RULE

Australian Energy Market Commission

DIRECTIONS PAPER

RESERVE SERVICES IN THE NATIONAL ELECTRICITY MARKET

PROPONENTS

Infigen Energy
Delta Electricity

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INQUIRIES

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ABOUT THE AEMC

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

EXECUTIVE SUMMARY

1 This paper focuses on reserve services in the National Electricity Market (NEM). It considers issues related to the ability of current energy and frequency control market frameworks to address variability and uncertainty in power system conditions.

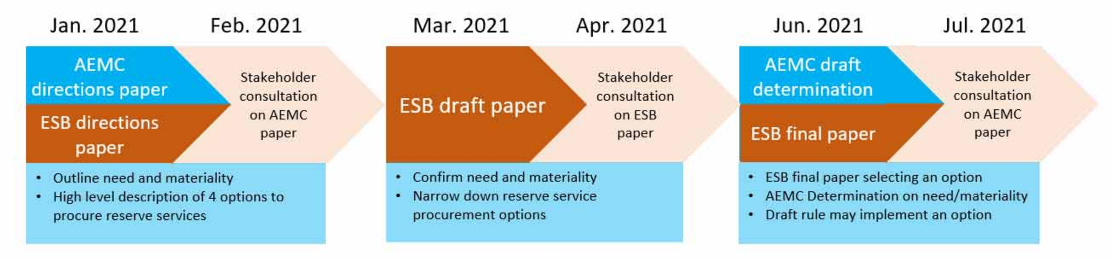
2 This paper accompanies the Energy Security Board's (ESB's) post-2025 market design project (post-2025 project) directions paper. That project aims to develop advice on a long-term, fit-for-purpose market framework to support reliability that could apply from the mid-2020s.

3 This paper forms part of the Australian Energy Market Commission's (AEMC's) consideration of rule change requests received from Infigen Energy and Delta Electricity, as well as a range of options to address the issues they raise. Infigen Energy proposes introducing a dynamic operating reserve market to operate alongside the existing energy and frequency control ancillary services (FCAS) markets. Delta Electricity proposes introducing 30-minute raise and lower "ramping" FCAS services using the existing framework for FCAS market design.

4 These projects are being progressed together as a single reform process considering the need for and appropriate design of reserve services in the NEM, which also forms part of the resource adequacy mechanism and essential system services market design initiatives under the ESB's post-2025 project.

5 An AEMC consultation paper was published on these rule change requests, along with five others, in July 2020. The issues raised by these rule changes relate to the ability of current energy and FCAS market frameworks to address variability and uncertainty in power system conditions. The market bodies are collaborating closely on this work, with the AEMC and ESB processes dovetailing as a single overarching reform process, shown in the diagram below.

Figure 1: Coordination of AEMC and ESB processes on reserve services



Source: AEMC.

Stakeholder feedback to date

6 Of the stakeholders who responded to the consultation paper in July 2020, 25 commented on matters relating to the Infigen Energy and Delta Electricity rule change requests.

7 Stakeholders generally agreed that reserves are critical to ensuring the security and reliability of the power system as it transitions. There were differing views, however, on whether an

explicit new reserve service is required, how such a service should operate, and the specific power system conditions it should address.

8 Stakeholders also held a range of views on the economic benefits of implementing a new reserve service. Some considered there are benefits to addressing the increasing uncertainty on the power system, while others considered that current arrangements are sufficient to address this issue.

9 The AEMC is also considering stakeholder feedback to the ESB's post-2025 project consultation paper, published in September 2020.

Current arrangements

10 Reserves are capacity that is available to change the supply/demand balance in the near future to keep the system secure and reliable. Reserves are needed for reliability to ensure that sufficient supply is available in real time, and in the right places, to match demand. Reserves are also required to ensure supply can meet demand following credible contingency events and to return the system to a secure state able to respond to future contingency events. Currently, we have both in-market and out-of-market reserves. In-market reserves are made up of capacity that has bid itself available but has not yet been dispatched in the energy market (to balance energy each five-minute dispatch interval) or FCAS market (to keep frequency within acceptable limits following credible contingency events (within a five-minute interval)). Out-of-market reserves are procured for specific purposes. For example, the Reliability and Emergency Reserve Trader (RERT) which is used as a last resort to meet demand.

11 Market participants make their own commitments to keep capacity in reserve based on price signals and the risks and operational costs associated with running their generating plant at a point in time. The need for reserves is therefore currently met through:

- market arrangements that price the need for energy and frequency control
- information provided to participants in those markets, and
- interventions in those markets by the market operator.

Reserves as the power system transforms

12 Reserves are used for a range of purposes on the power system, which fall into two main groups:

- reserves needed for events that are forecast and are therefore expected by market participants ('expected events'), such as evening ramping requirements and peak consumer demand events, and
- reserves needed for events that are not forecast and therefore not expected by market participants ('unexpected events'), such as significant uncertainty in the level of net demand or certain security events.

13 The market needs enough resources to meet net demand forecasts, accounting for uncertainty and variability. To achieve this, reserves of capacity are required so that they can

be dispatched as energy and balance supply and demand when needed. Reserve capacity must be able to be dispatched as energy within the required interval accounting for ramp rates, energy availability (e.g. state of charge and firmness of resources) and other operational considerations.

14 The current real-time energy market framework with the existing structure of market settings (i.e. market floor price, market price cap, cumulative price threshold and administrative price cap) has effectively achieved this to date. It is designed to incentivise the entry and exit of equipment necessary to meet this need for each dispatch interval, to the level consumers value.

15 Current arrangements are likely to provide sufficient in-market reserves to address expected events but may not be sufficient to address increasing variability and uncertainty as the power system transitions. The specific problem this gives rise to, and which we consider needs to be addressed, is the inefficiency of interventions in the market to ensure there are sufficient reserves to address:

- net demand forecast uncertainty, and
- system security, up to the level to prevent a contingency event resulting in involuntary load-shedding.

Options to address reserve needs

16 A number of options are available to address this issue.

17 These include incremental improvements to support the market in meeting increasing variability and uncertainty such as:

- improving the accuracy of net demand forecasts
- developing and publishing more information for the market
- pursuing potential market / system enhancements
- integrating emerging flexible resources, and
- adapting system definitions.

18 Another option to address the risk of insufficient reserves is to explicitly value the provision of reserves. This would separate the provision of this service from energy and FCAS markets, where in-market reserves are currently valued implicitly. This paper outlines four options to explicitly procure reserve services. An overview of these options is in the table below.

Table 1: **Reserve service procurement options**

	CO-OPTIMISED OPERATING RESERVE MARKET	CO-OPTIMISED AVAILABILITY MARKET	CALLABLE OPERATING RESERVE MARKET	RAMPING COMMITMENT MARKET
PROCURED	Megawatts (MW)	MW available for	MW in reserve	MW/minute in

	CO-OPTIMISED OPERATING RESERVE MARKET	CO-OPTIMISED AVAILABILITY MARKET	CALLABLE OPERATING RESERVE MARKET	RAMPING COMMITMENT MARKET
PRODUCT	in reserve that can be turned into energy in the next dispatch interval.	dispatch for interval 30 minutes ahead.	for interval 30 minutes ahead.	reserve available to call any time in next 30 minutes.
PRODUCT DESCRIPTION	MW held in reserve, but available to be dispatched as energy according to market scarcity (subject to ramp rate) in the next dispatch interval.	Commitment to offer additional capacity (above current generation) in the dispatch interval 30 minutes ahead.	MW held in reserve, available to be called in the dispatch interval 30 minutes ahead.	30 minutes of ramping capacity, held in reserve (FCAS 30 minute product), available to be called over the next 30 minutes.
AIM	Maintain economic level of reserve headroom on a five-minute basis to respond to unexpected events.	Ensure sufficient offers are available in the dispatch interval 30 minutes ahead to meet expected and unexpected ramps.	Ensure reserved 'uncommitted' capacity is available to call on if there is insufficient supply in the dispatch interval 30 minutes ahead.	Ensure reserved 'uncommitted' capacity is available to restore the system to a secure operating state following a credible contingency.
INTERACTION WITH ENERGY MARKET	Reserves co-optimised with energy and FCAS markets.	Reserves co-optimised with energy and FCAS markets.	Reserves unable to offer in the energy market.	Reserves unable to offer in the energy market.
HOW IT IS DISPATCHED	NEM Dispatch Engine (NEMDE).	NEMDE.	Separate dispatch - 15-minute call time.	Separate dispatch.
AMOUNT PROCURED	Increases in net demand over a 5-minute interval, accounting for	Increases in net demand over a 30-minute interval, accounting for	Uncertainty over a 30-minute interval.	Changes in net demand over a 30-minute interval, accounting for

	CO-OPTIMISED OPERATING RESERVE MARKET	CO-OPTIMISED AVAILABILITY MARKET	CALLABLE OPERATING RESERVE MARKET	RAMPING COMMITMENT MARKET
	uncertainty.	uncertainty.		uncertainty.

Consultation

19 The AEMC invites stakeholder feedback on this paper. The Commision is particularly interested in stakeholder views on:

- the nature of the need for reserves and how meeting this need will evolve as the power system transforms
- whether there is a material need for a new reserve service to address this evolving need, and
- if so, what the appropriate high-level design of a new reserve service should be, including how this could interact with existing arrangements both in the wholesale energy spot and secondary contract markets.

20 Written submissions are due by **11 February 2021**. These will feed into the progression of the ESB and AEMC's work on these matters.

CONTENTS

TABLES

FIGURES

1 INTRODUCTION

This directions paper considers the issues raised by two rule change requests, received from Infigen Energy and Delta Electricity. The issues relate to the ability of current energy and frequency control market frameworks to address variability and uncertainty in power system conditions.

This paper accompanies the Energy Security Board's (ESB's) post-2025 directions paper, given that these rule change requests complement and are interdependent with the ESB's post-2025 market design project (post-2025 project). The project aims to develop advice on a long-term, fit-for-purpose market framework to support reliability that could apply from the mid-2020s. These projects are being progressed together as a single reform process considering the need for and appropriate design of reserve services in the National Electricity Market (NEM), which forms part of the resource adequacy mechanism and essential system services market design initiatives. Further information on this process is provided in section 2.2.

This paper further investigates the nature of the variability and uncertainty facing the power system as it transitions and a range of approaches to address it. One approach to address uncertainty and variability is to explicitly value the reserve services required. Four different approaches that could be taken to procure reserves are outlined in this paper. Stakeholder comment is sought on both the need for a reserve service and the four approaches to procure reserves.

The following chapters describe and explore:

- **Process to date** for the rule change requests and coordination with the ESB
- **Current arrangements** that relate to the issues raised by the rule change requests
- **Reserves on the power system**, including:
  - the power system need for reserves
  - the capacity on the system able to provide reserves, and
  - the expected and unexpected circumstances in which reserves may be required
- **Options to address variability and uncertainty**, including:
  - incremental improvements to current arrangements, and
  - four options for the procurement of a new reserve service.

The Australian Energy Market Commission (AEMC or Commission) invites stakeholder comment on this paper, particularly with respect to the need for a new reserve service and the appropriate market design for the procurement of reserves.

Submissions are due on **11 February 2021.** Submissions will inform the direction of the ESB's post-2025 project work relating to operating reserves, as well as the AEMC's consideration of the two rule changes, which are the subject of this paper.

The Commission also welcomes interested stakeholders to contact them if they would like to meet to discuss this directions paper or any related issues. All enquiries should be directed to Dominic Adams by email at dominic.adams@aemc.gov.au or by phone on (02) 8296 7899.

2 PROCESS TO DATE AND COORDINATION WITH ESB

The AEMC has received seven rule change requests that relate to arrangements for the provision of essential system services in the power system.

These rule change requests both complement and are interdependent with the issues being explored by the ESB in its ongoing post-2025 project. They offer opportunities to action the thinking and assessment done within the ESB work program. Aligning the work will mean the issues raised can be addressed cohesively and thorough consideration can be given to making sure any new system services arrangements are in the long-term interests of consumers.

This directions paper, which accompanies the ESB's post-2025 directions paper, specifically focuses on exploring a reserve service and relates to two of these rule change requests:

- Infigen Energy — *Operating reserves market* (ERC0295)
- Delta Electricity — *Introduction of ramping services* (ERC0307)

2.1 Overview of the rule change requests

2.1.1 Infigen Energy - Operating reserves markets (ERC0295)

On 19 March 2020, the AEMC received a rule change request from Infigen Energy which seeks to amend the National Electricity Rules (NER) to introduce a dynamic operating reserve market to operate alongside the existing energy and frequency control ancillary services (FCAS) markets. The proposed operating reserve market comprises a dispatchable, raise-only service procured similarly to contingency FCAS services in real-time and co-optimised with the other energy market services.

The request proposes that this market would procure reserves 30 minutes ahead of time (with a 15-minute call time) to align with the requirement to return the system to a secure operating state within 30 minutes.

2.1.2 Delta Electricity - Introduction of ramping services (ERC0207)

On 4 June 2020 the AEMC received a rule change request from Delta Electricity to amend the NER to introduce 30-minute raise and lower "ramping" FCAS services using the existing framework for FCAS market design. Delta suggests these ramping services would address the price volatility that exists when dispatchable generators ramp through their energy offer stacks in response to predictable, daily, high rates of change from solar ramping up and down.

Delta Electricity proposes this service:

- be procured from dispatchable in-service generators
- reflect a similar dispatch and settlement process to existing FCAS raise and lower services, but with provision for generators to offer (perhaps three) incremental rates of change at different prices, and

- participants in this service would not be prevented from bidding into the other FCAS markets as long as they can comply with the associated obligations of each.

Further detail relating to the options proposed by both Infigen Energy and Delta Electricity is included in chapter 6.

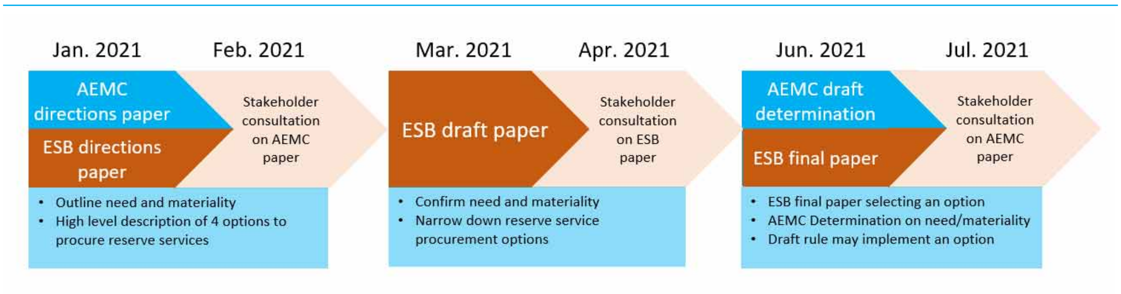
2.2 Project timeline

A consultation paper was published by the AEMC on **2 July 2020** seeking feedback on the seven system services rule change requests, including the two relating to reserve services which form the basis of this directions paper. Chapter 4 of the consultation paper sets out the assessment framework and principles for assessment of these rule change requests.[1]

On 24 September 2020, the Commission extended the timeframe to make a draft determination with respect to both rule change requests until **24 June 2021**. This extension better aligns the work with the ESB's post-2025 project so that the issues raised can be addressed cohesively, can give more consideration to the complexity of the issues, and can prioritise more urgent system security issues. The extension also allows time for the Australian Energy Market Operator (AEMO) to provide technical advice to inform both the AEMC's assessment of the rule change requests and the ESB's assessment of an operating reserve demand curve and mechanism as part of its resource adequacy mechanisms and essential system services market development initiatives.

On **5 January 2021** the ESB published a directions paper for the post-2025 project. The AEMC is publishing this directions paper for the two rule change requests relating to reserve services, accompanying the ESB directions paper, to allow for stakeholder consultation. This is part of a coordinated reform process relating to reserve services, which is illustrated in Figure 2.1.

Figure 2.1: Coordination of AEMC and ESB processes on reserve services



Source: AEMC.

2.3 Timetable for the consultation process

The aim of this directions paper, which accompanies the ESB's post-2025 directions paper, is to allow substantive consultation on the available options for a reserve service.

1 AEMC, *System services rule changes*: *Consultation paper*, July 2020.

The Commission invites stakeholders to make submissions, with submissions due on **11 February 2021**.

Stakeholder input on this paper will help inform the analysis of the issues and preliminary options, to be reflected in further ESB papers to be published in 2021 and the draft determination to be published by the AEMC in June 2021.

2.4 Interactions with internal and external projects

The work being undertaken by the AEMC to explore the reserve services rule change requests interacts with a range of internal and external projects. This section briefly describes these interactions.

2.4.1 The ESB post-2025 project

The ESB post-2025 project is developing advice on a long-term, fit-for-purpose market framework to support system reliability that could apply from the mid-2020s. The AEMC is working closely with the ESB and the other market bodies as it progresses the reserve services and other rule change requests, such that any new frameworks will be focused on delivering the most efficient outcomes for consumers.

The post 2025 project workstreams most relevant to the issue of reserves are those relating to:

1. **Essential system services:** this includes consideration of a range of system services, such as system strength and inertia, as well as an operating reserve service to address variability and uncertainty. This is directly relevant to the issues raised in the rule change proposals from Infigen Energy and Delta Electricity.
2. **Resource adequacy mechanisms:** investment signals for essential system services may be improved through resource adequacy mechanisms which strengthen real-time and longer duration price signals. An operating reserve market is one mechanism through which this may be achieved. The resource adequacy mechanisms market design initiatives is considering this in parallel with modifications to the Retailer Reliability Obligation (RRO) or the establishment of a decentralised capacity market, which would require retailers to procure sufficient capacity through contracts.
3. **Scheduling and ahead markets:** an ahead market is an additional settlement interval ahead of dispatch, allowing system services to be procured prior to real-time. An operating reserve service may be designed with an element of "aheadness" in this way. The scheduling and ahead markets workstream is also considering a unit commitment for security (UCS) design. The proposed UCS is an analytical tool to optimise the scheduling of resources and monitor the system to identify where additional resources may be needed. Although predominantly focused on synchronous services such as system strength and inertia, a UCS may complement an operating reserve market by systemising how AEMO monitors system services and addresses shortfalls.
4. **Demand side participation:** this relates to the ability of demand side resources, including distributed energy resources (DER), to participate in markets so that they can

efficiently be used to help balance the system. This work interacts with consideration of reserve services with respect to both its impact on variability and uncertainty of demand side resources on the system as well as its ability to participate in any potential market for the procurement of reserve services.

The AEMC is working closely with the ESB to progress this work, as well as coordinating the work with our assessment of these rule changes. The findings and recommendations from these workstreams will inform the reserve services work. More information on the above workstreams can be found in the ESB's post-2025 directions paper.

2.4.2 AEMO's renewable integration study (RIS)

On 30 April 2020, AEMO published its stage 1 report for the RIS.[2] The RIS investigates and describes the requirements for operating the national electricity system securely through to 2025. It seeks to quantify the technical renewable penetration limits of the power system for a projected generation mix and network configuration in 2025.

Appendix C of the RIS stage 1 paper is focused specifically on changes in supply and net demand due to the increasing variability and uncertainty in the power system.[3] The findings and recommendations from this section are a valuable input to the AEMC's assessment of the need for a reserve service. These have been discussed where relevant throughout this paper.

2.4.3 Reports provided by FTI Consulting

In mid-2020, FTI Consulting produced two reports for the ESB which explored options for the procurement of essential system services on the power system.

The first, titled *Resource adequacy mechanisms in the NEM*, presented and assessed a range of resource adequacy mechanisms potentially available to the power system. The conclusions highlighted the key aspects of potential resource adequacy mechanism designs for the ESB to consider.

The second, titled *Essential system services in the NEM*, outlined a range of options for procuring and scheduling essential system services, including operating reserves. FTI presented the advantages and disadvantages of market and non-market procurement of reserves, with the ESB proposing to further consider options for an operating reserve mechanism or operating reserve demand curve spot market.[4]

The AEMC is taking this work into account in its assessment of reserve service options, and this is discussed where relevant throughout this paper.

2 AEMO, *Renewable integration study: Stage 1 report,* April 2020.

3 AEMO, *Renewable integration study stage 1 appendix C: Managing variability and uncertainty*, April 2020.

4 ESB, *Post 2025 market design consultation paper*, September 2020, p. 64.

3 STAKEHOLDER FEEDBACK

The AEMC received 43 submissions to the July 2020 system services rule changes consultation paper.[5] Of these, 25 provided feedback relating to a reserve service.[6] ESB also received 108 submissions to the September 2020 post-2025 project consultation paper. Feedback relating to reserve services was provided in the resource adequacy mechanisms and essential system services market design initiatives. This feedback is also summarised in this chapter.

3.1 Feedback on approach and assessment framework

The AEMC introduced both the system services objective and the '4Ps' (plan, procure, price and pay) service design framework within the consultation paper as methods to assess the rule changes,[7] which provided detail and context for how we will be considering the National Electricity Objective (NEO) in relation to the system services rule changes. The majority of stakeholders[8] supported both the objective and the service design framework. Several stakeholders mentioned areas where more focus could be given when assessing the rule change requests. This included the Australian Renewable Energy Agency (ARENA), who noted a need for explicit recognition of the role of DER, demand response, and new technologies,[9] and GE Hydro, who noted the need to recognise the prevailing direction of the power system transition by encouraging the entry of new capacity rather than favouring the prolonged operation of existing capacity.[10]

Many stakeholders[11] expressed a need for transparency on whether the ESB or the AEMC would be the ultimate decision-maker responsible for implementing the rules relating to new system services and how the ESB and AEMC projects relating to reserves interacted. They considered this confusion to be a barrier to the effective engagement of stakeholders in the reform process.

The Commission notes that the ESB is leading the high-level direction of reform through its post-2025 project. The intention is that this work will proceed in most cases to AEMC projects to assess and implement reforms through changes to the rules. These rule change processes will involve extensive input from the market bodies and industry stakeholders.

We provide further detail on the coordinated reform process encompassing both ESB and AEMC deliverables, and how it works in practice, in section 2.2.

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5 AEMC, *Consultation paper: System services rule changes,* July 2020.

6 Submissions to the AEMC system services rule changes consultation paper may be found on the AEMC's website under any of the seven rule change requests covered by the paper.

7 See section 4.2, AEMC, *System services rule changes: consultation paper*, July 2020.

8 For example, in submissions to the consultation paper from: ENGIE, p. 2 and CleanCO QLD, pp. 2-3.

9 ARENA, Submission to the consultation paper, p. 1.

10 GE Hydro, Submission to the consultation paper, p. 1.

11 Including in submissions to the consultation paper from: Tesla, p. 3 ; Australian Energy Council(AEC), p. 1; and OMPS Hydro, p. 4.

3.2 Feedback on the technical need for a reserve service

Stakeholders generally agreed that "reserves" are critical to ensuring the security and reliability of the power system as it transitions. There were differing views, however, on what an explicit reserve service would constitute and the specific power system conditions it should address. Some stakeholders[12] recommended that a reserve service prioritises security objectives, while others[13] considered a reserve service would be better suited to meet the reliability needs of the power system.

Other stakeholders[14] noted that the issues on the power system that a reserve service could be used to address can be, or are already being, addressed in other ways with complementary mechanisms.

3.3 Feedback on the economic need for a reserve service

Stakeholders held differing views on the economic merit of a reserve service. Some stakeholders favoured a position that the existing frameworks provide adequate signals to invest in and make reserves available, including through encouraging new technologies to enter the market in the long-term. Alternatively, others noted that the uncertainty inherent throughout the transition is enough to deter investment in the absence of a more explicit reward for reserves.

A range of stakeholders[15] also supported the view that new market-based reserve arrangements would provide economic benefits.

Others[16] did not support new arrangements for reserves, citing that:

- a reserve service is unlikely to adequately address the challenges the power system faces over the course of the transition;
- there are already mechanisms in place to deal with similar challenges;
- the possible benefits of a new reserve service does not justify the costs; or
- a reserve service should not be prioritised at this time.

Some stakeholders[17] did not hold a particular position for or against the implementation of a reserve service, suggesting that the need for reserves ought to be tested and developed more.

12 Including in submissions to the consultation paper from: the Australian Renewable Energy Agency, p. 6; Brickworks, p. 4; Tesla, p. 21;, CS Energy, p. 21; and GE Hydro, p. 2.

13 Including in submissions to the consultation paper from: the Australian Energy Council, p. 3; Clean Energy Council, p. 3; Infigen, p. 5; MEA Group, p. 6; ENEL X, p. 4; CleanCO QLD, p. 5; and Snowy Hydro, p. 1.

14 Including in submissions to the consultation paper from: Monash University, pp. 3-4; Major Energy Users, p. 4; Tilt Renewables. p. 3; and Neoen, p. 3.

15 Including in submissions to the consultation paper from: AEMO, pp. 11-12; Reposit Power, p. 5; Tesla, p. 18; CS Energy, p. 20; MEA Group, p. 1; Delta Electricity, p. 17; Infigen Energy, p. 5; OMPS Hydro, p.8; Energy Queensland, p.15; and Clean Co, p. 1.

16 Including in submissions to the consultation paper from: the Energy Users Association of Australia, p. 9; Energy Australia, pp.8-9; Monash University, pp. 3-4; Neoen, p. 3; Stanwell, p. 9; Clean Energy Council, p. 3; Brickworks, p. 10; Intelligent Energy Systems, p. 10; Tilt Renewables, p. 3; Australian Renewable Energy Agency, p. 6; ENEL Green Power, pp. 2-3; and Major Energy Users, p. 4.

17 For example, in submissions to the consultation paper from: the Australian Energy Council, p. 3; Engie p. 3; Snow Hydro, pp. 8-9; and Maoneng, pp. 3-4.

3.4 Feedback on reserve services from the ESB's post-2025 project September consultation paper

The ESB received 108 submissions to the September 2020 post-2025 project consultation paper. Feedback relating to reserve services was provided in the resource adequacy mechanisms and essential system services market design initiatives.

Stakeholders largely supported the adoption of mechanisms that sharpened the short-term price signal for essential system services. Many noted that an operating reserve service specifically was the most direct method to support flexibility and incentivise investment in dispatchable capacity.

Responses from key stakeholder groups who were supportive of the introduction of an operating reserve service are described below:

- **Generators**[18] noted that an operating reserve service was the most effective means of sharpening price signals to ensure resource adequacy in operational timeframes. They agreed that the service would directly incentivise dispatchable capacity and could be introduced as early as 2021 to help manage the risk of coal closures. Engie[19] in particular stipulated that the operating reserve service (and the scarcity price adder)[20] were the most appropriate proposed mechanisms for further development. Tilt Renewables[21] also noted that the service should not simply be structured to subsidise the existing thermal fleet.
- Some **technology companies**[22] supported the development of an operating reserve service, noting that it may provide additional means for demand flexibility, while others[23] noted that an operating reserve market would not significantly improve the availability of essential system services.
- **Large loads**[24] noted that a co-optimised operating reserve linked to the reliability standard is their preferred resource adequacy mechanism. SA Water identified that an operating reserve service is likely to displace the need for some reliability and emergency reserve trader (RERT) capacity currently provided by large loads, a key benefit.[25] The Institute for Energy Economics and Financial Analysis echoed this, noting an operating reserve service should be designed to reduce or eliminate RERT and produce better economic outcomes for large loads.[26]
- **Retailers**[27] recommended continuing to explore the need for and design of an operating reserve service. However, they also specified that further analysis must consider how an

18 Including in submissions to the post-2025 project consultation paper from: AGL, p. 15; Engie , pp. 3-4; and Infigen, p. 2.

19 refer to Engie, post-2025 project consultation paper submission, pp.3-4.

20 More information on the scarcity price adder may be found in the ESB,*Post-2025 market design consultation paper*, September 2020, p. 38.

21 refer to Tilt Renewables, post-2025 project consultation paper submission, p. 4.

22 Including in the submission to the post-2025 project consultation paper from: Enel X, p. 2.

23 Including in the submission to the post-2025 project consultation paper from: Hitachi ABB Power Grids, p. 4.

24 Including in the submission to the post-2025 project consultation paper from: BlueScope Steel, p. 3.

25 Including in the submission to the post-2025 project consultation paper from: SA Water, p. 4.

26 refer to IEEFA, post-2025 project consultation paper submission, p. 5.

27 Such as in the submission to the post-2025 project consultation paper from Flow Power, p. 5).

operating reserve might affect generator's offers (and therefore prices faced by customers), and hedging arrangements.

Other stakeholders, while being supportive of an operating reserve service to sharpen investment signals, questioned whether it would be sufficient on its own to encourage investment in new capacity over the long-term.

A number of stakeholders[28] expressed variations on the sentiment that the ESB should continue to explore the concept of a reserve service. They agreed that it could boost investment signals, manage security and reliability in real-time and/or incentivise short-term investment in capacity. However, they echoed that the ESB must also look to parallel measures that would strengthen long-term investment signals to support revenue certainty.

In comparison with other stakeholders, Monash Energy Institute noted that reserve markets can do more harm than good by reducing available generation for the energy market.[29] In addition, MEU considered that an operating reserve service is likely to increase costs to consumers with no certainty that it would benefit them.[30]

28 Including in submissions to the post-2025 project consultation paper from: GE Renewable Energy, p. 2; Enel X, p. 4; the Australian Energy Council, pp. 10-11; Hydro Tasmania, p. 4; Origin, p. 3; Alinta, p. 4; and Energy Queensland, p. 12.

29 Monash Energy Institute,post-2025 project consultation paper submission, p. 5.

30 MEU, post-2025 project consultation paper submission, p. 8.

4 CURRENT ARRANGEMENTS

Reserves are capacity that is available to change the supply/demand balance in the near future to keep the system secure and reliable. Reserves are needed for reliability to ensure that sufficient supply is available in real time, and in the right places, to match demand. Reserves are also needed for security considerations within a dispatch interval, including to ensure sufficient capacity is available to keep frequency within acceptable limits in response to credible contingency events, compensated through the FCAS markets.

Market participants make their own commitments to keep capacity in reserve based on price signals in the energy and FCAS markets and the operational costs associated with running their generating plant at a particular point in time. AEMO considers any capacity that is offered into these markets as available but not dispatched to be megawatts (MW) of capacity that could be dispatched in response to changes in supply and demand. This is known as 'in-market' reserve.

Reserves can also be 'out-of-market'. This includes emergency reserves that AEMO procures through the RERT. These are used as a last resort intervention when the market has not responded to fill a reserve shortage.

This chapter outlines:

- the increasing levels of supply and demand uncertainty in the power system, which are driving a need to reconsider reserve arrangements, and
- the current arrangements used to manage uncertainties in the power system.

4.1 Increasing uncertainty drives a need to reconsider current arrangements

Traditionally, changes in the balance between supply and demand have been largely predictable and the result of movements in underlying demand (e.g. due to intra-day/seasonal changes) and the availability of generation and transmission (including planned and forced outages). The arrangements in place to date have been sufficient to maintain power system security and reliability through a combination of market participants responding to wholesale energy market signals and limited instances of intervention by AEMO. These arrangements appear to have been fit-for-purpose in the past, with predictable net demand and a stable generation fleet that can provide significant reserve capacity. There have been few times when emergency reserves have been required.[31] However, with the increasing penetration of variable renewable energy (VRE) generation, changes in the balance between supply and demand (net demand) are becoming less predictable and these conditions need to be met with fewer dispatchable resources. It is therefore less clear whether these arrangements are appropriate to manage the transition of the power system, which is described in more detail in chapter 5.

31 The RERT was dispatched in 5 instances in 2019/20 and 2 instances in 2018/19. Prior to 2018, AEMO has not recorded RERT activation.

We also note that the current arrangements are in transition, with the impending implementation of five-minute financial settlement and a range of market design initiatives being considered under the ESB's post-2025 project. The post-2025 project workstreams most relevant to the issue of reserves are those relating to essential system services, scheduling and ahead markets (specifically the UCS) and resource adequacy mechanisms. Any rule changes or proposed reforms are being considered in light of the evolving market frameworks, not just the current framework, given they will change how the market operates, how uncertainty is taken into account, and the incentives placed on participants.

The following sections set out the current arrangements used to maintain sufficient reserves on the power system. Understanding these arrangements is essential to considering whether they are likely to be fit-for-purpose to manage the transition of the power system.

4.2 How supply and net demand uncertainties are currently managed

The operation of the power system, accounting for uncertainty relating to supply and net demand, is currently addressed with mechanisms for:

- market incentives
- information provision, and
- intervention and out-of-market actions.

4.2.1 Market incentives

Under current energy market arrangements, price signals provide the primary incentive to secure the required energy supply to match demand. The aim is to ensure that system reliability objectives are met over both the short-term (pre-dispatch) and long-term (over several years). This incentive also secures the provision of reserves as generators manage their ability to respond to changing market conditions.

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

Price signals in investment timeframes

Energy is bought and sold in the energy market providing incentives for the entry and exit of generation and demand response capacity based on expected returns from participating in these markets over the long-term. The primary way of achieving these price signals is through the contract market. This is because the contract market plays an important role in parties investing - contracting lowers the cost of financing investment in generation and demand response, which lowers the cost of achieving and maintaining system reliability. It also provides certainty to these parties about how the costs of their investments will be recovered over time.

Contract prices have historically been based on expectations of what is happening in the energy market. So, as capacity (and so supply) is projected to decline, contract prices will rise to encourage new participants (and vice versa).

Price signals in operational timeframes

The capacity offered into the power system in operational timeframes will also be informed by signals - in this case, the spot price - as well as the short-run marginal costs (operating costs) of running generating/demand response assets. As the supply/demand balance tightens and capacity with lower operating costs are used up, energy spot prices increase. This encourages capacity with higher operating costs to respond and make themselves available to participate in the market.

Capacity response to price signals

Generators and demand response providers are constantly assessing likely outcomes in the energy market. Their aim is to predict a tightening of the supply/demand balance and to be available to respond to the higher prices entailed. Capacity that cannot respond to higher prices, either because it was not ready to do so or because it was not flexible enough, bears an actual or opportunity cost. As a result, capacity will make itself ready to respond and provide energy in the near future to avoid the risk of these opportunity costs. That is, capacity will be in *reserve* in the market.

The contract market and the spot market are related, creating a link between the two timeframes. The contract market provides additional financial incentives that operate outside of the energy market - but influence what is happening in operational timeframes. Generators sell hedging contracts (such as cap, floor and collar options) in secondary financial markets to smooth the risk of participating in the energy market. For example, a price cap option may require the generator to pay to the purchaser, for an agreed volume of generation, the difference between the energy spot price and an agreed cap price. The generator will therefore have a very high incentive to hold reserves in order to make sure it is able to generate when prices are above the agreed cap price. If the generator does not have sufficient reserves, then it is not able to earn revenue in the energy market but still must pay out under the hedging contract.

The current market design is intended to promote investment in capacity that can maximise value under these arrangements. As the power system evolves, the nature and frequency of high price events will change. Investors will need to respond to and anticipate the changes in that signal over time, making decisions about whether to invest in, say, gas turbines or grid scale batteries.

The nature of the price signal that investors respond to on an investment timescale, and that capacity responds to on an operational timescale, will change markedly when five-minute settlement is implemented in mid-2021. Indeed, this is likely to increase the value of flexibility as financial outcomes become linked more closely with 5-minute physical capabilities rather than 30-minute capabilities. The Commission is interested in stakeholder views on how this may change the analysis, and findings set out in this paper.

4.2.2 Information for in-market participation

The way participants respond to expected price outcomes on investment and operational timescales (including the level of reserves they provide) is based on the information available to the market. In order to assist with this, AEMO publishes a range of information so that participants can provide the system with energy and reserves without direct intervention.

In the NEM, the concept of unserved energy is applied to measure any supply interruptions consumers may experience from generation and interconnection inadequacy. Projections of the reliability standard and interim reliability measure - explained more below - are key to the forecasts and information provided to market participants.

BOX 1: KEY RELIABILITY METRICS IN THE NEM

Reliability standard

Key to most of this information is the reliability standard, which expresses the desired level of reliability sought from generation assets, demand response and the transmission lines that transport power between states. It underpins the operational and investment decisions that drive reliability. Set in the NER, the standard is expressed as the maximum forecast unmet demand (i.e. unserved energy) for each financial year, as a proportion of the total demand in that region. The current reliability standard (0.002 per cent unserved energy) requires that supply matches demand at least 99.998% of the time in every region each financial year. To uphold this, the expected level of supply needs to include a buffer (in-market reserves) to account for potential contingencies and unexpected events such that expected supply is greater than expected demand.

Interim reliability measure

In addition to the reliability standard, the NEM recently had the interim reliability measure introduced into the regulatory framework. The interim reliability measure was developed as part of the ESB's work to improve the reliability (resource adequacy) of the electricity system through interim measures. The interim reliability measure for generation and inter-regional transmission elements in the NEM is a maximum expected unserved energy in a region of 0.0006% of the total energy demanded in that region for a given financial year.

Forecasting tools

It is AEMO's responsibility to determine the level of reserves required in planning and operational timeframes to uphold the reliability standard using forecasting tools. AEMO therefore operationalises the reliability standard through its forecasting processes, which provide information to market participants and potential investors.

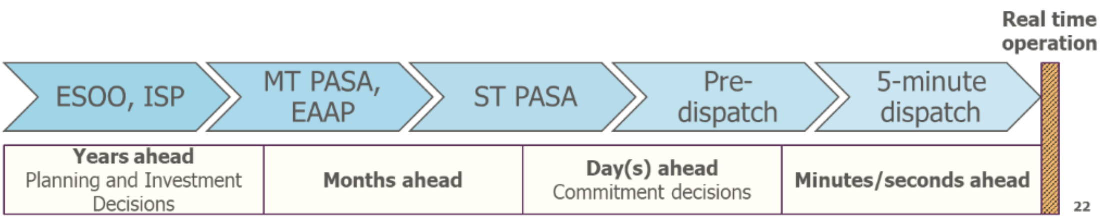
AEMO uses a range of tools to help inform market participant decision-making to secure sufficient levels of in-market reserve (and eventually determine if out-of-market reserve needs to be procured). These include publishing energy market outlook reports such as the Integrated System Plan (ISP) and the Electricity Statement of Opportunities (ESOO) and using the Projected Assessment of System Adequacy (PASA) process to forecast the overall supply/demand balance for electricity over various time periods. The ESOO must also include projections of the interim reliability measure.

The ISP[32] provides a roadmap to guide investment that secures an affordable, secure and reliable power system while meeting emissions reduction scenarios over a 20-year timeframe. Over a 10-year timeframe, the ESOO[33] forecasts electricity supply reliability. This includes an assessment against the reliability standard, as well as for the interim reliability measures for the purpose of the RRO (more on the RRO below). These publications aim to inform long-term investment by market participants in technologies that will fill forecasted shortfalls in capacity.

The PASA predicts supply constraints over shorter timeframes, based on the reliability standard. It takes into account AEMO's load forecasts, reserve requirements (to uphold the reliability standard) and network constraints information. These are balanced against participant inputs (offers) relating to unit capacity and energy availability. It is forecast over three time periods:

1. Medium term (MT) PASA (used in conjunction with the Energy Adequacy Assessment Projection (EAAP))[34] covers a two-year horizon[35] and is produced weekly.
2. Short term (ST) PASA covers 6 trading days (i.e. each day for the period 2 to 7 days ahead). The calculation of the ST PASA is run every 2 hours.[36]
3. Pre-dispatch (PD) PASA covers 1 day (i.e. forecast each day for the day ahead).[37]

Figure 4.1: Timeline of forecast information provision



Source: AEMC.

Lack of reserve (LOR) conditions

Reserve capacity is the spare capacity available to provide the buffer required under the reliability standard. AEMO uses the PASA process to calculate the level of reserve capacity by forecasting the regional excess supply (RXS) for a region for each 30-minute trading interval against the reliability standard. This forecast is based on:

32 AEMO, *2020 Integrated system plan*, July 2020.

33 AEMO, *2020 Electricity statement of opportunities*, August 2020.

34 AEMO, *Energy adequacy assessment projection,* November 2019.

35 The Commission made a rule in February 2020 that, amongst other things, extended the outlook of published generation availability as part of the MT PASA from two to three years. See: https://www.aemc.gov.au/sites/default/files/documents/erc0270_-_mt_pasa_final_determination.pdf

36 AEMO, *Short term PASA process description,* March 2012, p. 8.

37 AEMO, *Projected assessment of system adequacy (PASA)*, 2020.

- the aggregate capacity of scheduled generation (aggregate non-energy limited capacity, plus aggregate energy limited capacity, minus aggregate semi-scheduled capacity), plus
- interconnector support, plus
- forecast aggregate semi-scheduled availability, minus
- scheduled demand.[38]

An uncertainty factor (known as the forecast uncertainty measure (FUM)) is then generated using RXS error distributions, which take into account historical forecasted RXS minus actual RXS for various prevailing weather and generation mix scenarios.[39]

If a reserve shortfall is identified through the PASA process, AEMO will declare lack of reserve conditions. Lack of reserve conditions (whether forecasted or actual)[40] fall into a number of classifications:[41]

1. *Lack of reserve level 1* (LOR1) - LOR1 occurs when forecast reserve levels fall below the larger value of either the FUM or the sum of the two largest credible risks in the region.
2. *Lack of reserve level 2* (LOR2) - LOR2 occurs when forecast reserve levels fall below the larger value of either the FUM or the largest credible risk in the region.
3. *Lack of reserve level 3* (LOR3) - LOR3 occurs when the forecast reserve for a region is at or below zero.[42]

Issue of market notices

In practice, AEMO will inform market participants of the LOR condition through market notices. If a reserve shortfall is identified within the:

- ST PASA forecast (i.e. the period 2 to 7 days ahead), AEMO will issue a market notice advising forecast LOR1 conditions only if they appear in the PASA calculation run completed at 1400hrs (2pm AEST). LOR2 will be declared as soon as possible after being identified.
- PD PASA forecast (i.e. within the next trading day), AEMO will issue a market notice advising forecast LOR conditions if any LOR conditions (LOR1/LOR2/LOR3) are present in the current pre-dispatch period (i.e. the next trading day).[43] [44]

These notices provide information to market participants that inform their expectations of prices in the energy market. Market participants may respond to this information by making their capacity available (i.e. as reserves) to the market.

38 Applicable to NSW, QLD, SA and Victorian regions. RXS for Tasmania excludes components which are affected by a requirement to export due to network constraints.
39 AEMO, *Reserve level declaration guidelines*, December 2018, pp. 7-8.
40 AEMO, *AEMO LOR market notifications explained - what does a 'lack of reserve' mean?*, 2020.
41 As per Clause 4.8.4 of the *NER*.
42 AEMO, *Lack of reserve framework report Q2 2020,* July 2020, p. 17.
43 AEMO, *Short term reserve management,* October 2020, pp. 5-6.
44 AEMO may update or cancel the LOR conditions within the 1400hr ST PASA forecast period or most recent pre-dispatch schedule.

4.2.3 Market intervention and other out of market actions

If AEMO considers that the market has not responded to published information (whether that be the ISP, ESOO or LOR notices) by making sufficient reserves available, it may use a range of tools to intervene in or act out of the market. The following sections describe these tools and how they are used.

RRO

The ESOO forecasts electricity supply reliability over a ten-year period, including identifying any reliability gaps within the next five years. If, three years and three months out, AEMO determines that a material reliability gap will not be filled without intervention (e.g. investment in new capacity is not at a sufficient level), they may apply to the Australian Energy Regulator (AER) to trigger the RRO and issue a reliability instrument.[45] From October 2020, this trigger is based on a higher reliability standard. This is known as the interim reliability measure, which requires that supply meets demand 99.9994% of the time (i.e. no more than 0.0006% unserved energy in every region each financial year).[46] The RRO will be based on the interim reliability measure, which is intended to be in place until 30 June 2025.

A reliability instrument requires liable entities (i.e. retailers and large customers who directly purchase wholesale electricity) to enter into sufficient qualifying contracts to meet their share of peak system demand for the period covered by the instrument. They must report their net contract position to the AER to assess projected shortfalls.

AEMO may re-submit the application to trigger the RRO 1 year out if the material gap remains and may also commence procurement of energy reserves to activate under the RERT framework.[47]

Market intervention in operational timeframes

In operational timeframes, AEMO observes the market's response to LOR notices and allows the market to take its course up until the "latest time to intervene", which they estimate and publish when the LOR notice is released.[48]

If the latest time to intervene has passed and the market has not provided sufficient additional reserves to address the shortages projected in the ST and/or PD PASA, AEMO will intervene with supply scarcity mechanisms including directions, instructions[49] and RERT contracts.

1. **Directions:** in this context, directions are issued to registered participants (generators and scheduled loads) to operate at a specified output or consumption level and are dispatched through normal market processes. AEMO will consider cost estimates provided by potential directed participants and assess their effectiveness in meeting the prevailing

45 AER, *Retailer reliability obligation*, see: https://www.aer.gov.au/retail-markets/retailer-reliability-obligation.

46 ESB, *Interim reliability measures - RRO trigger: Decision paper,* October 2020.

47 ESB, *Retailer reliability obligations: Final rules package*, May 2019, pp. iii-iv.

48 In accordance with Clause 4.8.5A and 4.8.5B of the *NER*. For example, Reserve Notice 72883 published on 23/01/2020 at 11:16:35 AM forecasted LOR2 conditions from 1530 hrs to 1730 hrs the same day. The latest time to intervene was 1330 hrs that day. (At 11:22:50 AM, AEMO published an intention to commence RERT contract negotiations).

49 Instructions are issued in accordance with Clause 4.8.9 of the *NER*.

supply scarcity conditions (based on e.g. time taken to synchronise, fuel availability, minimum run time) before issuing directions. Generators are compensated for responding to the direction.

2. **Instructions:** instructions are final resort notices which require large energy users and distribution network service providers to load shed. AEMO will consider the cost of lost load and any material distortionary effects and assess the amount of the user's load available to shed, key network locations and load shedding procedures before issuing instructions.
3. **RERT:** under the RERT framework, AEMO secures contracts for emergency out of market reserves from providers which can be activated upon request. These providers are grouped into short-notice, medium-notice and long-notice providers:
    a. Short-notice providers are contracted for three hours to seven days. These providers receive compensation when reserve is required based on prices agreed upon appointment.
    b. Medium-notice providers are contracted for seven days to ten weeks. These providers negotiate prices if and when reserve is required.[50]
    c. Long-notice providers are contracted for 10 weeks or more via invitation to tender. Under the ESB's interim reliability measures, the long-notice RERT has been replaced by a mechanism that allows out of market reserves to be procured for up to three years, where an exceedance of the interim reliability measure has been forecast for two out of the three years including the first year, and following consultation with and approval from the relevant Energy Council Minister of directly impacted states and/or territories. This is intended to remain in place until March 2025.

RERT providers cannot offer capacity to the power system within the trading intervals to which the contract relates and appear to the market as a decrease in scheduled demand.

AEMO assumes that all facilities will deliver in accordance with generator performance standards and reserve contracts as anticipated.[51]

Interventions in or actions taken out of the market can be costly. For example, AEMO dispatched RERT on three occasions in NSW and two occasions in Victoria in 2019-20[52] and on two occasions in Victoria in 2018/19.[53] AEMO publishes cost estimates for exercising RERT, including the cost of compensating providers for their availability, pre-activation and activation and the cost inefficiencies associated with market intervention. In 2019-20, the cost estimate was $40.6 million[54] and in 2018/19, $34.5 million.[55]

A key matter to resolve in assessing these rule change proposals is whether the costs of these interventions, which are likely to rise as uncertainty on the power system increases,

50 AEMO, *Reliability and emergency reserve trader (RERT)*, 2020.
51 AEMO, *Short term reserve management,* October 2020, pp. 5-6.
52 AEMO, *RERT quarter Q2 2020 report and RERT end of financial year 2019-20 report*, August 2020, pp. 5-6.
53 AEMO, *RERT report for 2018-19,* 2019, p. 1.
54 AEMO, *RERT quarter Q2 2020 report and RERT end of financial year 2019-20 report*, August 2020, p. 7.
55 AEMO, *RERT report for 2018-19,* 2019, p. 1.

would be avoided and outweighed by the costs of implementing an arrangement to pay for reserve services separately.

5 RESERVES AND THE POWER SYSTEM

This chapter introduces the concept of energy reserves on the power system and:

- defines the power system need for reserves
- describes how reserves are used in practice on the power system, and
- discusses what we know and do not know about meeting the power system need for reserves over time, as the power system transforms.

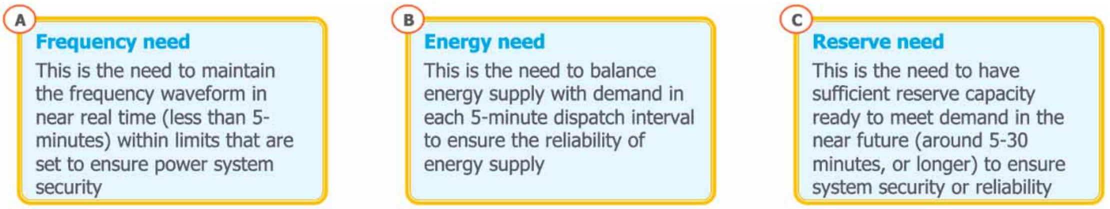
5.1 The power system need for reserves

The power system has two fundamental needs; to be secure and to be reliable. In essence:

- the system is *reliable* when there is enough capacity to meet consumer demand, without load shedding, almost all the time (that is, to the level consumers value), and
- the system is *secure* when, after being faced with sudden shocks or events, it can return promptly to a state where it can handle further shocks.

A reliable and secure power system seeks to balance supply and demand in near real time such that the frequency of the power system is maintained within limits and energy is delivered to consumers.[56] This is achieved by meeting three practical power system needs that relate to controlling active power on the system, illustrated in Figure 5.1.

Figure 5.1: Power system needs for active power control



Source: AEMC.

The power system needs enough resources to meet each of these needs, accounting for uncertainty and variability. To date, these needs have been met by arrangements that explicitly price the energy need and the frequency need, but do not explicitly price the reserve need.

Energy reserves ('reserves') are, conceptually, capacity that is not currently utilised but is available and capable of changing the supply/demand balance in the near future. This includes capacity on the supply side (generation) and the demand side (demand response). As this capacity must be available *in the near future*, it must be capable of meeting targets at a specified future time, accounting for ramp rates, state of charge, firmness of resources, and other operational considerations. We refer to this capability as being 'dispatchable'.

56 A secure system also requires other technical parameters to be met, such as system strength, voltage and inertia.

As described in section 4.2, market participants principally provide reserves in anticipation of outcomes in the energy market. Information available to participants allows them to determine the risks associated with readying capacity to participate in the energy market. There can be costs associated with being ready to generate or provide a demand side response. Participants must therefore consider whether it is worthwhile making their capacity ready (i.e. providing reserves), which is determined based on the assessment and risk appetite of that participant. These decisions about how many reserves are in the system are the product of market participant decisions in response to information provided by AEMO.

As explained in chapter 4, there are both in-market reserves and out-of-market reserves. The below assumes that the reserves are 'in-market', unless it is explicitly stated otherwise. This is because the RERT is a last resort mechanism to use when the other elements have been exhausted and is not a primary mechanism to provide reserves.

5.2 Circumstances where reserves are used

Reserves are needed to provide an active power response in the near future, which could be for a wide range of purposes. It is helpful to categorise these into two main groups:

- reserves needed for events that are largely expected by market participants ('expected events'), such as evening ramping requirements and peak consumer demand events that are relatively close to the net demand needs signalled by pre-dispatch information, and
- reserves needed for events that are not expected by market participants ('unexpected events'), such as instances where net demand needs vary significantly from what was signalled by pre-dispatch information.

The first category includes *reliability* events that are mostly expected and predictable, while the second category relates to *reliability and security* events that are unexpected and not able to be predicted. Figure 5.9 shows the range of unexpected security events.

The extent to which market participants provide in-market reserves is informed by the expectations they have. This is based on a variety of information they may have, including information published by AEMO, such as PASA information and LOR notices, as well as their expectations of how AEMO may act if it considers insufficient in-market reserves are forthcoming. This process is described in detail in chapter 4.

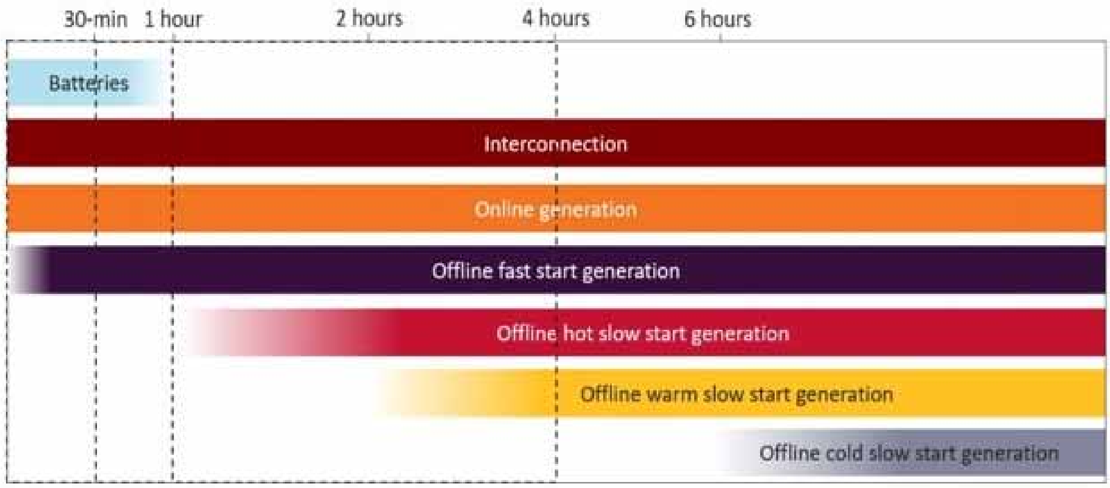
The ability of the energy market to provide sufficient reserves to maintain power system reliability and security is a function of the amount and type of capacity that is available, and the nature of the events it is required to respond to. The following sections draw from various sources of analysis and information to shed light on how each of these factors may develop, under current arrangements, as the power system transforms.

5.3 Reserve capacity on the power system

Reserves are generally provided by dispatchable capacity. While more demand is becoming responsive in the energy market, the majority of capacity that provides reserves is made up of scheduled generating units. Semi-scheduled generating units (large scale wind and solar generators) could theoretically provide reserve capacity if they reduced their energy output, creating the 'headroom' to ramp up if needed. This has not occurred to date on the power system. These generators tend to maximise their revenue in the energy and renewable energy certificate markets (and under power purchase agreements with off-takers) by generating at maximum output.

There are a range of different types of scheduled generating units on the power system. They each provide reserves with different characteristics. Figure 5.2 shows a range of different technologies and their response times.

Figure 5.2: Start-up times for dispatchable/flexible technologies



Source: AEMO, *Renewable integration study stage 1 appendix C*, April 2020, p. 51.

The characteristic that is most relevant to the provision of reserves is the 'flexibility' of the capacity. Flexibility is not a concept currently recognised explicitly in the NER. Flexibility is the extent to which a type of capacity's output can be adjusted or committed in or out of service. This includes the speed of response to start up and shut down, rate of ramping, and whether it can operate in the full range of capability, or has restrictions (such as minimum generation requirements, or other limitations).

The flexibility characteristics of a range of technology types is described below:[57]

- **Flexible conventional generation** – the most flexible generation types are hydro, gas turbines, and other liquid fuel generators. These can ramp their output up and down relatively quickly and can have short start-up times. They are also designed to switch on and off regularly, and it is generally economical to do so to take advantage of higher prices in the energy market. Some new generation gas peaker plants can have much shorter start-up times than current gas peaker plants.
- **Inflexible conventional generation** – coal-fired generation is relatively inflexible, having long start up times, high minimum operating levels, and high start-up and shut-

57 AEMO, *Renewable integration study stage 1 appendix C*, April 2020, p. 46.

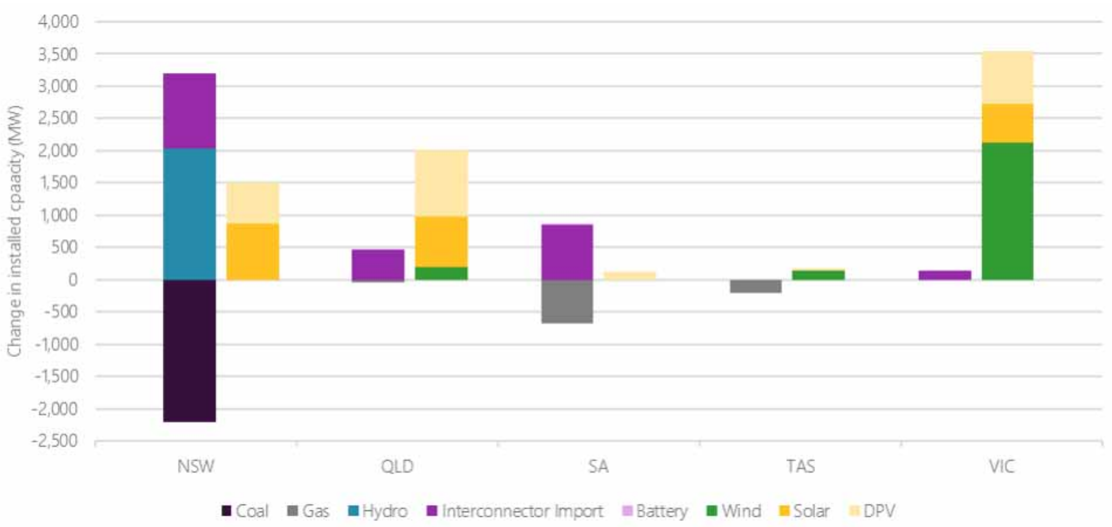
down costs (making it uneconomical to switch on and off frequently). Above their minimum operating levels, coal units have a wide operating range and provide significant reserves and contingency responses. Some coal units are also increasing in flexibility through plant upgrades, which allow lower minimum operating levels and more frequent cycling of units. However, this may increase wear and tear on units, which may reduce their technical life and increase running and maintenance costs.

- **Interconnection** – interconnection improves the sharing of flexibility between adjacent regions, increasing the diversity of generation and supply across a system. Headroom on interconnectors is limited by:
  - the available capacity from all generators in the adjacent region, subject to their ramp rate limits, and
  - the interconnectors that can import energy to that region, subject to any constraints imposed on the interconnector flow.
- **Storage** – storage can participate by increasing demand (load) or increasing supply (generation). Different types of storage have different characteristics, with the two principal types being pumped hydro and batteries. Pumped hydro can quickly produce or demand large amounts of energy over a longer duration, although there are limitations to how quickly it can switch between these modes. Batteries have fast response times and can cycle from charge to discharge much more quickly than pumped hydro. The ability of a battery to respond at any point in time is defined by its depth of charge, state of charge, and its maximum power output and input. The units currently installed on the power system have shorter running durations. Longer duration batteries are possible. For example, AGL has recently announced a longer duration 250 MW (1000 MWh) battery to be installed in South Australia.[58]
- **Demand response** – demand response is the ability for end-users to change energy usage in response to price signals or other incentives. Demand response can be from large or industrial customers or smaller customers (e.g. through controllable appliances or distributed storage). One of the challenges in utilising demand response is the difficulty issuing energy market price signals to these loads to incentivise the desired behaviour.

AEMO projects a number of changes in the capacity mix on the system over time. Figure 5.3 shows the projected changes in capacity from 2019 to 2025 under the ISP's central scenario (based on the draft ISP).

58 AGL press release, 16 November 2020: see https://www.agl.com.au/about-agl/media-centre/asx-and-media-releases/2020/november/agl-unveils-plans-for-grid-scale-battery-in-south-australia.

Figure 5.3: Capacity changes, 2019 to 2025 Draft 2020 ISP Central scenario



Source: AEMO, *Renewable integration study stage 1 appendix C*, April 2020, p. 48.
Note: Based on the Draft 2020 ISP Central scenario build to 2025.

Since this assessment was undertaken a number of projects have been announced but not yet committed. This includes a 300 MW battery in Victoria to be commissioned in late 2021 (which is supported by the Victorian Government) and a 250 MW battery in South Australia to be commissioned by 2024 (which has no financial support from government). This assessment also does not appear to include a range of other investments in dispatchable capacity not yet committed. In NSW alone, for example, this includes:

- a 250MW gas peaking plant at Newcastle and four large-scale 50 MW batteries (as part of AGL's strategy to replace Liddell's capacity)
- a 320 MW gas peaking plant at Tallawarra
- a 50 MW battery at Darlington Point, and
- 5 projects funded under the NSW Government's Emerging Energy Program[59].

In addition, there are a range of storage projects in earlier stages of development which may or may not proceed to commitment and commissioning. These will be further encouraged under the NSW Government's Electricity Infrastructure Roadmap,[60] which will support 12 gigawatts (GW) of new capacity across a number of renewable energy zones in NSW and 3 GW of new firm capacity by 2030.

The capacity mix on the power system will continue to evolve, with changes driven by market incentives and government intervention. As that capacity mix changes, the capability to

59 including a 50 MW battery at Wallgrove, a 30MW battery at Glen Innes, a 50MW battery at Uralla, an 84MW gas/battery hybrid project and a 6MW virtual power plant. (NSW Government, *Emerging energy program*, see: https://energy.nsw.gov.au/renewables/clean-energy-initiatives/emerging-energy-program)

60 NSW Government, *Electricity infrastructure roadmap*, see: https://energy.nsw.gov.au/government-and-regulation/electricity-infrastructure-roadmap.

provide reserves will change, as will the demands on that capacity with evolving drivers of the need for reserves.

5.4 Expected reserve requirements

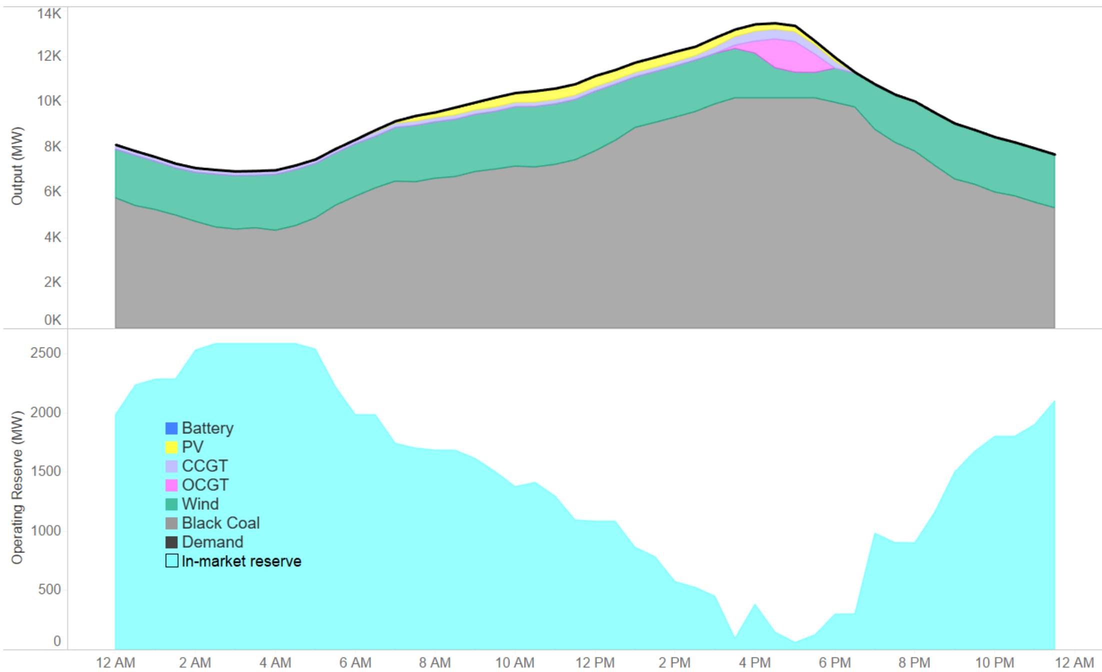
As noted above, reserves may be needed for circumstances on the power system that are *expected*, or those that are *not expected*. This section explores circumstances where the need for reserves is expected, including:

- when high peak demand is forecast, and
- when steep increases in net demand are forecast.

Forecast high peak demand

When underlying (or total) demand is at its highest point, prices in the energy market are generally high and almost all available capacity on the power system has responded and is generating (or has reduced demand). As a result, there is little capacity that is in *reserve* in the market. Capacity is not able to respond in the future because it has already responded. Figure 5.4 below shows a typical peak demand day in a simulated NEM region based roughly on NSW, with few in-market reserves available from about 4-6 pm. We note that this does not show reserves that could be provided through interconnection, which at any given time is limited by the spare capacity of interconnectors to transfer energy to a region and the capacity in adjacent areas to provide that additional energy.

Figure 5.4: Typical peak demand day



Source: AEMC.

This illustrates the risk that during peak demand events, there may not be sufficient capacity in reserve to maintain the reliability of the power system, particularly if demand is forecast to continue to increase. The current energy market frameworks are designed to address this risk through the reliability settings (i.e. market floor price, cumulative price threshold, administrative price cap, market price cap). For example, the market price cap is set at a level to incentivise participants to invest to ensure a level of reliability that is consistent with the reliability standard. The ESB is considering whether these arrangements are appropriate to ensure reliability to this standard, as the power system transforms, in the resource adequacy mechanisms market design initiative of its post-2025 project. The Reliability Panel will also commence its regularly scheduled review of the reliability standard and settings this year, which will allow further consideration of these issues in coordination with the ESB.

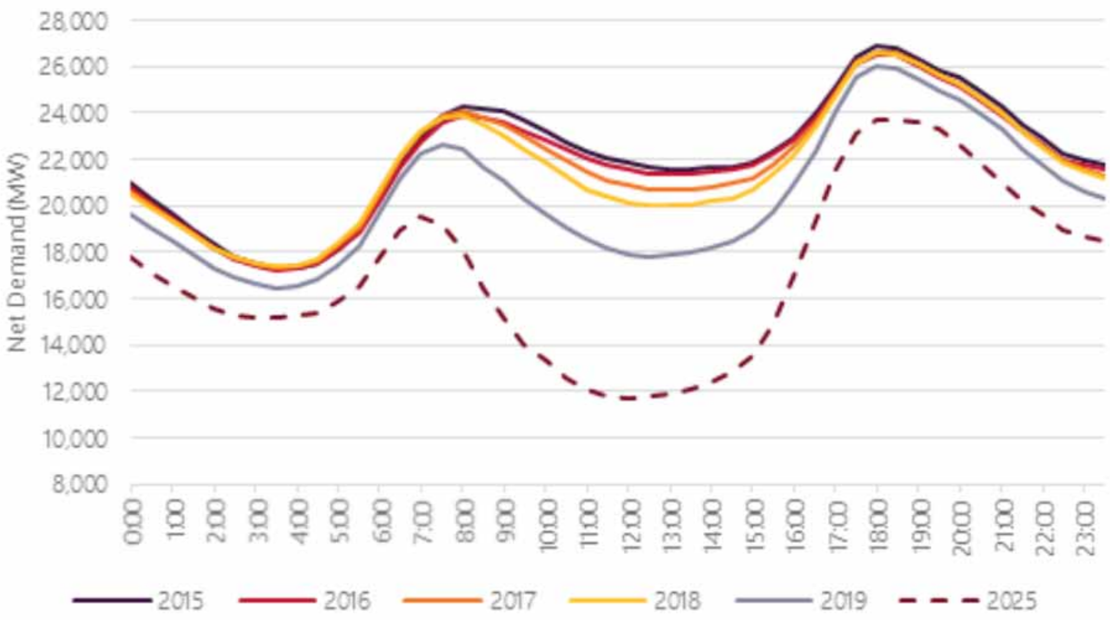
Forecast steep increase in net demand

There are times when reserves are needed to ensure capacity is available to meet significant changes in net demand that are forecast. Net demand is underlying (or total) demand net of VRE generation. This is the level of demand that must be met by scheduled generation sources and not by wind or solar generation.

This is perhaps best illustrated by showing the increasingly steep increase in net demand due to increasing penetrations of VRE on the power system. Figure 5.5 shows historical and projected average system-wide net demand curves for winter. It forecasts that evening ramping requirements will increase from around 5 GW over 4.5 hours in 2015 to around 12 GW over 6 hours projected in 2025.[61]

61 While the average evening ramping requirements are expected to increase significantly in each season, the winter months are expected to see the highest ramping events due to the confluence of total demand ramping up while VRE (particularly solar) ramps down.

Figure 5.5: Average system-wide net demand during winter



Source: AEMO, *Renewable integration study stage 1 appendix C*, April 2020, p. 33.

These changes in net demand profiles must be met by scheduled capacity ramping up or down to balance supply and demand. The scheduled capacity on the power system, as it transforms, must therefore be sufficient (in capacity and flexibility) to meet expected increased changes in net demand.

While this daily diurnal ramping is likely to increase, forecast changes in net demand outside of these times are also likely to increase. Figure 5.6 shows historical and expected changes in large variations in VRE output on the power system (e.g. variations greater than 10%, 20%, and 30% of installed capacity). These are called VRE ramps, and this analysis shows that the frequency and magnitude of these ramps is expected to increase significantly over time.

Figure 5.6: VRE ramps on the power system

	Threshold (MW)			Total occurrences (n)			Days (n)		
	10%	20%	30%	10%	20%	30%	10%	20%	30%
Upward ramp events									
2015	361	722	1,083	456	3	-	73	2	-
2016	835	1,671	2,506	381	1	-	61	1	-
2017	955	1,910	2,865	649	-	-	100	-	-
2018	1,175	2,350	3,526	932	-	-	126	-	-
2025	2,646	5,291	7,937	6,579	22	-	356	6	-
Downward ramp events									
2015	361	722	1,083	474	-	-	69	-	-
2016	835	1,671	2,506	844	-	-	100	-	-
2017	955	1,910	2,865	1,056	-	-	130	-	-
2018	1,175	2,350	3,526	1,521	-	-	160	-	-
2025	2,646	5,291	7,937	5,441	37	-	349	11	-

Source: AEMO, *Renewable integration study stage 1 appendix C,* April 2020, p. 21.

As more VRE enters the power system over time, we can expect increased needs for scheduled capacity to ramp up or down to "fill in the gaps". This may require significant levels of reserves and fleet flexibility.

The current energy market framework is designed to compensate participants for making their capacity ready (i.e. in reserve) to meet these expected ramping needs. This occurs through allowing prices to vacillate between the market floor price and market price cap. As prices rise, participants (depending on their contract positions) increase their availability. The cost to participants of being ready to provide their capacity to the energy market is built into their offers in the market, and for demand response providers, into the price at which they are willing to reduce demand. The growing need for reserves to provide for expected increased ramping requirements should manifest with higher prices during these times, increasing the incentive to invest in equipment with the capability to provide energy then. These high prices are also likely to sharpen through the implementation of five-minute financial settlement arrangements, where prices will not be averaged over 30 minutes as they currently are. This will increase the incentive for investment in highly flexible capacity.

There is no clear evidence to suggest that the current arrangements (that price the frequency and energy needs, but not the reserve need) will not be sufficient to provide sufficient reserves to meet e*xpected* ramping requirements on the power system.

Table 5.1 summarises our views at this stage regarding expected ramping requirements. The Commission is interested in stakeholder views on this.

Table 5.1: Reserves and expected ramping requirements

RESERVE REQUIREMENT	OBSERVATIONS / ANALYSIS	IS THERE A MATERIAL PROBLEM / ISSUE?	COULD A RESERVE SERVICE ADDRESS THIS PROBLEM?
Expected requirement for reserve capacity to meet peak demand.	Times of peak demand are likely to coincide with periods with low reserves. Current energy market arrangements are designed to address this requirement to a level valued by consumers through the current reliability settings.	The resource adequacy mechanisms market design initiative of the ESB's post-2025 project is considering the arrangements needed to provide reliable electricity supply to the extent consumers value through efficient and timely entry and orderly exit of capacity.	A reserve service could be used to influence the decisions of market participants to enter, exit or change the way they participate in the market (such as becoming scheduled). Incentivising new entry or delaying exit through a reserve service would likely increase overall costs in order to compensate participants for the additional investment to achieve this. This would need to be weighed against any reliability benefits.
Expected requirement for reserve capacity to meet forecast ramping events, such as evening peak ramps.	Ramping requirements for scheduled capacity will increase in magnitude and frequency as more VRE enters. These ramping requirements are designed to be met under current energy market arrangements through the current reliability settings.	A problem has not been identified, but one cannot conclude with certainty its absence. The energy market price is designed to attract reserves to meet this need over time.	A reserve service could be used to provide for such expected ramping requirements. This would likely affect prices in energy and FCAS markets over time.

5.5 Unexpected reserve requirements

Reserves may be needed for circumstances on the power system that are *not expected*. This section explores these types of circumstances, including:

- when forecasts of net demand are inaccurate and reserve capacity is required to be ready to meet this unexpected need, and
- when a security event occurs and reserve capacity is required to be ready to meet this unexpected need.

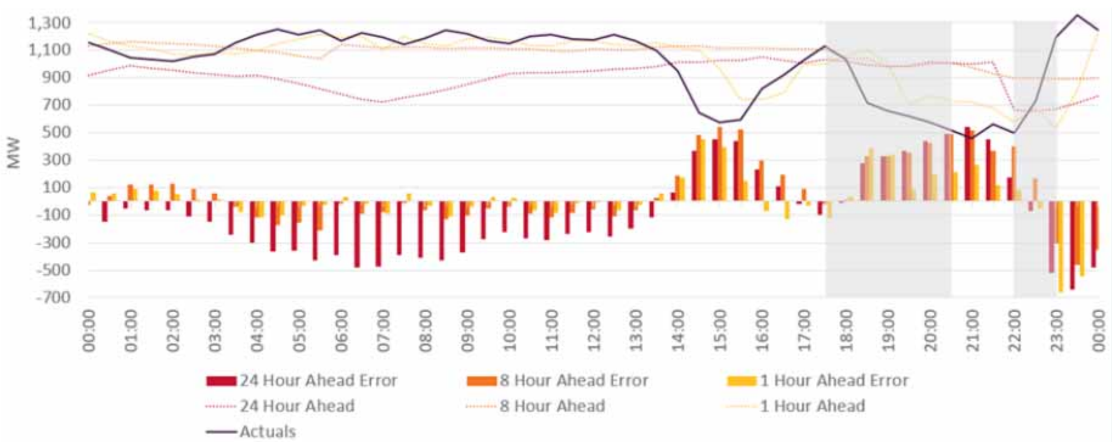
The term "unexpected" refers to the expectations of market participants. That is, changes in net demand that occur without sufficient time for updated information to have a material impact on the levels of reserve that are available to the energy market.

Unexpected changes in net demand due to uncertainty in forecasting

Historically, changes in net demand have been relatively easy to foresee. Underlying demand has been largely predictable and the proportion of VRE generation was relatively smaller than today. However, as more VRE generation enters the system, forecasts of net demand will be subject to greater uncertainty. VRE generation, particularly from large-scale wind and solar, is weather dependent and can vary significantly from the net demand needs that were signalled to market participants in pre-dispatch information.

Figure 5.7 shows the forecast and actual wind output for South Australia on 18 December 2017. This shows an actual drop in wind generation at 13:00 to 14:00 which occurred an hour earlier than predicted in the one-hour ahead forecast and was not predicted to occur at all in the 8 or 24-hour ahead forecasts. The change in net demand that was not expected an hour ahead of time reached close to 500 MW at 14:30.

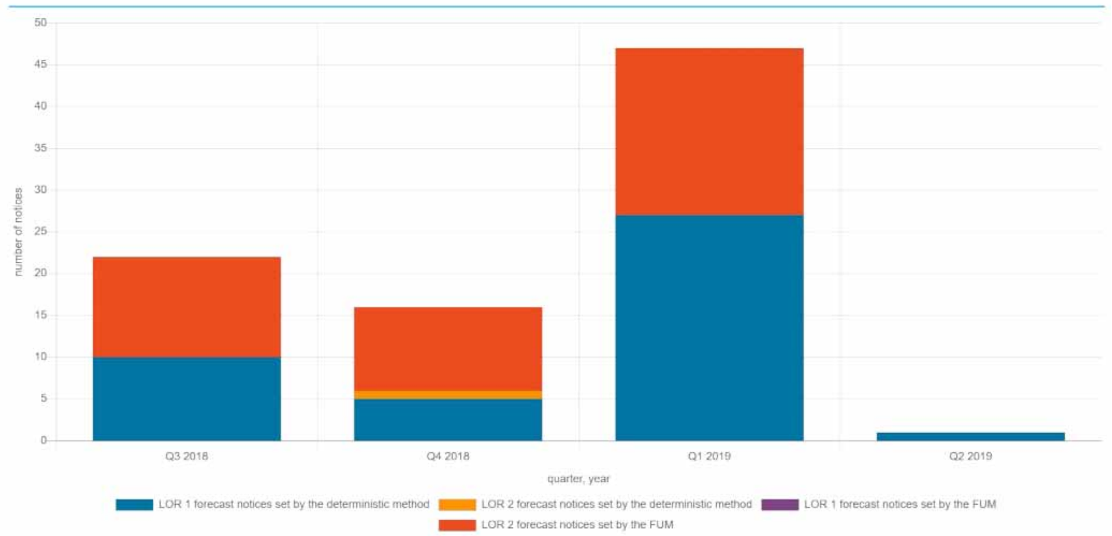
Figure 5.7: Actual and forecast wind generation in South Australia - 18 December 2017



Source: AEMO, *Renewable integration study stage 1 appendix C,* April 2020, p. 40.

As more VRE generation enters the system, the frequency and scale of unexpected changes in net demand is expected to grow. Indeed, the Reliability Panel recognised in its 2019 annual market performance review that the need for reserves is increasingly being driven by short term variability of intermittent generation output.[62] Figure 5.8 shows a significant proportion of LOR2 notices driven by forecast uncertainty, as opposed to the deterministic measure of reserves required to address contingencies.[63]

Figure 5.8: Forecast notices set by the FUM and the deterministic method in 2018/19



Source: Reliability Panel, *2019 Annual market performance review,* April 2020, p. 67.

The scale of forecast uncertainty can also be significant. Table 5.2 shows the magnitude of the variance between an actual one-hour ramping of VRE generation and what was forecast an hour before that ramping occurred in 2018 in the NEM.[64] Note there were no observed occasions in 2018 where wind generation ramped by a proportion of greater than 20% of installed capacity.

Table 5.2: One-hour VRE ramp forecast error in the NEM in 2018

RAMP SIZE (% OF INSTALLED CAPACITY)	OBSERVATIONS (N)	MAXIMUM UNDER-ESTIMATION (MW)	MAXIMUM OVER-ESTIMATION (MW)
SOLAR			
All	9,244	-134	163
>10%	5,558	-134	163
>20%	3,069	-134	156
>30%	1,232	-134	150

62 Reliability Panel, *2019 Annual market performance review*, April 2020, p. 67.

63 Reliability Panel, *2019 Annual market performance review,* April 2020, p. 67. Note the approach to calculating the FUM was changed in December 2018, which from that time would have the effect of reducing the number of LOR2 notices driven by the FUM.

64 Data from AEMO, *Renewable integration study*, April 2020, p. 39.

RAMP SIZE (% OF INSTALLED CAPACITY)	OBSERVATIONS (N)	MAXIMUM UNDER-ESTIMATION (MW)	MAXIMUM OVER-ESTIMATION (MW)
WIND			
All	17,520	-764	669
>10%	111	-718	669

Regardless of the size of the actual ramping event, the magnitude of the error is relatively consistent. However, the magnitude appears to be larger for wind, relative to solar. In shorter timeframes (e.g. under 5 minutes) output from large scale solar generation is more variable than wind, whereas in longer timeframes output from wind tends to vary from forecasts to a greater extent than solar.

This evidence all points to increasing uncertainty in net demand, particularly driven by an increasing frequency and magnitude of variances between actual net demand needs and the needs that were signalled to market participants in pre-dispatch information. These result in changes in net demand that are not expected by market participants as the information available to them does not predict the ramping requirement.

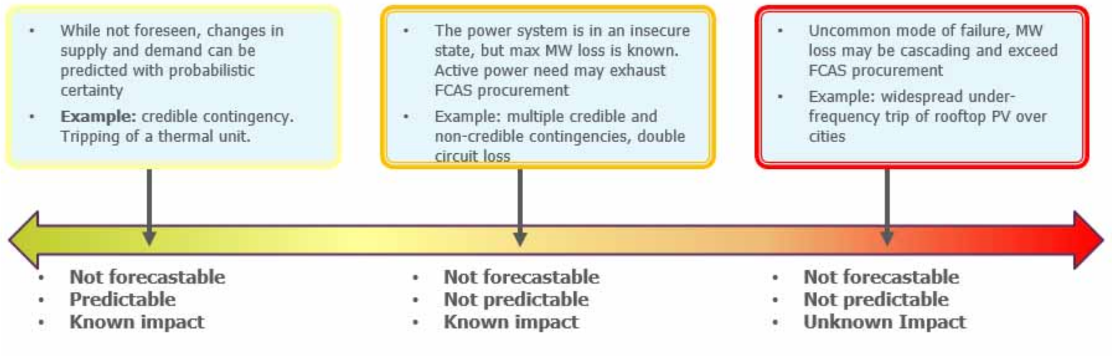
Unexpected changes in net demand due to security events

Net demand can also change rapidly and unexpectedly due to security events. FCAS arrangements are designed to address these events within the dispatch interval. Reserves are needed to address these events beyond the dispatch interval through the dispatch of energy on the system. AEMO will intervene to make sure reserves in the market are sufficient (for example, by dispatching out-of-market reserves through the RERT) if it does not see an in-market response to an LOR2 notice.

The current arrangements do not ensure sufficient reserves to address all security events. Security events can occur along a spectrum, shown in Figure 5.9. AEMO may intervene to return the power system to a secure operating state, such as by exercising RERT (if it has already procured it) or using directions or instructions under the NER.[65]

65 Although AEMO is expected to do all in its power to avoid load shedding using the above intervention mechanisms, there may be times when involuntary load shedding will be regrettable, but, unavoidable, in order to main secure and reliable outcomes.

Figure 5.9: Spectrum of security events



Source: AEMC.

Changes in net demand due to security events are not expected by market participants. While some may be in reserve and ready to address such events as part of their approach to managing risk in the energy market, others may not be ready. It is therefore appropriate that arrangements are in place to ensure consumers are not impacted (through load shedding) due to the inability of the energy market to provide sufficient reserves to meet a credible contingency event. The current approach however may be more costly than is necessary. The costs of intervention can be high. Interventions may increase as the power system transforms as AEMO operates the system to provide reserves to meet the largest credible contingency and forecast uncertainty.

We have not specifically considered whether more severe or unknown security events are more likely to occur as the power system transforms. It would appear logical that the increased complexity of the system through the transition could give rise to new and unknown risks. While there may be benefits in additional reserves being available to deal with such risks, there will be costs involved in providing additional reserves. The nature of those costs, and the ability to make the relevant trade-offs, is influenced by the approach to ensuring sufficient reserves are available. Under the current arrangements, ensuring sufficient reserves are available to manage a rapid change in the nature of the security risks faced by the system may be costly. It may be prudent to consider whether more flexible and scalable arrangements may be better suited to a rapidly transforming power system.

Table 5.3 summarises the Commission's views at this stage regarding *unexpected* ramping requirements. The Commission is interested in stakeholder views on this.

Table 5.3: Reserves and unexpected ramping requirements

RESERVE REQUIREMENT	OBSERVATIONS / ANALYSIS	IS THERE A MATERIAL PROBLEM / ISSUE?	COULD A RESERVE SERVICE ADDRESS THIS PROBLEM?
Unexpected	The magnitude and	Current frameworks	Yes, a reserve service

RESERVE REQUIREMENT	OBSERVATIONS / ANALYSIS	IS THERE A MATERIAL PROBLEM / ISSUE?	COULD A RESERVE SERVICE ADDRESS THIS PROBLEM?
requirement for reserve capacity to meet changes in net demand (ramps) due to forecast uncertainty.	frequency of unexpected ramping requirements due to forecast uncertainty is increasing. Flexible capacity may not be available in reserve to fulfil this requirement when it is needed, due to the uncertain nature of the reserve need.	can value the ability to respond to uncertain forecasts of net demand, yet may not be sufficient to meet the needs of the system as it transitions (i.e. as thermal units cycle or retire), leading to increased interventions in the energy market to address LOR conditions to meet the FUM.	could act as insurance and limit the need to intervene in the energy market.
Unexpected requirement for reserve capacity to maintain or return the power system to a secure operating state.	An increasingly complex power system may increase the risk of unexpected security events occurring. Flexible capacity may not be available in reserve to fulfil this requirement when it is needed, due to the unexpected nature of the reserve need.	Current frameworks would likely have difficulty valuing the ability to respond to such unexpected security events, which lead to interventions in the energy market to address LOR conditions to meet the deterministic contingency requirements. The current frameworks are not well-placed to respond flexibly if the security environment changes rapidly.	Yes, a reserve service could act as insurance and limit the need to intervene in the energy market.

5.6 Consultation on the need for a reserve service

The energy market needs enough resources to meet net demand forecasts, accounting for uncertainty and variability. To achieve this, reserves of capacity are required so they can be dispatched as energy and balance supply and demand when needed. Reserve capacity must be able to be dispatched as energy when it is needed, accounting for ramp rates, energy availability (e.g. state of charge and firmness of resources), and other operational considerations.

The current real time energy market framework has effectively achieved this to date. It is designed to incentivise entry and exit of equipment necessary to meet this need for each dispatch interval, to the level consumers value through the reliability standard.

The current arrangements may not be appropriate, however, as variability and uncertainty increase, as is expected throughout the transition. The specific problem this gives rise to, and which we consider needs to be addressed, is the inefficiency of interventions in the energy market to ensure there are sufficient reserves to address LOR2 conditions. At any given time, this requires sufficient resources to respond to:

- net demand forecast uncertainty, and
- system security, up to the level to prevent a contingency event from resulting in involuntary load-shedding.

The current framework is also relatively inflexible and may not be well suited to an environment with increasing unknown security events, if that were to eventuate.

A number of options are available to address this issue. This includes options to reduce the level of uncertainty and variability where possible, as well as valuing and procuring reserves above and beyond what a market participant might deliver under current arrangements. Chapter 6 explores these options in further detail.

The AEMC invites stakeholder views on the need for a reserve service to address the risk that insufficient reserves are available to the market, particularly to address uncertainty in the net demand needs signalled to market participants in pre-dispatch information or security events that are unable to be addressed through FCAS markets.

QUESTION 1: THE NEED TO ADDRESS VARIABILITY AND UNCERTAINTY

1. What are stakeholder views on the issues identified, in particular, on whether the primary issue is appropriately characterised as an increased risk of insufficient in-market reserves being available to meet net demand, due principally to forecast uncertainty and net demand variability as the penetration of VRE generation increases?
2. What are stakeholder views on the materiality of these issues? For example, are the issues material enough to warrant the further development of a reserve service market?
3. If not, what further information would be required relating to the nature of the issues facing the power system before progressing the development of a reserve service market?

6 OPTIONS TO ADDRESS UNCERTAINTY AND VARIABILITY

This section explores a range of available reserve service approaches and options. These aim to address the risk of insufficient reserves to manage increasing uncertainty in net demand forecasts or security events. The options include:

- incremental improvements to current arrangements,[66] and
- potential implementation of a new reserve service market - with there being several options for how this could occur.

6.1 Incremental improvements

A range of incremental improvement options are available to support the market in meeting increasing variability and uncertainty. These are set out in the sections below.

6.1.1 Improve the accuracy of net demand forecasts

A range of projects are underway to improve the accuracy of solar and wind forecasts. These projects are intended to reduce the scale of forecast uncertainty and should therefore result in reductions in FUM so far as it contributes to AEMO's assessment of in-market reserves.

For example, AEMO and ARENA are undertaking a program to demonstrate the potential benefits of wind and solar generator self-forecasting to the operation of the power system. Participants can register with AEMO to submit dispatch self-forecasts, with these being used in dispatch.[67]

AEMO also publishes an annual assessment of forecast accuracy to help build confidence in the forecasts produced.[68] As part of this, AEMO sets out what work they are doing to improve forecasts. AEMO's priority improvements for 2021 are:

- improved PV forecasts - AEMO will work on improving the visibility of recent uptake of PV to get better estimates of actual number of installations and changes to the rate of uptake; AEMO will also review the daily and seasonal profile of PV generation associated with a given level of installed PV capacity
- improved visibility and understanding of consumption patterns and trends - AEMO plans to focus on verifying and potentially improving existing models for residential and business consumption
- better visibility of forecast maximum demand within a year - AEMO will improve how it calculates and publishes more granular forecast data, in particular the forecasts published as part of the MT PASA process

66 The incremental improvements can be implemented either in isolation or to complement each other or a new reserve service.

67 AEMO, *Participant forecasting*, 2020.

68 AEMO, *Forecast accuracy report*, December 2020.

- wind generation trace development - AEMO intends to develop and implement a new wind generation model that will produce more realistic traces in the presence of high temperatures or wind speeds for the 2021 forecasts, and
- improved modelling of inter-regional transmission elements forced outages - AEMO will develop network forced outage simulations that better reflect the compound risk associated with the potential coincidence with high demand events.

Whilst these opportunities should continue to be pursued, chaotic weather imposes limits on forecast accuracy. Overall, the regularity and magnitude of unexpected ramping needs are likely to increase in a future with more wind and solar generation, and potentially also from coordinated behaviour from DER and electric vehicles. The AEMC invites feedback on the potential for forecasts to increase in accuracy in the future, and whether these improvements may mitigate the need for a reserve service.

6.1.2 Develop and publish more information for the market

The provision of additional information (whether within or in addition to regular reporting by AEMO) may support market participants in self-committing to better meet expected and unexpected ramps in net demand. This information could include:

- New or refined metrics expressing FUM over a variety of ramp windows (e.g. 15 min, 30 min, 1 hour, 4 hours). Currently, historical FUMs are published over 2 hour, 6 hour, 12 hour, 24 hour, 48 hour and 64 hour forecast horizons only within quarterly reports.[69] Participants could be given access to FUM estimates as they are formulated to inform decision-making in operational timeframes.
- Increased visibility of historical forecast accuracy. Currently, AEMO publishes annual Forecast Accuracy Reports, which identify possible improvements for future forecasting.[70]
- Enhanced indicators of scarcity of ramping reserves relative to ramping needs. This could include, for example, publication of reserve levels and net demand ramping needs across a number of timeframes.

The AEMC invites feedback on what additional information would support market participants in being able to better meet expected and unexpected ramps in net demand, and whether these improvements may mitigate the need for a reserve service.

6.1.3 Pursue potential market/system enhancements

There are options for AEMO to consider multi-period optimisation for the pre-dispatch and real time markets, which could improve the capability to meet expected ramping requirements. This may, however, involve significant implementation costs and challenges.

Such issues are relevant to the ESB's work on scheduling and ahead markets. In parallel with the post 2025 project, AEMO has been undertaking a project to investigate a replacement for ST PASA. AEMO's consultants have recommended, in their final report to AEMO, that ST PASA

69 See AEMO's *NEM Lack of reserve framework reports*

70 For the latest report, refer to: AEMO, *Forecast accuracy report*, December 2020.

should employ a sophisticated scheduling engine, that would include a security-constrained economic dispatch algorithm, with inter-temporal optimisation.[71]

The AEMC invites feedback on how such improvements may mitigate the need for a reserve service.

6.1.4 Integrate emerging flexible resources

As demand response, DER and electric vehicles become more flexible, plentiful and available for coordination, there is potential for them to respond quickly and at scale to high prices associated with unexpected ramping needs. This was part of the rationale for the AEMC making a final rule in 2017 to change the settlement period for the electricity spot price from 30 minutes to five minutes, starting in 2021. Five-minute settlement will provide a better price signal for investments in fast-response technologies, such as batteries, new generation gas peaker plants and demand response.

This additional flexible capacity may add to the in-market reserves under current arrangements. It could also participate in a potential reserve service market, which will be considered further in later consultations. In the absence of other changes, DER may also behave in ways that are not easy for the market operator to predict, particularly distributed batteries. This could become problematic at scale, particularly if many resources are aggregated and controlled by common algorithms, communications systems or have common modes of failure. The AEMC invites feedback on whether this is a material issue, and what options may be available to mitigate the issue.

6.1.5 Adapting system definitions

The security of the power system is defined, in part, through its ability to withstand credible contingency events, which have historically been associated with events *"that affect the power system in a way which would likely involve the failure or sudden and unexpected removal from operational service of a generating unit or transmission element."*

As the resource mix of the energy system transitions towards high penetration of VRE resources, there is potential to revisit the definition of 'contingency'. That is, the unforecast reduction of multiple GW of reduced wind generation over 15 minutes would not be considered a credible contingency event. Doing so may allow additional flexibility for the system operator to manage these events in the future.

Such issues are being considered through the *Enhancing operational resilience in relation to indistinct events* rule change request from the COAG Energy Council, which the Commission initiated in December 2020. The Commission is interested in any feedback on the interaction between these two projects.

71 AEMO, *ST PASA replacement project,* 2020.

6.2 Reserve services design options

One attractive approach to addressing the risk of insufficient reserves is to explicitly value the provision of reserves. This would separate the provision of this service from energy and FCAS markets, where in-market reserves are currently valued implicitly.

There are a number of approaches that could be taken to develop a market to procure reserves. This section outlines four alternative options for the implementation of a reserves market, including:

- a co-optimised operating reserve market
- a co-optimised availability market
- a callable operating reserve market, and
- a ramping commitment market.

Each of these approaches would aim to procure sufficient services to address the issues identified in Chapter 5. That is, addressing net demand forecast uncertainty and preventing a contingency event from resulting in involuntary load-shedding. The quantity of services that would need to be procured under any option would need to take into account other capacity that is available to meet imbalances in supply and demand, such as increased flows across interconnectors and the activation of FCAS. The effect of this would be to lower the volume of services that needs to be procured.

The aim of procuring services to this level would be to avoid the need for AEMO to intervene (potentially using out-of-market reserves) if it does not consider market participants are providing appropriate levels of in-market reserves. Another benefit of procuring a service to address these issues is that a procurement mechanism may be more flexible than current arrangements.

The design of the relevant service procurement option will also influence the volume of services required to be procured to meet the desired outcome. Some options will require the total expected and unexpected changes in net demand over a 30-minute period to be covered by services procured. Other options will only require the unexpected changes in net demand over that period to be procured, or a lesser amount that is rolling 'headroom' procured in a five-minute period.

Some options also set the precise volume of the service on the basis of a demand curve, called an 'operating reserve demand curve'. This approach would determine how much of the service should be procured on the basis of the probability of lost load and the value customers place on avoiding that outcome.

The Commission is also conscious that there will be interactions between each of these options and outcomes in the energy and FCAS markets. The costs to participants of providing in-market reserves are currently recovered in the energy and FCAS markets, and so procuring reserves separately will likely reduce price outcomes in those markets. Participants that can provide reserves can be compensated separately for that service and will therefore be able to offer their efficient costs of providing energy at a lower price in the energy market.

The particular design of a market to procure reserve services will also influence the scale and nature of the impact on the existing markets. Approaches that remove capacity (once it is enabled in reserve) from being able to bid into the energy or FCAS markets may have a greater impact than those that do not remove that capacity from availability (in other words, that are 'co-optimised'). For example, they could impact the flexibility of the fleet that remains 'in-market'. Further, approaches that procure capacity to be available a short time into the future may have different impacts on the energy market to approaches that procure services for availability further into the future. These impacts may vary on the basis of the volume of services that need to be procured, the way that different types of equipment can provide the services and the impact on the volatility of five-minute price signals in the energy market.

Each of these options will involve implementation costs. These costs will vary between options, perhaps substantially. Detailed input from AEMO will be required to provide estimates of implementation costs. It is likely that options that require the development of separate markets that are not integrated within existing arrangements for energy dispatch and financial settlement would have higher implementation costs.

The Commission is interested in stakeholder views on the impact that the introduction of one of the below options would have on the existing spot market and associated ancillary services markets.

6.2.1 Co-optimised operating reserve market

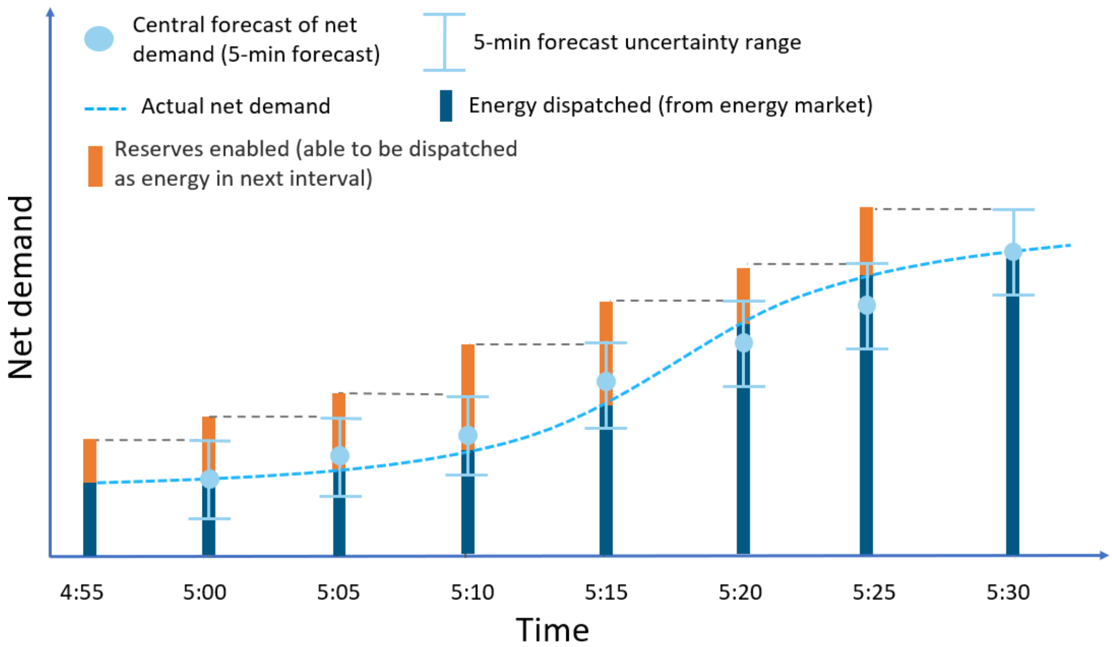
This option is for an operating reserve market that is co-optimised with the energy and FCAS markets, for resources with the capability to produce energy from the *next* dispatch interval. The market would operate broadly as follows:

- **A market participant** can, for a given dispatch interval, offer their capacity (simultaneously) in up to ten price bands in each market to provide energy, FCAS and 'reserve'.
- **The Market Operator** would co-optimise offers for each service in that dispatch interval, and:
  - dispatch energy in MW to meet demand
  - enable capacity in MW to be capable of responding as FCAS, and
  - enable capacity in reserve in MW, which is limited to the additional capacity that can be provided in the next dispatch interval.
- **The obligation** on MW enabled as reserve is to be capable of being dispatched as energy from the next dispatch interval.
- **If the supply/demand balance tightens** without warning:
  - the energy spot price will increase as additional resources are dispatched to meet demand (some of which will likely have been enabled as reserves in previous intervals), and
  - other resources (uncleared in previous intervals) will be enabled as reserves, likely at a higher price to reflect the short run costs of the next MW of reserve.

This process would occur on a rolling basis so there is always capacity ready to respond to changes in net demand in the next dispatch interval. This option would therefore procure sufficient reserve capacity available to address increases in net demand for the next dispatch interval, accounting for uncertainty. This amount comprises both the expected changes in net demand and an amount able to meet unexpected changes in net demand arising from forecast uncertainty. The amount procured is therefore lower than options that procure services to address net demand uncertainty over a 30-minute period. This option also proposes to procure a volume of reserves that is consistent with an operating reserve demand curve (i.e. the amount that consumers value to avoid the probability of lost load).

Figure 6.1 illustrates how this option could operate to help meet an unexpected ramping requirement.

Figure 6.1: Co-optimised operating reserve market



Source: AEMC.

Capacity that is enabled as reserves would need to submit energy offer quantities equal to or exceeding their reserve offer quantities.

Compliance should be relatively transparent. For example, a compliance issue may be apparent from a pattern of rebidding enabled reserve capacity out of the energy market. Equipment enabled as reserves that takes time to start up would need to be running to be physically capable of dispatching energy from the next dispatch interval.

This approach co-optimises the procurement of reserve capacity with the procurement of energy and FCAS. It also procures only the quantity required, in five minute increments, to respond to changes in net demand in the next dispatch interval, accounting for uncertainty.

On a rolling basis, the objective of this approach is to address the level of uncertainty or specific credible contingency necessary to maintain system reliability and security over a 30-minute time horizon. It relies on price-based incentives to ensure sufficient capacity is in reserve (through the reserve price), and then to ensure that sufficient capacity is dispatched as energy (through the energy price).

6.2.2 Co-optimised availability market

This option is for a market to procure availability in the dispatch interval 30-minutes ahead, co-optimised with the energy and FCAS markets. The market would operate broadly as follows:

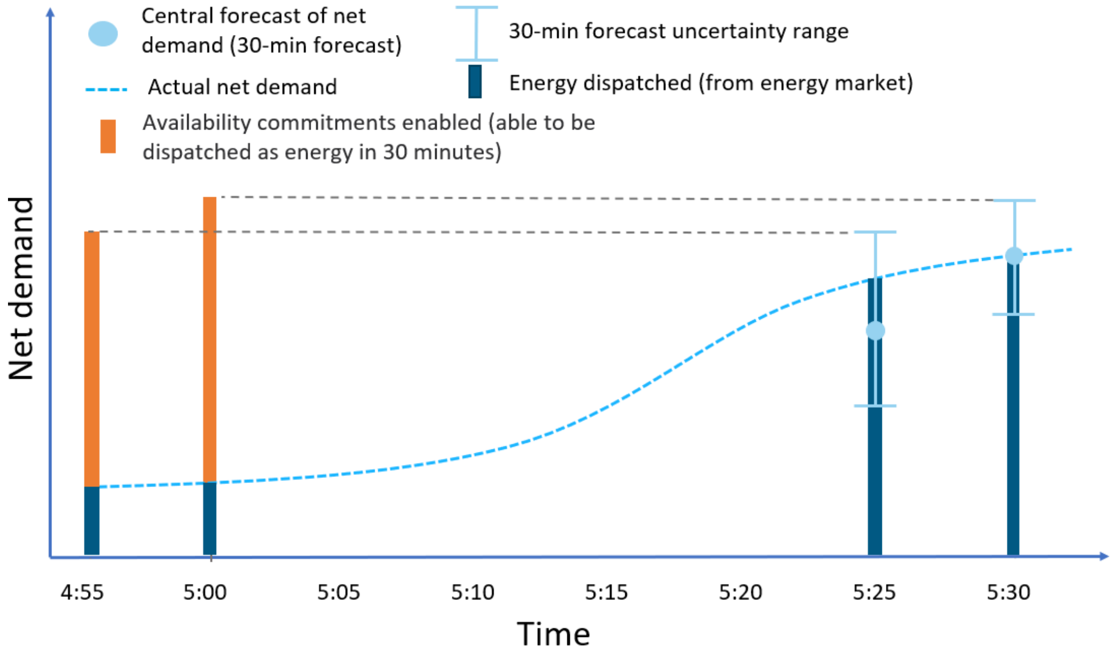
- **A market participant** can, for a given dispatch interval:
  - offer their capacity and price bands into the energy and FCAS markets, *AND*
  - offer capacity (greater than that being currently dispatched) that will be available in the energy market in the interval 30 minutes ahead.
- **The Market Operator** would co-optimise offers for the energy, FCAS and availability markets and:
  - dispatch energy in MW to meet demand in the current interval
  - enable capacity in MW to be capable of responding as FCAS in the current interval, and
  - enable capacity in MW to be available in the interval 30 minutes ahead.
- **The obligation** on MW enabled as reserves is to manage their resources such that they are available for dispatch in the energy market in the interval that is 30 minutes ahead.
- **If the supply/demand balance for energy tightens** without warning:
  - the energy spot price will increase as additional resources are dispatched to meet demand, and
  - resources that were enabled as reserves are dispatched as energy in the corresponding interval 30 minutes after dispatch as reserves, meeting forecast demand and any (credible) unexpected ramp.

Resources providing this service could offer and be dispatched as energy in all dispatch intervals from 5-25 minutes ahead through the National Electricity Market Dispatch Engine (NEMDE), but would manage energy offers, ramping and technical considerations as they see fit to guarantee availability in the dispatch interval in 30 minutes' time. Offline equipment or equipment with minimum generating levels may need to offer at least some capacity into the energy market at very low prices in order to guarantee availability in the relevant dispatch interval.

The total amount of availability procured by the system operator would comprise the total ramping requirement over a 30-minute period. This option would therefore procure sufficient reserve capacity available to address increases in net demand over a period of 30 minutes, accounting for uncertainty. This amount comprises both the expected changes in net demand and an amount able to meet unexpected changes in net demand arising from forecast uncertainty. This option also proposes to procure a volume of reserves that is consistent with an operating reserve demand curve (i.e. the amount that consumers value to avoid the probability of lost load). The demand curve for this unexpected amount could be calculated using historical errors and the probability of loss of load.

Figure 6.2 illustrates how this option could operate to help meet an unexpected ramping requirement.

Figure 6.2: Co-optimised availability market



Source: AEMC.

The service procured is availability for the dispatch interval that is 30 minutes ahead. This would create a very transparent environment for compliance. If capacity is offered and not available at the dispatch interval 30 minutes ahead, it will be non-compliant. By offering capacity at the dispatch interval 30 minutes ahead and having this capacity physically available to dispatch (including managing energy offers to ensure physical availability), the participant will be compliant.

This approach co-optimises the procurement of reserve capacity with the procurement of energy and FCAS. It procures the quantity of services required to respond to changes in net demand over a 30-minute period, accounting for uncertainty.

6.2.3 Callable operating reserve market

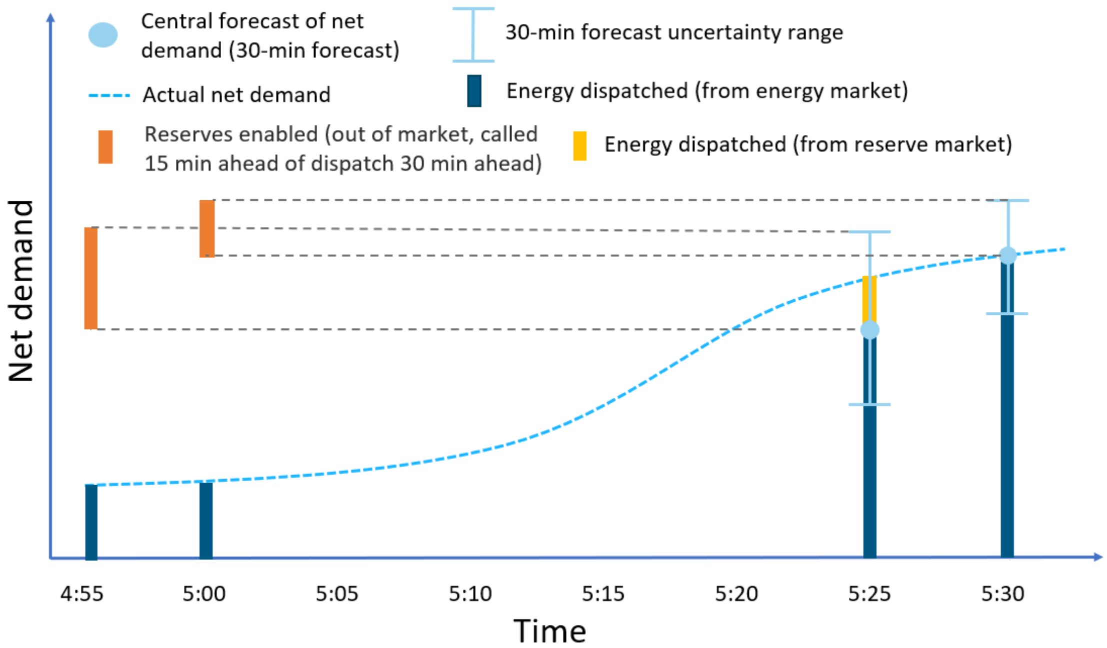
This option is for an operating reserve market that sets capacity aside from the energy and FCAS markets and calls upon it if it is required to become energy in a later dispatch interval. This option is in essence what is proposed in the Infigen Energy rule change request. The market would operate broadly as follows:

- **A market participant** can either:
  - offer their capacity and price bands into the energy and FCAS markets, or
  - offer their capacity and price bands into the reserve market.
- **The Market Operator** would co-optimise offers for the energy and FCAS markets (as they currently do) in that dispatch interval and:
  - dispatch energy in MW to meet demand
  - enable capacity in MW to be capable of responding as FCAS, and
  - hold aside capacity in reserve in MW to be called upon if needed to produce energy in a later dispatch interval.
- **The obligation** on MW held aside in reserve would be to produce energy in the later dispatch interval if called upon to do so.
- **If the supply/demand balance tightens** without warning:
  - the energy spot price will increase in the short term as additional resources are dispatched to meet demand
  - the Market Operator will call upon reserve capacity to ensure demand is able to be met in future dispatch intervals, and
  - when the later dispatch intervals arrive and reserve capacity is in use, it will displace the dispatch of capacity in the energy market and should accordingly suppress prices until the reserves are no longer in use.

The amount of reserves procured would broadly match the level of net demand uncertainty for the time period for which the reserve obligation relates (i.e. 15 or 30 minutes).

Figure 6.3 illustrates how this option could operate to help meet an unexpected ramping requirement.

Figure 6.3: Callable operating reserve market



Source: AEMC.

Reserve capacity is held out of the market and then dispatched separately if needed. This would create a very transparent environment for compliance. If reserve capacity is dispatched but cannot meet its targets, it will be non-compliant. Although, there may be many instances where generators are unable to comply for legitimate technical reasons and this will need to be monitored.

This approach does not co-optimise the procurement of reserve capacity with the procurement of energy and FCAS. Once enabled as reserves, it holds capacity out of those markets, only dispatching it when needed. While this option only procures the quantity necessary to address uncertain conditions, the lack of co-optimisation may affect the allocation of resources to meet the system needs of reliability and security.

BOX 2: VARIATION ON CALLABLE OPERATING RESERVE MARKET

It may be that a variation on the approach set out in this section is preferable. The variation would operate in broadly the same way, but would be co-optimised with other markets. It could operate as follows:

- in each dispatch interval, reserves would be procured that broadly match the level of net demand uncertainty for 30 minutes

- the obligation on enabled reserves would be to be capable of being dispatched as energy by the end of the dispatch interval that occurs 30 minutes later (with the amount enabled as reserves being limited by capability, such as time to switch on and ramp rates), and
- if reserve capacity is needed as energy, it will be dispatched as energy by NEMDE.

Under this approach there is no hard obligation on capacity enabled as reserves after the dispatch interval in which it is enabled as reserve. This means that equipment that requires time to start up could remain off-line until dispatched by NEMDE in the energy market. This approach would allow enabled reserves to be co-optimised with energy and FCAS services.

6.2.4 Ramping commitment market

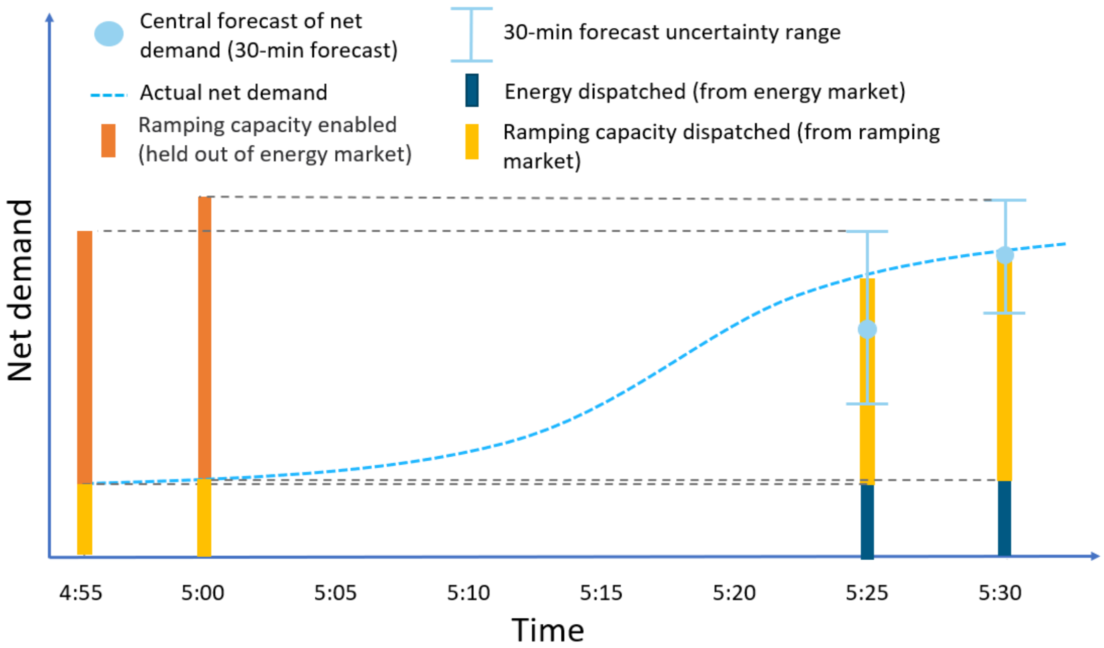
This option is for a 30-minute raise and lower "ramping" service using the existing framework for FCAS market design. This option is largely what is proposed in the Delta Electricity rule change request. The market would operate broadly as follows:

- **A market participant** can:
  - offer their capacity and price bands into the energy and FCAS markets, and
  - offer their capacity and price bands for different ramp rates into the 30-minute ramping reserve market.
- **The Market Operator** would co-optimise offers for the energy, FCAS and ramping reserve markets in that dispatch interval and:
  - dispatch energy in MW to meet demand
  - enable capacity in MW to be capable of responding as FCAS, and
  - enable ramping capacity in MW that can respond if called upon, and
  - if needed to meet changes in net demand, dispatch ramping capacity in MW/Min (set as 1/6th of the 30-minute target offer).
- **The obligation** on MW would be to be able to provide the ramping service immediately upon being dispatched to ramp and for the duration of the 30-minute interval they are enabled for.
- **If the supply/demand balance tightens** without warning:
  - the energy spot price will increase in the short term as additional resources are dispatched to meet demand
  - the Market Operator will dispatch ramping reserve capacity to ensure demand is able to be met in future dispatch intervals, and
  - for subsequent dispatch intervals, if the tight supply conditions persist, other resources will be dispatched as ramping reserves, likely at a higher price to reflect the short run costs of the next MW of ramping reserve available.

The proposal from Delta Electricity is that this framework should address the issue of sustained ramping requirements imposed on the power system's fleet of scheduled generators to accommodate the total solar daily generation profile. As a result, this proposal would require procurement of the total ramping requirement, made up of the expected and unexpected ramping needs.

Figure 6.4 illustrates how this option could operate to help meet an unexpected ramping requirement.

Figure 6.4: Ramping commitment market



Source: AEMC.

Ramping capacity is held out of the market and then dispatched separately when needed. This would create a very transparent environment for compliance. If ramping capacity is dispatched but cannot meet its targets, it will be non-compliant.

This approach does not co-optimise the procurement of ramping capacity with the procurement of energy and FCAS. Once enabled, it holds ramping capacity out of those markets and dispatches it separately when needed. It also procures the quantity necessary to address the expected ramping requirements and uncertain conditions. This approach is likely to affect the allocation of resources to meet the system needs of reliability and security.

6.3 Consultation on options

Each of the options described above has a range of benefits and drawbacks, including the extent to which the option:

- efficiently allocates resources to meet the power system needs for energy, FCAS and reserves
- provides sufficient certainty in meeting those power system needs
- impacts price signals in the energy and FCAS markets

- allows for efficient DER and demand side participation
- is easy to implement, and
- is capable of effective compliance.

The AEMC seeks stakeholder feedback on the options presented. We are particularly interested in guidance on the appropriate trade-offs to be made between the factors outlined above, as well as the interactions with other areas of the NEM such as intervention mechanisms and the wholesale contract market.

QUESTION 2: OPTIONS TO ADDRESS VARIABILITY AND UNCERTAINTY OF NET DEMAND

1. To what extent could any or all of the incremental improvements to current arrangements set out in section 6.1 address the issues sufficiently to negate the need to implement a new reserve service market? Are there any other incremental improvements that should be considered?
2. Which of the reserve service market options set out in section 6.2 is the most preferable to address the issues raised in Chapter 5, taking into account the way different technologies may operate under each option and the trade-offs between the options?
3. Are there any other reserve service market options not presented here (or variations on the options, such as the variation discussed in section 6.2.3) that would be preferable? If so, why?

ABBREVIATIONS

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ARENA	Australian Renewable Energy Agency
COAG	Council of Australian Governments
Commission	See AEMC
DER	Distributed Energy Resources
DNSP	Distribution Network Service Provider
ESB	Energy Security Board
ESOO	Electricity Statement of Opportunity
FCAS	Frequency Control Ancillary Services
FUM	Forecast Uncertainty Measure
GW	Gigawatt
ISP	Integrated System Plan
LOR	Lack of Reserve
LOR1	Lack of Reserve level 1
LOR2	Lack of Reserve level 2
LOR3	Lack of Reserve level 3
MT (PASA)	Medium-term (PASA)
MW	Megawatt
NEM	National Electricity Market
NEMDE	National Electricity Market Dispatch Engine
NER	National Electricity Rules
PASA	Projected Assessment of System Adequacy
PD (PASA)	Pre-dispatch (PASA)
RERT	Reliability and Emergency Reserve Trader
RIS	Renewable Integration Study
RRO	Retailer Reliability Obligation
RXS	Regional Excess Supply
ST (PASA)	Short-term (PASA)
UCS	Unit Commitment for Security
VRE	Variable Renewable Energy