RELIABILITY PANEL AEMC

REVIEW

Reliability Panel AEMC

ISSUES PAPER

Reliability Standard and Settings Review 2018

6 June 2017

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About the Reliability Panel
The Panel is a specialist body within the Australian Energy Market Commission (AEMC) and comprises industry and consumer representatives. It is responsible for monitoring, reviewing and reporting on reliability, security and safety on the national electricity system, and advising the AEMC in respect of such matters. The Panel's responsibilities are specified in section 38 of the National Electricity Law.

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1 Introduction

This issues paper has been prepared for the Reliability Panel's (the Panel's) reliability standard and settings review (the review). The Panel must publish its final report by 30 April 2018. The purpose of this paper is to facilitate consultation and seek stakeholder views.

This chapter:

- explains why the Panel is undertaking the review
- describes the review's scope and purpose
- outlines what happens with the recommendations from this review
- explains how you can provide input to the review, including on this issues paper.

1.1 The reliability standard and settings review

Under the National Electricity Rules (the rules) the Panel is required to carry out a review of the reliability standard and reliability settings every four years. This regular review allows the Panel to consider whether the current levels of the reliability standard and reliability settings remain suitable for expected market conditions, or whether changes should be made to ensure these mechanisms continue to meet the requirements of the market, market participants and consumers. The market environment and market arrangements are constantly evolving. Periodic review of the reliability standard and settings allows the potential impacts of changes to be assessed. If the reliability parameters were not regularly reviewed, they may not continue to allow appropriate price signals for investment. This would ultimately have a detrimental effect on the reliability of electricity supply to consumers.

Table 1.1 lists the reliability standard and reliability settings as at June 2017.

Table 1.1 Current reliability standard and reliability settings[1]

Reliability standard	The reliability standard for generation and inter-regional transmission elements in the national electricity market is a maximum expected unserved energy in a region of 0.002% of the total energy demanded in that region for a given financial year.
Market price cap	$14,000/MWh
Cumulative price threshold	$210,000
Administered price cap	$300MW/h
Market floor price	-$1000/MWh

1 Under the rules clauses 3.9.4 and 3.14.1, the Commission is required to adjust the market price cap and cumulative price threshold in line with the consumer price index by 28 February each year. Using the method set out in the rules, the values for the market price cap and the cumulative price threshold for the 2017-18 financial year are $14,200/MWh and $212,800 respectively, and will apply from 1 July 2017.

Many factors impact on investment and thereby system reliability

The scope of this review is limited to consideration of the reliability standard and the reliability settings. It is important to recognise that many factors bear on the investment environment in the energy sector and investment decisions in the national electricity market, and thereby reliability in the market. Some of these are internal to the market while others are external. While setting the reliability standard and the reliability settings at an appropriate level can *influence* investment in the market, they alone are not sufficient to ensure that investment to achieve the desired level of reliability actually occurs. There are many other factors that have an equally significant impact on participant investment decisions.

Market uncertainty—created by the absence of effective integration of emissions reduction and energy policy—is one factor currently impacting on investment in the market. The Panel considers that the Australian energy sector has suffered from a long vacuum around national, coordinated policy decisions. This has resulted in pervasive uncertainty, which makes it difficult for business and consumers to invest and undermines the reliability of power supply. A critical policy need is the effective integration of emissions reduction and energy policy.

Another source of uncertainty involves contract market conditions. The contract market is integral to the functioning of the physical national electricity market, despite being completely separate from it and the National Electricity Law and rules. In the national electricity market most consumers enter into fixed price contracts with their electricity retailers. Retailers then bear the risk associated with fluctuations in prices in the wholesale market.

The contract market provides a mechanism for retailers and other market participants to manage exposure to wholesale price volatility and uncertainty associated with the wholesale spot market outcomes. By providing options for greater certainty for retailers, generators, major industry and some consumers of electricity, the contract market provides a market-based mechanism to support efficient investment over time. Generators, through long-term off-take contracts, can obtain a degree of revenue certainty and secure project finance. Retailers on the other hand are able to deliver price stability for consumers and secure financing for their own operations. Contract market liquidity is important for the effective functioning of the national electricity market, and many factors impact on its liquidity. (The contract market is discussed further in Chapter 2.) Many factors bearing on investment decisions, contract market liquidity and contracting decisions are outside the scope of this review. The Panel will seek to make recommendations in the context of the issues as they exist today to the extent an issue and/or its impacts lie within the remit of this review.

The review is occurring at a time of transition in the sector

The Panel also acknowledges the significant changes underway in the energy sector and the national electricity market. Particularly relevant to this review are the changes in the generation fleet, such as retirement of large thermal units and the increased penetration of intermittent generation.[2]

Where relevant and to the extent possible, the Panel will consider these changes in the analysis we undertake in this review. In this issues paper we explain the trends in the market and our proposed approach to addressing them (Chapter 4). However, there are likely to be many changes and issues in the market that will fall outside of the scope of this review. The Panel will clearly identify where this is the case.

Reliability is distinct from system security

The term reliability has a specific meaning in the national electricity market.

"Reliability" of the power system is about having sufficient physical capacity in the system to generate and transport electricity to meet consumer demand.[3]

"Security" on the other hand relates to operating the power system within defined technical limits even if there is an incident, such as the loss of a major transmission line or large generator.

1.2 Scope and purpose of this review

Scope of this review

This review focuses on the reliability of the power system; specifically the reliability provided by power generation and interconnection assets.

The review does not address power outages caused by system security incidents. Issues related to system security are being progressed through the Commission's *System security market frameworks review*.[4]

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2 Consistent with the rules this paper uses the term 'intermittent generation' to describe a "generating unit whose output is not readily predictable, including, without limitation, solar generators, wave turbine generators, wind turbine generators and hydro-generators without any material storage capability" (Chapter 10, Glossary). The Panel recognises that other terms are in use such as 'variable renewable electricity generation', and that for the purposes of this review the subject of being 'not readily predictable' may benefit from elaboration.

The purpose of utilising a specific term to collectively refer to certain renewable technologies is to simplify discussion of the particular shared characteristics of their generation availability (or variability). See section 4.2.2 for a detailed discussion of the distinguishing availability characteristics of wind and solar technologies.

3 Unless otherwise stated, references to demand throughout this paper refer to operational demand, (consistent with the approach used previously by the Panel in the *Annual Market Performance Review*). Operational demand consists of electricity used by residential, commercial and large industrial consumers, as supplied by scheduled, semi-scheduled and significant non-scheduled generating units. Demand response activities and embedded generation are not included on the 'supply' (or 'capacity') side with large generating units. Instead these 'behind-the-meter' activities have the effect of reducing total demand. Nevertheless, behind-the-meter activities are relevant to reliability. As reliability relates to the ability to meet customers' demand for electricity, reductions in demand can make it easier to meet the desired level of reliability. For an explanation of scheduled, semi-scheduled and non-scheduled generating units see AEMC, *Demand side obligations to bid into central dispatch, consultation paper*, 2015, Sydney, pp. 2-3.

Reliability of the power system is a complex issue. Many factors impact on the system's overall reliability as well as the level of reliability a particular customer experiences. This review is limited to:

- Several key parameters that bear on reliability in the market—the reliability standard and the four reliability settings.
- The level of reliability provided by the power generation and inter-regional transmission assets (called "interconnectors").

The review does not evaluate other factors and processes that impact on system reliability, such as the powers of the Australian Market Operator (AEMO) to intervene in the operation of the market.[5] The Panel has other functions in relation to system reliability (and also system security). For instance the Panel publishes an annual review of the reliability, security and safety of the national electricity market. The Panel's report includes amongst other data, projections from AEMO that show there is a risk of insufficient of generation to meet peak demand in the future.[6]

Purpose of this review

The review is to consider the reliability standard and settings to apply on and from 1 July 2020.

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4 See the Australian Energy Market Commission's website at http://www.aemc.gov.au/Major-Pages/System-Security-Review. System security issues are dealt with under the system security provisions of the rules clauses 3.9.3C(b)(2)(ii) and (iii).

5 AEMO has powers to intervene in the market to address potential shortfalls of supply against the reliability standard. It has reliability and emergency reserve trader powers, and the power to issue directions to market participants under rules clauses 3.20.7(a) and 4.8.9(a). The reliability and emergency reserve trader powers allow AEMO to contract for reserves ahead of a period where reserves are projected to be insufficient to meet the reliability shortfall (known as a projected reserve shortfall). AEMO is able to dispatch these reserves to manage power system reliability and, where practicable, security. The reliability and emergency trader arrangements, or some form of power for the market operator to contract for reserves, have been a feature of the national electricity market since its commencement in December 1998.

AEMO also has the power to issue directions as a last resort measure to maintain power system security and reliability. AEMO may direct a registered participant to do any act or thing if AEMO is satisfied that it is necessary to do so to maintain or re-establish the power system to a secure operating state, a satisfactory operating state, or a reliable operating state. Where a direction affects a whole region, intervention or 'what if' pricing would be required. Under 'what if' pricing, the spot price is determined as if the direction had not occurred. AEMO also has powers of direction in regards to public safety. AEMO's powers of direction are set out in clause 4.8.9 of the rules.

Both arrangements are discussed further in Chapters 6 and 7. AEMO also holds Clause 4.8.9 instructions whereby AEMO can instruct Registered Participants with non-market, non-scheduled generating units or loads to maintain or re-establish the power system to a reliable operating state. These instructions include restoring load, in accordance with the Sensitive Loads and Priority Load Shedding Schedule procedure for the affected region. As a precursor to considering the use of reliability intervention mechanisms, AEMO may conduct informal negotiations with market participants. 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.

6 See Reliability Panel, *Annual market performance review 2016*, Final report, 16 May 2017, Sydney, available at www.aemc.gov.au

The purpose of this review is to:

- Consider whether the existing reliability standard remains appropriate for the market conditions expected from 1 July 2020.
- If the Panel considers that the existing reliability standard is not appropriate for the expected market conditions from 1 July 2020, recommend a revised reliability standard that should apply from 1 July 2020.
- Consider whether the existing reliability settings remain appropriate for the market conditions expected from 1 July 2020.
- If the Panel considers that the level of an existing reliability setting is not appropriate for expected market conditions from 1 July 2020, recommend the level appropriate to that reliability setting that should apply from 1 July 2020.
- Propose changes to the rules to implement any recommended changes arising from the review.

1.3 Requirements for this review

The Panel is undertaking this review in accordance with: the rules; the terms of reference issued by the Commission; and the Panel's *Review of reliability standard and settings guidelines* (the guidelines).[7]

Following the completion of this review, the Panel must submit any recommended changes to the reliability standard or a reliability setting to the Commission as a rule change request.

1.4 Consultation process and submissions

The Panel will consult with stakeholders by seeking comments on this issues paper and a subsequent draft report. We will also hold at least one public meeting.[8] The key dates are shown in table 1.2.

Table 1.2 Indicative review timetable

Issues paper – close of consultation	12 July 2017
Draft determination – consultation	November 2017
Final determination published	March/April 2018

The Panel invites comments from interested parties in response to this issues paper by 12 July 2017. All submissions will be published on the Commission's website.

Electronic submissions must be lodged online through the Commission's website www.aemc.gov.au using the link entitled "lodge a submission" and reference code "REL0064". The submission must be on letterhead (if submitted on behalf of an organisation), signed and dated.

7 Reliability Panel, *Review of reliability standard and settings guidelines*, final guidelines, 1 December 2016, Sydney. The guidelines and the terms of reference are available at www.aemc.gov.au

8 The rules require that the Panel follow the rules consultation procedures in carrying out this review. The rules consultation procedures are set out in section 8.9 of the rules.

If choosing to make submissions by mail, the submission must be on letterhead (if submitted on behalf of an organisation), signed and dated, and posted to:

Reliability Panel

c/- Australian Energy Market Commission

PO Box A2449

SYDNEY SOUTH NSW 1235

1.5 Structure of this issues paper

The remainder of this issues paper is set out as follows:

Chapter 2: Describes the roles of the reliability standard and the reliability settings, and the links between them.

Chapter 3: Explains how the Panel will conduct this review.

Chapter 4: Outlines key trends and policy uncertainties, and our proposed approach.

Chapters 5 – 9: Explain the assessment we will undertake of the reliability standard, the market price cap, the cumulative price threshold and the administered price cap, the market floor price, and pose questions for your comment.

Chapter 10: Describes the proposed modelling approach and seeks your input.

2 Overview of the reliability standard and settings

The term reliability has a distinct meaning in the national electricity market. Understanding reliability and the parameters that bear on reliability outcomes in the market is critical to this review.

This chapter:

- describes what reliability means (and how it differs from system security)
- explains the role of the reliability standard in the national electricity market
- explains the role the reliability settings serve in the market
- describes the connection between the reliability standard and the settings.

2.1 What is reliability?

A reliable supply of electricity requires generators to produce electricity and the transmission and distribution networks to transport the electricity to customers.

As a result, a reliable supply of electricity to customers requires adequate system planning, capacity availability and maintenance of all parts of the electricity supply chain.

Power outages that customers experience can be planned or unplanned. Planned outages generally occur so that maintenance or construction can be undertaken on generators, or the transmission or distribution networks. An unplanned interruption to electricity supply to consumers can be caused by a number of factors including:

- An incident such as a storm that brings down a major transmission line, making it difficult for the power system to operate within its defined technical limits.
- Disruptions to or outages in the transmission and distribution “poles and wires” within a region, causing difficulties in supplying electricity to homes and/or businesses.[9]
- A lack of sufficient generation capacity and/or transmission capability between regions to supply and meet demand for electricity at a particular point in time.

The first of these factors relates to system security, while the second and third relate to reliability of the power system overall.

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9 There are five regions in the national electricity market: Queensland, New South Wales (including the Australian Capital Territory), Victoria, South Australia and Tasmania. Chapter 10 of the rules defines a region as: “[a]n area determined by the AEMC in accordance with Chapter 2A [of the rules], being an area served by a particular part of the transmission network containing one or more major load centres or generation centres or both.” AEMO prepares a “regions publication” under clause 2A.1.3 of the rules that amongst other lists all regions. See AEMO, *Regions and Marginal Loss Factors FY2017-2018*, 2017, Sydney, p. 47.

Reliability is distinct from system security

To "keep the lights on", the power system overall needs to be:

- Reliable – have enough capacity (generation and networks) to supply customers.
- Secure – 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.

While "security" relates to the stability of the power system, "reliability" of the power system is about having sufficient capacity to generate and transport electricity to meet consumer demand.[10]

While these two concepts are often described separately they are closely related. As recently described by the Commission:

> A reliable power system is one that has a high likelihood of fully servicing the electricity needs of customers. A reliable power system is one which is in a secure operating state, has sufficient generation capacity, and a reliable transmission and distribution network.
>
> A secure operating state is one where the power system is in, or can be returned within 30 minutes, to a satisfactory operating state.[11]
>
> A reliable power system is also a secure power system. However, the converse is not necessarily true; a power system can be secure even when it is not reliable. The National Electricity Rules (NER or [r]ules) allow AEMO to undertake involuntary load shedding, potentially compromising reliability, in order to return the power system to a secure operating state. [12]

If there is an event or incident its classification as a system security or reliability event generally depends on the initiating occurrence.[13]

The black system event in South Australia in September 2016 was a power system security event and not the result of insufficient generation being available. The 8 February 2017 load shedding event in South Australia was partly due to

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10 Taking into account any reductions in total demand caused by demand response mechanisms and behind-the-meter generation, as discussed in section 1.1.

11 As cited in the AEMC paper (see subsequent footnote), rules clause 4.2.4A. A satisfactory operating state is defined in NER clause 4.2.2. The power system is in a satisfactory operating state when all vital technical parameters (such as voltage, frequency, and equipment loads) are within their design limits and ratings.

12 AEMC, *Extension of the Reliability and Emergency Reserve Trader, Rule Determination*, 23 June 2016, Sydney, p. 1.

13 The Panel acknowledges the complex relationship between a 'reliability incident and a 'security' incident. For example, if a reliability incident such as a shortfall in available capacity in a region is not addressed through an action like manual load shedding, this would result in the power system being in an insecure operating state. This in turn could trigger a security incident following a contingency which may result in a major supply disruption such as operation of the automatic load shedding scheme or even a system black. As such, while these events are classified separately, the Panel notes that both may result in loss of supply and therefore are more or less indistinguishable for consumers.

unprecedented hot weather on a weekday. The event related to reliability as there was insufficient generation available at that time to meet demand.[14]

Reliability for this review depends on two components of the electricity system

The reliability that customers experience is a combination of the services provided by generators, transmission networks and distribution networks. Most of the power outages that customers experience are due to issues on the distribution networks.

The scope of this review is limited to the reliability provided by the generation assets and inter-regional transmission assets (that is, the inter-connectors between regions). [15]

State and territory governments set the level of reliability that must be provided by transmission and distribution networks within a region (the "poles and wires").[16]

2.2 The reliability standard

A reliability standard has been a part of the national electricity market since it was established in 1998. The national electricity market and the energy sector more generally are not unique in using a reliability standard. The water and transport sectors, for instance, also use a standard to express the level of reliability sought from their systems.

The concept of a reliability standard essentially is an acknowledgement that building assets sufficient to meet all consumers' demand all of the time comes at a significant cost. A reliability standard expresses a decision about the trade-off between the level of service sought and the cost incurred to provide that level of service.

The trade-off the Panel is making when it sets the level of the reliability standard

As Figure 2.1 illustrates the setting of a reliability standard in the national electricity market embodies a trade-off, made on behalf of consumers, between the prices paid for electricity and the cost of not having energy when we need it. Consumers could have less unmet demand (greater reliability) but that would increase the cost of providing energy, which would lead to higher prices for consumers.

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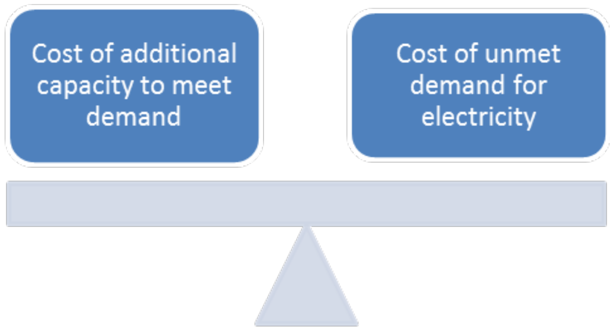
14 One of the contributing factors was that Engie did not bid its second unit into the market despite market notices earlier in the day seeking responses to an impending lack of reserves. Engie stated that one of the reasons it could not bid into the market was because it did not have gas. See AEMO, *System event report South Australia 8 February 2017*, *Reviewable operating incident report for the national electricity market*, 15 February 2017, Sydney, p. 5.

15 Rules clause 3.9.3C.

16 Each state and territory government retains control over how transmission and distribution network reliability is regulated and the level of reliability that must be provided. Reliability standards relate to how the transmission and distribution networks can withstand risks without consequences for consumers, and guide the level of investment that networks undertake. The reliability standards that transmission networks need to meet are generally set in advance of a transmission business' decision to invest and are set in place for a fixed period of time. The exception is in Victoria where reliability levels are determined at the time an investment need arises. Transmission reliability standards are generally planning standards, rather than outcomes based, as outages are rare. In comparison distribution reliability standards are generally outcomes based rather than planning standards, as outages are common.

Figure 2.1 The trade-off inherent to a reliability standard



More specifically, in setting the reliability standard for the national electricity market the Panel is making a trade-off between two sets of costs (assuming in both cases that demand remains unchanged).[17] That is the:

- **Cost of additional capacity** – higher levels of reliability require more investment in power generation capacity, and so a higher cost per unit of energy supplied to ensure financial viability. These costs are reflected in consumer prices.
- **Costs of unserved energy** – the alternative is not to supply the energy, that is to allow a higher expected level of supply interruptions to consumers. This too has costs, which are the costs of not having energy when we need it (known as the value of customer reliability).

The trade-off is expressed as the proportion of expected energy demand that is at risk of not being supplied to consumers—termed "unserved energy"—in a region in a given financial year.

The objective of the analysis and modelling undertaken in each review is to help the Panel make this trade-off, by providing information about the cost of achieving higher levels of reliability. As there are limitations to any modelling approach the Panel also considers a range of qualitative issues, such as the benefit of regulatory stability.

The role of the reliability standard in the national electricity market

In the national electricity market the reliability standard is an ex-ante planning standard. It is not a regulatory or performance standard that is "enforced". Rather it is a planning standard which planning and operational processes associated with generators and interconnectors, undertaken by AEMO, must seek to satisfy.[18]

The reliability standard is an expression of the reliability sought from the national electricity market's generation and inter-connection assets, which form the basis of the

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17 Note that if the Panel determines that the level of the standard should be changed, it is the decision of the Commission through a rule change request by the Panel, to determine whether that recommended change be made to the rules.

18 By national electricity market 'planning processes' we are not referring to AEMO's annual *National transmission network development plan* nor transmission service providers' *Annual planning reports*.

wholesale supply of electricity. It is used to indicate to the market the required level of supply to meet demand in a given financial year in a region; Queensland, New South Wales (including the Australian Capital Territory), Victoria, South Australia and Tasmania.

The reliability standard feeds into various wholesale pricing parameters (the reliability settings) that form part of the framework in which investment decisions are made.

It is also a key input into AEMO's planning and operational decisions.[19] In relation to planning and operationalising the reliability standard, AEMO performs the following functions:[20]

- Assess whether the power system meets, and is projected to meet, the reliability standard.
- Identify and quantify any projected failure to meet the reliability standard.
- Publish forecasts regarding reliability and its components to inform market participants, network service providers and potential investors, over ten year, two year and six day outlooks.[21]
- Monitor demand and generation capacity and, if necessary, initiate action in relation to a relevant AEMO intervention event to maintain the reliability of supply and power system security where practicable. This may include:
  - Publishing information about the potential for, or the occurrence of, a situation that could significantly impact, or is significantly impacting, on power system security.
  - Advising of any low reserve conditions for the relevant period.
  - Declaring a low reserve condition when AEMO considers the balance of generation capacity and demand for the assessment period does not meet the reliability standard.
  - Declaring a lack of reserve level 1, 2 or 3 to advise whenever capacity reserves reduce below the level required to manage credible contingency events.
  - Following the processes set out in the rules if AEMO declares a lack of reserve or low reserve condition event, including publishing any foreseeable circumstances that may require AEMO to implement an intervention event

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19 AEMO's *Reliability Standard Implementation Guidelines* set out how AEMO implements the reliability standard. See AEMO, *Reliability standard implementation guidelines final October 2016*, 2016, Sydney.

20 In accordance with the Reliability Standard Implementation Guidelines See AEMO, *Reliability standard implementation guidelines final October 2016,* 2016, *Sydney,* pp. 4-5.

21 AEMO implements the reliability standard using forecasts and projections over different timeframes. AEMO uses the following processes:
1. Electricity statement of opportunities to provide market information over a ten year projection to assist planning by existing and potential generators and market participants.
2. Energy adequacy assessment projection to forecast unserved energy for energy constrained scenarios over a two year projection.
3. Medium Term Projected Assessment of System Adequacy to forecast peak capacity reserve conditions over a two year projection.
4. Short Term Projected Assessment of System Adequacy to forecast capacity reserve over a six-day projection.

For further information see AEMO, *Reliability standard implementation guidelines final October 2016,* 2016, *Sydney,* pp. 7-15.

(for instance issuing an instruction or direction, or exercising reliability and emergency reserve trader powers).

The reliability standard provides a clear, actionable expression of the minimum generation and transmission capacity sought for the national electricity market.

The current reliability standard

The reliability standard requires that there be sufficient generation and transmission interconnection in a region such that at least 99.998 per cent of annual demand for electricity is expected to be supplied. The standard in fact specifies the *maximum expected unserved energy* or the amount of electricity demanded by customers *which is at risk of not being supplied*. It is currently set at 0.002 per cent of each region's annual energy consumption in a financial year.

It is important to note that by "expected" we mean a forward looking concept applied to each year as a discrete interval. As outlined previously the critical part of the definition of the reliability standard is that it is an ex-ante planning standard—a key input to relevant national electricity market planning and operational processes. It is not an operational standard, which the system either "succeeds" or "fails" in meeting in any given period. For example, if one year the level of unserved energy in a region exceeds the level of the reliability standard, this does not mean the standard has "failed". Rather, it indicates that actual supply outcomes for consumers did not align with the expected outcomes in the reliability planning and operational processes.

The history of the reliability standard is summarised in Appendix A and discussed further in chapter 5.

2.3 The reliability settings and the reliability standard

The remainder of this chapter explains the purpose of the reliability settings and their relationship to the reliability standard. In the first instance it is useful to revisit from an economic perspective the fundamental approach to price setting in the national electricity market.

The wholesale pricing framework

Like any market, the national electricity market was established utilising a certain pricing framework, in this case, a gross pool design with mandatory participation. Generators sell all of their electricity through the market, which matches supply to demand instantaneously. From the generators' offers, the market dispatch engine determines the combination of generation to meet demand in the most cost-efficient way, given the physical limitations of the power system. AEMO then issues dispatch instructions to these generators.

Underpinning this framework is the economic principle that the most efficient investment decisions are made if market participants can make their own decisions in response to price signals. A market price provides the signals needed for investors to make their own, informed investment (and divestment) decisions.

Since the market was established in 1998 the pricing framework has included a *maximum limit (cap)* and *minimum floor* on wholesale prices. Collectively these establish an envelope within which prices can vary. The current price parameters – the reliability settings – are:

- To limit high prices:
  - the market price cap
  - the cumulative price threshold and the associated administered price cap.[22]
- To limit low prices:
  - the market price floor.

Most consumers do not directly face wholesale market prices

It is important to note that while retailers and some large industrial consumers are exposed to variable prices of electricity in the wholesale market, most consumers—for instance small businesses and families—are not directly exposed to spot market prices. Rather, retailers act as intermediaries on behalf of consumers. Retailers purchase electricity on the spot market and manage price risk through participation in the parallel financial contracts market (see the section below on the reliability settings and the contract market).

The electricity price most consumers pay is the price they negotiate with their energy retailer. Nonetheless, these consumers are indirectly affected by conditions and prices in the wholesale spot market through the price they pay to the retailer. So spot market conditions, wholesale contract market conditions, wholesale market risk and importantly, the reliability standards and settings are relevant to all consumers.

The role of price settings in the national electricity market

The role of the price settings collectively in the national electricity market is to limit market participants' exposure to extreme prices. They do so by placing an "envelope" around the maximum and minimum possible prices that participants may experience in the market. In doing so, the settings promote the long-term integrity of the national electricity system for the long term interests of electricity consumers. However, the settings should allow for the market to send the price signals needed to support efficient operational and investment decision.[23]

Markets rely on the presence of willing participants. A principal consideration for participants is the risk that they are exposed to in a market. In the absence of market

22 The cumulative price threshold was established in December 2000 following a recommendation by the Panel.

23 The Panel acknowledges that the guidelines have a slightly different emphasis regarding the role of the market price cap, wherein its primary purpose is presented as facilitating efficient price signals in the market, with a secondary purpose of managing participant exposure to price risk. The characterisation of the settings overall in this chapter (and the subsequent discussion of the market price cap in Chapter 6) places more emphasis on the second purpose – the management of exposure to high prices – but is nevertheless consistent with the function of the reliability standard and settings.

price limits, purchasers of energy (as price takers) could be exposed to potentially unlimited energy cost risk in any dispatch interval. Such an extreme level of risk may make it unlikely that purchasers would be willing to participate in the market.

Similarly, in the absence of a market price cap, generators could be unwilling to provide energy on a "firm" basis – that is, they would not be willing to enter into contracts as by doing so the generator would take on the (limitless) exposure to movements in spot prices. Were the generator to have a technical difficulty limiting generation, or be constrained off at a time of high prices, it would have unlimited financial exposure.

In this, admittedly extreme, example a participant could stand to lose its entire business in a matter of hours. Such a level of risk threatens the integrity of the market, because it deters rather than supports use of the market.

Through the price setting process, markets align the costs and risks of consuming a service with the costs and risks of providing that service. A purist economic approach would warn against imposing any constraints on the prices that can occur in a market. But there is a point at which there are diminishing benefits in increasing market participants' exposure to price risk.

Placing some limits on participants' exposure to very high and very low prices to protect the integrity of that market is a feature of markets in many sectors. This is particularly important given the physics of electricity supply systems that require the instantaneous matching of demand and supply which is done through a focus on the supply side.

Although the reliability settings limit participant exposure to extreme prices, participants adopt their own strategies to mitigate or manage their overall exposure to price risk in the market. This may include vertically integrating to internally hedge their risk. Participants may also use the contract market. The contract market, mentioned earlier, is distinct from the electricity law and rules and has been integral to the national electricity market since its inception (see discussion later this chapter).

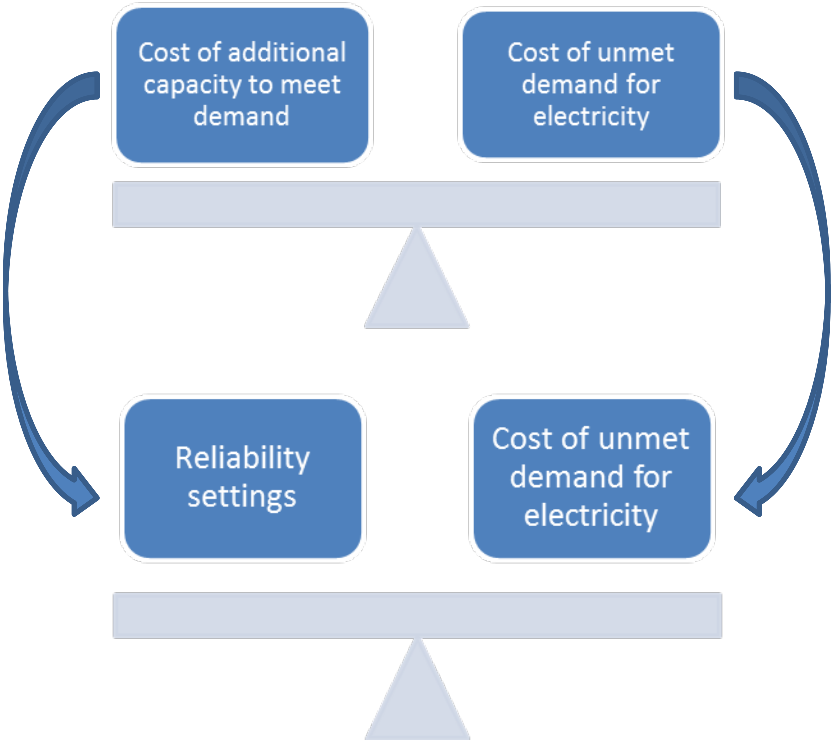
Linkage between price settings and the reliability standard

We noted previously that the reliability standard fundamentally involved a trade-off between price and unmet demand. We could have less unmet demand (greater reliability) but that would raise the price. The level at which the reliability standard is set reflects the Panel's view of the optimal trade-off.

If we were in a market with a reliability standard and a single, wholly regulated price, then that single price would be set at the price point of the trade-off embodied in the reliability standard.

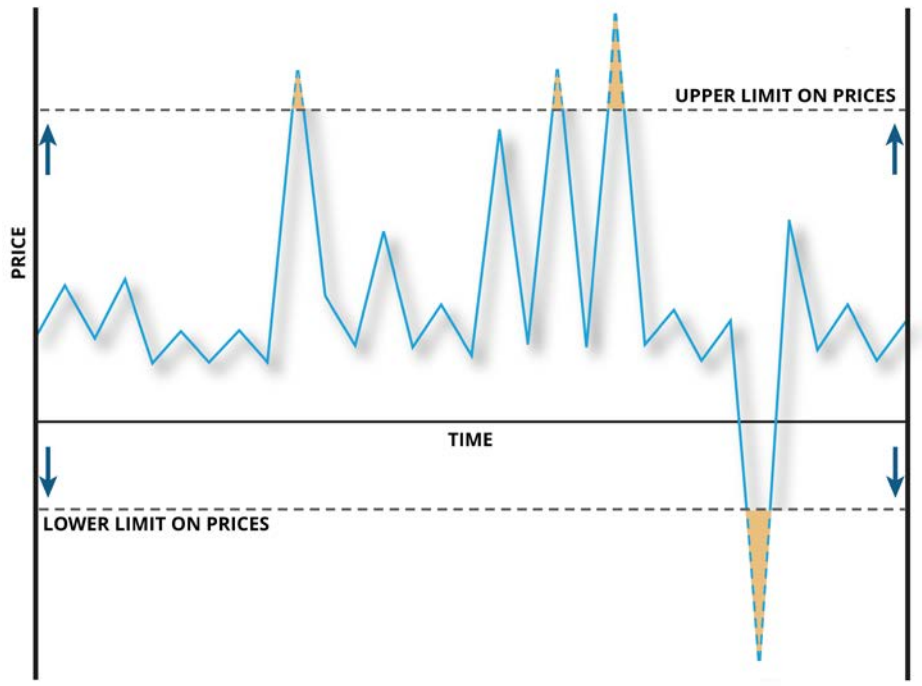
However the pricing framework for the national electricity market involves price variability within an envelope established by the price settings. As illustrated in Figure 2.2, in simple terms the price trade-off inherent in the level of the reliability standard is related to the pricing framework specific to the national electricity market.

Figure 2.2 How the reliability standard trade-off links with the reliability settings



The price settings should support investment signals sufficient to supply consumer demand for energy at least to the level of the reliability standard. The price settings are after all termed the "reliability settings". Figure 2.3 illustrates the role of price settings in limiting market participants' exposure to high and low prices, and delivering capacity to meet consumer demand at least to the level of the reliability standard.

Figure 2.3 Illustration of the role of price settings



The reliability settings

The four reliability settings are the:

- market price cap
- cumulative price threshold
- administered price cap
- market floor price.

As shown in Figure 2.4 the four reliability settings seek to limit different types of exposure to extreme prices.

Figure 2.4 Type of price risk exposure targeted by each reliability setting

High prices	Temporary	Market price cap
	Sustained	Cumulative price threshold
		Administered price cap
Low prices	Temporary	Market floor price

The **market price cap** is the maximum market price that can be reached in any dispatch interval and in any trading interval.[24] It is indexed to movements in the consumer price index each financial year. The market price cap is currently set at $14,000/MWh.[25]

The **cumulative price threshold** limits participants' financial exposure to the wholesale spot market during *prolonged* periods of high prices. It limits the total market price that can occur over a period of one week (336 trading intervals), before an administered pricing period is declared.[26] The cumulative price threshold can be triggered in different ways. For example, it could be triggered after many days of sustained high but not extreme prices (in the order of $625/MWh). It can also be breached in just a few hours if prices are at or close to the market price cap ($14,000/MWh). The

24 While the market price cap is in effect the maximum that can be reached in any trading interval it is defined in the rules as ‘a price cap which is to be applied to dispatch prices’. Rules, clause 3.9.4(a).

25 With indexation the values for the market price cap and the cumulative price threshold for the 2017-18 financial year are $14,200/MWh and $212,800 respectively and will apply from 1 July 2017.

26 Rules, clause 3.14.2(c)(1). An administered price period is triggered where the cumulative price threshold is reached at any point over a seven day period. Once an administered price period is triggered, the administered price cap applies (see subsequent paragraph). In addition, an administered price period in relation to ancillary service markets will apply where the cumulative price threshold for market ancillary service exceeds six times the cumulative price threshold.

cumulative price threshold is indexed to consumer price index and is currently $210,000.[27]

The **administered price cap** is intended to cap participants' exposure to sustained high prices. It is the maximum settlement price that can apply if the cumulative price threshold is reached over a seven day period (triggering an administered price period). It is currently set at $300/MWh.[28]

The **market floor price** is the minimum price that can be achieved in any dispatch and trading interval. Its purpose is to prevent market instability by imposing a negative limit on the total potential volatility of market prices. The market floor price bears on the clearing of supply and demand at times of low demand and excess generation. It is currently set at -$1,000/MWh.[29]

Chapters 5 to 8 address each of the reliability settings in turn, providing significantly more detail. The history of the reliability settings is summarised in Appendix A and discussed in the individual chapter on that setting where appropriate.

What the reliability settings do not do

The reliability settings create a price envelope intended to allow for the market to send the necessary price signals to deliver generation and interconnection capacity in the electricity system needed to meet consumer demand for energy at least to the level of reliability standard.

But the reliability settings do not guarantee that the particular outcome sought will in fact occur. Many factors – both within and external to the national electricity market—influence investors' decisions regarding electricity generation. Some of these factors are discussed in the following chapter.

Interrelationship between the standard and the settings

In practice, assessing the reliability standard and settings can be an iterative process. While the Panel typically starts from the existing level of the reliability standard to assess the level of the reliability settings, analysis of the settings can in turn provide insights into the potential outcomes of, and thereby help assess the appropriateness of, the reliability standard level.

27 The cumulative price threshold is also relevant to FCAS markets, as detailed in the chapter dealing specifically with the cumulative price threshold. For FCAS markets, an administered pricing period is declared after 2,016 dispatch intervals, if the cumulative price is 6 times the cumulative price threshold reflecting the five minute settlement period applicable to FCAS markets compared to the 30 minute settlement applicable to the electricity spot market. National Electricity Rules, clause 3.14.2(c)(1A).

28 Rules clause 3.14.1(a).

29 Rules clause 3.9.6(b).

The reliability settings and the contract market

As outlined previously, as many consumers transfer the risk of exposure to high wholesale prices to their retailers through fixed price contracts, retailers often rely on the contract market to manage their exposure to wholesale spot market risk.[30]

The reliability settings impact on the contracts market by constraining prices and price risk exposure in the spot market. This then influences market participants' pricing of, and demand for financial hedge contracts, which in turn impacts on participant investment and operational decisions.

For example, a wider price envelope may create an expectation of future high prices in the spot market and therefore increased potential price risk. This will increase generator price expectations and retailer demand for contracts, causing contract prices to rise. This creates incentives for investors to enter into contracts, which may act to underwrite new investment in generation. Conversely, the expectation of future low prices in the spot market will lower contract prices, which in turn reduces the incentive for potential investors to enter into contracts to underwrite new investment.

However, a wider pricing envelope can also increase the extent of down side risk to which participants are exposed. This is directly related to contract markets.

For example, as noted previously, a generator that suffers an outage may be unable to meet a contracted position. In such an event, the generator may suffer significant financial losses if it is unable to generate during periods of high market prices but is still required to pay out on its' contract position. The wider the boundaries of the price envelope the greater the extent of this potential risk for generators. This may impact on the appetite of generators to enter into contracting arrangements and may therefore influence investment and operational decisions.

These two examples demonstrate that changes to the pricing envelope established by the reliability settings can have a number of impacts in terms of contract markets and therefore investment and operational decisions.

Overview of the contract market

The contract market is a critical risk management tool for participating in the national electricity market. It allows market participants to hedge against fluctuations in prices in the spot market (both high and low) by entering into contracts.

From a retailer perspective, a fundamental driver of the contract market is the fact that many consumers enter into fixed price contracts with their retailer.[31] To the extent that consumers do enter into fixed price contracts with a retailer, the risks associated with exposure to high wholesale prices is held by the retailer.

30 See box:"Overview of the contract market".

31 The alternative is entering into a supply contract that passes the wholesale spot prices through to the consumer (ignoring the option of the consumer participating directly in the wholesale market).

A retailer may seek to manage that price risk by:

- Entering into a hedge contract with a generator in which case the price risk is passed to the generator, since if the generator is not generating at the time of a high price it will be financially exposed. This influences the generator's investment (capital) and operational (e.g. maintenance timing and fuel purchase) decisions.
- Directly acquiring generation to mitigate some or all of the price risk. That is, vertical integration enabling hedging to be undertaken within the corporation.
- Entering into demand-side arrangements to manage supply-side volumetric requirements.

Alternatively a retailer may choose to remain exposed to the spot market.

From a generator perspective, the risk of sustained or low average prices has the potential to undermine financial viability and creates an incentive to lock in some level of revenue certainty based on future expected prices, although as for retailers, generators may choose to remain exposed to the spot market.

In effect, contracts allow market participants to buy future generation or demand at prices consistent with their business strategy and risk appetite. Contracts allow generators and retailers to convert uncertain future spot market prices into more certain wholesale prices to better match upstream or downstream obligations that are also relatively stable across time. Contracts are settled by reference to the spot market price for the region in which their electricity production or consumption occurs.

Hedging risk can significantly reduce market participants' (and ultimately consumers) exposure to high price events and price volatility. By helping to smooth their future effective wholesale revenues or payments, contracts (including long-term power purchase agreements) lower participants' risk profiles and increase the ease with which they can obtain equity and debt financing from suppliers of capital.
A liquid contract market helps facilitate efficient generation investment and retirement decisions in the national electricity market.[32]

32 The description of the contracts market in this section is drawn from the Commission's submission to the Independent Review into the Future Security of the National Electricity Market, March 2017, available at http://www.aemc.gov.au/News-Center/What-s-New/Announcement-Documents-(non-project)/AEMC-submission-to-the-independent-review-on-the-f.aspx. Further information on contracts markets can be found in the submission from p. 19.

3. How the Panel will conduct this review

The Panel must apply a specific framework when assessing the reliability standard and settings. This chapter describes that assessment framework. Specifically it explains that:

- the Panel is guided by the national electricity objective in undertaking the review
- only certain components of the reliability standard and settings are to be reassessed
- we must use specific criteria to assess each component.

3.1 Promoting the national electricity objective

The national electricity objective is the goal (or objective) of the National Electricity Law, the legislation under which the Panel is established.

The Panel must be guided by the national electricity objective when it undertakes its assessment and makes recommendations for this review.[33]

The national electricity objective is:

> to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system.[34]

The objective is the achievement of efficient investment in, and operation and use of, electricity services in the long-term interests of consumers.

The national electricity objective also includes a specific set of variables – price, quality, safety, reliability and security of supply. The Panel must consider how the outcome of a particular decision would impact on these variables, where relevant. For this review, the most relevant variables are price and reliability.

The question the Panel is to answer through this review is therefore whether a recommendation to change the reliability standard or (one or more of) the reliability settings would likely promote more efficient investment in and operation and use of electricity services, which would ultimately promote the long term interests of consumers *with respect to price and reliability of supply of electricity and the reliability of the national electricity system*.

More information about how the Commission and Panel interpret the national electricity objective can be found in *Applying the energy objectives, a guide for stakeholders*.[35]

33 Guidelines p. 2.

34 National Electricity Law section 7.

35 AEMC, *Applying the energy objectives, a guide for stakeholders,* December 2016, Sydney.

In 2016 additional guidance was published regarding applying the national electricity objective when undertaking this review.[36] The Panel is to be guided by the following general principles in order to meet the national electricity objective: [37]

- **Allowing efficient price signals while managing price risk**: The Panel will exercise its judgment so as to allow the market to send efficient price signals while limiting price risk exposure for participants.
- **Delivering a level of reliability consistent with the value placed on that reliability by customers:** The Panel will have regard to estimates of the value placed on reliability by customers to exercise its judgment as to the level of the standard. The settings should be sufficient to support the level of investment necessary to deliver the standard, over the long run.
- **Providing a stable, predictable and flexible regulatory framework**: The Panel will exercise its judgment to achieve predictable outcomes, while reflecting significant changes in market conditions, to support efficient investment and operational decisions by participants.

3.2 What the Panel will review

Not all the components of the reliability standard and settings are automatically subject to review.

In 2016 the Panel determined that only certain components would be automatically reviewed every four years.[38] The Panel took this decision to deliver both a stable and flexible regulatory framework for system reliability. The level of the market price cap and the cumulative price threshold are the only two parameters that are automatically reassessed every four years.

Other parameters are subject to a materiality assessment at each review. This means that the Panel will only open these parameters for reassessment when it considers there is likely to be a material benefit in doing so. The existing levels of the reliability standard, the administered price cap and the market floor price are subject to a materiality assessment. These will remain unchanged unless the Panel considered there may be material benefit in reassessing them, determines through a reassessment that they should be amended, and then submits to the Commission through a rule change request that they be amended.[39]

36 Reliability Panel, *Review of reliability standard and settings guidelines final determination*, December 2016, Sydney (Guidelines Determination).

37 Full details are provided in the Guidelines Determination, section 2.

38 Guidelines pp. 4-9.

39 Guidelines pp. 4-9. A party could still submit—through a rule change request to the Commission—for a change to the reliability standard or reliability settings.

Other components are not subject to a four-yearly review at all. These are:

- The various measures (or metrics) used to express the reliability standard and each of the settings. For instance, the administered price cap will remain "a $/MWh value".[40]
- The annual indexation of the market price cap and the cumulative price threshold (and the non-indexation of the market floor price and the administered price cap).

Figure 3.1 shows the various components of the reliability standard and settings that are to be considered in this review and the nature of our consideration.

Figure 3.1 Components of the reliability standard and settings that will be reviewed

	Reliability standard	Market price cap	Cumulative price threshold	Administered price cap	Market floor price
Level	Materiality assessment	Automatically reassessed	Automatically reassessed	Materiality assessment	Materiality assessment
Basis of indexation		Materiality assessment	Materiality assessment		

3.3 The assessment criteria to be applied

The Panel's assessment framework is based on a series of obligations that are set out in the rules and the guidelines. It is the Panel's intention that the assessment framework, as well as our analysis and findings against this assessment framework, will be transparent and open to stakeholder input.

Figure 3.2 provides a graphical outline of the assessment process.

The Panel has divided the assessment criteria into two main types:

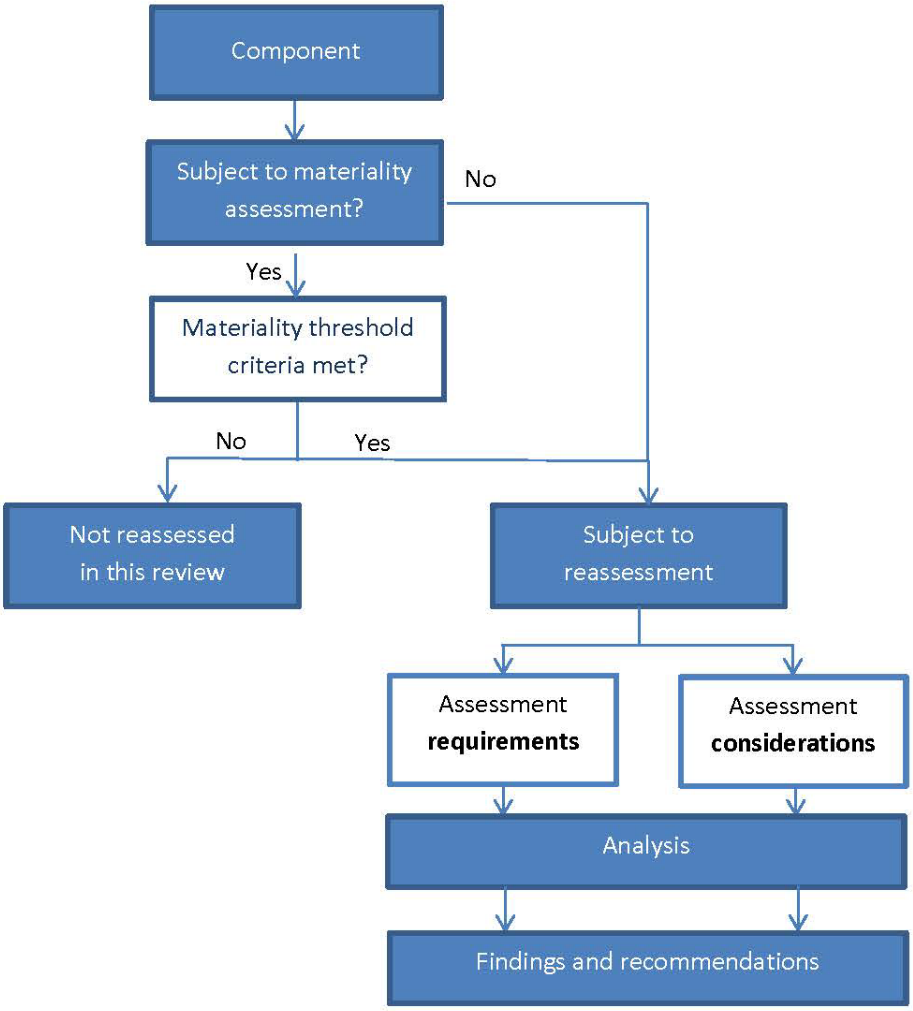
- ***Materiality threshold criteria.*** These are the criteria set out in the guidelines that are used by the Panel when assessing the reliability standard and the various settings that are subject to a materiality assessment (outlined in Figure 3.1).
- ***Assessment criteria:*** These are the criteria set out in the rules that the Panel considers when reassessing the reliability standard or a setting. In considering these criteria it is useful to differentiate between:
  - *Assessment **requirements*** – a condition that the Panel must meet when undertaking its review.
  - *Assessment **considerations*** – factors or impacts to which the Panel must (or may) have regard.

40 Guidelines p. 8.

For instance, in relation to the assessment criteria, in setting the level of the market price cap the Panel:

- May only recommend a market price cap that the Panel considers will allow the reliability standard to be satisfied without use of AEMO's powers to intervene, an assessment *requirement*.[41]
- Must have regard to the potential impact of any change to the market price cap on investment in the national electricity market, an assessment *consideration*.[42]

Figure 3.2 Assessment process and type of assessment criteria



The materiality threshold criteria and the assessment criteria, and hence the entire assessment framework the Panel will apply in undertaking the review, are established in the rules and the guidelines.

It is important to note that some assessment criteria (requirements or considerations) are specific to a particular reliability parameter. Others apply to the entire review

41 Rules, clause 3.9.3A(f).

42 Rules clause 3.9.3A(e)(3)(ii).

and/or several of the reliability standard or settings. These overarching assessment criteria are that the Panel:[43]

- Must have regard to the potential impact of any proposed change to a reliability setting on: (i) spot prices; (ii) investment in the National Electricity Market; (iii) the reliability of the power system; and (iv) Market Participants.
- Must have regard to any value of customer reliability determined by AEMO which the Reliability Panel considers to be relevant.
- Must have regard to the terms of reference provided by the Commission.
- Must comply with the reliability standard and settings guidelines, and may take into account any other matters specified in the guidelines or which the Panel considers relevant.

We detail the assessment criteria pertaining to each individual reliability parameter in chapters 5 - 9 and highlight relevant overarching assessment criteria.

43 Rules clause 3.9.3A(e).

4 Trends in the energy sector

Since the last review of the reliability settings in 2014, there have been significant changes in the national electricity market and the broader policy environment that bear on this review's approach.

Against this background, this chapter:

- outlines the Panel's overall approach in this review to change and uncertainty
- describes emerging market trends and how they may influence this review
- explains how the Panel will address policy developments and uncertainties.

4.1 The Panel's approach

We are undertaking this review at a time of significant change and uncertainty

The purpose of this review is to recommend the reliability standard and reliability settings that should be in place from 1 July 2020. Given this medium-term time horizon, for this review the Panel is necessarily concerned with the trends in the physical energy system, in the energy market and in the broader policy environment.

The Commission recently published a draft report analysing the drivers of future generation and transmission investment, in response to a request by the COAG Energy Council.[44] The draft report provides a qualitative assessment of the change in investment drivers since 2015. It identifies a growing uncertainty regarding future government environmental policies, and a rapid pace of technological development, deployment of new, non-synchronous generating technologies, and changing costs and cost relativities. Other developments impacting on the energy market include developments in wholesale markets, and in national electricity market rules and regulations.[45] The Commission concludes that "[t]here appears to be a large degree of uncertainty regarding future patterns and drivers of generation and transmission investment".[46]

We are currently facing transformational change of the energy system, the energy market and the policy environment, as well as uncertainty regarding the drivers and patterns of investment. Many of these trends and developments are likely to affect the national electricity market over the period of interest for this review.

Trends that have emerged, or persisted, in the physical system and the market of particular relevance to this review include:

- the continued retirement of thermal generation

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44 AEMC, *Reporting on drivers of change that impact transmission frameworks,* Draft Stage 1 Report, 11 April 2017, Sydney.

45 For instance the number of rule change requests that are currently under consideration by the Commission, which if final rules are made, will influence how generation and transmission investment decisions are made. AEMC, *Reporting on drivers of change that impact transmission frameworks,* Draft Stage 1 Report, 11 April 2017, Sydney, p. 55.

46 AEMC, *Reporting on drivers of change that impact transmission frameworks,* Draft Stage 1 Report, 11 April 2017, Sydney, p. i.

- an increasing penetration of renewable, intermittent generation
- the emergence of new technologies
- the increased coupling of gas and electricity prices.

These market trends are relevant to the review's approach to modelling, and examined in Chapter 10.

Significant emerging, or persistent, trends in the policy environment of particular relevance to this review include:

- proposed government investment in additional generation capacity
- the continued absence of effective integration of emissions reduction and energy policy
- securing generation inputs in the event of a forecast lack of reserves
- reviews into policies governing the market.

How the Panel proposes to address the general policy environment in this review is the focus of the next section. The relevance of each trend to this review, and the Panel's proposed approach, is outlined in section 4.3.

The Panel's overall approach

The Panel is cognisant that it is undertaking a review in an environment of rapid change and uncertainty. For this reason, it is important that the standard and settings are subject to review, to ensure they remain fit for purpose.

Consistent with the review's terms of reference, we will:

- Clearly outline in documents relating to the review, the key market and policy developments and uncertainties we consider relevant, and how we propose to address them. Some future market or policy conditions may be outside the scope of the review, and we will clearly define these.
- Outline in the review's final report any future market or policy conditions that are likely to have a significant bearing on the effectiveness of the reliability standard and settings recommended by the Panel. We may also recommend responses we consider necessary should these conditions arise, such as requiring a reassessment of the findings of the 2018 Review prior to the next four-yearly review.

While the rules require the standard and settings to be reviewed at this time, it is also important that any such review remain cognisant of the need to support stability and predictability in the market wherever possible. This is central to efficient investment over the long term.

For this reason, the rules require the reliability settings to be determined well in advance of when they will come into effect. This provides the market with sufficient time to adapt and make complex investment decisions.

The next section describes the trends particularly relevant to system reliability and this review; both in regards to the emerging market trends and the policy environment.

4.2 Relevant emerging market trends

This section focuses on four trends, namely:

- **Continued retirement of thermal generation** – the trend of withdrawal of thermal, scheduled generation from the market has continued.
- **Increasing penetration of renewable, intermittent generation** – as wind and solar PV form an ever-larger part of the generation mix, their output in certain regions may at times impact price outcomes.[47]
- **Emergence of new technologies** – new technologies have emerged that:
  - are altering the profile of demand for electricity sourced from the grid; and
  - may offer new options for supply of energy and demand reductions that were not mature at the time of the 2014 Review.
- **Coupling of gas and electricity prices** – increased use of gas as a fuel for power generation is strengthening the connection between the gas and electricity markets.

4.2.1 Continued retirement of thermal generation

Prior to 2009, there was considerable focus from policy makers and participants on the importance of building *new* generation capacity to meet rising demand. But when demand forecasts failed to meet expectations, it became clear that there was excess capacity in the system.[48] This excess capacity put downward pressure on spot prices, reducing the profitability of existing generators.

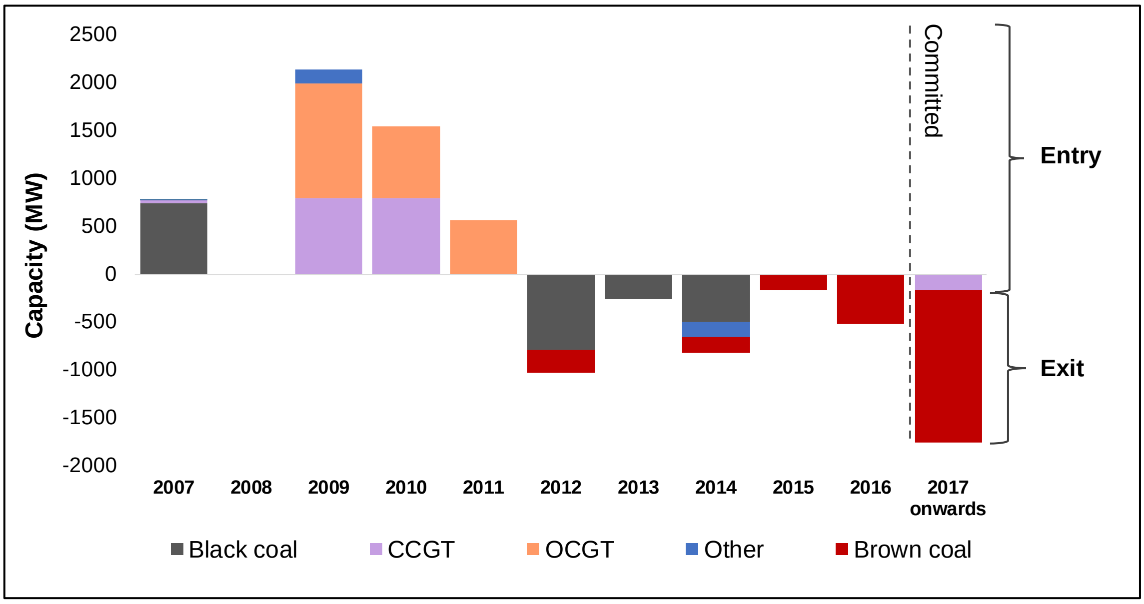
Instead of seeing additional capacity constructed, the national electricity market saw the *retirement* of existing generators in response to declining demand. Figure 4.1 shows the entry and exit of thermal generation capacity across the national electricity market by fuel/technology. The figure shows that no new thermal generation has entered the market since 2011. Indeed, there has been a strong trend of coal-fired generation *exiting* the market.

Figure 4.1 also shows that no new open cycle gas turbines (OCGTs) have been constructed since 2011. Over the last 6 years, the investment decisions that related to scheduled generation have principally been to withdraw capacity. It follows that an assessment of the market price cap should consider the effectiveness of the setting to the decisions of existing generation.

47 See footnote 2 for an explanation of the meaning and purpose of using the term 'intermittent'.

48 The Panel acknowledges that a range of factors, particularly the Renewable Energy Target, have driven investment outcomes in the national electricity market. Through their impacts on supply side capacity, these other factors have also affected price outcomes.

Figure 4.1 Changes in thermal generation capacity by fuel type



Source: Endgame Economics analysis of AEMO Market Management System database

Retirement decisions by existing generators are now increasingly important to outcomes for the physical system, and the market. Most notably, Engie's decision to close Hazelwood (indicated as the large closure in 2017) is likely to have a significant effect on price outcomes, and potentially the reliability of the system.[49]

4.2.2 Increasing penetration of intermittent technologies

While there has been no new thermal generation constructed in the national electricity market since 2011, there has been considerable investment in wind farms and small-scale solar over this period. Figure 4.2 shows the entry and exit of intermittent plant by technology type. Around 5000 MW of small-scale PV and 3700 MW of wind have been constructed since 2007 across the national electricity market.

The Clean Energy Council recently reported that the proportion of Australia's energy generated by renewables rose significantly from 2015 to 2016 — from 14.6 per cent to 17.3 per cent— representing "the highest proportion of Australia's electricity of any year this century".[50] Wind and solar technologies accounted for approximately 49% of renewable generation nationally in 2016.[51] Renewable projects set to start construction in 2017 are valued at $6.9 billion and represent 3,150MW of new generation capacity.[52]

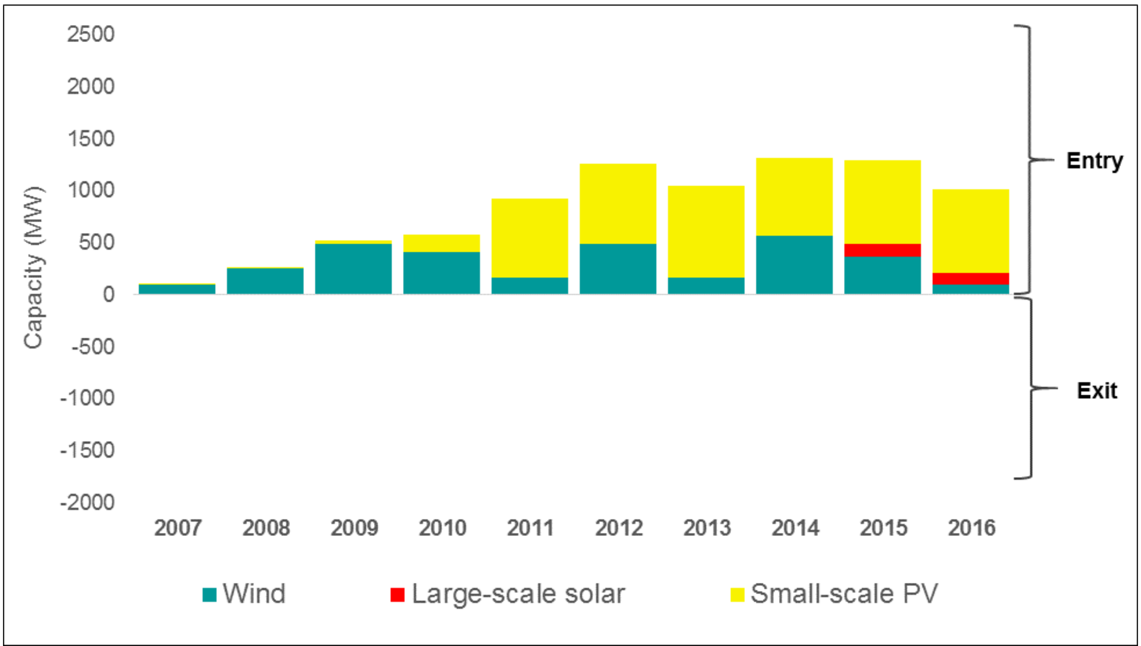
49 See AEMO, *Energy Adequacy Assessment Projection*, November 2016, Sydney; AEMO, *Gas Statement of Opportunities*, March 2017, Sydney; AEMO, *AEMO reaffirms position on energy security Media statement*, 23 March 2017, Sydney; AEMC, *2016 Residential Electricity Price Trends, final report*, 14 December 2016, Sydney.

50 In 2016 approximately 17,500 GWh of renewable energy was generated towards meeting the large-scale component of the Renewable Energy Target. Clean Energy Council, *Clean Energy Australia Report 2016*, Melbourne, May 2016, p. 8.

51 Clean Energy Council, *Clean Energy Australia Report 2016*, Melbourne, May 2016, p. 8.

52 Clean Energy Council, *Clean Energy Australia Report 2016*, Melbourne, May 2016, p.6.

Figure 4.2 Entry and exit of intermittent plant by technology type



Source: Endgame Economics analysis of the AEMO Market Management System database

The availability characteristics of different forms of electricity generation

The increasing contribution of intermittent technologies to electricity supply is focusing attention on the characteristics of different generation technologies. A factor currently distinguishing wind and solar technology from other forms of generation is the *characteristics of their availability*.

In the short-term, **thermal generation** availability (for example, coal-fired power stations and gas turbines) is largely at the discretion of the operator, as long as fuel is secured and the unit is not down for maintenance. In the long term, these units' availability is determined by fuel supply, and the cumulative wear and tear on the units, which influences their outage rates.

In the short-term, **hydro-electric plant** availability is also at the discretion of the operator, provided there is energy in storage and the unit is not down for maintenance.[53] In the long term, the availability of these units is determined by inflow patterns and decisions to build-up or run-down storages.

By contrast, the availability of **wind and solar generation** technologies is largely not at the discretion of the operator. Instead generation is driven by the time of year, weather conditions, and the time of day (illustrated in Figure 4.3). The future growth in installations of storage units linked to solar and wind projects have the potential to

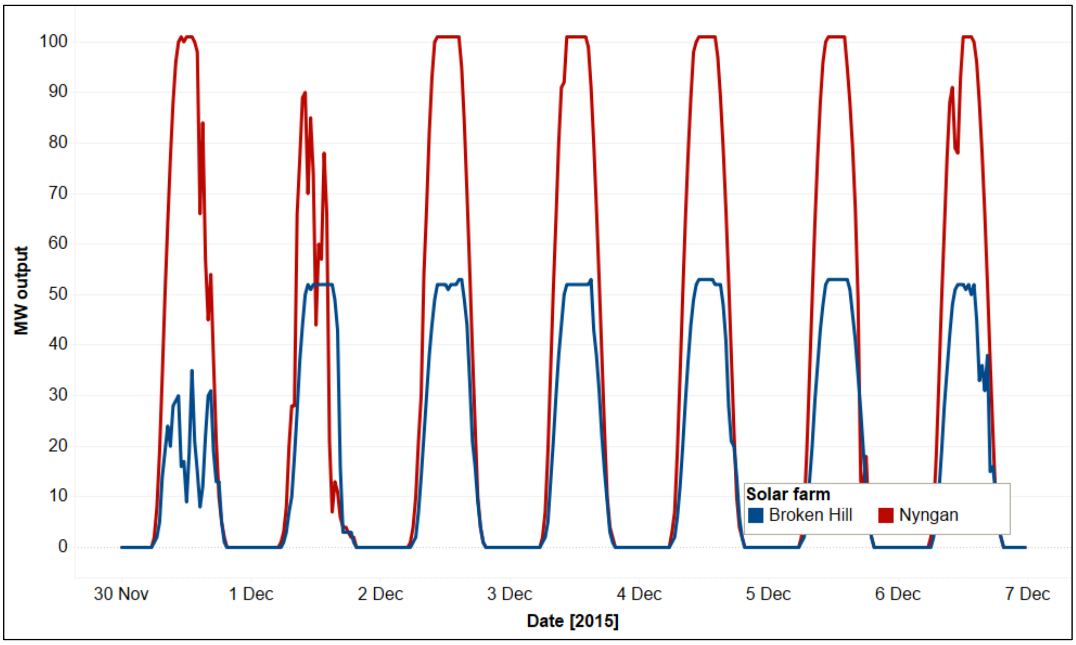
53 Run-of-river hydro plants are an exception as they exhibit similar characteristics to wind and solar.

lessen this availability distinction between solar and wind, and other forms of generation.

Wind and solar plants have other availability characteristics that distinguish them from alternative types of generation. In particular, they are unaffected by the availability or the price of gas and other fuels. Similarly, wind and solar technologies are not exposed to drought as are many hydro-electric plants. Further, the output of wind farms (or solar plants) that are located close to other wind farms (or solar plants) are highly correlated (illustrated in Figures 4.3 and 4.4). When wind farms located close to one another are generating, they tend to generate at the same time, and visa versa. Finally, wind and solar plants can also display a relatively high degree of predictability of availability in the short term.

One potential impact of the increasing penetration of solar and wind technologies on the national electricity market is that large volumes and/or proportions of generation in certain regions may become available (or unavailable) at the same time, and that this is outside the control of operators and thereby unresponsive to price signals in the national electricity market.

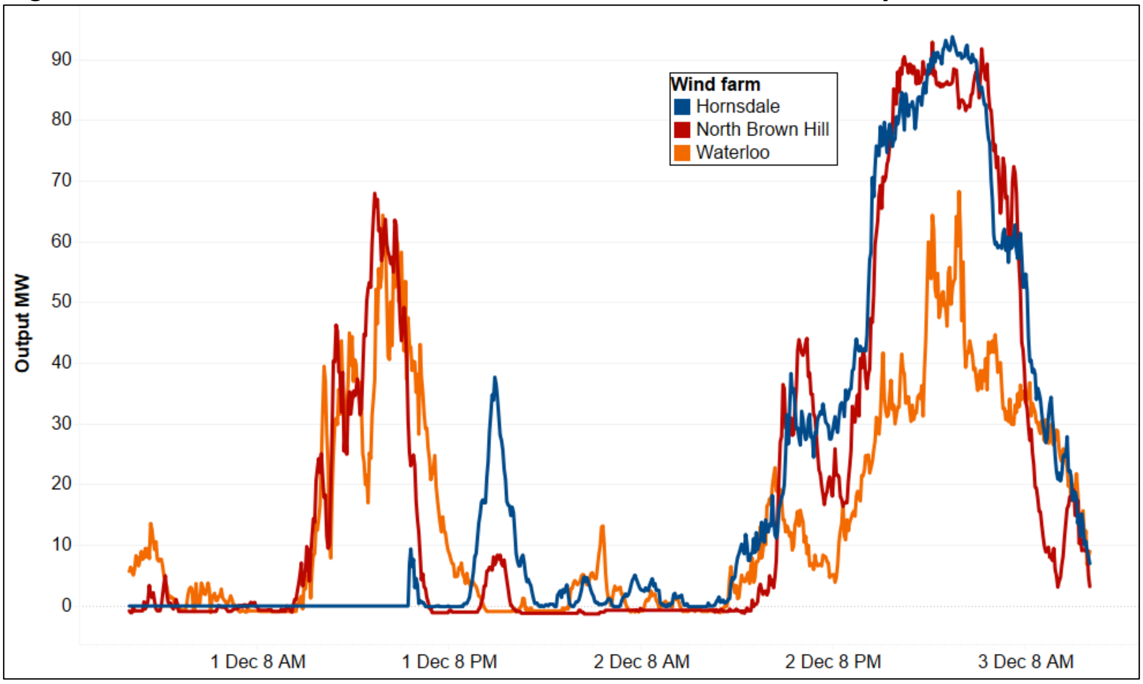
Figure 4.3 Illustration of output profile of solar farms **(30/11/2015 to 7/12/2015)**[54]



Source: Endgame Economics analysis of the AEMO Market Management System database

54 This figure shows the output profile for the Broken Hill and Nyngan solar farms over one week. Output varies with available sunlight (falling on 30 November and 1 December 2015 due to cloud cover). A further, related observation is that the output profiles of the two solar farms are highly correlated – they tend to generate at the same time, because they are both within similar time zones and therefore face similar temporal patterns of sunlight.

Figure 4.4 Illustration of three South Australian wind farms' output (30/11-4/12/2015)



Source: Endgame Economics analysis of the AEMO Market Management System database

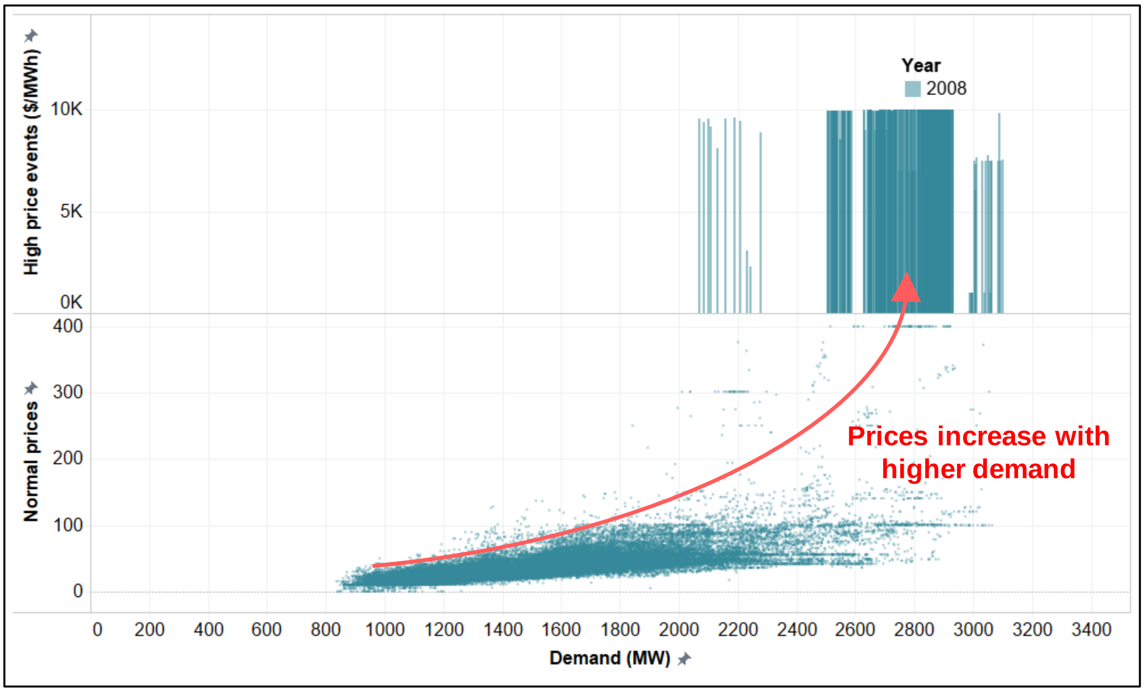
Potential changes in the relationship between high price events and demand

For consideration in this review, there is some evidence of a breakdown in the historical close relationship between high price events and periods of high demand in South Australia. Figure 4.5 shows the dispatch prices versus demand in South Australia for 2008:

- the bottom panel shows intervals where the price was less than $400 per MWh
- the top panel shows prices above $400 per MWh.

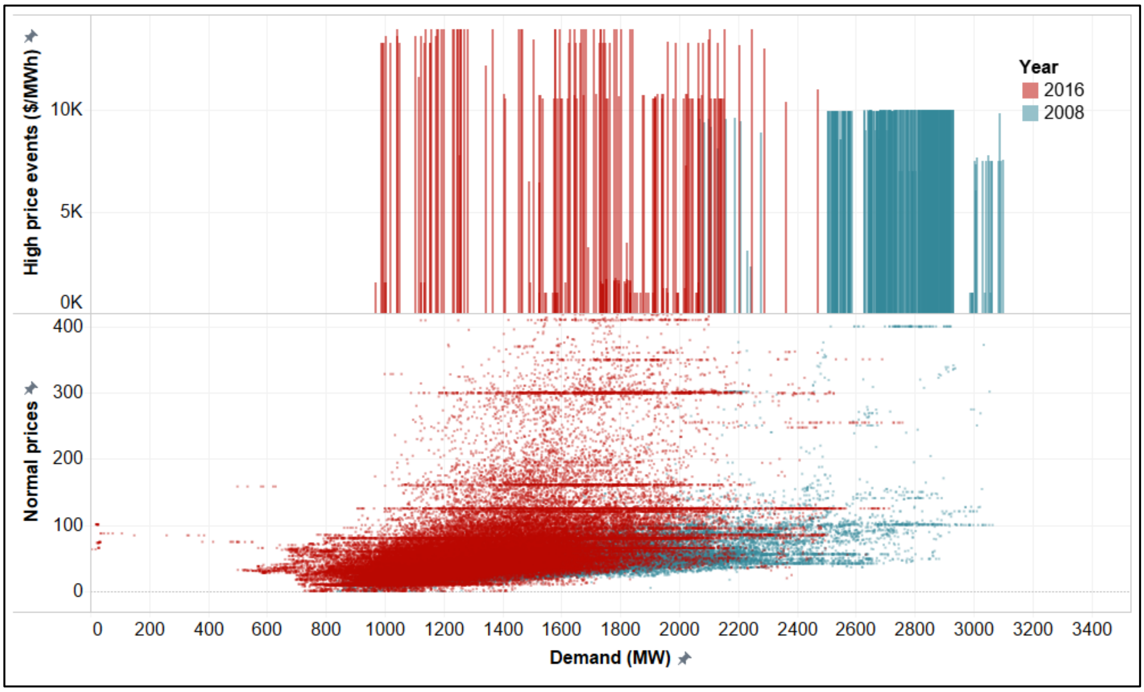
The chart shows a clear relationship between demand and price in South Australia in 2008. As demand increases, so does price, with market price cap events associated with levels of demand above 2500 MW. Figure 4.6 overlays outcomes for 2016 onto the analysis shown in Figure 4.5. In 2016, the relationship between and price and demand in South Australia is weaker; high prices regularly occurred at levels of demand as low as 1,000 MW.

Figure 4.5 Connection between price and demand, South Australia 2008



Source: Endgame Economics analysis of the AEMO Market Management System database

Figure 4.6 Connection between price and demand, South Australia 2008 and 2016



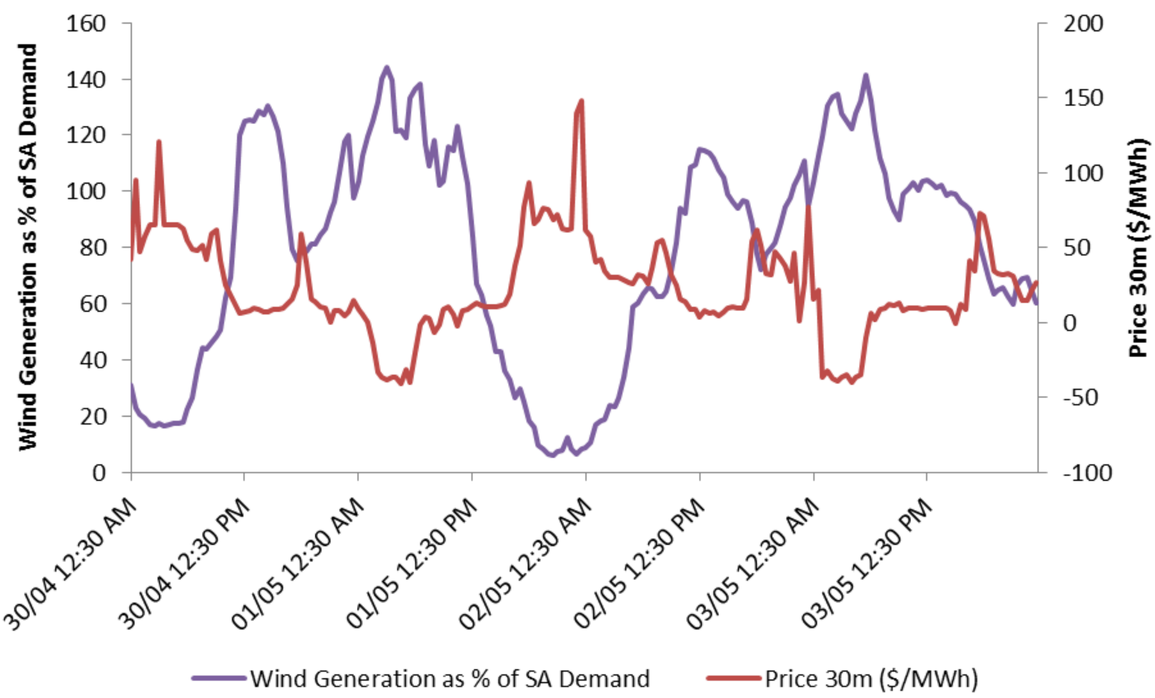
Source: Endgame Economics analysis of the AEMO Market Management System database

Various factors may have contributed to the occurrence of high prices with lower demand in South Australia in 2016. Outages on the Heywood interconnector may have played a role as well as increasing wholesale gas prices and changes in the overall generation mix (the combined outcome of thermal plant withdrawal and increased intermittent generation).[55]

Regarding the role of wind generation on a weakened price-demand correlation in South Australia in 2016, the net output amount of wind may be less relevant than the extent to which the levels of wind generation and demand rose and fell simultaneously (that is the extent to which wind generation supplied a high proportion of demand, whatever the demand level). High prices in part may have reflected instances when levels of wind generation and demand did not coincide.

As can be expected given the close to zero marginal cost of wind, there is evidence of a negative correlation between wind generation as a proportion of demand, and prices, in South Australia in 2016. Figure 4.7 indicates that from 20 April to 3 May 2016 low spot prices occurred when wind generation accounted for a high proportion of demand (a function of both the level of wind generation and the level of demand). For instance on 1 May following 12:30am. Conversely high spot prices occurred when wind generation accounted for a smaller share of demand. For example, on 2 May before and at 12:30am.

Figure 4.7 Wind generation, demand and price in South Australia (30/4/-3/5/16)



Source: AEMC analysis of Neopoint database

55 This issue was discussed by Clean Energy Council, see Clean Energy Council, *The rise of renewables in South Australia*, July 2016, Melbourne. The report "finds that higher-than-average electricity prices in South Australia have very limited correlation with the increased uptake of renewable energy. It is clear that electricity prices in South Australia are largely determined by wholesale gas prices." p. 3.

Considerations in this review

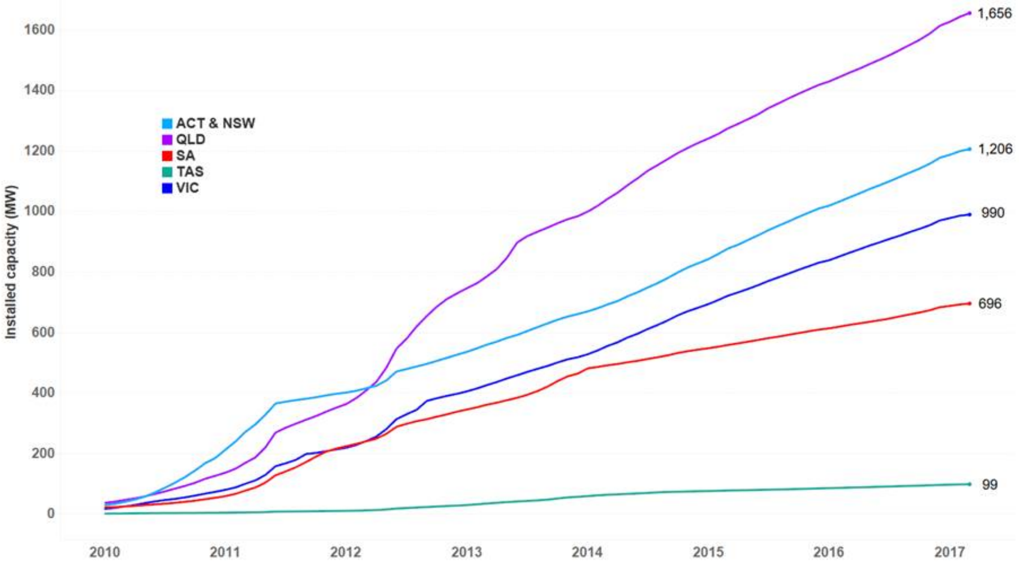
This discussion and analysis suggests that within certain regions of the national electricity market in the period of interest for this review (2020 – 2024) a disconnect may periodically emerge between prices and demand. It may be that high demand is not a necessary pre-condition for high prices in some regions. Although the growth of intermittent generation in these instances may be only one factor, the patterns of availability of wind and solar farms are likely to be significant to price outcomes in those regions.[56] In other words, such a trend could be expected in circumstances where significant amounts/proportions of generation are positively correlated and also outside the control of operators. These issues are relevant to the approach to modelling for this review (see Chapter 10).

The significance of intermittent generation on prices in the national electricity market may be impacted by increased storage, the subject of the next section.

4.2.3 Emergence of new technologies

We have noted that the last decade has seen a rapid rise in the penetration of renewable generation technologies. A portion of this has come in the form of small-scale solar PV, which is a distributed technology.[57] Figure 4.8 shows that from 2010 to March 2017, the installed capacity of small-scale PV systems rose significantly, from around 100 MW to 4.6 GW.[58]

Figure 4.8 Small-scale PV capacity by market region (2010 - 3/2017)



Source: Endgame Economics analysis of Clean Energy Regulator Postcode Data (May 2017)

56 This issue was highlighted by Oakley Greenwood in their review of modelling for reliability reviews, undertaken for the Panel in 2016. Oakley Greenwood, *Assessment of approach to modelling of Reliability Settings – Prepared for Australian Energy Market Commission*, report for the Reliability Panel, September 2016, Australia, p. 1.

57 The Clean Energy Council calculates that nationally small-scale solar PV accounts for 16% of renewable generation. Clean Energy Council *Clean Energy Australia Report 2016*, May 2016, Melbourne, p. 8.

58 Clean Energy Regulator, *Postcode data for small-scale installations*, http://www.cleanenergyregulator.gov.au/RET/Forms-and-resources/Postcode-data-for-small-scale-installations#Smallscale-installations-by-installation-year, viewed 12 May 2017.

Solar PVs have demonstrated that consumers are willing, even eager, to adopt new technologies that can alter their reliance on energy sourced from the grid.

Solar PVs are only one of the many technologies that are emerging that have the potential to alter the operation of the power system. Demand response and energy storage are two other notable technologies that are increasingly being marketed to end consumers, offering the prospect of reduced energy bills and reduced reliance on the grid, although the uptake of these technologies in the period considered in this review is uncertain.

One projection is that demand response will reduce peak demand by approximately 2,000 to 3,000 megawatts across the national electricity market in the period 2020-2025, up from approximately 1,000 megawatts currently.[59]

The Clean Energy Council reported that approximately 6,750 batteries with a capacity of 52 MWh were installed in 2016, more than 13 times the 500 installations in 2015, and noted predictions that market growth in 2017 will be at least treble that of 2016.[60] However, as battery storage is an emerging technology, predictions of the uptake of behind-the-meter energy storage vary widely. By 2020, Morgan Stanley expects up to one million behind-the-meter battery installations in Australia (approximately 6 GWh).[61] A report prepared for AEMO predicts that battery storage installed by residential and commercial customers will increase rapidly over the review period, from approximately 800 MWh in 2020 to 2,500 MWh in 2025.[62]

Solar PV and energy storage are also being considered for many large-scale projects. There are different costs and benefits associated with installing these technologies at small- and large-scale.

The uptake of behind the meter solar technologies, such as solar PV and storage, are relevant to the Panel's consideration of the reliability standard (see Chapter 5).

4.2.4 Coupling of gas and electricity prices

Over the last five years, there has been considerable structural change in the east-coast gas market, driven by the establishment of a liquefied natural gas export industry.

During the 1990s and 2000s, the eastern Australian wholesale gas market was characterised by the use of long-term bilateral contracts between a relatively small number of producers and consumers. The price of gas as a fuel for power generation was relatively low, given that gas-fired generators had to compete with low-cost coal-fired power stations.

59 Estimates provided by Bloomberg New Energy Finance, dated 29 November 2016.

60 Clean Energy Council, *Clean Energy Australia Report 2016*, May 2016, Melbourne, p. 32.

61 Morgan Stanley, 'Australia Utilities, Asia Insight: Solar & Batteries', 19 June 2016.

62 Jacobs Group, Projections of uptake of small-scale systems – Final Report (public), 6 June 2016, p29, available at: www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEFR/2016/Projections-of-uptake-of-smallscale-systems.pdf.

The discovery of large reserves of coal-seam gas in Queensland created the scale, and so the opportunity, to establish a liquefied natural gas export industry. In 2010, Australian and international energy businesses started to develop export capabilities, with a view to selling into the (then) higher priced Asian market. As of late 2016, all of these projects have been completed and are producing gas for export.

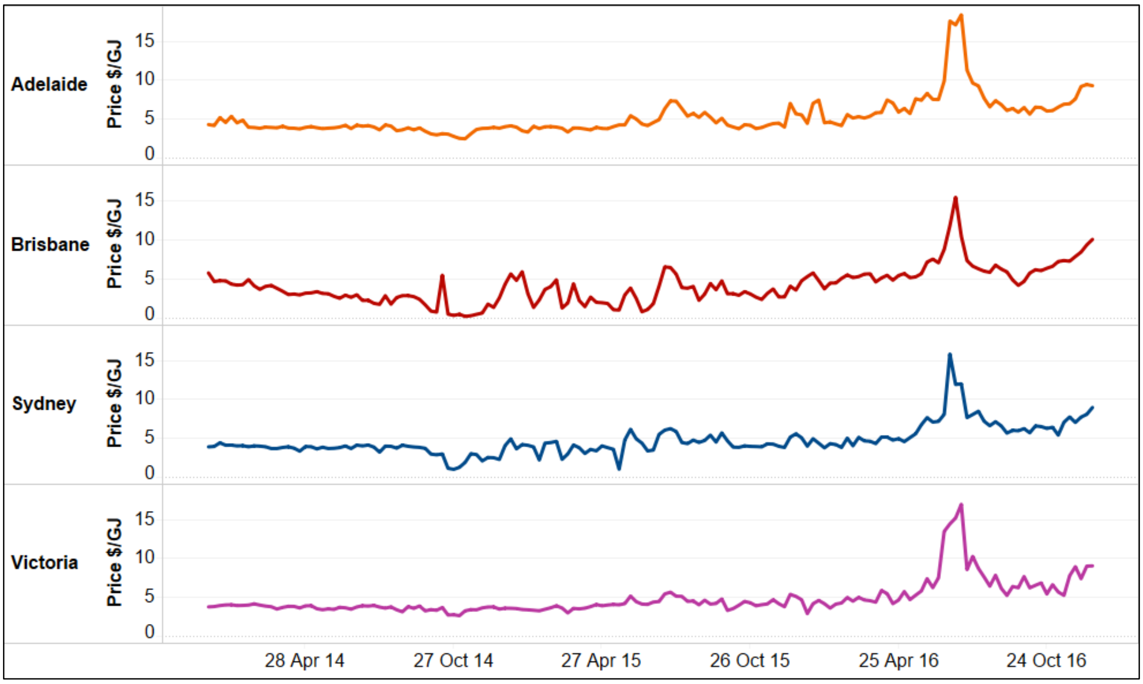
The consequences of the establishment of the liquefied natural gas export facilities are considerable with gas now being more expensive in the domestic market.

Linking of the domestic market to the international liquefied natural gas market has lifted the once low domestic gas price (around $4 per GJ) to the opportunity cost of exporting gas into the international market (in the order of $8-9 per GJ). Moreover, the massive increase in demand for gas has placed pressure on domestic supply infrastructure leading to yet further pressure on prices at times of high domestic gas demand (i.e., winter).

In addition, the expiry of long-term bilateral contracts and difficulty in renewing on commercially acceptable terms has meant that secondary markets are increasingly relevant. Put another way, prices in the spot market are becoming more and more representative of the marginal cost of gas.

In the winter of 2016, this combination of factors led to a sustained rise in the price of gas across the national electricity market as illustrated in Figure 4.9. Daily prices consistently rose to levels of $15 per GJ and beyond.[63]

Figure 4.9 Daily STTM and DWGM ex-ante prices (2014 to 2016)



Source: Endgame Economics analysis of AEMO STTM and Victorian Gas data sets

63 It is important to note that STTM prices represent the value of trades that occur at the relevant gas hub and do not include existing bilateral contracted gas volumes or values that occur outside the trading hubs (and that represent the vast majority of volume and value of gas transactions). As such, STTM prices generally reflect a very limited number of transactions and very low gas volumes and are therefore not necessarily indicative of either the availability or price of gas.

Higher gas prices led to higher electricity prices, with sustained high prices for extended periods in June and July 2016. The high gas price was in part a function of the demand for gas as a fuel for power generation. The closure of Hazelwood power station – and the attendant increase in gas-fired power generation – is likely to strengthen the connection between gas and electricity prices.

The impacts of changes in the gas market are relevant to modelling for the review (see Chapter 10).

4.3 Policy trends and uncertainty

While the policy environment in any sector is never static, the policy environment that impacts on the energy sector is particularly dynamic at present. This section describes how the Panel proposes to approach the trends and uncertainties in key policy areas for this review.

This section describes four relevant policy trends, namely:

- **Proposed government investment into additional "firm" (dispatchable) generation capacity** – the South Australian Government's energy plan and the Australian Government's feasibility study into Snowy Hydro 2.0.
- **Emissions policy uncertainty** – the lack of an integrated emissions reduction and energy policy.
- **Securing inputs to generation in the event of a supply shortfall** – gas companies' guarantee implementation plan.
- **Rule change requests and reviews into the policies governing the market** – these include the Commission's consideration of changes to rules regarding key features of the operation of the energy market, such as five- minute settlement, and various reviews underway by the Commission and a range of other bodies, for instance the Energy Council's *Independent review into the future security of the national electricity market* (the Finkel review).

The announcements cited in the following sections are current as of 17 May 2017.

4.3.1 Government funding for additional dispatchable generation capacity

The South Australian and Australian governments this year have announced that they will fund, subsidise or study the feasibility of investing in additional dispatchable generation capacity.

The South Australian Government's energy plan (*South Australian Power for South Australians*) includes building a state-owned gas power station, funding a large battery project, and incentives for gas development.[64]

The Prime Minister has directed the Australian Renewable Energy Agency to examine the feasibility of increasing the output of the Snowy Mountains Hydroelectric scheme

64 Jay Weatherill (Premier), *South Australia is taking charge of its energy future,* media release, Parliament House, Adelaide, 14 March 2017.

by 2000 megawatts.[65] In its recent budget the Australian Government announced it is looking at further hydro-electricity and pumped storage opportunities in Tasmania, South Australia and Queensland.[66]

Building a solar thermal plant or other large-scale solar project in Port Augusta was amongst the measures agreed to by the Australian Government as part of the company tax cut package on 30 March, with up to $110m funding.[67] An additional $36.6m was announced in the May federal budget to invest in energy infrastructure in South Australia under a bilateral Asset Recycling agreement.[68]

The Australian government also allocated $5.2m for a national interest and cost benefit study into the construction of gas pipelines to the east coast from the Northern Territory and Western Australia, through Moomba in South Australia.[69]

Where a government has announced a decision to build additional capacity, the Panel will consider factors such as the project's investment certainty, the time frame for commissioning and any operational distortions that may be associated with the mooted planned operating mode in our approach to incorporating the proposed asset into the modelling for this review.

The Panel therefore intends to observe these projects as they develop, with a view to exercising its judgement as to whether they should be incorporated into our analysis.

4.3.2 Emissions policy uncertainty

The lack of an integrated energy and emissions reduction policy and associated multiple policy changes has created significant uncertainty in terms of future market dynamics and as such can be expected to have a negative impact on investment sentiment which risks undermining the reliability of the power system in the long term.

Australia has set a target to reduce emissions by 26 to 28 per cent below 2005 levels by 2030 and made an international commitment to this under the Paris Agreement.[70]

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65 M Turnbull (Prime Minister), *Securing Australia's energy future with Snowy Mountains 2.0*, media release, Parliament House, Canberra, 16 March 2017. In its recent budget the Australian government announced it is open to acquiring a larger share or outright ownership of Snowy Hydro. J Frydenberg (Minister for the Environment and Energy) *Budget invests in a reliability energy future*, media release, Parliament House, 9 May 2017.

66 J Frydenberg (Minister for the Environment and Energy) *Budget invests in a reliability energy future*, media release, Parliament House, 9 May 2017.

67 N Xenophon (Senator), *Tax Cuts, Power Prices & Solar Thermal Plant at Port Augusta*, media release, Parliament House, Canberra, 1 April 2017. Also announced in the Australian government budget, and J Frydenberg (Minister for the Environment and Energy) *Budget invests in a reliability energy future*, media release, Parliament House, 9 May 2017.

68 J Frydenberg (Minister for the Environment and Energy) *Budget invests in a reliability energy future*, media release, Parliament House, 9 May 2017.

69 J Frydenberg (Minister for the Environment and Energy) *Budget invests in a reliability energy future*, media release, Parliament House, 9 May 2017.

70 The Paris Agreement sets in place a framework for all countries to take climate action from 2020. It includes a global goal to hold average temperature increase to well below 2°C and pursue efforts to keep warming below 1.5°C above pre-industrial levels. All countries are to set mitigation targets

Australia ratified the Paris Agreement on 10 November 2016.[71] The Panel will incorporate an assumption of meeting these targets into the review, for instance using various emission reduction scenarios for the 2020 – 2024 period.

Additionally, three Australian jurisdictional governments have implemented or proposed state-level renewable energy targets; the Australian Capital Territory, Victoria and Queensland. These state-based schemes may influence the technology type, amount and location of generation investment within the 2020 – 2024 time horizon. The Victorian target for instance "is designed to [d]eliver up to 1500 megawatts of new large-scale renewable energy capacity by 2020 and up to 5400MW by 2025" through a competitive reverse auction scheme.[72] For this review the Panel will consider potential impacts of progress towards meeting these targets on generation investment.

A detailed discussion of environmental and emissions reductions policies, and their impact on investment in generation and transmission, is provided in the Commission's *Reporting on drivers of change that impact transmission frameworks, Draft Stage 1 Report*.[73]

4.3.3 Securing inputs to generation in the event of a supply shortfall

There has been recent evidence of a lack of availability of gas supply for electricity generation, resulting in some interruption to the supply of electricity.

Specifically on 8 February 2017 there was a load shedding event in South Australia.[74] One of the contributing factors was that Engie did not bid its second unit at the Pelican Point Power Station into the market despite market notices earlier in the day seeking responses to an impending lack of reserves. Engie stated that one of the reasons it could not bid into the market was because it did not have gas.[75]

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from 2020 and review targets every five years. See: https://www.environment.gov.au/climate-change/international/paris-agreement.

71 The Hon Malcolm Turnbull MP, Prime Minister; The Hon Julie Bishop MP, Minister for Foreign Affairs; The Hon Josh Frydenberg MP, Minister for the Environment and Energy, *Ratification of the Paris Agreement on Climate Change and the Doha Amendment to the Kyoto Protocol*, joint media release, 10 November 2016, viewed 12 November 2016, https://www.pm.gov.au/media/2016-11-10/ratification-paris-agreement-climate-change-and-doha-amendment-kyoto-protocol.

72 The Victorian target is for 25 per cent of electricity generated in the state to come from renewable energy by 2020, rising to 40 per cent by 2025. Department of Environment, Land, Water and Planning (Victoria) *Victoria's renewable energy target,* webpage http://www.delwp.vic.gov.au/energy/renewable-energy/victorias-renewable-energy-targets, viewed 16/5/2017.

73 AEMC, *Reporting on drivers of change that impact transmission frameworks,* Draft Stage 1 Report, 11 April 2017, Sydney, Chapter 4.

74 AEMO, *System event report South Australia, 8 February 2017. Reviewable operating incident report for the national electricity market information as at 9.00 am, Friday 9 February 2017*, Sydney, 15 February 2017.

75 AEMO, *System event report South Australia, 8 February 2017. Reviewable operating incident report for the national electricity market information as at 9.00 am, Friday 9 February 2017*, Sydney, 15 February 2017, p. 5.

AEMO's 2017 *Gas statement of opportunities* foreshadows gas shortages in the summer of 2018/19 and comments that price increases may threaten the financial viability of some commercial and industrial customers.[76]

Following discussions with east coast gas companies, in late April the Prime Minister announced the introduction of export restrictions to "ensure the Australian market has adequate [gas] supplies before exports are permitted".[77] The Government intends to have regulations in place by 1 July 2017 for an Australian Domestic Gas Security Mechanism, which "will give the government the power to impose export controls on companies when there is a shortfall of gas supply in the domestic market".[78]

The Panel will monitor this and other gas sector policy developments and assess their relevance for this review.[79]

4.3.4 Policy reviews and rule change requests

There are a number of major policy reviews either currently underway or expected to begin. For example, the Commonwealth Government has asked the Climate Change Authority and the AEMC to provide advice on policies to enhance power system security, and to reduce electricity prices consistent with achieving Australia's emissions reduction targets in the Paris Agreement, with the advice due for completion by 1 June 2017.[80] Two federal parliamentary inquiries are underway; the Senate's "Resilience of electricity infrastructure in a warming world" and the House of Representatives' "Modernising Australia's Electricity Grid".[81]

AEMO, other market bodies, jurisdictional governments and the Energy Council are also pursuing work programs that may be directly or indirectly relevant to this review, such as the Energy Council's Independent Review into the *Future Security of the National Electricity Market* (the Finkel review).[82]

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76 AEMO, *Gas statement of opportunities for eastern and south-eastern Australia*, 9 March 2017, Sydney, p. 1.

77 M Turnbull (Prime Minister), *Delivering affordable gas for all Australians*, media release, Parliament House, Canberra, 27 April 2017. See also M Turnbull (Prime Minister), *Measures agreed for cheaper, more reliable gas*, media release, Parliament House, Canberra, 15 March 2017.

78 M Turnbull (Prime Minister), *Delivering affordable gas for all Australians*, media release, Parliament House, Canberra, 27 April 2017.

79 With the closer coupling of gas and electricity prices (see previous section) policy developments in the gas sector are increasingly relevant to reliability considerations in the national electricity market. On 30 March the Australian Government announced a national review through the Energy Council of the management and the effectiveness of policies in relation to undeveloped gas titles retained by companies with a view to introducing a nationally consistent stricter "use it or lose it" test.

80 See AEMC website http://www.aemc.gov.au/News-Center/What-s-New/Announcements/Joint-advice-on-power-system-security,-electricity

81 See http://www.aph.gov.au/Parliamentary_Business/Committees/Senate/Resilience_of_Electricity_Infrastructure_in_a_Warming_World/ElectricityInfrastructure and http://www.aph.gov.au/Parliamentary_Business/Committees/House/Environment_and_Energy/modernelectricitygrid

82 See http://www.environment.gov.au/energy/national-electricity-market-review

The Commission is currently undertaking reviews and considering rule change requests that may affect the market in the medium-term. One of these is a rule change request regarding a proposed five minute settlement period in the market.[83] The Commission released a directions paper on 11 April 2017 that outlines the impacts of changing the settlement period for the electricity spot price from 30 minutes to five minutes, and is receiving submissions to 18 May 2017.[84] The directions paper states that: "[g]iven the change occurring in the NEM [national electricity market], the Commission's initial position is that …[t]he adoption of five minute settlement would have a material benefit that is likely to outweigh the cost".[85]

While some reviews of policy do not directly relate to reliability many will impact on the trends in and/or features of the market for the period beyond 2020, and so are of interest to the assumptions and modelling approach for this review.

The recommendations of these reviews, once finalised, may bear on this review and its underpinning modelling. We will maintain a watching brief of these reviews and at a minimum respond to their findings and recommendations once released.

83 Sun Metals Pty Ltd has submitted a rule change request to reduce the time interval for settlement in the wholesale electricity market from 30 minutes to five minutes. The proposal involves compulsory five minute settlement for generators, scheduled loads and market interconnectors. Demand side participants in the wholesale market, including retailers and large consumers, could choose to be settled on either a five or 30 minute basis.

84 Details can be found on the Commission's website at http://www.aemc.gov.au/Rule-Changes/Five-Minute-Settlement#

85 AEMC, *Five Minute Settlement*, Directions paper, 11 April 2017, Sydney, p. iv.

5 The reliability standard

The guidelines establish that the Panel should only reassess the level of the reliability standard if it considers there is material benefit in doing so.[86] The Panel has not yet formed a view on whether there is a case for a review of the reliability standard in the 2018 Review. In reaching its view, the Panel will be guided by the principle of providing a stable, predictable and flexible regulatory framework in order to meet the national electricity objective.

This chapter:

- outlines the history of the level of the reliability standard
- recaps the reliability standard's role and the trade-off involved in setting its level
- describes the changes that in theory could lead to an assessment to alter the reliability standard
- describes the materiality threshold criteria
- provides initial observations on the materiality threshold criteria.

5.1 History of the reliability standard

Prior to the commencement of the national electricity market in 1998, each jurisdiction established its own standards for reliability and applied these in decisions relating to the installation of new generation capacity.[87] Long standing practice had generally been to manage the number of times interruptions to supply were likely. However the measures adopted to achieve this varied between jurisdictions; from statistical indicators that focused on achieving a particular loss of load probability (NSW and Victoria) to capacity margins calculated on the basis of the capacity of the largest one, two or three generating units.[88]

In 1998, the National Electricity Code Administrator's (NECA's) Reliability Panel conducted a review to determine the power system reliability standards to apply in the new national electricity market. It also needed to form the guidelines for market intervention by National Electricity Market Management Company as a last resort to maintain the reliability standard.[89]

In respect of the level of reliability to apply, the NECA Panel determined that the reliability standard in the national market would be set at a maximum of 0.002 per cent of USE in any region over the long term. The major issue for the NECA Panel at the

86 Guidelines section 3.2.2.

87 NECA Reliability Panel, *Power system reliability standards and guidelines for market intervention, Discussion Paper*, February 1998, p. 17 cited in Reliability Panel, *Reliability Standard and Reliability Settings Review 2014*, Final Report, 16 July 2014, Sydney p. 102.

88 Reliability Panel, *Reliability Standard and Reliability Settings Review 2014,* Final report, 16 July 2014, Sydney p. 102.

89 NECA Reliability Panel, *Power system reliability standards and guidelines for market intervention*, Discussion Paper, February 1998; NECA Reliability Panel, *Determination on reserve trader and direction guidelines*, June 1998, cited in Reliability Panel, *Reliability Standard and Reliability Settings Review 2014,* Final report, 16 July 2014, Sydney, p. 102.

time was: "a desire to introduce a common approach across the National Market at a level which balances natural energy market outcomes and avoids undesirable reliability shocks." The NECA Panel noted that it was "acutely aware of the risk of destroying confidence in the reform process by setting inappropriately high or low standards for the opening of the market." The NECA Panel, therefore, established a uniform approach to the NEM's reliability standard at approximately the same level as the existing standard in each jurisdiction.[90]

The standard has been set at its current level since the market was established, and was last reviewed in 2014 when the Panel recommended the level of the standard remain unchanged.[91]

Appendix A summarises previous Panel reviews and Commission determinations regarding the reliability standard and settings.

5.2 The role of the reliability standard

The reliability standard is an ex-ante planning standard. It is not a regulatory or performance standard that is "enforced". Rather it is a planning standard which national electricity market planning processes associated with generators and interconnectors must seek to satisfy.

The standard is an expression of the reliability sought from the national electricity market's generation and inter-regional transmission assets that form the basis of the wholesale supply of electricity.

The standard is used to indicate to the market the required level of supply to meet demand on a regional basis. The standard feeds into various national electricity market wholesale pricing parameters that form part of the framework in which investment decisions to meet consumer demand for electricity are made. The standard also drives the planning and operational decisions of the AEMO.[92]

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90 NECA Reliability Panel, *Determination on reserve trader and direction guidelines*, June 1998, p. 8, cited in Reliability Panel, *Reliability Standard and Reliability Settings Review 2014*, Final report, 16 July 2014, Sydney, p. 103.

91 Reliability Panel, *Reliability Standard and Reliability Settings Review 2014*, Final Report, 16 July 2014, Sydney, p. 21. The Panel also recommended the metric used to express the standard remain unchanged. Previously the Panel has changed the basis of measuring 'performance against the standard'. In 2009 an average was introduced whereby 'compliance with the standard' was measured over the long term using a moving average of the actual observed level of annual USE for the most recent 10 financial years. In July 2012 this was changed to 'Performance against this Reliability Standard for Generation and Bulk Transmission should be considered using the actual observed levels of annual USE for the most recent financial year. Plant performance and demand characteristics that occurred in that financial year should be assessed to determine whether there are any underlying changes occurring.' http://www.aemc.gov.au/getattachment/2ada2030-f22a-4454-9c4c-4092419b3d0e/Reliability-Standards-(expires-30-June-2012).aspx and http://www.aemc.gov.au/getattachment/f93100d9-72d2-46fb-9c25-ac274a04ae58/Reliability-Standards-(to-apply-from-1-July-2012).aspx, accessed 23/03/2017.

92 AEMO's *Reliability Standard Implementation Guidelines* set out how AEMO implements the reliability standard. See AEMO, *Reliability standard implementation guidelines final*, October 2016, Sydney 2016.

The role of the reliability standard is discussed in detail in Chapter 2, section 2.2.

5.3 The trade-off in setting the reliability standard

When setting the level of the reliability standard the Panel is making a trade-off, on behalf of consumers, between two sets of costs: the cost of additional generation and interconnection capacity to meet consumer demand for electricity, and the costs associated with not having energy when we need it. The trade-off is expressed as the proportion of expected energy demand that is at risk of not being supplied to consumers, termed "unserved energy", in a region in a given financial year.[93]

The objective of the analysis and modelling undertaken in each review is to help the Panel make this trade-off, by providing information about the cost of achieving higher levels of reliability.

A detailed explanation is provided in Chapter 2, section 2.2.

The rules require certain events to be included, and other events to be excluded, when determining the amount of energy demanded, but not supplied, in a region (unserved energy - the measure of reliability). These are set out in the table below. Events in the first column affect reliability for the purposes of this review, while events in the second column do not.[94]

Unserved energy *includes*:	Unserved energy *excludes*:
Energy demanded but not supplied due to power system *reliability* incidents resulting from:	Energy demanded but not supplied due to power system *security* incidents resulting from:
• A single credible contingency event on a generating unit or an inter-regional transmission element that may occur concurrently with generating unit or inter-regional transmission element outages. • Delays to the construction or commissioning of new generating units or inter-regional transmission elements, including delays due to industrial action or acts of God (such as extreme weather events).	• Multiple contingency events, protected events or non-credible contingency events on a generating unit or an inter-regional transmission element, that may occur concurrently with generating unit or inter-regional transmission element outages.[95] • Outages of transmission network or distribution network elements that do not significantly impact the ability to transfer power into the region where the unserved energy occurred. • Industrial action or acts of God at existing generating facilities or inter-regional transmission facilities.

93 As noted in section 1.1, demand response and behind-the-meter generation reduce total demand, rather than being considered to increase supply.

94 Rules clause 3.9.3C.

95 Such as the black system event in South Australia in September 2016.

5.4 Materiality threshold criteria

The guidelines establish that the level of the reliability standard is to remain unchanged unless the Panel considers there may be material benefit in reassessing it.[96]

Economic perspectives on amending the reliability standard

From an economic perspective, the following changes could lead to an assessment to suggest altering the reliability standard:

- **Change in value of customer reliability –** where the value that customers placed on reliability had decreased (increased) substantially since the last review, perhaps because of the widespread uptake of new devices that substitute for (rely upon) electricity supply. If all other factors remained constant, this may imply the need to decrease (increase) the reliability standard.
- **Change in cost of additional capacity –** where the cost of additional capacity has decreased (increased) substantially since the last review, perhaps because of a step change in technology costs. If all other factors remained constant, this could imply the potential to increase (decrease) the reliability standard.

Materiality assessment

It follows that the Panel's materiality assessment is to include consideration of factors including but not limited to:[97]

- any changes made to AEMO's measure of the value of customer reliability (AEMO's VCR)
- any marked changes to the way consumers use electricity, particularly through the use of new technology, that suggest a large number of consumers may place a lower value on a reliable supply of electricity from the NEM.

These factors relate to potential changes to the value of customer reliability.

Additionally the Panel:

- Must have regard to any value of customer reliability determined by AEMO which the Reliability Panel considers to be relevant.
- May take into account any other matters specified in the guidelines or which the Panel considers relevant.[98]

As the costs of additional generation is the counter point to value of customer reliability in the reliability "trade-off" the Panel believes that changes in the cost of producing an additional unit of generation to meet otherwise unmet demand warrant consideration.

96 Guidelines section 3.2.2.

97 Guidelines section 3.2.2.

98 Rules clauses 3.9.3A(e)(4) and (5).

5.5 Observations regarding the materiality threshold

The Panel has not yet formed a view on whether there is likely to be a material benefit in opening the level of the reliability standard for assessment in this review.

5.5.1 No change to AEMO's VCR measure

The Panel examined the value of customer reliability in the 2014 Review in the context of its relationship with the reliability standard and sought stakeholder input in formulating its views.[99] The final determination noted that costs of supply interruptions vary, depending on the type of customer, time of interruption, geographical location, and climate. Hence, to set the reliability standard at an appropriate level, detailed and accurate information about the cost functions of businesses, and the value of reliability for customers, are needed. At the time the value of reliability for all national electricity market customers had never been evaluated. However AEMO was close to finalising a national value of customer reliability review. The outcome of modelling undertaken for the 2014 Review indicated that the existing reliability standard of a maximum permissible USE of 0.002 per cent would be economically efficient if the value of customer reliability was assumed to be $30,000/MWh.[100]

In September 2014 AEMO released its *Value of customer reliability review, final report*, providing national level values of customer reliability for the first time.[101] The study estimated the value that all customers place on the reliability of supply from the grid based on a survey of different customer types across all national electricity market states and an average of the different values they place on reliability. The report produced estimates for valuations of the cost of outages by customer type and outage length. These values were aggregated to calculate a NEM-wide value of customer reliability of $33,460/MWh.

In 2016 the Panel considered the implications of AEMO's national study for the level of the reliability standard. We concluded the existing level of the standard (0.002 per cent USE) remained broadly consistent with AEMO's VCR. The Panel had regard to ROAM's 2014 finding that the level of the current standard was equivalent to a value of customer reliability of approximately $30,000/MWh, which corresponded to AEMO's estimated NEM-wide aggregate of $33,460/MWh.[102]

The Panel acknowledged that other measures of reliability exist and that AEMO's VCR measure only represents an estimation of the true value that customers place on reliability. However, as AEMO's VCR is used across the industry, the Panel was of the view that it represented a useful tool in assessing the current level of the standard.[103] We concluded in 2016 that the existing level of the standard was reasonably close to the

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99 AEMC Reliability Panel, *Reliability Standard and Reliability Settings Review 2014*, Final Report, 16 July 2014, Sydney, pp. 26-31.

100 AEMO, *Value of customer reliability review final report*, 2014, Sydney, p. 2.

101 AEMO, *Value of customer reliability review final report*, 2014, Sydney.

102 See: ROAM Consulting, *Reliability standard and settings review, report to the AEMC*, May 2014, p. 64, and AEMO, *Value of customer reliability review*, September 2014, p. 2.

103 Guidelines Determination pp. 23-24

optimal value of customer reliability that is commonly accepted across the NEM. If AEMO were to reassess its value of customer reliability measure, this may indicate a material benefit in reassessing the level of the standard.[104]

However, AEMO has not reassessed its value of customer reliability measure since its 2014 study.[105] On this basis the Panel does not consider that this materiality threshold trigger has been met.

Nonetheless to test the accuracy of this conclusion we intend to assess the value of customer reliability associated with the level of the current reliability standard, existing reliability settings and potential market conditions from 2020 – 2024 as a component of the modelling for the 2018 Review.

The Panel is of the view that there would need to be significant variance between AEMO's VCR findings and those calculated from the model in order to conclude there would be a material benefit in re-opening assessment of the reliability standard.

Subsequent to the 2014 Review and the publication of AEMO's study, AEMO released guidelines on applying the study's findings.[106] Consistent with these guidelines, the Panel acknowledges that the most appropriate value of customer reliability measure may relate to particular consumers and outage lengths. The relevant measure, for instance, may relate to the end-users that would experience the effects of unserved energy in a supply interruption event and the duration for which they would experience outages (stated by AEMO to be one to two hours).

The Panel will also seek to adjust AEMO's VCR for inflation. This reflects the fact that the value of customer reliability is a measure of real, and not nominal, value. The Panel's preliminary view (subject to consultation) is to adjust AEMO's VCR for historic and forecast changes to the consumer price index up to the 2020 – 2024 period.

More generally, the Panel will utilise AEMO's VCR as a calibration tool not as the fundamental basis for determining what the level of the reliability standard should be.

Question 1: The reliability standard

a. Are there any features of the methodology, results or significance of AEMO's value of customer reliability measure that should be considered by the Panel?

5.5.2 Changes to consumer use of electricity

The Panel must also consider any marked or forecast changes in the way consumers use electricity, particularly through the use of new technology, that suggest a large number of consumers may place a lower or higher value on a reliable supply of electricity from the national electricity market.[107]

104 Guidelines Determination p. 24.

105 https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Value-of-Customer-Reliability-review, accessed 7/03/2017 at 3:26PM.

106 AEMO, *Value of customer reliability – application guide final report*, Sydney, December 2014.

107 Guidelines section 3.2.2.

The following trends identified in the 2016 *National Electricity Forecasting Report for the National Electricity Market* may affect the value of customer reliability of particular consumers:[108]

- **Household appliance use:** Households are using more appliances and this trend is expected to continue to 2024. AEMO noted that residential consumption is not predicted to increase despite increased appliance use, in part due to an increase in the energy efficiency of appliances. AEMO also provides a measure of the consumer utility from appliances in the form of a "benefits index" which provides a basis for examining how appliance use has changed. It does not however indicate how short-term interruptions in supply affect the overall utility of appliance use (the utility of battery-operated appliances, for example, would not be significantly affected by short-term interruptions).
- **Non-manufacturing business use:** AEMO identified the (non-price) drivers of electricity consumption by non-manufacturing business use as being population, household disposable income, and heating and cooling needs. While long term forecasts exist for these factors, they may not fully describe change in the value of reliability for non-manufacturing business use.
- **Manufacturing business use:** AEMO identified that the long term drivers of manufacturing electricity use are producer input prices, and state output. While long term forecasts exist for these factors, they may not fully describe change in the value of reliability for manufacturing business use.
- **Rooftop solar PV:** Rooftop solar PV penetration is expected to increase over the forecast period (including systems that integrate solar PV and battery storage – see below). AEMO forecasts that rooftop solar PV is expected to decrease observed grid level residential consumption of electricity and non-manufacturing business consumption. This suggests a reduction in the value of grid sourced energy for these customers. However, many existing household PV installations cannot operate unless they are connected to the energised grid. For these consumers, rooftop solar PV would not reduce the value of the reliability of grid sourced energy, as the reliability of the grid is the main factor that determines whether their PV systems will operate.
- **New storage technologies:** New technologies, in particular, distributed energy storage, may insulate households and small businesses from the impact of interruptions in supply, and thus reduce the value of reliability for some consumers. AEMO forecasts that distributed energy storage penetration will make a material difference in maximum and minimum energy demand over the period 2020-2024. The caveat noted above, that many rooftop solar PV systems will not operate unless connected to the energised grid, also applies to many integrated solar and battery systems.

We note that the relevant assumption is a prospective measure of consumer use of electricity in 2020-2024. As such, reference to current consumer use of electricity is relevant only to the extent that it provides insight into likely future uses of electricity from 2020-2024.

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108 AEMO, *National Electricity Forecasting Report for the National Electricity Market*, June 2016, Sydney.

Estimating the overall impact of the above trends on the value of customer reliability is a complex process. As indicated above, the trends diverge in their bearing on the value of customer reliability and the magnitude of their impacts is uncertain. At this stage the Panel has not formed a view regarding the impact of expected changes to consumer use of electricity on the value of customer reliability for the period 2020-2024. Depending on stakeholder feedback and the final modelling approach used the Panel may examine the impacts of these trends on the value of customer reliability and market outcomes.

Question 1

b. Are there any changes/trends to the way consumers are likely to use electricity to 2020-2024 that suggest that they may place a higher or lower value compared to 2014 on a reliable supply of electricity from the national electricity market? Please detail the changes, consumers involved and the evidence of their impact on those customers' value of reliability.

5.5.3 Other relevant matters

In assessing whether there is a material benefit in reassessing the level of the reliability standard the Panel may consider any other relevant matters.[109]

Changes in the cost of marginal generation

The Panel will consider the materiality of changes in the cost of producing an additional unit of energy to meet otherwise unmet demand, as it is the costs of this marginal generation that are the counter point to value of customer reliability in the reliability "trade-off".

The cost of marginal generation is likely to have changed since the 2014 review. The Panel will assess whether the cost of additional capacity has changed substantially since the last review as an output of the modelling for the review.

Of interest is the cost of new entrant technologies, particularly generation that is capable of minimising the quantity of unserved energy. This restricts the analysis to dispatchable generation (including from batteries) that is sufficiently flexible to meet demand at times when there would otherwise be unserved energy and to intermittent generation that has output that correlates with dispatch intervals where there would otherwise be unserved energy.

Modelling has historically focused on the relationship between the reliability standard and total system costs. This approach assumed that the constraint on meeting a particular reliability standard has been system capacity. Thus modelling of system costs associated with marginal changes in the reliability standard has focused on the capital costs required to provide sufficient capacity to meet peak demand.

On a prospective basis however, the constraint on meeting the reliability standard will also have to take into account the capabilities, short-term operating costs, and correlation of output of potential generators rather than nameplate capacity. This will

109 National Electricity Rules clause 3.9.3A(e)(5).

necessarily include a greater focus on start-up times, start-up costs, idling costs and the correlation of output with existing intermittent generation.

Providing a stable, predictable and flexible regulatory framework

The Panel is to be guided by the principle of providing a stable, predictable and flexible regulatory framework in order to meet the national electricity objective.

We note that re-assessing the reliability standard necessarily requires the reassessment of other downstream reliability settings such as the market price cap, the administered price cap and cumulative price threshold. Furthermore, maintaining consistency in the reliability standard provides a degree of certainty and predictability for market participants when planning future operations.

On that basis, we are of the view that a significant change in the value of customer reliability and/or the cost of additional capacity would be required to meet the materiality threshold for reassessing the level of the reliability standard.

A key concern in the review is projecting (as best we can) the expected costs and values associated with the reliability trade-off for the period 1 July 2020 – 1 July 2024. The Panel acknowledges that the existing level of the reliability standard is based on a set of assumed conditions, some of which are likely to have changed by 2020-2024. We also note that actual conditions at present are relevant to the extent that they inform our assumptions regarding conditions in 2020-2024.

Question 1

c. Over the period 2020 - 2024, is the cost of marginal generation and/or demand response likely to change materially compared to the present?

d. Are there any other emerging factors the Panel should consider in its materiality assessment that support or erode the case for a reassessment of the reliability standard in the 2018 Review?

5.6 Assessment of the level of the reliability standard

If, following stakeholder input, the Panel does consider that there is material benefit in reassessing the level of the reliability standard then our review would be guided by the assessment criteria established in rules and the guidelines.

Additionally the Panel would be guided by the approaches to modelling and to market and policy uncertainties, which are described in subsequent chapters of this paper.

Question 1

e. If the Panel were to reassess the reliability standard, are there principles and assessment factors additional to those outlined in the rules and guidelines that the Panel should consider? Given recent market developments and pricing outcomes, and trends, is the current reliability standard appropriate for the period 1 July 2020 - 2024? If no, what would be an appropriate reliability standard, why and what is the evidence supporting your view?

6 The market price cap

The guidelines establish that the Panel is to review the level of market price cap in each review. Factors to be considered include setting a market price cap that:

- Allows the reliability standard to be satisfied without use of AEMO's directions powers or Reliability and Reserve Emergency Trader powers.
- In conjunction with other provisions of the rules, not create risks which threaten the overall integrity of the market.[110]

The guidelines also establish that the indexation of the market cap (and also the cumulative price threshold) will continue to be based on the consumer price index unless the Panel considers there is material benefit in reassessing the approach.[111] The Panel's preliminary view is that there is no material benefit in reassessing the use of the consumer price index for annual indexation of both parameters.

This chapter:

- highlights the historical levels of the market price cap and key issues from the 2014 review
- elaborates on the role the market price cap serves in the market
- describes the trade-off the Panel makes in setting the market price cap
- explains the assessment criteria the Panel must use to arrive at our recommendation on the level of the market price cap
- presents the Panel's preliminary view on continuing to use the consumer price index as the basis for annual indexation.

6.1 History of the market price cap

A market price cap has been a feature of the national electricity market since its inception.[112]

Table 6.1 shows historical levels of the market price cap since 2007/2008. The level of the market price cap has increased incrementally from $10,000/MWh to $14,000/MWh over the past decade. To keep its value constant in real terms, the market price cap has been indexed annually since 1 July 2012 in line with the consumer price index. The level of the market price cap has been at the same level in real terms since 1 July 2012.[113]

110 Rules clause 3.9.3A(f).

111 Guidelines section 3.7.2.

112 Noting that a 2009 rule change amended the term 'value of lost load (VoLL)' to 'market price cap', see Appendix A.

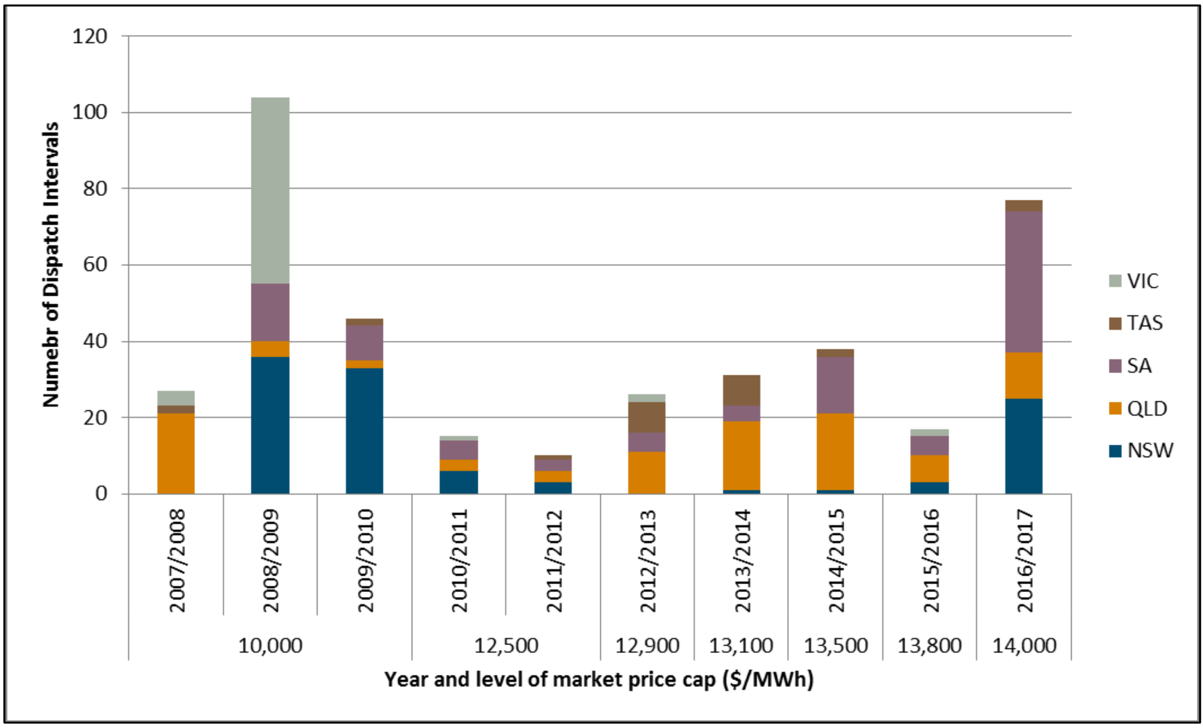
113 In May 2009 the National Electricity Amendment (NEM Reliability Settings: VoLL, cumulative price threshold and future reliability review) Rule 2009 No. 13 commenced operation. This increased the level of the market price cap from $10,000MW/h to $12,500/MWh effective 1 July 2010. A subsequent Rule change in 2011 (National Electricity Amendment (Reliability Settings from 1 July 2012) Rule 2011 No. 5) introduced annual indexation based on changes in the consumer price

Table 6.1 Market price cap historical levels

Financial Year	Market price cap ($/MWh)
2007/2008	10,000
2008/2009	10,000
2009/2010	10,000
2010/2011	12,500
2011/2012	12,500
2012/2013	12,900
2013/2014	13,100
2014/2015	13,500
2015/2016	13,800
2016/2017	14,000
2017/2018	14,200

Figure Figure 6.1 shows that, with the exception of 2015/16, the number of times the market price cap has been reached in the national electricity market has increased year-on-year since 2011/12, with the highest number of market price cap events in the 2016/17 year to date occurring in South Australia.

Figure 6.1 Incidence of market price cap events (2007/08 – 2016/17)[114]



index to preserve the value of the cap in real terms. Indexation of the market price cap commenced on 1 July 2012.

114 Year 2016/17 data current as of 7 March 2017.

The Panel recommended in the 2014 Review that no change be made to the real value of the market price cap to apply from 1 July 2016. Key issues that emerged in the 2014 Review regarding the level of the market price cap included:

- Stakeholder views on the purpose of the cap – stakeholders' views on the key purpose of the market price cap differed, in turn informing their arguments for amendments to the level of the cap.[115]
- Stakeholder views on changing the level of the cap – while several stakeholders considered the market price cap should change, their views differed on the factors that should be considered in setting the cap and whether its level should be raised or lowered. A number of stakeholders considered the existing value of the market price cap to be suitable to achieving the reliability standard.[116]
- The centrality of modelling – modelling approaches and outcomes were critical in informing the Panel's analysis and judgements regarding the level of the market price cap. The Panel considered further work on the modelling methodology would benefit future reliability standard and reliability settings reviews.[117]

6.2 The role of the market price cap

From an economic perspective the market price cap serves the following two functions in the national electricity market:

- **A default bid for loads** – the market price cap serves as a default bid for loads that do not participate in the market. Small customers have not historically been active participants in the wholesale market and so could not opt to alter their consumption to avoid high prices. The market price cap serves as a proxy "limit" on their bids – they will not pay more than this amount for energy in any dispatch interval. For those customers served by a retailer, the actual price paid will reflect the pricing plan found in their contract with their retailer, which will reflect the average cost the retailer expects to incur over the relevant period for that customer (as explained in chapter 2).
- **Limiting market participants' exposure to extreme prices** – notwithstanding the role of the market price cap as the default bid for loads, the cap also limits participants' exposure to very high and very low prices. That is it places an upper bound on the maximum possible price to which a participant can be exposed in the market.

As described in chapter 2, in economic terms the role of the market price cap is to limit market participants' exposure to very high prices and thereby serve to limit risk. In setting the market price cap the primary principle observed is that the market price cap

115 Reliability Panel, *Reliability Standard and Reliability Settings Review 2014*, Final Report, 16 July 2014, Sydney, p. 37

116 Reliability Panel, *Reliability Standard and Reliability Settings Review 2014*, Final Report, 16 July 2014, Sydney, p. 35

117 Reliability Panel, *Reliability Standard and Reliability Settings Review 2014*, Final Report, 16 July 2014, Sydney, pp. 38-43.

should not prevent the market sending efficient price signals, to support the efficient operation of and investment in electricity services over the long run. The process for setting the market price cap assumes that the reliability standard reflects the efficient level of expected unserved energy.

The level of the market price cap also should allow the market price to create incentives for participants to manage price risk; whether it is through the purchase of contracts or even investment in generation. If prices are not distorted or constrained by the market price cap, participants' risk management responses will:

- support efficient operational outcomes
- deliver the investment in generation capacity needed to at least meet the reliability standard.

Critically the market price cap is not a tool for putting downward pressure on the prices charged to consumers. Theoretically it is not necessarily the case that a higher market price cap leads to higher average prices. Actual price outcomes are determined by a range of other factors such as bidding behaviour, gas prices and depth of competition in the market.[118] The Panel has previously emphasised this view on the role of the market price cap: "the MPC [market price cap] should not be used to actively steer the market into a short run equilibrium position, or to actively drive disinvestment decisions".[119]

6.3 The trade-off in setting the level of the market price cap

To understand the factors the Panel must consider in this review, it is useful to elaborate on the trade-off the Panel is making when setting the level of the market price cap.

The market price cap is a constraint on prices. Its existence prevents prices from rising beyond a certain level. It follows that different levels of the cap may alter the payments for energy in the market. For example, if the cap were set sufficiently low (for instance at $300/MWh) it would prevent the market from sending efficient price signals at times when the marginal cost of energy exceeded $300/MWh. In turn this would feed through to the contract market, potentially reducing the incentive to enter into contracts, decreasing contract market liquidity and, over the long run, reducing incentives for efficient investment in electricity services.

Equally if the market price cap were set extremely high, market participants could be exposed to substantial price risk. This could threaten the stability of the market over the long run. While the contract market would act to provide services to minimise this price risk, market participants would remain exposed to some residual financial risk due to the difficulty of exactly matching contract volume with actual wholesale market

118 In theory, reducing the level of market price cap may reduce the ability of generators to earn revenue in the spot market, leading to lower prices for consumers in the short term. However, over the longer term a lower market price cap may dampen investment signals, leading to a shortage of generation capacity. In this case, a lower market price cap could result in increased prices to consumers over the longer term.

119 Guidelines p. 6.

outcomes. Also the cost of some forms of hedge contracts could be expected to significantly increase.

Setting the level of the market price cap therefore involves making a trade-off on behalf of consumers between:

- **Market participants' exposure to high prices** – the higher the price cap the greater participants' exposure to high prices and therefore price risk.[120]
- **Inefficient price signals** – the lower the market price cap the greater the chance of impeding efficient price signals for operation and investment, resulting in higher costs over the long term.

6.4 Assessment criteria

The guidelines establish that the Panel is to review the level of the market price cap in this review. Our analysis and judgements will be based on assessment criteria stipulated in the rules, the guidelines and the terms of reference for the review, and the overarching goal of promoting the national electricity objective.

6.4.1 Assessment requirements

The Panel may only recommend a market price cap that we consider will:

- Allow the reliability standard to be satisfied without AEMO using its directions or reserve trader powers.[121]
- In conjunction with other provisions of the rules, not create risks which threaten the overall integrity of the market.[122]

The rules also specify that if the Panel is of the view that a decrease in the market price cap may mean the reliability standard is not maintained, the Panel may only recommend such a decrease where it has considered any alternative arrangements necessary to maintain the reliability standard.[123]

These assessment requirements directly relate to the purpose of the market price cap and the trade-off involved in setting its level. The market price cap should be set at a level to allow requisite reliability outcomes to be achieved (everything being equal) through price signals incentivising investment in capacity, without AEMO:

- Exercising its power to issue directions to market participants.
- Exercising its reliability and emergency reserve trader powers through the dispatch of scheduled reserves available under scheduled reserve contracts or the activation of unscheduled reserves available under unscheduled reserve contracts.

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120 Noting that actual participant exposure to price risk is dependent on the risk management strategies they adopt, such as entering into contractual arrangements, or establishing a physical hedge of a retail business or generation capacity.

121 Established under clauses 3.20.7(a) and 4.8.9(a) of the Rules

122 Rules, clause 3.9.3A(f).

123 Rules, clause 3.9.3A(g).

Question 2: The market price cap

a. Given recent market developments and pricing outcomes, is the current market price cap appropriate for allowing the reliability standard to be met without the use of AEMO's powers to intervene? If not, what would be an appropriate market price cap, why and what is the evidence supporting your view?

b. Given recent market developments and pricing outcomes, is the current market price cap (in conjunction with other provisions of the rules) likely to "create risks which threaten the overall integrity of the market", including in the contract market)? If so, what would be an appropriate market price cap, why and what is the evidence supporting your view?

c. How might a change in the market price cap affect, if at all, contract market liquidity? More generally are there issues the Panel should consider regarding liquidity in the contract market or factors affecting its effective operation in the context of reliability settings? Please provide evidence supporting your view.

d. Would a change in the market price cap change generator operating strategies to underpin hedge markets?

6.4.2 Assessment considerations

The Panel must have regard to the potential impact of any proposed change to the market price cap on: the reliability of the power system; spot prices; investment in the national electricity market, and; market participants.[124]

As previously discussed the impact of the market price cap on system reliability is central to the Panel's considerations. The Panel may only recommend a market price cap that we expect will allow the reliability standard to be satisfied without use of AEMO's powers to intervene.

By definition, the market price cap sets a limit on spot prices. The key principle to be observed in setting its level is that the market price cap should not prevent the market sending efficient price signals, to support the efficient operation of, and investment in electricity services over the long run.[125] In other words limiting market participants' exposure to high prices should not come at the cost of the efficient operation of and investment in the market.

Finally, in reviewing the market price cap the Panel is to be guided by the principle of providing a stable, predictable and flexible regulatory framework.[126] The purpose of this principle is to promote investor certainty. The need for a stable and predictable market framework is not new as it was also discussed in the 2014 Review.[127] However it is particularly crucial to support efficient investment over this review's time horizon given the rapid change already underway in the physical system and considerable

124 Rules clause 3.9.3A(e).

125 Where efficient investment is taken to be investment sufficient to satisfy the reliability standard.

126 Guidelines p. 3.

127 Reliability Panel, *Reliability standard and reliability settings review 2014,* final report, 16 July 2014, Sydney, p. 42.

uncertainty in associated policy areas, such as the integration of energy and emissions policy.

In being guided by this principle the Panel may:

- Seek to achieve predictable market outcomes while also reflecting the significant changes underway in the physical energy system.
- Set a "high bar" for the case for changing the market price cap. For instance, requiring clear and compelling evidence that any change is warranted and that the potential benefits of an increase, or decrease, in the level of the cap are likely to outweigh the additional risks and costs that may be introduced by the change.
- If the Panel determines in favour of a change to the level of the market price cap, then recommending that the change occur incrementally over a period of several review periods.[128]

The Panel many take into account any other matters that we consider relevant.[129]

Question 2

e. What is the effectiveness of the market price cap in allowing for investment in the current uncertain environment?

f. What factors or impacts regarding spot prices, investment, market participants and/or the stability of the regulatory framework should the Panel pay particular attention to?

g. Are there principles and assessment factors additional to those outlined in the rules and guidelines that the Panel should consider?

6.4.3 Modelling to determine the market price cap

The previous section outlined the assessment criteria we will use to review the level of the market price cap. As was the case in 2014, detailed modelling will inform our judgement of the requisite market price cap. For instance, modelling will provide estimates of the expected impact of the market price cap on investment in the national electricity market.

Recognising the centrality of modelling to reliability reviews, one of our recommendations in 2014 was that a study be undertaken into the modelling approach for future reviews. That study, undertaken by Oakley Greenwood in 2016, proposed three principal changes to the 2014 modelling approach. These are explained and discussed in Chapter 10.

6.5 Materiality threshold criteria—indexation

6.5.1 Indexation is currently based on the consumer price index

Currently both the market price cap and the cumulative price threshold are adjusted annually to movements in the consumer price index. The guidelines indicate that the

128 Guidelines, section 3.3.2.

129 Rules clause 3.9.3A(e)(5).

Panel will continue to use the consumer price index to adjust both settings unless we consider there may be a material benefit in reassessing this approach.

In making this decision the Panel will consider the following factors:

- Whether there have been material changes in the basket of goods used to calculate the consumer price index that make it less relevant for indexation of the settings.
- Whether there have been changes in the methodology used to calculate the consumer price index.
- Whether a more preferable index has become available and/or there is a change in the designation of the consumer price index as an official statistic.
- Any other relevant matter.[130]

In 2009 the Panel proposed using a producer price index stage 2 index over the consumer price index.[131] The Commission rejected this proposal and indexed the cumulative price threshold to consumer price index.[132]

6.5.2 Observations

The Panel's preliminary view (subject to consultation), is that both the market price cap and the cumulative price threshold should continue to be adjusted using the same index and that both should remain indexed to the consumer price index.

This reflects the continuing use of the consumer price index within business and for investment decisions and modelling, and the continued degree of stability and predictability of the consumer price index.

The impact of any long-term deviations of the consumer price index from the actual cost of generation capacity is mitigated by the fact that reliability settings are reviewed every four years. Thus the potential for a long-term deviation between the actual cost of generation and the cost of generation implicitly used in the cumulative price threshold is limited to a four-year period.

Question 2

h. Has there been a material change in the method used to calculate the consumer price index that makes it less relevant for the indexation of the market price cap and the cumulative price threshold?

i. Is there a more preferable statistic that should be used to index either the market price cap and/or the cumulative price threshold? If yes, what is it and why is it preferable?

j. Should the market price cap and cumulative price threshold continue to be indexed using the same index?

130 Guidelines p 8-9.

131 Reliability Panel, *Reliability Standard and Reliability Settings Review*, Sydney, 30 April 2010, p. 41.

132 AEMC, *National Electricity Amendment (Reliability Settings from 1 July 2012) Rule 2011*, Sydney, 16 June 2011, p. 5.

7 The cumulative price threshold

The guidelines establish that the level of the cumulative price threshold is subject to four-yearly review. This chapter:

- outlines the history of the cumulative price threshold
- elaborates on the role it serves in the market
- describes the trade-off the Panel makes when setting the cumulative price threshold
- outlines the assessment criteria we must use in the review
- provides initial comment on the assessment considerations.

7.1 History of the cumulative price threshold

The cumulative price threshold was established in December 2000 and set at $150,000 by the ACCC, following a recommendation by the Reliability Panel.[133] Before the cumulative price threshold was established, the administered price cap would be triggered by the occurrence of "force majeure events".[134] The cumulative price threshold was introduced to provide greater certainty to market participants in relation to when prices would be capped as it was based on price alone, rather than the occurrence of events such as load shedding or network failure.[135]

In 2008 the Panel recommended that the level of the cumulative price threshold be formally defined at 15 times the market price cap. This would have increased the cumulative price threshold to $187,500. Historically, the cumulative price threshold has

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133 ACCC, *Determination- Application for Authorisation- VoLL, Capacity Mechanism and Price Floor*, 20 December 2000. Available at: http://www.accc.gov.au/content/trimFile.phtml?trimFileName=D03+38328.pdf&trimFileTitle=D03+38328.pdf&trimFileFromVersionId=756473.

134 The NECA defined force majeure events as the occurrence of a trading interval price in any region equal to VoLL due to involuntary load shedding or the occurrence of a network failure or de-rating that constrained one or more scheduled generators in the dispatch process. In defining force majeure events, NECA indicated that there was a need to balance the "conflicting objectives of overall market risk management and allowing the market to operate normally as long as possible". NECA, *Administered price arrangements and force majeure*, April 1998, p. 10, quote at p. 12.

135 ACCC, *Determination- Application for Authorisation- VoLL, Capacity Mechanism and Price Floor*, 20 December 2000, p. 6. It should be noted that, on the recommendation of the Reliability Panel, NECA initially sought to set the cumulative price threshold at $300,000, when it applied for Code change authorisation by the ACCC in 1999. A level of $300,000 was chosen as the Panel believed that the high price periods before each cumulative price threshold breach would provide incentives for the supply of cost effective peak generation investment, by allowing a new entrant open cycle gas turbine plant to recover three years' worth of its annual fixed costs. However, the ACCC indicated in its final determination in 2000 that a lower cumulative price threshold level was required to reduce the risk of Market Participants being exposed to extreme prices over prolonged periods of time before the administered price cap was imposed.
Reliability Panel, *Review of VoLL in the National Electricity Market: Report and Recommendation, Final Report, NECA*, Adelaide, July 1999, p. 20 . ACCC, *Determination- Application for Authorisation- VoLL, Capacity Mechanism and Price Floor*, 20 December 2000, pp. 44-45.

been linked to three years of revenue to sustain the marginal generation investment.[136] The Panel believed that the cumulative price threshold should only be exceeded in extreme circumstances, given its role as a financial safety net. Raising the market price cap without correspondingly raising the cumulative price threshold would have resulted in an increase in the incidence of the threshold being met. On that basis, the Panel recommended an increase in the market price cap and a commensurate increase in the cumulative price threshold.

In 2009 the Commission accepted that the cumulative price threshold should be raised in line with the market price cap, but decided against formalising the level of the threshold at 15 times the market price cap. Instead it set the level of the cumulative price threshold at $187,500 and indexed it in the same way as the market price cap.

As a result, the cumulative price threshold has continued to be approximately 15 times the market price cap but is defined separately in dollar terms.

There have only been five administered price periods in the energy market since inception of the national electricity market and sixteen instances of the cumulative price threshold being met in ancillary service markets.[137]

Appendix A summarises previous Panel reviews and Commission determinations regarding the reliability standard and settings.

7.2 The role of the cumulative price threshold

As discussed in Chapter 2, the purpose of the price settings collectively in the national electricity market is to help limit market participants’ exposure to price risk. The settings thereby promote the long-term integrity of the power system for the long term interests of electricity consumers.

The cumulative price threshold is one of the settings that limit market participants' financial exposure to the wholesale spot market during *prolonged* periods of high prices.[138] In frequency control ancillary services (FCAS) markets an administered pricing period is declared after 2,016 dispatch intervals, if the cumulative price is six times the cumulative price threshold.

7.3 The trade-off in setting the level of the cumulative price threshold

The level of the cumulative price threshold has historically been set together with the market price cap. Altering the cumulative price threshold unilaterally alters the trade-

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136 Oakley Greenwood, *Assessment of approach to modelling of Reliability Settings*, report to the Reliability Panel, September 2016, Sydney, p. 16.

137 Internal AEMC source. Section 7.4.3 discusses the increased occurrence in ancillary service markets.

138 Together with the administered price cap (see chapter 8). The cumulative price threshold also limits the risk of financial contagion across participants in the national electricity market. If market participants are insufficiently hedged, exposure to high price risk could result in sudden market exit. If the failed participant is particularly large, there is a risk of a financial contagion effect, whereby the financial failure of the large participant could trigger a cascading series of failures across the market, leading to significant instability and price impacts for consumers. There are several mechanisms in the rules designed to limit the risk of financial contagion. See: AEMC, *NEM financial market resilience, final report*, 6 March 2015, Sydney.

off between the exposure of participants to extreme prices in the market and the amount of revenue that a marginal generator earns.[139]

A lower cumulative price threshold makes it more likely that an administered price period will occur. This reduces market participants' exposure to sustained high prices but correspondingly reduces the revenue that generators can potentially receive. A lower cumulative price threshold thereby reduces the effectiveness of a given level of market price cap by reducing the potential revenue earned by the marginal generator in the market.

The converse is also true. A higher cumulative price threshold makes it less likely that an administered price period will occur. This increases the level of price risk faced but correspondingly increases the revenue that generators can potentially receive. As a result, a higher cumulative price threshold increases the investment incentive effectiveness of a given level of market price cap by increasing the revenue earned by the marginal generator in the market.

Limiting participant exposure to sustained high prices may also alter incentives for participants to manage price risk, which may in turn affect consequences for investment outcomes. For example by reducing the demand for hedge contracts and potentially reducing contract market prices, thereby reducing incentives for investment. Conversely, a higher cumulative price threshold may increase prices in the contract market as participants seek to manage a higher level of wholesale spot market price risk but may also increase incentives for investment.

As a result of this relationship, the cumulative price threshold and market price cap have historically been set together.

7.4 Assessment criteria

There are two elements of the cumulative price threshold that are subject to review:

- The level of the cumulative price threshold, which is to be assessed by the Panel.
- The form of indexation for the cumulative price threshold, which is subject to a materiality assessment.[140]

The remainder of this chapter addresses the Panel's review of the level of the cumulative price index. Consideration of the use of the continued use of the consumer price index has been addressed in chapter 6 together with the market price cap.

7.4.1 Assessment requirements

In accordance with the rules the Panel may only recommend a cumulative price threshold that it considers will:[141]

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139 "Marginal generator" in this context refers to the last generator to enter the market or the existing generator that would be the first to exit the market given a reduction in revenue resulting from a change in reliability settings. The level of the reliability settings is set to ensure that the marginal generator required to meet the reliability standard earns sufficient revenue to remain within the market. Altering the cumulative price threshold unilaterally alters the revenue earned by the marginal generator and therefore its viability.

140 Guidelines pp. 6-9.

- Allow the reliability standard to be satisfied without AEMO using its directions or reserve trader powers.[142]
- In conjunction with other provisions of the rules, not create risks which threaten the overall integrity of the market.

The rules also specifies that if the Panel is of the view that a decrease in the cumulative price threshold may mean the reliability standard is not maintained, the Panel may only recommend such a decrease where it has considered any alternative arrangements necessary to maintain the reliability standard.[143]

Question 3: The cumulative price threshold

a. Given recent market developments and pricing outcomes, is the current cumulative price threshold appropriate for allowing the reliability standard to be satisfied without the use of AEMO’s powers to intervene? If not, what would be an appropriate cumulative price threshold, why and what is the evidence supporting your view?

b. Given recent market developments and pricing outcomes, is the current cumulative price threshold (in conjunction with other provisions of the rules) likely to create risks “which threaten the overall integrity of the market”, including in the contract market? If so, what would be an appropriate cumulative price threshold, why and what is the evidence supporting your view?

c. How might a change in the cumulative price threshold affect, if at all, contract market liquidity? More generally are there issues the Panel should consider regarding liquidity in the contract market or factors affecting its effective operation in the context of reliability settings? Please provide evidence supporting your view.

d. Would a change in the cumulative price threshold change generator operating strategies to underpin hedge markets?

7.4.2 Assessment considerations

The guidelines establish the following principles for assessing the cumulative price threshold:

- The cumulative price threshold should protect all market participants from prolonged periods of high market prices, with particular consideration to the impacts on investment costs and the promotion of market stability.
- The cumulative price threshold should not impede the ability of the market to determine price signals for efficient operation and investment in energy services.

141 Rules, clause 3.9.3A(f).

142 Established under clauses 3.20.7(a) and 4.8.9(a) of the rules.

143 Rules, clause 3.9.3A(g).

- The cumulative price threshold should be determined giving consideration to the level of the market price cap.[144]

The following sections discuss aspects of these principles.

7.4.3 Observations

Implications of the distribution and frequency of high price events on protecting market participants

Due to the fact that the cumulative price threshold refers to 2,016 *consecutive* dispatch intervals, changes in the distribution over time of high price intervals will affect the likelihood of the cumulative price threshold being breeched. The Panel is therefore interested in changes in the frequency and extent of high price events within the national electricity market.

The distribution of high-price intervals in the energy market and FCAS markets has changed over time. Some evidence exists of high price events occurring more frequently outside high demand intervals (see Chapter 4).

Frequency control ancillary services markets

Prior to October 2013 there had not been any administered price periods arising from FCAS prices exceeding the cumulative price threshold. However since October 2013 the cumulative price threshold has been exceeded in ancillary services markets on 19 occasions. All occurred in South Australia when the state was either deemed to be at risk of an islanding event or was in fact islanded.

This sudden increase in extreme FCAS pricing events is of interest to the Panel in terms of potentially signalling a significant change in underlying price volatility in FCAS markets. However as AEMO noted in its report on these extreme pricing events, specific temporary factors in South Australia are likely to have contributed to these outcomes. These included work on the Heywood interconnector (creating an islanding risk) and a small pool of potential suppliers of FCAS services within the State over this period (leading to limited competition in supply of FCAS services).[145]

AEMO does not expect there to be a system-wide shortfall of FCAS in the near term. It considers that the challenge of attracting sufficient FCAS is restricted to regions with the potential for islanding.[146] AEMO is currently working on FCAS frameworks and procurement including: "exploring options to adjust [FCAS] system parameters to manage system security of an islanded South Australian region".[147]

The Panel's current view is that these high prices reflect either temporary and/or local circumstances rather than indicating long-term structural change, which would warrant a reassessment of the level of the market price cap and the cumulative price threshold for FCAS markets. However we will monitor this issue including the implications of AEMO and others' findings for the system-wide reliability settings. For

144 Guidelines p. 7.

145 Reports available at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Market-notices-and-events/Pricing-event-reports

146 AEMO, *Progress report, Future power system security program*, 2017, Sydney, p. 9.

147 AEMO, *Progress report, Future power system security program*, 2017, Sydney, pp. 9-11, p. 22.

instance we will review the Australian Energy Regulator's report into the high prices of regulation ancillary services on 22 May 2017 in South Australia.[148]

The Panel welcomes stakeholder comments on whether there is likely to be a significant and sustained increase in the number and magnitude of high FCAS prices and if so, in which regions and why.

The energy market

More generally, the Panel is interested in information regarding the likely future distribution and frequency of high price events in the energy market and their corresponding impacts on the likelihood of triggering an administered pricing period. Information relating to the distribution of high price events across a contiguous seven day period or 2,016 dispatch intervals will be most relevant.

Question 3

e. Are there material changes to the distribution and frequency of high price events that are relevant to modelling the cumulative price threshold?

f. In particular, are there material changes to the distribution and frequency of high price events at the level of granularity associated with 2,016 dispatch intervals?

The cumulative price threshold and market price cap should be considered together

Modelling of the impact of a particular level of the cumulative price threshold in this review will examine whether or not the cumulative price threshold compromises the effectiveness of the market price signals enabled by the level of the market price cap.

This will require examining how the level of the cumulative price threshold affects the expected outcome for a marginal generator facing a given market price cap. This is done by estimating the potential for an administered pricing period to be triggered under a given level of the cumulative price threshold.

The Panel's preliminary view (subject to consultation) is that the level of the cumulative price threshold should be considered together with the market price cap. This reflects the interrelated nature of the market price cap and cumulative price threshold and the fact that changing one setting affects the basis on which the other setting is determined.

The Panel is interested in submissions relating to the absolute level of the cumulative price threshold and the appropriate relationship, implicit or explicit, between the cumulative price threshold and market price cap.

148 On Monday 22 May 2017 the price of regulation ancillary services in South Australia exceeded $5000/MW for five trading intervals. As part of its role, the Australian Energy Regulatory is to report on events in that result in frequency control ancillary services prices exceeding $5000 per megawatt and will publish a report into these recent price events.

Question 3

g. What factors should the Panel consider when seeking to ensure the cumulative price threshold does not compromise the price signals from the market price cap? Specifically, should the cumulative price threshold be adjusted if the market price cap is adjusted, thereby preserving the ratio of cumulative price threshold to market price cap at 15:1? Should the ratio between the cumulative price threshold and the market price cap be adjusted?

h. Should the cumulative price threshold be set with reference to another benchmark?

8 The administered price cap

The guidelines establish that the level of the administered price cap is subject to a materiality assessment.

The Panel's consideration to date suggests support for the case for a review of the administered price cap in the 2018 Review.

This chapter:

- provides an overview of the history of the administered price cap
- expands on the role of the cap
- describes the trade-off the Panel makes when setting the administered price cap
- explains the materiality threshold criteria we will use in this review
- outlines the Panel's preliminary observations against these criteria.

8.1 History of the administered price cap

The administered price cap was set at the commencement of the national electricity market in 1998 as:

- $100/MWh between 7.00am and 11.00pm on business days, and
- $50/MWh at other times.

The NECA Panel proposed increasing the administered price cap to $300/MWh in 1999, but NECA did not adopt the recommendation. The administered price cap remained unchanged until May 2008 when the current value and uniform price structure of $300/MWh for all time periods was adopted. The administered price cap has not been revised since then.

An administered price period is triggered where the cumulative price threshold is reached over a seven day period.[149] The administered price period remains in force until the later of:

- the end of the current trading day at 04:00
- the cumulative price threshold as calculated from dispatch prices without capping is less than the cumulative price threshold.[150]

There have only been five administered price periods in the energy market since inception of the NEM. As noted in section 7.4.3, up until October 2015, there had been no administered price periods arising from frequency control ancillary services prices exceeding the cumulative price threshold. However, over the period October to November 2015 there were 19 instances of the cumulative price threshold being

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149 In addition, an administered price period in relation to ancillary service markets will apply where the cumulative price threshold for market ancillary service exceeds six times the cumulative price threshold.

150 Rules clause 3.14.2(c).

exceeded in ancillary service markets in South Australia and subsequently there have been a further three such events.[151]

8.2 The role of the administered price cap

The administered price cap is one of the reliability settings intended to cap participants' exposure to sustained high prices, while maintaining incentives for participants to supply energy.[152]

The administered price cap also sets the limit for the administered floor price which is set at negative of the value of the administered price cap.[153]

A detailed explanation of the collective role of the reliability settings in the national electricity market is provided in section 2.3.

8.3 The trade-offs in setting the administered price cap

Setting the administered price cap involves balancing a number of competing objectives, namely:

- having a sufficiently low administered price cap so as to mitigate the risk of a systemic financial collapse of the electricity industry during an extreme market event
- having a sufficiently high administered price cap so as to incentivise market participants to supply electricity during administered price events
- having a sufficiently high administered price cap so as to minimise compensation claims by market participants following an application of the administered price cap.

An administered price period is associated with an extended period of high prices. High prices are connected to a tightening of the supply demand balance as increasingly high cost generation capacity is dispatched to satisfy demand. Having an administered price cap that is too low will discourage high-cost generators from bidding into the market potentially resulting in high cost generators choosing to not make a unit commitment decision. This would reduce available generation and potentially delay removal of the administered price period and return to normal market operations.

The value of the administered price cap can impact on the contract market through either decreasing or increasing expected future prices and residual risk and potentially decreasing or increasing the incentive for, and ability to finance, new investment.

If the administered price cap is too low and a high cost generator is nevertheless dispatched, it has the option of pursuing a compensation claim to ensure it recovers all eligible costs.[154] However, this is likely to be an expensive and time consuming

151 On 11 August 2016, 1 September 2016 and 18 April 2017 all in South Australia.

152 Guidelines section 3.6.2. The other reliability setting with this role is the cumulative price threshold, and the two are closely related see the subsequent section of this chapter addressing the materiality threshold criteria.

153 Rules clause 3.14.1(b).

154 Rules clause 3.14.6.

process. As such, ensuring that the administered price cap is sufficiently high to minimise the likelihood of triggering a compensation claim is highly desirable.

Where the administered price cap is too high, it may unnecessarily contribute to the financial distress of energy purchasers and risk contributing to financial collapse of the electricity industry.

8.4 Materiality threshold criteria

The guidelines require that a materiality test be applied to the level of the administered price cap with particular consideration given to any:

- significant changes in the typical short-run marginal costs of generators in the national electricity market
- compensation claims since the last review.[155]

The Panel may also consider any other matters it considers relevant.

A fundamental assumption in setting the administered price cap is that the level of the cumulative price threshold is such that, over time, it would enable capital investment in generation to be recovered and therefore would not put at risk future potential investments. This assumption is reflected in the assessment framework within the guidelines. This means that the level of the administered price cap need only cover the marginal cost faced by the generator in order for the generator to be left financially whole and willing to generate.

8.5 Observations regarding the materiality threshold

8.5.1 Changes in the short-run marginal cost of generation

The short run marginal cost of generation generally includes:[156]

- the cost of the additional fuel required
- any non-fuel variable operating and maintenance costs (such as water, chemicals, ash disposal), and bringing forward of maintenance.

Of increasing concern is the impact of gas supply uncertainty and price volatility on gas turbine short-run marginal costs. Given the timeframe until the next review of the administered price cap, consideration will need to be given in this review to possible further fuel price volatility and the impact on the optimal level of the administered price cap and by extension, whether the marginal generation type will remain a OCGT over the period to which this review applies. This is discussed further in Chapter 10 regarding potential changes to the modelling approach for this review.

155 Guidelines section 3.6.2.

156 The marginal generation technology will vary over time and as such the nature of the short run costs will also vary. For example, if the marginal generator was considered to be a battery, the short run costs would include electricity purchased for storage, the round trip efficiency impact, and any cyclic costs associated with a charge/discharge cycle for the battery technology chosen.

In the last administered price cap review in 2008, the Commission reported the following information for generators with a short run marginal cost estimated to exceed the administered price cap:[157]

Generator	Region	Estimated SRMC 2008/09
Hunter Valley Gas Turbine	NSW	$307.37/MWh
McKay Gas Turbine	QLD	$328.15/MWh
Port Lincoln Gas Turbine	SA	$335.05/MWh
Snuggery Power Station	SA	$353.26/MWh

Even limiting consideration to increases in underlying inflation based on changes in the consumer price index would suggest that the above short run marginal cost estimates would have increased by approximately 20 per cent since 2008 or to between $350 and $400/MWh. Assessment of fuel price increases may well give an even higher increase in costs. Finally, if the marginal (highest cost) generation technology changes, then these indicative short run marginal costs are likely to be less relevant. Taken together, these factors may support a review of the administered price cap.

Question 4: The administered price cap

a. Has the marginal (highest cost) generation technology changed since the last review and is it likely to change over the review period, or is continued reliance on OCGT as the marginal generation technology still reasonable?
b. Have typical generator short-run marginal costs increased significantly? Or are they expected to do so over the period 2020-2024?

8.5.2 Compensation claims

There has only been one compensation claim pursuant to application of the administered price cap, namely, the Synergen Power compensation claim in 2010. This claim was successful as it was found that the legitimate costs incurred by Synergen Power had exceeded the amount received under the administered price cap and that compensation in the amount of $130,486.94 was payable.[158]

The success of this compensation claim indicates that by 2010, there were at least some generators in the national electricity market with a short run marginal cost materially higher than the administered price cap and this may support the case for an increase in the administered price cap.[159]

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157 AEMC, *Determination of Schedule for the Administered Price Cap*, Final Report, 20 May 2008, Sydney.

158 http://www.aemc.gov.au/Markets-Reviews-Advice/Compensation-claim-from-Synergen-Power

159 Note that under the rules compensation is only payable to certain types of entities. For example, it is payable to scheduled and non-scheduled generators and scheduled network service providers to maintain the incentive for these parties to supply energy during an administered price period (rules clause 3.14.6(c)). It is not currently payable to entities that provide demand reductions.

8.5.3 Other relevant matters

As noted above, the value of the administered price cap has not been adjusted since 2008. Since that date there have been significant changes in availability and price of fuel sources. In particular, there has been increased fuel price volatility which suggests that at any particular time there could be significant variance in short run marginal cost for marginal peaking generators.

This impact is also reflected in the relative value of the administered price cap versus other elements of the reliability settings. For example, at the last administered price cap review in 2008, the administered price cap represented 3% of the then prevailing value of lost load price (now referred to as the market price cap). If this relativity was to be maintained, the administered price cap would currently be $426/MWh (representing 3% of the market price cap of $14,200). This would represent a 42% increase in the administered price cap.

Question 4

c. Are there any other emerging factors the Panel should consider in its materiality assessment that support or erode the case for a reassessment of the administered price cap in the 2018 Review?

8.6 Assessment of the level of the administered price cap

If, following stakeholder input the Panel considers there is material benefit in reassessing the level of the administered price cap, then the assessment criteria in the rules and guidelines would guide our reassessment.

Additionally the Panel would be guided by the approaches to modelling and to market and policy uncertainties, which are described in subsequent chapters of this paper.

Question 4

d. Given recent market developments and pricing outcomes, is the current administered price cap appropriate? If not, what would be an appropriate administered price cap, why and what is the evidence supporting your view?

e. If the Panel were to reassess the administered price cap, are there principles and assessment factors additional to those outlined in the rules and guidelines that the Panel should consider?

9 The market floor price

The guidelines establish that the level of the market floor price should remain as previously determined unless the Panel considers there may be material benefit in reassessing it.[160]

It is the Panel's preliminary view (subject to consultation) that there is not sufficient evidence of a material benefit from a reassessment of the market floor price.

This chapter:

- outlines the history of the market floor price
- details the role it serves in the national electricity market
- describes trade-offs involved in setting the level of market floor price
- outlines the conditions that must change to merit an assessment of the market floor price
- discusses the potential impact of any proposed change to market floor price.

9.1 History of the market floor price

The level of the market floor price has been -$1,000/MWh since December 2000.

Prior to market start, the National Electricity Code required all slow start generators to provide at least one negative, offloading bid, reflecting the amount that they would be prepared to pay to remain on line at minimum load. The code prohibited the pool price seen by market customers going below zero. In the circumstances where an excess generation period was declared, the pool price for customers was set to zero, while generators would be charged for supply at the negative clearing price.

In 1999, the National Electricity Code Administrator proposed a code change to replace the zero price floor with a new negative price floor of -$1,000/MWh. The Administrator argued that a floor at some level is essential to set a bound on the despatch algorithm and would also improve price signals in the market by allowing customers to see the marginal value of electricity more often.

The -$1,000/MWh level was significantly below the lowest market outcome for dispatch prices, which would ensure that it did not interfere with the normal clearing of the market, while providing some protection to participants. These amendments were confirmed by the Australian Competition and Consumer Commission in its determination on 20 December 2000.[161]

The market floor price has been reviewed a number of times:

- As part of the *Comprehensive reliability review* in 2007, the Panel opted not to change the form or level of the market floor price.

160 Guidelines section 3.5.2.

161 Reliability Panel, *Reliability Standard and Reliability Settings Review 2014*, Final Report, 16 July 2014, Sydney, p. 108.

- In the 2010 Reliability standard and settings review, the Panel found no evidence supporting a change to the market floor price. The Panel did not recommend the indexation of the market floor price, as the floor price differs from the market price cap and the cumulative price threshold as "it does not provide an investment signal and is therefore decoupled from the costs of capital".[162]
- In the 2014 Review, the Panel determined that no change be made to the form and level of the market floor price.

Appendix A summarises previous Panel reviews and Commission determinations regarding the reliability standard and settings.

9.2 The role of the market floor price

The market floor price serves as the minimum price that can be achieved in any dispatch and trading interval. It limits market participant's exposure to very low, negative prices and total market price volatility so as to prevent market instability. In setting the market floor price, the principle to be observed is that it should not interfere with efficient outcomes being achieved.

Cycling costs and the role served by the market floor price

Thermal generation units (such as coal and gas generators) incur significant costs when they are operated (cycled) at varying load levels in response to system demand, including on/off and low load.[163]

During low demand periods there may be multiple generators competing to remain online (dispatched) to avoid costs associated with cycling units or to be able to access high prices later. However, the total energy provided by these generators running at minimum generation, may exceed total demand at a given point in time.

By allowing generators to bid at negative price levels, the market can determine which generators should remain dispatched and which should be turned off in order to maintain the supply/demand balance.

162 As cited in the Reliability Panel, *Reliability Standard and Reliability Settings Review 2014*, Final Report, 16 July 2014, Sydney, p. 65.

163 The increased incremental costs attributed to cycling fall into the following categories: increases in maintenance and overhaul capital expenditures; forced outage effects, including forced outage time, replacement energy, and capacity; cost of increased unit heat rate, long-term efficiency and efficiency at low/variable loads; cost of start-up fuels, auxiliary power, chemicals; and additional manpower required for unit start-up. APTECH Engineering Services, 'The Cost of Cycling Coal Fired Power Plants', *Coal power magazine,* Winter 2006, accessed at http://www.pserc.cornell.edu/empire/100_coalpowerwintermag16-20.pdf. Hydro, solar and wind generators have negligible cycling costs.

Influences of the market floor price on generator behaviour

The market floor price influences a number of important behaviours in the national electricity market, including:

- strategic re-bidding, where the market floor price forms the lowest possible negative price at which constrained-off generators rebid capacity, in order to maximise dispatch[164]
- the ability of generators with alternative revenue streams (for example, renewable energy certificates or hedge contracts) to rebid capacity at negative prices to maintain dispatch.

The Panel acknowledges these two interactions with the market floor price. However, in both cases, the interaction with the market floor price is a function of there being a market floor price, rather than the specific level of the floor price. Any such issues should be addressed through policy measures rather than changing the level of the market floor price.

9.3 The trade-off in setting the level of the market floor price

In setting the market floor price, the Panel is making a trade-off on behalf of market participants and consumers, between:

- **Allowing the market to clear in most circumstances** – if the market floor price was not at a sufficiently low level to allow thermal generators with different cycling costs to differentiate themselves through their negative bids, a lower (more negative) market floor price would in theory, reduce distortion and enable the market to clear without intervention for a larger proportion of the time.
- **Not creating substantial risks which threaten the overall stability and integrity of the market** – an extremely low market floor price would in theory, expose thermal generators wishing to remain dispatched to increased negative price risk. The financial viability of specific generators could be affected if there were multiple instances at which the marginal unit for an interval had bid at a very low level. A generator incurring these losses may seek to pass through these costs onto other market participants by bidding in at a higher price level in the future. The high level of risk associated with having an extremely low market floor price would also have implications for the contract market.

164 While a dispatch price is determined for each five minute dispatch interval, settlement - the transfer of money for electricity supplied to the market and consumed by end users - is calculated on a 30 minute basis (i.e. for each trading interval). The settlement price is the time-weighted average of the six dispatch prices that occurred during any given trading interval. Participants are settled on the basis of the half hourly settlement price and their aggregate production or consumption during the respective half hour.

9.4 Materiality threshold criteria

Theoretical perspectives on amending the market floor price

From an economic perspective, the following changes could lead an assessment to suggest altering the market floor price:

- **A change in the number and frequency of trading intervals where the market has been, or has approached, the level of the market floor price.** A greater incidence of trading intervals in which the market floor price is reached could arise due to more low demand periods given increased penetration of rooftop solar generation. Holding all other factors constant, this would imply the need to lower (make more negative) the market floor price if the current negative bound of the price envelope did not allow generators to sufficiently differentiate themselves according to the value they placed on remaining dispatched.
- **Changes in the generation fleet, such that average generator cycling costs have changed significantly.**[165] A significant change in the nature of the generation fleet such that the range of generator cycling costs had decreased could result from the retirement of ageing thermal units. Generators would be able to use bids to differentiate themselves (according to the value they place on being dispatched), over a narrower price range. Holding all other factors constant, this would imply the need to raise (make less negative) the market floor price so that participants do not bear unnecessary risk; tightening the price envelope and reducing potential volatility.

Materiality assessment

The Panel will consider factors including the following when deciding whether there may be material benefit in reassessing the market floor price:

- the number and frequency of trading intervals where the market price has been, or has approached, the level of the market floor price
- whether there have been significant changes in the generation fleet, such that the range of generator cycling costs have changed significantly. [166]

9.4.1 The number and frequency of market floor and low price events

The number of market floor and low price events

Market floor price events are rare occurrences.[167] In the past ten years, across all mainland regions of the national electricity market, a dispatch interval has only reached the actual market floor price on 213 occasions, or 0.02 per cent of the time. On 628 occasions, or 0.06 per cent of the time, low price events (dispatch intervals less than

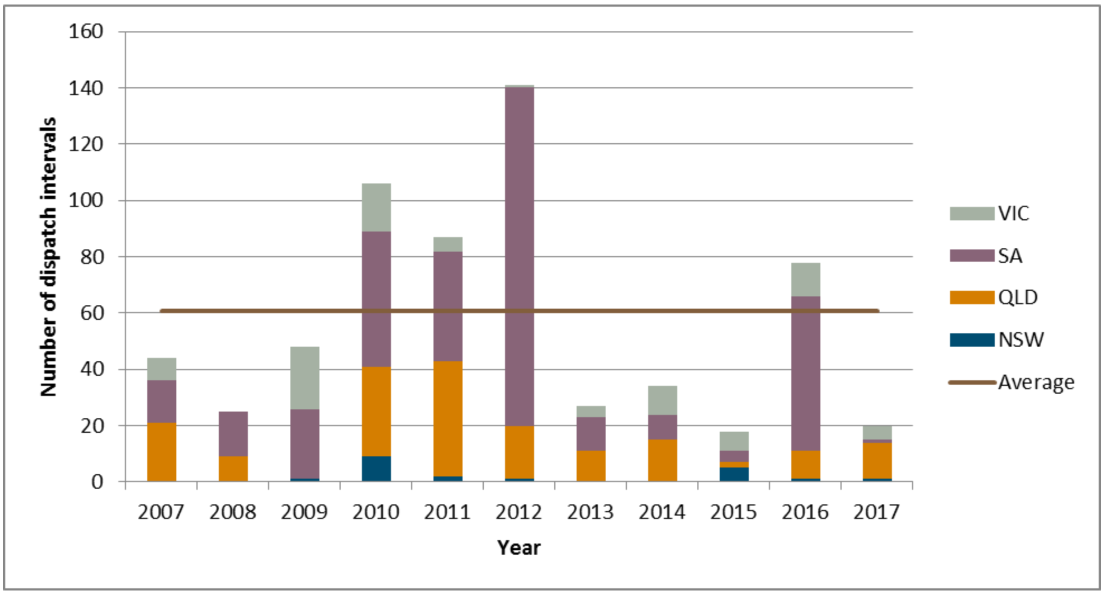
165 Footnote 163 lists the categories of incremental costs attributed to generator cycling.

166 Guidelines section 3.5.2.

167 The analysis in this section is current as of 7 March 2017 and omits Tasmania due to its unique market structure. In 2014, ROAM did not determine the required reliability settings in Tasmania since reliability in Tasmania is more significantly impacted by hydrology, rather than investment signals for peaking generation. Furthermore, Tasmania has a significant capacity reserve margin over the forecast peak demand.

-$900/MWh) have occurred. Figure 9.1 shows that while low price events seldom occurred from 2013 to 2015, in 2016 there was an increase in the number of low price events and multiple low price events have already taken place in 2017. However, fewer low price events were observed in 2016 than in 2010-2012.

Figure 9.1 Low price events in the national electricity market (2007-2017)



Source: AEMC analysis of Neopoint database

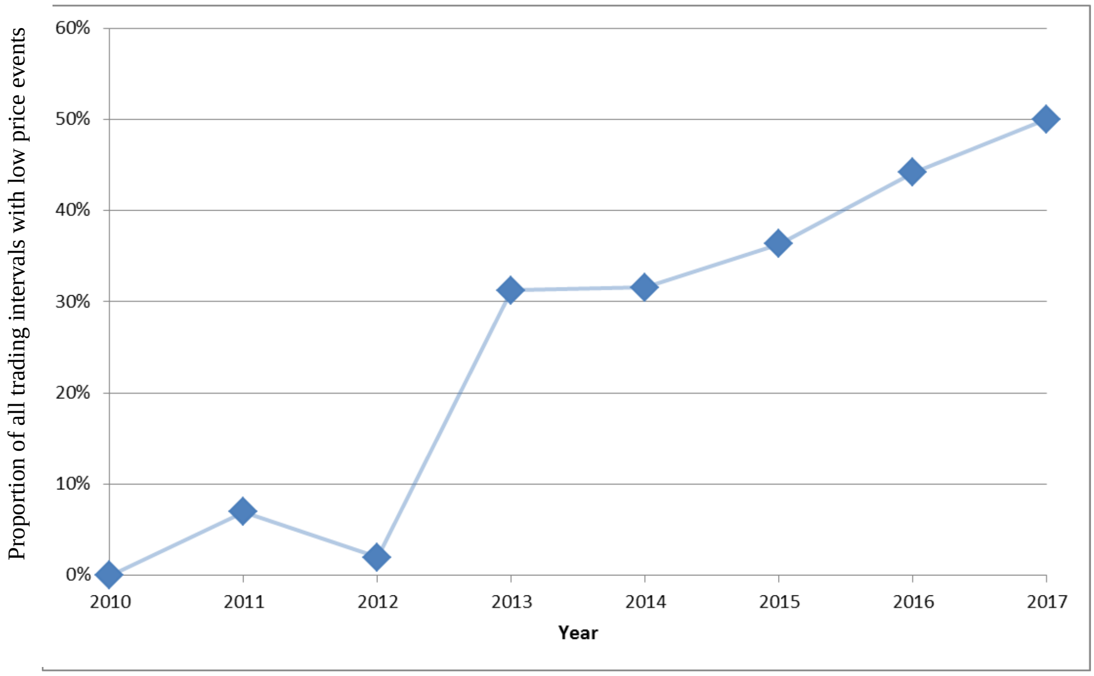
Figure 9.2 shows the coincidence between low and high dispatch interval price events (>$12,000/MWh) in the national electricity market within a single 30 minute trading interval. Low price events are expected at times of excess generation whereas high price events are expected at times the supply/demand balance is tight. An increasing proportion of low price events are occurring in the same trading interval as high price events. In 2016 over 40 per cent of trading intervals with a low price event occurred in conjunction with a high price event. Given that under normal operation, demand does not vary by thousands of megawatts over the course of a single trading interval, the co-occurrence of low and high price events implies vast swings in the generation offered at a given price.

These extreme changes in supply offers are likely to be driven by generator's attempts to maximise dispatch following a price spike event (strategic re-bidding), rather than technical limitations of plant. Strategic re-bidding is likely to have contributed to increases in the number of low price events; and the market floor price has an effect on the magnitude of the gains that can be realised through strategic re-bidding.[168]

168 A recent example of strategic re-bidding in the national electricity market occurred on 8 November 2016 during the trading interval ending 3.30pm, following a trip of three generators at the Braemar 2 Power Station in New South Wales. In the first dispatch interval, the price reached the market price cap. In the second and third dispatch intervals prices returned to normal levels as generation started to come online in response to the price. In the fourth and fifth dispatch intervals prices approached zero as generators attempted to maximise dispatch. In the sixth dispatch interval, the price fell to the market floor price as further generation entered the market. The trading price in New South Wales for the trading interval was $2,191/MWh.

However, as mentioned earlier strategic re-bidding will not be addressed by adjusting the level of the market floor price.

Figure 9.2 Trend in trading intervals with both low and high dispatch interval prices



Source: AEMC analysis of Neopoint database

The final row in Table 9.1 lists the number of trading intervals in which a low price event has occurred independently of a high price event, since 2010. There has not been a clear increasing trend in low price events driven by an excess of generation. This suggests there would not be merit in a re-examination of the market floor price level.

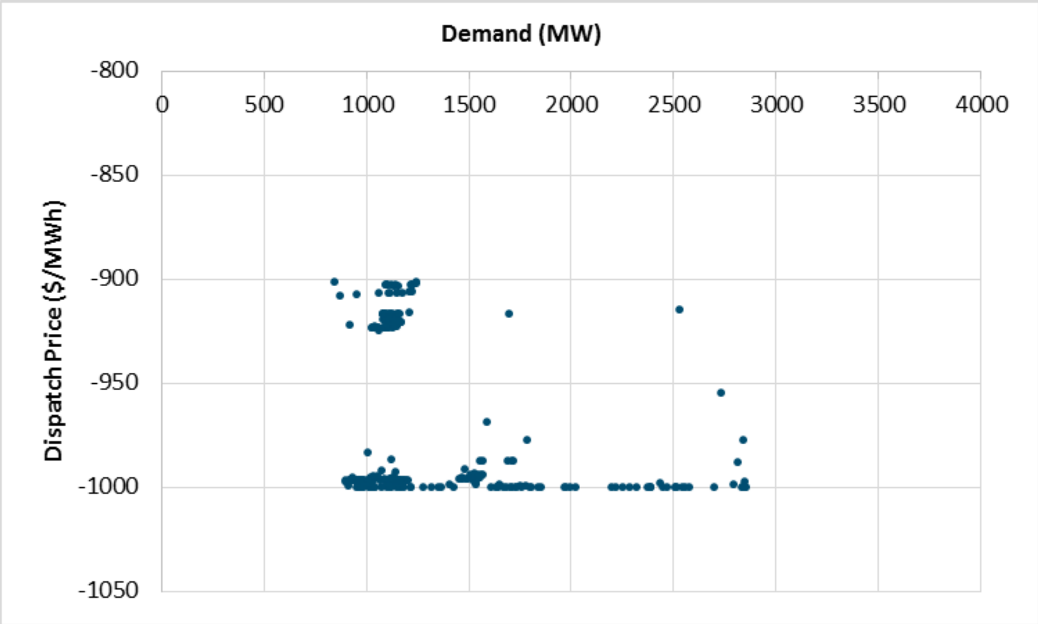
Table 9.1 Low and high price events in the national electricity market (2010 – 2017)

	2010	2011	2012	2013	2014	2015	2016	2017
Number of trading intervals with a high price event	7	35	18	72	58	108	113	107
Number of trading intervals with a low price event	50	43	50	16	19	11	43	12
Number of trading intervals with a low and high price event	0	3	1	5	6	4	19	6
Number of trading intervals with a low price event independent of a high price event	50	40	49	11	13	7	24	6

Source: AEMC analysis of Neopoint database

Excess generation that can lead to low price events is likely to occur at times of low demand. Figure 9.3 shows the relationship between demand and low price events since 2010 in South Australia, the jurisdiction in which the most low price events have occurred. A significant number of low price events occur at times of high and moderate demand (2,000-3,000MW). This may be indicative of strategic re-bidding behaviour. The Panel has acknowledged these events should not be addressed through the changing of the market floor price.

Figure 9.3 Distribution of low price events demand, South Australia (2010 -2017)



Source: AEMC analysis of Neopoint database

Frequency of low price events

The guidelines require an analysis of whether there has been a change in the frequency (as distinct from the number) of low price events.

Figures 9.4 and 9.5 show the occurrence of negative price dispatch intervals for 2012 and 2016; that is, the distribution throughout each year of sub-zero prices.[169] The year 2012 was selected as the basis for comparison as low price events were rare during 2013-2015.

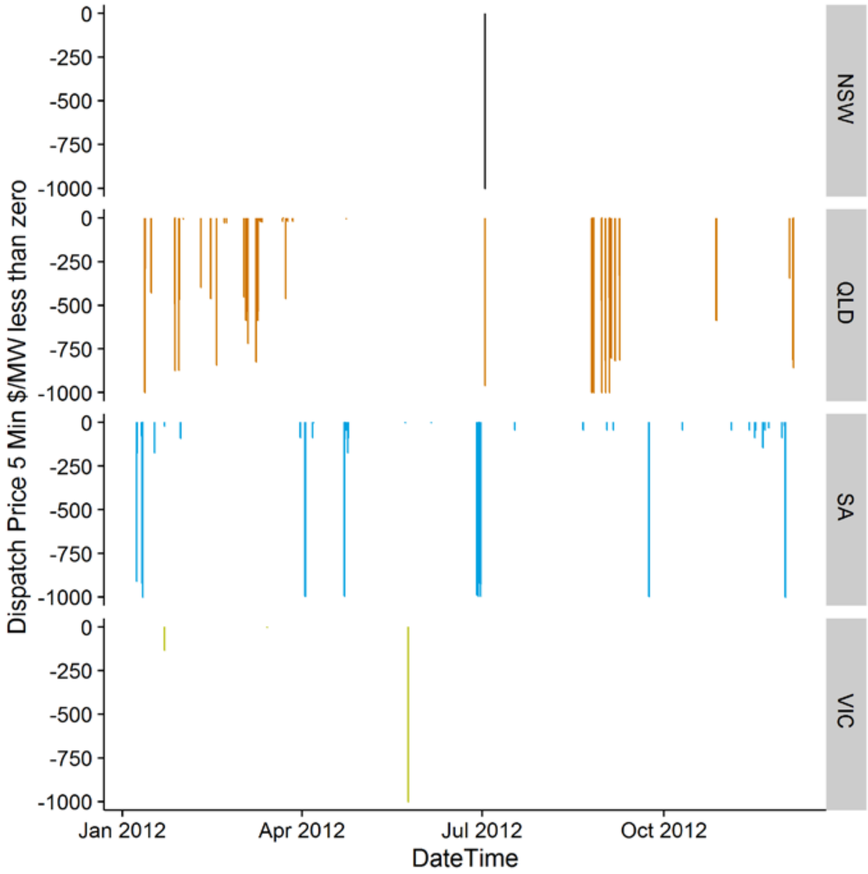
Comparing those states with the most negative price events in each year (South Australia and Queensland in 2012 and South Australia and Victoria in 2016) the frequency of low price events appear more dispersed throughout the year in 2016 compared to 2012.[170]

This analysis suggests that low price events are more likely to be isolated and infrequent events with the market clearing, and then quickly returning to “normal” prices. The relative absence of prolonged periods of low price events suggests that the current level of the market floor price is appropriate.

169 Analysis has been conducted on a dispatch interval basis (rather than trading interval basis as recommended by the guidelines) as it is extremely uncommon for low price events to persist for an entire trading interval.

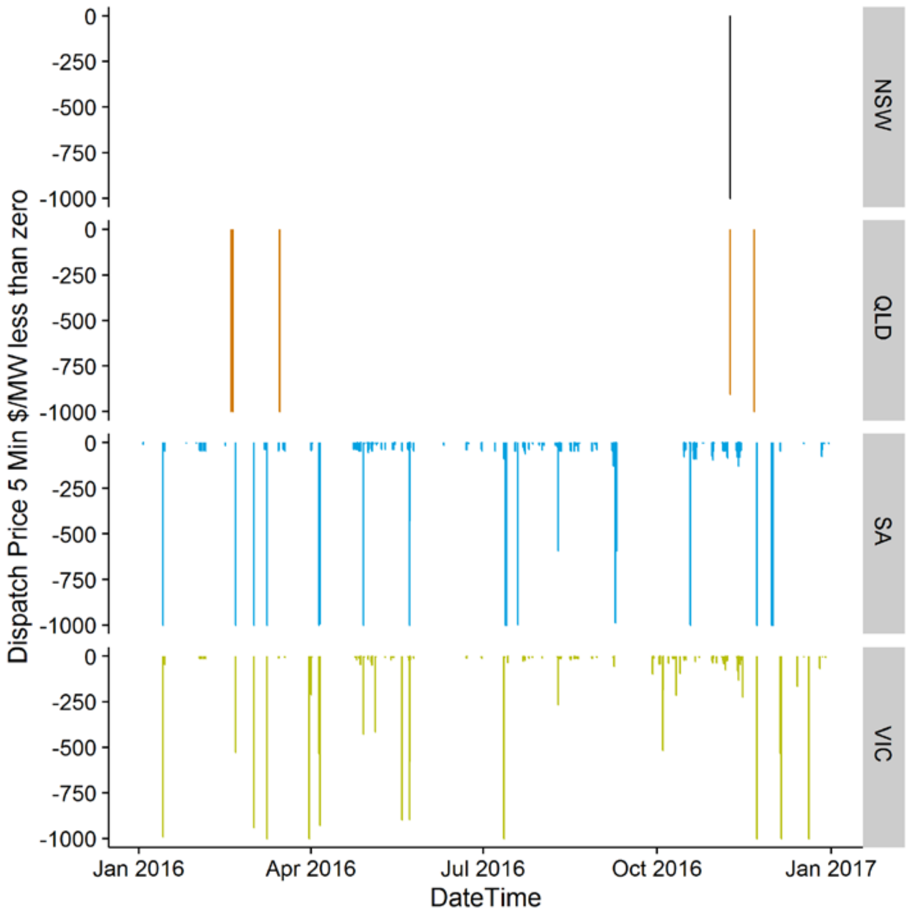
170 Noting that the total number of sub-zero dispatch intervals (excluding Tasmania) in 2012 and 2016 were 497 and 3,473 respectively (including prices just below $0).

Figure 9.4 Frequency of negative price events in 2012



Source: AEMC analysis of Neopoint database

Figure 9.5 Frequency of negative price events in 2016



Source: AEMC analysis of Neopoint database

Question 5: The market floor price

a. Are there specific considerations relating to changes in the number and frequency of trading intervals where the market has been, or has approached, the level of the market floor price that the Panel should take into account?

9.4.2 Changes to average generator cycling costs

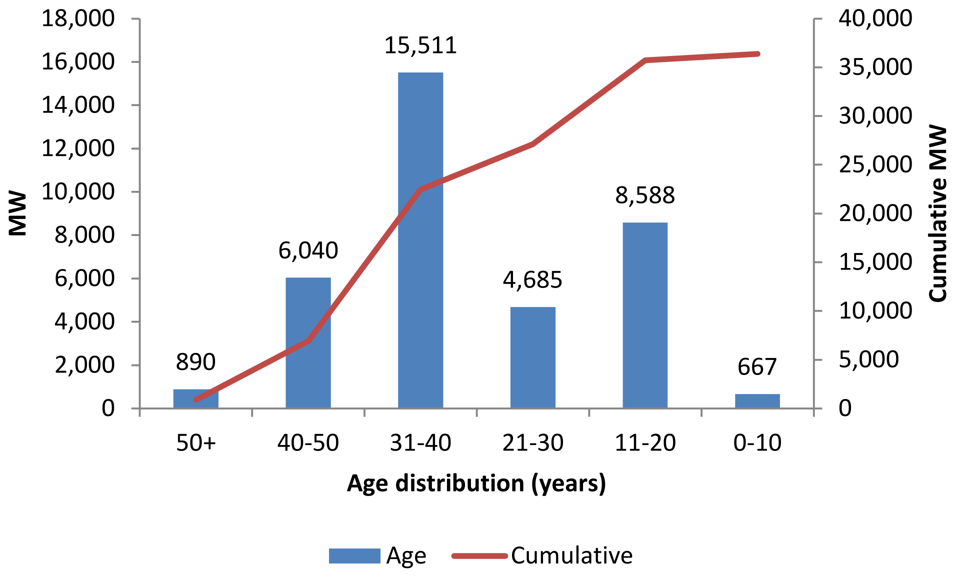
The Panel is required to consider whether there have been significant changes in the generation fleet, such that average generator cycling costs have changed significantly.

Recent changes in the generation mix include:

- retirement of ageing thermal units
- growth in intermittent technologies.

Figure 9.6 shows the age distribution of thermal plant in the national electricity market, and reveals that a significant proportion of the generation fleet consists of ageing thermal generators. These ageing thermal generators have significant cycling costs. The withdrawal (retirement) of these units from the fleet, is over time likely to decrease the range of generator cycling costs. This reduces pressure to lower the market floor price. From a modelling perspective, anticipating retirements is challenging with the recent exit of the Hazelwood Power Station a prime example. In the base case for the 2014 review Hazelwood was only assumed to be half retired by 2017 (800MW).[171]

Figure 9.6 Age distribution of national electricity market thermal generators



Source: AEMC analysis

Growth in intermittent technologies is likely to increase the frequency of cycling operations of conventional thermal units. Repeated cycling of thermal units may cause deteriorations to plant and lead to increased cost per cycle for some units.

As Oakley Greenwood reported in its 2016 modelling assessment, the economic estimation of cycling costs is problematic as costs of operation are uncertain and variable. For example, generator costs for operation at very low output or cycling on and off are quite variable and linked to costs to provide frequency control and voltage control capability, and intermittent generation capability (in particular wind) will inevitably vary from day to day, thereby changing the dynamics of operation. The additional maintenance ("wear and tear") costs associated with cycling can also be difficult to calculate.

Notwithstanding these estimation challenges, based on 2016 AEMO information cycling costs have not materially changed since the 2014 Review. The cycling costs used in the 2014 Review were based on AEMO's *2012 National Transmission Development Network Plan* data set.[172] ACIL Allen and GHD reviewed this 2012 data set

171 ROAM Consulting, *Reliability Standard and Settings Review*, report to the Reliability Panel, 21 May 2014, Brisbane.

172 Oakley Greenwood, *Assessment of approach to modelling of reliability settings*, report to the Reliability Panel, 2016, p. 24.

and found the cycling costs remained largely appropriate for existing generators.[173] The *2016 National Transmission Development Network Plan* adopts the cycling costs that ACIL Allen/GHD recommended. Oakley Greenwood proposed that cycling cost data for this 2018 Review be sourced from the *2016 National Transmission Development Network Plan*.[174]

Question 5

b. In your view, have average generator cycling costs increased or decreased since the 2014 Review? Please provide data and analysis.

9.4.3 Other relevant matters

The Panel notes advice from Oakley Greenwood in 2016 that: [175]

- the current level of the market floor price is such that it normally allows the market to clear during low demand periods
- there are a number of cost assumption sensitivities that may limit the usefulness of modelling the market floor price, suggesting that the market floor price may be more effectively set by reference to pragmatic considerations.

In 2014, the Panel did not find sufficient evidence to recommend a change in the market floor price and generally stakeholders supported maintaining the value of -$1,000/MWh. The Panel notes the effect of any adjustment in the level of market floor price on encouraging investment and reliability may be blunted by uncertainties in the policy and market environment.

ROAM's 2014 analysis indicated the short-term cycling of coal-fired generation is not necessary in the near future. However, ROAM cautioned against drawing inferences from the outcomes of its modelling. Analysis was based on an assumed set of cycling costs, which are difficult to estimate given the potential impacts of cycling on unit "wear-and-tear" and outages.

In submissions to past reviews, stakeholders have expressed that the market floor price should be sufficiently low to drive down surplus generation but not so low as to result in driving off conventional generation that may be required to support intermittent generation, for example the provision of frequency support services and system inertia.[176]

Negative price periods represent the most efficient time for energy storage technologies to charge and consume energy from the grid. The incidence of negative prices and market floor price events may serve as a signal to investors in new

173 ACIL Allen Consulting, *Fuel and Technology Cost Review*, 2014. No new thermal generators have entered the market since the last review.

174 Oakley Greenwood, *Assessment of approach to modelling of reliability settings*, report to the Reliability Panel, 2016.

175 Guidelines Determination p. 35.

176 GDF Suez Submission to 2014 Review.

technologies, such as batteries, to enter and operate in the market.[177] The market floor price limits the amount that these new technologies would be able to receive when operating as loads.

The market floor price has not been indexed and remains at the same level it was in 1998. This means in real terms the market floor price has reduced in magnitude. As indicated earlier, we have not seen a historic increase in the number of floor price events. This further reduces pressure to adjust the market floor price.

In light of the uncertainty currently prevailing in the national electricity market (detailed in chapter 4) there may be merit in retaining the current level of the market floor price to provide regulatory certainty.

Question 5

c. Are there any other emerging factors the Panel should consider in its materiality assessment that support or erode the case for a reassessment of the market floor price in the 2018 Review?

9.4.4 Summary

On balance, it is the Panel's preliminary view (subject to consultation) that sufficient evidence for a material benefit from a reassessment of the market floor price does not yet exist.

There has not been a sustained increase in low price events over recent years. Further, a significant proportion of low price events may reflect strategic re-bidding behaviour, a feature of the market that cannot be addressed by an adjustment in the level of the market floor price. Cycling costs are difficult to estimate accurately and appear not to have materially changed since the 2014 review. Finally, there is substantial value in maintaining the current level of the market floor price as this provides regulatory certainty in the context of considerable investment uncertainty.

9.5 Assessment of the level of the market floor price

If after considering stakeholder input the Panel determines that there is sufficient evidence of a material benefit in reassessing the market floor price, then the Panel may only recommend a market floor price which it considers will:

- allow the market to clear in most circumstances
- not create substantial risks which threaten the overall stability and integrity of the market.[178]

In this event the Panel would commission modelling to inform its analysis and judgement. The overall modelling approach for the review is explored in chapter 10 and stakeholders are encouraged to provide input on the proposed approach.

177 Snowy Hydro submission to 2014 Review.

178 Rules clause 3.9.3A(h).

Were the market floor price to be reviewed, the Panel must have regard to the potential impact of any proposed change to a reliability setting on:

- spot prices
- investment in the national electricity market
- the reliability of the power system
- market participants.[179]

The Panel notes that a lower (more negative) level of the market floor price broadens the price envelope in the national electricity market. This may lead to greater volatility in the market and in turn increase the risk market participants must bear. Increased risk exposure has implications for the contract market. For example, demand for contracts may rise as participants seek to hedge and cover their risk.

As stated earlier, a lower market floor price increases the potential volatility of market prices. This may increase the cost of investing in and operating units with high cycling costs. Additionally a lower market floor price may mean these generators face greater costs as they may have to bid at lower prices to ensure they are dispatched. Hence, the level of the market floor price may have some impact on the efficiency of investment and operation of energy services, although less significant than the level of the market price cap and cumulative price threshold.

If the market floor price is set at a level that is too high (too close to zero), it may not allow for efficient outcomes; more generators would be willing to pay the floor price as a penalty, requiring AEMO to intervene. If this persisted, generators with high cycling costs may be cycled regularly and may exit the market. This would reduce the generation capacity available to meet demand.

It is also important to note the uncertainty currently prevailing in the national electricity market (as detailed in chapter 4). The level of this uncertainty suggests that there may be merit in retaining the existing market floor price level to provide regulatory certainty.

Question 5

d. Given recent market developments and pricing outcomes, is the current market floor price appropriate? If not, what would be an appropriate market floor price, why and what is the evidence supporting your view. If the Panel were to reassess the market floor price, are there principles and assessment factors additional to those outlined in the rules and guidelines that the Panel should consider?

179 Rules clause 3.9.3A(e).

10 Modelling for the review

Detailed modelling of the electricity market informs each review of the reliability standard and settings. The general approach to modelling is established in the guidelines.

In the 2014 Review we recommended:

> The AEMC or the Panel (as appropriate) develop a methodology for undertaking future reliability standard and reliability settings reviews. This should include consideration of how the outcomes of any market modelling could be treated. This work should take place prior to the next reliability standard and reliability settings review, due to commence around 2017.[180]

The Panel made this recommendation in recognition of the need for stakeholders' desire for increased clarity and transparency around the Panel's decision making framework, including how the outcomes of any market modelling could be treated.[181]

Additionally, since the last review of the reliability settings, there have been significant changes in the national electricity market that bear on the modelling approach.

In September 2016, the Panel commissioned Oakley Greenwood to investigate whether the modelling approach adopted for the 2014 Review remained appropriate.[182]

Oakley Greenwood recommended three principal changes to the approach adopted in 2014, and these recommendations have been embodied in the guidelines. The Panel is to follow the modelling approach set out in the guidelines.[183]

This chapter describes the principal challenge for this review – developing and implementing a modelling approach that responds to the changing circumstances in the national electricity market. The chapter:

- describes the modelling approach adopted by ROAM in 2014 for the setting of the market price cap, and the reliability standard[184]
- explains the rationale for the three changes to the modelling approach identified by Oakley Greenwood that have subsequently been embodied in the guidelines, and the challenges in addressing them.

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180 Reliability Panel, *Reliability Standard and Reliability Settings Review 2014*, Final Report, 16 July 2014, Sydney, p. iii.

181 Reliability Panel, 'Letter from Reliability Panel to the AEMC, Reliability Standard and Reliability Settings Review – Final Report', Sydney, 16 July 2014, http://www.aemc.gov.au/getattachment/9b6e780f-0570-4c16-ac2e-ae57d8f5aca6/Letter-from-Reliability-Panel-to-the-AEMC.aspx, accessed 12/4/2017, p. 2.

182 Oakley Greenwood, *Assessment of approach to modelling of Reliability Settings*, report to the Reliability Panel, September 2016, Australia, referred to as the Oakley Report.

183 Guidelines, pp. 10–11.

184 ROAM Consulting, *Reliability Standard and Settings Review*, report to the Reliability Panel, 21 May 2014, Brisbane, referred to as the ROAM Report.

10.1 Objectives and outputs of the modelling in 2014

The modelling to inform the 2014 Review involved five principal stages:

Stage 1: Modelling to determine the market price cap.

Stage 2: Forecasting of reliability under the status quo reliability settings.

Stage 3: Assessment of the suitability of the current reliability standard.

Stage 4: Modelling to review the suitability of the market price floor.

Stage 5: Assessment of the effect of a reduction in the market price cap.

Each of these five stages informed the Panel's review. However, this chapter focuses on Stages 1 and 3, that is, the modelling to determine the market price cap, and to assess the optimum level of the reliability standard.

10.2 Modelling to determine the market price cap in 2014

As discussed in section 6.3, in setting the level of the market price cap the Panel is making a trade-off on behalf of consumers between participants' exposure to high prices and the need to retain efficient price signals in the market for operation and investment.

The 2014 Review of the market price cap centred on the use of a "cap defender" analysis.[185] In simple terms, this analysis asked the question:

> *What level of the market price cap will allow a new entrant OCGT to operate profitably in a market which achieves the reliability standard?*

The modelling therefore provided the Panel with an assessment of the minimum market price cap to allow new entrant OCGTs to be profitable across a set of potential future scenarios, where the outcomes were consistent with the reliability standard. This informed the Panel's setting of the market price cap.

In 2014, ROAM's approach to this assessment involved:

- retiring existing generation to achieve average USE of 0.002 per cent in each region; and then
- determining the minimum market price cap that allowed an OCGT employing a "cap defender" strategy to achieve its required rate of return.

ROAM describes its method for calculating regional market price cap in its report.[186] This process is illustrated in Figure 10.1.

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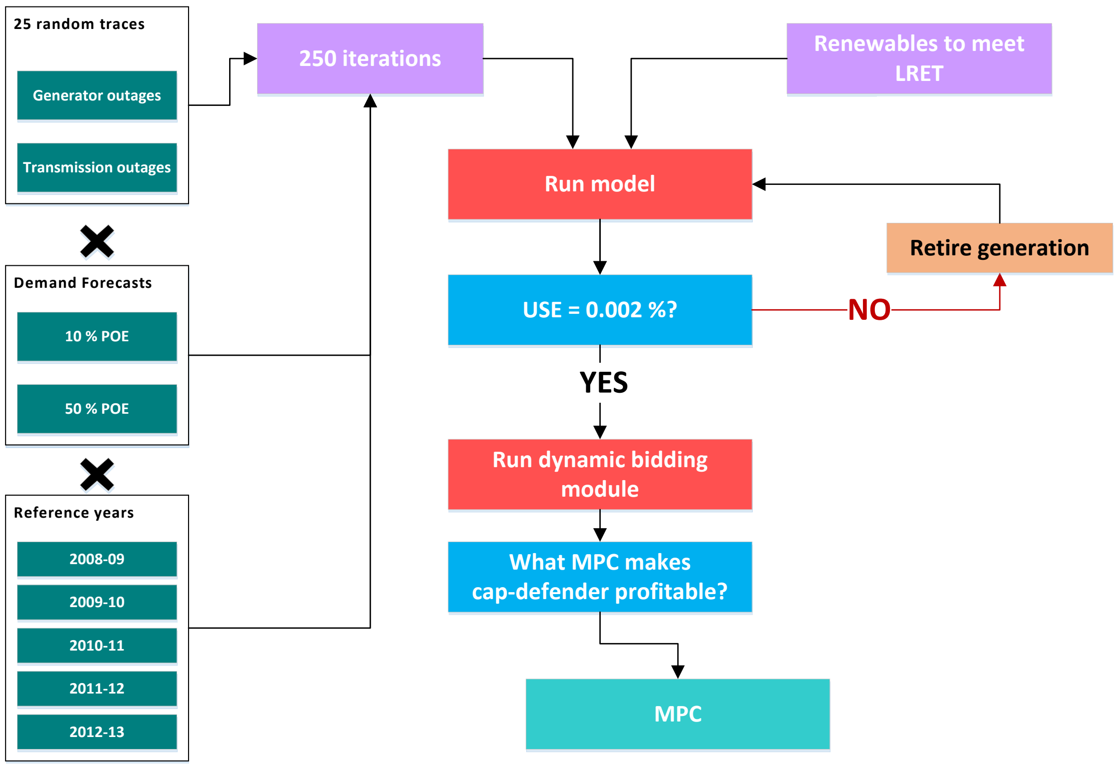
185 In addition, the 2014 review also included the use of an extreme peaker analysis. However, in its report ROAM stated that "the cap defender method is the preferred approach used in this review".

186 ROAM Consulting, *Reliability Standard and Settings Review*, 21 May 2014, Brisbane, p. 7.

Figure 10.1 Illustration of 2014 modelling approach to assess market price cap



This approach could be interpreted as asking the question:

> *Given a future scenario (or set of possible future scenarios) where:*
>
> *(1) the RET is met; and*
>
> *(2) generation has retired so that USE is equivalent to the reliability standard,*
>
> *what level of the market price cap would be high enough for a 1 MW OCGT operating as a cap defender to achieve its required rate of return?*

It is important to note that:

- Although the current market is used as a starting point, the modelling retires generation to create a scenario where the reliability standard is only just satisfied.
- The new entrant technology is assumed to be an OCGT – other technologies, such as storage, are not considered.

The modelling involved 250 different simulations for each financial year of the study. These simulations considered different levels of demand, generator outages, and transmission outages. As we understand it, the simulations did not consider varying levels of intermittent output, gas prices, or the relationship of these variables with demand.

10.3 Modelling the reliability standard in 2014

The setting of the reliability standard involves balancing two sets of costs: the cost of additional capacity to supply electricity and the cost of not having that additional energy when we need it (the value of customer reliability).

As part of the 2014 Review, ROAM completed modelling to investigate the suitability of the reliability standard, which is maximum USE of 0.002 per cent. ROAM's analysis asks the question:

Given a value of customer reliability, what should the reliability standard be?

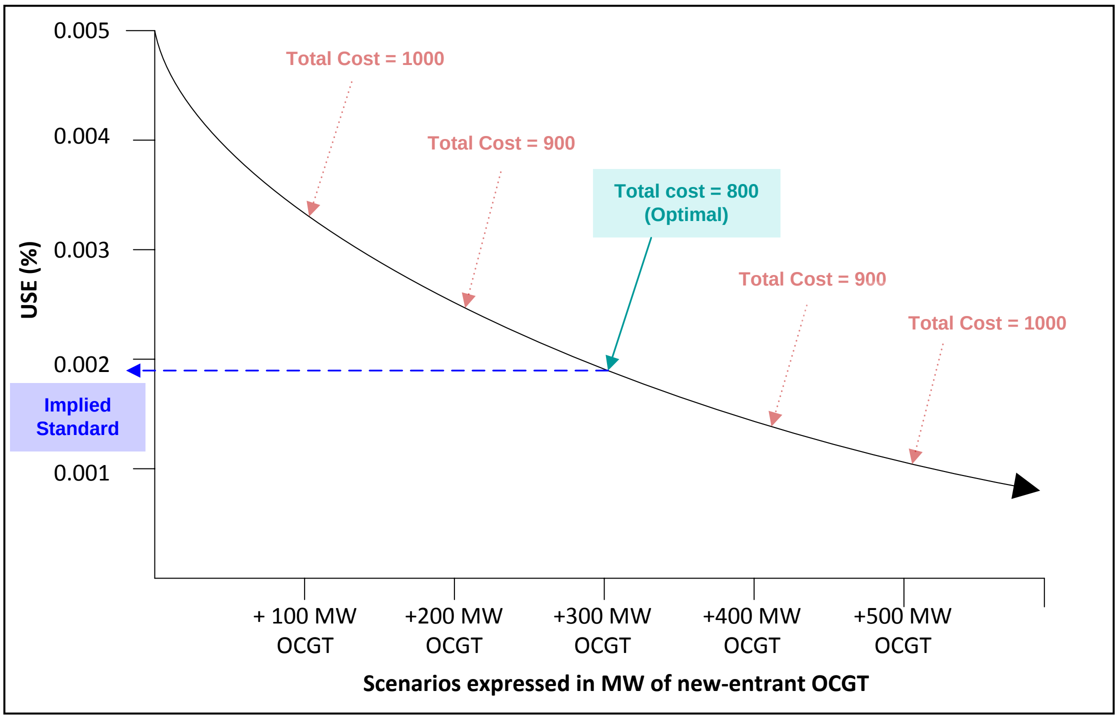
This question treats value of customer reliability as given. The modelling therefore focusses on the relationship between USE and costs of additional capacity, and seeks to identify the point at which the marginal cost of additional reliability is equal to VCR.

ROAM's approach to the modelling was to consider cost and USE outcomes for various levels of additional OCGT capacity. Put another way, ROAM:

- modelled different scenarios, each defined by a different level of new entrant OCGT capacity spread out across the regions of the national electricity market
- calculated the resultant total cost (including USE costs) for each scenario
- identified the scenario that minimised total cost, and associated level of USE.[187]

FigureFigure 10.2 illustrates this approach, and how it informs the setting of the reliability standard.

Figure 10.2 Illustration of 2014 modelling approach – Reliability standard



Note: This figure is purely illustrative, and so the values do not represent actual modelling outcomes.

187 ROAM Consulting, *Reliability Standard and Settings Review*, report to the Reliability Panel, 21 May 2014, Brisbane, p. 11.

In this illustration, the horizontal axis shows each of the scenarios, expressed in terms of a different level of OCGT capacity. For each scenario there is an associated level of USE, which is shown on the vertical axis. The greater the new-entrant capacity, the lower the level of USE because additional capacity reduces the probability of load-shedding. Each scenario has an associated "total cost" that includes the costs of USE. The scenario with the minimum total cost is shown in green.

These results imply that the optimal level of the standard is around 0.002 per cent, indicated by the blue arrow.

Several points are worth noting:

- Reliability is characterised as being a function of new entry – the role of the existing generation mix is static across scenarios.
- Once again, the new entrant technology is assumed to be an OCGT, and other technologies are not considered.

The modelling considered a set of 17 different scenarios, each defined by a different level of new-entrant capacity. As we understand it, once again there was no variation across scenarios in terms of the level of intermittent penetration, the level of demand, or gas prices.

10.4 Changes to the modelling approach for this review

In September 2016, the Panel commissioned Oakley Greenwood to investigate whether the modelling approach adopted for 2014 Review remained appropriate. Oakley Greenwood recommended three principal changes:

1. a focus on **assessing supply and demand equilibrium**, not just the conditions for additional investment
2. the model should be **technology neutral**, and so should treat the marginal technology as an output rather than an input to the model
3. the **approach to development of scenarios** should account for both:
   - the growing disconnect between reserve, demand and price
   - the increasing significance of availability of intermittent resources.

The guidelines embody these changes in setting out a general approach to the modelling that the Panel will use in each review, and so the modelling for the 2018 Review must address them.[188]

The remaining sections explain the significance of each of these three changes, and the challenges in addressing them. The chapter concludes with a brief review of other modelling considerations described in the Guidelines that may pose challenges for the 2018 Review.

188 Guidelines pp. 10-11.

10.4.1 Focus on assessing supply-demand equilibrium

The 2014 modelling approach centred on the price-signals provided to new-entrants. ROAM recognised that:

> …a number of market participants have contested this approach. These participants have proposed that it is not appropriate to retire generation to force the market to deliver USE at the reliability standard and that the assessment of a new entrant is inappropriate in a market that has sufficient capacity installed to just meet the reliability standard.[189]

But in response, ROAM stated that:

> It is the intention of the reliability settings to provide an investment signal such that if the market is expected to breach the reliability standard, that a new entrant OCGT could enter the market and operate profitably.[190]

The question of whether the assessment should focus on new-entrants alone is therefore not a new issue.

Rationale for shifting to a focus on supply-demand equilibrium

In its 2016 report, Oakley Greenwood identified the focus on new-entrant technologies, stating that:

> Analysis will increasingly need to focus on assessing supply and demand equilibrium rather than only the conditions for additional investment. [191]

Oakley Greenwood goes on to state the following rationale for this change in focus:

> Assessment of equilibrium will be important in a market where capacity withdrawal is as important as investment, and a transition of generation and demand technology … is underway.[192]

Oakley Greenwood is referring to the trends identified in Chapter 4 regarding entry and exit of generation capacity across the national electricity market by fuel/technology, specifically that:

- No new thermal generation has entered the market since 2011 – new entry has exclusively been from intermittent generation. Indeed, there has been a strong trend of coal generation *exiting* the market.
- No new OCGTs have been constructed since 2011.
- Over the last 6 years, the investment decisions that related to scheduled generation have principally been to withdraw capacity.

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189 ROAM Consulting, *Reliability Standard and Settings Review*, report to the Reliability Panel, 21 May 2014, Brisbane, p. 5.

190 ROAM Consulting, *Reliability Standard and Settings Review*, report to the Reliability Panel, 21 May 2014, Brisbane, p. 5.

191 Oakley Greenwood, *Assessment of approach to modelling of Reliability Settings*, report to the Reliability Panel, September 2016, Australia, p. 1.

192 Oakley Greenwood, *Assessment of approach to modelling of Reliability Settings*, report to the Reliability Panel, September 2016, Australia, p. 1.

It follows that an assessment of the market price cap should examine the consequences of different retirement scenarios.

Challenges for the modelling in adopting this change

The Guidelines express this principle as follows:

> … in considering long-term equilibrium, the modelling should consider both new investment and the potential for retirement of capacity.[193]

We anticipate that satisfying this principle – that is, by incorporating the effect of the market price cap on existing generation – is likely to require a major change to the modelling approach.

There are three key considerations, or questions:

- Would the approach consider the profitability of all existing generators, or would it consider only a single, marginal unit in each region?
- Would the approach preserve the assumption that the marginal unit (now potentially an existing unit) is a price-taker? Or would it account for the lumpy nature of retirement decisions?
- Given the additional computational complexity introduced by the above, would other aspects of the model need to be simplified?

Suggested approach to retirement

Retirement is an important driver of reliability outcomes. The challenge is how retirement should be incorporated into the modelling approach. It seems that an assessment of the market price cap should not be driven heavily by its influence on the retirement decisions of existing, aged generators – decisions that are typically driven by factors that are highly uncertain (e.g., remaining operating life), unobservable (e.g., fixed costs and rehabilitation costs) or outside the market (e.g. a corporate divestment strategy).

But retirement decisions – whatever may drive them – will be critical to any assessment of the relationship between the market price cap and new entry decisions within the modelling. The modelling should therefore consider how the market price cap might be altered across a range of future potential retirement scenarios.

One approach would be to consider a range of sensitivities that vary the amount and speed of retirement. Retirements would be exogenous to the model – it would be an input rather than determined within the model. The output of this approach would show how the different retirement schedules affected the market price cap.

10.4.2 Model should be technology neutral

As previously described, throughout the 2014 Review the modelling consistently focused on the relationship between the reliability settings and a single new entrant technology, i.e., OCGTs. This is demonstrated by ROAM's statement that:

193 Guidelines p. 10.

> It is the intention of the reliability settings to provide an investment signal such that if the market is expected to breach the reliability standard, that a new entrant OCGT could enter the market and operate profitably. [194]

As outlined above the modelling for the 2018 Review will consider not only new-entrant, but also existing plant. An additional change to the modelling for the 2018 Review is that it should not pre-suppose that the cheapest new-entrant technology will be an OCGT.

Rationale for considering multiple technologies

In its 2016 report, Oakley Greenwood noted the assumption of a single new-entrant technology, stating that:

> In light of the evolving technology being deployed and a growing disconnect (reduced correlation) between the timing of peaks and troughs in demand, reserves and spot price due to changing characteristics of technology and intermittency, we consider it is important that the outputs rather than inputs of future modelling should identify the technology and therefore costs at the margin.[195]

This statement involves two parts: a claim that there has been a change in the market, and a recommendation stemming from that claim.

The emergence of new technologies (eg, storage, solar PV) is well understood. But the “growing disconnect … between the timing of peaks and troughs in demand, reserves and spot price” is not as well recognised. As we noted in Chapter 4, there is some evidence of a growing disconnect between prices and demand in some regions.

Why does this emerging trend suggest that “the outputs rather than inputs of future modelling should identify the technology and therefore costs at the margin”?

In the past, reliability was typically only a challenge on a few days per year where demand reached very high levels. The response to these periods of sustained demand was simple – build more capacity and the cheapest option was to build an OCGT.

But this simple formula no longer holds. Reliability can be threatened for a range of reasons, including the availability of wind, gas supply problems, and ramping constraints. It follows that OCGTs are no longer necessarily the best solution to a reliability problem, particularly given the many new technologies that are emerging.

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194 ROAM Consulting, *Reliability Standard and Settings Review*, report to the Reliability Panel, 21 May 2014, Brisbane, p. 5.

195 Oakley Greenwood *Assessment of approach to modelling of Reliability Settings,* report to the Reliability Panel,, September 2016, Australia, p. 1.

Potential challenges for the modelling in adopting this change

The Guidelines express this change via the following principle:

> …the model should be technology-neutral and assess market price cap on the basis of the cheapest marginal technology that can be used to deliver the standard.[196]

The challenge for the modelling is to incorporate not just one, but multiple possible new-entrant technologies *and combinations of them*. For example, rather than restricting the analysis to a single 1 MW OCGT, it could be necessary to consider some combination of:

- OCGTs
- CCGTs
- storage devices
- demand response
- some measure of deferral of retirement of existing generation (see previous section).

Such an approach would not presuppose a single, optimal technology, but would instead provide an optimal mix of technologies as an output of the model. We anticipate that this would increase the complexity of the modelling exercise, but would be achievable.

Suggested approach to the model being technology neutral

The consideration of a single, new-entrant technology, that is an OCGT, was appropriate in 2014. However, in the time since the 2014 Review both the market and technology have evolved.

Changes in the market – and in particular in the relationship between demand and reliability – mean that OCGTs may no longer be the best fit to improve reliability. More OCGTs may not provide the capability required to enhance reliability, or may not be the most cost-effective option.

Advances in technology mean that there are also alternatives to OCGTs that were not mature technologies at the time of the 2014 Review. Most notably, grid-scale batteries were an untested, highly prospective technology at the time of the 2014 Review.

There are now grid-scale batteries being installed, and indeed operating, in power systems throughout the world. For example, in California in 2017 three large battery storage plants have been installed by AES Corporation (37.5MW, 150MWh), Tesla (20MW, 80MWh) and AltaGas Ltd (20MW, 80MWh).[197]

Against this backdrop, OCGTs are no longer necessarily the unrivalled and unequivocal source of additional reliability, and so consistent with the guidelines our modelling approach will contemplate the use of other, alternative technologies.

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196 Guidelines p. 10.

197 Bloomberg, 'Tesla's Battery Revolution Just Reached Critical Mass', 30 January 2017, https://www.bloomberg.com/news/articles/2017-01-30/tesla-s-battery-revolution-just-reached-critical-mass, viewed 04/05/2017 at 1.35pm.

10.4.3 Approach to development of scenarios

This chapter has described that throughout the 2014 Review the development of scenarios (and the use of multiple simulations) typically focussed on varying levels of demand, generation outages, and transmission outages.

It explained the "growing disconnect between reserve, demand and price" in the previous section. The third recommended change to the modelling for the 2018 Review is to alter the approach to the development of scenarios to account for this change.

Rationale for a new approach to development of scenarios

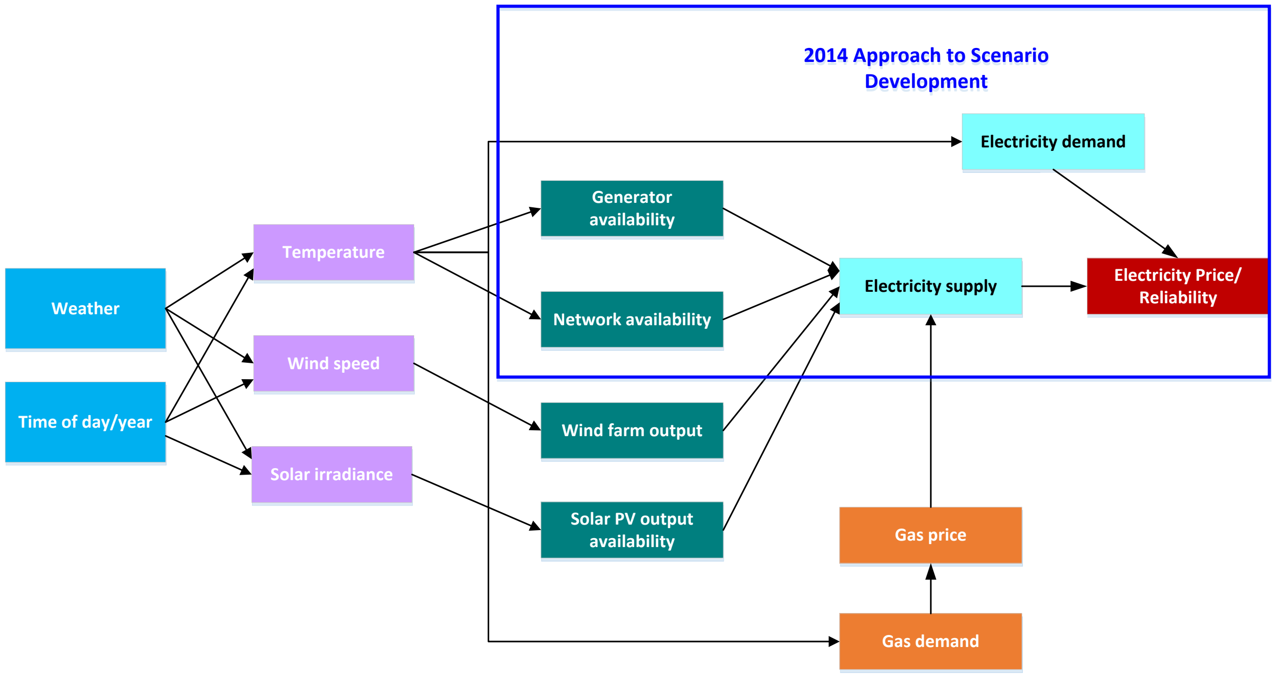
The Oakley Greenwood report recommended that:

> … the approach to the development of scenarios in the modelling should be overhauled to more robustly account for the growing disconnect between reserve, demand and price on the one hand, and an increased significance between atmospheric conditions and availability of a number of renewable resources on the other.[198]

Given that the connection between demand and reliability is weakening, the scenarios for the modelling should no longer focus only on examining the sensitivity of the results to variations in demand alone. Instead, the scenarios should be designed looking at atmospheric conditions ("weather") as the principal source of variance in outcomes, particularly for the output of intermittent renewables.

Figure 10.3 illustrates how weather can be seen as the primary driver of variance in outcomes in a system with high intermittent penetration. This compares to the approach to scenario development for the 2014 Review, shown in blue.

Figure 10.3 Illustration of weather as primary driver of variance in outcomes



198 Oakley Greenwood, *Assessment of approach to modelling of Reliability Settings*, report to the Reliability Panel, September 2016, Australia, p. 1.

The Guidelines express the new approach to scenario development by stating a list of drivers of scenarios, including:[199]

- changes in load profiles, including withdrawal of large industrial loads
- different emissions reduction and renewable target settings
- high and low gas price projections
- different timelines for exit of large customers.

The recommendation by Oakley Greenwood to develop scenarios to account for the atmospheric conditions and renewable resource availability expands on the Guidelines' list of scenarios.

Challenges for the modelling in adopting this change

The modelling approach for the 2014 Review did contemplate variation in wind, solar irradiance, and other factors that influence the availability of intermittent generation. Indeed, an important part of the modelling process was to align assumptions about demand and these factors. For example, when a demand profile is based on the 2013 reference trace, the wind farm profiles are based on their 2013 reference traces.[200] It follows that by considering different profiles of demand the modelling approach is also considering different profiles of wind output.

The 2014 approach was appropriate given the level of penetration of renewables over the modelling horizon. But given the higher penetration of renewables for the modelling period for the 2018 Review (the period 1 July 2020 – 1 July 2024), we consider that there is merit in adopting a more robust process to the development of scenarios. In particular, it is important to know whether the chosen set of demand profiles captures the potential variation in:

- the availability of renewables
- the relationships between the availability of different renewables, and demand itself.

The challenge that this change presents is that there are more factors to consider – as illustrated in Figure 10.3 – and that the underlying relationships between them are likely to be more complex. We therefore anticipate that there will be considerable work required to develop the scenarios in a logical, robust manner.

10.4.4 Other modelling considerations in the Guidelines

Beyond the three changes already described, the other considerations in the Guidelines principally relate to the inputs that should be used in the model.

We consider that in the current environment it will be particularly challenging to develop assumptions, and more generally a modelling approach, related to gas price trajectories.

199 Guidelines p.11.

200 The term "reference trace" refers to a data time series that forms the basis for a modelling input.

Challenges in the development of gas price assumptions

Gas prices are a critical input to any modelling exercise, because gas is increasingly the fuel of the marginal generator in the national electricity market. It follows that gas price assumptions often determine spot prices (see section 4.2).

But gas and electricity markets are increasingly coupled – the demand for gas is heavily influenced by the demand for electricity. In 2016, the national electricity market saw extended periods of high electricity prices (ie, around $300 per MWh) driven by high gas prices. The high gas price was in part a function of the demand for gas as a fuel for power generation. The closure of Hazelwood power station – and the attendant increase in gas-fired power generation – can only act to strengthen the connection between the gas and electricity markets.

Against this backdrop, an important question for the 2018 Review will be the approach to the modelling of gas prices. There are three key considerations, or questions:

- Will gas prices be endogenous or exogenous to the model?
- If gas prices are exogenous to the model, how significant is this assumption for the results of the modelling?
- If gas prices are endogenous, what assumptions will be made about the relationship between gas demand and price?

We anticipate that, over the course of the 2018 Review, the coupling of gas and electricity markets will become progressively stronger. It follows that the approach to developing gas price assumptions, and indeed the treatment of gas in the model, will be subjected to close external scrutiny throughout the Review.

Question 6: Modelling for the review

a. What are your views on the three proposed changes to the modelling approach for the 2018 review, namely:
    1. a focus on assessing supply and demand equilibrium, not just the conditions for additional investment
    2. the model should be technology neutral, and so should treat the marginal technology as an output rather than an input to the model
    3. the approach to development of scenarios should account for both:
        - the growing disconnect between reserve, demand and price
        - the increasing significance of availability of intermittent generation?

    What comments would you offer in regards to the challenges described for adopting each change?

b. Do you have any other comments on the modelling approach? For instance on approaches to the inputs that should be used in the model regarding gas price assumptions, or issues should the cumulative price threshold, the administered price cap and/or the market floor price be reviewed?

Appendices

Appendix A: Summary of previous Panel reviews and Commission determinations

The table below summarises the key Panel reviews, and Commission determinations, regarding the reliability standard and settings, since 1998.[201]

Year	Panel Advice/Decisions	Commission Determinations
1998	Review: Determined the power system reliability standards to apply in the national electricity market. The Australian Competition and Consumer Commission accepted the need for a market cap and a proposed level of "value of lost load" of $5,000/MWh. Value of lost load to be reviewed annually.	
1999	First annual yearly review of value of lost load commenced. Following this the Australian Competition and Consumer Commission determined to increase the value of lost load to $10,000/MWh.	
2007	Comprehensive reliability review: first review of the reliability standard since the national electricity market's inception. Prior to the comprehensive reliability review, the price mechanisms (settings) and intervention mechanisms had only been reviewed as discrete elements, never as part of a coherent and integrated whole. Key recommendations relating to intervention mechanisms included: the redesign of the Reserve trader safety net to become the Reliability and emergency reserve trader; and the introduction of the Energy adequacy assessment projection. These recommendations led to rule change requests and the rules being amended.	
2008	Rule change request lodged. Based on price mechanism recommendations made in the comprehensive reliability review, the Panel proposed that: value of lost load is increased from $10,000/MWh to $12,500/MWh; value of lost load is renamed the market price limit; cumulative price threshold is increased from $150,000 to $187,500; cumulative price threshold defined in the rules as 15 times value of lost load; and the annual review of value of lost load is replaced with a biennial review of the standard and settings.	Determination of the final schedule that specifies the administered price cap. Commission assumed responsibility for setting the administered price cap from the National Electricity Code Administrator. Administered price cap of $300/MWh to apply to spot price and market ancillary prices in all regions. Prior to the change, the administered price cap was:

201 For further information regarding the assessment framework and underlying principles and assumptions, refer to the Guidelines Determination.
For further information regarding the most recent review of the settings and standard, refer to the Panel's Reliability standard and settings review, final report, 2014.
For further information regarding the underlying theory for the reliability standard and settings, refer to the Panel's Comprehensive reliability review, final report, 2007.

Year	Panel Advice/Decisions	Commission Determinations
		$100/MWh between 7:00am and 11:00pm on a business day; $50/MWh at all other times.
2009	Review of operational arrangements for the reliability standard. Recommendations made on the methodology used by AEMO to calculate minimum reserve levels. Clarifications made with regards to the reliability standard. Modifications made to the Guidelines for the management of electricity supply and shortfall events.	Rule change: value of lost load increased to $12,500/MWh and renamed market price cap. Annual review of value of lost load to be replaced with an integrated biennial review of the standard and all settings, with two years notice of any change. Cumulative price threshold is increased from $150,000 to $187,500. The Commission determined that the cumulative price threshold should not be defined as a value relative to that of value of lost load.
2010	Review: Proposed the existing form and level of settings be retained. Panel proposed the introduction of indexation of the market price cap and cumulative price threshold. Rule change request lodged.	
2011		Rule change: Market price cap and cumulative price threshold indexed to consumer price index rather than producer price index as initially proposed by the Panel. Four yearly reviews of standard and all settings to replace biennial review.
2013		Advice to Standing Council on Energy and Resources on linking the reliability standard and reliability settings with value of customer reliability. The Commission's preferred approach is similar to the previous approach but with the inclusion of a requirement for the value of customer reliability, estimated for the customers most affected by a supply shortfall, to be used as a cross-check on the

Year	Panel Advice/Decisions	Commission Determinations
		reliability standard.
2014	Review: Panel determined that the current form and level of the reliability standard be retained. No change to be made to the levels and forms of settings. Market price cap and cumulative price threshold to continue to be indexed to consumer price index. This was the first four-yearly review.	
2015		Rule Change: Reliability standard is incorporated into the rules and subject to the rule change process, to allow any person to submit a rule change request to the Commission to change the standard. Panel required to develop guidelines that must be followed when conducting reviews on the standard and guidelines. AEMO required to develop and publish *Reliability standard and implementation guidelines*. Administered price cap is added to the scope of the reliability standard and setting reviews.
2016	Guidelines for the reliability standard and settings review are published. The guidelines set out the principles and assumptions the Panel will apply when conducting future reviews.	

Appendix B: List of consultation questions

1) The reliability standard

   a) Are there any features of the methodology, results or significance of AEMO's value of customer reliability measure that should be considered by the Panel?

   b) Are there any changes/trends to the way consumers are likely to use electricity to 2020-2024 that suggest that they may place a higher or lower value compared to 2014 on a reliable supply of electricity from the national electricity market? Please detail the changes, consumers involved and the evidence of their impact on those customers' value of reliability.

   c) Over the period 2020 - 2024, is the cost of marginal generation and/or demand response likely to change materially compared to the present?

   d) Are there any other emerging factors the Panel should consider in its materiality assessment that support or erode the case for a reassessment of the reliability standard in the 2018 Review?

   e) If the Panel were to reassess the reliability standard, are there principles and assessment factors additional to those outlined in the rules and guidelines that the Panel should consider? Given recent market developments and pricing outcomes, and trends, is the current reliability standard appropriate for the period 1 July 2020 - 2024? If no, what would be an appropriate reliability standard, why and what is the evidence supporting your view?

2) The market price cap

   a) Given recent market developments and pricing outcomes, is the current market price cap appropriate for allowing the reliability standard to be met without the use of AEMO's powers to intervene? If not, what would be an appropriate market price cap, why and what is the evidence supporting your view?

   b) Given recent market developments and pricing outcomes, is the current market price cap (in conjunction with other provisions of the rules) likely to "create risks which threaten the overall integrity of the market", including in the contract market? If so, what would be an appropriate market price cap, why and what is the evidence supporting your view?

   c) How might a change in the market price cap affect, if at all, contract market liquidity? More generally are there issues the Panel should consider regarding liquidity in the contract market or factors affecting its effective operation in the context of reliability settings? Please provide evidence supporting your view.

   d) Would a change in the market price cap change generator operating strategies to underpin hedge markets?

   e) What is the effectiveness of the market price cap in allowing for investment in the current uncertain environment?

   f) What factors or impacts regarding spot prices, investment, market participants and/or the stability of the regulatory framework should the Panel pay particular attention to?

   g) Are there principles and assessment factors additional to those outlined in the rules and guidelines that the Panel should consider?

h) Has there been a material change in the method used to calculate the consumer price index that makes it less relevant for the indexation of the market price cap and the cumulative price threshold?

i) Is there a more preferable statistic that should be used to index either the market price cap and/or the cumulative price threshold? If yes, what is it and why is it preferable?

j) Should the market price cap and cumulative price threshold continue to be indexed using the same index?

3) The cumulative price threshold

a) Given recent market developments and pricing outcomes, is the current cumulative price threshold appropriate for allowing the reliability standard to be satisfied without the use of AEMO's powers to intervene? If no, what would be an appropriate cumulative price threshold, why and what is the evidence supporting your view?

b) Given recent market developments and pricing outcomes, is the current cumulative price threshold (in conjunction with other provisions of the rules) likely to create risks "which threaten the overall integrity of the market", including in the contract market? If so, what would be an appropriate cumulative price threshold, why and what is the evidence supporting your view?

c) How might a change in the cumulative price threshold affect, if at all, contract market liquidity? More generally are there issues the Panel should consider regarding liquidity in the contract market or factors affecting its effective operation in the context of reliability settings? Please provide evidence supporting your view.

d) Would a change in the cumulative price threshold change generator operating strategies to underpin hedge markets?

e) Are there material changes to the distribution and frequency of high price events that are relevant to modelling the cumulative price threshold?

f) In particular, are there material changes to the distribution and frequency of high price events at the level of granularity associated with 2,016 dispatch intervals?

g) What factors should the Panel consider when seeking to ensure the cumulative price threshold does not compromise the price signals from the market price cap? Specifically, should the cumulative price threshold be adjusted if the market price cap is adjusted, thereby preserving the ratio of cumulative price threshold to market price cap at 15:1? Should the ratio between the cumulative price threshold and the market price cap be adjusted?

h) Should the cumulative price threshold be set with reference to another benchmark?

4) The administered price cap

   a) Has the marginal generation technology changed since the last review and is it likely to change over this review period, or is continued reliance on OCGT as the marginal generation technology still reasonable?

   b) Have typical generator short-run marginal costs increased significantly? Or are they expected to do so over the period 2020-2024?

   c) Are there any other emerging factors the Panel should consider in its materiality assessment that support or erode the case for a reassessment of the administered price cap in the 2018 Review?

   d) Given recent market developments and pricing outcomes, is the current administered price cap appropriate? If no, what would be an appropriate administered price cap, why and what is the evidence supporting your view?

   e) If the Panel were to reassess the administered price cap, are there principles and assessment factors additional to those outlined in the rules and guidelines that the Panel should consider?

5) The market floor price

   a) Are there specific considerations relating to changes in the number and frequency of trading intervals where the market has been, or has approached, the level of the market floor price that the Panel should take into account?

   b) In your view, have average generator cycling costs increased or decreased since the 2014 Review? Please provide data and analysis.

   c) Are there any other emerging factors the Panel should consider in its materiality assessment that support or erode the case for a reassessment of the market floor price in the 2018 Review?

   d) Given recent market developments and pricing outcomes, is the current market floor price appropriate? If no, what would be an appropriate market floor price, why and what is the evidence supporting your view. If the Panel were to reassess the market floor price, are there principles and assessment factors additional to those outlined in the rules and guidelines that the Panel should consider?

6) Modelling for the review

   a) What are your views on the three proposed changes to the modelling approach for the 2018 review, namely:

      i) a focus on assessing supply and demand equilibrium, not just the conditions for additional investment

      ii) the model should be technology neutral, and so should treat the marginal technology as an output rather than an input to the model

      iii) the approach to development of scenarios should account for both:

         (1) the growing disconnect between reserve, demand and price; and

         (2) the increasing significance of availability of intermittent generation?

What comments would you offer in regards to the challenges described for adopting each change?

b) Do you have any other comments on the modelling approach? For instance on approaches to the inputs that should be used in the model regarding gas price assumptions, or issues should the cumulative price threshold, the administered price cap and/or the market floor price be reviewed?