system within the above context.

Consumers who experience an interruption may not be able to distinguish clearly the “type” of supply interruption that were identified in Figure 2.1: whether an outage is driven by a security event, a reliability event, or a network event. From a consumer’s

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54 AEMO, advice to the Commonwealth relating to AGL's proposal to replace Liddell, accessed from http://www.aemo.com.au/Media-Centre/AEMO-observations---operational-and-market-challenges/AEMOs-liddell-response.

55 Ibid. p. 4.

56 Ibid. p.5.

57 It is not clear exactly which assumptions AEMO used in the NSW modelling. However, AEMO has noted, in other contexts, that its analysis with respect to the risk of unserved energy means that significant load shedding could occur during severe demand and supply balance conditions. AEMO states that this risk and any associated load shedding would not meet most stakeholder expectations. See AEMO, proposal for an enhanced RERT rule change request, p. 6.

58 However, AEMO may intervene for reliability purposes in instances where the market has failed to resolve reliability issues, using the measures available to it under the NER.

59 See clause 4.2.4 and Chapter 10 of the NER for a definition.

perspective, the lights are either on or they are not. While the consumer may not recognise 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.

Further, consumers' experience may differ depending on the length and extent of an outage - distribution outages typically last for a short amount of time in a localised area, whereby as a system security or a system black would be expected to be more widespread and may potentially last longer.

However, the cause of supply interruptions is important to policy makers in relation to the regulatory framework. Having the cause of the problem be clearly identified, results in the most direct and least cost solutions being pursued and implemented. A reliability fix to a security problem may help the security problem as a by-product, but it will likely result in more expensive outcomes than dealing with the problem directly.

Consistent with the National Electricity Objective, there are two costs that need to be balanced in considering the reliability framework:

- Costs of reliability - Reliability involves costs. Higher levels of reliability require more investment in capacity (e.g. more generation, demand-side resources or network assets) and/or more stringent operating conditions, all which impose costs on parties. For example, having more generation being operated more stringently creates higher per unit costs of electricity. These costs will be reflected in consumer prices.

- Costs of unserved energy - The alternative is not to supply the energy. That is to allow for an expected level of supply interruptions to consumers. This also has a cost - reflecting the customer's willingness to pay for the reliable supply of electricity (this is known as the value of customer reliability, see Box 2.1). If a customer has an interruption, when they were willing to pay for electricity, they will face costs e.g. lost production if it is a business; or a colder / hotter home for residential customers with air conditioning.

A reliability framework therefore embodies a trade-off 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 supply of energy would exceed the value placed on it by consumers. The magnitude of such costs are discussed below in Box 2.3 below.

Therefore, it is particularly important to factor in the value that consumers place on reliability - see Box 2.1.

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60 See clause 4.2.7 and Chapter 10 of the NER for a definition.

Box 2.1 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, purchase a new car in order to be able to commute to work, so too might they value the reliability of their electricity supply very differently.

How consumers value electricity supply depends on what they use their energy for, from heating water in residential homes to helping to run a small business to powering large-scale manufacturing processes. So valuing reliability depends on the value they place on these services and because these services differ, so too does the value of reliability.

In addition to what services the customer uses the electricity for, 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.[61]

In September 2014, AEMO released a report containing the first estimates of value of customer reliability undertaken at a national level.[62] It put the NEM-wide average value of customer reliability at $33,460/MWh.[63]

In December 2017, the COAG Energy Council submitted a rule change request to the AEMC to allow the AER to assume responsibility for establishing values of customer reliability.[64] This will establish nationally consistent and updated value of customer reliability to assist in setting appropriate network reliability standards, network planning, economic regulation of network services as well as informing wholesale market settings such as market price caps.

The most recent Energy Consumer Sentiment survey run by Energy Consumers Australia has some useful data that is relevant to these observations. It found that

61 Because the actual costs to customers of supply interruptions cannot be observed unless consumers directly participate in the wholesale market, 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.

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

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

64 See https://www.aemc.gov.au/rule-changes/establishing-values-of-customer-reliability

consumers are broadly satisfied with the reliability of their electricity services. Specifically, between 60 and 70 per cent of consumers say they are satisfied in every state and territory in the NEM. However, the proportion of consumers expressing confidence that the market will deliver increased reliability in the *future* had fallen since the last time the survey was undertaken - to between 34 to 46 per cent.[65] Consumers say that their primary concern is affordability, suggesting that while investment is needed, care should be taken not to spend more than necessary on new generation or upgrading or maintaining the networks.[66]

AEMO's submission on the interim report also considers this issue. AEMO notes that any loss of load is not a publicly acceptable outcome and that frequent outages could lead business consumers to leave the grid to achieve higher reliability.[67] Further, AEMO considers that during hot weather, involuntary load shedding poses significant risk of harm to public health and safety.

It should be noted that in assessing and considering any changes to the existing arrangements, the Commission is guided by the NEO, which 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:
>
> - price, quality, safety and reliability and security of supply of electricity
> - the reliability, safety and security of the national electricity system”

As noted in the assessment framework for this review, the Commission considers that the most relevant aspects of the NEO 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.[68] However, other elements of the NEO (including the “safety… of supply of electricity” and the “safety of the national electricity system”) may also be relevant.

The term safety has a particular meaning in the context of the NEO: for example, the safety of the national electricity system is linked to the security of the power system and relates to the operation of assets and equipment within their technical limits. More

65 See: http://energyconsumersaustralia.com.au/wp-content/uploads/Energy-Consumer-Sentiment-Survey-December-2017.pdf

66 See: http://energyconsumersaustralia.com.au/news/new-data-attitudes-energy-households-small-businesses-demands-focus-affordability/

67 AEMO, submission to interim report, p. 9.

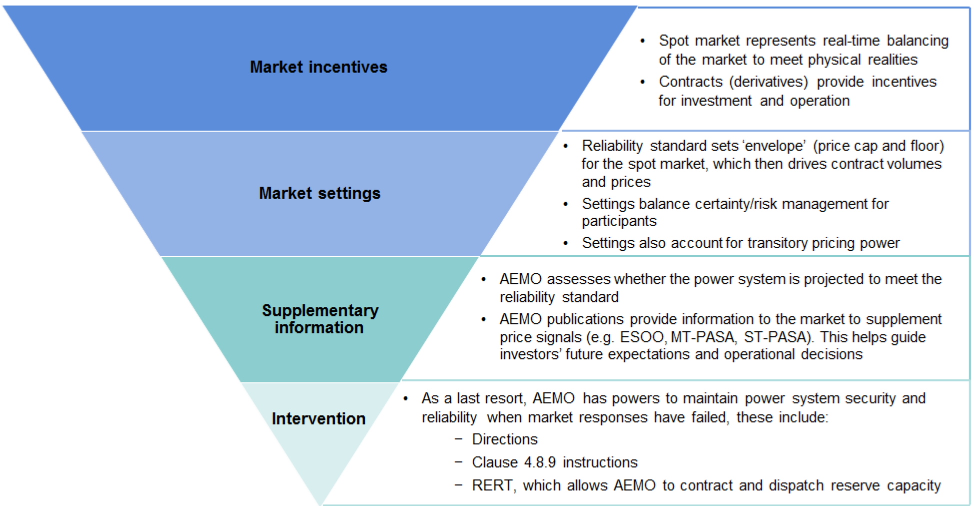
68 See appendix A of the Interim Report for this Review.

information on how the Commission implements the NEO may be found on our website. [69]

2.2 Current reliability framework

Figure 2.2 provides a summary of the existing reliability framework, including the reliability standard, the reliability settings and AEMO's intervention mechanisms.

Figure 2.2 Current framework with escalating series of interventions



2.2.1 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. Market participants make investment and operational decisions based on these market signals. 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.

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[70] which will inform operational decisions and provide an incentive for entry and expansion, addressing any potential reliability problems as or before they arise.

The most critical thing to recognise is that, in the NEM, it is generally left to competing businesses to make investment and operational decisions rather than a central planner with imperfect information about the 'least cost' or 'most efficient' outcome and

69 See https://www.aemc.gov.au/sites/default/files/content/Applying-the-energy-market-objectives-for-publication.pdf

70 Within the price envelope, as discussed in section 2.2.1.

positive incentives to overbuild. The framework provides incentives for an efficient mix of technologies to be deployed - for example, expectations of highly volatile supply and demand conditions translate into expectations of highly volatile spot market prices. The degree of volatility affects the demand for and value of hedge contracts such as caps and swaps. In turn, this provides incentives for investment/retention of plant best able to capitalise on that volatility, such as peaking plant and storage solutions.

Spot market

The NEM's spot market is 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 (near) instantaneously, including an allowance for a sufficient quantity of reserves. Reserves in the NEM are represented by those generators that offer their availability into the wholesale market, but are not dispatched.

Scheduled and semi-scheduled generators and loads offer and bid into the market dispatch engine, operated by AEMO. Once these offers are received, AEMO then forecasts the expected consumer demand for electricity in each region for each 5-minute pricing interval. Then, the dispatch engine seeks to optimise outcomes by attempting to maximise the value of trade given the physical limitations of the power system. These physical limits are otherwise known as "constraints" which, for example, restrict how much electricity can flow over a particular piece of equipment i.e. keeping it within its technical capability.

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 limit 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 are discussed further below in section 2.2.2.

While the spot market forms part of the NER, there are also accompanying financial derivative markets which sit outside the formal NER framework, and which play an integral part of the reliability framework. This is discussed below.

Contract market

The contracts or financial derivatives market serves the following four purposes:

- It provides a mechanism for retailers and generators to manage their exposure to spot prices, by allowing participants to trade uncertain and variable spot market prices for fixed prices[71] going forward.

71 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

- On a short-term operational timescale (e.g. hourly), generators who have sold contracts are incentivised to be available when needed (i.e. when spot prices are high), in order to be dispatched to at least the volume of their contracts so earn revenues in the spot market to fund payouts on their contract positions. They are indifferent to the level of spot prices as the price they receive is determined by their contracts, *provided* they are dispatched. This incentive to 'turn up' is heightened during high price/tight demand-supply periods, which is precisely when the system most values the generator's output.

- It lowers the cost of financing investment in generation capacity, which lowers the cost of achieving and maintaining system reliability. Contracts provide generators a steadier stream of revenue compared to taking spot price exposure. This reduces 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.

Alternatively, a retailer (generator) could invest in generation (retail), which is more commonly known as vertical integration.

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.[72] 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 parties to these hedging instruments do not have to physically deliver electricity,[73] and so 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

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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.

72 The Commission has recently made a final rule determination to move the NEM to 5-minute settlement from 2021. See www.aemc.gov.au/rule-changes/five-minute-settlement

73 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.

financial hedging instruments and counter parties promotes reliability over both the short-term and long-term.

Incentives for flexible and dispatchable generation

In any electricity system, decisions need to be made ahead of real time to start (or stop) individual generating units. The decision, depending on generation technology, may need to be made many hours in advance of the need to produce energy, and may have significant cost. This decision is known as the "unit commitment decision". In the NEM, the unit commitment decision is, in effect, taken by individual market participants. The unit commitment decision is distinct from the centralised dispatch process undertaken by AEMO.

Historically, unit commitment decisions in some pre-NEM markets (e.g. Vicpool) were undertaken centrally. However, this was changed in response to recognition that central commitment of generations limits the efficiency that occurs through rebidding.[74]

In the NEM, the 5-minute spot price provides a signal of the value of energy during that five minute interval. In and of itself, the 5-minute spot price provides limited indication of the value of energy in the future. This has led some commentators to assert that there is no transparent and explicit value for reserves, flexibility or dispatchability in the NEM, and that as a consequence these characteristics are not (or will not be in the future) sufficiently valued or provided. The Commission agrees that there is no transparent and explicit value for flexibility and dispatchability in the NEM, but considers that this does not of itself necessarily lead to the conclusion that these are (or will be) under-valued or under-provided.

In drawing their conclusions, some commentators appear to have overlooked that market participants take account of their estimations of the future spot price together with their sold financial contract positions in making their unit commitment decisions.

A market participant's estimations are informed by AEMO forecasts of spot prices (themselves informed by information provided by market participants through pre-dispatch), which are also reflected in forward contract prices, as well as the market participant's own views on the supply and demand balance.

Market participants do not focus only on the next five minutes – the prospect of potential high spot prices in the future provide incentives for market participants to structure their bids so as to commit units ahead of time and hence provide reserves to the market. This is the case even if the market participant makes a loss during any individual 5-minute interval (or indeed a great number of successive 5-minute intervals).

74 CRA, Short-term forward market, Report for South Australia Department of Treasury and Finance, 30 June 2004.

The factors which influence unit commitment decisions made by market participants are complex, and include:

- their estimation of the likelihood of spot prices being at a variety of levels in the future (i.e. their probability-weighted expectation of future spot prices)
- their sold contractual position and their aversion to making potentially large losses through their contracts if not also generating when the spot price is high
- their ability to ramp generation from a variety of operating states in order to maximise their output to capture high spot prices and minimise their generation to avoid low spot prices
- any fixed costs associated with starting and stopping units, as well as the costs associated with running the units (for example at minimum output).[75]

If a market participant deems that the probability and extent of high spot prices in the future is low, then, depending on a variety of other factors including those described above, it may choose to avoid costs and structure its bids so as to not commit (or de-commit) plant. In effect, it considers that the prices that it would earn would not compensate it for incurring the short-run costs (including fuel + unit commitment costs) of running.

The consequence of this would be to steepen the supply curve. In the event that additional generation is required to meet demand, those generators that remain committed and so are able to supply receive a higher spot price. This in turn influences market participants' estimations of the likelihood of spot prices being at a variety of levels in the future. A generator's commitment decision is therefore iteratively determined based in part on future spot price expectations (and changes in these expectations), which are in turn informed by all generators' commitment decisions.

Box 2.2 A simple example of iterative unit commitment decisions in the NEM

The following example is simplified, but illustrates the iterative process discussed above.

There are four generators, A, B, C and D, which each have individual expectations of the probability weighted average spot prices in the future, and different "thresholds" for the probability weighted average spot prices above which they will commit their plant. This threshold is influenced by a variety of factors, including their contractual position. In reality, it is difficult to distil these concepts into precise numbers, but for the purposes of this simplified example unique numbers are provided.

75 Market participants may also factor in the prospect of being directed by AEMO, and hence receiving compensation.

Each generator has to make a commitment decision, say, six hours in advance of real time.

24 hours in advance of real time, the situation is as follows.

Generator	Individual probability weighted expectation of future spot prices ($)	Threshold for commitment ($)	Indicating it will commit through bidding profile?
A	60	30	Yes
B	50	55	No
C	44	56	No
D	46	44	Yes

As can be seen, each generator has different views of the future and different thresholds for commitment. Those generators with an expectation which exceeds their threshold are indicating, through their bidding profile, that they will commit. The collective commitment decisions of market participants' indicative commitment decisions are provided to the market via the pre-dispatch process.

20 hours ahead of real time, generator D adjusts its probability weighted expectation of future spot prices downwards – perhaps in response to its own demand forecasts. Consequently, it alters its bids (in bold in the table below).

Generator	Individual probability weighted expectation of future spot prices ($)	Threshold for commitment ($)	Indicating it will commit through bidding profile?
A	60	30	Yes
B	50	55	No
C	54	56	No
D	**43**	44	**No**

In response, the other generators' expectations of spot prices increase, shown in bold in the table below.

Generator	Individual probability weighted expectation of future prices ($)	Threshold for commitment ($)	Indicating it will commit through bidding profile?
A	**65**	30	Yes
B	**56**	55	**Yes**
C	**55**	56	No
D	43	44	No

As a consequence, generator B structures its bids so that it will now commit (providing no other changes).

This process continues iteratively and continuously until the time at which the generators need to make their unit commitment decisions. Rebidding by generators (see Box 4.4) and updates to demand forecasts by AEMO occurs frequently in the NEM.

Reserves are implicitly valued through this process. If spot prices are low, and market participants' probability-weighted expectations of future spot prices are also low, then this implies that the market has sufficient reserves.

As generators de-commit where the costs of committing are not outweighed by the expected (low) future spot prices, market participants' probability-weighted expectations of future spot prices will rise until an equilibrium is reached where an efficient level of reserves have been committed.

Conversely, if market participants' probability-weighted expectations of future spot prices are high, then market participants will commit their plant (even if spot prices are *currently* low) in order to receive those expected high spot prices or defend their contractual positions. In this case, probability-weighted expectations of future spot prices will again drop until an equilibrium is reached. Crucially, it is market participants' probability-weighted expectations of future spot prices along with a number of other factors such as their contractual position, rather than the current spot price or AEMO's pre-dispatch forecasts of spot prices (as distinct from demand), which influences their bidding behaviour.

Market participants have strong financial incentives to ensure that they are not individually short of generation in order to meet their contractual commitments, or, if not contracted for all their capacity, in order to avoid missing the opportunity of earning revenue. The market price cap is determined with this process in mind. It is high compared to the average wholesale spot price of electricity in order to provide sufficient enough reward to generators to be available despite making losses in individual dispatch intervals. In effect, a high market price cap serves to increase the probability-weighted expected future spot price: even if the probability of a high spot price is low, the fact that the spot price could go very high serves to provide incentives for sufficient generators to be available "just in case".

Some commentators have suggested that the unit commitment decisions taken by individual market participants are inefficient and that as a result, dispatch is inefficient. They suggest that instead, unit commitment decisions should be centralised. This argument at times appears to be based on the assumption that generators bid at the cost of their fuel (i.e. not taking account of unit-commitment costs), and will therefore seek to de-commit whenever spot prices are below the cost of their fuel. However, as discussed above, generators structure their bids not simply based on the current spot price, nor solely on AEMO's pre-dispatch forecast of prices, but on their own weighted average expectations of future price, amongst other factors such as their unit commitment costs.

The process of optimising dispatch is therefore a complex one, not solely undertaken through the NEM dispatch engine in real time, but also through the iterative process described above. While the dispatch engine only takes account of the next five minutes in determining which generators to dispatch given their bids, these bids made by market participants themselves take account of a longer term view. It is through this process that unit commitment and dispatch optimisation occurs over time.

The Commission is interested in views in whether this iterative process that currently exists in the NEM could result in inefficient unit commitment or dispatch decisions, or that unit commitment decisions or dispatch could be more efficient under a central-commitment model.[76]

A centralised commitment model, by definition, requires the system operator to take a view about the future and commit units on this basis. The risk of centralised unit commitment decisions taken by the system operator would likely be borne by all market participants (for example through "make whole" uplift payments for generators committed by the system operator but not required with the benefit of hindsight) and ultimately by customers.

In contrast, under the existing framework, individual market participants are responsible for gathering and evaluating information that they consider relevant in

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76 It is relevant to note that the AER recently released a report on the market outcomes in Victoria and South Australia since the closure of the Hazelwood power station. On 3 November 2016 the Treasurer and the Federal Minister for Environment and Energy requested that the AER monitor market developments in Victoria and South Australia in light of the potential for the closure of Hazelwood to enable anti-competitive behaviours among remaining generators. We were requested to provide advice to the Council of Australian Governments (COAG) Energy Council on any factors affecting the efficient functioning of the market within one year of the station's closure. The AER's key finding is that the exit of Hazelwood removed a significant low fuel cost generator, which was largely replaced by higher cost black coal and gas plant - at a time when the input costs of black coal and gas plant were increasing. These factors, in turn, drove significant increases in wholesale electricity prices. We found no evidence to suggest that prices were being driven by rebidding close to dispatch, or physical or economic withholding - behaviours more usually associated with the exercise of market power. See: https://www.aer.gov.au/wholesale-markets/market-performance/aer-electricity-wholesale-performance-monitoring-hazelwood-advice-march-2018

order to structure their bids and make unit-commitment decisions. Furthermore, both the unit-commitment decisions and the consequences of those decisions are borne by the individual market participants, who, providing the market is workably competitive, are unable to pass the costs associated with poor decisions through to consumers. In turn, this provides incentives for generators to gather and evaluate information to inform their commitment decisions in an efficient manner. Indeed, the Commission understands that the decision to allocate to market participants both the decisions to commit units and the associated risks was a deliberate one when the NEM was founded for the reasons described above.

Of course, the market as a whole could be wrong in its view of the future, and reserves could be under-provided as a consequence of individual commitment decisions. Collectively and conceivably, insufficient generation may be available in any given dispatch interval. But, crucially, this is *unlikely* given the strong financial incentives placed on market participants through the spot and contract market. The historic low level of unserved energy in the NEM is evidence of this.[77] At its heart, the reliability framework seeks to balance the cost of lost load with the cost of investing and operating generation. The reliability standard and the market price cap seek to balance this trade-off.

A relevant question is whether the process described above continues to be fit for purpose in light of changing market conditions such as an increased variability of both the supply of, and demand for, electricity. The Commission is interested in stakeholder views on whether or not this is the case. As market conditions change, market participants' probability-weighted expectations of future spot prices change. For example, the high prevalence of variable renewable energy sources may serve to depress spot prices at certain times. But it will also increase the likelihood of very high spot prices: for example, when supply provided by variable, renewable energy resources unexpectedly and rapidly drops off. As through the process described above, this should influence unit commitment decisions of other generators.

This discussion has focussed on operational decisions. However, similar arguments can be made with regard to investment decisions. The market provides incentives for investment in not only the correct quantity but also the appropriate type of generation capacity and potential demand response. As noted above, commitment decisions can be influenced by the ability of plant to ramp quickly and the costs associated with committing and de-committing units. Those types of generators that are able to ramp quickly will incur fewer losses (or opportunity costs, depending on their contractual position) in the event that prices are high and they are not available, because they will be able to quickly commit. The time period of which they were unavailable is short. Similarly, those generators which are able to be committed at very low cost will be more profitable than those with higher commitment costs. This in turn improves the business case associated with investing in these types of generators, including through

77 Over the past decade, unserved energy was only recorded in two years – once in 2008-09 when the reliability standard was not met and once in 2016-17, when it was well within the reliability standard. There was no unserved energy (i.e. reliability load shedding) observed in any other year over the last decade.

reducing the risk associated with entering into contracts for a large proportion of their capacity.

Through expectation of future spot prices, and the variability of these prices, the market provides a mechanism to support investment decisions in flexible and dispatchable generation, which in turn delivers reliability. However, as noted earlier, the effective operation of these market mechanisms has historically been impacted by the lack of a nationally consistent long-term policy approach to emissions reduction.

The introduction of five-minute settlement will further sharpen the incentives to make investment and operation decisions consistent with the needs of the system, while the proposed National Energy Guarantee should provide policy certainty regarding emissions reduction.

2.2.2 Reliability standard and settings

The reliability standard and reliability settings – the market price cap, cumulative price threshold, administered price cap and market floor price – are an integral part of this market-based 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 investment. While the reliability standard and settings cap extreme prices, they remain part of the broader reliability framework.

Every four years, the Reliability Panel (the Panel) must review the reliability standard and the reliability settings.[78] The Panel is currently reviewing the reliability standard and settings. In November 2017, the Panel published a draft report that recommended leaving the reliability standard and settings unchanged. The Panel found:

- The current reliability standard and settings are achieving their purpose and are likely to continue to do so out to 2023/24.
- The market price cap and cumulative price threshold have been effective at limiting market participants' exposure to excessively high prices with the overall market integrity maintained. These settings appear to be sufficiently high to allow investment in enough generation so there is not more unserved energy expected than that allowed for by the reliability standard.
- 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 national electricity market, and the absence of sufficient evidence in support of a change to the price settings.

A final report is due for the Panel's review in April 2018.

78 Clause 3.9.3A of the NER.

Reliability standard

The reliability standard is the maximum expected unserved energy (USE) in a region for a given financial year. In general terms, '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. 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 total energy demand in a financial year is expected to be supplied.[79]

Importantly, setting the level of the reliability standard involves a trade-off between the prices paid for electricity and the cost of not having energy when it is needed. As noted earlier, increasing the levels of reliability involves increased costs. Further, given that reliability outcomes in the NEM have historically been high, improving these even further, will likely involve significant costs. Indicative costs of tightening the reliability standard are discussed below in Box 2.3.

Box 2.3 Indicative costs of tightening the reliability standard

The following provides some indicative supply 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 by Ernst & Young (EY).

The modelling indicated that expected unserved energy under the base scenario conditions in Victoria was very low at around 0.000003 per cent in 2021-21. EY indicated that reducing this already very low level of expected unserved energy to zero would require an additional 1,000 MW of capacity to be in place in Victoria in 2020-21. 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 the reliability standard in Victoria is threatened through early coal fired generation retirement.[80] Under this scenario, EY indicated there is a peak unserved energy of approximately 3,000 MW, or three times the amount that was modelled 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

79 See definition of 'unserved energy' in Chapter 10 of the NER and clause 3.9.3C of the NER.

80 Meaning that the reliability standard would be exceeded if the reliability settings such as the market price cap were not set sufficiently high to incentivise new entrant investment to keep unserved energy below 0.002 per cent.

An absolutely reliable system (one where the expected unserved energy is zero) is physically impossible. Even if there was a very large amount of excess capacity in the system (implemented at very high cost), there is always a possibility, however remote, of demand exceeding available capacity in a region. That is the reality of operating any power system.

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, and to inform the market of any projection that the reliability standard is expected to not be met. If a market response to a projected expectation that the reliability standard will not be met is not forthcoming, then AEMO may intervene through either using the RERT or clause 4.8.9 instructions or directions.

AEMO has been active in identifying and seeking to address the changing nature of the risks in its operations. As discussed in chapter 3, a number of initiatives are being undertaken to improve forecasting, for example, a trial for semi-scheduled generators to provide their own forecasts to AEMO. Further, last year in response to a rule change request from AEMO, the Commission made a final rule that enables AEMO to take into account broader risk factors for managing short-term reserves.[81]

Although a number of rule changes and initiatives have been put in place to help AEMO better manage the changing risk factors impacting the operation of the power system, AEMO has raised concerns about the appropriateness of the current reliability standard as a mechanism to operationally manage reliability in the power system going forward.[82]

AEMO concerns centre on the nature of the reliability standard as a statistical expectation. In particular, whether the existing reliability standard is still fit for purpose in an environment with very peaky supply and demand. It notes that the approach was developed when there was significantly less variability in supply and demand than there is today, with the changing demand profiles experienced today suggesting there is merit in discussing whether this mechanism remains sufficient for the future.[83]

AEMO highlights the operational challenges in managing the risks associated with increasing temperatures and presence of prolonged heat events.[84] The reliability standard, by its very nature (i.e. expected unserved energy measures across an average of a number of simulations) takes into account risks associated with different scenarios, including with hot weather days. These risks associated with operating the power system have always been there. However, the *nature* of this risk is changing – with

81 See https://www.aemc.gov.au/rule-changes/declaration-of-lack-of-reserve-conditions.

82 AEMO, submission to interim report, pp.57-62.

83 See: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power-system-requirements.pdf

84 AEMO, submission to interim report, p.5.

prolonged heat events becoming more commonplace and weather forecasting, becoming more important due to the changing generation mix. Other risks may be lessening in importance. Regardless, risks are assessed as part of determining the reliability performance and standard and should incorporate an up-to-date risk assessment.

AEMO's submission explores alternative and / or additional mechanisms including a Loss of Load Probability (LoLP). A LoLP shows the probability of any load shedding, regardless of its magnitude or regardless of whether or not the reliability standard is likely to be met.

AEMO has also raised this issue in the enhanced RERT rule change request. The Commission proposes to analyse the AEMO proposal in that context.[85] The rule change request is summarised in chapter 6.

Reliability settings

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

- Market price cap - The maximum price that a generator may bid during a dispatch interval is $14,200/MWh.[86] This 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 is set at such a level that prices over the long-term incentivise enough new investment in generation, as well as appropriate operational decisions, to achieve the reliability standard.[87]

- Market floor price - The minimum price that a generator may bid during a dispatch interval is -$1,000/MWh. This limits the amount of money a generator can lose in a single half hour, preventing market instability.

- Cumulative price threshold - This limits participants' financial exposure to prolonged high prices, by capping the total market price (currently at $212,800/MWh) that can occur over seven consecutive days. As with other reliability settings, it is set at a level such that prices over the long-term incentivise enough new investment, as well as operational decisions, so the reliability standard is expected to be met.

- Administered price cap - This $300/MWh cap 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

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85 The Commission intends to ask for the Panel for advice in the context of this rule change request, given their role in reviewing the reliability standard, whose role it is to review the reliability standard and settings.

86 This is indexed annually by the consumer price index (CPI) by the AEMC.

87 E.g. when prices are high more capacity is provided to the market.

cumulative price threshold.[88] 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.

2.2.3 Information processes

AEMO is required by the NER to publish various materials which provide 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 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 and over the next day)
- Pre-dispatch schedules – AEMO provides two sets of pre-dispatch data (i.e. solution of the dispatch engine using the information that is available at the time); 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 over the next 24 months.
- Low reserve conditions notices which are reported in MT PASA or lack of reserves (LOR) notices which are reported in ST PASA[89] – AEMO may publish these notices to advise participants when reserves are already or projected to be below critical levels.

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88 This is indexed annually by CPI by the AEMC.

89 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. The rule change request was proposed by AEMO.

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. 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 a potential problem. Similarly, the medium-term PASA, which looks forward 2 years and is updated weekly, 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.

2.2.4 Intervention mechanisms

As effective as information processes can be in delivering the desired reliability outcomes through market incentives, they do not always elicit the outcomes needed. If the market fails to respond to the information it publishes (that is, invest in additional capacity), 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.

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 distortion possible to the operation of the market. Under the NER, 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, and where practicable, for power system security. AEMO can dispatch/activate these reserves to manage power system reliability and, where practicable, security.
- 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.

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. It does this by instructing a transmission network service provider to arrange for the interruption of consumer load under clause 4.8.9 of the NER. 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.

Interventions to maintain reliability can have the potential to distort outcomes in the market since they can lessen the incentives on participants to respond through the market processes. Therefore, interventions in the NEM are designed to have as little distortionary impact 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[90] 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/activated (each is termed an 'AEMO intervention event').[91] Clause 4.8.9 instructions to network service providers to shed customer load involuntarily are not defined under the NER as an AEMO intervention event. Instead, the market price cap is automatically applied when involuntary load shedding occurs

2.3 Challenges to the existing framework

Australia's energy system is undergoing a transformation - driven by changing consumer choices and rapidly evolving technology. Meanwhile, various policy settings – including a lack of an emission reduction policy, but multiple policies to support investment in renewable technologies – 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 questions about its ongoing suitability. However, to date, as noted above, reliability events have been well *within* the reliability standard.

90 Intervention pricing is also known as 'what-if pricing' as it overrides the dispatch price with what the price would have been if the intervention event has not occurred.

91 In the case of a direction, there is an additional test that is required to be satisfied before intervention pricing is applied. As a result, not all directions result in intervention pricing.

More importantly, these forces are significantly impacting on the system security framework, manifesting in actual outcomes creating concerns with and putting pressure on the current system security framework. The Reliability Panel recently found that the performance of security in the NEM in 2016-17 was mixed, with this discussed further below.

In the context of these challenges, it is worth acknowledging the significant body of work underway that is currently considering how to maintain the security and reliability of the NEM. This includes the Energy Security Board's (ESB) National Energy Guarantee, the Panel's *Reliability standard and settings review*, the Panel's *Review of the Frequency Operating Standard*, the AEMC's *Frequency control frameworks review,* the AEMC's *Coordination of generation and transmission investment* review and the AEMC's *Generator technical performance standards* rule change.

Similarly, a number of rule change requests, received by the Commission in March 2018, seek to make changes to the current reliability framework, including a rule change request from AEMO to reinstate the long-notice RERT, a second rule change request seeking broader changes to enhance the RERT, and a rule change request from Dr Kerry Schott AO seeking to introduce a three-year notice of closure for generators. Dr Schott's proposal is focussed on the provision of additional information to AEMO on expected closure dates, including a proposed requirement that scheduled and semi-scheduled generators provide at least three years' notice of when they will cease to supply electricity or trade directly in the market.

In relation to security a number of changes have already been made to the security frameworks. For example, the frameworks requiring Transmission Network Service Providers (TNSPs) to maintain minimum levels of inertia and system strength will also commence 1 July 2018. These frameworks arise from the Commission's *Managing the rate of change of power system frequency* and *Managing power system fault levels* final rules. AEMO's first power system frequency risk review, required by the *National Electricity Amendment (Emergency frequency control schemes)* rule was published in September 2017.[92]

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 exclusive domain 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.

92 See http://www.aemo.com.au/-/media/Files/Stakeholder_Consultation/Consultations/Electricity_Consultations/2017/Power-System-Frequency-Risk-Report---Multiple-Generator-Trips---FINAL.pdf

The emergence of distributed energy resources such as small-scale PV systems (of which there is now around 5,700MW in the NEM) – often assisted by heavily subsidised feed-in tariffs and the small-scale renewable energy scheme– 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.[93]) 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.[94]

However, as noted by AEMO in its submission to the interim report, the rise of distributed energy resources, particularly rooftop solar, can also result in operational challenges.[95] For example, the "duck curve" (low grid demand in the middle of the day with a high ramp in the evening) is creating challenges for AEMO.[96]

There are a number of existing projects that are aiming to address the integration of distributed energy resources, which would limit or mitigate these concerns. These include:

- The *distribution market model* project, which was completed by the AEMC in August 2017. The recommendations from this report are being pursued by a number of parties including the Commission through its *Frequency control frameworks review* and *electricity network economic regulatory framework review.*
- The AEMC's *annual review of electricity network economic regulatory framework* for which a final report is due in July 2018.
- AEMO's and Energy Networks Australia's work on distribution system operators (DSOs).

It could also be expected that with cost-reflective tariffs, consumers would have an incentive to shift consumption to flatten out the duck curve.[97]

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

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93 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.

94 AEMO, Electricity forecasting for the National Electricity Market, June 2017.

95 AEMO, submission to interim report, p.7.

96 Ibid.

97 We understand that SAPN is also investigating potentially shifting charging of hot water load to occur in the middle of the day which would also assist in managing the duck curve.

evidence suggesting that the potential quantum of demand response available in the market is growing.[98]

However, although demand response exists throughout much of the electricity supply chain, the NEM remains predominantly a supply-side market. While loads could opt to become scheduled, and be bid directly into the wholesale pool, currently no loads are scheduled. 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. When desired reliability outcomes can be most efficiently met through reduced demand instead of increased supply, the framework should facilitate that outcome. If not, consumers will be paying *more* to receive a higher level of reliability than may otherwise be the case.

In the long term, the Commission considers that the role of the demand side in the wholesale market will be much stronger, resulting in a genuine two-sided market. A number of chapters discuss interim steps towards this goal. For example, chapter 5 discusses potential options to facilitate demand response in the NEM while chapter 3 examines the option of retailers forecasting their own load to deal with greater volumes of distributed energy resources in the long term.

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, relevantly for the purposes of this review, it is scheduled.[99] Provided these generating 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:

98 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 $35.7 million initiative will deliver 200MW (179,000$/MW) of capacity by 2020, with 143 MW having been made available over the 2017-18 summer.

99 A generator with an aggregate nameplate capacity of 30 MW or more is usually classified as scheduled if it has appropriate equipment to participate in the central dispatch process managed by AEMO.

- Variable, weather dependent 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[100]
  - 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
  - capital incentives provided in terms of credits from the small-scale renewable energy scheme
  - government grants through ARENA and long-term contracts under the ACT Government's reverse auction scheme.[101]
- 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.[102]

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 schemes that provide revenues for renewable generation that are not linked to the physical needs of the system. At the same time, high gas prices and lack of certainty about an emissions reduction mechanism that is integrated with the wholesale market, have acted as a disincentive to new coal and gas generation.

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. 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. It has also had the effect of tightening the supply-demand balance over time. The confluence of these factors could result in perceived, or actual, reliability problems in the future.

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100 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

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

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

Impacts of changing generation mix on reliability

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 detrimental 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 3 explains.

The second and arguably most fundamental challenge is that currently most variable renewable generation is non-dispatchable (at least in the absence of adequate storage capacity, for example, large banks of batteries).[103] This means that AEMO cannot depend upon those types of generation to ramp up when, say, a shortage is emerging, because their availability is dependent on the weather. 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. AEMO considers that with fewer synchronous generators in the supply mix, operating reserve margins are declining. At the same time, variability is increasing as described above, and so the amount of headroom required to prudently manage the power system is increasing.

Third, the displacing of scheduled capacity for variable renewable generation has the potential to affect the number of hedging contracts. One of the reasons for this is that variable renewable generation is typically financed by long-term power purchase agreements (PPAs, typically an offtake agreement) rather than relying on selling hedge products in the contract market. Since they are financed through these PPAs, and not hedges, there is a corresponding impact on the number of hedging contracts traded, as the penetration of variable renewable energy continues to increase. Another reason for variable renewable energy not offering hedge contracts commonly may be that they are less willing to risk the financial exposure associated with high prices due to the fact that they are typically not backed by firm capacity.[104]

Impacts of changing generation mix on security

Operationally, however, this change in generation mix has been and is challenging for system security because the different generators have different characteristics. The rules of physics dictate various technical features that are needed for system security - like frequency control, inertia, and voltage parameters. Coal, gas and hydro generation have spinning generators, motors and other devices that are synchronised to the frequency of the power system. This synchronous generation provides a number of

103 However, as technological advancements continue, this is likely to change.

104 Market participants are aware of these issues and are developing portfolios of generation that allows them to manage these risks. For example, Meridian has recently adjusted their portfolio to address this as discussed in section 2.4. Similarly, AGL in its NSW generation plan has targeted a blend of dispatchable and renewable technologies. See: AGL, AGL Energy FY18 Interim Results, 8 February 2018.

aspects of system security almost as a by-product. Wind and solar photovoltaic powered generators do not readily provide these features easily though the relevant technology is evolving. As the proportion of non-synchronous generation rises, the security of the power system is becoming more at risk.

Issues arising from the changing generation mix on security include, among others:

- frequency performance under normal operating conditions has been deteriorating in recent times, evidenced by a flattening of the distribution of frequency within the normal operating frequency band[105]
- decreases in available system inertia, resulting in increased challenges to maintain system frequency following disturbances[106] and
- as traditional, synchronous generators retire and are replaced by increasing numbers of non-synchronous generators connected to the power system by inverters, the system strength is decreasing.[107]

Of particular focus recently, has been the management of power system frequency with the Commission conducting a comprehensive *Frequency control frameworks review*, for which a draft report was recently published. Specifically, an increased potential for imbalances between electricity demand and supply is driven by a reduction in frequency control capability and increased variability and unpredictability of supply and demand. These drivers are creating challenges for conventional forms of frequency control in the NEM and making it more challenging for AEMO to manage power system security.

The existing frequency control frameworks were largely established when the technical characteristics and capabilities of the generation mix were very different. As the generation fleet changes and the needs of the power system evolve, the required services needed to maintain power system security are also likely to evolve. There may now be opportunities for the new energy technologies being connected to provide services that help support power system security, including frequency control, in addition to the above review. The Commission has a substantive system security program, which is addressing these issues as explained in section 1.4.

2.3.3 General policy uncertainty

The challenges described above have been exacerbated by the prolonged considerable uncertainty over a long term emissions reduction mechanism that is integrated with

105 See: https://www.aemc.gov.au/sites/default/files/2018-03/Draft%20report.pdf

106 See: https://www.aemc.gov.au/sites/default/files/content/f510069a-791b-4e4d-8bc0-9e6a216be7a2/System-Security-Market-Frameworks-Review-Final-Report.pdf

107 See: https://www.aemc.gov.au/sites/default/files/content/f510069a-791b-4e4d-8bc0-9e6a216be7a2/System-Security-Market-Frameworks-Review-Final-Report.pdf

the energy market; the potential impacts of this on the reliability framework are becoming more acute as time passes.

Prospective investors in new generation may also be disconcerted by the increasing role of the state and Commonwealth governments in funding, subsidising or studying the feasibility of additional dispatchable generation capacity. Private investors may be less inclined to invest in new generation for fear that their returns could subsequently be truncated by government-sponsored initiatives.[108]

It is not the task of this Review to make recommendations in relation to these various areas of policy uncertainty. But their potential impacts upon the reliability framework cannot be ignored, however. The potential negative effects on reliability of continued policy uncertainty would, naturally, be best addressed by providing clarity. In this Review, we have assumed that the reliability framework may need to adapt to accommodate that ongoing uncertainty (rather than wait for it to be resolved).

The proposed Guarantee seeks to address some of these concerns by implementing an obligation on retailers to do two things - to make sure the energy they are purchasing meets emissions reduction targets for the electricity sector and to meet reliability requirements in each region. If designed properly, the Guarantee would integrate energy and climate change policy, giving investors the certainty needed to underpin investment decisions. Under the proposed mechanism, energy sector development could continue confidently with emissions and reliability objectives implemented in lockstep under the NER.

2.4 Policy and market 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 interim report in December.

The policy responses to the increased focus and attention on reliability 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.
- On 16 March 2017, the Commonwealth Government, through 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.

108 However, this may not always be the case. See section 2.4 for example.

- The Hornsdale power reserve, announced in 2017 is a South Australian Government project consisting of a 100 MW/129 MWh lithium battery provided by Tesla at Neoen's 309 MW Hornsdale Wind Farm in South Australia.

- 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 2017. AEMO analysis showed the current reliability standard (0.002% of USE) may not be met under some plausible contingency events, such as higher demand or the extended unavailability (or early retirement) of existing generation.[109]

- On 4 February 2018 the South Australian Government announced a $800 million plan to build the world's largest virtual power plant. Tesla has been awarded funding for an initial trial with 1,100 households

- On 23 March 2018, AEMO provided advice (on request) to the Commonwealth Government in relation to AGL's proposal to replace the generating capacity of Liddell power station, which AGL plans to close in 2022. In its advice, AEMO noted that approximately 850 MW of additional dispatchable resources are needed by 2026-27 in order to decrease the likelihood of customer interruptions in high demand scenarios.[110]

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.

However, more encouragingly, despite all the challenges highlighted above, there have been numerous announcements from the market responding to these challenges. For example:

- Reflecting an increasing focus on the demand-side and technological developments, Flow Power has recently announced an expansion of its operations, expanding into two new cities and employing new staff. Flow Power connects its business customers to market signals and wholesale power prices, and gives it customers the ability to control load in response to price fluctuations, while still being scalable. The company's product was designed to meet a specific need and solve a complex problem for which there was no off-the-shelf solution. It is ultimately able to make complex decisions, interact with control systems and help save businesses money.[111]

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109 It should be noted that AEMO's modelling shows a heightened risk of unserved energy, particularly in summer. However, the reliability standard is still forecast to be met.

110 AEMO, advice to the Commonwealth relating to AGL's proposal to replace Liddell, accessed from http://www.aemo.com.au/Media-Centre/AEMO-observations---operational-and-market-challenges/AEMOs-liddell-response.

111 See: https://flowpower.com.au/we-announce-a-change-in-ownership/

- Also reflecting an increasing focus on the demand-side, Powershop and Reposit Power are working together on a program that will help Powershop dispatch surplus solar battery capacity during demand peaks. The program, known as Grid Impact, guarantees payments to customers that have signed up and agreed to let Powershop control their solar batteries during peaks. Powershop will then use the program to represent cap contracts to manage its risk.[112]

- Similarly, another example of facilitating the demand side is GreenSync's Decentralised Energy Exchange (deX), which is a proposed digital marketplace that changes the way energy is produced, traded and consumed. Specifically, deX is a software platform designed to drive the development and implementation of distributed energy resources throughout the energy market. The platform allows distributed energy resources to participate in energy markets by making them visible and enabling stored energy to be dispatched on command.[113]

- Reflecting the changing generation mix, participants are starting to look to create more balanced portfolios to better manage their risks in the wholesale market as the generation mix transforms. For example, on 1 February 2018 Meridian Energy entered into an agreement to purchase three hydro power stations from Trustpower, and signed three power purchase agreements for wind and solar projects in Victoria and New South Wales. It was noted that "having a balanced portfolio of wind, solar and hydro allows [Meridian] to more effectively manage risk in the market".[114] Similarly, on 7 February 2018, Tilt Renewables plans to build a 44 MW solar farm and 21 MW battery system to connect to its existing wind farm new Snowtown. It also plans a 300 MW pumped hydro energy storage project in South Australia's disused Highbury quarry.

- AGL has announced a new derivative product that seeks to 'firm up' wind generation. The product is a financial derivative that is exercised when wind generation across a region starts to fall. By financially firming up wind generation, the owners of wind farms can enter into swap contracts with other parties. This product is explained in more detail in Box 2.4.

- Despite policy uncertainty around emissions, Energy Australia recently noted that they are looking at investing in more than 1000 MW of new gas-fired plants at Tallawarra and Marulan in NSW, whereas a new gas generator is possible at Yallourn coal generation site in Victoria.[115]

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112 See: http://www.afr.com/news/powershop-reposit-power-join-virtual-power-plant-stampede-20180313-h0xe3s

113 See https://dex.energy/.

114 Powershop, Media Release, Meridian Energy Australia invests in renewable energy by adding hydro, solar and wind projects to meet on-going customer growth, 1 February 2018.

115 See: http://www.afr.com/business/energy/electricity/energyaustralia-eyes-new-gas-generators-in-nsw-vic-20180302-h0ww7n

Box 2.4 Wind firming derivative

AGL has announced a new derivative "swap"[116] product that seeks to 'firm up' wind generation. The product is being marketed to South Australia and Victorian generators (as the unit is based on either South Australian or Victorian spot electricity prices), given these regions have the highest wind penetration in the NEM. There are plans to roll this out to other NEM regions in time, depending on interest and penetration of intermittent renewables. The product is sold over-the-counter (OTC), listed by High Voltage Brokers via Reuters news service.

The product comprises a threshold percentage of wind generation in a region and a strike price. When the amount of wind in a region (as a percentage of the rated wind capacity in that region) falls below the threshold percentage, the swap is exercised. This means that if the owner of a wind farm bought this product, they would effectively have a swaption that is exercised when the wind farm has low output or is not generating. The product is works as follows:

- If wind output is *above* the threshold percentage of wind output, the swap is **not active**.
- If the wind output is below the threshold percentage of wind output, the swap **is active**. The buyer pays (and the seller receives) the difference between the threshold percentage of wind output and actual wind output, multiplied by the difference between the strike price and the spot price.

The pay out of the product increases as the spot price increases relative to the strike price and as the level of wind decreases toward zero.

The effect is that a wind farm owner could use this product to back a swap:

- When the wind is blowing, the wind farm is generating and selling electricity to the wholesale market, covering a swap position.
- When the wind is not blowing, the wind firming product is exercised which (to an extent) covers a swap position that the wind farm has sold.

The buyer and the seller of the wind firming product settle on a strike price. This is the price that the swap will be settled around when the product is active. This price is generally higher than the expected spot price (a regular swap would be closer to the expected spot price) for two reasons:

- Spot prices would be expected to generally be higher as wind generation decreases and is replaced by generation with higher short run marginal costs

116 It has a two-sided strike price unlike a cap.

- The price includes a premium for the seller effectively providing on-call insurance for when wind generation falls.

An example is included below to demonstrate how the product works.

Example of wind firming product being exercised

A wind firming product was sold in Victoria with a strike price of $100/MWh. The threshold percentage of wind generation in Victoria is 30% of the total rated capacity of installed wind. That is, when wind generation in the region falls below 30%, the swap becomes active. To determine how to settle the product, the following formula is used:

- If wind output > 30%, the swap is not active.
- If wind output < 30%, the payment = (30% - Actual wind output %) * (Spot price - Strike price).

Imagine a wind firming product was sold in Victoria with a strike price of $100/MWh. The threshold percentage of wind generation in Victoria is 30% of the total rated capacity of installed wind. When wind generation in the region falls below 30%, the swap becomes active.

- If wind generation was 40% of the rated capacity of Victoria's total wind capacity, the swap would not be exercised.
- If wind generation fell to 20% of rated capacity, and the spot price was $150/MWh, the buyer would **receive**:
  - (30% wind capacity - 20% wind output) * ($150/MWh - $100/MWh (the difference between the spot price and the strike price)) = $5/MWh.
- If wind generation fell to 0%, and the spot price was $150/MWh, the buyer would **receive**:
  - (30% - 0%) * ($150/MWh - $100/MWh) = $15/MWh.
- If wind generation fell to 0%, and the spot price was $10/MWh, the buyer would **pay**:
  - (30% - 0%) * ($10/MWh - $100/MWh) = $27/MWh.

The introduction of the product shows the ability of the contract market to adapt to the changing risk profiles of participants. Traditionally, wind generation would not be used to back swap contracts because of its intermittent nature. However, this product reflects the value placed on dispatchability and flexibility driving intermittent generators to bundle with dispatchable resources to offer firm financial products.

Source: http://aglblog.com.au; and discussions with HV Brokers.

These developments, while they might solve "reliability" issues, are not likely to resolve some of the system "security" issues that were discussed above. However, there are significant amounts of other work underway to address these other concerns.

It is worth noting before we conclude this chapter that one of the core objectives of this Review is 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 we 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 we 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 - are considered throughout this paper.

3 Forecasting and information provision

Key points

- The purpose of forecasting is not necessarily to predict the future per se, but to provide market participants and AEMO with information that influences their decisions today.
- The accuracy of centralised forecasting in the NEM can have an impact on reliability. Our analysis of centralised forecasting shows that the level of deviation between actuals and forecasts has not become worse over time.
- Analysis of the differences between forecast and actual demand values for Medium Term Projected Assessment of System Adequacy (PASA) and Short Term PASA reflects a level of over forecasting of actual demand outcomes in the Medium Term PASA timeframe but to a lesser extent in the Short Term PASA timeframe.
- The transparency that would arise from greater reporting on the differences between actual and expected outcomes, with more focus on demand rather than price outcomes would be conducive to industry participants and AEMO in understanding how to use and, if necessary, improve the forecasts.

Overview of chapter

- In any electricity system, decisions need to be made today based on information and forecasts of the future - from decisions about how much power to dispatch in the next five minutes, to investment decisions that will last for decades. This is unavoidable. With this in mind, the purpose of forecasting is not necessarily to predict the future per se, but to provide market participants with information that influences their decisions today
- In the NEM, some forecasting is undertaken by market participants in the course of making investment and operational decisions. Other forecasts are undertaken by the system operator, which are then used in participant and AEMO's own decision-making. The Commission considers that forecasting activities will be most effective when:
  - Centralised forecasts are well-understood via the publication of details on how they are produced and the risks associated with how accurate they are – this informs decisions on how the forecasts are used and, if necessary, where improvements can be made.
  - Entities other that the system operator have the opportunity to provide their own forecasts, since by disaggregating the provision of forecasts, risks associated with the forecasts can be shared between

multiple parties that may be better placed to manage them.

- In this review, stakeholders have raised concerns about the accuracy of centralised forecasting in the NEM and the impact that this may have on reliability. In response, the Commission analysed the differences between forecast and actual demand values produced for the Medium Term Projected Assessment of System Adequacy (PASA) and Short Term PASA. We also analysed the following inputs to the 30-minute pre-dispatch forecast: demand, semi-scheduled generation and non-scheduled generation. We focussed on demand, rather than price, since price outcomes are what the market is settled on and so reflect the expected real-time conditions at the time the price is forecast.

- In most cases, the analysis shows that while the forecasts do not perfectly match actual outcomes (as would be expected since forecasts are, by definition, uncertain), the size of the differences between the actual and forecast outcomes has not increased over time. However, in a tighter demand-supply balance with the changing characteristics of the system, having differences between forecast and actual values may have more significant consequences. Transparency and systematic regular reporting of these differences will become increasingly important. The Commission's analysis shows that:

  - In the MTPASA timeframe (between 2-years and 7-days ahead of dispatch), forecast demand has been consistently higher than actual demand across all NEM regions over the past six years. The historical differences between forecast and actual demand are relatively large compared to average and maximum regional demand. The differences are often of a similar magnitude across the six year analysis period, showing there have not been material changes over the period analysed.

  - In relation to the STPASA analysis, the 10 per cent "probability of exceedance" level, forecasts tend to over forecast actual demand outcomes, but to a lesser extent than the MTPASA. At the 50 per cent "probability of exceedance" level, the results are more varied, with all regions displaying quarters of under and over forecasting over the analysis period.

  - The 30-minute pre-dispatch analysis considered trends in the deviation between forecast and actual demand at different forecasting horizons (i.e. 24-hours, 12-hours, 4-hours and 1-hour ahead of dispatch). The analysis shows that the level of deviation in forecasts has not become worse over time. To the extent deviation between forecast and actual demand increased in 2016, it has since "rebounded" and decreased.

- AEMO is currently undertaking steps to improve its forecasting capabilities.
- Forecasting is likely to become more difficult due to the continued uptake of distributed energy resources, deployment of variable renewable energy resources and more extreme weather days. Consequently, the Commission considers that there are some potential changes that could serve to make forecasting more effective in the future.
- There could be benefit in an entity undertaking greater reporting on the differences between forecast and actual outcomes, especially in relation to the 30-minute pre-dispatch, STPASA and MTPASA forecasts. The existing reporting under the NER is somewhat limited, and more focussed on price, rather than on demand outcomes. The transparency that a common source of reporting could provide would be conducive to industry participants and AEMO in their decision making, risk management and, if necessary, point to how to improve the forecasts. This would be a relatively straightforward change to implement.
- The Commission welcomes the work being undertaken by AEMO and ARENA to enable five-minute ahead self-forecasting by utility-scale wind and solar projects on a voluntary basis. Self-forecasting for a longer horizon could provide a tangible reliability benefit by better informing AEMO and the market of the likely future output of wind and solar generators. The Commission will seek to understand though the AEMO-ARENA project the forecasting horizon over which market participants' forecasts could assist in improving the centralised forecasting process.
- In the long-term, an option to deal with greater volumes of distributed energy resources could involve retailers forecasting their own load, and submitting this information into AEMO's systems. This could occur through the submission of individual forecasts, or by retailers appointing a third-party forecast provider (e.g. a DNSP) to produce an aggregate forecast. The design of such an arrangement would seek to promote accurate forecasting and efficient demand response decisions. Providing entities other than the system operator the opportunity to provide their own forecasts should increase efficiency by placing the risks with parties that may be better placed to manage them. The Commission acknowledges that this obligation would be a substantial change and not be without costs.

Issues for consultation

- The Commission welcomes stakeholder feedback generally on the analysis documented in this chapter but particularly on:
  - greater reporting on the differences between forecast and actual values be undertaken and in particular the objective for such reporting, who is best placed to do it and the costs associated with this

— a self-forecasting obligation for wind and solar generation should be implemented through the NER

— a retailer forecasting obligation, including the rationale for such an obligation, how it could be implemented, and the potential cost.

This chapter is structured as follows:

- section 3.1 provides background on AEMO's existing forecasting processes, provides a summary of conclusions made in the interim report, and describes the purpose of this chapter
- section 3.2 provides a summary of stakeholder comments in submissions to the interim report and at the technical working group
- section 3.3 presents the Commission's analysis of AEMO's demand forecasts
- section 3.4 presents the Commission's consideration of some potential changes to forecasting and information provision in the NEM that would seek to make forecasts more effective in the future.

3.1 Background

Forecasting affects all components of the NEM. The purpose of forecasting is not necessarily to predict the future, but to provide market participants and AEMO with information to make decisions today.

Some forecasting is done by AEMO, while some is done by participants themselves. AEMO provides a range of forecasts to the market of metrics such as demand, supply and price, which cover a range of timeframes. These are based on its own analysis, as well as information provided by participants as inputs to its processes. Participants, including generators, retailers and network businesses, also do their own forecasting, based on their own view of the future and their market position. The outcomes from participant forecasting activities feed into their investment and operational decisions, as well as the information that they provide to AEMO for its forecasting purposes. Figure 3.1 below shows how forecasts can be used by participants to optimise investment and operational decisions by an iterative process.

Figure 3.1 Using forecasts to optimise investment and operational decisions

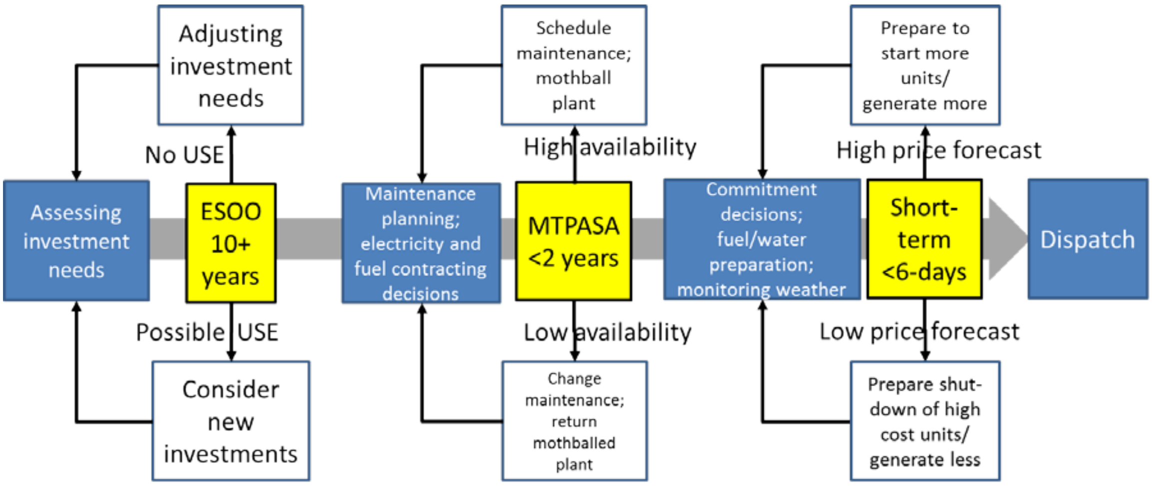

Table 3.1 below summarises the forecasts that AEMO currently provides.

Table 3.1 Summary of AEMO's forecasting processes

Forecast	Timeframe	Frequency of publication	Resolution	Purpose
ESOO	Ten years	Annually (by 31 August)	Annually	To allow existing and potential new market participants to assess opportunities in the NEM over a 10-year period.
EAAP	Two years	At least annually	30-minute traces	Provide analysis of the impact of energy constraints (e.g. water shortages, fuel supply constraints) on energy availability.
MTPASA (from May 2018)	Two years	Weekly (reliability assessment); three-hourly (regional availability)	30 minutes[117]	Inform participant decision making in regard to supply, demand and transmission network outages up to two years in advanced.
STPASA	Six days	Two-hourly[118]	30 minutes	Inform participant decision making in regard to supply, supply, demand and transmission network outages in the upcoming six days.

117 Clause 3.7.2(c) requires preparation of 10 per cent probability of exceedence daily peak load, but the Commission understands that the revised MTPASA will have a 30-minute resolution.

118 Clause 3.7.3(a) requires publication at least daily, but AEMO publishes an update to this forecast every two hours.

Forecast	Timeframe	Frequency of publication	Resolution	Purpose
Pre-dispatch	One day	30 minutes	30 minutes	Provides projections of the prices and generation dispatch based on market participants' bids and offers, and AEMO forecasts of demand and other system conditions
Dispatch	Five minutes	Five minutes	Five minutes	Publishes dispatch information every five minutes, for the next dispatch interval.

More detail on each of these processes, including the inputs, specific information provided to the market, and method for identifying potential breaches of the reliability standard,[119] can be found in appendix C of the interim report.

3.1.1 Conclusion of interim report

In the interim report, the Commission acknowledged that many stakeholders consider that inaccurate forecasts are contributing to reliability issues in the NEM. However, the analysis available to the Commission and summarised in the interim report did not definitively support this view. The analysis showed that while AEMO's forecasts do not perfectly match actual outcomes, the size of the differences between actual and forecast outcomes has generally not increased over time. The Commission indicated that it will undertake further historical analysis of AEMO's pre-dispatch forecast, which is presented in this report.

Looking forward, the Commission acknowledged that increasing volumes of distributed energy resources and variable renewable generation, combined with more extreme weather days, are likely to make it harder to accurately forecast demand and supply. This may result in increased risks for participants and AEMO, which would ultimately result in higher costs for consumers.

The Commission considered it may be worthwhile exploring whether there are ways these variances can be better managed through the existing centralised forecasting process or, alternatively, whether there are ways to rely less on centralised forecasts. Further to this, the interim report expressed a preliminary view that:

- allowing wind and solar generators to offer their availability could be worthwhile exploring on a trial basis
- in relation to non-scheduled generation, the Commission will work closely with AEMO to examine forecasting issues and develop appropriate mechanisms to ensure it has the necessary tools to operate the market

119 As specified in AEMO's *Reliability standard implementation guidelines*.

- to address the increasing variability of the demand side, retailers could be required to forecast their own load and submit bids into AEMO's system to then be dispatched.

Stakeholder feedback was invited on these options, with the comments received discussed below.

3.1.2 Purpose of this chapter

The purpose of this chapter is to:

- summarise stakeholder views received on forecasting and information provision, including the items listed above
- present the Commission's new analysis on AEMO's demand forecasts
- set out the Commission's further consideration of ideas to improve existing forecasts, or rely less on centralised forecasting, in order to improve the effectiveness of forecasting in the NEM.

3.1.3 Interaction with the Guarantee

In developing the reliability requirement for the Guarantee, the Energy Security Board has identified eight key steps to a reliable energy supply with a number of design options at each step. Particularly relevant to the issue of forecasting is steps 1 and 2:

- Step 1 – forecasting the reliability gap: AEMO forecasts whether the reliability standard is likely to be met (or not) in any NEM region over a forecast period
- Step 2 – updating the reliability gap: AEMO updates the forecasts of any reliability gap over time, as the market changes e.g. to reflect a notification of retirement of a particular generator.

Understanding the purpose of forecasting, and increasing the transparency of forecasting, will be relevant to the forecasting that would be undertaken through the Guarantee.

3.2 Stakeholder views

3.2.1 Submissions to interim report

Stakeholders generally acknowledged that forecasting is becoming both more important as well as more challenging. ERM Power noted that this has greater importance due to a tightening supply/demand balance.[120] Most stakeholders agreed that variable renewables, distributed energy resources and extreme weather conditions

120 ERM Power, Interim report submission, p. 2.

are adding to the forecasting challenge.[121] S&C Electric explained that minimum demand can be difficult to forecast as it involves predicting the behaviour of distributed generation.[122]

Other contributing factors were also identified. Meridian Energy noted that ageing generation and network assets will contribute to the forecasting challenge, while also cautioning that "variable" does not mean "non-forecastable".[123] Similarly, ARENA submitted that current or anticipated forecasting challenges should not present barriers to the widespread adoption of renewable energy and demand response technologies. It noted that ARENA is investing in demonstration projects and observing the emergence of new forecasting businesses.[124] The Clean Energy Council also considered that there are solutions available for dealing with forecasting errors.[125]

AEMO recognised the importance of forecasting and noted that it is undertaking initiatives to improve its operational and long-term forecasts.[126] It listed improvements to short-term forecasting, which include the trial of wind and solar participants submitting their own five minute ahead forecasts, obtaining more high resolution data from the Bureau of Meteorology, and the recently implemented Forecast Uncertainty Measure (FUM).[127] Improvements to AEMO's long-term forecasting are listed in its 2017 *Forecast Accuracy Report*. AEMO also noted that "given the number of variables involved, attempting to make forecasting more accurate is not the solution by itself". It considered there to be a need to forecast and manage a range of possible outcomes, in recognition that variability is an essential characteristic of the power system.[128]

Stakeholders provided examples of how differences between actual and forecast outcomes contributes to reliability. It affects decisions by participants around maintenance, operation and scheduling of plant, as well as decisions by end users to reduce their load.[129] AEMO's forecasts also inform decisions to issue LOR notices and to intervene in the market through the RERT and directions.[130] Submitters identified

121 E.g. Interim report submissions: Origin Energy, EnerNOC.

122 S&C Electric, Interim report submission, pp2-3.

123 Meridian Energy, Interim report submission, p. 1.

124 ARENA, Interim report submission, p. 4.

125 Clean Energy Council, Interim report submission, p. 3.

126 AEMO, interim report submission, pp. 26-30.

127 AEMO implemented the FUM following the *Declaration of Lack of Reserve Conditions* rule change made by the AEMC in December 2017.

128 AEMO also indicated at the March 2018 NEM Wholesale Consultative Forum meeting that it is undertaking a project to replace the "neural network" model used to forecast demand for dispatch (i.e. regional demand forecast for five minutes in the future). It intends for the new system to be implemented in the November 2018 update to IT systems.

129 Interim report submissions: ENGIE, p. 5; ERM Power, pp. 2-3.

130 Interim report submissions: ENGIE, p. 5; ERM Power, pp. 2-3.

the 8 February 2018 load shedding and RERT activation on 30 November 2017 as interventions that could have been avoided if forecasts had been more accurate.[131]

Views were provided on potential changes to forecasting and information processes. These are summarised below.

- **Reporting on differences between forecast and actual outcomes.** A group of stakeholder supported greater accountability for, and reporting on, the differences between forecast and actual outcomes. From this group, the Australian Energy Council (AEC) considered that non-financial performance measures are necessary, while ENGIE suggested reinstating NEMMCO's demand forecast accuracy as a corporate key performance objective.[132] ERM Power considered that the existing obligation for AEMO to report on the accuracy of its ESOO demand forecasts should be broadened to include the short-term forecasts as well.[133] ENGIE explained that such reporting would draw attention to unusually large errors or diminishing accuracy, which would inform decisions on whether improvement would be possible or warranted.[134] There was also a desire for greater transparency in AEMO's processes and methodology, which could be facilitated by requiring AEMO to publish more data.[135]
- **Self-forecasting by semi-scheduled generation.** There was some stakeholder support for this option.[136] While supporting the measure, the Clean Energy Council indicated that this should only be on an opt-in basis. ARENA noted that it is working with AEMO on proof-of-concept demonstration projects for wind and solar self-forecasting.[137]
- **Demand-side forecasting.** ARENA and S&C Electric expressed support for retailers providing forecasts of their demand to AEMO, with ARENA noting that the decentralisation of short-term forecasting may be more adaptive and accurate in the long-term.[138] On the other hand, EnergyAustralia thought that such a move would entail significant costs.[139] Origin Energy and Stanwell expressed support for the Commission investigating a load contribution to forecasting.[140] AGL Energy considered that there could be greater transparency around distributed energy resources, and provided a series of principles for the

131 Interim report submissions: Australian Energy Council, p. 2; Snowy Hydro, p. 5.

132 Interim report submissions: Australian Energy Council, p. 2; ENGIE, p. 6.

133 ERM, Interim report submission, p. 2.

134 ENGIE, Interim report submission, p. 6.

135 Interim report submissions: Snowy Hydro, p. 4; ERM Power, pp. 2-3.

136 Interim report submissions: AGL Energy, p. 7; Clean Energy Council, p. 3; Stanwell, p. 7; TasNetworks, p. 2.

137 ARENA, Interim report submission, p. 4.

138 Interim report submissions: ARENA, p. 4; S&C Electric, p. 6.

139 EnergyAustralia, Interim report submission, p. 2.

140 Interim report submissions: Origin Energy, p. 2; Stanwell, p. 7.

provision of this data.[141] Energy Queensland submitted that the effectiveness of AEMO's *Demand Side Participation Information Guidelines* should be assessed before further amendments of the framework are considered.[142]

Some stakeholders expressed concerns about the visibility of non-scheduled generation.[143] The AEC considered that non-scheduled activities represent a growing challenge, with this review presenting an opportunity to reconsider this issue.

With reference to the Commission's November 2017 decision on the *Non-scheduled generation and load in central dispatch* rule change request, ERM Power commented that the existing NER provisions set an impossibly high threshold for AEMO to schedule a non-scheduled participant.[144] Snowy Hydro expressed a similar concern, noting that since the Commission's decision there has been no further detail on how AEMO could make a non-scheduled participant participate in central dispatch.[145] However, Snowy Hydro also noted AEMO's interim arrangements for utility scale battery technology, whereby batteries in excess of 5 MW are required to register as both a scheduled generator and a scheduled load. Stanwell also mentioned the interim arrangements, observing that some information required to be provided is not able to be represented in current market structures.[146]

3.2.2 Technical working group

At a meeting of the Technical Working Group on 21 February 2018, Commission staff presented preliminary analysis of the differences between actual and expected forecasts for the short-term PASA (STPASA) and pre-dispatch. Feedback received from the group has been incorporated into the analysis presented later in this chapter and appendix B.

Members of the group considered that there needs to be more information on the differences between forecast and actual values, and trends in these differences, in order to better understand where problems may be. There was a view that this should occur before changes to the forecasting process are recommended. There were differing views about who is best placed to undertake this analysis.

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141 AGL Energy, Interim report submission, p.6.

142 Energy Queensland, Interim report submission, p. 2.

143 Interim report submissions: Australian Energy Council, p. 2; ERM Power, p. 3; Snowy, pp. 4-6; Stanwell, p. 7.

144 The relevant provisions are clauses 2.2.3(c) and 3.8.2(e): Under cl. 2.2.3(c), if in AEMO's opinion it is necessary for any reason (including power system security) for a participant registering as a non-scheduled generator to comply with some of the obligations of a scheduled or semi-scheduled generator, AEMO can impose such terms and conditions as it considers reasonably necessary on the classification of that participant's relevant generating units. Clause 3.8.2(e) enables AEMO to require registered participants (who may otherwise be exempted from participating in the central dispatch process) to participate in central dispatch to the extent necessary to ensure system security. This power can be exercised in relation to generators or loads.

145 Interim report submission, Snowy Hydro, p. 5.

146 Interim report submission, Stanwell, p. 7.

3.3 Commission's analysis of forecasts

The Commission has analysed the differences between actual and expected forecasts for ESOO, medium-term PASA (MTPASA), STPASA and pre-dispatch. With the exception of the pre-dispatch forecast, the only metric that has been analysed in these forecasts is demand. We have not focussed on price forecasts, since price forecasts are a signalling mechanism. Price forecasts are directly influenced by participants and their behaviour and so are not as relevant to reliability as demand forecasts are (since it these forecasts that AEMO has more control over). Therefore, we have focussed on demand.

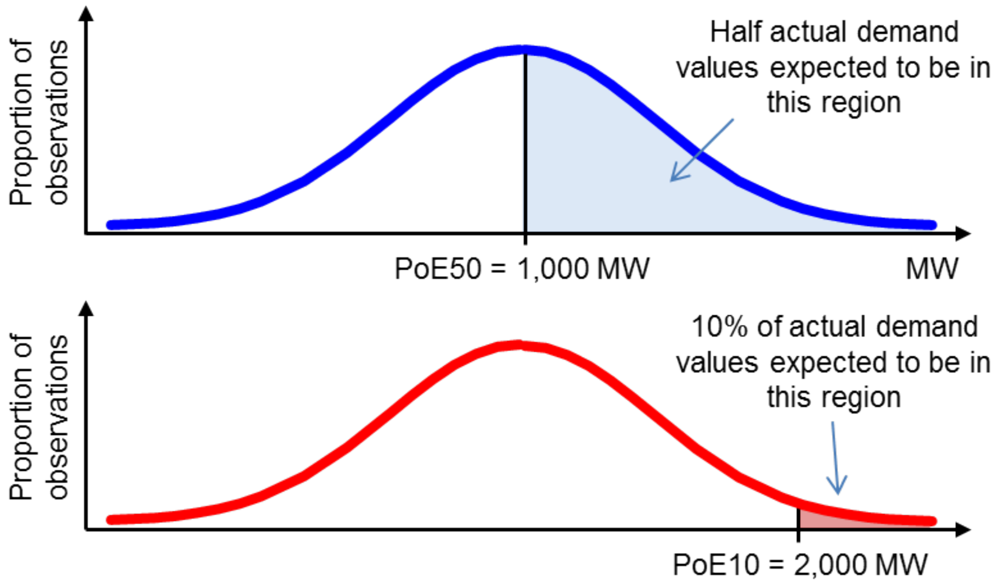
Although the methodologies used to analyse each forecast are slightly different, at a high level each is a relatively simple comparison between a forecast and an actual value. A deviation value has been calculated as the sum of the forecast value minus the actual value. The Commission's methodology is just one way in which this analysis can be done, but it hopes that this is informative for stakeholders.

The type of analysis undertaken varies between the forecasts due to the specific features of each one. A key determinant is whether the forecast is a 'point' forecast or a 'probabilistic' forecast. These two categories of forecast are explained below.

- Point forecasts (e.g. 30-minute pre-dispatch) estimate an actual value at a given time. An assessment of forecast efficiency is based on how close the forecast is to the actual observation. For example, if demand is forecasted at 1,000 MW and actual demand turns out to be 1,100 MW, the error of the forecast is simply the difference between the forecast and actual observation, i.e. 100 MW, or 10 per cent. An accurate point forecast aims to minimise this error over all time periods.

- Probabilistic forecasts (e.g. MTPASA, STPASA) are typically used when forecasting on longer time horizons. They state that for a specified Probability of Exceedance (PoE) level, it is expected that the number of actual observations greater than the forecast would correspond with the level of that PoE. For example, suppose that PoE50 forecast demand is 1,000 MW. This is equivalent to the statement, "there is a 50 per cent chance that demand will be higher than 1,000MW". This is represented visually in Figure 3.2 below, which is a probability distribution of expected outcomes. An efficient PoE50 forecast would result in half of the actual demand values being higher than the forecast demand. Unlike a point forecast, if an actual value happens to be 1,100 MW, this single observation does not in itself enable an assessment of the accuracy of the forecast. Rather, probabilistic forecast accuracy is based on how close the probability distribution of forecast values is compared to the probability distribution of actual values. In practical terms, this assessment can be thought of as a comparison of a forecast PoE value with every value in the actual distribution, counting how many times the actual demand is greater than the forecast value.

Figure 3.2 Stylised representation of PoE50 and PoE10 forecasts

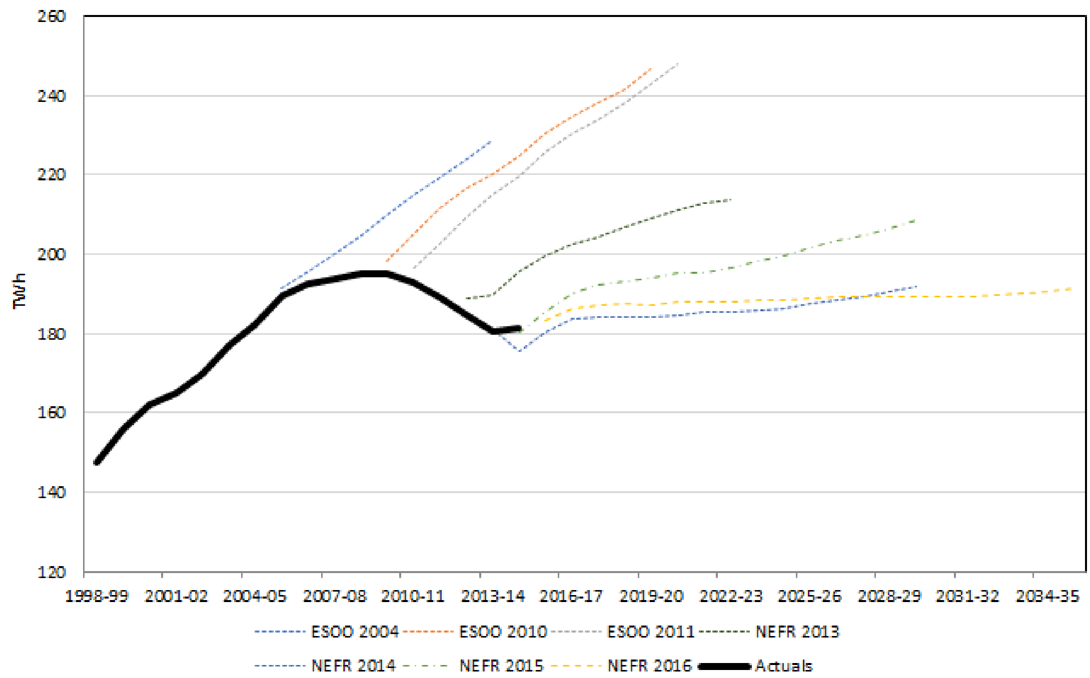


3.3.1 Long-term forecasts

AEMO is required under the NER to produce the Electricity Statement of Opportunities (ESOO). Among other things, it must include projections of aggregate demand and energy requirements for each region of the NEM for a ten year outlook period. Between 2012 and 2016, AEMO published the forecasts used in the ESOO in the standalone National Electricity Forecasting Report (NEFR). The NEFR has now been renamed the Electricity Forecasting Insights (EFI). The EFI provides electricity consumption and maximum and minimum demand forecasts over a 20-year outlook period for the NEM regions.

The Commission previously reported on the outcomes of AEMO's annual energy forecasts (i.e. annual TWh) in the interim report. Historically, these forecasts have overestimated actual annual energy outcomes. This can be observed in Figure 3.3 below.

Figure 3.3 Annual energy forecasts versus actuals



3.3.2 MTPASA

For the MTPASA, AEMO prepares a probabilistic forecast of electricity maximum demand for each region for each day based on the peak demand forecasts from the NEFR. The annual NEFR results for winter and summer peak demand are converted to daily MTPASA demand forecasts by applying historical patterns of energy use (e.g. seasons, day of week, public holidays) and subtracting demand expected to be met by non-scheduled and exempt generation as well as taking account of demand response.[147]

In a submission, ERM Power provided analysis comparing MTPASA forecasts against actual demand outcomes, as well as Bureau of Meteorology monthly historical and actual temperature outcomes for the corresponding period. It showed that while the temperature outcomes during the period were in the 90th and 95th percentile of historical temperature outcomes, maximum demand outcomes generally did not exceed the MTPASA 50 per cent PoE demand forecasts. ERM Power notes the importance of this outcome being that the MT PASA forecasts were used as the basis for the contracting of the RERT for the 2017-18 summer, the costs of which will be borne by consumers.[148]

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147 Generally, a non-scheduled generator has a nameplate capacity rating less than 30 MW or does not have the technical capability to participate in the central dispatch process (NER, cl. 2.2.3). Currently, a person with a generating system with a nameplate capacity rating of less than 5 MW has been exempted by AEMO from the requirement to become registered. AEMO also considers applications for exemptions where a generating system is larger than 5 MW and certain other conditions are met. See: AEMO, *Guide to Generator Exemptions & Classification of Generating Units*.

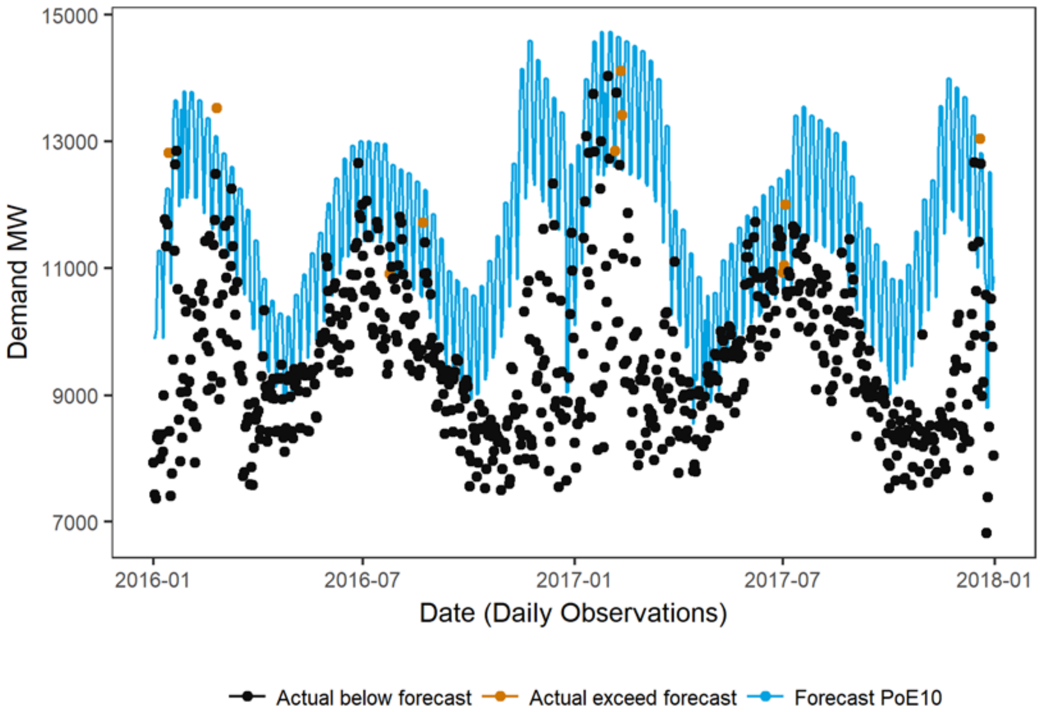
148 ERM Power, Interim report submission, p. 3, p.7.

The Commission has undertaken a similar analysis comparing actual maximum demand outcomes with the MTPASA PoE50 and PoE10 forecasts for each NEM region. As explained above, analysing this probabilistic forecast is based on how close the probability distribution of forecast values is compared to the probability distribution of actual values. However, the challenge is that on any one day there is only a single value for regional maximum demand, and a single forecast value for each of the MTPASA PoE50 and PoE10 forecasts. From a single value it is not possible to construct a probability distribution. Instead, we have sought to compare the distribution of forecast demand values in a quarter (i.e. three months) with the actual daily maximum demand outcomes for the corresponding period.

First, Figure 3.4 provides a 'snapshot' of the data used for this analysis. The daily PoE10 maximum demand forecast is represented via a blue line, which features a weekly and seasonal pattern.[149] Actual daily maximum demand values are shown as points – black when the actual value is less than the corresponding daily forecast, and orange when the opposite is true. Figure 3.4 shows New South Wales over the 2016-18 period. If the PoE10 forecast was accurate, we would expect that actual demand would exceed the forecast ten per cent of the time. In fact, actual maximum demand values rarely exceeded the corresponding daily PoE10 forecast, which indicates over forecasting. It is notable that in Figure 3.4 most instances of actual demand exceeding the corresponding PoE10 forecast value occurred on public holidays and weekends, when demand is typically low and the likelihood of a reliability supply interruption is exceptionally low.

149 The small oscillations reflect the difference in demand between weekdays and weekends. The annual cycle that repeats twice across the figure reflects the relatively higher demand in summer and winter, compared to spring and autumn. The dips in late December and early January are public holidays, when demand is typically low.

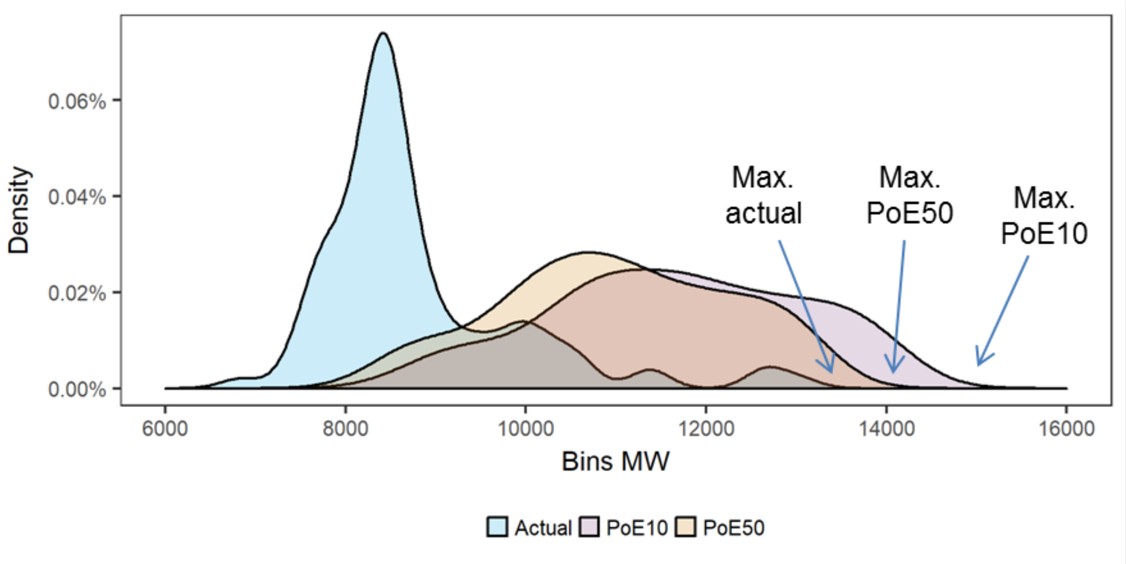
Figure 3.4 **Actual daily maximum demand versus MTPASA forecast maximum demand (NSW, 2016-18)**



Next, this same data is represented in Figure 3.5 as histograms of the actual and forecast maximum demand values for a whole quarter. These charts plot the probability distribution of each of these demand values, such that the 'peak' of each curve represents the most common range of values,[150] while the 'tails' reflect the less common and, eventually, the maximum and minimum values in each distribution. Figure 3.5 features data for New South Wales in Q4 2017. It shows that in this quarter most of the PoE10 and PoE50 forecast values sat outside of the distribution of actual maximum demand values, indicating that forecast values have tended to exceed actual demand. However, the difference between the maximum actual demand (far right of the blue histogram) and the maximum PoE10 or PoE50 value (far right of purple and orange histograms), is less pronounced.

150 Each range is referred to as a 'bin'. The bins are used to categorise the data into similar groups.

Figure 3.5 **Probability distribution of actual, PoE10 and PoE50 daily maximum demands (NSW, Quarter 4, 2017)**



Note: The area under each curve adds up to 1, or 100 per cent. The values on the y-axis represent the contribution of each 'bin' (used to categorise the data into similar groups) to the total. The values are small due to the granularity of the bins.

Below, the Commission's analysis is a comparison of:

- Actual: maximum regional demand in a quarter (i.e. three months)
- Forecast: maximum MTPASA PoE10 and PoE50 regional demand forecasts for the quarter.[151]

A comparison of the maximum values was chosen to focus on instances when demand is highest and when differences between forecast and actuals will potentially have the biggest impact on reliability outcomes.

The comparison takes the form of a "MW difference", calculated for each quarter (and each PoE) as forecast demand minus actual demand. Some caution needs to be taken in interpreting this analysis. While the analysis above compares the distributions of forecast and actual demand over time, consistent with the fact that MTPASA is a probabilistic forecast, the analysis below attempts to establish a MW deviation value for MTPASA demand forecasts.

The "MW difference" reflects the horizontal distance between the far right of the blue histogram and far right of the PoE histograms, as illustrated in Figure 3.5 above. A positive difference therefore reflects over forecasting while a negative difference reflects under forecasting. Importantly, it should be noted that the instance of the highest forecast demand was not necessarily on the same day as the highest actual

151 The MTPASA forecast uses the demand met by scheduled and semi-scheduled generation, i.e. Native Demand, net of demand met by non-scheduled and exempt generation, including non-scheduled wind and solar generation. See Appendix B of: AEMO, *Medium Term PASA Process Description*, 25 November 2016.

demand. That is, the analysis compares the highest forecast demand within the season with the highest actual demand (regardless of whether they were on the same day).

This calculation has been performed for PoE10 and PoE50 at different time horizons at the beginning, middle and end of the MTPASA forecast period (i.e. 7 days, 30 days, 365 days and 730 days ahead of dispatch). The analysis covers a period of six years.[152]

Figure 3.6 below presents the result for Victoria as an indicative region, comparing PoE10 forecast demand with the maximum of actual demand. The difference between forecast and actual demand has consistently ranged between positive 500 MW and positive 3,000 MW, indicating over forecasting. For context, regional demand in Victoria typically ranges between 3,500 MW and 7,000 MW throughout the year. The four quarters of the year are indicated in different colours, reflecting a degree of seasonality (i.e. the difference between forecast and actual demand has been consistently 1,000-1,500 MW larger in Q1 and Q4 than Q2 and Q3).

Figure 3.6 MTPASA forecast versus actual demand by forecast horizon (Victoria, PoE10)

The results for the rest of the NEM regions are provided in appendix B. The analysis shows that:

- The differences between forecast and actual demand are relatively large compared to average and maximum regional demand.

152 Six years was chosen to manage the size of the data set being analysed.

- The MW difference is often of a similar magnitude across the six year analysis period, indicating that differences between actual and forecasts have neither improved nor deteriorated during this time. The exceptions to this are New South Wales and Queensland, and the PoE50 forecast in Tasmania, where the size of the difference has reduced in absolute terms.
- The instances of under forecasting are very isolated and, where they have occurred, small in magnitude, e.g. multiple quarters in Tasmania, Q1 and Q4 in Victoria, and Q4 in South Australia in 2015.
- With the exception of Queensland and New South Wales during 2013-15, and Tasmania in 2012-15 (PoE50 only) there is no obvious minimising of the differences between forecasts and actuals as the time period approaches real-time. The MW difference is often very similar at the 2-year horizon as it is at 7-days prior to dispatch.
- There is some seasonal variation in the size of the MW difference, e.g. PoE10 for Victoria and South Australia. This implies that the demand forecast may not fully account for seasonal variation in demand.

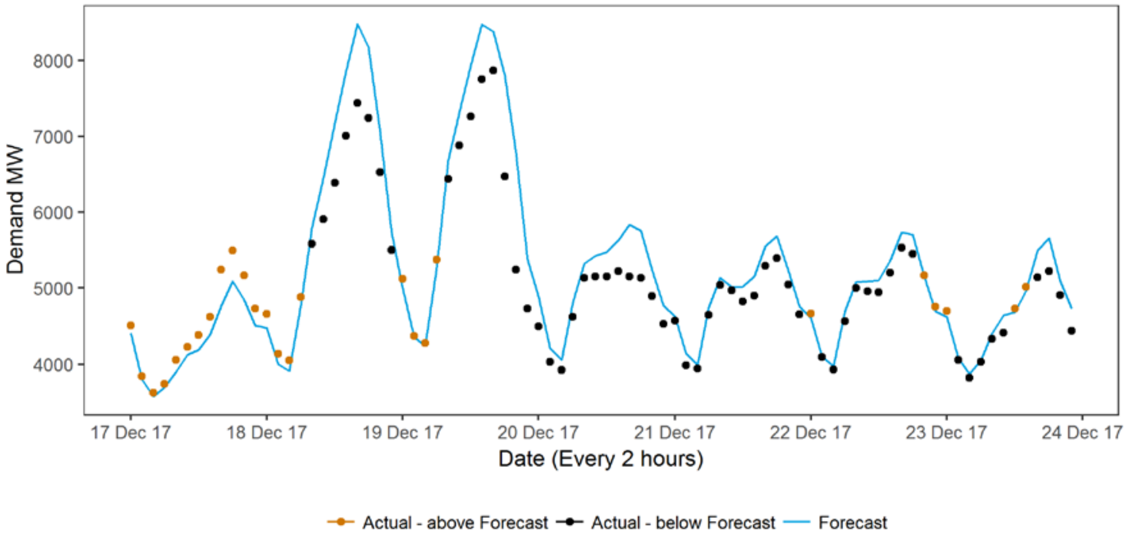
3.3.3 STPASA

Like the MTPASA, STPASA demand is also a probabilistic forecast that is expressed as the probability that actual demand will exceed a particular value. The Commission's analytical approach to STPASA the demand forecasts is similar to the MTPASA analysis above, but is able to be more targeted as there are more data points for both actual demand and forecast demand. The reasons for this are two-fold:

1. There are a greater number of forecast demand values. The STPASA demand forecasts for the PoE10 and PoE50 levels are updated every two hours. Hence, for a defined forecast horizon (e.g. 48 hours in advance of dispatch), there will be 12 forecast demands for each of the PoE levels.
2. There are a greater number of actual demand values. As MTPASA is a forecast of maximum demand, there is only a single actual value for each day, i.e. the maximum demand for the day. STPASA, on the other hand, forecasts demand at PoE10 and PoE50 levels. Hence, every actual demand corresponding with a forecast demand (12 in total) can be used for the analysis.

An example of the data is provided in Figure 3.7 below. It depicts the two-hourly granularity described above, and features the same colour scheme as in Figure 3.4 above – black when the actual value is less than the corresponding daily forecast, and orange when the opposite is true.

Figure 3.7 Actual demand versus STPASA forecast demand (NSW, Dec 2017)



The Commission's analysis is a comparison of:

- Actual: PoE10 and PoE50 demands for each day in a quarter. The PoE10 level corresponds with the 90th percentile of demand, whereas the PoE50 level corresponds with the 50th percentile, or median. In a sample of ten values, the second largest value represents the 90th percentile.[153]
- Forecast: the STPASA PoE10 and PoE50 forecast values, 48 hours ahead of dispatch, that correspond with the PoE10 and PoE50 actual demands.[154]

Below, that data used for this analysis is represented as histograms of the actual and forecast demand values for a whole quarter. As above, these charts plot the probability distribution of each of these demand values, with the 'peak' of each curve representing the most common range of values (or, 'bin'); the 'tails' reflect the less common and, eventually, the maximum and minimum values in each distribution. In contrast to the MTPASA histogram, these curves are a more direct comparison between forecast and actual demand as the values in the distributions have been filtered to only include the PoE10 or PoE50 actual demands, and their corresponding forecast values. In the case of an accurate forecast, the forecast and actual curves would be identical.

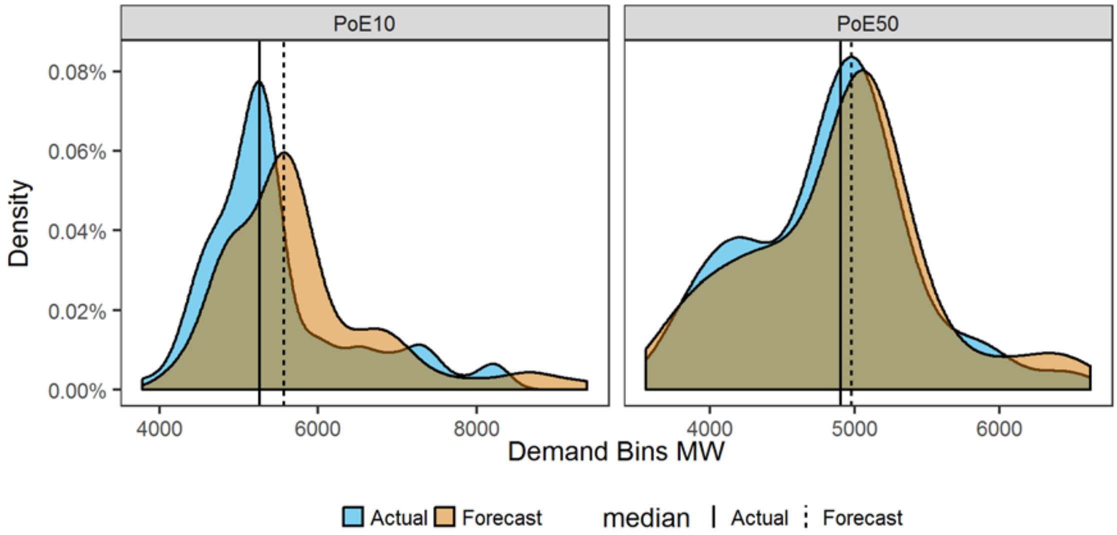
As an example, Figure 3.8 below features data for Victoria in Q4 2017. It shows that the distributions of actual and forecast demand are a close match at the PoE 50 level, but at

153 Technically, the PoE10 observation used here is a PoE8 level. As there are 12 observations in a day (one every two hours), the closest one can get to the 90th percentile of demand is the second largest demand, that is exceeded by only one other observations on the day. 11/12 = 0.917, which rounds to the 92nd percentile, or PoE8.

154 The STPASA forecast is net of non-scheduled wind and solar. The PoE10 forecast is derived from the PoE50 forecast by applying a scaling factor that may be different for every half hour of the forecast period. See: AEMO, *Power System Operating Procedure – Load Forecasting*, 11 June 2014.

the PoE10 level the forecast distribution is shifted to the right, representing over forecasting of demand.

Figure 3.8 Distributions of actual and STPASA forecast demand (Victoria, Q42017)



As was the case with the MTPASA, we have calculated a quarterly "MW difference" between forecast demand and actual demand to observe trends in over time. However, the calculation differs from the MTPASA analysis as the data has been filtered to only include the PoE10 and PoE50 actual demands (and their corresponding forecast values). As an accurate forecast would be represented by identical distributions of forecast and actual values, the STPASA "MW difference" is defined as the difference between the median of the forecast distribution and the median of the actual PoE10 or PoE50 distribution. As above, "MW difference" is calculated as forecast demand minus actual demand.

The quarterly "MW differences" for each NEM region over the past five years are provided in Figure 3.9 and Figure 3.10 below. All observations are in relation to differences between forecasts 48 hours ahead of dispatch and actual outcomes. The results show that the STPASA PoE10 forecasts tend to over forecast actual demand outcomes, however in absolute terms the "MW differences" are much smaller than for the MTPASA 7-day horizon (the closest point to comparison to the 48 hour ahead STPASA analysis). This is to be expected given that STPASA forecasting occurs closer to dispatch (when information is generally improved relative to a longer horizon), and models weather more dynamically.

The STPASA PoE10 results are consistent over time, indicating no material changes over the period analysed. Queensland is a possible exception to this, with a slightly larger "MW difference" observed in the past two years.

The "MW difference" results for the PoE50 forecast level are more varied, with all regions displaying quarters of under and over forecasting over the analysis period. However, Victoria shows over forecasting in all aside from two quarters. The "MW differences" are relatively small compared to the differences observed at the PoE10 level, and to average demand in the regions. This result suggests that the STPASA PoE50 forecasts have been reasonably good.

Figure 3.9 STPASA PoE10 forecast versus actual demand

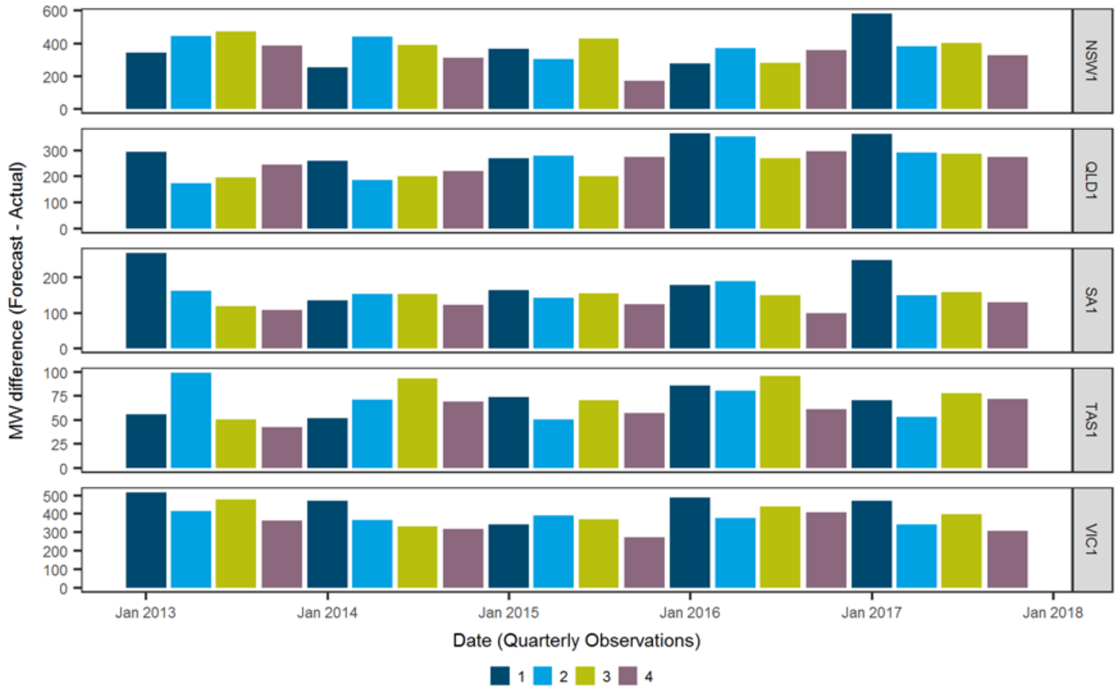
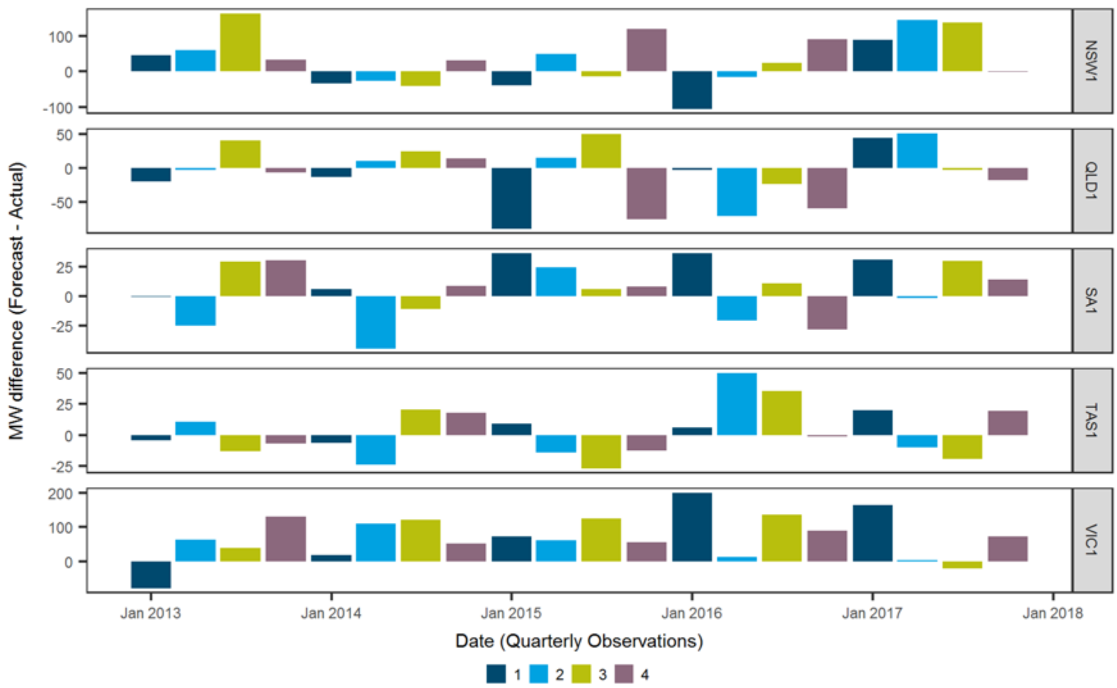


Figure 3.10 STPASA PoE50 forecast versus actual demand



3.3.4 Pre-dispatch

Pre-dispatch is a 30-minute resolution point forecast. To analyse these forecasts we assess how close the forecast is to the actual observation at any point in time. In the following analysis, we have calculated deviations between forecast pre-dispatch and actual demand as:

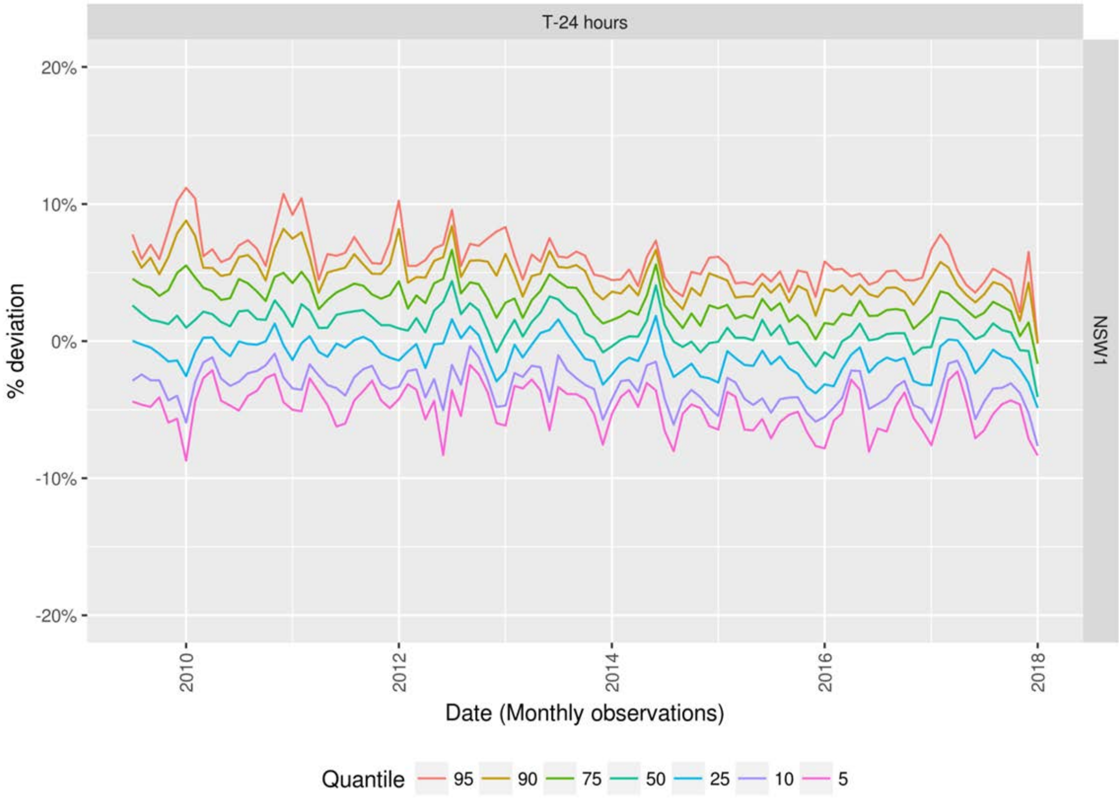
- absolute deviation: Forecast – Actual
- percentage deviation: (Forecast – Actual)/Actual × 100%

As was the case with the MTPASA analysis above, a positive deviation represents over forecasting (forecast > actual) and a negative deviation represents under forecasting (forecast < actual).

To observe how these deviations have evolved over time, we have calculated monthly percentiles of the half-hourly deviations, ranging from the 95th percentile to the 5th percentile.[155] These monthly percentiles have then been plotted for a period of seven years. Figure 3.11 below is an example of this for New South Wales. It shows the range of monthly deviation between 24-hour ahead forecasts and actual demand over the seven years. The trends in monthly deviation appear to be consistent across the period and have not become better or worse.

155 We have chosen monthly analysis since it is more granular than annual, but not as detailed as daily data. It also allows us to observe seasonality (since it is a time period less than a year), while at the same time filtering out the "noise" which would be observed in daily data.

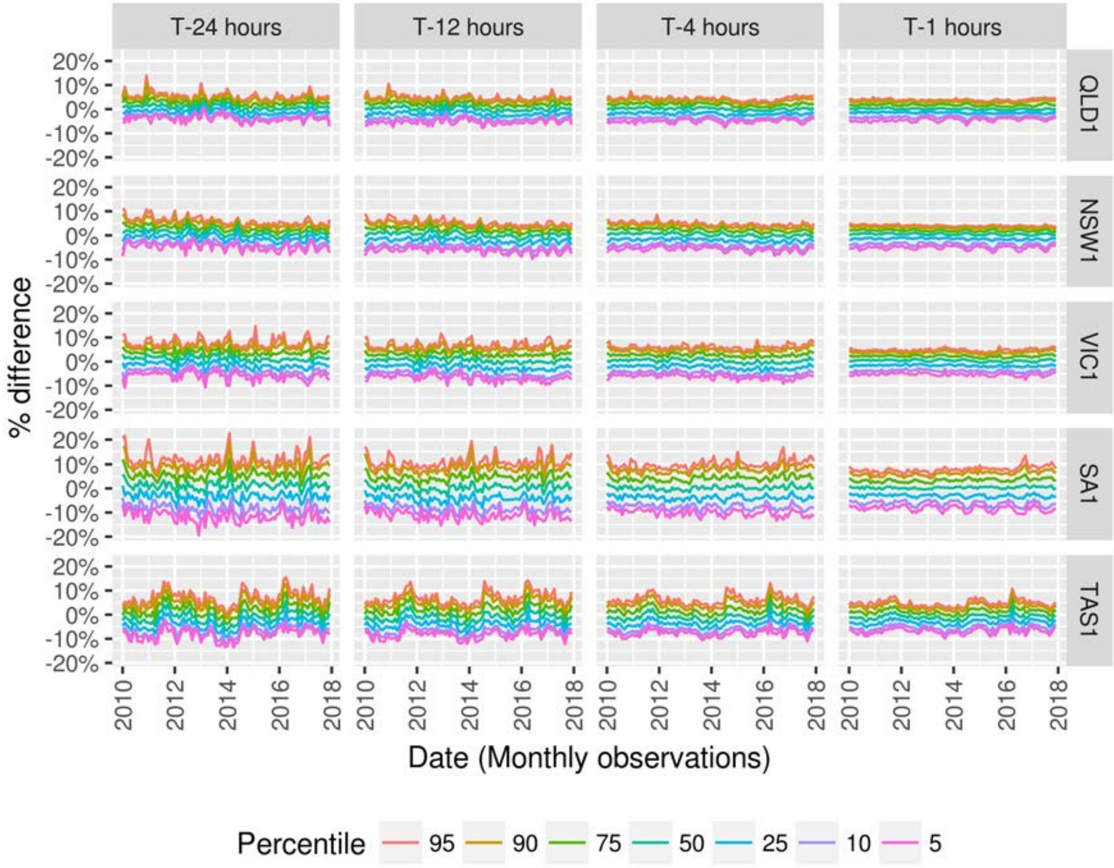
Figure 3.11 Deviation between forecast and actual demand (NSW, T-24 hrs)



The following chart repeats this analysis for each NEM region, for different forecasting horizons (i.e. 24-hours, 12-hours, 4-hours and 1-hour ahead of dispatch). Figure 3.12 provides several insights:

- The forecast deviation value becomes smaller as time approaches dispatch, as evidenced by the bunching of the percentiles closer to the x-axis in the 1-hour horizon compared to the 24-hour horizon.
- South Australia has the largest forecast deviation value of all the regions. This can be seen by the spread of the percentiles (range between the 5th and 95th percentiles) at the 1-hour time horizon being larger than other regions.
- There is some seasonal variation in forecast deviation value, even at the 1-hour time horizon. This implies that the pre-dispatch forecast may not fully account for seasonal variation in demand. This can be seen most clearly in the 10th percentile and 5th percentile forecasts in states such as South Australia and New South Wales for the period after 2014. These variations manifest in a regular pattern of increasing and decreasing forecast deviation value over the course of a year.

Figure 3.12 Deviation between forecast and actual demand (all regions)



Similar analysis for the forecasts of semi-scheduled and non-scheduled generation that are used in pre-dispatch are presented in appendix B.

3.4 Potential changes to forecasting and information provision

Based on the above analysis there does not seem to be any systematic worsening in the differences that are observed between forecast and actual values. However, in a tighter demand-supply balance with the changing characteristics of the system, the differences between forecasts and actual outcomes may have more significant consequences. Transparency and systematic regular reporting of these differences will become increasingly important.

As noted in the interim report, as the uptake of distributed energy resources continues, demand side participation grows, there are more variable renewable energy resources and more extreme weather days it is likely that forecasting will become more difficult. Consequently, the Commission considers below some changes to improve the effectiveness of forecasting in the future, given these changes.

3.4.1 Periodic reporting on forecasts

Why would periodic reporting be helpful?

As mentioned above, an option that received some support from stakeholders was for there to be greater accountability for, and reporting on, the differences between forecast and actual values of AEMO's forecasts. Currently, there is limited public information on this.

Both AEMO and the AER report on forecast accuracy for some aspects of the forecasting framework, as required by the NER. The relevant clauses are:

- Clause 3.13.3(u): by 1 November each year, AEMO must prepare and provide a report to the Reliability Panel on the accuracy of the demand forecasts to date in the most recent annual ESOO publication, and any improvements made by AEMO or other relevant parties to the forecasting process that will apply for the next ESOO.

- Clause 3.13.7: the AER must prepare and publish a report that identifies and reviews each occasion when the AER considers that a significant variation has occurred between the 30-minute pre-dispatch spot price forecasts and the actual spot price in any trading interval. The report must state why the AER considers that the significant price variation occurred.[156] As noted above, the focus of the analysis in this chapter has been on demand forecasts, rather than price forecasts.

Some analysis of forecasts are also presented in the Reliability Panel's *Annual Market Performance Review* which is produced in accordance with clause 8.8.3(b) of the NER. However, the requirement to produce this report does not explicitly mandate reporting on forecasts.

Some market participants may undertake their own analysis, but would typically be targeted at the aspects of the forecasts that are particularly pertinent to that specific stakeholder. The specific areas of interest for one participant may be different to another, and the analysis produced may not be publicly available.

In the absence of broader information being provided to all market participants, some parties may be more informed than others. It may also be difficult for the industry to get a sense about how forecasts are performing over time, e.g. whether there are any noticeable trends in forecasts. If there was a common source of reporting on forecasting, then industry participants and AEMO would be better prepared to have

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156 Under cl. 3.13.7(a), the AER must, after consulting with the AEMC, specify and make available to Registered Participants and the public, criteria which the AER will use to determine whether there is a significant variation between the spot price forecast published by AEMO in accordance with clause 3.13.4 and the actual spot price in any trading interval. The AER's criteria are published on the AER's website: https://www.aer.gov.au/system/files/Electricity%20rule%203_13_7_a%20criteria%20for%20forecast%20vs%20actual%20price%20variations.pdf

conversations around inputs, outputs and methodology of forecasts, which would be conducive to identifying areas for improving forecasts as the energy sector transforms.

Increased transparency is generally in the long-term interests of consumers, provided the costs on industry participants and AEMO of information provision are less than the potential benefits of the information being released. More transparency around trends and drivers in forecasts should help energy market participants to make more efficient decisions. In addition, this may be a lower cost solution to resolve some of the problems that it is speculated an ahead-market could resolve.[157]

Given that the existing reporting under the NER is somewhat limited, the Commission considers that there could be benefit in some party undertaking greater reporting of the differences between forecast and actual values, especially in relation to the short-term and medium-term forecasts (i.e. pre-dispatch, short-term PASA and medium-term PASA). The transparency that a common source of reporting could provide would be conductive to industry participants and AEMO in their decision making, risk management and, if necessary, point to how to improve the forecasts. The Commission is also interested in stakeholder views on the costs associated with this.

As noted in chapter 4, participants at the Technical Working Group identified one area where forecasts could be improved. Participants noted that there could be more transparency around the inputs, assumptions and methodologies that are used in calculating AEMO's forecasts. Without insight into how forecasts are calculated, stakeholders cannot provide comments or suggestions on how forecasts could be improved or developed further. Participants noted that AEMO are continuing to work with industry in a collaborative way to improve their forecasts.

What would be the objective of such reporting?

Forecasting activities are the most effective when the differences between forecasts and actuals are well-understood via the publication of details on how they are produced and how accurate they are - this informs decisions to use and, if necessary, improve the forecasts. The below design questions for the reporting should be considered with this objective in mind.

A key question is what the scope should be for new reporting on forecasts. The Commission considers that the most useful analysis as a starting point would be to analyse demand forecasts in the medium-term PASA, short-term PASA and pre-dispatch timeframes. As noted above, there are many different methodologies that could be used to assess this. The Commission thinks that any methodology should be developed through industry consultation, and so whoever is tasked with undertaking the reporting (see below) should develop a guideline setting out its proposed methodology, inputs and assumptions prior to producing the reporting.

157 Chapter 2 chapter provides further detail on the potential objectives of a day-ahead market in the NEM.

Who should be required to undertake such reporting?

Some factors that are relevant to determining the party or parties that are best placed to undertake this analysis and reporting are:

1. ability to access the data required to undertake the analysis

2. having the technical skills and systems necessary to undertake the analysis

3. strength of incentive to identify sources of differences between actual and forecast values

4. ability to address these potential differences and explain what improvements, if any, are underway.

The four candidates for undertaking the reporting are AEMO, the AER, the Reliability Panel and leaving it up to market participants themselves. It is assumed that all three parties possess the skills and systems necessary to undertake the analysis as AEMO is the creator of the data, the AER already undertakes similar analysis, the Reliability Panel undertake similar analysis in their annual market performance review reports, and market participants create and consume NEM market data in their day-to-day operations.

The Commission welcomes stakeholder input on the potential role of AEMO, the AER, the Reliability Panel and market participants in enhanced periodic reporting on the differences between expected and actual values.

The Commission's preference is to first identify the information that is currently not transparent to stakeholders, then consider who is best placed to do the reporting. Accordingly, stakeholders are encouraged to submit on the forecasting information that should be published – which could include methodologies as well as data, including forecasting costs – and views on who is best placed to undertake further periodic reporting.

3.4.2 Self-forecasting by semi-scheduled generation

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, pre-dispatch and short-term PASA.

AEMO and ARENA recently started a project to enable self-forecasting by utility-scale wind and solar projects on a voluntary basis. The Commission understands that from mid-2018, operators of wind and solar generators will be able to provide an output forecast for the upcoming dispatch interval. So long as the self-forecast satisfies a series of validation checks, it will take precedent over AEMO's UIGF. The Commission understands that participants often have the capability to forecast more accurately than AWEFS by factoring in the operational status of individual turbines and ambient conditions that AWEFS does not reflect.

The Commission supports this work being undertaken by AEMO and ARENA. While the initial, voluntary implementation will allow for self-forecasting for the upcoming dispatch interval (i.e. five-minutes ahead), the Commission understands that the IT interface being deployed by AEMO will accommodate a longer forecast horizon. Self-forecasting for a longer horizon, such as a few hours or even a day ahead, could provide a tangible reliability benefit by better informing AEMO and the market of the likely future output of wind and solar generators. In doing so, it would make wind and solar generators operate more similarly to scheduled generators who offer into the market.

The Commission welcomes stakeholder views on whether a self-forecasting obligation for wind and solar generation should be implemented through the NER, recognising that it will be important to let the trial to complete in order to fully understand the consequences of this potential change – and the capabilities of different forecasting approaches. The Commission will seek to understand though the AEMO-ARENA proof-of-concept projects the forecasting horizon over which market participants are able to provide more accurate forecast than AWEFS or ASEFS. However, stakeholders are invited to also comment on this in submissions if they already have this analysis on hand.

3.4.3 Demand-side forecasting

Why is such forecasting necessary?

As the proportion of demand side participation and distributed energy resources 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.

A potential remedy that is being pursued through other processes is for AEMO to request more information from retailers or aggregators about any distributed energy resources (e.g. virtual power plants) dispatch intentions and expectations. AEMO recently published the *Demand side participation information guidelines*, which will facilitate the provision of some of this information from participants.[158] The Commission is also currently assessing the *Register of distributed energy resources* rule change submitted by the COAG Energy Council which seeks to give AEMO and distribution network businesses more data to help keep the power system secure and safe, and enable more accurate forecasting of consumer demand.[159]

158 See: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Demand-Side-Participation-Information-Guidelines

159 See: https://www.aemc.gov.au/rule-changes/register-of-distributed-energy-resources

As an alternative (or, potentially, a complement), the interim report invited stakeholder views on whether we should explore an arrangement where retailers forecast their own load, and submit bids into AEMO's system to be "dispatched". The relevant timeframe for this forecasting would be the short-term (i.e. STPASA, pre-dispatch and dispatch). There was some support for continuing this line of enquiry, but also one submission that such a move would involve significant costs.

Allowing entities other that the system operator to provide their own forecasts is likely to be beneficial, since by disaggregating the provision of forecasts, risks associated with the forecasts can be shared between multiple parties that may be better placed to manage them.

Who is best placed to do the forecasting?

The Commission's further consideration of demand-side forecasting for this report covers:

- the suitability of this obligation being imposed on retailers
- whether the obligation would provide an incentive for retailers to forecast accurately and/or to schedule their load.

The logic for retailers to provide load forecasts to AEMO is two-fold:

1. They have a greater incentive to have accurate forecasts since they could bear the financial consequences of the forecasts 'being wrong'.[160]
2. In some cases, retailers already hold better information about the likely demand for electricity, including the location of distributed energy resources.

Many retailers already undertake this forecasting for internal purposes. This is most true for the largest retailers that also own generation assets, as in these cases there is typically an incentive to match load and generation output in real-time.[161] Non-vertically integrated and smaller retailers may hold contractual positions that make it less useful to forecast load in real-time. For example, a retailer could have entered into a load-following hedge, such that the counter-party (a generator) has acquired the retailer's volume risk. Hence, it may be appropriate to exempt smaller retailers from a demand-side forecasting obligation, if it was demonstrated that it would impose a disproportionate burden. The participation threshold could be defined based on maximum demand, energy, or number of customers.

160 The nature of this incentive would depend on the compliance mechanism (discussed below). Stanwell (Interim report submission, p. 7) identified a potential instance of conflicting objectives for retailers: "a retailer may have an incentive to under-forecast and set the energy price low while incurring the cost of balancing services [which are] unlikely to exceed the gains obtained by reducing the wholesale energy price".

161 When spot prices equal or exceed the short-run marginal cost (SRMC) of generating. Vertically-integrated businesses that are financially 'long' on generation would typically also have an incentive to generate in excess of their retail position, so long as the SRMC condition is met.

Retailers also have existing commercial relationships with consumers and access to their data. An obligation for retailers to forecast load could potentially provide a greater incentive for them to seek out more opportunities to monitor and control, with consent, the load of their customers. This could assist reliability through better integrating distributed energy resources with the wholesale market.[162] This could involve using energy disaggregation technology to offer energy management services to customers, and/or selling energy storage and other load control devices (e.g. smart thermostats). Retailers are well-placed to offer these services by virtue of their existing commercial relationships. Conversely, sellers of energy products and services (such as those mentioned above) that have sold these directly to consumers could contract with retailers to facilitate load control capabilities.

It has been noted in submissions to this review that network businesses have been undertaking significant work to identify distributed energy resources as this information is important for planning and operating their networks. This may provide information that could be useful for forecasting, or indeed even supply forecasts of demand on their network. To the extent that network businesses have access to different or more complete data, there could be scope for retailers or AEMO to access this for forecasting purposes, subject to considerations around customer consent and privacy.

How could a retailer forecasting obligation be implemented?

The design of a retailer demand-side forecasting obligation would need to identify the most appropriate mechanism for compliance. For scheduled NEM participants, there is a currently a strict requirement to comply with dispatch instructions. Participants can be the subject of enforcement action by the AER and have to pay civil penalties in the case of non-compliance. Deviations from targets, and an assumed linear ramp between targets, are also penalised through the frequency control ancillary services (FCAS) Causer Pays regime.[163]

Applying a strict compliance obligation, involving civil penalties, on retailer forecasts would be too blunt an instrument. On the other hand, a system of deviation charges may be more appropriate, as was recently discussed in the draft report for the AEMC's *Frequency control frameworks review*.[164] The difference from FCAS Causer Pays would be that the resolution of the retailer forecast would be five minutes, whereas regulation FCAS liabilities are derived from four second operational data. Conceivably, changes

162 This is consistent with the AEMC's recommendation in the Distribution Market Model report that the AEMC will examine the ways in which parties providing 'optimising services' can better coordinate with wholesale market operations undertaken by AEMO as well as alternative ways of facilitating greater co-ordination between distribution level markets and the wholesale market through the *Reliability Frameworks Review*.

163 Causer pays is the mechanism by which AEMO recovers the cost of regulation FCAS services from Market Participants. Under this methodology the response of measured generators and loads to frequency deviations is monitored and used to determine a series of causer pays factors. Potential changes to this aspect of the market design are currently being considered at through the AEMC's *Frequency Control Frameworks Review*.

164 See: https://www.aemc.gov.au/markets-reviews-advice/frequency-control-frameworks-review

in the regional load served by a particular retailer, or all retailers in aggregate, from one five minute interval to the next could be compared with a regional forecast to arrive at a deviation volume which would be multiplied by a deviation charge. The challenge would be to arrive at a deviation charge methodology that promotes both accurate forecasting and efficient demand response decisions. It would likely be advantageous for this mechanism to be integrated with the prevailing arrangements for frequency control.

An arrangement where retailers provide an aggregate forecast, potentially through collectively appointing a third-party forecast provider, could be a way of retaining the benefits of a centralised forecast, while also allowing retailers to make the trade-off between the cost and the quality of the forecast. An incentive to pursue efficient forecasts would exist since the parties incurring the deviation charges could compare these charges with the costs of improving the accuracy of their forecast. Over time, retailers that desire more accurate forecasts than other retailers, could engage their own third-party forecast provider, or undertake the forecasting themselves, separating from the initial forecasting group.

In the long run, the ideal outcome would be for retailers to schedule some of their customer demand, bidding it in different price tranches representing the opportunity cost to shift and/or reduce load. This would allow for demand response to be explicitly represented in the dispatch engine. The purpose of the interim step of retailer forecasting without a strict compliance obligation, but incentives to forecast accurately through deviation charges, would be to allow monitoring, forecasting and control technologies to develop so that retailers are sufficiently confident to schedule load.

Requiring such parties to provide load forecasts would be a substantial change to the current arrangements – although it could help facilitate a possible objective of an ahead-market, which is to provide more and/or better quality information to market participants. It may also help facilitate demand response in the NEM, by providing retailers with an increased incentive to engage in demand response in order to manage their positions in the wholesale market. Such a change would not be without costs, which would include:

- retailers installing systems in order to bid
- retailers being required to have some form of trading desk to manage the forecast provision
- learning and education costs over time to become used to the new regime.

The Commission welcomes stakeholder views on the ideas relating to a retailer forecasting obligation discussed here, including the rationale for such an obligation, how it could be implemented, and the potential costs.

4 Day-ahead markets

Key points

- 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 position in response to new information as it becomes available including changes in market conditions as well as responding to offers or bids of other participants.

- In this review to date the Commission sought stakeholder feedback on what existing ahead features of the NEM may require change. To date little feedback has been forthcoming and deficiencies in existing market design generally relate to information provision and / or security-related matters (e.g. not being sure whether there will be enough synchronous generators running in the system at a particular point in time), as distinct from reliability (having sufficient capacity or supply to meet demand).

- Feedback on the deficiencies with the current market design is important. This is because clearly identifying what part of the existing market design may no longer be serving its purpose, and articulating the materiality causes of such an issue, is necessary in order to work out what the best solution is to address the deficiencies. It will also help identify the causal link between reliability issues arising from the transformation of the sector and how these would be addressed through a formalised ahead market.

- The Commission understands that AEMO is currently in the process of identifying the existing ahead features of the NEM that may require change and compiling the evidence of the deficiencies that it considers need to be addressed, either through targeted improvement to existing arrangements or through a centrally facilitated ahead market design.

Overview of chapter

- A centrally-facilitated ahead market could be designed to achieve a number of alternative objectives. The objective of any such design focuses on how existing arrangements might need to change, and the nature of deficiencies in the existing market in relation to each particular objective that could be addressed.

- The Commission has identified and focussed on three high-level objectives an ahead market could potentially achieve, which sit along a spectrum. These are:

- To provide market participants (both demand and supply side) with more, or better quality, information so that they can incorporate this information into their unit commitment or demand response decisions and bids/offers and therefore increase the efficiency of outcomes in the NEM wholesale market, including reliability and security outcomes.

- To provide the system operator with more, or better quality, information so that the system operator can use this information to manage the system in relation to reliability and security outcomes, while maintaining the current generator self commitment arrangements.

- To provide the system operator (rather than participants) with a schedule that centrally coordinates unit commitment decisions, the intent being to increase the efficiency of outcomes in the NEM wholesale market, including in relation to reliability and security outcomes.

- These objectives exist on a spectrum - from the first objective, which is similar to current NEM arrangements, to the third objective, which would change responsibility for unit commitment decisions from market participants to the system operator - a fundamental change to the competitive underpinnings of the market design. Each of these objectives will necessitate a different form of day-ahead market and would require different changes to the current market design. The Commission considers that these objectives represent the ends and middle of the spectrum.

- An ahead market that provides more or better quality information to market participants, may provide stronger incentives to market participants to provide more accurate forecast information and stronger incentives to reveal their intentions to the market. Price certainty may increase under this type of market which may assist with risk management. Load-side participation through bidding at the ahead stage may also help facilitate increased levels of demand response as well as increasing efficiency on the demand-side more generally.

- If an ahead market was designed to pursue the second objective it would provide more certainty to the market operator and therefore may lead to a reduction in the number of out-of-market interventions that are needed to maintain system security or reliability (or both). This may improve the efficiency of overall dispatch outcomes but the extent of this potential efficiency gain is difficult to estimate.

- The third objective rests on the contention that the system operator is best placed to make unit commitment decisions. Implementing an ahead market to achieve such an objective would require the most changes to market design and it remains to be proven if the benefits of such a change would outweigh the implementation costs. It may also be the case that under such a market design, specific information about specific plant conditions are not available to the system operator which may reduce the quality of information used to inform dispatch.

Issues for stakeholder consultation

- The Commission welcomes stakeholder feedback on deficiencies of the current market arrangements and how they can potentially be addressed by a formalised ahead market in the NEM.
- The Commission is interested in stakeholder feedback on the objectives generally but specifically on how an ahead market, or other changes, to address objectives 1 or 2 could be introduced in the NEM i.e. what changes would be required to address these objectives.
- The Commission notes more targeted changes and improvements to the current market arrangements could be made to achieve some of the objectives of a day-ahead market. These include changes to the process for operating pre-dispatch, changes to forecasting, the introduction of new markets for system security services or valuing characteristics such as flexibility that are not currently separately remunerated in the market. The Commission will continue to work with AEMO and stakeholders to develop these.

4.1 Introduction

The Finkel Panel recommended the Commission and AEMO "consider the suitability of a day-ahead market to assist in maintaining system reliability".[165]

This chapter builds on the analysis in the interim report and considers what objectives a day-ahead market could achieve in the NEM.

4.1.1 Conclusions of interim report

The interim report considered a number of options for the design and implementation of day-ahead markets. It discussed 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.

The interim report came to the following conclusions:

- It was unclear how a day-ahead market in the NEM would assist in maintaining reliability. To the extent that deficiencies with existing market design had been

165 Finkel Panel, Independent Review into the Future Security of the National Electricity Market: Blueprint for the Future, June 2017, p. 23.

identified, they generally related 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 capacity or supply to meet demand). Clearly identifying what part of the existing market design may no longer be serving its purpose , and articulating the materiality of such an issue, is important in order to work out what the best solution is to address it.

- 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. Therefore, 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.

- The US-style approach could be beneficial in improving reliability outcomes if there was evidence the contract market was not already driving these outcomes. Its implementation in the NEM may require the introduction of complementary reforms in order to achieve its intended outcome. Reforms of this nature also take a considerable amount of time and resources to implement. We noted that there may be more immediate actions that could be done to address any issues with reliability in the NEM.

- The NEM, despite not having a formalised day-ahead market, has many features which play a similar role to that of a formalised day-ahead market. These features include information that is provided to AEMO as part of the pre-dispatch process with rebidding down to five minutes before real time, supported by the financial derivatives market. 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, conditions within the generator, network constraints as well as responding to offers or bids of other participants, as would be expected and necessary in a workably competitive market.

4.1.2 Purpose of this chapter

This chapter provides further detail on the potential objectives that a day-ahead market could achieve in the NEM. Given that the limited feedback to date on what existing ahead features of the NEM may require change we consider it useful to think through the various objectives that a day-ahead market could have in order to think through how existing arrangements might need to change, and the nature of deficiencies in the existing market in relation to each particular objective.

The objective of a day-ahead market has implications for the design of any form of day-ahead market that would be put in place.

In order to determine whether the implementation of a day ahead market in the NEM is of benefit, there first needs to be an identification of the parts of the existing market design that may no longer be serving its purpose.

4.2 Stakeholder views

4.2.1 Submissions to the Interim Report

There was general support for the Commission’s analysis of day-ahead markets in the interim report.[166]

AEMO raised a number of concerns with the short-term forward processes of the NEM, including that:[167]

- the real-time spot price does not provide an explicit and transparent value for the flexibility and dispatchability that is required in the system to keep operating reserves. The implication of this is that these essential services will not be provided in sufficient quantities by the market.
- the current 5-minute dispatch and pricing framework may not optimise dispatch
- an increased need for emergency intervention
- the need for price certainty to allow participants to commit to purchase fuel.

In contrast, many submissions agree that further work needs to be done to identify the problem (if any) that would be solved by introducing a formalised day-ahead market.[168] None of these submissions identified what part of the existing market design may no longer be serving its purpose.

A number of stakeholders considered that more NEM context is needed, rather than just relying on international examples.[169]

Stakeholders had differing opinions on the value of introducing a day-ahead market.

Three submissions were in favour of the introduction of a day-ahead market.[170] AEMO presented a range of benefits, most notably that a day-ahead market would:[171]

166 See submissions to the interim report: AEC, p. 3 Meridian, p.2; Energy Networks Australia, p.4; Hydro Tasmania, p.2; Snowy Hydro, p.8; Major Energy Users, p.9; Origin, p,4.

167 AEMO, submission to the interim report, pp.47-48.

168 See submissions to the interim report: AEC, p.3; Meridian, p.2; Hydro Tasmania, p.2; EnergyAustralia, p.4; ARENA, pp.9-10; Snowy Hydro, p.8; Tesla, p.5; Origin, p.4.

169 See submissions to the interim report: AEC, p.3; Energy Networks Australia, p.5 Energy Australia, p.4; TasNetworks, p.4; ARENA, pp.9-10; Origin, p.4

170 See submissions to the interim report: TransGrid, p.3; S&C electric, p.8; AEMO, pp.47-51.

171 AEMO, submission to the interim report, pp.48-49. Additional benefits are also listed on p.51 of AEMO's submission.

- allow for reserves and "on demand" energy to be explicitly valued (and hence provided by the market in sufficient quantities)
- enable coordinated unit commitment decisions by AEMO to deliver an overall optimal dispatch
- in turn, would replace, and be more efficient than, the current AEMO intervention process.

AEMO provided international examples of day-ahead markets which have these benefits, and an overview of typical day ahead market design features.[172]

AEMO further noted short-term trading benefits for a range of different types of market participants, including renewables, pumped storage and batteries, gas-fired generators and the demand side.[173] ARENA also noted that there may be some benefits associated with a day-ahead market with respect to energy storage and demand response.[174] Finally, S&C Electric argued the consultation paper's logic had implied the current arrangements were an ad-hoc form of day ahead arrangement, which demonstrated there was already a need that "should be properly formalised and the only discussion should be the format of the day-ahead market".[175]

Stakeholders also noted that there may be security as well as reliability benefits associated with a day-ahead market and that a holistic assessment of potential benefits should be undertaken.[176]

One submission considered that the costs of implementing a day-ahead market would outweigh the potential benefits.[177]

There was general agreement with the Commission's conclusion that the NEM currently has many features of a day-ahead market. Submissions noted that the contract market and pre-dispatch process provide the same functions as a day-ahead market.[178] Snowy Hydro noted that generators already structure their bids to incorporate their costs, plant characteristics and contract positions to ensure dispatch of their fleet and to cover their contract positions.[179] The AEC considered that difficulties with the current dispatch process and the ability of participants to regularly update their positions would need to be demonstrated in order to justify the introduction of a mandatory day-ahead market.[180]

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172 AEMO, submission to the interim report, pp.49, 65-66.

173 AEMO, submission to the interim report, p.50

174 ARENA, submission to the interim report, pp.9-10.

175 S&C Electric, submission to the interim report, p.8.

176 See submissions to the interim report: SA Govt, p.3; Tesla, p.5

177 TasNetworks, submission to the interim report, p.4.

178 See submissions to the interim report: Tesla, p.5; Snowy Hydro, p.9.

179 Snowy Hydro, submission to the interim report, p.9.

180 AEC, submission to the interim report, p.3.

In contrast, AEMO suggested that, in many hours of the day, the actual and forecast presence of zero marginal cost resources caused dispatchable generators with higher short-term marginal costs not to bid during these periods.[181]

Stakeholders noted that the introduction of a day-ahead market would be a large change to the current market design.[182] Meridian further noted that, given the scale of change that would be involved with the introduction of a day-ahead market, there may be a negative effect on investor confidence due to the uncertainty that would be created.[183] However, AEMO did not agree with the observation in the AEMC's Interim Report that introducing a day-ahead market would also require nodal pricing to be implemented.[184]

Four submissions noted that instead of a fundamental change to market design, incremental changes to the current NEM could instead be considered to achieve the same objectives.[185] Tesla noted that a useful approach may be to consider the effectiveness of how pre-dispatch information is currently used.[186] Origin noted that potential enhancements to current forecasting practices and processes should be explored before a day-ahead market is considered.[187]

One submission suggested that a useful way forward would be for the Commission to develop a 'strawman' model of what a day-ahead market could look like in an Australian context.[188] This would allow stakeholders to assess the potential benefits and drawbacks of a potential change to market design.[189]

The Commission understands that AEMO is currently in the process of identifying the existing ahead features of the NEM that may require change and compiling the evidence of the deficiencies that it considers need to be addressed, either through targeted improvement to existing arrangements or through a centrally facilitated ahead market design.

4.2.2 Technical working group views

The topic of day-ahead markets was discussed with participants at a Technical Working Group meeting on 21 February. Participants at the Technical Working Group

181 AEMO, submission to the interim report, p.40.

182 See submissions to the interim report: ARENA, pp.9-10; Energy Networks Australia, p.5; Meridian, p.2.

183 Meridian, submission to the interim report, p.2.

184 AEMO, submission to the interim report, p.48. Transmission rights and nodal pricing is discussed further in appendix C.

185 See submissions to the interim report: EnergyAustralia, p.4; Hydro Tasmania, p.2; ARENA, pp.9-10; Origin, p.4.

186 Tesla, submission to the interim report, p.5.

187 Origin, submission to the interim report, p.4.

188 SA Govt, submission to the interim report, p.4

189 Ibid, p.4.

meeting were not typically supportive of the introduction of a day-ahead market. More detailed comments from the technical working group are discussed in the relevant sections below.

4.3 Identifying what a day-ahead market would address

This section discusses the potential deficiencies with the current market design that may be addressed through the introduction of a day-ahead market. These have been linked back to the objective that a day-ahead market could achieve. These objectives can relate to "reliability" or "security" matters or both. In considering objectives a day-ahead market could solve, the Commission is of the view that it may not need to be “a day” ahead, but rather “hours ahead”. Therefore, we simply refer to a “ahead market” throughout the remainder of this chapter.

The Commission welcomes stakeholder feedback on deficiencies of the current market arrangements and the potential for an ahead market to address any issues identified.

The Commission also welcomes stakeholder feedback on the objectives outlined below.

4.3.1 Why the objective of an ahead market matters

Ahead markets have been introduced in other jurisdictions for a number of reasons. The objective of the introduction of an ahead market will inform the design of that market. For example, if the introduction of an ahead, or multi-settlement, system in the NEM is to provide market participants with better information, many of the existing features of the NEM, such as simple bids, can be retained. If, however, the objective was to allow the system operator's scheduling software to make unit commitment decisions then this would be a significant change from current arrangements. Currently, participants adjust their bid prices to commit to operating or not and so there would need to be a number of corresponding changes to the market design to facilitate central unit commitment, including more complex bidding structures and non-linear dispatch optimisation.

The Commission has considered the potential design of an ahead market under a number of different objectives (described below).

As part of the Commission's work on examining the design of a potential ahead market in Australia, a mapping exercise was undertaken on the activities and actions that occur under the current NEM design. This is described in more detail in Box 4.1.

Box 4.1 Mapping the NEM

The Commission conducted a mapping exercise as a first step in progressing our thinking on the issue of day-head markets. The purpose of this mapping exercise was to provide a comprehensive description of the current market design. It allows for changes that would be necessitated by the introduction of a day/hours ahead market to be identified. It also highlights what features of the current market design are common under an ahead market.

The "mapping timeframes" is provided in appendix D and seeks to set out all the key activities that occur in the NEM, from AEMO's perspective, as well as from the market participants' perspective.

This mapping tool can then be used to identify activities and actions that are currently performed in the NEM that would potentially change in an ahead market. The actions can be identified and grouped by activity (for example pre-dispatch, dispatch, interventions and settlement).

For each of these potential changes a range of design options are possible, with these relating to the three identified objectives of an ahead market, which are discussed in more detail below.

4.3.2 High-level objectives of an ahead market

Submissions to the interim report indicated that stakeholders have different views on what objective (if any) an ahead market could achieve in the NEM. Indeed, there are a range of objectives that could apply to an ahead market. The objective chosen informs how an ahead market might be designed, and so how it might differ from the NEM of today. It is therefore important to gain clarity around what an objective for an ahead market may be.

In defining the objectives of an ahead market, it is useful to consider how the introduction of such a change to the market design in the NEM could improve reliability outcomes by reference to a recent reliability event. This is discussed in more detail in Box 4.2.

Box 4.2 Would an ahead market prevented the system reliability event on 8 February 2017?

As set out in the Reliability Panel's *Annual market performance review 2017*,[190] on 8 February 2017, South Australia experienced high temperatures, causing high demand and leading to a reliability event. This was the only reliability event in 2016-17. According to AEMO in its system event report,[191] at 18:00, demand was higher than forecast, wind generation was lower than forecast, and thermal generation capacity was reduced due to a few forced outages (e.g. Port Lincoln (73 MW) notified at 16:07). AEMO contacted but did not find offline generators available to generate in time to help the situation (Pelican Point (165MW) notified at 17:39, Torrens Island (190 MW) notified at 17:42) so at 18:03, AEMO declared an LOR3 situation for South Australia and load shedding (100 MW for 27 minutes) was implemented to bring the power system back into a secure state.

This provides an interesting case study to think through whether an ahead market would have helped in this instance or not.

In this event, the major issue would appear to have been that the actual outcomes observed (i.e demand, wind generation) were significantly different to those forecast. The outcomes in the ahead market would have presumably reflected the same forecasts. It is unlikely therefore that an ahead market in and of itself would have resulted in a different outcome.

However, it is worth noting that an ahead market typically involves less reliance on a central forecast by requiring market participants' forecasts to be used. This creates a stronger financial incentive for market participants' forecasts (demand and generation) to be accurate so it is possible that having an ahead market in place might have caused the forecasting improvements necessary to provide market participants and AEMO with more notice of the seriousness of the supply situation on the day. The addition of complex bidding and central unit commitment might also have induced bids by the owners of offline generation that resulted in them being scheduled for the day.

However, given that this day involved forecasting errors it is important to realise that forecasting improvements could be made without implementing a day-ahead market (see chapter 3) i.e. there may be other more targeted ways to achieve the same outcome.

We have developed three possible objectives that an ahead market could seek to achieve and relate this objective back to potential deficiencies with the current market design. These are not the only possible objectives – and there are others that could be

190 AEMC, *Annual Market Performance Review 2017*, 20 March 2018. Available at https://www.aemc.gov.au/markets-reviews-advice/annual-market-performance-review-2017

191 AEMO, *System event report South Australia*, 8 February 2017, AEMO website, Media centre webpage, 15 February 2017.

considered. The materiality of the identified deficiencies will be relevant to considering whether an ahead market should be considered alongside other changes that could also resolve these.

We have developed these objectives by reviewing why ahead markets were introduced overseas and by looking at some of the issues that have been developing in the NEM. In some other markets, ahead markets were introduced to facilitate liquidity in trades outside the spot market.[192] The NEM already has a financial derivatives market that sits alongside the spot market, which is reasonably liquid in most regions, in a quarterly or monthly timeframe.[193] It is also worth noting in this context that the Energy Security Board is currently developing the Guarantee (discussed further in section 4.3.5 below), with one of the objectives of this mechanism being to increase contracting levels in the NEM (both in terms of tenure and quantity).

Other ahead markets were introduced for the purposes of having more centrally coordinated unit commitment decisions – which was particularly important in the context of US markets with a high penetration of nuclear plants, which require long start up times.[194] In the NEM, there have been some calls for increased central coordination of unit commitment decisions in light of the emerging security concerns – the directions AEMO has exercised in South Australia to ensure system strength being commonly cited.

Increasing penetration of intermittent renewable technologies, distributed energy resources (DER) and demand response also has resulted in calls for more coordination and apparent certainty of spot price, which an ahead-market could potentially achieve. These relate more to reliability concerns – having sufficient capacity there on the day.[195]

Therefore, in developing objectives we have focussed our attention around objectives that seek to improve reliability and security outcomes.

At a high level these objectives are:

1. To provide market participants (both supply and demand side) with more, or better quality, information so that they can incorporate this information into their unit commitment and demand response decisions and bids/offers and therefore increase the efficiency of outcomes in the NEM wholesale market, including reliability and security outcomes.

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192 This is described as a "European-style" day-ahead market in the interim report .

193 Chapter 5 of the interim report examined the contract market and the issue of contract market liquidity. The result of this analysis was that we did not find evidence from ASX futures trading data that would confirm the concerns of some stakeholders that trading in the contract market is in significant decline. However, it was noted that that only information about contracts traded on the ASX electricity futures exchange are readily available to market bodies and participants.

194 For example, see the description of the ERCOT market in Texas which is given in Appendix F of the interim report.

195 AEMO, submission to the interim report, p.48

2. To provide the system operator with more, or better quality, information so that the system operator can use this information to manage the system in relation to reliability and security outcomes.

3. To provide the system operator (rather than participants) with schedule that centrally coordinates unit commitment decisions, the intent being to increase the efficiency of outcomes in the NEM wholesale market, including in relation to reliability and security outcomes.

These objectives can be thought of as existing along a spectrum, with number one representing an incremental change and number three being a large departure from how the NEM is currently designed. The Commission considers that these objectives represent the ends and middle of the spectrum.

The first two objectives are based around the philosophy that market participants are best placed to make decisions regarding unit commitment, as you move further down the spectrum toward the third objective, decisions over operational commitment moves to the centralised system operator.

Currently, NEM participants continuously update their bids during the pre-dispatch process enabling the market to ultimately dispatch itself in a near-optimal manner.[196] It can therefore be said that in order for the third objective to be pursued, significant issues with the current arrangements would need to be identified.

The spectrum of objectives also enables a staged approach to implementation of an ahead market. Some reforms could be introduced to achieve the first objective in the short-term, which could be supplemented at a later date with further changes to move further along the spectrum toward the third objective, if it was considered beneficial to do so.

These three potential objectives for an ahead market were presented to the Technical Working Group (Group). It was noted by members of the Group that an ahead market was not likely to provide any benefits in terms of reliability, but that there may be some system security benefits associated with an ahead market. There was general agreement by participants that it is not clear what deficiencies would be addressed by an ahead market that would require such a change to the existing market design. However, it was noted by participants that there may be some benefits for the demand-side associated with an ahead market.

The next sections discuss each of these objectives and identify the associated issues that need to be examined with respect to each of the objectives.

196 Further detail on the frequency with which generators adjust their positions through rebidding is provided in Box 4.4 below.

To provide better information to market participants

First, an ahead market could provide market participants (both supply and demand side) with more, or better, information than is currently provided by the pre-dispatch scheduling process. This first objective is based around facilitating transparency of information to market participants. This may improve efficiency as market participants could make better informed unit commitment and demand response decisions and bids/offers, which may lead to more efficient dispatch outcomes.

Under this form, the current pre-dispatch process could still be used with some changes. The effect of these changes and their potential to improve the information available to market participants are discussed below. These changes may include:

- Load would provide bids, which would provide information on their expected demand at each dispatch interval ahead of real-time. This would be a change from current arrangements as AEMO currently provides the demand forecasts inputs to the pre-dispatch schedules.
- At some point ahead of real-time the bids and offers of market participants would become financially binding. This means that the market would be settled ahead of real-time at the ahead prices and quantities and provide incentives for market participants to be accurate in their bids and offers. Through this process, retailers could be incentivised to provide more demand response offers.
- Market participants would still be able to trade away from their positions in the ahead market in the real-time market. This trading would register as deviations from the ahead positions and those deviations would be settled at the real-time price. There would still be some form of rebidding in the periods ahead of the ahead market, and then again in the real-time market. Illustrative examples of how this would occur are given in Box 4.3.

Box 4.3 Examples of settlement of deviations between the ahead and real-time market

This box provides some simplified illustrative examples of how deviations between the ahead and real-time market could occur and how participants would manage these deviations through trading in both markets.

Example 1: Generator output is lower than forecast

In this example there are two generators, a wind farm and a thermal station. The output of the wind farm is lower than forecast owing to changes in the weather forecast. Trading by both generators in the ahead and real-time markets can be summarised as:

- The wind farm sells 80 MWh and the thermal station sells 100 MWh in the ahead market at the ahead price of $50/MWh.
- The wind farm only produces 50 MWh so must procure 30MWh in the

real-time market at the real-time price of $90/MWh.

- Extra production by the thermal station supplies the shortfall, which explains the higher real-time price.
- The thermal station sells 30 MWh at a real-time price of $90/MWh.
- Effective prices received for generation in the trading interval:
  - $50/MWh for any generator that did not deviate from their position between the ahead and real-time markets.
  - $59.23/MWh for the thermal station. This is the sum of the trading in the ahead market plus the trading in the real-time market, divided by the total amount of energy traded. (100 MWh × $50/MWh + 30 MWh × $90/MWh)/130 MWh)
  - $26.00/MWh for the wind farm (80 MWh × $50/MWh – 30 MWh × $90/MWh)/50 MWh)

Example 2: Generator output is higher than forecast

In this example there are two generators, a wind farm and a thermal plant. The output of the wind farm is higher than forecast owing to changes in the weather forecast. Trading by both generators in the ahead and real-time markets can be summarised as:

- The wind farm sells only 50 MWh and thermal station sells 130 MWh in the ahead market, both at $50/MWh.
- The wind farm actually produces 80 MWh, which is effectively a sale of 30 MWh in the real-time market at $20/MWh (the real-time price is lower because of unexpectedly high wind generation)
- The thermal station buys back 30 MWh in real-time at $20/MWh.
- The effective prices received for generation in the trading interval:
  - $50/MWh for parties that did not deviate from day ahead quantities
  - $59.00/MWh for the thermal station (130 MWh × $50/MWh – 30 MWh × $20/MWh)/100 MWh
  - $38.75/MWh for the wind farm (50 MWh × $50/MWh + 30 MWh × $20/MWh)/80 MWh.

These examples show that generators are likely to receive a lower price per MWh for their production if their output is higher or lower than forecast. In other words, under an ahead market structure, certainty of output and flexibility is valued.

Example 3: Consumption by a load is less than forecast

In this example, there are two energy consumers that are participating in both the ahead and real-time markets. Consumer A's consumption turns out to be lower-than-expected, due to inaccurate forecasting of their demand. Trading by both consumers in the ahead and real-time markets can be summarised as:

- Consumer A buys 110 MWh and Consumer B buys 70 MWh in the ahead market, both at the ahead market price of $60/MWh.
- Consumer A actually consumes 100 MWh, which is effectively a sale of 10 MWh in the real-time market at the real-time price of $55/MWh.
- Consumer B consumes 70 MWh (i.e. no deviation from ahead quantity).
- The effective prices paid for consumption in the trading interval:
  - $60.50/MWh for consumer A (110 MWh × $60/MWh – 10 MWh × $55/MWh)/100 MWh.
  - $60.00/MWh for consumer B (no deviation from ahead quantity).

Example 4: Consumption by a load is greater than forecast

In this example, there are two energy consumers that are participating in both the ahead and real-time markets. Consumer A's consumption turns out to be higher-than-expected, due to inaccurate forecasting of their demand. Trading by both consumers in the ahead and real-time markets can be summarised as:

- Consumer A buys 100 MWh and Consumer B buys 70 MWh in the ahead market, both at the ahead market price of $60/MWh.
- Consumer A actually consumes 110 MWh so it has to buy 10 MWh in the real-time market at the real-time price of $82/MWh.
- Consumer B consumes 70 MWh (i.e. no deviation from ahead quantity).
- The effective prices paid for consumption in the trading interval:
  - $62.00/MWh for consumer A (100 MWh × $60/MWh + 10 MWh × $82/MWh)/110 MWh.
  - $60.00/MWh for consumer B (no deviation from ahead quantity).

These examples show that load is likely to pay higher prices per MWh of demand if they consume more or less than forecast. In other words, providing an accurate forecast of your consumption is likely to lead to cost savings as a multi-settlement market structure rewards more accurate estimates of consumption with lower prices.

However, self-commitment decisions would still be made by participants themselves, with AEMO simply settling once at some point in time ahead of real-time, and then again in real-time. No additional measures would be given to AEMO to assist in managing reliability and security, ahead of real-time. Rather, improvements would come from the better quality information that is available to participants through the incentives that would be created to provide more accurate forecasts and to reveal their true intentions to the market.

The advantages of this model of ahead market could relate to stronger incentives of market participants to forecast better and reveal their intentions to the market, greater price certainty and it may also facilitate greater participation and integration of new generation technologies or demand response. It is not clear at this stage what the extent of these potential benefits would be, relative to the status quo.

First, as bids and offers into the ahead market would become financially binding in advance of real-time[197], market participants could be incentivised to provide better information to the market at an earlier stage. Generators may have an incentive to provide more accurate information regarding their intentions, potentially creating incentives to improve their own forecasting methods. This is because, if they do not reveal their true intentions, they would have to balance their positions in the real time balancing market and the price they may receive for this deviation from the ahead schedule would be more volatile and uncertain than the ahead price. There is potential for the generator to reduce its revenue through balancing its position in the real-time market, relative to accurately representing its position in the ahead market.

Second, the presence of demand bids in the ahead market could result in a more accurate forecast of demand than is currently available. Market customers would have a strong incentive to provide accurate forecasts of their demand in order to match their position in the ahead market. They would also be able to calculate the value of improvements in their demand forecasts.

Third, an ahead market could provide market participants, both generation and load, with more price certainty. Both generators and load could sell or buy energy at a known price in the ahead market, which may assist market participants in managing price risk. Currently in the NEM this is done through the contract market but an ahead market may provide a more efficient way of risk management as liquidity is concentrated at a moment both ahead of and in real time. Participants at the Technical Working Group noted that there could be some value in increased price certainty under an ahead market, particularly for the demand-side, and that it may make risk management easier. The addition of an ahead market may therefore provide more effective risk-management outcomes than the contract market on its own. This is because of the price certainty provided at the ahead stage and the ability to adjust your position ahead of real-time.

There would still be an important role for the contract market under an ahead market design. Under an ahead market the natural buyers—those with load obligations—and

197 This is done by settling bid and offer quantities at the ahead price in the ahead market.

the natural sellers—the generators—have a strong tendency to engage in trade to manage risk, just as they do now in the NEM. Typically, most energy would be contracted well in advance of the ahead market in monthly, annual, or multi-year forward contracts. Similarly to how things occur under current arrangements, under an ahead market design forward trade would anticipate the expected prices in the ahead market in the same way the ahead market anticipates the expected prices in the real-time market. The ahead and real-time markets would provide a means for participants to adjust forward positions.[198]

Finally, an ahead market of this form could help to integrate a greater amount of new generation technologies such as batteries or load-side participation such as demand response. An ahead market that produces a financially binding schedule would provide battery operators and price-responsive load with better quality information than is currently available to improve their decisions to charge/discharge or consume/not consume electricity. For instance, one barrier that limits demand response in the current market is that demand response often needs several hours' notice in order for it to be deployed. Deviations from the ahead market schedule (e.g. high price in real-time after a low price is secured in the ahead market) would provide demand response an arbitrage value. This benefit is over and above the price certainty that would occur in an ahead market and this may provide a stronger incentive for demand response.

AEMO notes in its submission to the interim report that demand-based resources can benefit from a market design that supports earlier commitment (for example, by having increased certainty about prices at a day-ahead timeframe). It notes that participants would have more notice to charge batteries or take other actions to optimise their planned use of resources.[199]

The above potential benefits of an ahead market with the objective of improving market transparency would need to be considered with respect to the potential improvements it would bring, relative to the states quo. Such a change to the market design could be beneficial if the following deficiencies with the current market design are identified:

- the information provided to the market by market participants through the current pre-dispatch process is inaccurate or lacking in detail
- the current process for forecasting demand in the NEM could be improved if market participants were responsible for it (even if it remained a central forecast - see option in chapter 3)
- there are insufficient means for market participants to manage price risk under current market arrangements

198 Peter Crampton, *Electricity Market Design*, Oxford Review of Economic Policy, Vol. 33, Number 4, November 2017.

199 AEMO, submission to the interim report, p.53.

- the current market design cannot adequately provide for the integration of battery storage or demand response.

To provide better information to the system operator

The second objective also relates to information provision but this time it concerns the information that is provided to the system operator. This objective is framed around facilitating transparency of information to the system operator so that the system operator can better manage the system in respect of reliability and security. For example, in its submission to the issues paper, AEMO stated its position on the objective of an ahead market is to "increas[e] transparency and certainty for the operator has the potential to reduce the margin of error and allow the system to be operated less conservatively".[200]

This objective also relates to the provision of information and would likely include all of the features discussed in the previous section. However, the key difference under this objective is that the ahead market would be designed to achieve the objective of providing the system operator with greater certainty with respect to the unit commitment decisions of generators than currently is the case. This may require providing the system operator with additional tools or information to intervene in the market ahead of real time.[201]

By implementing an ahead or multi-settlement market the bids and offers of market participants would become financially binding ahead of dispatch. This means that market participants bid and offer amounts are settled in the ahead market at the ahead price in advance of the real-time market.

As discussed in the previous section this may provide market participants with a stronger incentive to reveal their intentions to the market, and the system operator, than is currently the case. Under the current market design the information provided to AEMO may not be sufficiently credible to be used as the basis for any operational decisions by AEMO. This is because market participants have the opportunity to rebid up until five minutes before each dispatch interval without bearing any financial costs for this rebidding (apart from the change to revenue earned from the dispatch process as a result of the new information provided through rebidding). This ability to rebid provides flexibility to market participants to change their bids but may not provide the system operator with the information it needs at the right time to ensure the power system security and reliability is maintained. The incidence of rebidding in the NEM is discussed in more detail in Box 4.4.

200 AEMO submission to Reliability frameworks review Issues Paper, p.6.

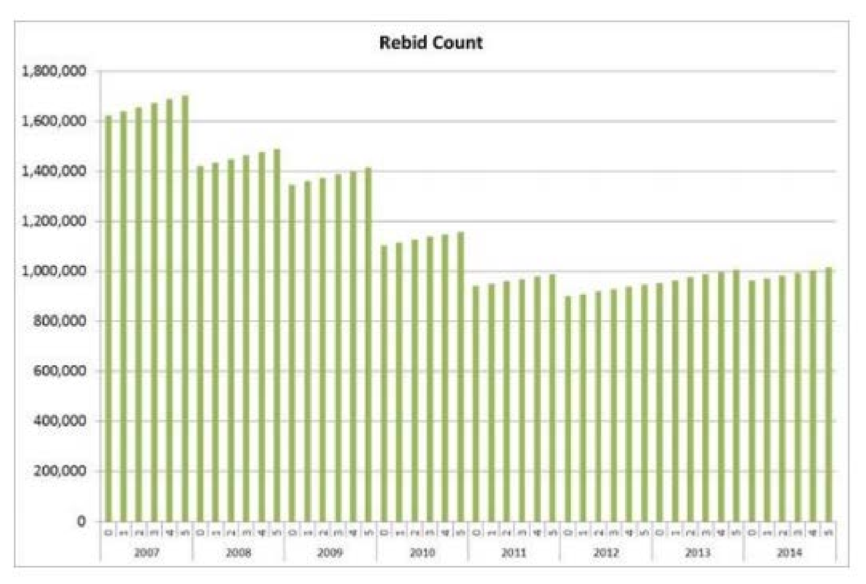
201 This could be done by giving the system operator the ability to commit units in advance of real-time if it has concerns regarding reliability. An example of such an intervention is the Reliability Unit Commitment process used in ERCOT. This is discussed in more detail in appendix C.

Box 4.4 Incidence of rebidding in the NEM

Rebidding is an important feature of the NEM wholesale market that provides generators with the ability to alter their bids to the wholesale market in response to unexpected events or new information. The practice of rebidding reflects the iterative process undertaken where generators reflect their intentions and physical condition of their plant through their bids.

As part of the *Bidding in good faith* rule change[202], the Commission examined the practice of rebidding in detail. Figure 4.1 shows the count of rebids that applied to dispatch intervals in the years 2007 to 2014.[203] While the trend in rebidding was downward, it is clear from the graph rebidding is an important mechanism for responding to changes in expectations and real-time events as they unfold.

Figure 4.1 Count of rebidding in dispatch intervals 2007-2014



Source: AEMC

The widespread use of rebidding also implies that market participants continually re-optimise their own portfolios in response to new information and reflect this through adjusting their bids.

Being exposed to sudden or uncertain price movements is an inherent aspect of participating in the spot market, reflecting a power system where not everything is foreseeable. Rebidding provides generators with necessary flexibility to adjust their position to accommodate changes in market conditions and to respond to the offers or bids of other market participants. Generators may also choose to rebid to cover their contracted position in the financial market. The resulting dynamic process of

202 See https://www.aemc.gov.au/rule-changes/bidding-in-good-faith

203 More recent data on the incidence of rebidding was not available at the time of publication.

participants learning and responding to constantly changing market conditions, expectations and the actions of their competitors is an important part of a well-functioning market.[204]

The above discussion on rebidding leads to the next potential advantage of an ahead market, designed to provide the system operator with better quality information at an earlier stage, relative to the status quo. If AEMO had more accurate information regarding the intentions of market participants ahead of dispatch it may be able to reduce the amount of out-of-market interventions needed to maintain security and reliability. Directions and the Reliability and Emergency Reserve Trader (RERT)[205] are out-of-market actions that are motivated by security or reliability concerns and may reduce the efficiency of dispatch outcomes.

As an example, the use of directions may indicate that there are issues with the current market design that is preventing the market from reaching efficient outcomes while making sure the system is operating in a secure and reliable operating state, noting that reliability directions remain rare, while directions to maintain power system security have been on the rise.

The introduction of a multi-settlement system may reduce the number of out-of-market interventions by the system operator as it may have better quality information to rely on before dispatch. The information produced at the close of the ahead market could be used to test whether there are sufficient units committed to meet expected demand and if there are any emerging system security issues related to the dispatch schedule for the upcoming period. These potential issues could therefore be identified earlier than is currently the case, which may provide AEMO with more options and a greater degree of certainty to ameliorate these issues before real-time. These options may include additional ways in which the system operator could intervene under an ahead market.

It is not clear at this stage the extent to which the introduction of an ahead market could reduce the number of out-of-market interventions in the NEM, relative to the status quo. The scale of the potential efficiency gain that would accrue under this form of ahead market is therefore difficult to estimate.

In order for this objective to be achieved through the introduction of an ahead market, a number of issues with the status quo would need to be identified. These include:

- the information provided by market participants through the pre-dispatch process is not credible and is inaccurate
- the system operator does not have sufficient credible information to operate the system without relying on out-of-market interventions to an inefficient degree

204 See: https://www.aemc.gov.au/sites/default/files/content/8d8ee814-aa4e-46bd-ba2f-addef9fa08a2/Bidding-in-good-faith-information-sheet-final-determination.pdf

205 See chapter 6 for the discussion on the RERT.

- the system operator has insufficient tools available to them in advance of dispatch to maintain system security and/or reliability to an acceptable level.

To change who is responsible for unit commitment decisions

The third objective relates to who is best placed to make unit commitment decisions. An ahead market schedule could be devised to make unit commitment decisions centrally, under the argument that it would co-ordinate inflexible units more efficiently than participants can themselves. Ideally, the scheduling software would optimise unit commitment and therefore dispatch outcomes, taking both security and reliability into account. An objective of this type would be a significant departure from current NEM arrangements and would likely require fundamental changes to the competitive underpinnings of the current market design and dispatch optimisation.

Under this objective, the key contention that would need to be proven is that the scheduling software would make more optimal unit commitment decisions and increase the efficiency of dispatch outcomes compared to the status quo. This potential for increased efficiency is centred on the information available to different parties in the market. A more detailed discussion of the incentives faced by market participants in making unit commitment decisions and the process through which resources are optimised in the NEM is given in section 2.2.1.

In some mandatory ahead markets, unit commitment decisions are made in the ahead scheduling software via provision of multi-part bids by the owners of inflexible resources. These bids incorporate each unit's start up, no load costs (or minimum generation costs) and incremental energy costs. Using this more detailed information, the day ahead schedule may optimise commitment decisions over multiple dispatch intervals.

There are also potential system security benefits associated with this type of ahead market. The system operator may be able to incorporate system security considerations into the schedule for the ahead period. This may include making sure that there is enough synchronous generation online in the system at a given time, for example in expected low load conditions when wind output is expected to be high.

On the other hand, market participants have more detailed, timely and granular information available to them on the conditions of their individual generating units. They also have strong financial incentives to make efficient unit commitment decisions. Currently in the NEM, market participants reflect their costs and operational decisions in their bids. The contention in the current market design is that this leads to efficient dispatch outcomes as market participants have strong incentives to maximise their revenue from the spot market, given operational constraints and their contracted position.

Under current market arrangements, market participants receive information on expected market conditions over a number of timelines from numerous sources including medium and short term PASA and pre-dispatch. Information is also provided to the market on generator availability. Individual generators overlay their own operational decisions on this market information and express their intentions to generate to the market through their bids. These bids incorporate, among other things, all the generator short-run and unit commitment costs. The process of market participants' revealing their intentions to the market through their bids is an iterative one. There are numerous opportunities for generators to update their bids to respond to the most up-to-date information, such information may include more accurate weather or demand forecasts, unplanned generator outages or other unexpected events. The Commission notes that in calendar year 2017, AEMO issued over 3300 market notices.[206]

Some examples of how market participants adjust to new information or unexpected events under the current market arrangements are given in Box 4.5.

Box 4.5 What happens in the NEM within a day

In the NEM, generators are allowed to rebid up to seconds before real time for each dispatch interval. This is by design – being able to make changes until very close to the dispatch interval provides flexibility and promotes efficiency. It gives generators a chance to change their offers based on changes occurring on the day, such as unplanned outages or contingencies, which could affect the decisions they made a day earlier.

AEMO’s forecasting processes project how much demand will be needed and the operator also maintains a level of reserve to manage the system in case something happens – while these reserves take into account some of the uncertainty that could occur on the day, it is arguably more efficient for each generator to change their bids in response to any unplanned or unexpected occurrence – in other words, allowing the market to respond.

The following two examples from earlier this year show what can occur within a day and how, because of the ability to rebid, generators are able to respond should they want to.

Example: 11 February 2018 – unexpected fuel restrictions

At 20:00 on 11 February 2018, AEMO published a market notice stating that it had received advice of coal supply reliability issues at two Victorian power stations (Loy Yang A and Loy Yang B).

Both stations source coal from the same mine, which meant that when the unplanned issue of supply from the mine occurred, both stations reduced output at short notice. The market notice advised that there would be a reduction of about 1,400 MW across the two stations in order to conserve coal. The lower output was due to last six hours, the time it would take to make repairs at the coal mine.

206 Data on the number of market notices issued was sourced from NEOpoint.

Given the short notice of the unplanned reduction in output and prolonged reduction, under current rules, Loy Yang A and Loy Yang B would have been able to reduce their offered output for the next six hours to reflect their fuel restrictions. Prices would likely rise to reflect the tighter demand and supply balance. Other generators would have been able to change their offers in response to lower offered outputs from Loy Yang A and B, if needed.

In a market where rebidding is not allowed after, say, 19:00, then this event would have had to be managed in the real-time market. Loy Yang A and B and other generators would have been "locked" into their 19:00 position and AEMO would have to use directions to manage the situation.

Example: 17 March 2018 – non-credible contingency event

At 13:45, AEMO informed the market that a non-credible contingency event occurred: one unit at Loy Yang A and two units at Pelican Point tripped within a minute of each other. The trips were unexpected and the fact that they occurred together meant that they would not have been factored into anyone's decisions a day before due to the low likelihood of such an event.

This would have led to an unexpected decline in output with no notice at all. Other generators would have been able (once aware of the trips) to provide a market response by adjusting their offers accordingly if they were willing and able to do so.

It should also be noted that AEMO issued two directions in South Australia on the day as well, to maintain the power system in a secure operating state. This would also have affected the offers and decisions of other generators.

In order for this type of day-ahead market to be implemented in the NEM the following questions would need further consideration:

- whether there are significant issues with the current process for market participants committing units for dispatch
- whether the centralised commitment model would result in a higher level of dispatch efficiency, and whether this would outweigh the costs of changing the market design
- whether there are system security issues that cannot be accommodated under the current market design that an ahead market would address.

The last point requires further consideration in the context of assessing the suitability of an ahead market in the NEM. It may be the case that new markets for system security services could be introduced under the current market design. This is discussed in more detail in section 4.4.3.

4.3.3 Uncertainty and market design

The above discussion of the objectives of an ahead market relies on providing market participants or the system operator with increased certainty, or the appearance of greater certainty. However, there will always be some form of inherent uncertainty in electricity markets that cannot be addressed by market design.

It was noted by participants at the Technical Working Group meeting that there may be a lack of certainty in future prices ahead of real-time and that uncertainty related to weather forecasting was also necessitating the availability of more flexible resources. However, several participants noted that these issues could be addressed in other ways rather than the introduction of an ahead market. Examples of such potential improvements ranged from incremental changes such as improvements to the current pre-dispatch process or facilitating more liquidity in the contract market on a day-ahead basis to more significant changes such as the establishment of new markets for services such as ramping capability or system strength. Examining these questions was generally thought to be more useful than examining the suitability of an ahead market in isolation.

As part of the system security work programme the Commission has made two rules that make TNSPs responsible for maintaining minimum fault levels and inertia sufficient to maintain system security under a range to conditions.[207] The Commission is also considering potential future markets for inertia and fast frequency response through its *Frequency control frameworks* review.[208]

Unexpected incidents, plant outages and weather outcomes will always occur and this inherent uncertainty will need to be managed by market participants and the system operator in any market, regardless of the design.

In the case of variable renewable energy generation, uncertainty due to the difficulty in forecasting weather conditions will always need to be managed. There may be some benefits associated with improved forecasting incentives in an ahead market. However, this uncertainty can never be removed, regardless of the design of the market.

4.3.4 Australian context

Submissions to the interim report stated that there was a lack of an Australian context in the current discussion of day-ahead markets. It was further noted that some of the features of other markets that motivated the introduction of an ahead market in other jurisdictions are not present or relevant to Australia. These features include the existence of a separate capacity mechanism, interconnection with other electricity markets and a different generation fleet.

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207 For more information see https://www.aemc.gov.au/rule-changes/managing-power-system-fault-levels and https://www.aemc.gov.au/rule-changes/managing-the-rate-of-change-of-power-system-freque

208 See: https://www.aemc.gov.au/markets-reviews-advice/frequency-control-frameworks-review

As noted in the interim report, the ultimate design of an ahead market in a given market is often driven by local market conditions; both the physical characteristics of the system (e.g. meshed versus long network), the market design in place before the introduction of the ahead market and the market structure (e.g. level of competition etc.).[209]

It is therefore important to identify the features of international markets that are not part of the NEM. These are discussed in more detail in this section.

Capacity mechanism

First, Australia does not currently have a separate capacity mechanism in place.[210] In the NEM a combination of energy and capacity are valued together through both the spot and contract markets. A capacity mechanism would be an addition to the NEM design intended to provide additional revenues to generators over and above those earned in the electricity wholesale and contract markets and additionally remunerate the provision of generation capacity, irrespective of the volume of electricity produced.[211]

In other jurisdictions there is an interaction between the operation of the ahead market and eligibility for capacity payments. For example, in PJM[212] participation in the day-ahead market is mandatory for all generators that participate in the capacity market and voluntary for all other resources. This interaction would not be present in Australia (without other substantial market design) and may reduce the need for an ahead market in the NEM.

However, the Commission notes that some markets that do not have capacity mechanisms also have an ahead market, an example of such a market is the Electric Reliability Council of Texas (ERCOT)[213].

Interconnection with other markets

One of the key motivating factors in the introduction of ahead markets in many European jurisdictions was to facilitate greater efficiency in allocating capacity and

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209 Interim report p.166

210 The Commission notes that there are differences between a capacity mechanism and a capacity market. A capacity mechanism implies a centrally planned approach where a body procures and pays for a targeted amount of capacity. A market-based approach is decentralised and both supply and demand are determined by market forces, i.e., there are two sides that equilibrate towards an outcome. An advantage of a market based approach is that it generally provides a technological-neutral framework to procure additional capacity.

211 FTI report, supplementary annex.

212 PJM Interconnection is a regional transmission organization (RTO) in the United States that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

213 See appendix F of the interim report for a case study of ERCOT.

flows across member states. This was a key part of a wider European reform aimed at harmonising European energy markets and convergence of prices across Europe.

In the western United States there are mechanisms such as the Energy Imbalance Market[214] that allow more efficient allocation of resources across regional interconnected markets. These markets are settled a day-ahead but inter-regional flows can be used to balance supply and demand at real-time across a larger geographical area. These mechanisms allow participants to buy and sell energy close to dispatch and give system operators real-time visibility on the operation of neighbouring grids. The benefits of such a mechanism include increased efficiency from finding the lowest cost energy across a wider geographic area and facilitating increased renewable penetration through greater geographical diversity.[215]

The NEM is not connected to any other markets and therefore cannot trade energy with other electricity markets. This may reduce the benefits associated with the introduction of an ahead market.

Generation fleet

In other markets the particular generation mix in place may be more suited to a multi-settlement market. In PJM there is a large proportion of both nuclear generation and generation with a long start time (over 24 hours). Nuclear generation is generally not dispatchable by PJM, whereas slow start generators generally engage in self commitment rather than being committed by PJM in the day-ahead market.

In such a market, an ahead market allows for the inflexible baseload units to be optimised over the day and provides enough notice for the slow start plant to be online when they are expected to be needed. There are no nuclear fleet in the NEM and the majority of plant do not require more than 24 hours' notice to start. Therefore the generation mix in the NEM has not led to calls for the introduction of an ahead market. If, however, a multi-settlement market was pursued in the NEM, the start times of the generation fleet would be a consideration in deciding the timing of the ahead market.

4.3.5 Interaction with other market changes

The introduction of an ahead market would interact with other proposed market changes or changes that are under way. These include:

- wholesale demand response
- the National Energy Guarantee
- forecasting.

These interactions are discussed below.

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214 For more information see https://www.westerneim.com/pages/default.aspx

215 See: https://www.westerneim.com/Documents/EnergyImbalanceMarketFAQs.pdf

Wholesale demand response

The introduction of an ahead market may facilitate increase demand-side participation in the wholesale market - achieving a similar outcome to the options being considered in the wholesale demand response chapter (chapter 5), which presents three potential options that may facilitate demand response.

An ahead market could facilitate higher levels of demand response in the wholesale market by providing the opportunity and incentive to participate by offering bids (assuming they are sufficiently flexible and resourced to do so). In the same way that the supply side would participate, consumers would be able to have some price certainty at the ahead market stage. Consumers would then respond to real time prices if they are different from what they were at the ahead market stage, by, for example, reducing consumption if prices are higher in real time. They would benefit from this action by receiving the difference between the ahead market price and the spot market price for any quantities consumed below the quantity cleared in the ahead market. If prices were lower in real-time, price-responsive loads could increase consumption to avoid consuming energy at a time when they expect prices to be higher.

National Energy Guarantee

The Guarantee is currently being developed by the Energy Security Board. There are potentially interactions between consideration of an ahead-market, and the development of the Guarantee, with the level and materiality of the interaction changing depending on what objective for an ahead-market is being pursued. Further, as noted there are alternative measures that could be pursued to achieve some of the same objectives that an ahead-market would be looking to achieve, which may also potentially interact with the Guarantee. In progressing this work the AEMC is working closely with the Energy Security Board on these matters.

Forecasting

Given that one of the objectives of an ahead market is to provide greater incentives to participants to forecast better, incremental changes to forecasting and information processes, including, for example, providing incentives for the demand side to provide forecasting information may also achieve a similar objective. As a result, there are interactions between an ahead market and the forecasting process. This is discussed below.

4.4 Changes to the NEM design that could achieve some of the objectives of an ahead market

The objectives that would motivate the introduction of an ahead market in the NEM may also be achieved by other means. For completeness, this section considers changes that could be made to the current market design that could fully or partly achieve the objectives outlined in section 4.3.2. These incremental changes may involve less time and costs to implement than fundamentally changing the competitive underpinnings of the existing market design.

These incremental changes focus on areas of the market that have been identified as potentially posing challenges under the current market design.[216] The areas of focus include, information provision, forecasting and valuing system security services. Each is described in turn in the following sections.

4.4.1 Information provision

There are two related aspects of the provision of information to both market participants and the system operator that may be improved - namely, the timeliness and quality of information. The timeliness of information refers to whether parties have information at the right time to inform their own decisions and that they have sufficient time to act in response to any new information. The quality of the information refers to how credible the information is, that is to say how likely is it that the information you have received will change. This section relates to information provision generally and not the accuracy of forecasts, which is discussed in the next section.

As part of our analysis of ahead markets, the Commission conducted a mapping exercise of the information available to market participants at different points in time. Participants at the Technical Working Group noted that the mapping exercise highlighted that there was ample information available and that this information was generally sufficient for participants to make operational decisions. It was also noted that there are areas where participants receive no information, for example on the output of non-scheduled generation or distributed energy resources. There is work ongoing to improve this information, for AEMO is reviewing ways to improve the visibility of distributed energy resources.

However, it was noted by participants, and through the Commission's own analysis, that there may be areas where the information available to parties may be improved. These improvements do not necessarily require the introduction of a ahead or multi-settlement market.

First, it may be possible to improve the quality of the pre-dispatch process. It is likely that some compliance action on the quality of the pre-dispatch process could change any behaviours that there may be on the part of participants to put in “lower quality” information.[217] It may also be beneficial to provide more specific guidance to

216 Although, as noted, the scale or materiality of these potential challenges has not yet been established.

217 However, it should be noted that there has not been any evidence presented that the quality of the information provided through the pre-dispatch process is poor. The Commission's analysis of the performance of pre-dispatch found that the level of deviation between pre-dispatch forecasts and actual demand outcomes has not deteriorated over time. This is discussed in more detail in chapter 3.

participants about what data is required, and how it is to be defined. Most of this is possible under the existing framework.

Further, the credibility of information contained in pre-dispatch could be improved through changes to compliance and enforcement. If the system operator is concerned that the information provided by market participants through the pre-dispatch process is not reflective of their true intentions a number of mechanisms could be used to incentivise the provision of information reflective of their true intentions at that time. Examples of such mechanisms may include, increased reporting requirements to explain rebidding or other restrictions on rebidding. These changes would need to be carefully considered as the flexibility available to generators to change their position through rebidding is necessary under a number of circumstances.

It may also be the case that the current pre-dispatch information could be improved through changes to the current rules, if it was found to be lacking in particular details or if the timing was no longer fit-for purpose. It may also be possible to have load participate in the current pre-dispatch process without moving to a multi-settlement market. This could provide generators and the system operator with more detail on the expected demand by retailers and other customers in the hours before dispatch and may provide better quality information to the market.

The Commission notes that there has been no evidence presented to it of systemic issues with pre-dispatch and little indication of any dissatisfaction or issues with the current process thus far.

4.4.2 Forecasting

In a market with increasing penetration of variable renewable resources and the need for more flexible plant understanding the uncertainty associated with forecasts is becoming increasingly important. As noted above, it is not possible to remove all uncertainty under any market design. However it is important that the information used by market participants in making operational decisions is as accurate as it can be (taking account of the costs involved in forecasting to higher degrees of accuracy).

An ahead market is said to provide greater incentives to participants to provide accurate forecasts as their bids are financially settled in the ahead market ahead of dispatch and any deviations from this position need to done through trading in the real-time market. However, the incremental changes to the current pre-dispatch process, as described in the previous section, may replicate these incentives to provide accurate forecasts.

The participants at the Technical Working Group identified one area where forecasts could be improved. They noted that AEMO's forecasts can be thought of as a 'black box'. This is because the results of the forecasting exercise are provided but the inputs, assumptions and methodologies used in calculating these forecasts are not provided. Without insight into how forecasts are calculated, stakeholders cannot provide comments or suggestions on how the accuracy of AEMO's forecasts could be improved or developed further. It was noted, however, that AEMO are continuing to work with industry in a collaborative way to improve their forecasts. This work can continue without any changes to market design.

Issues and potential improvements related to forecasting, including improving transparency, are described in further detail in chapter 3.

4.4.3 Valuing system security services

It may be the case that there are system security services that are not adequately valued and remunerated under the current market design. However, it does not immediately follow that an ahead market is the only means through which such services could be delivered. There are a number of mechanisms that could be used to deliver the required security and reliability outcomes without having to introduce a multi-settlement market. For example, new markets for ramping capability could be introduced or new means for valuing flexibility could be established under the current market design. Box 4.6 provides an overview of ramping capability in other jurisdictions.

Box 4.6 Ramping capability in other jurisdictions

Different jurisdictions have started developing new flexible ramping products to address short-lived scarcity conditions. These aim to improve the market's ability to make sure that there is sufficient ramping capability available to meet the forecast demand and to cover any potential errors in forecasts. This box provides a brief summary of ramping product arrangements in a number of jurisdictions.

EirGrid and Soni (Ireland)

In Ireland, the ramping margin is not a separate product, but rather a variation of ancillary services. The difference between the ramping margin and other ancillary services is in time the service must be delivered in. The ramping margin is defined by Eirgrid as the guaranteed margin that a unit provides to the system operator at a point in time for a specific horizon and duration.

Horizons of 1, 3 and 8 hours with associated durations of 2, 5 and 8 hours respectively were adopted.[218] The ramping margin is defined by both the minimum ramp-up and output durations. Thus, the ramping margin represents the increased MW output that can be delivered with a good degree of certainty by the product horizon time and sustained for the product duration window.[219]

218 See: https://www.semcommittee.com/sites/semcommittee.com/files/media-files/SEM-13-098%20%20DS3%20System%20Services%20Technical%20Definitions%20Decision%20Paper%20-%20FINAL_1.pdf

219 See: http://www.eirgrid.ie/site-files/library/EirGrid/DS3-System-Services-Portfolio-Capability-Analysis.pdf

The transmission system operators (TSOs) for the Republic of Ireland and Northern Ireland procure ramping margin services on a contractual basis from the providers. There is no co-optimisation of ramping margin and other ancillary services or energy. The TSO undertakes modelling to estimate the volume for ramping margin procurement, and dispatches the service.

CAISO (California) and MISO (Midwest United States and Manitoba and a southern United States region)

On 1 November 2016 the CAISO implemented a marked-based flexible ramping product (FRP) in order to address the operational challenges of maintaining power balance in the real-time dispatch. This product is only procured in the real-time market, which consists of the fifteen minute market and the real-time dispatch market. FRP is composed of flexible ramping up and flexible ramping down products. Resources capable of providing FRP include natural gas-fired power plants, energy storage, demand response, and other flexible resources.

While there are other "standby" ancillary services, FRP is the only market product targeting net system demand changes between dispatch intervals. FRP is a 5-minute ramping capability product, which is continuously procured and dispatched in real-time dispatch to meet the net system movement. FRP is to-optimised with both energy and ancillary services.[220] By submitting an offer to provide energy, generators are submitting an offer to provide whatever combination of energy and ramping capacity the dispatch model finds most cost-effective to the system.

MISO launched its voluntary ramping capability service on 1 May 2016. MISO and CAISO ramping services are quite similar, but with slightly different methods to forecast required volumes of ramping services. Ramping requirements are determined by MISO to manage both the expected net load changes (variations) and unexpected net load changes (uncertainties) over a defined response time - 10 minutes.[221]

As noted above the Commission has recently made rules on managing minimum fault levels and inertia and continues to work on these issues through its system security work programme. The Commission's *Frequency control framework* review will also consider potential new markets for system security services such as fast frequency response and inertia.[222]

220 See: https://www.caiso.com/Documents/RevisedDraftFinalProposal-FlexibleRampingProduct-2015.pdf

221 See:https://www.misoenergy.org/Library/Repository/Communication%20Material/Key%20Presentations%20and%20Whitepapers/Ramp%20Capability%20for%20Load%20Following%20in%20MISO%20Markets%20White%20Paper.pdf

222 See: https://www.aemc.gov.au/markets-reviews-advice/frequency-control-frameworks-review

AEMO has recently published a "power systems requirement" paper to explain the "technical and operational needs of the power system in relation to both security and reliability, based on the laws of physics that remain constant even as modern power systems like the NEM transform".[223]

Our technical working group noted that the need for these potential system security services should be established first, and once this has occurred, then consideration should be given to the means of delivering these services[224] to the NEM.

4.5 Conclusion

The Commission understands that AEMO is currently identifying the existing ahead features of the NEM that may require change and compiling the evidence of the deficiencies that AEMO considers need to be addressed, either through targeted improvements to existing arrangements or through a centrally facilitated ahead market design. The AEMC welcomes this. AEMO's contribution is important to understand what part of the existing market design is inadequate or needs to be improved, as well as the materiality of these matters. This is to help determine the most targeted solution and least cost solutions, whatever those solutions might be.

In this chapter, the Commission has considered three different objectives that may support the introduction of an ahead market in the NEM. The objective chosen would determine how the day-ahead market is designed and how it would differ from the current market arrangements.

An ahead market with the objective of providing market participants with more and better quality information is the most aligned with the current market design. This objective would be achieved by making participants' bids and offers financially binding by settling the ahead market at the ahead price at some point in advance of dispatch. This change may incentivise market participants to provide more accurate forecasts and information on their intentions, and would also provide increased price certainty to participants. The demand-side may benefit from the introduction of an ahead market as there may be more price certainty and the ahead market may assist in managing price risk and by enabling payments for demand response. However, this form of ahead market may not provide benefits to the system operator. For this objective to be pursued through the introduction of an ahead market, issues with the current pre-dispatch and risk management processes would need to be demonstrated.

Another objective that may be achieved through the introduction of an ahead market is to provide the system operator with better information to run the system more efficiently. The main issue that would need to be explored in order for this objective to be pursued is considering whether AEMO has, or does not have, sufficient information or tools available to them under the current market design to operate the system in a

223 See:http://www.aemo.com.au/Media-Centre/AEMO-publishes-Power-System-Requirements-paper

224 For example, through an ahead market.

secure and reliable way. Further, considering whether the number of out-of-market interventions issued by AEMO would be significantly reduced by introducing an ahead market.

A final objective considered in this chapter relates to who is best placed to make unit commitment decisions in the NEM - the system operator or market participants. The system operator has a view of the market as a whole but individual market participants have more detailed and up-to-date information on plant conditions and other operational considerations, as well as financial incentives to efficiently commit their plant. To achieve this third objective would require the most change to the NEM design and in order for such changes to be made it would need to be shown that the benefits of changing the responsibility of unit commitment decision to the system operator would outweigh the associated costs.

The Commission notes more targeted changes and improvements to the current market arrangements could be made to achieve some of the objectives of an ahead market. The Commission will continue to work with AEMO and stakeholders to develop these. These changes may include the introduction of new markets for system security services, facilitating within day trading of financial contracts, or new ways of valuing characteristics such as flexibility. The Commission is interested in stakeholder views on how objectives 1 and 2 may be achieved – either through the introduction of ahead type markets, or other alternative changes to the current NEM design.

5 Wholesale demand response

Key points

- The Finkel Panel review recommended that the Commission should undertake a review to recommend a mechanism that facilitates demand response in the wholesale energy market.
- Some consumers want *more opportunities* to offer wholesale demand response – and consider in many instances wholesale demand response can more efficiently contribute to reliability than building new generation. This is particularly true when a tight supply-demand balance is only forecast to occur for a short period of time.
- Due to lack of transparency around how much wholesale demand response is currently being utilised, it is very difficult to draw firm conclusions on how much demand response is occurring in the NEM, nor whether the level of demand response is efficient, which also makes it hard to ascertain the value that demand response would bring.
- Commercial and industrial consumers are generally better equipped to provide wholesale demand response. These parties also have greater opportunities to participate in the wholesale market when compared to residential consumers.
- The current arrangements theoretically place incentives on retailers to use demand response to hedge against the wholesale price to the extent this is more cost effective than other forms of hedging such as investing in more generation assets or entering hedging contracts. However, in practice, there may be factors that stop this being fully facilitated in the NEM.
- Of the factors influencing wholesale demand response in the NEM, there are two possible issues the Commission considers could be addressed through changes to the regulatory frameworks:
  - the requirements for there to be a single financially responsible market participant at a connection point
  - the difficulties faced by retailers offering demand response products such as acquiring customers for demand response programs and recovery of costs associated with investments in demand response capability.

Issues for stakeholder consultation

- The Commission is seeking feedback on the three options it has presented that may address the above possible issues. They are:

- two options that could allow multiple parties, for instance a specialist demand response aggregator and a retailer, to engage a single consumer behind a connection point without that being contingent on the original financially responsible market participant
  - providing additional incentives for retailers to offer demand response products.
- However, ways to do this require further consideration since they could have flow-on effects for a number of elements in the market, including the efficiency of the market and hence potentially prices for consumers and the Commission is interested to hear further from stakeholders on these.
- The Commission is also seeking feedback on the costs associated with the systems needed to participate in wholesale markets, either as a retailer or as a small generation aggregator.

This chapter is structured as follows:

- section 5.1 provides a summary of conclusions made in the interim report, and describes the purpose of this chapter
- section 5.2 provides a summary of stakeholder comments in submissions to the interim report and at the technical working group
- section 5.3 presents the Commission's analysis
- section 5.4 presents the Commission's preliminary conclusions.

5.1 Introduction

5.1.1 Context for this work stream

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 the demand side 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.[225] Demand response is being used by a number of retailers and technology providers, as well as having its value highlighted in:

- the Independent Review into the Future Security of the National Electricity Market ('Finkel Panel review')

225 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 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 spot prices are high.
- The NEM currently does not have sufficient incentives for encouraging the participation of distributed demand response aggregation services. 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 Australian Energy Market 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."

In addition, as the market transitions, the demand-side is expected to increasingly participate and contribute to power system reliability. Accordingly, when the Commission commenced this Review it committed to a consideration of methods to further engage demand response in the wholesale energy market.

5.1.2 Conclusions from the interim report

In the interim report, the conclusions made in respect of the wholesale demand response work stream were:

- Demand response refers to participants, specifically loads, changing their level of consumption in response to signals to do so. There are different types of demand response: wholesale, emergency, network and ancillary service.

- 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 other out-of-market reserves or involuntary load shedding to restore the supply-demand balance.

- For participants that face the real-time spot price for purchasing electricity, wholesale demand response can offer a number of valuable services.

- The NEM currently provides limited visibility on the amount of wholesale demand response.

- Firm and fast acting demand response requires time, education and equipment to develop. In contrast, there is wholesale demand response that can be utilised without investing as much time or resources but the extent of this demand response is likely to be both less firm and more variable.

- Based on our analysis, as well as discussions with stakeholders, the Commission invited feedback on any potential limitations raised to the uptake of demand response that may 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 noted that 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.

The Commission sought stakeholder views on these conclusions.

5.1.3 Purpose of this chapter

This chapter provides the next iteration of Commission's wholesale demand response work stream.

In the interim report, we committed to exploring ways in which the value of wholesale demand response could be more easily utilised.

In this chapter, we outline the aspects of regulatory frameworks that could be changed to allow third parties to access the value of wholesale demand response and provide it to the market. It also considers some of the challenges and opportunities associated with these changes to the regulatory frameworks.

Lastly, the chapter provides three high-level options that could be implemented to facilitate wholesale demand response. These options are not mutually exclusive.

The extent to which other changes to reliability frameworks may facilitate wholesale demand response, such as an ahead market, strategic reserve and the Energy Security Board's consultation on the National Energy Guarantee, these are also considered.

5.2 Stakeholder views

5.2.1 Submissions to the interim report

Wholesale demand response was commented on significantly by stakeholders in submissions to the interim report. Generally, stakeholders fell into three groups in regards to the need for more ways to facilitate wholesale demand response:

- There were no barriers to wholesale demand response in the current regulatory frameworks.
- The current market design has restricted the ability for third-parties to capture the value of wholesale demand response, resulting in demand response being underutilised.
- Further consideration and investigation is warranted.

Stakeholder views on wholesale demand response are presented by topic below.

Role for wholesale demand response in reliability frameworks

Stakeholders generally agreed that wholesale demand response supports the reliability of the power system.[226]

Tesla considered the participation of distributed energy resources in wholesale markets will be a key component of ongoing reliability considerations in the NEM.[227] Flow Power submitted that wholesale demand response is the cheapest capacity available to the NEM as users respond to market signals and provide valuable reliability services.[228] The Energy Efficiency Council highlighted demand response as a low-cost, dispatchable resource that is suited to a power system with high penetrations of intermittent generation.[229] Stanwell submitted that the distinction between demand side participation and demand response (i.e. where the demand side signals its intentions and price sensitivities to the market, as opposed to responding to wholesale

226 Submissions to interim report: Australian Energy Council, p. 2; Origin Energy, p. 2; AGL, p. 7; Clean Energy Council, p. 5; Major Energy Users, p. 8; TransGrid, p. 2; Energy Queensland, p. 3; EnerNOC, p. 8; ENGIE, p. 7; Flow Power, p. 5; Stanwell, p. 8; AEMO, p. 53.

227 Tesla, submission to interim paper, p. 5.

228 Flow Power, submission to interim report, p. 5.

229 Energy Efficiency Council, submission to interim report, p. 5.

market conditions) likely to be important when considering the contribution that these resources can make to reliability.[230]

Barriers to wholesale demand response

The AEC, Snowy Hydro, Origin Energy, EnergyAustralia, ERM Power, Stanwell and Meridian Energy all submitted that there were no regulatory barriers to wholesale demand response.[231] The AEC noted that its members were actively facilitating demand response and Snowy Hydro considered any mechanism introduced to facilitate wholesale demand response would be unnecessary and distortionary.[232] Origin Energy noted that demand response can and is happening in the NEM through different products offered by retailers.[233]

Stanwell submitted that there are examples of both demand response specialists becoming retailers and existing retailers offering wholesale demand products.[234]

In contrast, Major Energy Users, ARENA, Tesla, EnerNOC, S&C Electric and Energy Efficiency Australia suggested that there are barriers in the current regulatory frameworks to wholesale demand response.[235] The South Australian Government and ARENA agreed that further consideration of barriers for third parties utilising demand response is warranted.[236] ARENA also noted there are material hurdles for new retailers, including: regulatory complexity, upfront costs and customer acquisition.[237]

ARENA submitted that while it had observed increasing interest in commercialising demand side services, it is not clear that the current market design and settings will present the best framework to encourage an efficient level of demand side participation.[238]

In its submission, EnerNOC highlighted that during 18 and 19 February 2018, when wholesale prices were high, no retailers appear to have attempted to procure wholesale demand response based on a survey of its own employees. EnerNOC considered that this indicates that despite having a theoretical incentive to utilise wholesale demand response, retailers are not doing so.[239]

230 Stanwell, submission to interim report, p. 8.

231 Submissions to interim report: Australian Energy Council, p. 2; Snowy Hydro, p. 2; Origin Energy, p. 2; ERM Power, p. 4; EnergyAustralia, p. 3; Stanwell, p. 8; Meridian Energy, p. 2.

232 Submissions to interim report: Australian Energy Council, p. 2; Snowy Hydro, p. 7.

233 Origin Energy, submission to interim report, p. 2.

234 Stanwell, submission to interim report, p. 8.

235 Submissions to interim report: Major Energy Users, p. 8; ARENA, p.5; Tesla, p. 5; EnerNOC, p. 8; S&C Electric, p. 8; Energy Efficiency Council, p. 5.

236 Submission to interim report: South Australian Government, p. 4; ARENA, p. 6.

237 ARENA, submission to interim report, p. 5.

238 Ibid.

239 EnerNOC, submission to interim report, p. 8.

S&C Electric noted that there are challenges for demand side investments to access the full value of the services they can provide.[240] ARENA agreed with this point.[241]

Major Energy Users highlighted a number of challenges faced by consumers in seeking to provide wholesale demand response:[242]

- A lack of price certainty affects the ability for consumers to offer demand response and have certainty of cost recovery.
- Consumers typically need time to implement demand response.

AEMO noted that demand-based resources can benefit from a market design that supports earlier commitment in advance of price signals.[243]

Major Energy Users also suggested certainty provided to demand response in capacity markets facilitated greater amounts of wholesale demand response.[244]

ARENA considered that there appear to be weak incentives for gentailers to cultivate a competitive market for demand side service provision.[245] S&C Electric considered it would be difficult to see why a retailer would reduce consumption unless they were a new, innovative retailer providing new products.[246]

The Energy Efficiency Council submitted that while the NER does not explicitly prevent wholesale demand response, it inhibits wholesale demand response through the bundling of retail supply and demand response.[247]

The need for additional regulatory frameworks to facilitate wholesale demand response

Snowy Hydro suggested that separating wholesale demand response from energy would require significant changes to the current market design, which it considered to be unnecessary.[248] ENGIE submitted that it did not support the introduction of special mechanisms to encourage demand response.[249]

Tesla considered regulatory frameworks should allow for wholesale demand response and other services without requiring the involvement of the retailer.[250] EnerNOC

240 S&C Electric, submission to interim report, p. 8.

241 ARENA, submission to interim report, p. 5.

242 Major Energy Users, submission to interim report, p. 8.

243 AEMO, submission to interim report, p. 53.

244 Major Energy Users, submission to interim report, p. 9.

245 ARENA, submission to interim report, p. 5.

246 S&C Electric, submission to interim report, p. 8.

247 Energy Efficiency Council, submission to interim report, p. 10.

248 Snowy Hydro, submission to interim report, p. 8.

249 ENGIE, submission to interim report, p. 7.

250 Tesla, submission to interim report, p. 6.

suggested that the review should focus on creating a market framework that allows distributed energy resource owners/controllers to offer their capacity to the NEM's market(s), without needing to become the customer's retailer.[251]

Meridian Energy considered that in considering a potential development of a retailer-independent demand response market, the potential costs to consumers and the impacts on the NEM, would need to be carefully balanced against any potential benefits.[252]

The Energy Efficiency Council considered that developing an open, competitive market for demand response will likely lead to more retailers offering their customers attractive demand response services or incentive payments, either directly or through a third-party provider. The Energy Efficiency Council likened the bundling of wholesale demand response and retail supply to forcing consumers to buy car insurance from a car manufacturer, highlighting that this would lead to sub-optimal levels of competition for both products.[253]

The Energy Efficiency Council suggested that a mechanism be introduced in line with a set of principles:[254]

- allowing a customer to provide demand response
- separating wholesale demand response from electricity retail services
- recognition that demand-response facilitation and aggregation are services
- an effective system for establishing baselines.

The extent of wholesale demand response in the NEM currently

In the interim report, the Commission noted that the NEM currently provided limited visibility on the amount of wholesale demand response.

Energy Networks Australia agreed that it is difficult to determine the extent of wholesale demand response.[255] EnergyAustralia and Energy Queensland suggested that AEMO's demand side participation guidelines and COAG Energy Council's *Register of distributed energy resource* rule change request would make the extent of demand response in the NEM more visible.[256] EnergyAustralia also noted that in attempting to improve the visibility for wholesale demand response, regulatory frameworks should maintain the confidentiality of commercial arrangements.[257]

251 EnerNOC, submission to interim report, p. 11.

252 Meridian Energy, submission to interim report, p. 2.

253 Energy Efficiency Council, submission to interim report, p. 11.

254 Ibid.

255 Energy Networks Australia, submission to interim report, p. 4.

256 Submissions to interim report; EnergyAustralia, p. 3; Energy Queensland, p. 4

257 EnergyAustralia, submission to interim report, p. 3.

TasNetworks and Energy Queensland encouraged efforts to increase the visibility of wholesale demand response as it would lead to better network investment decisions.[258]

Origin Energy submitted that the Commission should evaluate the extent to which wholesale demand response is currently being underutilised to ensure a balanced way forward.[259]

Energy Efficiency Council acknowledged that while levels of demand response may not be transparent, there is evidence to suggest the level of demand response is below the economic potential.[260]

AEMO noted that wholesale demand response exists in the NEM currently, but asserted that it is underused because:[261]

- there is significant confusion over the difference between efficient and non-intrusive price responsive demand management and involuntary load shedding
- demand-based resources can benefit from a market design that supports earlier commitment in advance to price signals and system reserve requirements.

Role for networks

TasNetworks welcomed any policy initiative that encouraged and expanded on the role for network services providers in facilitating demand response for the purpose of network reliability.[262]

TransGrid submitted that regulatory framework should allow for innovation by transmission businesses to actively build up the demand response market, in the same way that an innovation scheme has been introduced for distribution businesses.[263] Energy Queensland considers the role for DNSPs to be underutilised and suggested demand response provided by DNSPs could provide value until a demand response market has reached a sustainable level of maturity.[264]

Stanwell suggested that the Commission investigate whether demand response provided by network businesses would be able to be provided to AEMO to be dispatched. Stanwell noted that this would lead to lower costs to consumers when compared to network businesses offering demand response through the RERT.[265]

258 TasNetworks, submission to interim report, p. 3.

259 Origin Energy, submission to interim report, p. 2.

260 Energy Efficiency Council, submission to interim report, p. 7.

261 AEMO, submission to interim report, p. 53.

262 TasNetworks, submission to interim report, p. 4.

263 TransGrid, submission to interim report, p. 2.

264 Energy Queensland, submission to interim report, p. 2.

265 Stanwell, submission to interim report, p. 8.

5.2.2 Technical working group

At the technical working group the Commission presented analysis on the issue being considered in this work stream. The Commission also presented two high-level options for facilitating wholesale demand response.

Stakeholders were mixed in their views that further analysis of options for facilitating wholesale demand response was appropriate. Some stakeholders suggested that limitations on wholesale demand response might lay in the broader challenges for small retailers looking to utilise demand response, but were struggling to acquire customers.

Stakeholders disagreed on the need for changes to regulatory frameworks to facilitate wholesale demand response. Some stakeholders considered that the current arrangements were leading to levels of wholesale demand response lower than what would be economically efficient. Others highlighted that wholesale demand response was being used and the cost of procuring wholesale demand response from smaller customers was prohibitive. Further, some stakeholders considered the issues being raised in this work stream had already been thoroughly considered previously.

5.3 Analysis

This section provides:

- the Commission's views on factors driving the extent of wholesale demand response in the NEM
- the Commission's views on the issues that should be addressed in order to facilitate wholesale demand response
- three high-level options for addressing these issues.

5.3.1 Lack of transparency around amounts of wholesale demand response

In the interim report, the Commission noted the lack of 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. Indeed, since the publication of the interim report we have heard anecdotally of consumers being offered demand response products. The recent announcement of the expansion of Flow Power, which is based around exposing parties to wholesale prices, and engaging in demand response, shows the increased focus and incentives available to companies operating in an electricity market that has a tight supply-demand balance.

Therefore, it is very difficult to draw firm conclusions about how much demand response is currently occurring in the NEM. Notwithstanding this, we recognise that consumers want *more opportunities* to offer wholesale demand response[266] – and that in many instances demand response can more efficiently contribute to reliability than building new generation. It is for these reasons that we are exploring ways to facilitate wholesale demand response in the NEM.

5.3.2 Factors contributing to the level of wholesale demand response in the NEM

The Commission considers the following factors, which are discussed in more detail below, currently present an obstacle to greater amounts of wholesale demand response in the NEM:

- Uncertainty of cost recovery for wholesale demand response
- There is only one financially responsible market participant (FRMP) for each connection point
- Third parties (i.e. parties who are looking to utilise wholesale demand response but are not registered as market customers) intending to utilise wholesale demand response may not be able to do so under the current arrangements
- Enabling demand response from smaller customers is technically difficult and has an upfront cost. While this technical difficulty and cost appears to be subsiding, the rate of uptake of enabling technology (e.g. smart meters) may limit the development of wholesale demand response from smaller customers, despite it being increasingly technically feasible.
- Challenges for new retailers using wholesale demand response to acquire customers and become established in the market.

Uncertainty of cost recovery

A challenge for wholesale demand response 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.[267] Unless a consumer 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.[268] 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

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266 The Australia Institute, *Polling - demand response*, October 2017.

267 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.

268 A separate, but related issue, is the distortion that future trading periods have on current behaviour i.e. if prices spike in the first interval, there is an incentive to demand respond in the later intervals even if the supply demand balance is less tight (to respond when the market no longer needs it).

settlement outcomes which should reduce the extent of wholesale market price uncertainty for demand response providers.[269]

Another challenge for wholesale demand response is having certainty of avoiding a forecast high price. A consumer may see a forecast wholesale price and start reducing consumption to avoid paying the high price. However, the consumer will only see the benefit of its wholesale demand response if the high price actually occurs. The extent to which the consumer is unsure of future electricity prices will reduce the certainty associated with achieving full value out of wholesale demand response. This uncertainty, and the associated risk management, is analogous to decision making process for commitment of generators, which was discussed in chapter 4.

Market customers are the sole intermediary with the wholesale market

Wholesale demand response provides economic benefits to parties by changing the level of consumption in the wholesale market i.e. by reducing demand when prices are high to avoid purchasing energy to meet that demand. To benefit from wholesale demand response under the current arrangements, a participant must have some form of access to the wholesale price - since wholesale demand response typically provides benefit in the form of reduction in consumption at high prices.

Parties gain access to the wholesale price either directly through wholesale market exposure, or indirectly through an arrangement with a participant exposed to the wholesale market. In the NEM, the only party that is directly exposed to the wholesale market price for most loads is the market customer – for smaller customers this is generally the retailer.

Therefore, in order to benefit from wholesale demand response, a consumer can undertake either of the following options:

- Register as a Market Customer and purchase their electricity at the wholesale price. The consumer would be able to use demand response and/or enter into financial contracts to manage the risks associated with purchasing electricity directly from the wholesale market. This option is generally not accessible for smaller customers because of the costs associated with direct participation in the wholesale market, as well as costs associated with registration and metering.

- Enter a contract with a retailer with full or partial spot price pass through. This would give the consumer some direct exposure to the wholesale electricity price. Similar to registering as a Market Customer, the consumer would be able to use wholesale demand response to reduce exposure to wholesale prices. This option requires the involvement of the retailer and is unlikely to be made available to smaller customers.

- Enter into a retail contract with a demand response product. The consumer may not necessarily have any direct exposure to the wholesale price, but it would agree with the retailer to change consumption under certain conditions. This

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

would allow a consumer to utilise wholesale demand response in conjunction with its retailer in response to wholesale prices. Like the previous option, this requires the involvement of the retailer. The Commission understands that there are currently limited retail offers that utilise wholesale demand response, particularly for smaller customers.

The value of demand response from individual customers, particularly small consumers, may be relatively small compared to total cost of retail energy consumption. This may generally lead to consumers focussing on the price for the majority of their consumption (as opposed to the potential value of demand response) when choosing a retailer.

Retailer incentives to utilise wholesale demand response

A retailer is responsible for purchasing electricity from the wholesale market on behalf of its entire retail portfolio. Inherent in doing so is the risk of high wholesale prices occurring, exposing the retailer to high costs. Typically, retailers are able to manage this risk in a number of ways, including:

- entering into financial contracts such as swaps and caps
- using its own generation assets (vertical integration)
- employing its own customer demand response arrangements or procuring a third party's wholesale demand response to alter the extent of wholesale price exposure
- passing wholesale market exposure to its customers through spot price pass through arrangements.

A retailer can use any combination of the above. There are a number of reasons why a retailer, particularly an established retailer may prefer to use the former two options:[270]

- Established retailers may not have the experience or the organisational expertise to utilise wholesale demand response. At the technical working group meeting, it was noted that for at least some of the existing retailers, the cheapest option of managing wholesale risk was entering into derivative contracts or generating electricity with their own assets. As a result, the most efficient option for a retailer may indeed be to not engage in wholesale demand response. Where a retailer opts not to use wholesale demand response, this could conceivably co-exist with a third-party aggregating demand response from that retailer's customers to offer wholesale demand response.
- Engaging a consumer to provide wholesale demand response has associated upfront and ongoing costs. These transaction costs include the costs of engaging customers, explaining what demand response actually is, installing necessary

270 This is not to say that established retailers do not offer demand response products.

equipment and agreeing to conditions. The costs generally increase with firmness of the wholesale demand response. The payback period for these costs may be greater than the terms of the retail contract, leaving the retailer exposed to the risk of not recovering their costs if a customer changes retailer. AGL noted in its submission to the interim report that the installation of control technology has high upfront costs, particularly for small customers.[271] In addition, for some retailers, utilising wholesale demand response may require changes to IT which would have associated costs.

As a result, some retailers in the NEM may opt not to utilise wholesale demand response to manage wholesale electricity market risks (or to utilise it less than they otherwise would). Conversely, other retailer business models are dependent on spot price pass through arrangements and wholesale demand response. Box 5.1 details an example raised in submissions to the interim report that highlights one approach.

Box 5.1 Example of Flow Power using wholesale demand response

Flow Power is an electricity retailer that operates in all regions of the NEM. 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's 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.

In their submission to the interim report, Flow Power highlighted an example of one of its customers responding to forecasts of high wholesale prices on 19 January 2018. In this example, a customer shifted load from the afternoon to the morning by altering production and maintenance schedules. This example also demonstrates the role of forecasting in facilitating wholesale demand by responding to *expected* wholesale prices. Forecasting is discussed more generally in chapter 4.

271 AGL, submission to interim report, p. 7.

Figure 5.1 Flow Power customer's wholesale demand response

Source: Flow Power, submission to interim report, p. 3.

Therefore, while theoretically retailers have incentives to offer demand response products, in practice there may be reasons why retailers have incentives not to offer demand response products. Stakeholders are divided as to what actually is the reality. If such a statement is true, in order to facilitate more wholesale demand response in the NEM there would need to be more demand side aggregators who could offer demand response products as an alternative to retailers.

Existing frameworks may not be conducive to third parties independently providing wholesale demand response

If a third party engages with consumers to facilitate wholesale demand response as set out above they can only do so currently by either being a retailer themselves, or having a deal with a retailer. However, there are limitations with these options:

- Third parties could be exposed to risk if consumer switched retailers to one that they didn’t have a deal with. This could only be avoided if the third party was able to enter into an agreement with all possible retailers. As retailers all have individual, unique ways of risk management it is unlikely that a third party would be able to contract with all possible retailers.

- Demand response aggregators may not want to become retailers. They may not necessarily have the capabilities to be a successful retailer. Retailing electricity typically requires expertise in risk management, marketing, IT systems administration and being able to meet prudential requirements. The third parties looking to provide wholesale demand response may instead be experts in load production processes, and dispatch / control technologies. Retailing electricity also require registering and meeting the prudential and consumer protection requirements set out in the NER.

- In addition, stakeholders have raised concerns regarding the costs associated with the systems needed to participate in wholesale markets, either as a retailer or as a small generation aggregator suggesting that these costs can potentially make it more difficult for smaller parties to participate in the wholesale market. For example, we understand that one stakeholder has raised that they consider that AustraClear, the electronic funds transfer facility used in the NEM, imposes significant costs on wholesale market participation. The Commission is interested in understanding from stakeholders the extent of costs associated with participation in the wholesale market.

Therefore, there may be limited opportunities for third party demand-side aggregators in the current framework.

Technological developments

For a consumer to be able to offer and provide demand response, a variety of education, equipment and time will be needed, depending on the type of demand response.

More firm and faster acting demand response require more time, education and equipment to develop. In contrast, there is wholesale demand response that can be achieved through simpler methods such as sending a message to customers inviting demand response; however, this form of wholesale demand response is likely to be less firm and more variable in quantity and duration.

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.

The costs of compiling a demand response portfolio have fallen with technological developments. These costs are likely to continue to fall over time.

Commercial and industrial customers are more likely to have the appropriate metering to provide wholesale demand response. They are also more likely to already have monitoring and communications equipment that could help them in providing wholesale demand response. For these larger consumers new equipment is likely to be needed to allow for any remote control over load processes.

Residential consumers are less likely to have the technical capability to provide demand response. However, this is changing with the falling costs of technology and increased penetrations of enabling technology, such as advanced metering. 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. The ability for smaller consumers to offer demand response should improve as metering equipment improves and consumer interest increases.[272] The Commission notes that there have been some recent developments demonstrating that in may be increasingly feasible to gain visibility on the consumption of smaller customers. For example, AGL announced a trial in which it provides information to some of its residential customers on energy

272 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. For more information, see: https://www.aemc.gov.au/rule-changes/expanding-competition-in-metering-and-related-serv

being consumed by various household appliances. Based on feedback from the customers participating in the trial, AGL highlighted that this information could assist in reducing electricity consumption.[273]

Education and consumer expectations of demand response

Another factor to consider is how consumers react to and understand demand response.

In 2016 the AEMC commissioned Oxera to consider how behavioural insights can be applied to retail energy markets in Australia. This included some relevant insights that are applicable to consumers engaging with demand response. For example, Oxera found that when making energy-efficient investments and purchases, people's decisions are often affected by present bias, which makes upfront costs much more salient relative to future energy savings.[274] Research in the UK shows that consumers' reluctance to incur an upfront cost for energy-efficient capital investments such as cavity wall insulation and ceiling insulation, despite this cost being substantially outweighed by the future benefits from savings on energy expenditure. Similar logic can likely be applied to installing demand response equipment.

In addition, Oxera noted that people place a higher value on what they already purchase or own (the 'endowment effect'). In the energy retail market, consumers do not own a physical object, but purchase services from a retailer and associate value with the retailer's brand. Values attached to brands vary significantly from one consumer to another, but are expected to be higher for established brands (incumbent retailers) and suppliers that invest more in advertising and brand-building activities. This status quo bias presents a problem for the introduction of innovative products such as time-of-use tariffs.

This can also be applied to demand response. A number of smaller, innovative retailers who may be less inclined to integrate with generation or purchase financial hedges are looking to offer demand response products (either themselves or via a third party) e.g. Sonnen with Energy Locals, Pooled Energy, Flow Power, Reposit with Diamond Energy, Simply Energy and Powershop). It may therefore be difficult for these retailers to gain consumers and uptake due to the status quo bias.

Further, 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 utilise wholesale 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 price/cost of electricity when choosing a retailer.

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273 AGL, *Media Release - AGL's Energy Insights helps customers to take charge of their energy usage*, 31 January 2018.

274 Oxera, *Behavioural insights into Australian retail energy markets* - prepared for the Australian Energy Market Commission, March 2016.

While there has likely been a lack of education around what demand response is – ARENA knowledge sharing, and education resources produced by retailers (e.g. Powershop and Flow Power) are assisting in overcoming this information barrier.

Summary

The current arrangements theoretically place incentives on retailers to use demand response to hedge against the wholesale price. However, in practice, there may be aspects that stop this being fully facilitated in the NEM – although this is not fully clear due to the lack of visibility about demand response in the NEM.

Of the factors influencing wholesale demand response in the NEM, there are two issues the Commission considers could be addressed through changes to the regulatory frameworks:

- the requirements for there to be a single FRMP at a connection point
- the difficulties faced by retailers offering demand response products.

These are discussed in turn below.

While the options discussed below all facilitate wholesale demand response, any regulatory response under the NER needs to be in the long-term interests of consumers. Just as it is possible to have excess generation capacity, too much wholesale demand response could develop. Market participants could over-invest in utilising wholesale demand response and fail to make a return on this investment. Additionally, a consumer could enter into an agreement to provide wholesale demand response and consequently be required to reduce demand at times when the cost to the consumer of doing so outweigh the benefits of being a party to that agreement.[275] To be in the long term interests of consumers, facilitating wholesale demand response should reduce total system costs. The reduction in costs should be greater than the values that consumers place on the electricity services they are foregoing.

In theory, if prices are high and consumers want to use electricity despite these high prices, this is an efficient outcome. Taken to the other extreme, levels of demand response such that consumers radically decrease their consumption to near zero, despite valuing their consumption more than the cost of its provision, is also not efficient. There is therefore an appropriate level of demand response at the point which balancing the cost of the provision of generation with the cost of foregone electricity consumption.

275 For example, in the context of water the Productivity Commission noted that some prescribed approaches to integrated water cycle management are inefficient. Instead, the approach should be to create incentives and opportunities for recycling, reuse and conservation technologies where they are economically worthwhile and preferred by customers, by removing impediments to contestability and freeing up prices. See: Productivity Commission, Inquiry Report, Volume 1, Australia's Urban Water Sector, No. 55, 31 August 2011, p. xxxiii.

5.3.3 Single financially responsible market participant at a connection point

One of the most significant restrictions on facilitating more wholesale demand response in the NEM is that current arrangements allow only a single FRMP at a connection point. Unless a customer is willing to directly participate in the wholesale market or has a retailer that is willing to offer demand response (either from itself, or via a third party aggregator), the customer will not be able to engage in wholesale demand response.[276]

The issues faced in regards to wholesale demand response also apply to smaller distributed energy resources accessing markets. Under the current arrangements, unless a distributed energy resource is connected behind a separate connection point, it is the FRMP that benefits from the value created by interactions between that resource and the wholesale market.[277]

The Commission considers that there are two options that would allow multiple parties to engage a single consumer behind a connection point without it being contingent on the cooperation of the FRMP. The options are:

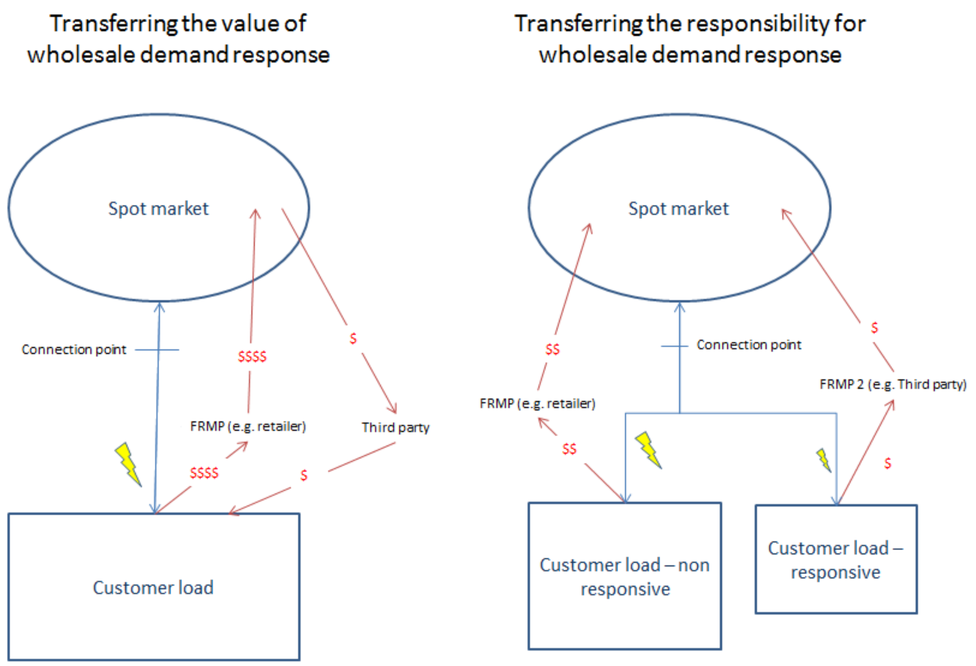
- Transferring the value of the wholesale demand response from the existing FRMP to the aggregator
- Transferring spot market responsibility for demand responsive load from the existing FRMP to an aggregator.

We discuss the relevance of each of these below.

276 The Commission notes that changes made in the *Expanding competition in metering services* final rule may make it easier to install demand response functionality at the meter. This may make it easier for larger customers to engage in demand response.

277 The FRMP could then share this value with the consumer.

Figure 5.2 High-level options for separating retail supply and wholesale demand response



Transferring the value of the wholesale demand response from the existing FRMP to the aggregator

Existing framework analogy

There is an existing aspect of the NEM that can be considered somewhat analogous to this option – the market ancillary service provider (MASP) framework.

In 2016, the Commission introduced the MASP framework into the NER. A MASP is able to offer appropriately classified ancillary services loads or aggregation of loads into FCAS markets without having to be the customer's retailer. Since the introduction of this framework, demand response has been participating significantly in the FCAS markets, creating competition and driving down prices.[278]

Some stakeholders have commented that the MASP framework provides a useful comparison since it unbundles energy from "energy". However, what it actually unbundles is energy for use in the wholesale market from energy for the purpose of controlling frequency. In this framework, MASPs do not interact with the wholesale market.

There are a number of key differences between the MASP framework and any form of mechanism to facilitate wholesale demand response:

- Wholesale demand response, by definition, involves participants in the wholesale market. The MASP framework does not facilitate participation in the wholesale market.

278 EnerNOC, submission to interim report, p. 13.

- The issues of an appropriate baseline (i.e. working out the counterfactual to be used to measure the extent of the demand response) are of less significance. When providing FCAS with demand response, the amount of response is assessed against the consumer's level of consumption prior to being dispatched for FCAS. The contribution of the load to helping to correct a frequency deviation is assessed against the level of consumption immediately prior to being dispatched for FCAS. Because FCAS is dispatched over short timeframes, this reduces the extent to which a baseline is needed to determine the counterfactual level of consumption. With demand response provided over a longer timeframe (such as wholesale demand response) it is generally necessary to determine the counterfactual consumption.

The extent that the level of consumption behind a connection point changes to help correct frequency, this change in consumption will still be settled by the FRMP (in this context, the retailer) in the wholesale market. However, the MASP framework can still prove instructive when considering how the value of wholesale demand response might be unbundled from the retail supply of energy.

How this option would work

This option is based around transferring the value of the wholesale demand response from the existing FRMP to the aggregator. Creating a mechanism that can do this would facilitate wholesale demand response since it will allow other parties – aside from retailers – to offer demand response products.

Broadly, this option would entail:

- The ability for a third party to submit demand response bids to the wholesale market – third parties would submit an offer into the wholesale market of how much demand a particular customer would be willing to reduce at particular prices. These offers would then be incorporated into AEMO's optimisation engine in order to coordinate outcomes in the wholesale market, given physical limitations in the transmission system.

- Given that third parties would submit bids, the wholesale demand response would be scheduled. Demand response would ideally be scheduled in order to create consistency with how generators are treated in the wholesale market. However, the Commission accepts that there are reasons why demand response may not be subject to the full range of obligations that apply to scheduled participants. For example, it might be easy to constrain down demand response (i.e. get it to 'generate' more, which would imply a decrease in consumption), but not up (i.e. get it to 'generate' even less, which would imply an increase in consumption) unless the demand had already been dispatched down.

- The third party submitting the wholesale demand response bids would be exposed to the wholesale price for the difference between the baseline level of consumption and the actual level of consumption. To the extent that the third party reduces actual consumption to level less than the baseline, it would receive the wholesale price. The FRMP would be settled in the wholesale market for the baseline level of consumption. This would allow the value of the wholesale demand response to be accrued to the third party without the involvement of the retailer.

- It would be compulsory for retailers to be participate in this option. This would best enable wholesale demand response to be facilitated, since retailers would not be able to prevent third party wholesale demand response.

In particular, the Commission notes that this option would require the use of a baseline to determine the extent of any demand response. The design of the baseline is likely to be a determinant in the effectiveness and efficiency of this option because setting the baseline significantly influences financial outcomes for the parties involved and hence the incentives on parties to undertake an efficient level of demand response – as it was when the Commission last considered a demand response mechanism.

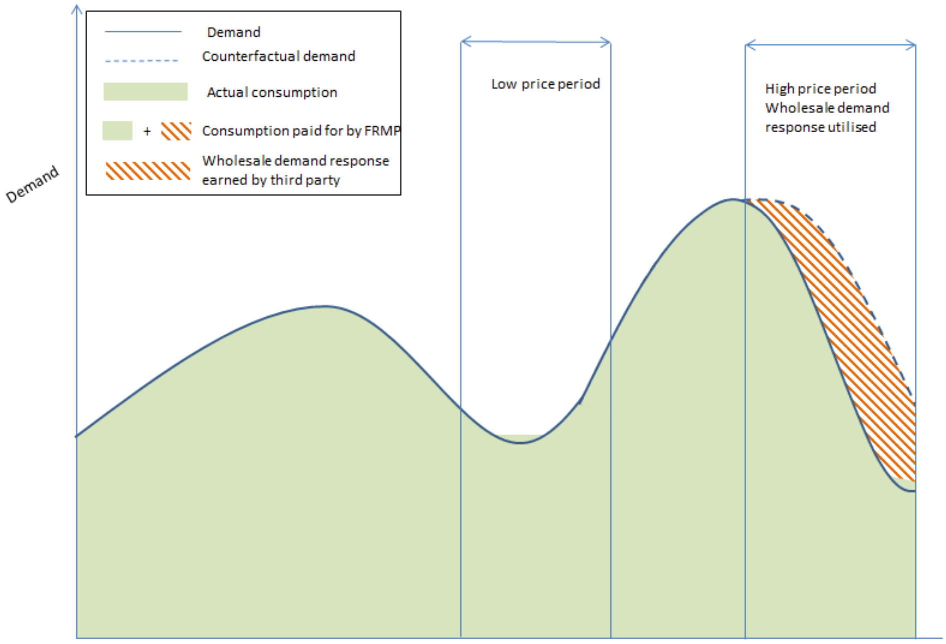
The Commission notes that the current AEMO/ARENA RERT trial is using baselines to determine the extent of demand response provided into that program by loads. We understand that there are useful insights being produced from this trial which will inform any future work to design a methodology for determining a baseline level of consumption.

The Commission notes that the use of baselines is likely to become more difficult as the demand side becomes increasingly responsive to external signals. When loads do not have a consistent, regular pattern of consumption (e.g. a battery responding to a learning algorithm), it can become difficult to determine a counterfactual level of consumption. For example, developing a baseline level of consumption for a battery would need to account for what the battery would have been doing which could be a factor of a number of decisions in the household or different external signals.

The party that determines the baseline would require further consideration. Baselines can be centrally determined, or they could be determined and submitted by the third party offering demand response. In considering who would be best placed to determine the baseline, consideration would need to be given to the ability of the baseline to be gamed. Given that the demand response bids would be scheduled or semi-scheduled this could allow for third parties to submit a baseline level of consumption.

Figure 5.3 shows an example of a customer reducing consumption following notice from a third party under this option. The third party would receive the wholesale price for the wholesale demand response and the FRMP would purchase the counterfactual amount of demand from the wholesale market.

Figure 5.3 Option 1 - Transferring value of wholesale demand response



Further considerations

This option requires further consideration as to whether this would be in the long-term interests of consumers. Aspects the Commission consider requires further consideration include:

- whether it would actually facilitate wholesale demand response, or whether some of the other factors that limit wholesale demand response (e.g. behavioural biases from consumers) would limit this option's ability to facilitate wholesale demand response
- the level of changes to existing systems that would be required to facilitate this option
- views from participants on what an effective methodology for establishing a baseline would be and who would be best placed to determine it. As can be seen from Figure 5.3, the level of the counterfactual demand (the baseline) is material to the financial outcomes of both the FRMP and the third party, in turn influences the incentives of the third party (or its customer, the load) to invoke the efficient level of demand response.

An alternative approach for transferring the value of demand response from the FRMP to a third party, adapted from the model used in the National Electricity Market of Singapore, is presented in Box 5.2.

Box 5.2 Adapting the Singaporean demand response mechanism to Australia

As recognised above, as loads become more dynamic and controllable (e.g. batteries), it may become increasingly difficult for a central algorithm to accurately anticipate the consumption had loads not offered demand response. Having consumers provide information regarding their operational decisions with incentives to provide honest information may allow for a baseline to be submitted that more readily accommodates wholesale demand response from less predictable loads.

Similar to Option 1, a mechanism to facilitate demand response could allow third parties to bid demand response into the wholesale market. The third party would have to submit price/quantity pairs that reflect the various price levels that the load is willing to consume at. The load would then be centrally dispatched to a level reflecting willingness of the load to consume at different wholesale electricity prices.

In the National Energy Market of Singapore, a demand response mechanism has been introduced that shares some similarities with Option 1.[279] Both ultimately seek to allow third parties to submit bids for demand response into the wholesale market without also becoming the FRMP at the connection point. However, there are a number of key differences between Option 1 and the demand response mechanisms in Singapore. These are highlighted in Table 5.1.

Table 5.1 Differences between Option 1 and the Singapore demand response mechanism

Feature	Option 1	Singapore demand response mechanism
Amount of energy the FRMP is settled for in the wholesale electricity market	A *baseline* level of consumption	The *actual* metered level of consumption
Determination of baseline	The baseline is centrally determined using historical consumption data	The baseline is submitted by the party offering the demand response
Value to demand response provider	The value of reduced consumption accrues to the third party providing the demand response	The value of the reduced consumption accrues to the FRMP and the third party get a share of any reduction in wholesale prices resulting from the wholesale demand response

279 For more information, see: Energy Market Authority, *Implementing Demand Response in the National Electricity Market of Singapore*, Final Determination Paper," October 2013, available at https://www.ema.gov.sg/cmsmedia/Electricity/Demand_Response/Final_Determination_Demand_

Summary of the Singapore model

The Singaporean demand response mechanism allows third parties to provide wholesale demand response. That is, parties who are not the FRMP at the connection point are able to sell demand response into the wholesale market.

The program involves the demand response aggregator bidding into the energy market and then following a dispatch signal from the system operator if their bid clears—with penalties for non-compliance. Effectively the demand response aggregator (on behalf of the demand response resource) is required to bid a range of quantities it will consume at different wholesale electricity prices. The load will need to consume to the level that it is dispatched to. If the load submits a bid to reduce consumption that is cleared, the load or aggregator receives an incentive payment (discussed below). The incentive payment encourages the participation by large loads and aggregators and retailers are settled based on metered load. Incentive payments to demand response aggregators will be provided from an uplift charge applied to all load and charged to retailers.

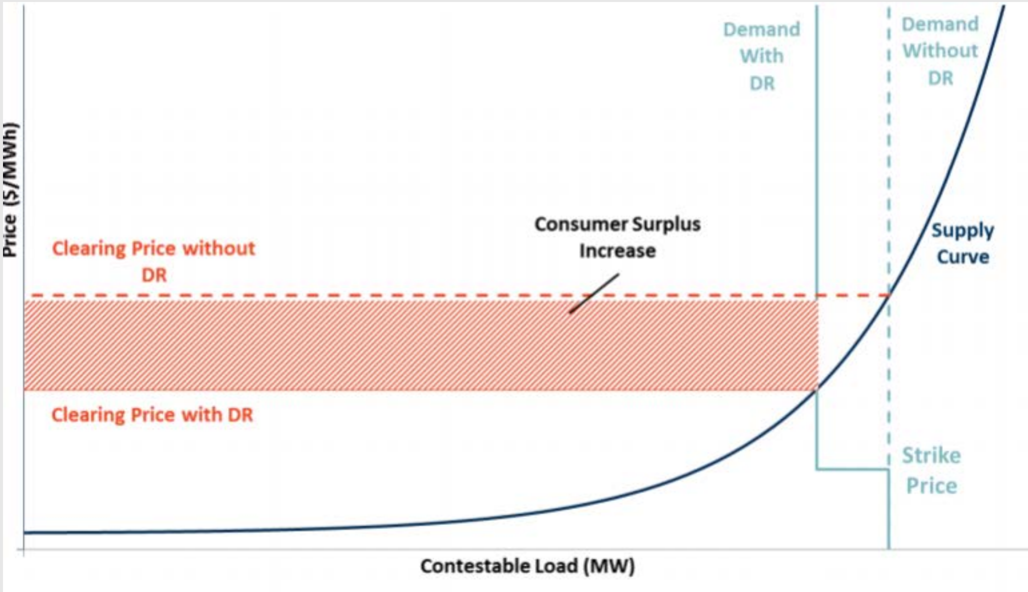
Incentive payment

The incentive payment to the third party providing demand response is related to the reduction in energy prices associated with demand side participation. According to the Energy Market Authority (the regulatory body that introduced the demand response mechanism in Singapore), the payment will provide "an appropriate level of incentives for consumers to participate in the demand response program".[280] Calculating the size of the incentive payment involves running the system's Market Clearing Engine twice for each settlement interval where demand response clears: once including demand response and once excluding it. Figure 5.4 illustrates for a hypothetical scenario in which demand response reduces the market clearing price. This price reduction is multiplied by the portion of load served to contestable consumers[281] to calculate a consumer surplus increase associated with demand response. Contestable consumers are the segment of electricity customers who are eligible to switch to a competitive retail provider.

280 Ibid, p.15.

281 Essentially, all non-household customers.

Figure 5.4 Example of Singapore demand response mechanism with reduction in clearing price



The Brattle Group, *International review of demand response mechanisms*, The Brattle Group, October 2015.

Under the Energy Market Authority of Singapore's model, demand response aggregators (on behalf of providers) would be paid 1/3 of the additional consumer surplus in aggregate. This incentive payment would be allocated among demand response providers proportional to their energy curtailment during the period of demand response activation. The payment will be collected from an uplift charge on all retailers.[282]

How it could be adapted to the NEM

This model could be adapted to facilitate more demand response in the wholesale market in the NEM. Instead of a mechanism such as Option 1 where the baseline is administratively determined by looking at historical data, a mechanism to facilitate demand response could rely on the demand response aggregator submitting their willingness to consume at various prices through submitting bids. It is an open question as to how value is provided to the third party providing demand response. This is discussed more below.

Further considerations

This design could be considered as an adaptation of Option 1. However, it some respects, this model is substantially different and would require further consideration of how it would be best implemented in the NEM. Some of the aspects that would require further thought include:

282 The Brattle Group, *International review of demand response mechanisms*, The Brattle Group, October 2015, p. 25.

- **Measures to prevent gaming**: the Singaporean model includes features that aim to mitigate the ability for gaming by the party submitting demand response bids. These measures include:

  - **Strict compliance with dispatch instructions for demand response bids**: In Singapore mechanism, the bids submitted by demand response providers are binding. If the market clears below the strike price, the demand response provider is subject to a penalty if its load falls below 95% of its baseline bid. If the market clears above the strike price, the provider is subject to a penalty if its load reduction falls below 95% of the reduction in its bid. If a mechanism that allowed third parties to bid their own baseline, it may also require complimentary compliance measures.[283]

  - **Bid floors**: The Singapore mechanism also had a minimum bid price for demand response bids. The concern is that without a bid floor, a demand response aggregator could submit a bid with a very low strike price during a period when it intended to reduce consumption even in the absence of an incentive payment. By making a low-risk gamble that the market clearing price exceeds this very low strike price, the demand response provider would be eligible for an incentive payment for a demand reduction it was already intending to make. A price floor makes this kind of gamble riskier.[284] Again, if this style of mechanism was introduced in the NEM, it may need to be accompanied by some form of bid floor.

- **Whether the FRMP should be settled on actual or baseline consumption**: The Singaporean mechanism settles the FRMP on actual metered energy. The model considered under Option 1 would settle the FRMP on a baseline level of energy. If the FRMP is settled on actual metered energy, the FRMP will capture the value of any demand response at high wholesale prices. The value provided to the third party facilitating demand response would need to come from an additional incentive payment (such as the uplift charge used in Singapore). If the FRMP was to be settled on the baseline level of energy (e.g. the bids submitted by the third party), it is not necessarily clear how the value of the wholesale demand response should be shared between the third party and the FRMP.

Transferring spot market responsibility for demand responsive load from the existing FRMP to an aggregator

Existing framework analogy

The Commission cited the Small Generation Aggregator (SGA) framework in the interim report as being potentially relevant to wholesale demand response. The SGA

283 Ibid, p. 27.

284 Ibid.

framework allows a participant to aggregate small generating units and sell the collective output into the wholesale market. A SGA is required to:

- sell all sent out generation through the spot market for all market connection points it is financially responsible for[285]
- purchase all electricity supplied through the national grid to the market connection points it is financially responsible for.[286]

How this option would work

This option is based around transferring spot market responsibility for demand responsive load from the existing FRMP to an aggregator. This would allow a consumer to elect to have a standard retail contract while third parties would be able to disaggregate demand responsive load (and other resources e.g. batteries and solar PV) to be used in the wholesale market. The consumers would be able to change retailer for the non-responsive load component of their consumption without impacting on the third party accessing the controllable demand response.

Broadly this option would entail:

- Enabling third parties to be FRMP behind a connection point for metered load that is subset of total demand (an existing facility already provided in market settlement and transfer solutions (MSATS)) without becoming the FRMP for all of the load behind that connection point. Since the party would only be responsible for a subset of the load, it is likely that the costs (e.g. prudential requirements) associated with this would be less onerous than becoming a retailer for the whole of the load.
- In order to give effect to this there would need to be two or more meters behind the same connection point – one measuring the load from the aggregator, and one measuring the load from the retailer. In some respects, this could be considered similar to the SGA framework, as well as the previous 'multiple trading relationship' concept.[287]

This would facilitate customers electing to have spot price pass through arrangements for certain loads or resources behind a connection point and possibly engaging a demand management service provider. It would also allow third parties to become the FRMP for that responsive load. The third party would be similar to a Small Generation Aggregator or a retailer.

This framework could also apply to distributed energy resources. This framework would allow customers to retain their existing retailer for the majority of their load and

285 See clause 2.3A.1(g) of the NER.

286 See clause 2.3A.1(h) of the NER.

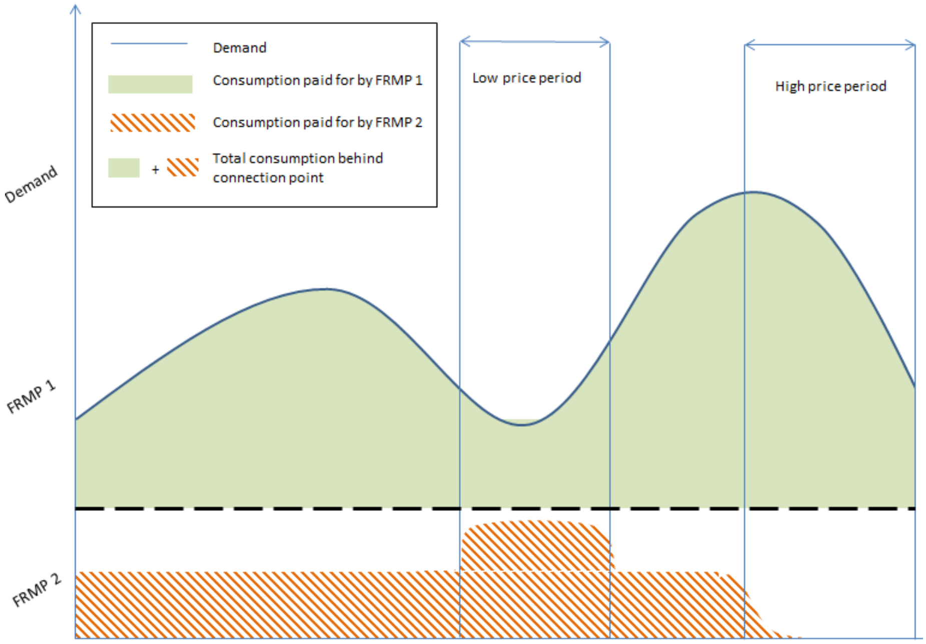
287 Multiple trading relationships aim to make it easier for customers to engage multiple FRMPs on a single premises. Customers can currently enter into these kinds of arrangements only if they establish a second connection point.

without the participation of that retailer, access the wholesale market for responsive loads and utilise wholesale demand response.

In some ways, this option could be considered achievable under current arrangements. A third party could establish a second connection point for responsive loads and distributed energy resources. However, we understand barriers to this include: the cost of having two connection points; and possibly having to set up an embedded network. The intent of this option is to give effect to the above outcome, while reducing the associated administrative and regulatory burden.

Figure 5.5 shows an example of a customer reducing consumption following notice from a third party under this option. The benefit to the third party would be its reduced exposure to the wholesale price during the high price period. The original FRMP would continue to purchase demand from the wholesale market for the rest of the customer's load.

Figure 5.5 Option 2 - Transferring responsibility for wholesale demand response



Further considerations

This option requires further consideration as to whether this would be in the long-term interests of consumers. Aspects the Commission consider requires further consideration include:

- whether it would actually facilitate wholesale demand response, or whether some of the other factors that limit wholesale demand response (e.g. behavioural biases from consumers) would limit this option's ability to facilitate wholesale demand response

- the extent to which this option may already be achievable under current arrangements or what streamlining of regulatory frameworks could be necessary
- its technical feasibility e.g. whether resources could be properly separately metered, particularly at a residential level
- any changes to metering arrangements and prudential requirements that could be made
- the implementation costs associated with this option.

The potential application of this framework to wholesale demand response in considered in further detail in below.

Business model for aggregators under these options

These options may change the business model for the third party. Option 1 would allow third parties to use wholesale demand response to earn the wholesale price. Option 2 would allow third parties to change their level of consumption in response to the wholesale price, which would reduce costs. This would influence the ability of the third party to offer products such as cap contracts.[288] This distinction is detailed in Box 1.3. Additionally, under Option 1, a third party would not necessarily need to be constantly managing risk in the wholesale market. However, under Option 2 the third party would be purchasing electricity from the wholesale market and would need to manage the associated risk.

Box 5.3 Different exposure to wholesale price under different models

Option 1 and Option 2 provide different forms of access to the wholesale price for electricity. To demonstrate this, one could consider how each option would facilitate third parties offering financial products such as caps.

Cap contracts are generally bought by buyers of electricity to help manage exposure to high wholesale prices.

The seller of a cap should be exposed to the wholesale market as a seller and should be selling electricity when a high price occurs. It is possible to sell a cap without having any generation through entering into other financial contracts.

When a retailer uses wholesale demand response from its customers, it is able to reduce the need for a cap by instead reducing its exposure to high prices that needs to be hedged.

If a third party was aggregating wholesale demand response as the FRMP, it would be exposed to the wholesale market as a buyer. To avoid high prices, it

288 The Commission notes that financial contracts can allow third parties to change consumption and "earn" the wholesale electricity price.

would reduce exposure by reducing demand. If a third party was paid for demand response, it would be accessing the wholesale market as a seller because it would be paid the wholesale price. This would allow the third party to sell a cap to other parties.

Table 5.2 Buying and selling caps

Type of resource Exposure to wholesale market	Slow and/or unfirm	Flexible and firm
Demand-side	Would generally need to buy a cap product	Would not necessarily need to buy a cap product
Supply-side	Would not generally sell a cap product	Would be able to sell a cap product

Note that this is a simplification of the reasons for why parties may or may not enter into financial contracts. This is also dependent of other factors including appetite for risk and other physical and financial positions.

Box 5.4 has a figurative example of how Option 1 and Option 2 could address some of the limitations for wholesale demand response raised in this chapter, and could facilitate greater amounts of demand response in the wholesale market.

Box 5.4 Figurative example of the two options

The Kerrigans are a large suburban family. They consume large amounts of electricity and consequently have a large retail bill.

Fortunately, the Kerrigans' son Steve is an ideas-man, who worked out that by turning off their air conditioner and pool pumps, the Kerrigans can substantially reduce their net load.

The Kerrigans' approached their existing retailer to see whether they could utilise their ability to respond to wholesale prices to reduce their bill. Unfortunately, their retailer told them they were dreaming - the cost for the retailer to update its IT systems and billing system would far outweigh the benefit of the Kerrigans' demand response to the retailer. In addition, the Kerrigans have a preference towards well known retailers and tend to not like the vibe of the lesser known retailers who may offer demand response products.

Option 1

The Kerrigans are approached by a third party who is aggregating demand response across a number of customers. The Kerrigans sign up with the third party and agree that under certain conditions, they will reduce consumption.

On an ongoing basis, the Kerrigans are billed by their original retailer. These bills do not necessarily reduce as the original retailer is purchasing electricity as if the Kerrigans had not responded to wholesale prices - a counterfactual level of demand. However, the Kerrigans' wholesale demand response is valued through payments from the third party for reducing demand when they are called upon. The third party will either be able to remotely control the air-conditioner and pool pump or it will communicate with the Kerrigans in the lead up to a period with high wholesale prices.

Option 2

The Kerrigans are approached by a third party aggregating demand response across a number of customers. The Kerrigans agree that under certain circumstances they will reduce consumption. The third party becomes the financially responsible market participant for the load associated with the air conditioning and pool pump. To do so, the third party may need to rewire the air-conditioner and pool pumps and install a separate meter.

On an ongoing basis, the Kerrigans have a financial relationship with their original retailer and the third party. Because the original retailer is no longer retailing the total load, the bill from that retailer is reduced. The Kerrigans also have bill from the third party; however, because the air-conditioner and pool pump are able to be turned off during high wholesale prices, this bill reflects the value of their wholesale demand response – meaning that the combined total of the bills (from the original retailer and the third party) is less than it would have been. This reduction in the combined total of the bills is driven not only by a reduced overall consumption, but by a reduced price on the proportion of the consumption served by the third party.

5.3.4 Increasing incentives for wholesale demand response

As noted above, one of the factors that is limiting increased facilitation of wholesale demand response in the NEM is not the fact that only retailers can offer wholesale demand response – it is that retailers may have limited opportunities to offer products given that some consumers may not want to engage in wholesale demand response. Therefore an alternative solution to the above options is to address the problem in a different way and create additional incentives for retailers to offer wholesale demand response products.

How this option would work

This option would create a retailer incentive fund or scheme to create and market demand response products. The retailer incentive scheme would be a pool of funds accumulated over time that could be accessed by retailers to assist in promoting demand response products. The objective of the fund would be to encourage retailers to make efficient decisions in relation to offering demand response products, such that consumers' demand for electricity in the wholesale market is met at the lowest total system cost. The scheme would reward retailers for implementing demand response options that deliver net cost savings to their customers, where it is efficient to do so.

Wholesale demand response contributes to reliability. 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 for 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 design of the fund would need to be considered further, as well as who would administer it. The fund would recover its costs via retailers, who would contribute to the fund.

While there would be a cost element associated with this, it is likely that the costs associated with establishing and administering a fund may be smaller than the costs associated with setting a demand response mechanism. As noted above, the Commission considers that in theory there are no regulatory barriers to demand response; however, in practice, there may be limitations. This option is designed around addressing these practical limitations.

Further considerations

This option requires further consideration as to whether this would be in the long-term interests of consumers. Aspects the Commission consider requires further consideration include:

- whether it would actually facilitate wholesale demand response
- the costs associated with this arrangement
- how a fund could be designed and administered. This would need to consider:
  - who makes contributions to the fund and on what basis
  - how access to the fund is determined.

5.3.5 Interactions with other market changes

Additional options to facilitate more wholesale demand response would interact with other market changes underway. The other possible market changes that may interact with options to facilitate wholesale demand response include:

- a day-ahead market
- a strategic reserve
- the National Energy Guarantee.

These interactions are discussed below.

Ahead market

The introduction of a ahead market may facilitate increased demand-side participation in the wholesale market.

A ahead market could give the demand side the opportunity to purchase (or sell) electricity at the ahead market. Consumers may be able to lock in a price for consumption ahead of time which would provide price certainty. To the extent that real time prices deviated from the ahead market, consumers could change their level of consumption for financial benefit.

Strategic reserve

As well as being able to respond to wholesale electricity prices, demand is able to participate in emergency demand response programs to reduce demand when the supply/demand imbalance is tight.

For those consumers for whom the value of customer reliability is above the market price cap and under the cost of load shedding, then it is efficient to participate in a strategic reserve. These consumers do not have an incentive to participate in the market/respond to wholesale spot prices (because they will only avoid costs equal to, at most, the market price cap, which is less than the value they place on reliability.

Customers participating in a strategic reserve should not also be utilising wholesale demand response otherwise this would distort the natural functioning of the market.

This is discussed in more detail in section 6.5.5.

National Energy Guarantee

The Guarantee is designed to provide a clear investment signal so the cleanest, cheapest and most reliable generation gets built in the right place at the right time. It can also signal opportunities for demand response which may help reduce the need for costly new generation infrastructure.

Given this, the consultation paper for the Guarantee noted that the development of the Guarantee will need to be done in concert with the development of a demand response mechanism for the wholesale electricity market to ensure that any demand response products developed also qualify for compliance under the Guarantee.[289]

5.4 Conclusions

This chapter provides the Commission's thinking regarding the progression of the Finkel Panel review recommendation to undertake a review to recommend a mechanism to facilitate demand response in the wholesale energy market.

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289 Energy Security Board, *National Energy Guarantee - Draft design consultation paper*, February 2018, p. 38.

We have assessed the issues that may be limiting wholesale demand response in the NEM currently. The current arrangements theoretically place incentives on retailers to use demand response to hedge against the wholesale price to the extent that it is efficient to do so. However, in practice, there may be aspects that stop this being fully facilitated in the NEM. Of the factors influencing wholesale demand response in the NEM, there are two issues the Commission considers could be addressed through changes to the regulatory frameworks:

- the requirements for there to be a single financially responsible market participant at a connection point
- the difficulties faced by retailers offering demand response products.

However, due to the lack of transparency around how much wholesale demand response is currently being utilised, it is very difficult to draw firm conclusions about how much wholesale demand response there is in the NEM. While the Commission notes that some stakeholders would like more wholesale demand response, we also note that the lack of visibility makes it challenging to assess the extent to which there is a deficit in wholesale demand response.

The Commission has presented three options that may facilitate more demand response in the wholesale energy market. They are:

- two options that would allow multiple parties to engage a single consumer behind a connection point without that being contingent on the original financially responsible market participant
- providing additional incentives for retailers to offer demand response products.

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.

We are seeking stakeholder feedback on these options.

6 Strategic reserve

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.
- RERT is a form of strategic reserve allowing AEMO to contract for reserves (generation or demand-side capacity not otherwise available in the market), that it can use if it projects that the market will not meet the reliability standard and, where practicable, to maintain power system security
- In the interim report, we provided the following preliminary views:
  - Some form of a safety net is appropriate in the event that it is assessed that market may not 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 potential costs.
  - Alternatively, some enhancements to the RERT may be appropriate to improve its efficiency and lower the cost of additional reserves.
- Stakeholders, in submissions to the interim report, generally agree that some form of safety net was appropriate, but that care should be taken to minimise market distortions and costs and make sure that the mechanism is only used as a last resort. There are mixed views on potential enhancement to or replacement of the RERT.
- On 9 March 2018, AEMO submitted two rule change requests to the Commission with regards to the RERT:
  - The first rule change requests that the Commission reinstates the long-notice RERT as a short-term measure for the upcoming summer.[290]
  - The second asks the Commission to consider AEMO's proposal for an enhanced RERT - this is a broader proposal to enhance the existing RERT, which is to be considered as a longer term measure.[291]
- As a result, the Commission will explore the potential improvements to the

290 See: https://www.aemc.gov.au/rule-changes/reinstatement-long-notice-reliability-and-emergency-reserve-trader

291 See: https://www.aemc.gov.au/rule-changes/enhancement-reliability-and-emergency-reserve-trader

RERT, that are within the scope of the rule change requests, through the rule change processes rather than through the next stage of this Review. The Commission plans to initiate the rule changes shortly. For completeness, the Commission has summarised, in this chapter, the work done to date, including stakeholder submissions.

The structure of this chapter is as follows:

- section 6.1 provides background information to this chapter
- section 6.2 sets out stakeholders' views with respect to a strategic reserve
- section 6.3 summarises AEMO's two RERT rule change requests.

6.1 Introduction

The term strategic reserve is typically used to refer to additional reserves that are available outside of the market and used in emergency situations when the demand and supply balance is tight in order to avoid involuntary load shedding. A strategic reserve is a common feature of energy market designs and may take many different forms depending on particular design choices, with some types of strategic reserves being available all the time, while others are only available if there is an identified gap, e.g. a potential reliability or system security issue.

Currently, the Reliability and Emergency Reserve Trader (RERT) is the NEM's strategic reserve. The RERT allows AEMO to contract for additional reserves (generation or demand-side capacity not otherwise available in the market) for a period (up to 10 weeks) ahead of when AEMO projects there to be reserve shortfalls, typically a forecast expectation that the reliability standard will not be met and where practicable, to maintain power system security..

6.1.1 Interim report views

The Finkel Panel review recommended that:[292]

> "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."

In the interim report, we focussed our analysis on reviewing the existing strategic reserve mechanism in the NEM, the RERT, and considering the need for any

292 Finkel Panel, Independent Review into the Future Security of the National Electricity Market: Blueprint for the Future, June 2017, p.103.

enhancements to it, or an alternative mechanism consistent with the Finkel Panel recommendation in relation to this.

Our preliminary views, expressed in the interim report, were 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.

We also noted that in assessing or considering potential changes to current arrangements, it is important to be clear about the problem. In particular, our view was that, 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 standing strategic reserve.

Instead, the 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 more conservative trigger,[293] this could result in distortions to the market.

6.1.2 Purpose of this chapter

This chapter provides an update of stakeholders' views on strategic reserve based on submissions to the interim report.

On 9 March 2018, AEMO submitted two rule change requests to the Commission with regards to the RERT. The rule change requests will be progressed alongside this review. As a result, this workstream will no longer be progressed as part of this Review. Any feedback we receive will be incorporated into the rule change request processes.

This chapter, therefore, only focusses on stakeholder submissions and AEMO's rule change requests.

6.1.3 Interactions with the National Energy Guarantee

In developing the reliability requirement for the Guarantee, the Energy Security Board has identified eight key steps to a reliable energy supply with a number of design options at each step. Particularly relevant to the issue of strategic reserves is step 7 –

293 A more conservative trigger than the reliability standard could, for example, be that the RERT is procured when unserved energy is forecast to be below 0.001 per cent. Another way of putting this is that the tolerance for involuntary load shedding would be lower.

procurer of last resort. Under this step, it is proposed that if retailers do not meet the reliability requirement by the compliance date, AEMO will need to procure resources to fill any remaining gap.

There is therefore a linkage between the issue of strategic reserve and the development of the Guarantee. The AEMC, in progressing the two rule changes from AEMO on the RERT, will work with the Energy Security Board to manage these interactions.

6.2 Stakeholder views

Most submissions to the interim report include comments on strategic reserves/the RERT.

Stakeholders are supportive of having a safety net, with some caveats

Many stakeholders agree with our preliminary view that it is appropriate to have some form of a safety net mechanism in the NEM.[294]

However, they also suggest exercising caution about the use and design of the mechanism, noting that it should be designed so as to minimise market distortions and used only as a last resort.[295] Most stakeholders commented on the distortionary aspect of the RERT.[296]

Stakeholders have mixed views when it comes to making changes to the RERT

Some stakeholders are in favour of introducing standing strategic reserves or support significant changes to the existing RERT mechanism.[297]Those in favour typically state that it would be more efficient to have a standing reserve as it would provide more certainty and would lead to lower costs. In particular:

- EnerNOC recommends a strategic reserve with a minimum standing quantity due to the increasing challenges of accurately forecasting future needs, with associated benefits in terms of efficiency of products and prices, as well as transparency about costs.[298]

- The Energy and Technical Regulation Division of the Department of Premier and Cabinet, South Australia (SA Government thereafter) would like the procurement trigger removed (effectively introducing a standing reserve) since it

294 Origin, Energy Networks Australia, SA Government, Hydro Tasmania, Flow Power, Stanwell, AEMO: submission to interim report.

295 AGL, Energy Networks Australia, Flow Power: submission to interim report.

296 Australia Energy Council, Hydro Tasmania, Clean Energy Council, ERM Power, ENGIE: submission to interim report.

297 Major Energy Users, Energy Efficiency Council, EnerNOC, SA Government, S&C Electric: submission to interim report.).

298 EnerNOC, submission to interim report, p. 3.

considers that having certainty that reserves will be procured will improve efficiency and lower costs.[299]

Other stakeholders are more in favour of retaining the RERT, either as is, or with some enhancements, or did not express explicit support for a standing strategic reserve mechanism.[300] Generally, those in favour of the status quo are concerned about costs imposed on consumers or sceptical about the need for such a mechanism. For example:

- Snowy Hydro does not support the need for a strategic reserve that is separate to the RERT but notes that improvements could be made to reduce complexity and associated costs.[301]
- Australian Energy Council notes that a standing reserve would be a substantial escalation from the existing RERT and may be problematic if it targets a higher level of reliability. It also states that community and political expectations should be managed through education.[302]
- ERM Power is unconvinced that additional measures with respect to the RERT are needed and is concerned about potential market distortions.[303]

Energy Queensland states that there is no compelling case for a strategic reserve for retailers but there may be value for distributors who have demand response for network purposes.[304]

Stakeholders also comment on the role of strategic reserves during transition periods, noting that they may be needed only during transition to a higher penetration of variable renewable energy.[305]

In its submission to the interim report, AEMO notes that it has developed a proposal to enhance the RERT and intends to lodge a rule change request seeking changes to the RERT framework to align with a strategic reserve structure and, at the same time, seeks that the long-notice RERT be reinstated by June 2018.[306] AEMO has already submitted these rule change requests which are summarised below.

299 SA Government, submission to interim report, p. 2.

300 Snowy Hydro, Australian Energy Council, Clean Energy Council, Flow Power, EnergyAustralia, AGL, ERM Power, ENGIE, Meridian, Stanwell: submission to interim report.

301 Snowy Hydro, submission to interim report, p. 7.

302 Australian Energy Council, submission to interim report, p. 2.

303 ERM Power, submission to interim report, p. 5.

304 Energy Queensland, submission to interim report, p.9.

305 TransGrid, Origin: submission to interim report.

306 AEMO, submission to interim report, p.44.

Stakeholders note interactions between the Guarantee and strategic reserves

Stakeholders' comments range from wanting more clarity around the interaction of the Guarantee and strategic reserves, [307]to suggesting that the likely inclusion of a reliability obligation as part of the development of the Guarantee will likely negate the need for a separate strategic reserve.[308]

Stakeholders raise some concerns around process

Most stakeholders who provided comments on this issue note that consultation will be important if changes to the RERT are to be made.[309] AGL states that concerns about reliability and investment may be best addressed through the existing Reliability Panel processes.[310]

There are mixed views on changes to the RERT

The most commented on areas are:

- Increasing the procurement lead time: There is support for increasing the procurement lead time to six months or a year in order to lower costs and obtain more reliable products.[311] AEMO is seeking to reinstate the long-notice RERT (i.e. a nine-month lead time).[312] Other stakeholders either do not support an increase to the lead time or would like a more careful assessment of how difficult procurement is now.[313]
- Transparency: A number of stakeholders support the need for more transparency and clarity, including around the procurement amount, methodology and costs of the RERT.[314]
- Standardisation of products: EnerNOC offers strong support for standardising products and provides six reasons for why standardised products are better than bespoke products.[315] SA Government also notes that product standardisation is likely to be beneficial.[316] Stanwell states that the procurement process could benefit from standardisation of contracts.[317]

Minimising market distortions is important to stakeholders

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307 SA Government, submission to interim report, p. 3.

308 Snow Hydro, submission to interim report, p. 7.

309 Meridian, Origin, AGL: submission to interim report.

310 AGL, submission to interim report, p. 8.

311 EnerNOC, Energy Efficiency Council: submission to interim report.

312 AEMO, submission to interim report, p. 44.

313 Origin, ERM Power: submission to interim report.

314 ERM Power, ENGIE, Origin, Hydro Tasmania, Stanwell: submission to interim report.

315 EnerNOC, submission to interim report, pp. 5-6.

316 SA Government, submission to interim report, p. 3.

317 Stanwell, submission to interim report, p. 12.

Some stakeholders propose options to minimise market distortions:

- ARENA considers that the development of a strategic reserve mechanism would need to be accompanied by reforms that ensure easy access by demand response providers to the electricity market in order to minimise market distortions.[318]
- EnerNOC recommends exploring setting prices at the market price cap for the duration of a RERT activation. This would preserve investment signals and put pressure on AEMO to intervene as late as possible, thereby minimising distortions.[319]
- SA Government notes that more rigorous ring-fencing between strategic reserves and the energy market could be explored, e.g. extending the prohibition for reserves providers to participate in the market for an entire financial year.[320]

In its submission, AEMO also notes that it is important to restrict resources from moving back and forwards between reserves and the energy market.[321] It also observes that demand response could be both in-market and out-of-market:[322]

- in-market price-responsive demand response, according to AEMO, would participate actively in the market
- out-of-market demand response (such as through the RERT) is demand which potentially has a revealed cost of activation that is higher than the market price cap, but lower than the value of customer reliability of other consumers.

Some stakeholders support a technologically neutral strategic reserve

AGL notes that a reserve mechanism should not include any limitations on the types of technologies, stating that advances in technology will promote new forms of demand response and distributed energy resources product development.[323] Energy Efficiency Council believes in technological neutrality, although it notes that it is likely that demand response would represent the bulk of providers.[324]

318 ARENA, submission to interim report, p.9.

319 EnerNOC, submission to interim report, p.7.

320 SA Government, submission to interim report, p.3.

321 AEMO, submission to interim report, p.44.

322 Ibid. p.45.

323 AGL, submission to interim report, p. 8.

324 Energy Efficiency Council, submission to interim report, p. 17.

6.3 RERT rule change requests

On 9 March 2018, the AEMO received two rule changes from AEMO in relation to the RERT. These are summarised in turn next and are also available on the AEMC's website.[325]

We will commence these rule change request process shortly and will inform stakeholders of the timing of these rule changes as soon as they are known.

6.3.1 Reinstatement of long-notice RERT

On 9 March 2018, the AEMC received a rule change request from AEMO to reintroduce the long-notice RERT provisions in the NER by mid-2018 to enable AEMO to procure reserves further out for summer 2018-19. The requested rule change would have the effect of increasing the procurement lead time from 10 weeks to nine months. AEMO requested that the rule change be considered as an urgent rule change to support the delivery of secure and reliable supply during summer 2018-19.

AEMO's rationale for reinstating the long-notice RERT is that the power system has continued to undergo rapid transformational change with an increasing chance of supply shortfalls since the Commission allowed the long-notice RERT to expire in 2016.[326] It notes that reinstating the long-notice RERT would better equip AEMO with the ability to manage reliability in circumstances where there is a rapid increase in distributed energy resources and wind and solar energy, coupled with retirements of conventional plant.[327]

AEMO also states that it has relied on the pre-existing long-notice RERT to manage risk for the 2017-18 summer.[328] It further notes that it is currently projecting a heightened risk of load shedding in summer, especially in Victoria and South Australia in the near term.[329]

Specifically, when it comes to the procurement lead time, AEMO considers that the current 10-week period does not provide a sufficient lead time for the procurement of reserve capacity in the most competitive and cost-effective way, limiting the range of reserves AEMO can access, acting as a barrier to entry.[330]

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325 See https://www.aemc.gov.au/rule-changes/enhancement-reliability-and-emergency-reserve-trader and https://www.aemc.gov.au/rule-changes/reinstatement-long-notice-reliability-and-emergency-reserve-trader

326 AEMO, reinstatement of long notice RERT, rule change request, p. 2.

327 Ibid.

328 Ibid.

329 Ibid. p. 5.

330 Ibid. p.5.

The Commission will make a decision as to whether or not to expedite the rule change request as requested by AEMO and publish a consultation paper shortly. AEMO's rule change proposal may be found on the AEMC's website.[331]

6.3.2 Proposal for an enhanced RERT

On 9 March 2018, the AEMC received a rule change request from AEMO to enhance the RERT. In particular, AEMO states that its high-level design identified three key areas requiring enhancement to the regulatory framework, noting that only the first two aspects would require rule changes:[332]

- procurement horizon and contracting period
- RERT and the reliability standard
- standardisation of reserve products.

In terms of the need for an enhanced RERT, AEMO puts forward the following rationale in its rule change request:[333]

- Procurement horizon and contracting period: the current 10-week limit on signing contracts for reserves has the potential to limit the availability or increase the cost of reserves.
- RERT and the reliability standard: there is a lack of comprehensive risk assessment framework. There is inconsistency between the operational objectives of the current RERT (meeting the reliability standard, which allows some load shedding in a financial year) and directions (maintaining a reliable operating state which means no load shedding)
- Standardisation of reserve products: highly bespoke products are difficult to compare and implement.

As a result, AEMO is proposing the following specific changes, which require changes to the NER:[334]

- Allowing reserves to be procured up to one year ahead of an identified shortfall under an annual contract.
- If a longer-term requirement is projected, that reserves be allowed to be procured for up to three years (in circumstances where this would be at a lower overall cost), effectively implementing standing reserves.

331 See https://www.aemc.gov.au/rule-changes/reinstatement-long-notice-reliability-and-emergency-reserve-trader

332 AEMO, proposal for an enhanced RERT, rule change request, p. 3

333 Ibid. p. 6.

334 Ibid. p.7.

- AEMO considers that the trigger for procuring reserves, and the determination of the volume to be procured, should be in the context of a broader risk assessment which should take into account the risk of unserved energy, not just the expected value.

AEMO also intends to develop standardised products, which it states would not require a rule change to implement.

AEMO's high-level design of an enhanced RERT may be found on our website.[335] The Commission will initiate this rule change request shortly.

335 See https://www.aemc.gov.au/rule-changes/enhancement-reliability-and-emergency-reserve-trader.

Abbreviations

ERCOT	Electric Reliability Council of Texas
AEMC	Australian Energy Market Commission or Commission
AER	Australian Energy Regulator
ARENA	Australian Renewable Energy Agency
ASEFS	Australian Solar Energy Forecasting Systems
AWEFS	Australian Wind Energy Forecasting Systems
COAG	Council of Australian Governments
DER	Distributed energy resources
EAAP	Energy Adequacy Assessment Projection
EFI	Electricity Forecasting Insights
ESB	Energy Security Board
ESOO	Electricity Statement of Opportunities
FCAS	Frequency control ancillary services
FRMP	Financially responsible market participant
FUM	Forecast Uncertainty Measure
LOR	Lack of reserves
LRET	Large-scale renewable energy target
MPC	Market price cap
MTPASA	Medium-term PASA
NEFR	National Electricity Forecasting Report
NEL	National Electricity Law
NEM	National Electricity Market
NER	National Electricity Rules

PASA	Projected assessment of system adequacy
RERT	Reliability and Emergency Reserve Trader
RUC	Reliability Unit Commitment
SGA	Small Generation Aggregator
STPASA	Short-term PASA
TNSPs	Transmission Network Service Providers
UIGF	Unconstrained intermittent generation forecast
USE	Unserved energy

A 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.

A.1 Reliability standard and settings review

In accordance with National Electricity Rules, the Reliability Panel is required to review the reliability standard and settings every four years. On 21 November 2017 the Panel published a draft report to present, and seek stakeholder views on, the Panel's draft findings and recommendations on the reliability standard and reliability settings to apply in the NEM from 1 July 2020.

The Panel's draft recommendation is 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.

A final report is due in April 2018.

A.2 Coordination of generation and transmission investment

The COAG Energy Council asked the AEMC to implement a biennial reporting regime on a set of drivers that could impact on future transmission and generation investment. The Commission commenced stage 2 of this Review in August 2017. We also published a discussion paper for that review 13 April 2018. The discussion paper presents the Commission's initial view on current issues that are impacting on the coordination of transmission and generation investment. It also provides an opportunity for stakeholders to provide input to the review, ahead of the final report being published in mid-2018.

The interim report for the *Coordination of Generation and Transmission Investment* review examines implications for the transmission framework of the changing generation mix. It provides initial analysis of some of the features of the current framework that could be altered to improve coordination of transmission and generation investment to continue to deliver a reliable supply of electricity to consumers at least cost in a changing environment. The report examines the issues of network congestion, the role of storage and renewable energy zones and the implications of these issues for the existing transmission framework.

A.3 Other AEMC projects in the reliability work program

On 8 March 2018, the AEMC received a rule change request from Dr Kerry Schott AO seeking changes to the NER that would that would require scheduled and semi-scheduled generators to provide information to AEMO on expected closure dates and keep this information up to date.[336] Dr Schott's proposal is focussed on the provision of additional information to AEMO on expected closure dates, including a proposed requirement that scheduled and semi-scheduled generators provide at least three years' notice of when they will cease to supply electricity or trade directly in the market.

On 9 March 2018, AEMO submitted two rule changes in relation to the RERT, one to reinstate the long-notice RERT by June 2018 and a broader rule change seeking enhancements to the RERT. For a summary of these rule changes, see chapter 6.

A.4 National Energy Guarantee

On 24 November 2017, the COAG Energy Council agreed that the Energy Security Board should provide further advice on a National Energy Guarantee (Guarantee). This is to be provided in April 2018, after broad consultation. The initial advice on the Guarantee broadly and conceptually set out changes needed to the NEM and its legislative framework such that:

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

On 15 February 2018, an initial consultation paper was released by the Energy Security Board to facilitate public consultation on the high-level design of the proposed Guarantee. Subject to COAG Energy Council's in-principal agreement to proceed with the detailed design of the Guarantee, further consultation will be undertaken from May to July 2018.

The initial consultation paper for the Guarantee recognises the interaction between the Guarantee and some of the workstreams of this Review. Namely, our workstreams to address the following Finkel recommendations: the suitability of strategic reserves, the need for a day-ahead market and a mechanism to facilitate demand response. The

336 See https://www.aemc.gov.au/rule-changes/generator-three-year-notice-closure.

AEMC is briefing the Energy Security Board on the progress of this review to enable them to fulfil their coordination role in relation to the Finkel recommendations.

A.5 AEMO's work

In September 2017, AEMO provided advice to the Commonwealth Government on dispatchable capability in the NEM.[337] AEMO noted that the NEM is not delivering enough investment in flexible dispatchable resources to maintain a "defined target level of supply reliability",[338] as it transitions from traditional generation to variable renewable generation proceeds. AEMO noted the fact that it is pursuing around 1,000 MW of strategic reserves in its summer 2017-18 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. 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.[339]

AEMO was recently 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 the earlier advice.[340] This is summarised in chapter 2.

AEMO has also recently published a "power systems requirements" paper to explain the "technical and operational needs of the power system in relation to both security and reliability, based on the laws of physics that remain constant even as modern power systems like the NEM transform".[341]

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

338 Ibid.

339 Ibid.

340 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.

341 See http://www.aemo.com.au/Media-Centre/AEMO-publishes-Power-System-Requirements-paper

B Forecasting analysis

This appendix provides supporting analysis for chapter 3 in relation to the Commission's analysis of AEMO's MTPASA and 30-minute pre-dispatch forecasts.

B.1 MTPASA

The Commission's analysis of MTPASA demand was introduced in section 3.3.2.

The data was extracted from the Electricity Market Management System (MMS). Specifically, the MTPASA_REGIONSOLUTION table and DISPATCHREGIONSUM table. The methodology used is as follows:

1. We have used the low reserve condition runs, which are the MTPASA runs which evaluate the likelihood of reliability standard breaches.
2. We have obtained MTPASA demand10 and demand50 forecasts.
3. We have obtained actual demand based on five minute TOTALDEMAND from DISPATCHREGIONSUM.
4. We have calculated maximums actual demand for each day. We have also created a separate column that holds the day in date format.
5. We have matched the DAY in MTPASA_REGIONSOLUTION and DAY columns in actual demand. In the former, the DAY variable is the day that the forecast solution is for. This joins the MTPASA dataset with the corresponding actual maximum demand so that there is a demand10, demand50 and maximum actual demand for each day and region.
6. We have calculated the forecast horizon (i.e. number of days ahead of dispatch) of the MTPASA outlook. This is done by calculating the difference between RUN_DATETIME from MTPASA_REGIONSOLUTION, and the 'day' column from step 4. This gives us the forecast horizon in number of days.
7. For each region, we have calculated the maximum of actual maximum demand, demand10 and demand 50 forecasts for every quarter.
8. We have calculated the difference between maximum forecast (demand10/demand50) and maximum actual maximum demand.
9. We have filtered results based on the forecast horizon for 7, 30, 365, 730 days ahead in order to summarise the results.

The follow charts are the results of this analysis. Commentary on these was provided in section 3.3.2. Please note that the scales on the vertical axis of the graphs differ by state and by PoE.

Figure B.1 MTPASA forecast versus actual demand by forecast horizon (NSW, PoE50)

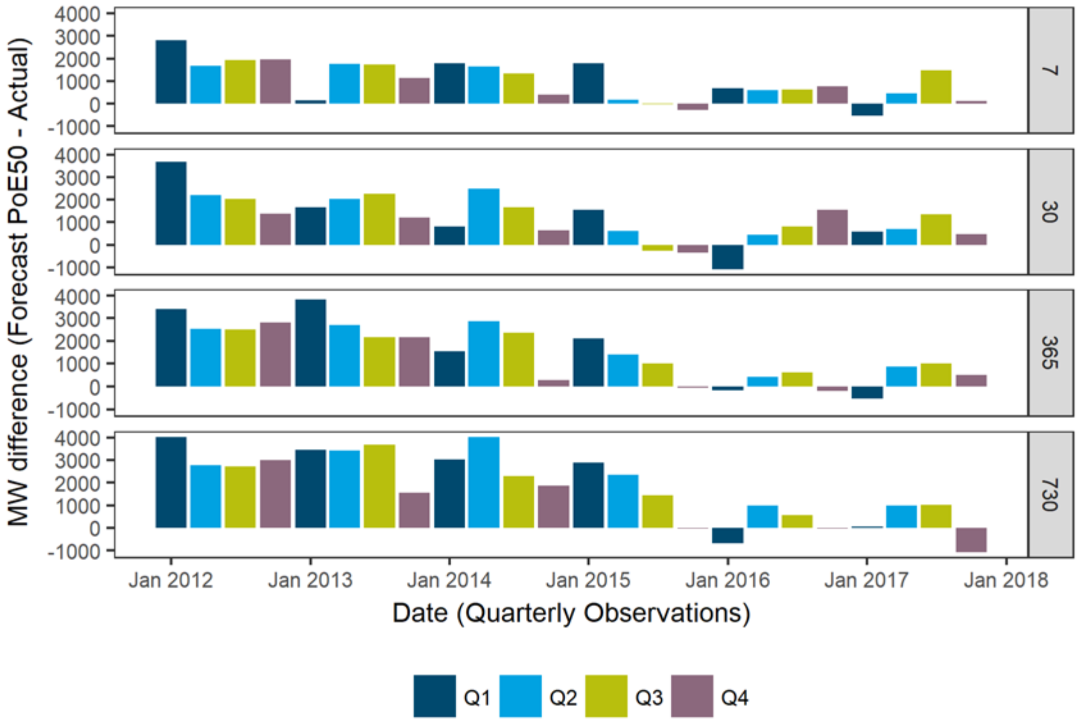


Figure B.2 MTPASA forecast versus actual demand by forecast horizon (NSW, PoE10)

Figure B.3 MTPASA forecast versus actual demand by forecast horizon (Queensland, PoE50)

Figure B.4 MTPASA forecast versus actual demand by forecast horizon (Queensland, PoE10)

Figure B.5 MTPASA forecast versus actual demand by forecast horizon (Victoria, PoE50)

Figure B.6 MTPASA forecast versus actual demand by forecast horizon (Victoria, PoE10)

Figure B.7 MTPASA forecast versus actual demand by forecast horizon (South Australia, PoE50)

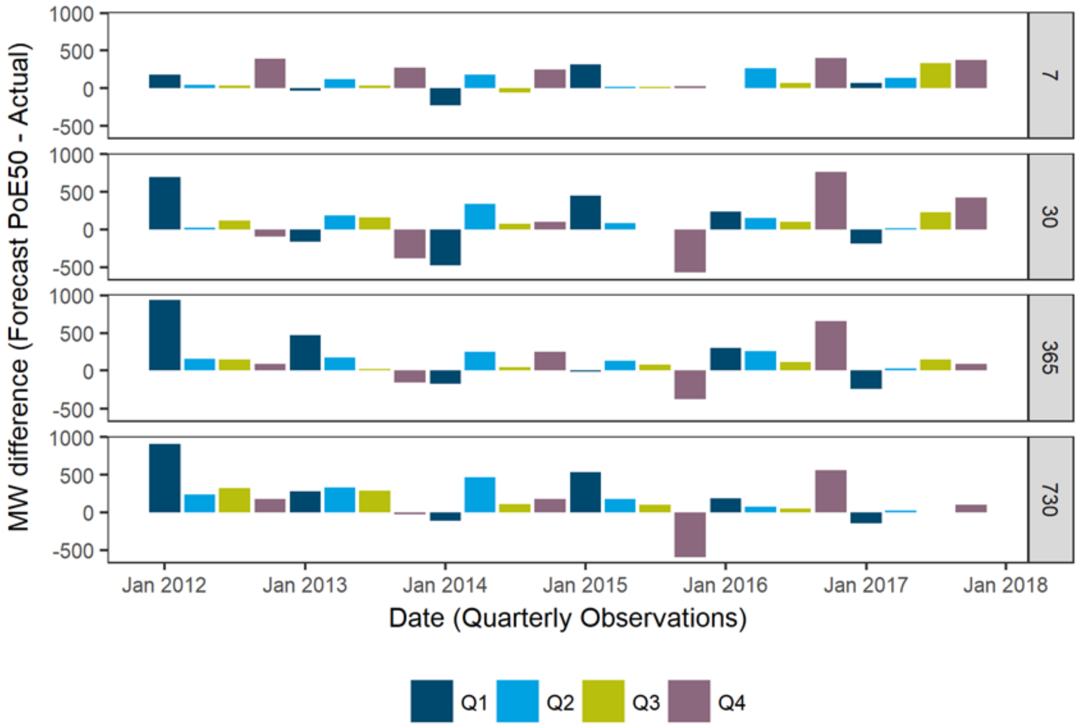


Figure B.8 MTPASA forecast versus actual demand by forecast horizon (South Australia, PoE10)

Figure B.9 MTPASA forecast versus actual demand by forecast horizon (Tasmania, PoE50)

Figure B.10 MTPASA forecast versus actual demand by forecast horizon (Tasmania, PoE10)

B.2 Pre-dispatch

In this section, we examine differences between forecast and actual values across demand, semi-scheduled generation and non-scheduled generation. High level findings from the demand analysis was presented in chapter 3, whereas the analysis of semi-scheduled and non-scheduled generation forecasts were not.

Pre-dispatch is a 30-minute resolution point forecast, and analysing this involves determining how close the forecast is to the actual observation at any point in time. In the following analysis, we have calculated deviations between forecast and actual demand as:

- absolute deviation: Forecast – Actual
- percentage deviation: (Forecast – Actual)/Actual × 100%

B.2.1 Demand

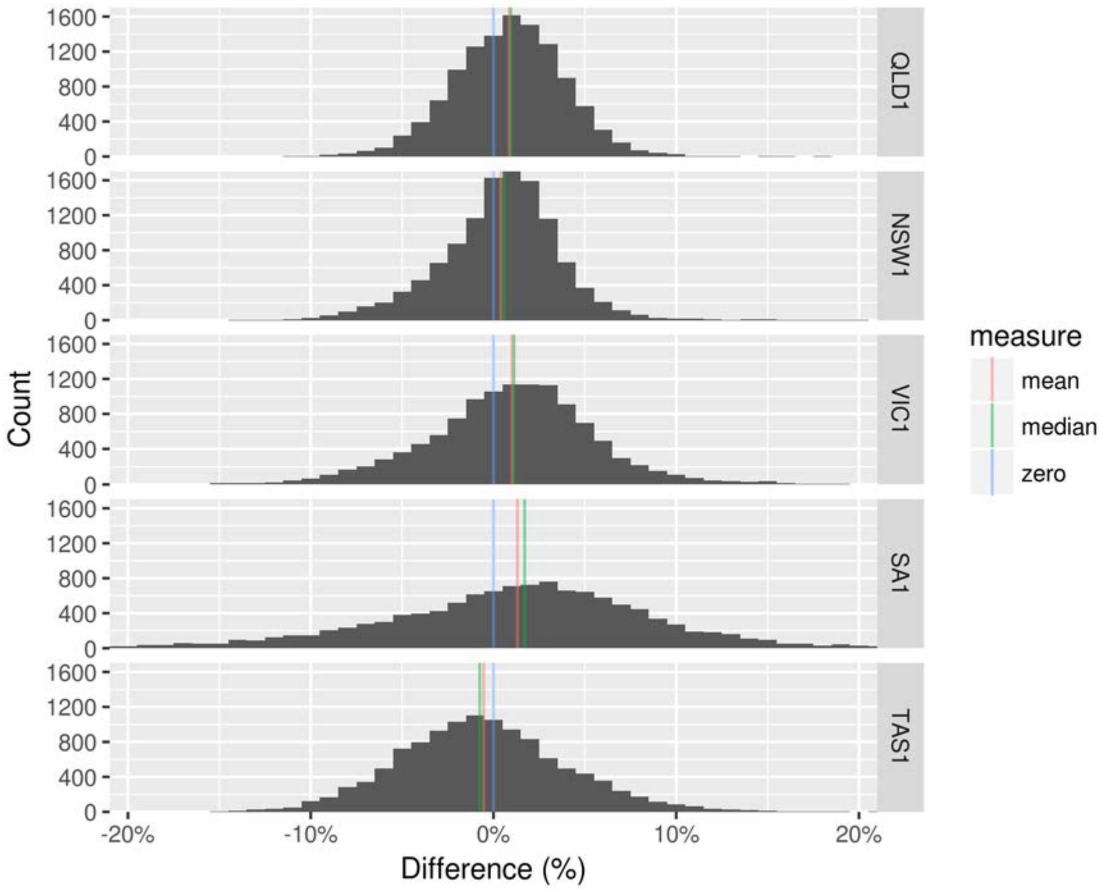
T-48 trading intervals (T-24 hours)

The chart below shows histograms of percentage demand difference between forecast and actual by region at the T-48 trading intervals (T-24 hours) time horizon.

A histogram shows the frequency with which observations are located within a particular range. Thus, for example, each of the observations below have a bar centred on the line labelled "zero" that spans -0.5 per cent to 0.5 per cent range. The height of that bar represents the number of intervals with differences between forecast and actual demand of between -0.5 per cent and 0.5 per cent.

The histograms drawn in the chart below are comprised of many such bars, each having a width of 1 per cent.

Figure B.11 **Differences between actual and forecast demand at T-48 trading intervals (T-24h) by region, 2017**



The overall shape of the histogram provided is also of interest. In particular, we are concerned with:

1. centrality
2. spread of the differences
3. number of modes.

Some observations on each of these properties are provided in the table below.

Table B.1 **Observations in relation to histograms of differences between actual and forecast demand, 2017**

Property	Observation
Centrality	Given that we are plotting differences between actual and forecast values, we are interested in noting whether or not the forecast is unbiased, ideally by checking if the distribution of the errors is centred on 0. Depending on the forecast, centrality can be measured through the mean of the differences between actual and forecast demand, the median or even the mode. The chart above shows the mean and median in red and green lines.

Property	Observation
	Notably, the mean and median for all regions except Tasmania are greater than 0. This implies that there is an observed tendency for slight over forecasting in these regions. However, the data appears to be approximately centered on 0. The centredness of the distribution can also be inferred from the overall shape of the histogram. The fact that each of the histograms have a singular peak which appears to occur to the right of the zero line, implies that there is a tendency for slight over forecasting.
Spread of the differences	The shape of the histogram also provides information on the precision of the forecast. A forecast with the differences between forecast and actuals that are clustered tightly around 0 can be said to be more precise since these fall within a narrower range. To that end, it is worthwhile noting that the forecast in South Australia appears to be much less precise than the forecasts in other regions such as Queensland. This manifests in the fact that the shape of its histogram is more spread out and has a lower peak. It is also worthwhile noting that outcomes in this chart are measured in relation to percentage deviations. As a result of the fact that South Australia has relatively low levels of demand when compared to regions like New South Wales or Queensland, a relatively small absolute difference (in MW) in a demand forecast will be a more significant percentage difference in South Australia demand than in New South Wales demand or Queensland demand.
Number of modes	In a data set, the mode is the value that appears most often. In a histogram, it is represented as the maximum, or peak, of the distribution. It is worthwhile noting if any distribution appears to have more than one mode (i.e. multiple peaks). The presence of more than one mode suggests that the distribution is potentially produced by two separate sources.

Differences approaching dispatch

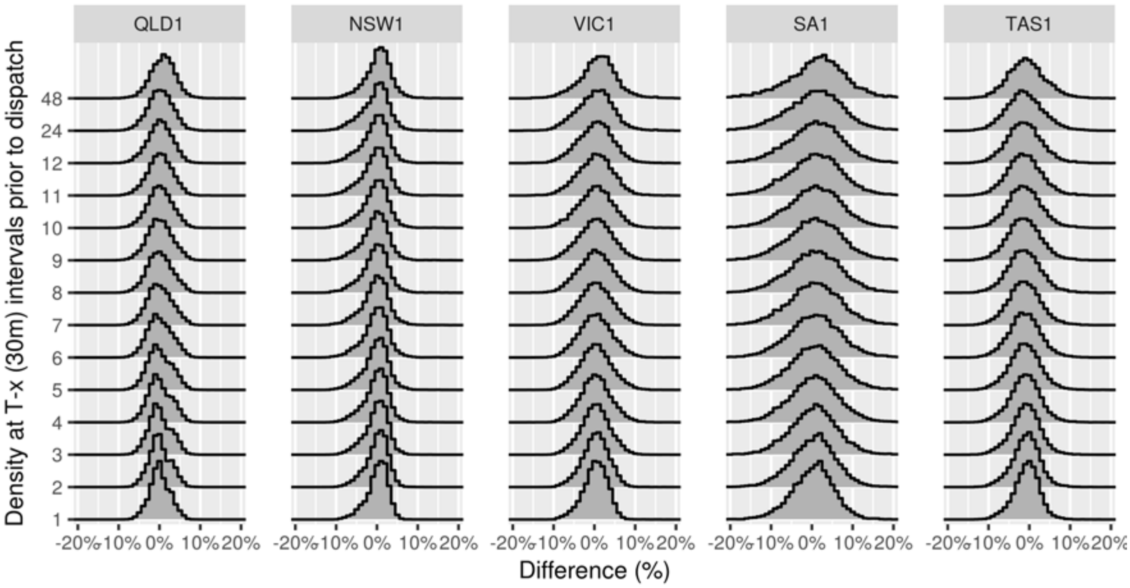
First we seek to analyse how the difference between forecast and actual values changes as we approach dispatch.

This chart shows histograms of percentage demand differences between actual and forecast values across dispatch intervals by region.

The sample is taken from calendar year 2017, which is chosen as a useful baseline year as it is the latest complete year of observations.

In the interests of space, the analysis shows results for 1 to 12 trading intervals (6 hours) prior to dispatch. It also includes observations 24 trading intervals (12 hours) and 48 trading intervals (24 hours) prior to dispatch.

Figure B.12 **Differences between actual and forecast demand approaching dispatch by region, 2017**



The chart shows that, as would be expected, the differences between forecast and actual differences in pre-dispatch quantities improve as we approach dispatch. This can be seen from the tightening in the distribution as we go from T-48 trading intervals to T-1 trading intervals.

Note that these charts show percentage differences, not absolute differences. While the percentage differences in South Australia is higher than the other regions, it has a lower demand than all of the other regions apart from Tasmania – meaning that relatively small absolute differences register as relatively large percentage differences

Seasonality in demand

We can also see if the differences between actual and forecast demand is correlated with the time of the year. To do this, we plot the distribution of the differences in actual and forecast pre-dispatch values at the T-48 trading intervals (T-24h) time horizon at regular intervals. By visualising these on a chart we can see:

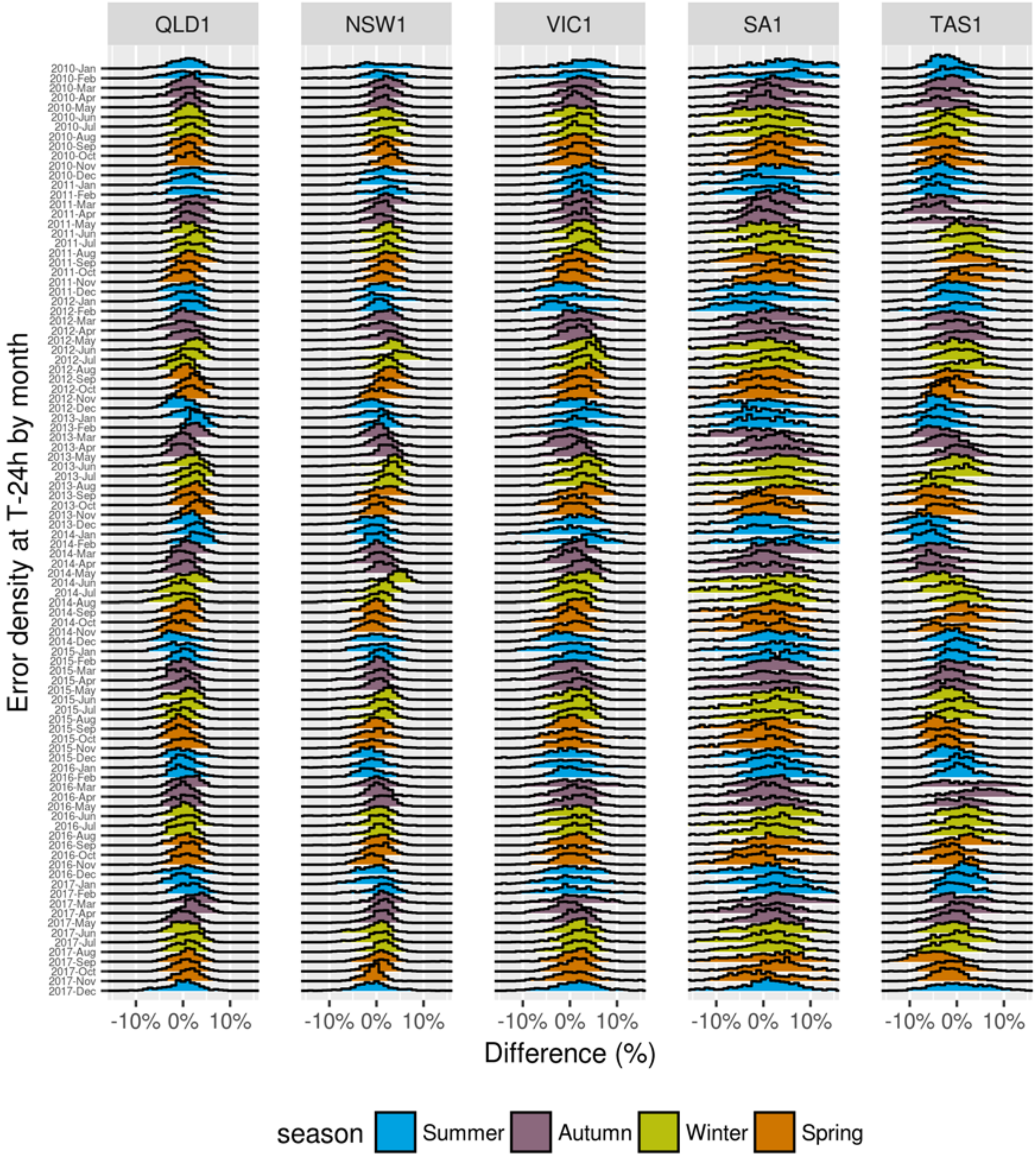
1. how the distribution has evolved over time
2. whether or not there is seasonal variation in the differences.

The chart below shows histograms of the differences at the T-48 trading intervals (T-24h) time horizon. This can be understood as a series of monthly snapshots of the distribution of the differences for demand. These snapshots are then ordered vertically from Jan 2010 to Dec 2017.

Colour has been added to identify the season of each month.

Note the x-axis scale in this chart is from -15 per cent to +15 per cent.

Figure B.13 Differences in actual and forecast monthly demand by region, 2010-2017



Two things can be observed from the chart above.

Firstly, there is obvious seasonal variation in New South Wales and Tasmania. In New South Wales for example, there is a tendency to over forecast demand in winter and under forecast demand in summer. This manifests in the form of the distribution moving left in winter and moving right in summer.

This implies that there may be an element of seasonality or time of year that could be better incorporated into the forecast. AEMO are currently working with the Bureau of Meteorology, which should provide further insights.

The trend observed above is not being driven by a small share or subset of trading intervals, implying that seasonal variations in forecasting affect all of the intervals. If the seasonal differences affected only a small subset of trading intervals, one would expect perhaps a blowout in the tails or anomalous increases in the frequency of trading intervals with large differences, unconnected to the overall distribution. Instead, the shape of the histogram (as distinct from its left-right position) appears uncorrelated to the time of year.

Secondly, there are no structural breaks, or obvious points in time, beyond which forecasts have gotten worse. This chart serves as evidence that the differences in actual and forecast values has not been obviously worsening over time. This is examined in further detail below.

Changes in distribution over time

To more formally examine changes in the distribution over time, we can examine how particular percentiles of the distribution have evolved over time. The xth percentile measures the value at which x per cent of observations are below or equal to a particular value. Thus if the 75 per cent percentile of a distribution is 0.05, this implies that 75 per cent of observations in that distribution are equal to or less than 0.05.

The use of percentiles allows us to directly focus on events with extreme outcomes, by looking more closely at the tails of the distribution.

To this end, we construct a chart showing the following percentiles over time:

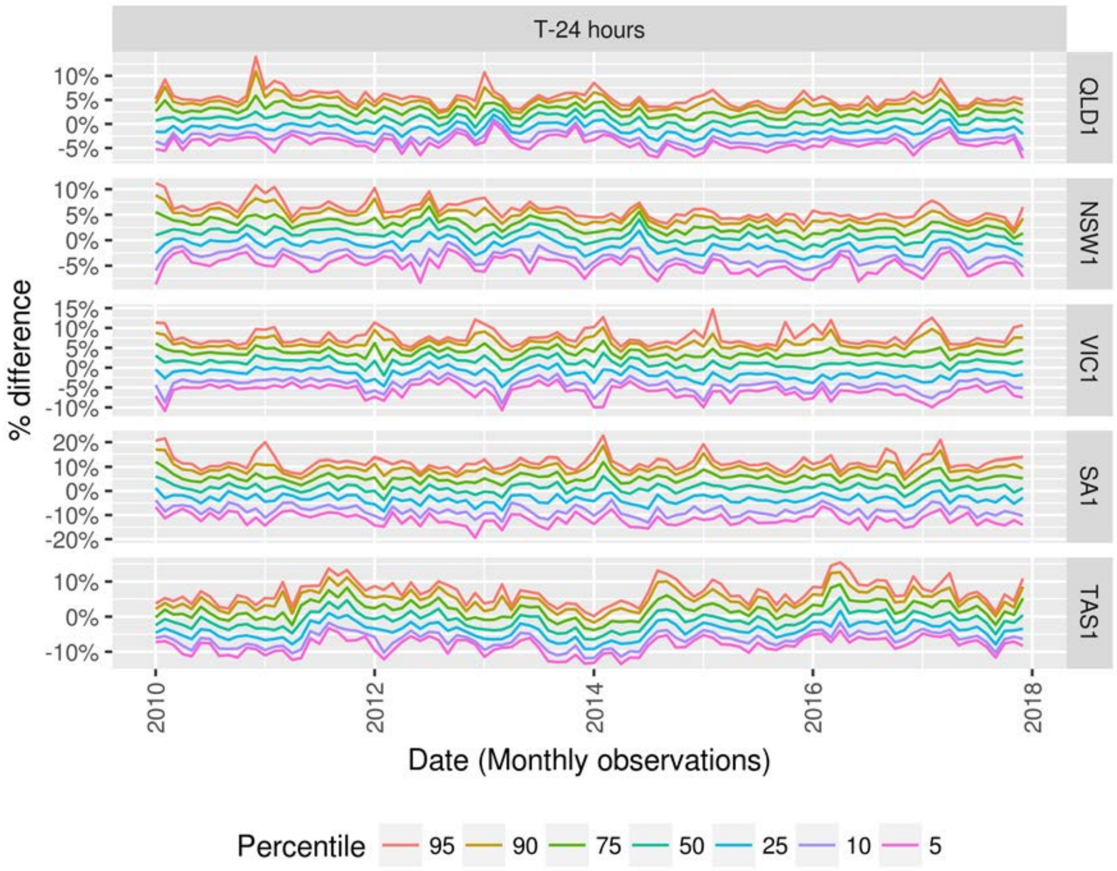
- 95th percentile
- 90th percentile
- 75th percentile
- 50th percentile (median)
- 25th percentile
- 10th percentile
- 5th percentile.

We include observations at the 5th percentile to track the level at which extreme under-forecasting is observed and the 95th percentile to track the level at which extreme over-forecasting is observed.

As an initial example, we do this for forecasts made at the T-48 trading intervals (24 hours) time horizon.

Note that the chart below has a different y-axis for each region.

Figure B.14 Percentiles of monthly differences in forecast and actual demand at T-24 hours by region, 2010-2017



Several things can be observed from the above chart above.

Firstly, the overall trend appears to be stable across the entire examined time period (2010 to 2017). There are no substantial deviations from long term trends, nor are there obvious discontinuities in the series.

Secondly, this stability in the differences appears to hold across all of the percentiles examined. It is therefore not possible to say that extreme differences (5th percentile and 95th percentile) have gotten worse over time.

Multiple time horizons

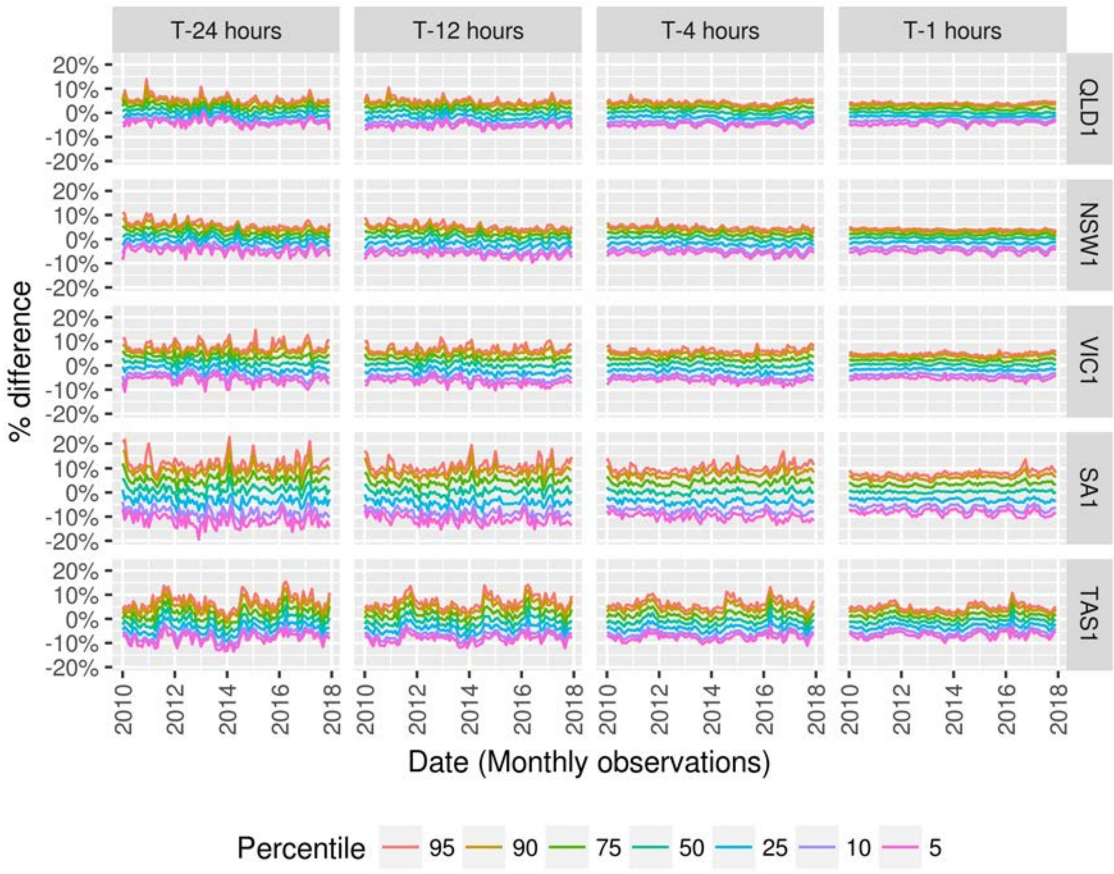
It is also worthwhile repeating this analysis across a range of time horizons beyond just T-48 trading intervals (T-24h).

The chart below replicates an analysis of the percentiles at the following time horizons:

- T-48 trading intervals (T-24h)
- T-24 trading intervals (T-12h)
- T-8 trading intervals (T-4h)

- T-2 trading intervals (T-1h).

Figure B.15 Percentiles of monthly differences in forecast and actual demand at T-24h, T-12h, T-4h and T-1h by region, 2010-2017



The chart above shows several insights.

First, as expected and as was noted above differences between forecast and actual demand reduce as time approaches dispatch. This can be seen by the fact that the percentiles are bunched closer to the x-axis as time approaches dispatch (i.e. moving left to right across panels in the figure).

Second, it appears that South Australia has the greatest differences of the different regions. This can be seen by the relatively spread out percentiles in South Australia at the T-1h time horizon.

Third, seasonal variation in the differences appears to remain, even at the T-1 time horizon. This implies that the pre-dispatch forecast may not fully account for seasonal variation in demand. This can be seen most clearly in the 10th percentile and 5th percentile forecasts in regions such as South Australia and New South Wales for the period after 2014. These variations manifest in a regular pattern of increasing and decreasing differences over the course of a year.

B.2.2 Semi-scheduled generation

The above analysis is repeated for the forecast of semi-scheduled generation.

Outcomes approaching dispatch

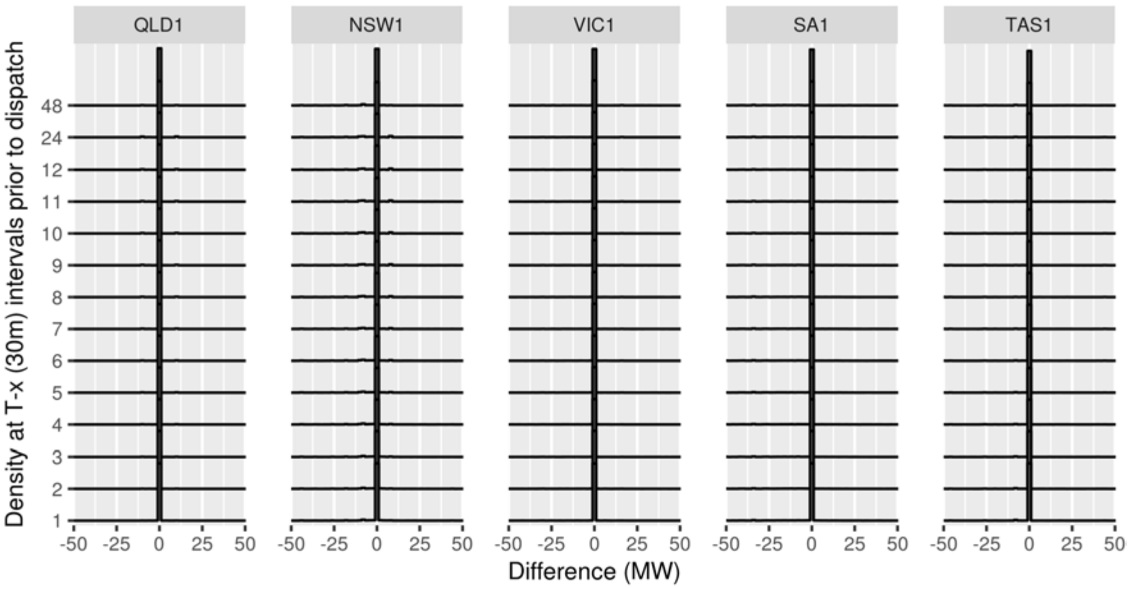
First, we show the difference in forecast and actual values in semi-scheduled generation approaching dispatch.

The sample is taken from calendar year 2017, which is chosen as a useful baseline year.

The chart below is a histogram, similar to Figure B.16 Note however, that the x-axis in this chart is measured in absolute difference (i.e in MW) and not as a percentage error (i.e. as a percentage of the actual outcome).

Charts for semi-scheduled generation use absolute values as the relatively low levels of generation exaggerates the significance of relatively minor differences if percentage differences are displayed.

Figure B.16 Differences between forecasts and actuals for semi-scheduled generation approaching dispatch by region, 2017



Notably, differences are much smaller for semi-scheduled generation implying that forecasts are relatively accurate from the T-48 trading intervals to T-1 trading intervals time horizons. This is explained in Figure B.17 below, where the differences are typically very small between the 10th and 90th percentiles of observations.

It is also worthwhile noting that any improvements in forecasts compared to actuals over time is not visible in the above chart.

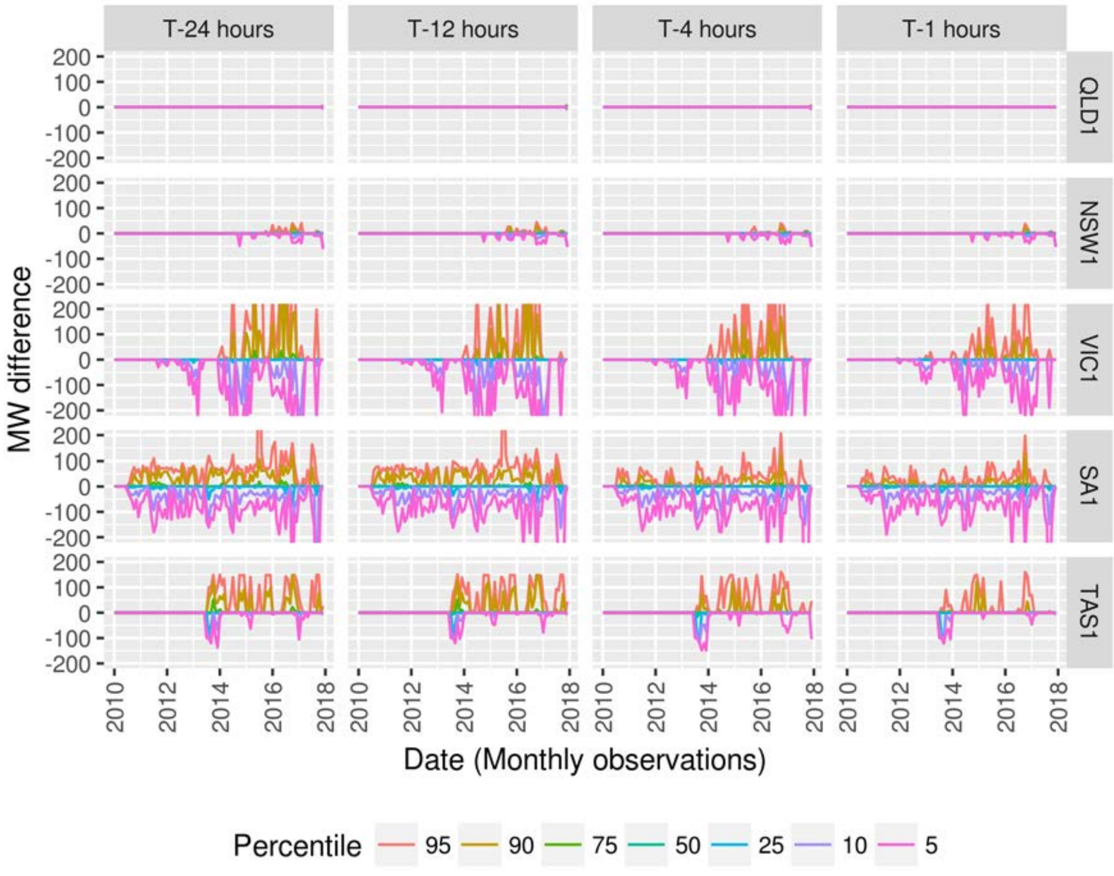
A seasonality analysis was conducted, but the result is not shown as no obvious seasonality can be discerned from the data.

Changes in distribution over time

Finally, we look at the change in percentiles over time for semi-scheduled generation. This is particularly helpful as it allows us to examine any changes in the extreme portions of the distribution over time.

Note: the charts below have the y-axis limited to -200MW to +200MW, to avoid having extreme observations blowing out the scale of the chart.

Figure B.17 Percentiles of differences in monthly forecasts and actuals for semi-scheduled generation at T-24h, T-12h, T-4h and T-1h by region, 2010-2017



From the charts above, we can see that Queensland and New South Wales have minimal differences in semi-scheduled forecasting, while Victoria and South Australia have some degree of differences.

However, it is worth noting that the Victoria and South Australia results only become significant when looking at relatively extreme portions of the distribution (95th, 90th, 10th and 5th percentiles). This implies that the semi-scheduled forecast is relatively accurate at present. Furthermore, the above data does not show any obvious signs of changes in the difference between actual and forecast values for semi-scheduled generation.

If it is of interest, further work can be done to decompose the results.

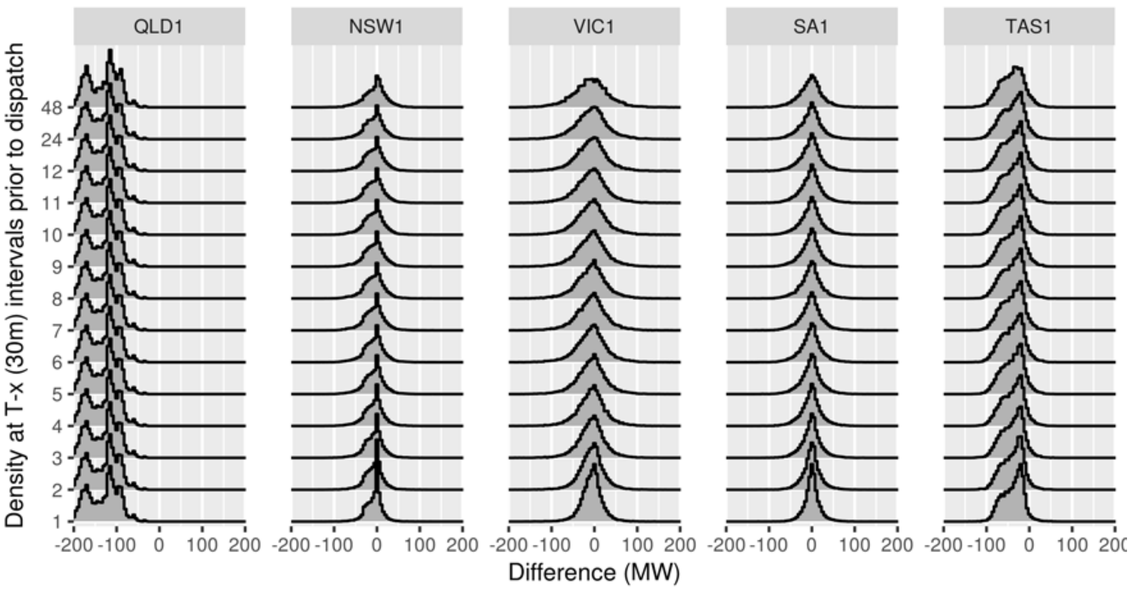
B.2.3 Non-scheduled generation

A similar analysis can be conducted for non-scheduled generation.

Outcomes approaching dispatch

First, we show the differences between forecasts and actuals for non-scheduled generation approaching dispatch.

Figure B.18 Differences between forecasts and actuals for non-scheduled generation approaching dispatch by region, 2017



Several things can be observed from distribution for non-scheduled generation.

Firstly, in all regions except for Queensland, differences in the actual and forecast values improve as we approach dispatch. This can be seen from the tightening in the distribution as we go from T-48 trading intervals to T-1 trading intervals.

Secondly, we note that in New South Wales, Victoria and Tasmania, the distribution is asymmetric: there is a tendency towards under forecasting rather than under forecasting indicated by the "hump" tending to be the left of the charts (i.e. to the left of 0 MW). This is potentially worth investigating further, particularly if the asymmetry is driven by an as yet unobserved factor.

Thirdly, we understand that the slightly unusual distribution of non-scheduled generation errors in Queensland is likely to be driven by the fact that the non-scheduled generation forecast in Queensland appears to be permanently set at 0 in the 30-minute pre-dispatch. This setting seems to mean that whenever there is non-scheduled generation in Queensland, there is always a difference in the actual value compared to the forecast. This also explains why the difference in the forecast is entirely negative, with no positive deviation. (In other words, the forecast only under forecasts and never over forecasts non-scheduled generation.)

The apparent bimodal distribution in Queensland are likely to be driven by seasonality, which is discussed further below.

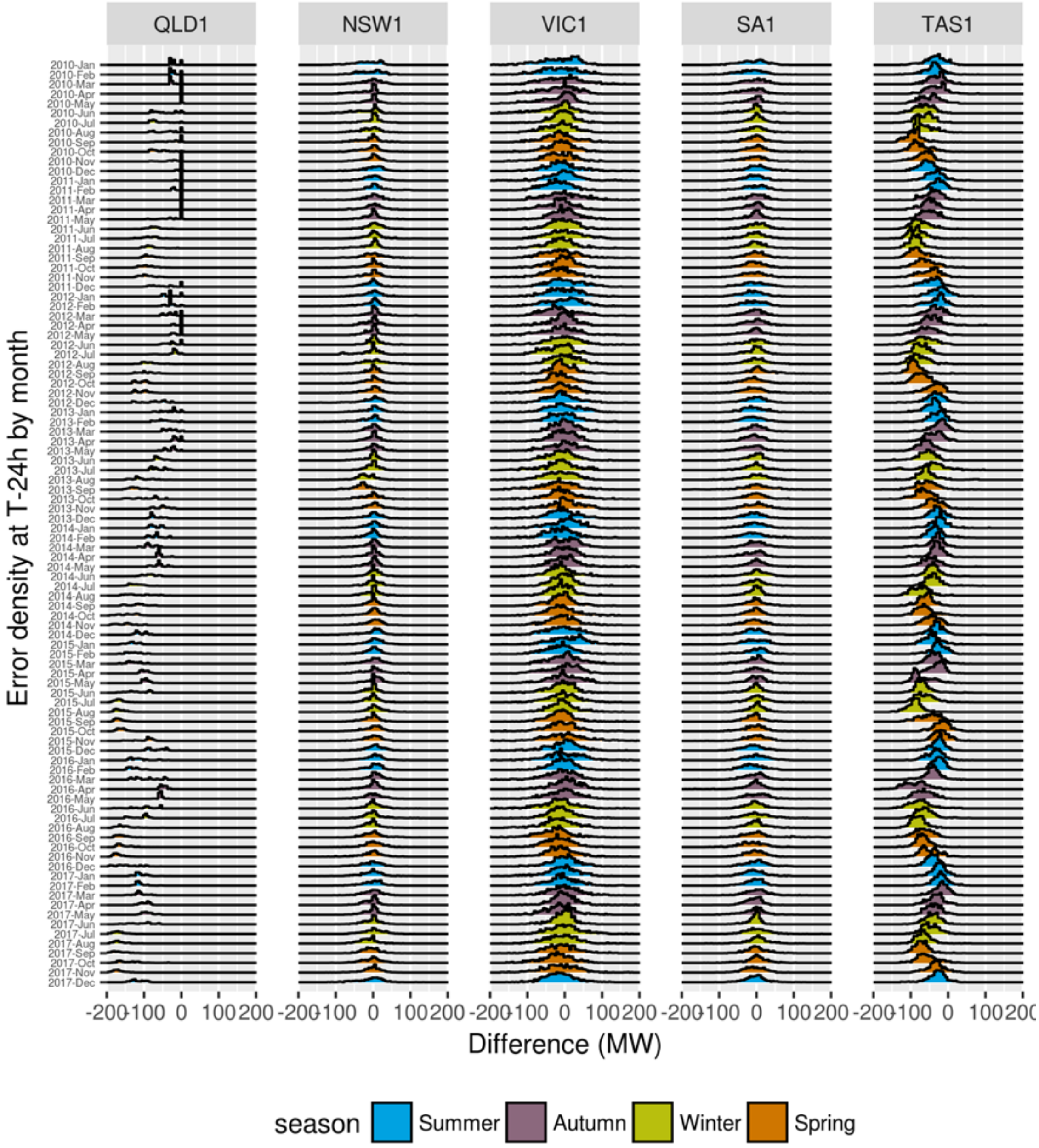
Seasonality

Given the asymmetry and unusual shape of the differences in non-scheduled actuals from forecasts, it is worthwhile decomposing this over time, to observe if there is any obvious seasonality. The chart below shows histograms of forecast error at the T-48 trading intervals (T-24h) time horizon. This can be understood as a series of monthly snapshots of the distribution of for demand. These snapshots are then ordered vertically from Jan 2010 to Dec 2017.

Colour has been added to identify the season of each month.

Note the x-axis scale in this chart is from -200MW to +200MW.

Figure B.19 **Monthly difference in forecasts and actuals for non-scheduled generation by region, 2010-2017**

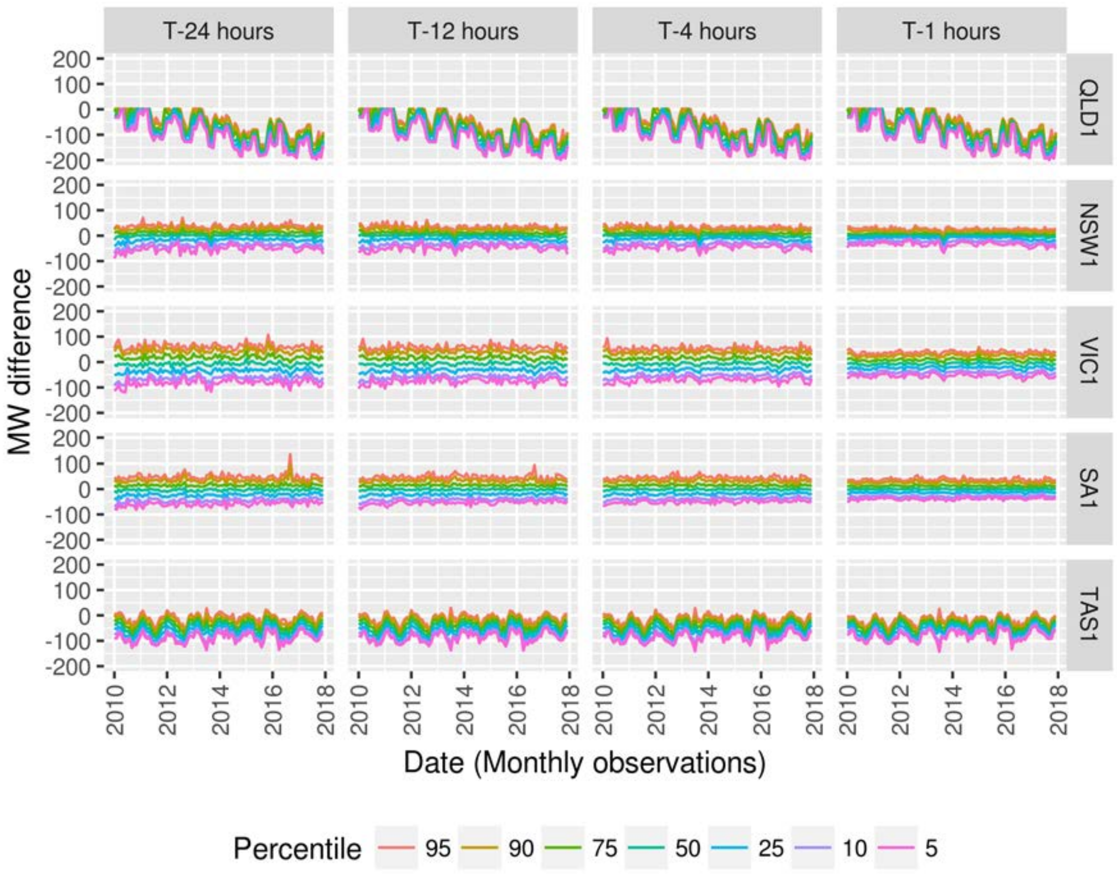


With regards to seasonality, it appears that Queensland and Tasmania exhibit seasonality, indicated by the left-and-right movement of the histograms over time, in sync with the seasons, which suggests that the time of year may not be explicitly taken into account when generating a forecast.

Changes in distribution over time

Finally, we can look at the change in percentiles over time for non-scheduled generation.

Figure B.20 **Percentiles of monthly differences between actuals and forecasts for non-scheduled generation at T-24h, T-12h, T-4h and T-1h by region, 2010-2017**



The chart above also illustrates that in all regions other than Queensland, results do not appear to have deteriorated over the period 2010 to 2017. This can be seen in the fact that the differences in all regions other than Queensland appear to be stable over the entire period examined.

C Design features of a day-ahead market

C.1 ERCOT's Reliability Unit Commitment

ERCOT's Reliability Unit Commitment (RUC) is often quoted as an example of how a day-ahead market helps reduce the need for interventions. ERCOT has stated that the aim of the RUC is to make sure the market is secure and reliable through physically and financially binding commitment.[342] Box C.1 summarises the RUC process.

Box C.1 ERCOT's Reliability Unit Commitment

In ERCOT, the day-ahead market clears based on voluntary energy offers and bids instead of a central load forecast by the system operator. As a result, resources committed in the day-ahead market may not be enough to meet energy and ancillary services demand in the real-time market.

In order to make sure that forecast demand and ancillary services requirements are met, the system operator then uses the RUC process to procure any additional requirement capacity.

The RUC is a daily and hourly process conducted to make sure sufficient generation capacity is committed and transmission system security exists to reliably serve demand.

The RUC is run as follows:

- Day-ahead RUC (DRUC): DRUC runs once a day once the day-ahead market has cleared. It is used to determine if additional commitments needed to be made for the next operating day.
- Hourly RUC (HRUC): HRUC runs every hour. It is used to fine-tune the commitment decision made by DRUC based on more up-to-date conditions system conditions.

The DRUC relies on offers submitted in the day-ahead market but that were not awarded by the day-ahead market. The system operator then compares the load (and therefore generation) cleared in the day-ahead market to its own expectations of conditions for that day. If a shortfall is forecast, the system operator will use the RUC process to make sure that there is sufficient generation available to meet expected demand. If committed by the DRUC (a "RUC instruction"), participants are guaranteed energy revenue based on the offers they submitted in the DAM. If revenue in real time is different from that implied by the DRUC commitment, participants' revenue are adjusted accordingly.

342 See ERCOT http://www.ercot.com/.

The HRUC relies on offers made after the adjustment period following the close of the day-ahead market.

Source: ERCOT.

The RUC is somewhat analogous to pre-dispatch processes and directions in the NEM, although they are not directly comparable:

- The day-ahead market does not clear in the same way as pre-dispatch does, for example. Pre-dispatch would take all variables into account, including load forecasting and network constraints. The day-ahead market is voluntary and does not include forecast load or transmission constraints.
- DRUC is based on offers made at the day-ahead market stage and revenue received is based on that. Reliability directions are often seen as out-of-market as they often involve units that are not offering into the market. Security directions typically involve units that are outside of the bid stack (in the market but not cleared), which is more similar to the RUC.
- RUC commitment guarantees revenue at the offer price, with a causer-pays style penalty system if outcomes deviate from expected revenue. Directed participants are paid compensation in addition to receiving revenue at the spot price.
- ERCOT does not manage in-market reserves the same way the NEM does, meaning that a direct comparison of interventions is not possible.

Notwithstanding the points above, the equivalent of a RUC in the NEM would be directions carried out in a physically and financially binding way after the close of the day-ahead market. AEMO would run an equivalent of pre-dispatch that would identify, as it currently does, potential reliability shortfalls and security concerns. AEMO would then commit units on, at the day-ahead stage based on these identified shortfalls. There would be penalties for not complying with the day-ahead direction in real time.

It is unclear, therefore, how exactly a RUC-adapted-for-the-NEM would reduce the need for interventions since it would still represent an intervention, done proactively through central unit commitment rather than through the traditional NEM intervention process which leaves as much time as possible for the market to respond. It is possible that doing so in a holistic way at the day-ahead stage based on offers made at that point in time may be a more transparent way of carrying out directions. It could also reduce the need for any further interventions, such as the RERT if the system operator is more confident, at a day-ahead stage, that it has enough capacity committed to meet energy and ancillary services.

C.2 Transmission rights and nodal pricing

In the interim report the Commission identified that implementing a US-style ahead market may require a number of complementary reforms such as nodal pricing (or some form of more locational pricing than the current regional model used in the NEM) and the introduction of firm transmission rights.

The extent to which these additional reforms would be required is closely related to the objective of the day ahead market. It is likely that under the first and second objectives the introduction of firm transmission rights and locational marginal pricing would not be required, or at least would not be required initially.

As part of the *Coordination of generation and transmission investment* review the Commission has completed analyses of the incidence and cost of congestion that currently exists in the NEM.[343] The results show that congestion in the NEM was relatively small at present and largely restricted to congestion between regions. The cost of congestion in 2016/17 was just under $17 million (or 0.36 per cent of total actual AEMO dispatch).[344] Furthermore, according to AEMO's analysis for the Integrated System Plan, the bulk of network congestion in 2016/17 resulted from interconnector transfer limits.

In order to achieve the third objective it may be necessary to introduce reforms to transmission frameworks and pricing in the NEM. The preliminary conclusions with respect to this are as follows:

- The choice is not so much a nodal versus regional market as a question of firm versus non-firm access for generators.
- The absence of firm transmission rights in the NEM may undermine the development of an ahead market. Constraining off generators without compensation undermines the incentive of generators to participate in the ahead market at the day-ahead stage because it would expose them to constraint risk:
  - Whether lack of compensation is material depends on the frequency of constraints and the volatility of wholesale prices.
  - If constraint risk is material, it may hinder the functioning of an ahead market. This is because generators may raise their bids (in a mandatory ahead market), or decline to participate (in an voluntary ahead market).
  - Many of the potential benefits of the introduction of firm transmission rights and nodal pricing are independent to whether an ahead-market is introduced. The introduction of firm transmission rights in order to support an ahead market may not be worth the costs of doing so.
- The choice between a nodal signal and a market wide signal is essentially unchanged, i.e. that:

343 For more information on this review see: https://www.aemc.gov.au/markets-reviews-advice/reporting-on-drivers-of-change-that-impact-t ransmi

344 This result is given by taking the "constrained" dispatch costs of $4,671,652,600 form the "unconstrained" dispatch costs of $4,654,676,735, giving a cost of congestion of $16,975,865.

- Compensating constrained-off generators may be less dynamically efficient than existing arrangements, where wholesale market prices do not signal the value of intra-regional constraints, and increase balancing costs for consumers. If constraints occur between regions rather than within regions, then zonal prices (as currently exist in the NEM) may be a reasonable proxy for nodal pricing.
- Nodal prices may be more dynamically efficient than offering firm transmission rights without a locational signal. However the introduction of nodal pricing may necessitate further interventions in the market such as market power controls to address potential concerns regarding market concentration at specific nodes.

The Commission recognises that changes to transmission access arrangements and the introduction of more granular or locational pricing would be a significant change to current arrangements and would take a number of years to implement. The potential benefits of such a change would need to be carefully considered and balanced against the costs and time involved to implement these reforms.

D Mapping timeframes in the NEM

This appendix provides the results of the Commission's work in identifying and mapping all of the activities and decisions made by parties under the current NEM design. This table demonstrates what information is available to participants and at what time, relative to dispatch. We welcome stakeholder comments on this mapping exercise.

Please note the following with respect to the table:

- Timeframes are all defined relative to a dispatch interval “D” of 4.30am NEM time
- Timeframes are also expressed by reference to the first time the information will appear e.g. the NTNDP forecasts 20 years in the future so it appears as “D – 20 years”. The table also notes how frequently the information gets updated
- With respect to market participant actions, *italicised text* means it is a NER requirement while **bolded text** means it involves the contracts market.

The mapping was discussed at a meeting of the Technical Working Group. Participants at the Technical Working Group were broadly in agreement with the results of the mapping exercise and noted that the results show that there is a large amount of information available to market participants at different points in time. It was further noted that decisions made by market participants in advance of dispatch were iterative and are continually updated as new information becomes available.

It was also noted by the Technical Working Group that there are areas where participants receive no information, for example on the output of non-scheduled generation or distributed energy resources. There is work ongoing to improve this information, for AEMO is reviewing ways to improve the visibility of distributed energy resources.

Table D.1 Mapping timeframes in the NEM

Timeframe (relative to dispatch interval "D" of 4.30am NEM time)		Subject	AEMO action	Market participant action
Day	Hour			
D – 20 years (updated annually)		Information provision	National Transmission Network Development Plan Produces a strategic vision of the transmission network over the next 20 years.	
D – 20 years (updated annually)		Information provision	National Electricity Forecast Insights Provides independent electricity consumption, maximum demand and minimum demand forecasts for each NEM region over a 20 year forecast period	
D – 20 years (updated annually)		Information provision		Participant forecasting of future trends in the market, including considering AEMO view of the world This directional forecasting will inform long-term contracting, fuel supply decisions and financial outlook
D – 10 years (updated annually by 31 August)		Information provision	ESOO Provides technical and market data that informs the decision-making process of existing and potential market participants	*Participants must provide required information to AEMO as soon as practicable.*

Timeframe (relative to dispatch interval "D" of 4.30am NEM time)		Subject	AEMO action	Market participant action
Day	**Hour**			
			as they assess opportunities in the NEM over a 10 year outlook period.	
D – 2 years (updated at least annually, but more frequently if required)		Information provision	EAAP 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 shortages during drought conditions or constraints on fuel supply for thermal generation or supply adequacy in the NEM	*Generators must provide relevant information and updated information if there has been a material change that affects the energy constraints.*
D – 2 years (updated weekly)	16.00	Information provision	AEMO publishes MT PASA, which provides information on generator and network availability	*Generators must provide information to AEMO in accordance with a timetable* *Generators must update AEMO of any changes in generator availability in relation to the MT PASA as soon as they occur.* This will be based on planned / actual outage profile and will include details of any planned outages as a result of maintenance decisions. *Networks must inform AEMO of any network outages as soon as they are scheduled*
D – 2 years (updated weekly)	16.00	Information provision	AEMO assesses USE through the MT PASA process, and will inform the market of low reserve conditions.	Market notice issued, for the purpose of seeking a market response.

Timeframe (relative to dispatch interval "D" of 4.30am NEM time)		Subject	AEMO action	Market participant action
Day	**Hour**			
			Market notice issued, for the purpose of seeking a market response.	
Periodically		RERT	AEMO issues expressions of interest for additional or new potential providers to join the RERT panel	Participants consider whether they wish to be on the RERT Panel or not, and if so, apply to be on the Panel.
D > 1 year		Maintenance		Major maintenance planning Participants block in major (multi week / month) planned outages. Up to a 4 year cycle for major thermal outages
D > 1 year		Contracts		**Participants will establish longer-term multi-year contract levels, which may be provided by a retail book for gentailers**
D > 1 year		Fuel		**Contract for primary fuel and delivery, typically multi-year contracts, long negotiation lead times (probably shorter for liquid fuel)**
D > 1 year		Fuel		Long-term mine planning based on operational outlook and mine conditions, including long-lead decisions e.g. overburden removal
D – 1 year		D – 1 year	AEMO informs market participants of the settlement calendar, based on public holiday information, for an upcoming three year period.	

Timeframe (relative to dispatch interval "D" of 4.30am NEM time)		Subject	AEMO action	Market participant action
Day	**Hour**			
D – 1 year		Participant forecasting & planning		Participants prepare formal annual / quarterly budgets (for internal use), based on information provided to the market and forecasts. These are used as an input to the company's planning, and the corporate annual budget.
D – 1 year		Fuel		Nominate contract volumes for coal, gas and liquid fuel where long term contracts provide flexibility. Negotiate additional fuel / delivery contracts where required. Review plant operating and water plans, informed by rainfall / streamflow and operating outlook for hydro
D – 1 year to D – 3 months		Contracts		**Participants will undertake additional contracting to progressively approach target levels. Hedging is typically executed on a rolling basis to progressively approach targets** **Participants arrange market linked insurance product coverage for forced outage risks**
D – 1 year to D – 3 months		Maintenance		Minor maintenance planning

Timeframe (relative to dispatch interval "D" of 4.30am NEM time)		Subject	AEMO action	Market participant action
Day	**Hour**			
				Participants will block in minor planned outages, typically of 1-2 weeks duration Minor maintenance will be committed sometime between 1 week and 1 year in advance, depending on the outage work required
D – 1 year to D – 1 week		Maintenance		Commit major maintenance Finalise timing for planned major outages, which may require lead times of up to 1 year
D – 3 months to D – 1 week		Participant forecasting and planning		Participants prepare a medium-term operating outlook **Participants refine budgeted operating / financial outlook for near months, incorporating latest market outlook, plant condition, fuel & contrast positions** **Participants adjust contracting levels to refined targets, taking into account latest market, plant conditions**
D – 3 months to D – 1 day		Fuel		Manage fuel stocks (coal stockpile, liquid & auxiliary fuel levels in line with operating outlook) For hydro review plant operating and water plans, optimise pumping plans

Timeframe (relative to dispatch interval "D" of 4.30am NEM time)		Subject	AEMO action	Market participant action
Day	**Hour**			
D – 7 days to D – 1 day		Participant forecasting and planning		Participants prepare a short-term operating outlook Participants consider a week ahead market and plant operating outlook, incorporating "live" weather data, plant capability, information from the ST PASA, which will drive slow start commitment decisions **Participants contract to respond to unexpected changes in portfolio position e.g. short duration typically bilateral contracts**
D – 7 days		Bidding		Participants develop a base bid set for their default / standing bids
D – (7 days to – 10 weeks)		RERT	If a forecast low reserve condition is issued, AEMO informs the market of the latest time at which it will intervene. Then, AEMO informs the market that it intends to procure the RERT. AEMO seeks tenders from medium-notice panel members or from non-panel members. Market notice issued	Participants consider providing medium-notice RERT and participate in AEMO's tender

Timeframe (relative to dispatch interval "D" of 4.30am NEM time)		Subject	AEMO action	Market participant action
Day	**Hour**			
D – (7 days to – 10 weeks)		RERT	AEMO publishes ST PASA	*Participants must update AEMO of any changes in generator availability in relation to the ST PASA as soon as they occur* Participants will monitor and update near term availability & capability based on latest plant and weather conditions
D –7 days to D		Information provision:	AEMO forecasts a lack of reserve condition 2 Market notice issued and AEMO may seek a market response	Participants monitor LOR notices, and may adjust availabilities into the ST PASA and pre-dispatch accordingly.
D – 7 days to D		RERT	If a lack of reserve condition 2 has been forecast, AEMO informs the market of the latest time at which it will intervene. Then, that it intends to enter into reserve contracts from the short-notice RERT Panel Market notice issued	Participants on the short-notice RERT Panel are contacted, and may informally be told to prepare for activation
D – 7 days to D		RERT	Once AEMO procurers reserves, it will inform the market of an outcome Market notice issued	
D – 7 days to D –		Fuel		Short-term water planning (including

Timeframe (relative to dispatch interval “D” of 4.30am NEM time)		Subject	AEMO action	Market participant action
Day	**Hour**			
1 day				pumping). Hydro plants will plan water & station operations to manage and optimise operations given water levels and constraints to maximise value of run of river and discretionary water.
D – 7 days to D -1 hour		Fuel		Place gas market bids for forecast fuel requirements where applicable e.g. VicGAS, STTM, generally based on electricity market pre-dispatch Nominate daily gas delivery and transportation volumes under contracts
D – 2 days	12.30	Bidding		*Participants must provide AEMO with information about commitment times, capacity profile, and energy availability for D0*
D – 2 days		Unit commitment		Initiate cold start for coal-fired plant, since cold start may require 24-48 hours’ notice & lead time
TI – 40 hours (updated every 30 minutes)	12.30	30 minute pre-dispatch	AEMO runs 30 minute pre dispatch, which includes using a demand forecasting system	
TI – 40 hours (updated every 30 minutes)	12.30 + 10s	30 minute pre-dispatch	AEMO runs a SCADA snapshot	

Timeframe (relative to dispatch interval "D" of 4.30am NEM time)		Subject	AEMO action	Market participant action
Day	**Hour**			
TI – 40 hours (updated every 30 minutes)	12.30 + 140s	30 minute pre-dispatch	AEMO completes pre-dispatch process	
TI – 40 hours (updated every 30 minutes)2.30 + 155s	12.30 + 155s	30 minute pre-dispatch	AEMO pre-dispatch solution published to participants	Participants see pre-dispatch outcomes Participants establish / refine "on the day" market price & dispatch outlook. This is an iterative process, with participants bidding / rebidding to optimise position given market conditions, plant & fuel constraints, contingent contracts etc
TI – 40 hours (updated every 30 minutes)	12.30 + 174s	30 minute pre-dispatch	AEMO loads data to participants' database	
D – 1 day	12.30	Bidding		Bidding closes for day 0. Participants must provide AEMO with price / quantify bands, with the price of each band cannot be changed after this point. Commitment and volume profiles are informed by the participants' short-term operating outlook.
D - 1 day		Fuel		Monitor raw coal bunker, revise plant operation / bids in response to constraints For batteries, rebid to maintain battery charge

Timeframe (relative to dispatch interval “D” of 4.30am NEM time)		Subject	AEMO action	Market participant action
Day	**Hour**			
				levels and dispatch capability
D – 12 hours		Unit commitment		Initiate warm start for coal fired plant, typically 4 – 12 hours’ lead time Initiate start for slow-start gas units, typically 1 hour (CCGT) to 6 hours (steam cycle) hours’ lead time
D		Bidding	If no valid bid or offer is received, AEMO uses the last valid bid or offer is used	
D	ASAP after receipt of valid bid	Bidding	AEMO acknowledges receipt of valid dispatch offer, dispatch bid or market ancillary service offer.	
D	ASAP after receipt of valid bid	Bidding		Semi-scheduled generators need to update AEMO if generating unit plant availability differs more than 6 MW from the nameplate rating
Sometime ahead of real-time, typically up to 24 hours		RERT	AEMO will pre-activate the RERT it has contracted	If pre-activated, participants will start to get ready to be dispatched in relation to the RERT
D - 1 hour	3.30am	Expected synchronising time and de-synchronising time		Scheduled generator to confirm with AEMO the expected synchronising time and de-synchronising time at least 1 hour before, and update this advice 5 minutes before

Timeframe (relative to dispatch interval "D" of 4.30am NEM time)		Subject	AEMO action	Market participant action
Day	**Hour**			
				synchronising or desynchronising
D - 1 hour (updated every 5 minutes)	3.30am - 67s	5 minute pre-dispatch	AEMO starts 5 minute pre-dispatch process	
D - 1 hour (updated every 5 minutes)	3.30am - 3s	5 minute pre-dispatch	AEMO takes a 5 minute pre-dispatch SCADA snapshot	
D - 1 hour (updated every 5 minutes)	3.30am + 36s	5 minute pre-dispatch	AEMO completes 5 minute pre-dispatch process	
D - 1 hour (updated every 5 minutes)	3.30am + 48s	5 minute pre-dispatch	AEMO publishes 5 minute pre-dispatch solutions	Participants see 5 minute pre-dispatch solutions Participants use this to manage real time position, including fast start signals. Rebid to manage market outturn, plant capability, fuel position
D - 1 hour (updated every 5 minutes)	3.30am + 77s	5 minute pre-dispatch	AEMO loads 5 minute pre-dispatch information	
D	4.30am - 67s	Dispatch	AEMO starts dispatch process	
D - 15 minutes	4.15am	Bidding		Rebidding closes. The last time when rebids can be captured in dispatch.

Timeframe (relative to dispatch interval "D" of 4.30am NEM time)		Subject	AEMO action	Market participant action
Day	**Hour**			
				Participants rebid to optimisation their position give market conditions and constraints.
D	4.30am - 3s	Dispatch	AEMO takes a SCADA snapshot	
D	4.30am + 8s	Dispatch	Dispatch process complete	
D	4.30am + 17s	Dispatch	Solution published to participants	NEMDE solutions are sent to participants
D	4.30am + 22s	Dispatch	Data loaded to participants' database	NEMDE solutions are received by participants
D	4.30am	RERT	AEMO dispatches the RERT	
D	4.30am	Intervention	AEMO issues a direction & undertakes counter actions. AEMO typically dispatches the RERT ahead of using directions.	
D	4.30am	Intervention	If RERT or direction, AEMO will declare intervention pricing. If it is a direction, this will involve applying the RRN test to see if intervention pricing should be implemented.	
D	4.30am Every 5 minutes during an	Intervention	During an intervention, AEMO reruns NEMDE to determine the prices that would apply in the what if scenario	

Timeframe (relative to dispatch interval "D" of 4.30am NEM time)		Subject	AEMO action	Market participant action
Day	**Hour**			
	intervention		Intervention pricing applies to all dispatch intervals whereby an intervention is active.	
D	4.30am	Intervention	AEMO load shedding – recurring LOR2 not sufficiently alleviated by market response or intervention; LOR 3 Instructing a NSP to reduce customer load taking into account sensitive loads / load shedding list Market notice issued	
D	4.30am	Intervention	If load shedding, automatically set prices at the market price cap for the duration of the load shedding event.	
D	As needed	Dispatch	If NEMDE does not solve on the first run, it has to re-run it. This happens when a constraint is violated and a price exceeds the price settings	
D	4.30am	Dispatch	NSPs may dispatch generators for NSCAS in which case AEMO will constrain them on	
D	4.30am	Dispatch	To limit flows on interconnectors if negative settlement residues accumulate to $100,000	

Timeframe (relative to dispatch interval “D” of 4.30am NEM time)		Subject	AEMO action	Market participant action
Day	**Hour**			
			A market notice is published if this occurs	
D	4.30am + [some time period in the future]	Intervention	AEMO informs the market that the RERT and /or direction is no longer in place. AEMO also informs the market that intervention pricing has ceased.	
D + 1 day	morning	Prudentials	AEMO provides an accurate estimate of the amounts outstanding for each market participant in relation to prudential assessments i.e. energy consumed but not yet paid.	
D + 1 day	morning	Settlement	The Electricity Market management system (EMMS) calculates a settlement estimate for the day before, called a daily estimate which provides a preliminary estimate of their financial position from the previous day.	
D + 1 day		Prudentials	Prudential standings produced for each participant	
End of billing period + 5 business days	Approx 12.00 Sydney time and no later than 18.00	Settlement	AEMO issues a preliminary statement to participants to provide MPs with a preliminary statement of the amount owing/payable for the billing period containing Day 0. Allows AEMO participants to check and reconcile the	

Timeframe (relative to dispatch interval “D” of 4.30am NEM time)		Subject	AEMO action	Market participant action
Day	**Hour**			
			settlement results from the preliminary statements, which form the basis for the final statements.	
D + 7 days		Information		*AER provides a weekly electricity market analysis report that contains information on significant price variations, movements in the contract market, together with analysis of spot market outcomes and rebidding behaviour.*
19 days after direction cancelled		Intervention	AEMO makes provisional determination on compensation amounts) & regional benefits factors for compensation recovery amounts AEMO issues Final Settlement Statements for Billing Week AEMO notifies Directed and Affected Participants of provisional determination on compensation amounts	
26 days after direction cancelled		Intervention	Directed Participants may seek additional compensation Affected Participants or Market Customers may seek to vary compensation amount	
End of billing period +20	By 10.30 Sydney time	Settlement		Participants pay AEMO in cleared funds the amount stated to be payable on relevant final

Timeframe (relative to dispatch interval "D" of 4.30am NEM time)		Subject	AEMO action	Market participant action
Day	**Hour**			
business days				statement
End of billing period +20 business days	By 14.00 Sydney time	Settlement	AEMO pays participants in cleared funds the amount states to be payable on the relevant financial statement	
End of billing period +20 weeks	Approximately 12.00 Sydney time, no later than 18.00	Settlement	AEMO issues routine revised statement Covers the Billing period including Day 0. Based on amended metering data, trading amounts, participant fees or other amounts payable or receivable by the participant	
End of billing period +30 weeks	Approximately 12.00 Sydney time, no later than 18.00	Settlement	AEMO issues routine revised statement. Covers the Billing period including Day 0. Based on amended metering data, trading amounts, participant fees or other amounts payable or receivable by the participant	
As soon as practicable		Information provision	AEMO prepares an intervention report on the intervention	
Generally, as soon as practicable		Information provision	AEMO prepares a report on scheduling errors	
No timeframe provided		Information provision	AEMO prepares a report on power system operating incidents that include: black systems, non-credible contingences,	

Timeframe (relative to dispatch interval "D" of 4.30am NEM time)		Subject	AEMO action	Market participant action
Day	**Hour**			
			multiple credible contingencies	
No timeframe provided		Information provision	AEMO prepares a report on power system reclassification events on the reasons for all decisions to reclassify contingencies	
No timeframe provided		Information provision	AEMO prepares pricing event reports on on significant price events to support market transparency, by highlighting unusual pricing outcomes in the NEM and providing information on the factors that contributed to these outcomes	
Within 40 business days of the end of a week in which the event occurred		High price event reports		*The AER is required to publish a report whenever the spot price for electricity exceeds $5000/MWh.*
As required		Compliance reports		*The AER prepare a quarterly report summarising their monitoring and enforcement activities in the wholesale electricity market.*
Within 6 months		Market participants have a six-month window to notify AEMO of their concerns regarding settlement results.		*Notification of concerns to AEMO must be provided in writing to provide AEMO with the basis for determining the earliest billing period that ultimately may be revised.* The whole of the billing period that contains the date which is 6 calendar months prior to the date of notification will be revised if affected by the outcome of the investigation. The whole of the

Timeframe (relative to dispatch interval “D” of 4.30am NEM time)		Subject	AEMO action	Market participant action
Day	**Hour**			
				billing period immediately prior to that will be ineligible under Rules clause 3.15.18(b)

E Summary of submissions

This appendix sets out the issues raised in the second 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.

Table E.1 Summary of submissions

Stakeholder	Comment	Commission response
Dispatchability and flexibility		
Most stakeholders commented on this issue, including Australian Energy Council, Hydro Tasmania, Energy Networks Australia, S&C Electric, Snowy Hydro, Major Energy Users, Tesla, ARENA.	Stakeholders had a mix of views on defining dispatchability and flexibility, with some noting that it is important to define them in order to determine whether the existing market adequately rewards them, while others suggested that introducing these concepts risk distorting investment. Most stakeholders noted the practical difficulties in defining these concepts and highlighted the overlap with the National Energy Guarantee work. Some stakeholders suggested that further work is needed to understand whether or not they are valued in the current NEM framework. There were mixed views on whether or not they were already valued.	The Commission will progress this workstream in the final report of the *Reliability Frameworks Review*. As a result, it has not provided specific responses to stakeholder submissions on this topic in this directions paper.
Contract market		
Most stakeholders commented on this issue, including ERM Power, ENGIE, SA Government, Meridian, EnergyAustralia	There was strong agreement in terms of the importance of the contract market in supporting reliability and on the importance of availability of information on contract	The Commission will progress this workstream in the final report of the *Reliability Frameworks Review*. As a result, it has not provided specific

Stakeholder	Comment	Commission response
Australian Energy Council, Hydro Tasmania, TasNetworks, S&C Electric, Snowy Hydro, TransGrid, Tesla, ARENA, AGL, Origin, Stanwell.	trading. One stakeholder, however, noted that the primary functions of contracts were to keep generation financially viable and provide price stability. However, the balance of views expressed on liquidity leaned toward pessimism about the health of the contract market. A couple of stakeholders raised questions about the source and value of price arbitrage projects we listed in the interim report. A few stakeholders expressed concerns about our analysis of circumstances in South Australia and Tasmania.	responses to stakeholder submissions on this topic in this directions paper. By this time, the AFMA survey should be reinstated and so useful observations may be able to be drawn from this dataset.
Forecasting and information provision		
TasNetworks	TasNetworks contends predicting dynamic behaviour of asynchronous generation during transmission network contingencies is also worthy of further consideration. (p.3)	The Commission acknowledges this as an issue but notes that system security concerns are outside of the scope of this Review. The Commission has a comprehensive system security work program underway, which is coordinated with its reliability work program.
S&C Electric	It is of great concern that the rebidding practices of generators has been found to be a significant factor in impacting negatively on the ability of AEMO to prepare accurate forecasts. (p. 6)	The Commission has assessed the accuracy of short-term forecasts in chapter 3 and provided some areas for improvements.
Ian Waters (private individual)	Mr Waters recommended a number of options to improve transparency and provide additional information to the market, e.g. by publishing the charge and discharge power from the Hornsdale battery and what the cost of electricity would have been if Hazelwood and Northern	The Commission notes that most of the options are already information that is available to market participants. Other suggestions such as modelling prices under different scenarios would be too costly to do on a regular basis.

Stakeholder	Comment	Commission response
	power stations were still in operation. (p. 2)	
Day-ahead market		
Energy Networks Australia	Energy Networks Australia notes the impact of any changed network circumstances as a result of a DAM could have a significant effect on dispatch and would need careful consideration. (p. 5)	As discussed in chapter 4, the design of any day-ahead market is closely related to the objective of the market. As the objective of a day-ahead market has not been clearly articulated, it is not possible to address specific design questions. It is worth noting that the ACCC's inquiry into the supply of retail electricity and competitiveness of retail electricity prices in the NEM is looking at market power issues in the electricity market.
Snowy Hydro and Major Energy Users	Snowy Hydro (pp. 8-9) and Major Energy Users (pp. 9-10) are concerned about the potential market power issues such as strategic capacity withholding or disorderly bidding under a DAM.	
Strategic reserves and interventions		
Energy Queensland, ENGIE	A number of stakeholders commented on the level of the reliability standard. Energy Queensland questions the assertion that community expectations have changed in relation to reliability across the NEM. (p. 9) ENGIE notes that if there is a new political or public view that the current standard needs to be changed, then the increase in cost that this will introduce needs to be justified against the fact that the actual unserved energy for most years under the NEM has been zero. (p. 9)	The Commission notes these comments and will further progress them through its RERT rule change request processes, should they be in scope of the requests.
Origin	Origin recommends that the first step in evaluating the need for availability payments should be to investigate the extent to which this has inhibited participation in the RERT to date. If an availability payment is considered	The Commission notes this comment and will further progress it through its RERT rule change request processes.

Stakeholder	Comment	Commission response
	appropriate, its structure should be carefully assessed to ensure it provides the correct incentives to participants and does not lead to considerable cost that would ultimately be recovered from consumers. (p. 3)	
Stanwell	Stanwell notes that with the revised lack of reserve declaration guidelines not operational at the time of writing and no publicly available analysis of back-casting results there is no way to compare the relative merits of alternative arrangements. (p. 13)	The Commission notes that AEMO is required to publish a report every quarter on the operation of the lack of reserve framework. The first report is due in April 2018.
Environmental Performance Australia	The concept of “strategic reserve” needs to be formulated more broadly around load shedding and distributed distribution instead of the 20th century concept of some physical generation plant sitting idle waiting for an emergency to occur. Dynamic control systems and technology offer a much lower cost option for managing system failures. (p. 1).	The Commission notes this comment and will further progress it through its RERT rule change request processes.
TransGrid, Energy Networks Australia	A number of stakeholders commented on the definition of unserved energy. TransGrid would like a rethink of the unserved energy definition to include voluntary curtailment or curtailment of large loads. (pp. 2-3) Energy Networks Australia notes that there is consumer dis-satisfaction with the amount of unserved energy reported vis-à-vis amount of load shedding in NSW and that consumer expectations should be regarded as an important consideration in defining, and attaining a more holistic understanding of unserved energy. (pp. 4-5).	The Commission acknowledges this issue and intends on progressing it further in the final report.

Stakeholder	Comment	Commission response
Wholesale demand response		
Clean Energy Council	The selective focus on wholesale and emergency demand response schemes, rather than multiple demand response markets, should be questioned. When considering barriers to entry, it must be considered that demand response providers will likely be participating in multiple markets, and not be restricted to the wholesale market. (p. 5)	The focus on wholesale demand response and emergency demand response (strategic reserves) is the result of two specific Finkel Panel recommendations asking the AEMC to assess these particular areas. The Commission also sees the two markets as distinct.
S&C Electric	S&C Electric suggested further consideration of the demand side to not only reduce consumption but also increase consumption under different market conditions. (p. 7)	The Commission notes S&C Electric's comment. The scope of this review clearly includes the demand-side, and as such it is considered throughout this review.
TasNetworks	TasNetworks noted that any regulatory initiative to facilitate wholesale demand response needs to account for specific jurisdictional issues. (p. 4)	The Commission notes TasNetworks' comment. Such considerations will be considered when the demand response workstream is further advanced.
Energy Efficiency Council	The EEC would like to engage with the AEMC to ensure that a new modelling exercise on the costs and benefits of a demand response mechanism includes realistic assumptions. (p. 9) At their heart, objections from generators to demand response, were really concerns about increasing competition in the wholesale energy market, and we urge the AEMC to dismiss such claims as shameless rent seeking. (pp.8-9)	The Commission notes the EEC's concerns and modelling suggestion. The directions paper does not address modelling or competition issues within demand response.
Other		
Energy Networks Australia	Energy Networks Australia would like clarification on	These are outside of the scope of this Review. The

Stakeholder	Comment	Commission response
	whether emergency demand / generation response (e.g. underfrequency load shedding, over-frequency generation shedding/special protection schemes) are within the scope of the RFR. (p. 4)	Commission has a comprehensive system security work program underway, which is coordinated with its reliability work program.
Environmental Performance Australia	My concern is that the concept of “reliability” as alluded to in the draft is meaningless. The scope of the review has been poorly formulated. Poor scoping will deliver poor outcomes. Reliability must also be defined in terms of response times and frequency, voltage and phase in the network. The framework review has not included price aspects. (p. 1)	Reliability in the NEM is separate from security. The Commission also has a power system security work program under way to address security concerns (such as voltage), which is coordinated with its reliability work program. Price (and cost) is implicit in the reliability framework in the NEM.
Dr Paul Kennedy	Dr Kennedy's submission recommended nuclear to solve the world's carbon emission and energy problem.	The Review assesses the market and regulatory framework that underpins reliability in the NEM. The Review assesses the framework from a technologically neutral approach.
Docklands Science Park	Docklands Science Park's submission recommended a particular technology to address the issues raised in the Reliability Frameworks Review.	The Review assesses the market and regulatory framework that underpins reliability in the NEM. The Review assesses the framework from a technologically neutral approach.
John Roberts	For each scenario considered by AEMC, the report must include the projected average wholesale electricity cost in $/MWhr. Australia must return to affordable and reliable electricity (p. 2).	The Review assesses the market and regulatory framework that underpins reliability in the NEM. The Commission's assessment framework involves trading off the costs and benefits of higher reliability.
Private individual	This individual's submission provided an example of what India is doing in the energy space.	The Commission notes this submission.
Bryan Leyland	A single buyer market where a central entity – as free as possible from government control – manages and	This type of market is outside of the scope of this

Stakeholder	Comment	Commission response
	optimises power generation, contracts with each existing generator on a long-term basis based on paying an annual sum to cover capital costs, operation and maintenance and profit and paying for fuel at cost is a much better option. (p.2)	Review.