RELIABILITY
PANEL AEMC

REVIEW

Reliability Panel AEMC

FINAL REPORT

2019 ANNUAL MARKET PERFORMANCE REVIEW

12 MARCH 2020

INQUIRIES

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ABOUT THE RELIABILITY PANEL

The Panel is a specialist body established by the Australian Energy Market Commission (AEMC) in accordance with section 38 of the National Electricity Law and the National Electricity Rules. The Panel comprises industry and consumer representatives. It is responsible for monitoring, reviewing and reporting on reliability, security and safety on the national electricity system, and advising the AEMC in respect of such matters.

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FOREWORD

I am pleased to present this report setting out the findings of the Reliability Panel's annual review of market performance, for the period 2018/19.

The Panel has reviewed the performance of the national electricity market (NEM) in terms of reliability, security and safety over the 2018/19 period, in accordance with the requirements of the National Electricity Rules (Rules) and the terms of reference issued by the Australian Energy Market Commission (AEMC). Security concerns the technical resilience of the power system itself and is primarily the responsibility of the Australian Energy Market Operator (AEMO); reliability is about having sufficient capacity to meet consumer demand for energy and is primarily driven by efficient market investment. We have considered both historic trends and projections of the security and reliability of the NEM.

A number of key trends continued to play out during the period 2018/19. In particular:

- As the power system transitions to a lower emissions generation mix, challenges for power system security persist. System strength, inertia and frequency control will continue to need further work to make sure the system can be operated securely.
- While the reliability standard was not breached at any point in the reporting period, reliability continues to be challenging to maintain. In 2018/19, emergency reserves were required and involuntary load shedding occurred.

I also note that the broader conditions in which the power system operates are becoming more challenging. In particular, changing weather patterns due to climate change, as well as uncertainty around government policy presents challenges for operating and investing in the NEM. These are most recently evidenced by events over January 2020, noting that these are outside the reporting period for the Panel. With these growing challenges, the regulatory frameworks, AEMO and market participants have continued to provide for a power system that is secure and reliable for the vast majority of the time.

The Panel has structured this report to enhance usefulness for different readers. An executive summary is provided for those readers seeking a high level overview of the review and key trends. A data portal provides stakeholders with access to the data underlying the analysis in this review. Technical detail and background information about the regulatory framework and work underway to address challenges is available in appendices.

The preparation of this report could not have been completed without the assistance of AEMO, the AER, network service providers, and state and territory government departments and regulatory agencies in providing relevant data and information. I acknowledge their efforts and thank them for their assistance.

Finally, the Panel commends the staff of the AEMC secretariat for their efforts in coordinating the collection and collation of information presented in this report, and for drafting the report for the Panel's consideration.

Charles Popple Chairman, AEMC Reliability Panel,

Commissioner, AEMC

EXECUTIVE SUMMARY

1 This report sets out the findings of the Reliability Panel's (Panel) 2019 annual market performance review (AMPR) as required by the National Electricity Rules (rules or NER). This review is conducted in accordance with terms of reference issued by the Australian Energy Market Commission (AEMC). Covering the period 1 July 2018 to 30 June 2019, the 2019 AMPR includes observations and commentary on the security, reliability and safety performance of the power system primarily relating to that timeframe, but also comments on current and emerging trends.

2 Most of the data included in this report is already publicly available. The value of this report comes from the Panel, with its diverse membership, collating and interpreting the data to make sense of what is happening across the power system and market. This year, the Panel has also developed a data portal so stakeholders can use key data sets more easily.

3 The National Electricity Market (NEM) faces a distinct set of emerging and persisting challenges. Diverse in their technical complexity, economic efficacy and in the participants who are affected, these challenges are materially altering the reliability and security outcomes the NEM is designed to provide.

4 The challenges can be attributed to a unique confluence of factors that have redefined the ways we think about power system management compared to how it was done in the past. Most notably, this change is occurring due to the transition to a low emissions future. Change in the power system inevitably leads to the evolution of regulatory structures, so they are able to support participants in delivering secure, reliable, safe and affordable electricity to consumers.

5 While historically, the system has largely delivered satisfactory reliability outcomes, and is equipped with tools to resist and respond to security events when they occur, both the NEM and the world in which the NEM operates have changed.

6 Generators are now increasingly smaller, more variable, and located in remote and weak areas of the transmission network, while the larger, more centrally located thermal fleet are aging and some have retired from the NEM. Demand profiles are changing as consumers participate more in the market to meet their needs, enabled by digitalisation and new technologies. Further, changing climate conditions make the system more vulnerable to more frequent and more intensive weather events that can threaten reliability and security outcomes.

7 Existing frameworks were largely designed to deliver enough generation at the least cost to the consumer. The challenge now is different – uncertainty and variability has increased in most parts of the market, technology has changed, consumer confidence and expectations have evolved. Given this increased uncertainty, we need to consider of how the resilience of the power system can be maintained.

8 This poses the question of how best to run a transitioning system so that we can deliver reliable energy to consumers with a high degree of confidence across multiple scenarios?

9 In this year's AMPR the Panel assessed the security, reliability and safety performance of the NEM and found that security and reliability are both more challenging to deliver given the broader changes underway.

Reliability

10 A reliable power system requires an adequate supply of capacity to meet demand and with a buffer available to respond to shocks, a reliable transmission and distribution network, and the system being in a secure operating state.

What happened in 2018/19

11 The Panel has found that reliability performance of the NEM has been satisfactory during 2018/19 with the regulatory framework including its intervention mechanisms, being leveraged to support reliable delivery of electricity to customers**.** Key reliability outcomes include:

- The reliability standard was not breached in any region although there was load shedding (i.e. unserved energy) in Victoria and South Australia.
- There was one major reliability event across 24 and 25 January 2019. Three key elements of the reliability framework were used to respond and deal effectively with this:
  - The Australian Energy Market Operator (AEMO) had to call on emergency reserves (i.e. reserves procured through the reliability and emergency reserve trader (RERT)). This is the second year in a row the RERT has been used to maintain a reliable power system. The price of the reserves procured through the RERT decreased compared to last year.
  - AEMO issued instructions for load to be shed on both 24 and 25 January 2019. The load shedding was necessary to keep the power system secure.
  - Intervention pricing was used for reliability purposes as part of RERT activation (twice) and an administered price cap (APC) was put in place after the cumulative price threshold (CPT) was triggered.
- The number of lack of reserve notices issued by AEMO was lower than in previous years. Of the notices issued, the majority were in summer when demand levels are typically higher. The majority of forecast lack of reserve conditions did not eventuate, which may indicate participants in the market responding to forecast tight supply/demand conditions.
- Centrally determined forecasts of demand and intermittent generation output, which are a key components of the reliability framework, are as accurate as they were in past years. Given the growth of intermittent generation, it is important that these forecasts remain accurate.

12 The Panel also assessed network performance as this is a key part of delivering reliable supply to consumers. The Panel observed that:

- Interconnectors are becoming an increasingly important component of reliability and can be used strategically to enable competitive sharing of resources across regions, and allow the market to deliver the technological requirements for the evolving power system.
- Priority transmission projects are progressing as planned to support the large amounts of new generation connecting in coming years, as well as to increase connection between the regions. Continued investment in transmission infrastructure is needed into the future with AEMO's Integrated System Plan (ISP) identifying the need. The ESB is also undertaking a process to action the ISP and so embed it in the regulatory framework – making transmission investment more streamlined, while still maintaining the checks and balances on investment to protect consumers. The AEMC's *Coordination of generation and transmission investment review* (COGATI) proposal goes hand in hand with this. It proposes introducing locational marginal pricing and financial transmission rights, which will send locational price signals to generators, making sure that the transmission network that is built is used effectively.

What are the implications

13 The Panel notes that while the reliability standard was met in each region, reliability is becoming more challenging to maintain as the supply/demand balance tightens - especially on very high temperature/high demand days. This is evidenced by the increasing reliance on emergency interventions to maintain reliable outcomes for customers. There is an emerging concern that reliability issues may arise in non-peak periods, for example when generators and network equipment are taken off-line for maintenance.

14 The Panel is concerned by the increasing reliance on interventions to maintain reliable supply. The core objective of the reliability framework in the NEM is to deliver efficient reliability outcomes through market mechanisms to the largest extent possible. Using emergency tools means the market is not delivering sufficient capacity to meet demand and indicates a need for new investment that can be relied upon at times when consumers need it.

15 Existing generators are not necessarily available when they are needed. Very hot days can affect the technical performance of both renewable and thermal generators and lead to lower output when demand is often at its highest. For example in 2018/19 a number of thermal generators were not available or running at lower capacity when lack of reserve notices were in place which may have been due to technical or safety concerns resulting from high temperatures. In addition, new generators connecting to the system are largely weather-driven and, depending on sun and wind availability, are not always available to help meet peak demand.

16 To contribute to the concern, private sector investment in dispatchable capacity in response to strong regulatory signals and attractive market incentives is not as strong as might be expected.

What should be done to address the reliability challenges identified

17 The Panel highlights the importance of market signals and mechanisms in delivering reliability outcomes. These market signals and mechanisms will be fundamental in delivering reliable supplies of electricity over the long term at a cost that is acceptable to consumers. The Panel

has proposed that those involved in the energy sector could focus on the following areas to address the current reliability challenges:

- **Adapting to changing power system conditions and community expectations:** as the power system changes, the approach to delivering reliable supply may also need to change. For example the most recent summer has seen the NEM draw on all options to withstand storms, drought, bushfires and higher and higher temperatures.
- **Improving coordination and total system thinking:** the investment pipeline is robust with over 60GW of committed or proposed generation on the books. The aim should be to encourage investment in a range of different technologies and locations so that the total system costs are minimised and the benefits for customers maximised.
- **Fostering regulatory and policy certainty:** regulatory reforms and government policies will continue to transform the power system, influence private sector investment and impact on reliability outcomes into the future. Regulatory and policy certainty wherever possible, including integrating emissions and energy policy, will help smooth the power system transition to deliver reliable supply over the long term.

18 Focusing on these three areas will be a step towards encouraging the new wave of investment necessary to underpin reliability in the NEM.

Security

19 Power system security involves maintaining power system equipment within its allowable ratings, maintaining the power system as a whole in a stable condition, within defined technical limits, and returning the power system to operate within normal conditions following a disturbance.

What happened in 2018/19

20 The Panel found that power system security continues to be a challenge to maintain as the generation fleet transitions into one characterised by smaller and more geographically dispersed generators with different technical characteristics to what the power system was designed around.

21 Key security outcomes include:

- There were four incidents in 2018/19 where the power system was not in a secure operating state for more than 30 minutes. These raised some broader security issues including that the power system may be becoming less resilient to large disturbances and that there is a growing administrative complexity of running security-constrained dispatch. There is also a need for greater understanding about how different technologies (including new protections schemes and distributed energy resources) respond to a range of disturbances so these can be effectively leveraged as part of the existing power system.
- The use of directions to manage system strength in South Australia increased again in 2018/19. As a result, the cost of the interventions also increased. Directions of this magnitude will continue until the system strength shortfall is addressed by synchronous condensers expected to come online by the end of 2020.

- High voltages in some parts of Victoria continued to be an issue. These were managed manually by de-energising lines in the area. This is a short term solution and will be addressed in the long term through network augmentations.
- The distribution of frequency during normal operation in the NEM has continued to flatten in the reporting period. This means there is a higher risk of frequency leaving the normal operating band. Frequency left the normal operating range more times in the mainland and Tasmania when compared to last year. This is being addressed through the AEMC's consideration of the *Mandatory primary frequency response* and *Removal of disincentives to primary frequency response* rule changes, which seek to adjust incentives for generators so they deliver the required amount of primary frequency response to support system security.
- There was a small increase in total FCAS costs in 2018/19 when compared to 2017/18. This trend has continued into 2019/20. The cost increases were driven by increased amount and price of regulating FCAS. On the other hand, the price of contingency FCAS services fell relative to 2017/18.
- The increase in FCAS prices over the past five years coupled with technological developments, have driven new types of FCAS providers to enter the market. This includes demand response, virtual power plants, wind farms and utility scale batteries. These new entrants demonstrate that new technologies and business models will have an increasingly important role in maintaining system security.
- Emergency managements and special protection schemes are an increasingly important part of power system operation. In 2018/19, there was a significant increase in the installation of protection schemes, particularly protection schemes to address system strength concerns.

What are the implications

22 Transitioning to a low emissions electricity sector means the NEM will continue to be at the global forefront for integration of renewable energy. The Panel expects the security challenges identified to continue, given forecasts of continued technology change. As a result a number of the necessary services and characteristics of a secure power system may not be available at the same level or in the same way. These services will become more and more important to support this transition.

23 At the same time, as the number and range of weather events such as prolonged extreme temperatures, cyclones and bushfires continue to increase as a result of climate change, the challenge of maintaining the secure operation of the power system will grow.

24 The assessment in this AMPR suggests that maintaining power system security is getting harder. However, this also reflects a greater awareness of the operational needs of the power system. For example, a greater understanding of system strength may manifest itself in AEMO directing more participants in order to maintain system security.

What should be done to address the security challenges identified

25 Significant work has been undertaken by AEMO and the AEMC to understand what is needed for the secure operation of the power system. It is also a key focus of the ESB.

26 Understanding the nature of these risks and operating the power system with resilience will be important to preserving power system security. The Panel has proposed that those involved in the energy sector could focus on the following areas to address the current security challenges:

- **Defining system service needs:** clearly articulating the type and level of services required is a critical step is designing regulatory frameworks that can provide for these needs.
- **Incentivising investment in system services:** each of the required system services has different characteristics, and may need different approaches to valuing and procuring them. The Panel notes progress has been made in relation to some services for example frameworks are in place to provide for system strength and inertia and rule changes underway looking at how to incentivise the provision of primary frequency response.
- **Leveraging the opportunities associated new technologies:** in this transition, there are going to be challenges that test the system security frameworks. However, there is also an opportunity for new technologies to assist with maintaining the secure operation of the power system. These new technologies should be embraced to assist with maintaining power system security through the transition.

27 The NEM is at the global forefront of dealing with these issues. It is important to acknowledge that some solutions may only be temporary fixes. Other solutions may take time to mature and become effective.

Safety

28 The safety of the power system, and associated equipment, power system personnel and the public is covered in general terms under the National Electricity Law (NEL). However there is no national safety regulator specifically for electricity. Instead, state and territory legislation governs safety generally which includes the safe supply of electricity and the broader safety requirements associated with electricity use in households and businesses.

29 The Panel notes that its safety role for the purposes of this report is narrow, and relates primarily to the operation of assets and equipment within their technical limits and not to the broader safety requirements governed by jurisdictional legislation.

30 The Panel has reviewed AEMO's power system incident reports and consulted with AEMO to understand if there were any instances where actions to maintain the power system within relevant standards and technical limits resulted in technical safety issues.

31 The Panel is not aware of any incidents during the 2018/19 reporting period where AEMO's management of power system security has resulted in a safety issue with respect to maintaining the system within relevant standards and technical limits.

32 There were also no instances in 2018/19 where AEMO issued a direction and the directed participant did not comply on the grounds that complying with the direction would be a hazard to public safety, or materially risk damaging equipment or contravene any other law.

Work underway

33 In the context of all of these challenges, the Panel acknowledges the significant body of work underway that is considering how to maintain the ongoing security and reliability of the NEM. Short-term challenges are being addressed through urgent work streams - sometimes with interim solutions being put in place while a longer term solution is developed, which takes account of the evolution of technology.

34 Key pieces of work include:

- **The AEMC's work program to value and procure enough of the technical services required to keep the power system secure:** This includes new requirements to mandate and incentivise frequency control, improvements to the system restart standard framework and potential new frameworks to have sufficient system strength and power system resilience on a NEM-wide scale. This work will address immediate and emerging power system needs as they arise.
- **Market body and ESB actions to coordinate investment in new generation and transmission infrastructure:** This includes AEMO's Draft 2020 ISP, which identifies over 15 projects to augment the transmission grid to provide a "least-regret, dynamic, resilient and transparent roadmap for the NEM."[1] The ISP goes hand in hand with the AEMC's COGATI reforms that incentivise generators to locate in places where transmission infrastructure can be used most effectively to get energy to market. The ESB has been working on rules to action the ISP by embedding the process into the regulatory framework. Together, these reforms will facilitate new technologies connecting into the grid, promoting security and reliability.
- **The Energy Security Boards (ESB) interim advice on reliability and security as part of its post-2025 market design advice:** The COAG Energy Council requested the ESB review the reliability standard. This advice is being considered by Ministers at the March 2020 COAG Energy Council meeting. The reliability standard advice is an interim part of a broader ESB project to advise on a long-term, fit-for-purpose market framework to support reliability, modifying the NEM as necessary to meet the needs of future diverse sources of non-dispatchable generation and flexible resources including demand side response, storage and distributed energy resource participation.

35 A more detailed list of market body and ESB security and reliability projects is included in appendix a**.**

36 The Panel intends to monitor and review how these projects progress over the coming year, with a view to highlighting key issues that need to be addressed or recommending whether any further work remains to be done, in the 2020 AMPR.

1 AEMO, Draft 2020 Integrated System Plan, 2019

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1 INTRODUCTION

This report has been prepared as part of the Reliability Panel's (Panel) *Annual market performance review* (AMPR) of the National Electricity Market (NEM). It covers the 2018/19 financial year. The review is a requirement of the National Electricity Rules (rules or NER).

1.1 Background

The functions of the Panel are set out in clause 8.8.1 of the NER. Among other things, the Panel is required to:

- monitor, review and report on the performance of the market in terms of reliability of the power system[2]
- report to the Australian Energy Market Commission (AEMC) and participating jurisdictions on overall power system reliability matters, power system security and reliability standards and the Australian Energy Market Operator's (AEMO) power to issue directions in connection with maintaining or re-establishing the power system in a reliable operating state.

Consistent with these functions, clause 8.8.3(b) of the NER requires the Panel to conduct a review of the performance of certain aspects of the market, at least once every financial year and at other such times as the AEMC may request. The Panel must conclude each annual review under this clause by the end of the financial year following the financial year to which the review relates. The Panel must conduct its annual review in terms of:

- reliability of the power system
- the power system security[3] and reliability standards
- the system restart standard
- the guidelines referred to in clause 8.8.1(a)(3) of the NER[4]
- the policies and guidelines referred to in clause 8.8.1(a)(4) of the NER[5]
- the guidelines referred to in clause 8.8.1(a)(9) of the NER.[6]

1.2 Purpose of the report

The purpose of this report is to set out the Panel's findings for its annual market performance review for 2018/19. In conducting this review, the Panel has only considered publicly

2 In performing this function, clause 8.8.1(b) of the rules prohibits the Panel from monitoring, reviewing or reporting on the performance of the market in terms of reliability of distribution networks. However, the Panel may collate, consider and report information in relation to the reliability of distribution networks as measured against the relevant standards of each participating jurisdiction, in so far as the reliability of those networks impacts on overall power system reliability.

3 Standards and guidelines relevant for security are discussed in more detail in section 2.4.

4 The guidelines referred to in clause 8.8.1(a)(3) of the NER govern how AEMO exercises its power to issue directions in connection with maintaining or re-establishing the power system in a reliable operating state.

5 The policies and guidelines referred to in clause 8.8.1(a)(4) of the NER govern how AEMO exercises its power to enter into contracts for the provision of reserves.

6 The guidelines referred to in clause 8.8.1(a)(9) of the NER identify, or provide for the identification of, operating incidents and other incidents that are of significance for the purposes of the definition of 'reviewable operating incident' in clause 4.8.15 of the NER.

available information as well as information obtained directly from relevant stakeholders and market participants.[7]

The Panel's findings include observations and commentary on the reliability, security and safety performance of the power system. The review also provides an opportunity for the Panel to consolidate key information related to the performance of the power system in a single publication for the purpose of informing stakeholders. Among other things, this may assist governments, policy-makers and market institutions to monitor the performance of the power system, and to identify the likely need for improvements to the various measures available for delivering reliability, security and safety.

1.3 Scope of the report

The Panel is undertaking this review in accordance with the requirements in the rules and the terms of reference issued by the AEMC.[8]

The AEMC requests that the Panel review the performance of the market in terms of reliability, security and safety of the power system in 2018/19. The Panel has had regard to the following matters when conducting its review:

- **Overall power system performance:** A comprehensive overview of the performance of the power system is provided. The Panel has considered:
  - Performance in terms of reliability and security from the perspective of the generation bulk transmission sectors and impacts on end-use customers where relevant information is available.
  - Significant power system incidents (including but not necessarily limited to 'reviewable operating incidents') that have occurred in the financial year 2018/19 including the cause of the incident (a reliability or security event), the impact of the incident (on reliability or security, and in terms of the costs to consumers) and the sector of origin (generation, transmission or distribution).[9]
  - In particular, the Panel has considered incidents, when the power system was not in a secure state for more than 30 minutes. In 2018/19 there were four such incidents.
- **Reliability performance of the power system:** The Panel has reviewed reliability performance of generation and bulk transmission (i.e. interconnection). In doing so, it has considered:
  - actual levels of unserved energy in 2018/19

7 The data and information gathered has been provided by a number of organisations including AEMO, network service providers, the Australian Energy Regulator (AER) and jurisdictional government departments and regulators. This data and information provided by other parties has not been verified for accuracy or completeness by the Panel. It has been assumed that those organisations have undertaken their own quality assurance processes to validate the data and information provided.

8 The terms of reference for this review are available on the AEMC Reliability Panel website.

9 A reviewable operating incident is a term defined in clause 4.8.15 of the NER. It refers to, among other things, a non-credible contingency event or multiple contingency events on the transmission system; or a black system condition; or an event where the frequency of the power system is outside limits specified in the power system security standards; or an event where the power system is not in a secure operating state for more than 30 minutes; or an event where AEMO issues an instruction under clause 4.8.9 of the NER for load shedding - an incident where AEMO has been responsible for the disconnection of facilities of a Registered Participant under the circumstances described in clause 5.9.5 of the rules; or any other operating incident identified, in accordance with guidelines determined by the Reliability Panel under rule 8.8 of the NER, to be of significance to the operation of the power system or a significant deviation from normal operating conditions.

  - actual and forecast supply and demand conditions including an assessment of lack of reserve notices in order to form a view on whether any underlying changes to reliability performance have occurred, or are expected to occur
  - AEMO's use of the reliability safety net mechanisms in 2018/19, including incidents of, and reasons for, the use of directions and instructions, and the Reliability and Emergency Reserve Trader (RERT) mechanism.
- **Security performance of the power system:** The Panel has reviewed performance of the power system against the relevant technical standards. In particular, the Panel has had regard to:
  - frequency operating standards, voltage limits, interconnector secure limits and system stability.
  - AEMO's use of the security safety net mechanisms in 2018/19, including incidents of, and reasons for, the use of directions and instructions or other mechanisms to ensure power system security.
- **Safety performance of the power system:** The National Electricity Law and rules set out the functions and powers of the Reliability Panel, which include a function to monitor, review and report on safety in accordance with the rules. However, the rules do not specify additional requirements in relation to safety performance reporting.[10] However, the Panel also has the function of advising in relation to the safety of the national electricity system at the request of the AEMC.[11] The terms of reference for the *2018 Annual market performance review*, as they relate to safety, were considered by the Panel as a request for advice from the AEMC.[12] In accordance with the terms of reference issued by the AEMC, for the purposes of the safety assessment the Panel has considered the maintenance of power system security within the relevant standards and technical limits.[13]

1.4 Review process

The Panel is carrying out this review in accordance with the process set out in the NER and reflected in the AEMC's terms of reference. The Panel sought targeted feedback from stakeholders on the approach and issues to be considered with a view to developing information that improves participants, market institutions, policy-makers and other stakeholders' understanding of the market and power systems' performance. This in turn can contribute to more informed decision-making by all stakeholders. The following table outlines the timetable for delivery of the Panel's final report to the AEMC.

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10 Instead, the functions of the Reliability Panel under clause 8.8.1 of the Rules provide that the functions of the Panel is to, among other things, monitor, review and report on the performance of the market in terms of reliability of the power system, report to the AEMC and jurisdictions on overall power system reliability matters and undertake a number of functions relating to the security of the power system. The reliability and security focus of the Panel under the Rules is reflected in the scope of the annual market performance review that the Panel is required to undertake under clause 8.8.3(b) of the NER.

11 If the AEMC requests such advice, the Panel is required to provide it (section 38(4) of the NEL).

12 Under section 38(2)(b) of the NEL.

13 More information on safety concept is provided in chapter five.

Table 1.1: Timeline for final report

MILESTONE	DATE
November 2019	Initiation of 2019 annual market performance review.
December 2019 - January 2020	Stakeholder consultation on approach to review.
March 2020	Publication of final report.

1.5 Structure of this report

Most of the information presented in this report is publicly available. The Panel, with its membership representing a cross-section of industry and consumers, have collated and interpreted this information to inform its assessments of what is happening across the power system and market.

The executive summary provides a high level overview of the Panel's findings, while this main body of the report provides detail behind these findings by measuring the power system outcomes against market and regulatory incentives, guidelines, standards and rules that were put in place to produce efficient outcomes for customers. This year, the Panel has developed a data portal so stakeholders can use key data sets more easily.

A number of regulatory changes took effect just prior to or during the 2018/19 reporting year. A list of these changes can be found at appendix a. The Panel has highlighted where these changes have had an impact on the performance of the market and power system. The Panel has also included in appendix a information about a market body and government projects underway to address the remaining challenges relating to security and reliability.

In this report the Panel has distinctly assessed reliability and security. A secure system is one that is able to operate within defined technical limits, even if there is an incident such as the loss of a major transmission line or large generator. A reliable power system has enough generation, demand response and network capacity to supply customers with the energy that they demand with a very high degree of confidence. A reliable power system will also be a secure power system. However, the converse is not necessarily true; a power system can be secure even when it is not reliable.

The two concepts are closely related operationally and it is not always simple to separate them. For consumers, the final result of either a reliability event or a security event may be indistinguishable. However, the Panel considers it important to clearly describe and identify how these two aspects of power supply work, and the extent to which each is responsible for final interruptions to consumers. This is because each is managed through the use of different tools and regulatory frameworks, and where further actions may be needed to improve outcomes for consumers, it is helpful to know which parts of the framework to focus on.

The report is structured as follows:

- Market trends relating to reliability, security and safety
- Reliability assessment
- Security assessment
- Safety assessment
- What this means for participants and policy-makers
- Appendix A - Work underway to address reliability, security and safety challenges

2 MARKET TRENDS

2.1 Outline

This chapter examines some key market trends in the generation mix and bulk transfer capability (i.e. interconnectors) in the NEM. These trends relate to new generation entry and withdrawals, interconnector capability, distributed energy resources, and forecast trends in energy consumption and demand levels. It also provides some high-level information on wholesale market price outcomes.

The trends in generation, bulk transfer, distributed energy resources and demand play a key role setting the context for our assessment of the present and future reliability of the NEM, as reliability is determined to be the ability of generation capacity and bulk transfer to meet demand.[14] Changes to the generation mix and demand profiles also impact on security management in the NEM, for example:

- The withdrawal of synchronous generation and higher penetrations of non-synchronous generation is changing the way secure frequency and voltage levels are maintained during normal operation periods and when responding to disturbances.
- Increased uptake of behind-the-meter rooftop PV affects the way distribution networks manage voltage disturbances, and the way AEMO manages the supply-demand balance under emergency conditions.

The propagation of existing trends in the NEM is representative of the fundamental structural transitions under way in the power system.

A summary of key trends examined in this chapter include:

- **New generation**: There was a continued growth in the capacity of installed renewables. The growth was lower in 2018/19 than previous years. The amount of energy produced by renewable energy is at its highest ever levels and is especially prominent in South Australia and Tasmania.
- **Changes in capacity**: The entry and exit of generation capacity has not been steady over the past ten years. Large and sudden entry and exits of generation capacity has had implications for maintaining power system security and reliability. These fluctuations are driven by a number of factors including general market trends and changing long term policies relating to environmental objectives. These implications are explored in more detail in chapters three and four.
- **Availability of thermal generators**: A number of thermal generators have not been available during high demand periods over the reporting period.
- **Energy demand**: Total energy consumption is expected to remain flat in the short to medium term but maximum demand is expected to grow. At the same time, minimum demand is falling which poses some challenges for power system security.
- **Distributed energy resources**: The installed capacity of rooftop PV, batteries and electric vehicles has grown and will continue to grow.

14 The relationship between power system reliability and the market trends in the chapter are explored in chapter three.

- **Supply interruptions**: Most blackouts have been caused by breakdowns in grid's poles and wires, while new transmission infrastructure is needed to support proposed investment in generation.
- **Wholesale prices**: Wholesale electricity prices reached record levels in a number of regions. This was predominantly driven by mid-range prices as opposed to large price spikes. There were also significant instances of negative prices in Victoria and Queensland over the reporting period.

This chapter includes Panel observations relating to:

- changing power system operating environment
- supply side trends
- demand side trends
- network trends and supply interruptions
- wholesale market trends.

2.2 Changing power system operating environment

Considerations of weather and climate are an essential input into power system operation and planning. A secure and reliable power system depends on a variety of variables which, due to either the physics of the system or the economic and policy arrangements that govern it, can either have minor impacts on the system, or present more persistent, structural challenges. Underlying environmental conditions are critical inputs in delivering these outcomes, and are factored into all decision-making processes, either explicitly or implicitly.

The performance of the assets that deliver secure and reliable outcomes is directly linked to weather conditions prevailing at the time and to the climatic conditions that are expected into the future. This link is clearly exhibited in the way weather and climate influence both operational, real-time decisions in the short-term, and structural, investment decisions in the long-term. For example:

- In the short-term, hot weather reduces the efficiency of generating units and increases consumer demand, storms and bushfires can remove assets from service, and consumers usage patterns differ depending on the temperature. The increased penetration of wind and solar PV has increased the influence of weather and climatic factors on both supply and demand (the latter due to the impact on rooftop PV). Drought and bushfires can lead to unexpected outages of transmission lines and generation units.
- In the long-term, market participants in the NEM make investment decisions based on the likely performance of assets over long horizons - typically decades. To the extent that regular weather patterns and extreme events reflect structural climatic patterns, not transitory forces, market participants extrapolate such patterns to inform the viability of assets in the long-term. This applies to both the generation and transport of electricity;

for example, transmission wires have particular thermal ratings, transmission towers have set tensile strengths and are reinforced with certain thickness of steel,[15] and generators are located in areas where they have good access to their resource, and where this access is expected to continue into the future.

Historically, variables and circumstances such as those above have been managed, either in control rooms, at trading desks or in board rooms, with the confidence that weather events and climatic projections are largely forecastable and predictable, and that conditions in the future will largely resemble the past. This has allowed policy-makers and system operators to design and implement frameworks and tools that deliver reliability and security cost-effectively while managing a likely set of risks. It also enabled investors and asset owners to manage long-term risk with agreeable level of uncertainty.

Under the NEL, the Reliability Panel is charged with monitoring, reviewing and reporting on the safety, security and reliability of the national electricity system, which infers the identification of trends that may compromise any of these attributes. The Panel notes that climate change already casts significant uncertainty over the stability of this power system operating environment, and will continue to do so into the future.

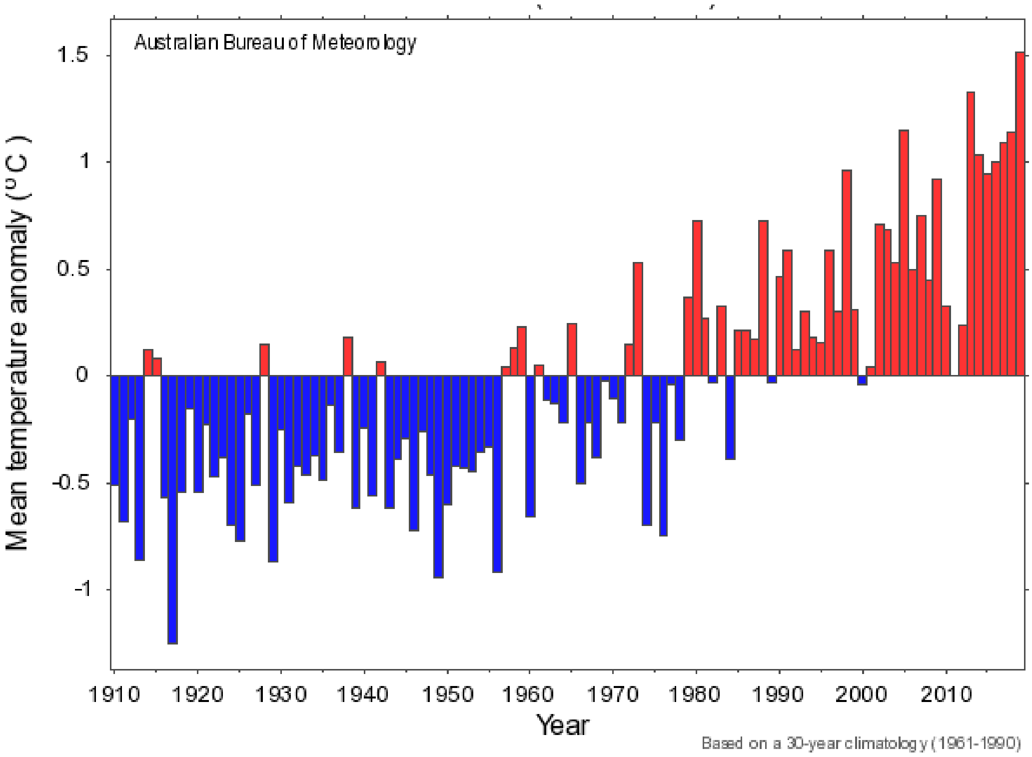
The Panel recognises the work of the Intergovernmental Panel on Climate Change (IPCC), the Bureau of Meteorology and the CSIRO in describing the effects of climate change in an Australian context. Observed global mean surface temperature for the decade 2006-2015 was 0.87°C above pre-industrial levels,[16] while Australia's area-average mean temperature for 2017 was 0.95° Celsius (C) above the 1961-1990 average, illustrated in Figure 2.1.[17]

15 Tensile strength measures the force required to pull a wire to the point where it breaks. The tensile strength of a material is the maximum amount of tensile stress that it can be subjected to before failure.

16 Intergovernmental panel on climate change, *Special Report: Global Warming of 1.5°C*, 2018.

17 Australian Bureau of Meteorology, *State of the Climate 2018*, p. 4.

Figure 2.1: Annual mean temperature anomaly Australia (1910 to 2019)



Source: Australian Bureau of Meteorology, 2019.

The predicted and demonstrated effects of this trend in Australia are an increase in the frequency and intensity of weather events.[18] These weather events are expected to include an increased incidence of high temperatures and prolonged periods of high temperatures, illustrated in Figure 2.2, as well as a decline in cool season rainfall, but more intense extreme rain events.[19] These trends are likely to contribute to both increased time in drought as well as increased frequency of extreme drought, and subsequently longer and more intense fire-weather seasons due to more ready-to-burn fuel-availability.[20] Further, average windspeeds are projected to change across regions,[21] while the combination of these trends will also likely heighten the frequency, magnitude and impact risk of "compound events", where windspeed and rainfall extremes occur at the same time.[22]

In short, the Panel notes that climate change is likely to exacerbate the underlying environmental conditions which policy-makers, system operators and market participants have historically considered to be stable, and have factored into decision-making processes

18 Ibid.

19 CSIRO, *Climate Change in Australia Technical Report*, 2015

20 Ibid.

21 Ibid

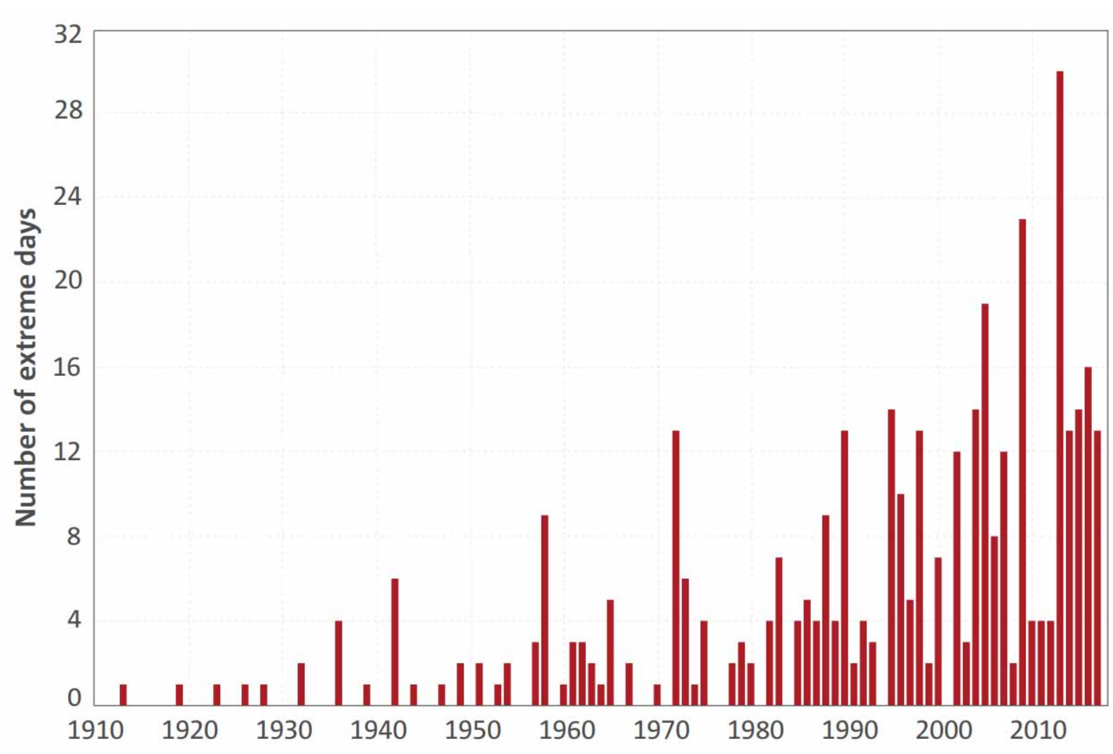
22 Australian Bureau of Meteorology, State of the Climate 2018, 2018.

with a high-degree of confidence. In a world with a more uncertain power system operating environment, the power system will likely be expected to deliver reliable and secure outcomes under climatic conditions that:

- over the long-term may now place a more strenuous demand on power system assets
- over the short-term may inflict more intense and more frequent weather events, which will challenge the ability of the system to provide sufficient capacity to meet demand, but also to withstand and recover from more uncertain shocks.

The Panel also notes that as renewables continue to constitute a greater proportion of the generation mix, the power system's dependency on underlying environmental conditions is increasing at the same time that environmental conditions themselves are likely to grow more extreme and frequent.

Figure 2.2: Number of days each year where the Australian area-average daily mean temperature is extreme



Source: Australian Bureau of Meteorology, *State of the Climate 2018*, p 4.

The Panel has identified three broad groupings that describe the way climate change and an altered power system operating environment will impact on reliability and security outcomes:

- **Risks emerging from climate change -** This includes risks to system security and reliability inflicted directly through changes to the power system operating environment. Prolonged, more intense heatwaves impact reliability outcomes by reducing the operating efficiency and increasing wear on generating units and transmission lines, particularly in aging thermal units. This is reducing the power system's resource adequacy to meet the demands of a peakier system. Over the long-term, changing wind and rainfall patterns will affect the resource adequacy of technologies such as wind and hydro. More frequent, more extreme weather events impact security outcomes by threatening to remove from service crucial generating assets or transmission lines and network assets for extended periods of time, which depletes the capacity of the system and erodes the capability of the system to withstand n-1 credible contingency events.

- **Risks emerging from mitigation action -** This includes risks to system security and reliability associated with action taken to mitigate anthropogenic climate change. Australia's electricity sector is the largest proportion of the country's total emissions, contributing 33.8%.[23] Actions to mitigate the effects of anthropogenic climate change are therefore likely to include structural changes to the electricity sector that impact the generation mix and the market's design. Mitigation techniques (either implemented by government or the market) such as increasing penetrations of utility-scale wind and solar and household distributed energy resources, will continue to have implications for the system strength, inertia, voltage and frequency management of the system, while also posing reliability challenges by increasing the magnitude of the 'later and shorter' evening peak. This said, a lack of mitigation action has its own risks, namely the increased risk of extreme weather events and their associated impacts on the power system.
- **Risks emerging from adaptation action -** This includes risks to system security and reliability associated with action taken to adapt to physical climate changes. This includes choices made by consumers that affect their electricity usage patterns in response to risks emerging from climate change, as well as choices made in response to risks emerging from mitigation action. In response to prolonged and more intense heat waves, consumers are likely to continue installing air conditioners which can contribute to heightened peak events, as well as improving their energy efficiency. Both trends will affect the demand profile in the NEM. In addition, a lack of adaptation action creates its own risks, namely the reduced ability for the power system to 'ride through' or maintain uninterrupted supply during prolonged heat waves, droughts, bushfires, storms and other extreme weather events, following the frequency and intensity of such events has been altered by changes in the underlying power system operating conditions.

2.3 Supply side trends

BOX 1: A SUMMARY OF SUPPLY SIDE TRENDS

The Panel notes the following key supply trends emerging or continuing in the NEM:

23 Department of Agriculture, Water and the Environment, *Quarterly update of Australia's National Greenhouse Gas Inventory*, June 2019.

- There was about 800MW of generation installed in 2018/19, the majority of which was large scale solar and wind.
- There has been a continuing growth of renewable energy sources in the NEM. In 2018/19, renewable energy sources reached new record levels of capacity and energy produced.
- A number of thermal generators have not been available during high demand periods over the reporting period.
- Over the past 10 years, there has been significant variation in the rates of entry and exit of generation. While these trends are driven by a number of different factors, long term policy uncertainty has contributed to this unsteady entry and exist of generation.

These trends have the following implications for reliability and security in the NEM:

- Sudden withdrawals of large generators can result in significant impacts of market prices and reliability outcomes.
- The unprecedented entry of several renewable generators at the same time has presented a number of security related challenges.
- If Australia is going to meet its emissions commitments, the NEM will need to continue transitioning to generation sources with lower emission intensity. Managing the orderly entry and exit of generation capacity, particularly through stable, long term policy will help with managing reliability and security challenges as they emerge.

The delivery of electricity is undergoing a period of transition, as smaller, geographically-dispersed non-synchronous renewable generators enter the market and significant numbers of thermal generators approach the end of their operational lives. This section highlights the trend implications of this transition up to the end of the 2019 financial year, highlighting:

- the change in generation capacity by technology
- change in output by technology
- entry and exit trends of generation technology
- trends in generation plant availability.

2.3.1 Capacity and output

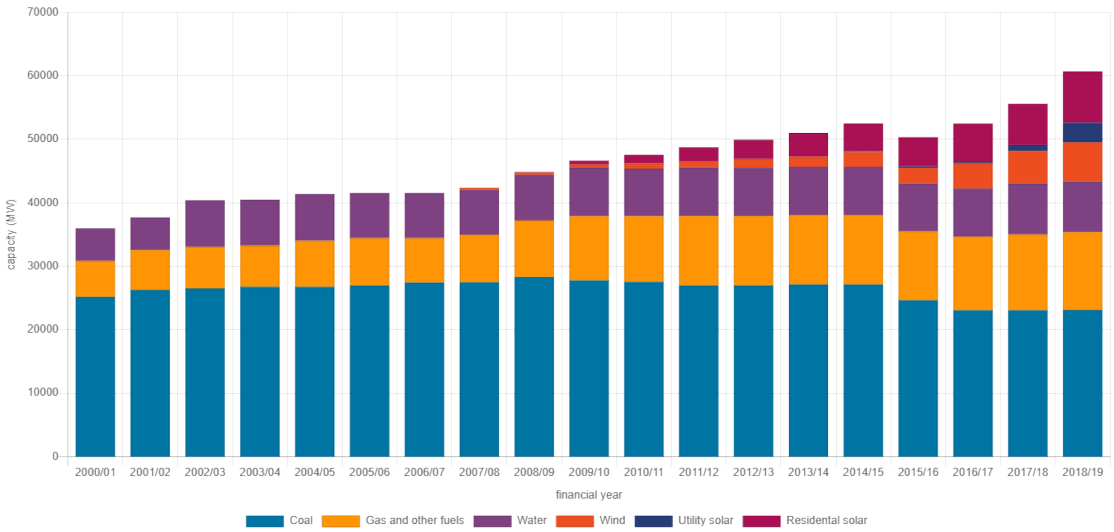
A key trend on the supply side of the market is the expected exit of large synchronous thermal generation, coupled with significant new entry of large scale asynchronous, variable renewable generation. Consistent with previous reporting periods, this trend was observed in 2018/19.

Key changes in the NEM's installed generation capacity over 2018/19 include:

- The entry of 804 MW of generation capacity, including 492 MW of wind, 282 MW of large-scale solar and 30 MW from other sources, such as Bagasse.[24]
- Large plant entries included Tailem Bend solar farm in South Australia (95 MW rated capacity), Coleambally solar farm in New South Wales (150 MW), Bungala One and Two solar farms in South Australia (110 MW each), Daydream solar farm in Queensland (180MW) and Lincoln Gap wind farm in South Australia (212 MW).[25]
- The installed capacity of coal, all gas and hydro powered generation remained the same over the reporting period.

These trends are illustrated in Figure 2.3, which shows the total installed generation capacity in the NEM increasing since 2017 as more large-scale wind and solar projects connect to the power system. In 2018/19, renewable generation (wind, solar and hydro) accounted for 32% of all installed capacity in the NEM, largely due to decreasing cost in large-scale wind and solar technologies. Black and brown coal-fired generation still constitute a large proportion of installed capacity (43%), despite significant retirements of brown coal generators in recent years. The installed capacity of gas and hydro have remained largely consistent.

Figure 2.3: NEM generation capacity (installed megawatts) by fuel type 2001-2019



Source: AEMC analysis of AEMO, AER and other publicly available information on existing generators.
Note: The data for this chart is available in the AMPR data portal.

Figure 2.4 demonstrates the proportion of the electricity demanded by consumers is actually met per technology type.[26] While solar (1.7% of total output in 2018/19) [27] and wind (8% of total output in 2018/19) have increased their proportion of total output over the last decade,

24 Bagasse is a dry fibrous waste product in sugar cane production, which is typically burned in non-scheduled generators in Queensland.

25 AEMO, *Generator Information Page*.

26 This chart does not include non-scheduled generation output which include smaller generators such as rooftop PV systems.

27 This figure relates only to utility scale solar, and does not include output generated from rooftop solar systems.

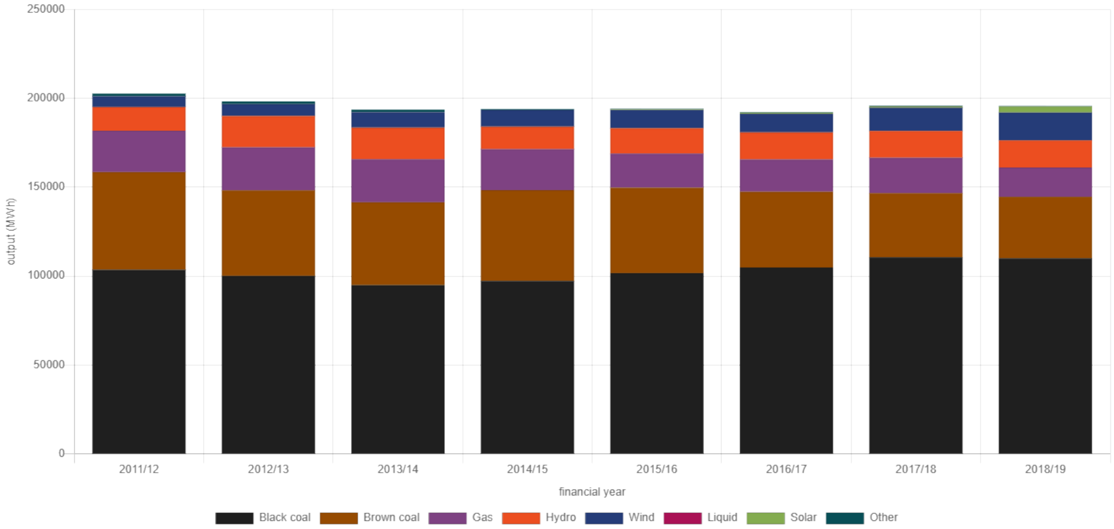
coal (74% of total output in 2018/19) continues to represent the greatest proportion of generated electricity.

Hydro power contributed about 8% of total NEM output in 2018/19, making the overall contribution of renewables about 17.5% of NEM demand. Gas technologies contributed about 8.5% of total NEM output, but its use in all NEM regions fell 2017/18.

The comparison between Figure 2.3 and Figure 2.4 illustrates that, due to generally lower capacity factors, large quantities of renewable energy sources will be needed to replace retiring thermal plant. This also highlights the importance of maximising the utilisation of new renewable plant as aging thermal fleet retire and exit the NEM.

In South Australia this has been demonstrated. After Northern power station closed in 2015/16 and withdrew 19% of electricity output in South Australia, wind power output increased from around 32% of South Australian output in 2015/16 to about 46% in 2018/19. Notably, in March 2019 51% of South Australia's demand was met by renewables.

Figure 2.4: NEM generation output (gigawatt hours) by fuel type 2011/12-2018/19



Source: AEMC analysis of AEMO, AER and other publicly available information on existing generators.
Note: This does not include non-schedule generation output. Gas includes Coal Seam Methane, Natural Gas, Natural Gas/Diesel, Natural Gas/Fuel Oil and Waste Coal Mine Gas. Liquid includes Diesel and Kerosene. Other includes Bagasse, Battery and other remaining fuel sources.
Note: The data for this chart is available in the AMPR data portal.

Figure 2.5 shows the challenges to this orderly transition in more detail. The chart illustrates the entry and exit of generation in the NEM by technology type since 2008. There are significant fluctuations in the amount of capacity of generation entering and exiting the market.

Regarding entry to the market:

- There are noticeable spikes in capacity entering in:

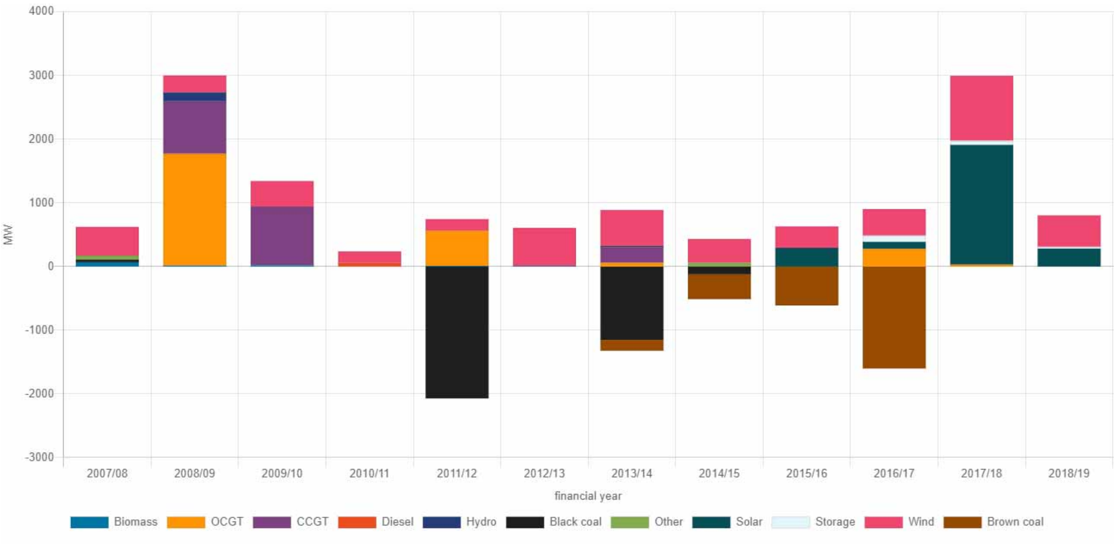
- 2008/09 which was due to the entry of gas-powered generation, such as Tallawarra and Uranquinty power stations in New South Wales
- 2017/18 which was due to the entry of utility-scale solar and wind under the Renewable Energy Target

- In other years entry of new generation, predominantly renewables, has been continued and steady.

Regarding exits from the market:

- In some reporting periods, including 2018/19, there were no withdrawals from the market.
- In other years, the exit of aging thermal generators has been 'lumpy' and at times sudden which has lead to significant market impacts, particularly given the capacity factors of the entering plant are lower than those that are exiting.

Figure 2.5: Entry and exit of generation (installed megawatts) by fuel type - 2007/08-2018/19



Source: AEMC analysis of AEMO, AER and other publicly available information on existing generators.
Note: The data for this chart is available in the AMPR data portal.

These trends highlight the potential consequences of persistent uncertain market and policy arrangements which may either stifle investment and induce sudden, unexpected exits or sudden bursts of investment.

Cognisant of the impact of generation retirements, the Panel notes that in November 2018, the AEMC made a rule that requires large electricity generators to provide at least three years' notice to the market before closing. The rule requires AEMO to maintain an up-to-date list of expected closure dates for generating units on its website. In March 2019, AEMO published for the first time the expected closure years for scheduled and semi-scheduled generators in the NEM. As of March 2019, there were 20 generators on the list with the closure years starting from 2028 to 2049.[28]

These ongoing trends in the nature of supply can impact on the reliability of the NEM. While there has been significant investment in new generation capacity in recent years, much of this capacity is variable, semi-scheduled or non-scheduled generation. Changing generation mix has a number of impacts on reliability of the electricity supply:

- Variability of renewable generation can make it harder to forecast its long term output when compared to than other forms of generation. These long term forecasts are an important component of the reliability framework. The Panel notes that there have been, and will continue to be, technological advances that have improved the ability to forecast the output of renewable generation.
- Most of this variable renewable generation is largely non-dispatchable. This means that the availability of these generators is typically dependent on weather and they are generally unable to ramp up to meet increasing demand.

These trends may also have implications for maintaining the security of the NEM. With greater levels of inverter-connected generators (i.e. wind and solar), there have been a growing number of instances where system security issues, such as keeping frequency and voltage at appropriate levels, have limited the output of generators.

This trend is most prominent in regions of the grid where high penetrations of non-synchronous generation are accompanied by declining levels of system strength. Low levels of system strength can jeopardise the ability of generators to maintain connection to the power grid, thereby causing flow on effects to the stability of grid frequency and voltage.

To address these issues, AEMO typically directs synchronous generation to generate as has occurred in South Australia, or it curtails generation from non-synchronous generation located in weak parts of the grid as has occurred in north-west Victoria. These actions undertaken to manage power system security are explored in more detail in chapter four.

2.3.2 Availability and retirements of thermal generation

Generators are not available all the time. While the regulatory framework provide signals through forecasts, information and notices about how much supply may be needed to meet demand, and the market tends to provide increasingly attractive financial incentives as the supply/demand balance gets tighter, there are a range of factors that impact all generators' availability to bid capacity into the market. This may include fuel availability (coal, gas, wind, sun, water), maintenance schedules, start-up and running costs and technical performance factors such as when units de-rate during high temperature events to mitigate higher risk of plant failure.

In the 2019 ESOO, AEMO looked at generators not being available due to forced outages. A forced outage is when a generator is unavailable to produce power due to unexpected equipment failure or breakdown. In its 2019 ESOO, AEMO used information collected from all

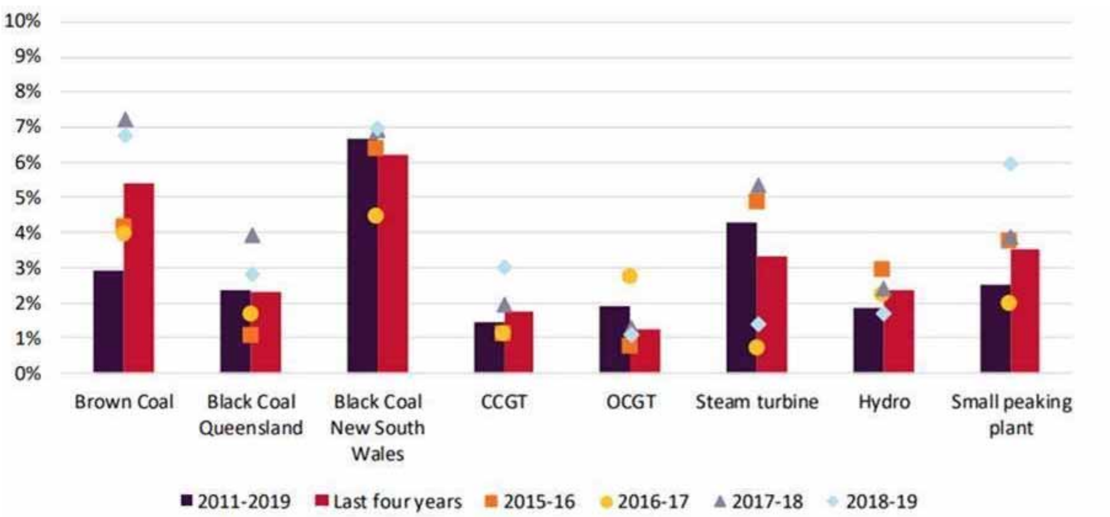
28 Closure dates of generation plant can be found on AEMO's *Generation information page*.

generators through an annual survey to illustrate the timing, duration, and severity of historical unplanned forced outages.

This is shown in Figure 2.6. The bars show a comparison of rates for AEMO's entire historical dataset (July 2010 to March 2019) and the average of the previous four years. The markers on the chart show the single year outage rates.

In its analysis,[29] AEMO noted that some categories of generator have seen a deterioration compared with the longer-term historical performance and that the biggest discrepancy between the long-term outage rates and performance in recent years is for brown coal, where recent forced outage rates sit well above the long-term average. All other types of generators have rates in the past four years which have been both above and below long-term and short-term averages, with a relatively small discrepancy between the long-term average and the average over the most recent four years.

Figure 2.6: Historical full forced outage rate comparison



Source: AEMO, *Electricity statement of opportunities*, p. 68.

While AEMO's 2019 ESOO looked at the forced outage history over a number of years, the Panel was interested in understanding more specifically whether thermal generators were available at times when they were needed from a reliability perspective in 2018/19.

The Panel chose to examine thermal plant in this reporting period's review, as opposed to other scheduled or semi-scheduled plant, because information on thermal units was readily accessible in the public domain and given their dispatchability, thermal generators could be expected to respond when needed. The Panel will seek to identify trends in different types of generators, including intermittent renewables and storage in future reviews.

29 AEMO, 2019 *Electricity statement of opportunities*, pp. 67-68.

This section therefore examines the percentage of capacity made available by each thermal generator in the NEM when lack of reserve conditions were in effect, and compares this against the level of operational demand on the grid at that time.

Periods when lack of reserve conditions are in effect indicate times when the supply/demand balance in the system is tight. In most circumstances when the supply/demand balance is tight, price signals in the wholesale electricity market reflect this scarcity and encourages generators to produce electricity to meet consumer demand. As such, periods when lack of reserve conditions are in effect are typically correlated with high price events, but the Panel acknowledges this may not always be the case.

A tight supply/demand balance may occur at any point throughout the year. It may occur during the summer peak period when consumer demand increases and environmental conditions strain the efficiency of generators, or it may occur during shoulder periods, when resource adequacy is reduced due to scheduled maintenance and networks capacity is limited due to planned network augmentations.

Given this, this section assesses the availability of thermal generators according to the following two assumptions:

- From a reliability perspective, there is a strong signal sent through a lack of reserve notice for generators to be available and to offer additional capacity to help meet demand.
- From a market perspective, there is an expectation that a generator would respond to price incentives, and make itself available when lack of reserve conditions are in effect.

The Panel acknowledges the fact that, at times, extraneous factors prevent all generators from responding to regulatory and price signals. There may also be commercial reasons why a generator has provided reduced capacity to the market. Lack of reserve conditions may also be predicated on the unavailability of thermal plant scheduled ahead of time, rather than a thermal plant's failure to respond to market signals during the interval in which there was a tight supply/demand balance. The Panel emphasises this section ultimately seeks to observe if the NEM's thermal generation fleet was available both when they were most needed from the perspective of maintaining power system reliability, and consequently, when they are also likely to face strong financial incentives to make capacity available.

For the following charts:

- Vertical boxes represent the performance of specific thermal generation units.
- Data points within each box represent individual five-minute dispatch intervals when the supply/demand balance was tight.[30]
- The x axis represents the operational demand of each region at the time when there was a tight supply/demand balance.

30 In order to define what constitutes a 'tight supply/demand balance', the Panel used AEMO's lack of reserve quarterly reports, which can be found here: https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/power-system-operation/nem-lack-of-reserve-framework-quarterly-reports. The Panel have considered any five minute dispatch period to which AEMO applied a lack of reserve condition (Forecast, Updated and Actual LOR 1s, 2s, and 3s) to qualify as an interval in which there was an expectation of tight supply/demand balance in the system

- The y axis represents the percentage of capacity made available and bid into the market by each generator at times when supply/demand balance was tight.

As such, a tight spread of data points, near the top of the box, implies a generator consistently made capacity available during intervals where there is a tight supply/demand balance, therefore demonstrating a high degree of reliability.

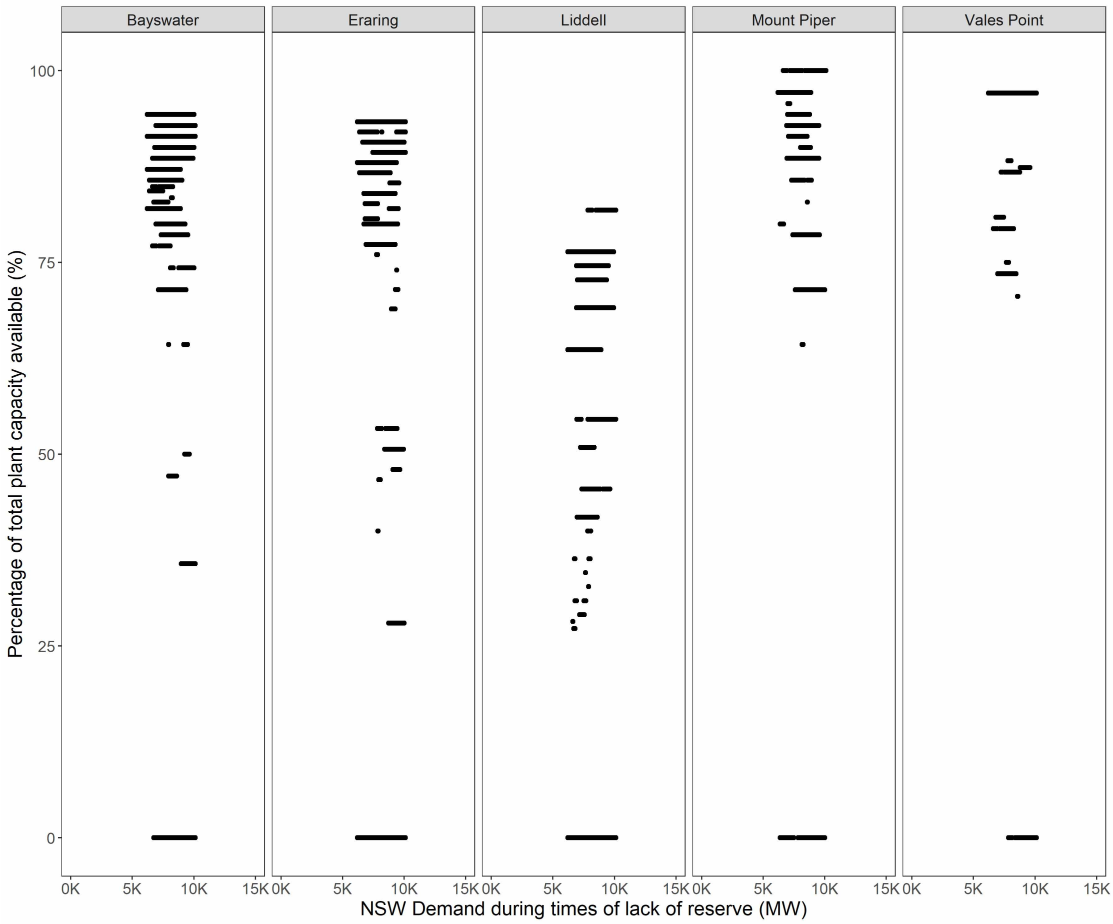
A wider spread, further down, or a spread with significant outliers implies a generator does not consistently make capacity available during intervals where there is a tight supply/demand balance, therefore demonstrating a lower degree of reliability.

NSW thermal fleet availability

Figure 2.7 illustrates the availability of NSW's thermal fleet during periods of tighter supply/demand balances.

- Mount Piper and Vales Point appears to consistently make most of their capacity available during periods when there are tight supply/demand balances. Vales Point makes over 90% of its capacity available for over 80% of periods when there is a tight supply/demand balance, while Mount Piper makes about 70% of its capacity availably during these times.
- Bayswater and Eraring demonstrate similar availability profiles. Both Bayswater and Eraring make over 90% of their capacity available in about 50% of times when there is a tight supply/demand balance, but have more intervals where some capacity is unavailable compared to Mount Piper and Vales Point.
- Liddell exhibits a different availability profile to other NSW thermal generators. Unlike the rest of the thermal fleet, Liddell never made over 90% of its capacity available during periods when there was a tight supply/demand balance. Liddell made some of its capacity available for about 75% of times when there was a tight supply/demand balance, while it was completely unavailable for about 25% of times there was a tight/supply demand balance.

Figure 2.7: NSW thermal plant availability during times of tight supply/demand balance in 2017/18 and 2018/19



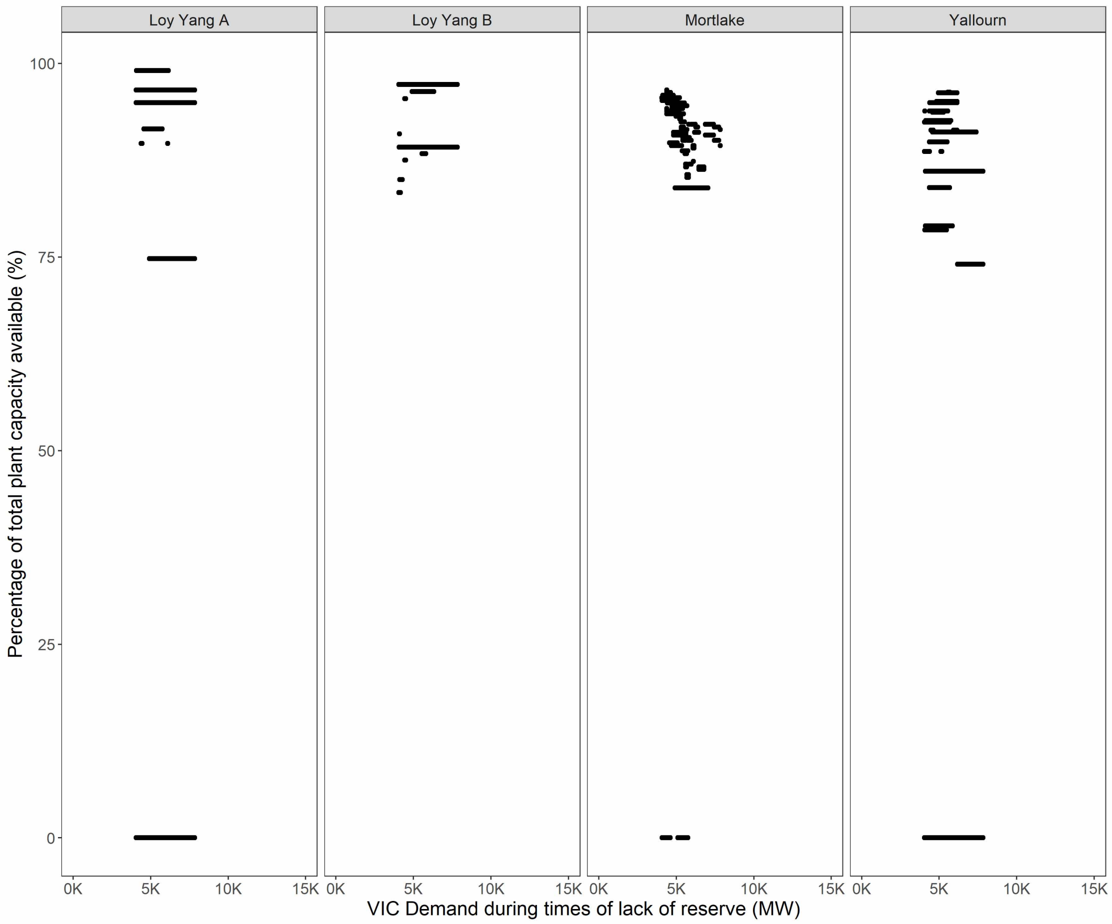
Source: AEMC analysis of publicly available data.
Note: The data for this chart is available in the AMPR data portal.

Victoria thermal fleet availability

Figure 2.8 illustrates the availability of VIC's thermal fleet during periods of tighter supply/demand balances.

- Loy Yang B appears to make over 80% of its capacity available all times where there is a tight supply/demand balance.
- Loy Yang A and Yallourn typically make over 75% of their capacity available during periods when there is a tight supply/demand balance. However, they were both completely unavailable for about 20% of times when there was a tight supply/demand balance over the course of the 2018/19 reporting period.
- Mortlake made 90% of its capacity available for over 80% of times there was a tight supply/demand balance in Victoria.

Figure 2.8: VIC thermal plant availability during times of tight supply/demand balance in 2017/18 and 2018/19



Source: AEMC analysis of publicly available data.
Note: The data for this chart is available in the AMPR data portal.

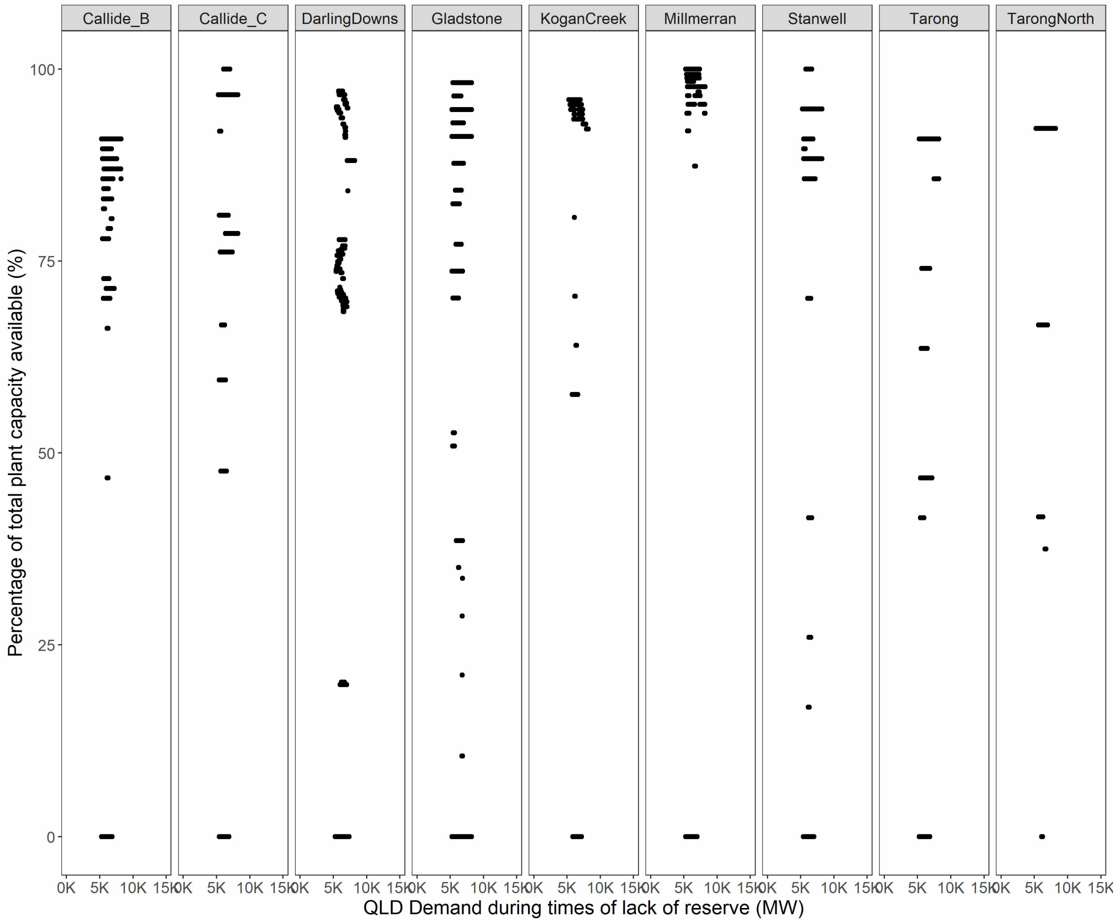
Queensland thermal fleet availability

Figure 2.9 illustrates the availability of QLD's thermal fleet during periods of tighter supply/demand balances.

- Most Queensland thermal generators (including Gladstone, Kogan Creek, Millmerran, Stanwell, Tarong and Tarong North) make over 90% of their capacity available for at least 75% of times when there is a tight supply/demand balance.
- Stanwell, Gladstone and Callide C exhibit more variability in their availability in scarcity periods compared to other major thermal generators, suggesting they are less consistent in the volume of capacity they make available in times when the supply/demand balance is tight. Further, Millmerran and Gladstone were completely unavailable for 10-15% of the times there were tighter supply/demand balances in the region.

- Although consistently making around 75% of its capacity regularly available during tight supply/demand balances in Queensland, Darling Downs was also completely unavailable for just less than 50% of the times there were tight supply/demand balances.
- Queensland's thermal generation fleet is the youngest in the NEM and likely most flexible.

Figure 2.9: QLD thermal plant availability during times of tight supply/demand balance in 2017/18 and 2018/19



Source: AEMC analysis of publicly available data.
Note: The data for this chart is available in the AMPR data portal.

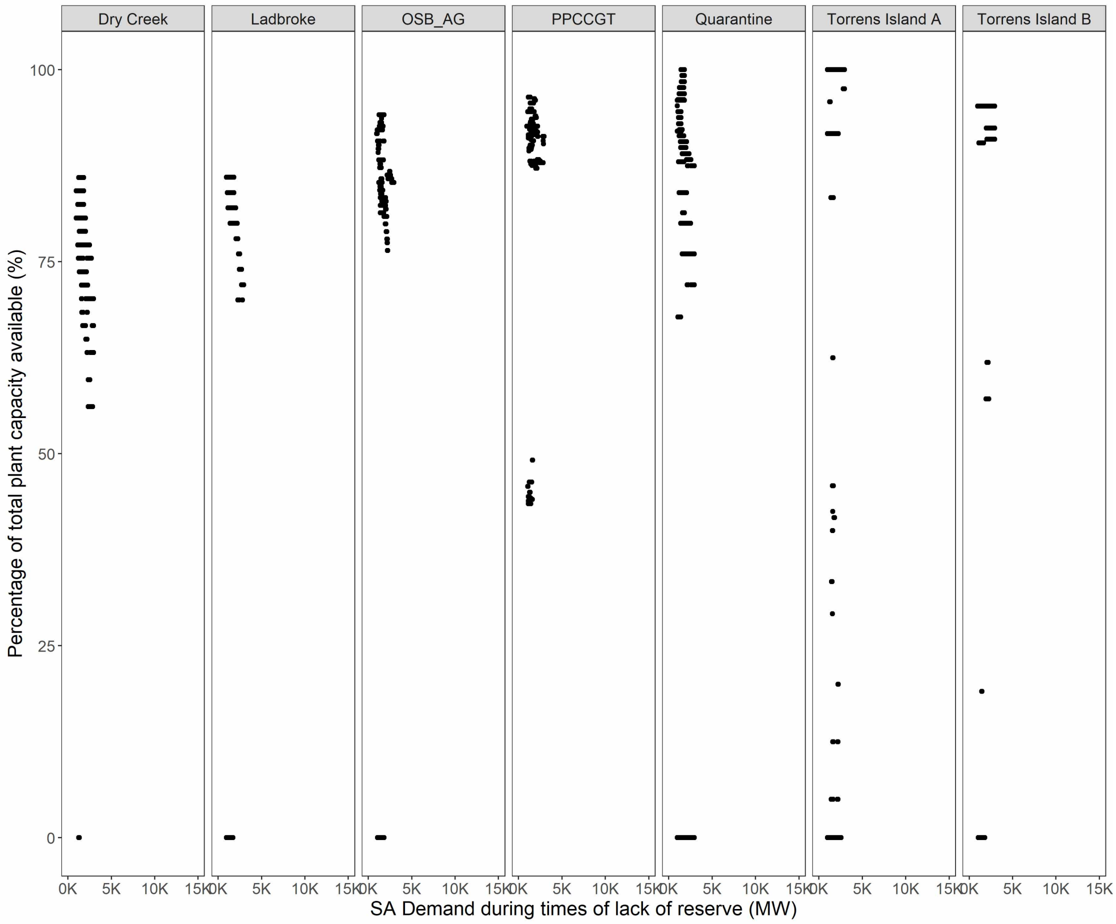
South Australia thermal fleet availability

Figure 2.10 illustrates the availability of SA's thermal fleet during periods of tighter supply/demand balances.

- Thermal fleet in South Australia, which is all gas-fired, has consistent, high availabilities (Dry Creek, Ladbroke, Osbourne, Pelican Point and Quarantine) in periods of low market reserves.

- Pelican Point made capacity available during all low reserve conditions. It made above 90% of its capacity available for about 60% of these times.
- Torrens Island A (two of four units scheduled for retirement in 2020) was completely unavailable for over 50% of times there were tight supply/demand balances in South Australia.

Figure 2.10: SA thermal plant availability during times of tight supply/demand balance in 2017/18 and 2018/19



Source: AEMC analysis of publicly available data.
Note: The data for this chart is available in the AMPR data portal.

Anticipated closure of NEM thermal generation

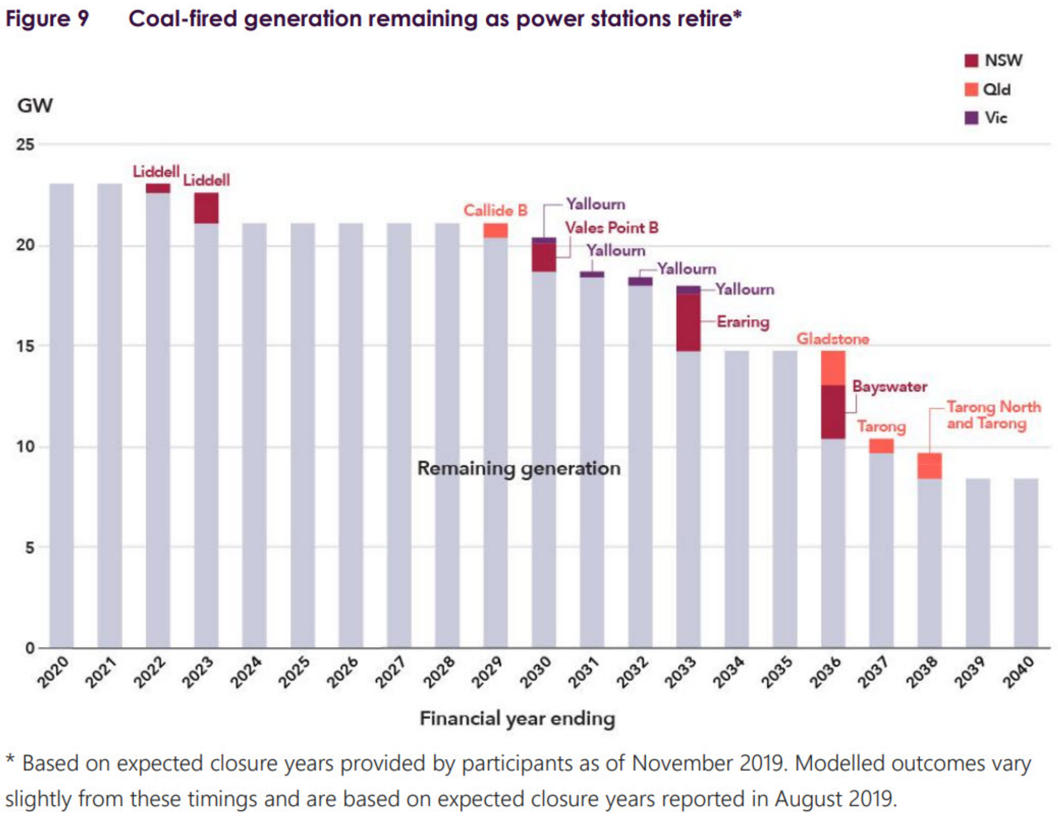
Over 2,300 MW of synchronous generation has announced its retirement within the next decade, while at least an additional 3,500 MW is expected to reach the end of its operating life and withdraw from the NEM by the beginning of the 2030s. The key synchronous generation that has announced its withdrawal from the NEM include:

- In July 2019, AGL announced it was delaying the planned closure of its first two Torrens A units (120 MW each) in South Australia, originally scheduled for withdrawal in 2019. Under the schedule AGL has provided to AEMO, the first two units will instead be closed in September 2020, the third in September 2021 and the final unit in September 2022. The station will be partially replaced by the Barker Inlet Reciprocating Engine Power Station (210 MW), which started operation in November 2019
- Having previously announced its intention to withdraw the Liddell Power Station (1,800 MW summer capacity) in New South Wales in 2022, AGL pushed back the closure of three of its 500 MW to be available during the 2022/23 summer months. One of its units will close in January 2022.
- Stanwell has announced its intention to withdraw the Mackay Power Station (34 MW) in Queensland in 2021.

Figure 2.11 illustrates the anticipated closure dates of generators in the NEM coal fleet that are expected to retire within the next decade. Key unit retirements include:

- Callide B (700 MW) is expected to reach the end of its operating life in 2028/29
- Yallourn (1,450 MW) is expected to reach the end of its operating life between 2029/30 and 2031/32
- Vales Point B (1,320 MW) is expected to reach the end of its operating life in 2029/30.

Figure 2.11: Coal generation remaining as power stations retire



Source: AEMO, *Draft 2020 Integrated system plan*, December 2019.

Note: New rules requiring generators to register their closure date and provide three years notice of closure as a minimum, means AEMO now has more visibility on when plant expected to close and can use this to inform system planning such as development of the ISP.

There are two main contributing factors that may lead to thermal fleet retiring from the NEM:

- The combination of low spot market prices and low residual demand, especially during the day, as larger volumes of utility-scale wind and solar enter the market, accompanied by the continued uptake of rooftop solar. Building renewable generation has become the cheapest source of new electricity supply, and costs are expected to continue to decline.[31] Higher penetrations of renewables setting lower spot market prices more frequently will affect the commercial viability of thermal fleet. It may also drive them out of the bid stack of periods of the day when they have traditionally met the majority of consumer demand.
- Uncertainty over climate and emissions policy, particularly in regard to meeting international emissions reduction targets such as the Paris Agreement, and how this impacts on existing thermal assets. This uncertainty can add risk to maintaining

31 Bloomberg New Energy Finance, New Energy Outlook 2019.

generation assets that produce emissions. Research has shown that many market participants already factor in an expectation of future emissions policies into their assessment of future commercial operations of thermal generation.[32] There is also a growing impact of investor and stakeholder pressure to transition away from emissions-intensive assets.

It is important to note that these factors are complex and bespoke to individual assets. For example, the retirement of a thermal generator in the NEM would improve the profitability of the remaining generators, potentially reducing the likelihood of other immediate closures.[33]

2.4 Demand side trends

BOX 2: A SUMMARY OF DEMAND SIDE TRENDS

The Panel notes the following key demand trends emerging or continuing in the NEM:

- The amount of energy consumed is expected to remain flat for the short to medium term before growing as electricification increases.
- Maximum demand is generally growing across the NEM. It is also shifting to later in the day as rooftop PV uptake increases.
- Minimum demand is an emerging concern in regions with high penetrations of rooftop PV, especially South Australia.
- Rooftop PV has continued its significant uptake while battery storage and electric vehicles are forecast to grow significantly over the coming years.

Demand side trends refer to the changes over time related to the consumption of electricity in the NEM. They reveal patterns in the electricity usage profiles of residential and business consumers, and where they choose to consume it from. The consumption of electricity has changed significantly since the commencement of the NEM, and it will continue to evolve rapidly. This will accelerate as changes and improvements in household and network technology enable greater consumer participation and growing two-way flows of electricity.

Energy use can be considered in terms of the total amount of energy consumed over a time period (i.e. energy consumption) or in terms of the rate at which energy is used at a single point in time (i.e. demand).

Each of these measures are relevant to market outcomes in the NEM. For example, growth in total energy consumption is relevant to how much bulk energy supply is needed in the NEM. Changes in patterns of maximum or minimum demand are relevant to the specific kinds of generation that are needed in the NEM, and how those generators and loads behave.

32 Aurora Energy Research, *Analysis of AEMO's ISP Part 2: economics of coal closures*, 2019.

33 Ibid.

This section looks at:

- trends in operational consumption
- trends in DER uptake
- implications of DER uptake.

2.4.1 Trends in operational consumption

Changes in operational consumption in the NEM are driven by a number of factor, including:

- **Population:** The combination of Australia's immigration and natural rate are expected to lead to faster growth rates. [34] Increasing the number of consumers, both residential and businesses, is likely to put upward pressure on operational consumption, while infrastructure built to meet the needs of a growing population is also likely to increase levels of electricity consumption.
- **Electrification:** The widespread electrification and digitalisation of goods and services will continue increase electricity consumption. In the household, this is observed in the improved affordability of household appliances, the electrification of stove tops and heating, electric vehicles, the proliferation of smart devices and the integration with the internet of things. In the business sector, consumers increasingly use electricity for their heating and cooling needs, continue to electrify their manufacturing capabilities and rely on energy-intensive data-storage and technology solutions.
- **Energy efficiency:** Improvements in the efficiency of technology and appliances, as well as the improved efficiency of usage profiles in both households and businesses. While increased electrification of goods and services may lead to an increase in appliances and equipment that rely on electricity, technological improvements help them consume more efficiently. Further, the introduction of smart meters, smart-switches and the internet-of things have helped consumers to adapt their load profiles and use electricity only when it is needed, while the emergence of AI and machine learning algorithms have been able to improve the efficiency of electricity-intensive business equipment.

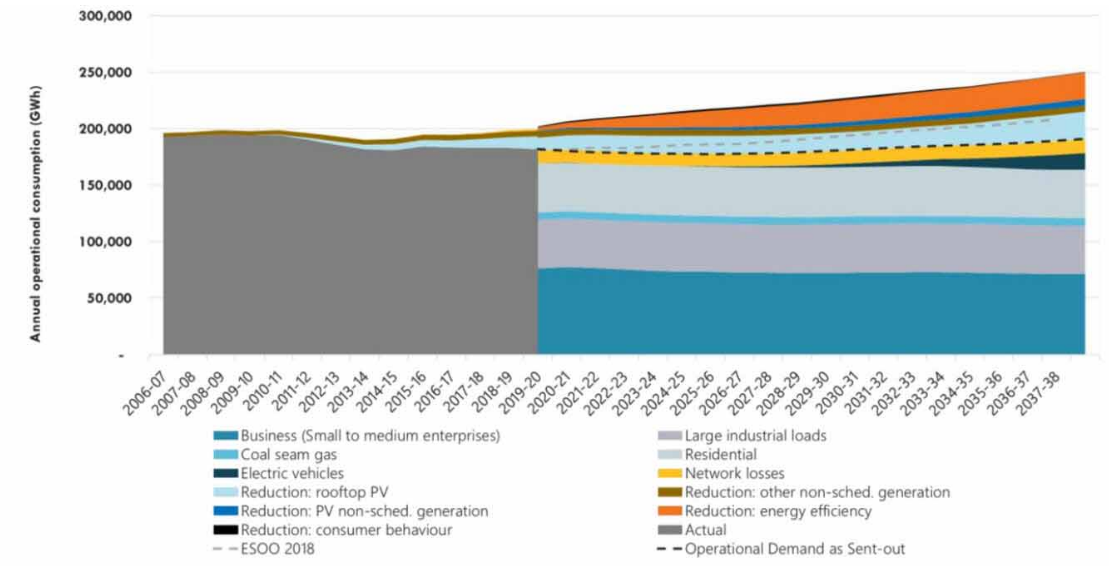
The combination of these influences lead to the current observable trends, observable in Figure 2.12:

- the 2019 NEM ESOO forecast operational consumption to be fairly steady over the next 20 years
- While there has been a growing number of connections and increased reliance on electricity in both households and businesses in the NEM, growth in operational consumption has been in decline. AEMO's 2019 ESOO[35] identifies the continued uptake of embedded PV systems as a main driver reducing the demand on the grid, while increases in energy productivity and structural changes in the economy away from energy-intensive industries will also contribute.

34 The Australian Bureau of Statistic anticipates population growth the average 1.6% per year in the short term, which will revert to 1.2% beyond 2030. Source: ABS, Population Projections Australia. More information can be found here: https://www.abs.gov.au/AUSSTATS/abs@.nsf/DetailsPage/3222.02006%20to%202101?OpenDocument

35 AEMO, *2019 Electricity Statement of Opportunities*, August 2019.

Figure 2.12: Total NEM operational consumption in gigawatt hours, actual and forecast, 2006/07-2038/39



Source: AEMO, *2019 Electricity statement of opportunities*, August 2019.
Note: This figure shows that the 2019 NEM ESOO forecast operational consumption to be fairly steady over the next 20 years. The forecast growth is around 6% lower than the 2018 NEM ESOO.

The Panel notes that, by definition, forecasts will always be incorrect to some extent. This inaccuracy is often more pronounced in longer term forecasts. As such, the Panel notes that long term forecasts, while useful for consideration of broader systemic changes, are likely to change as more information becomes available and market conditions change.

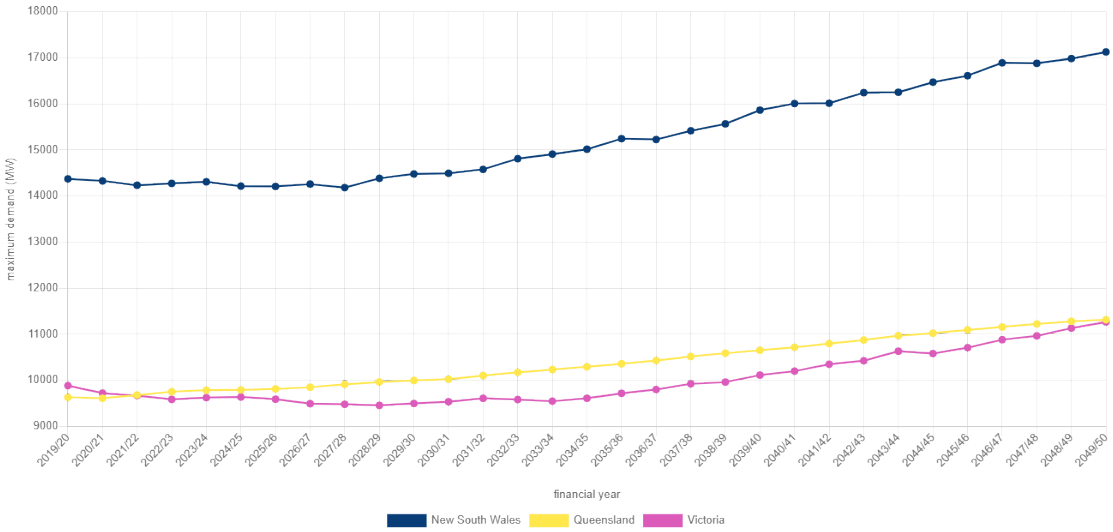
2.4.2 Maximum demand, minimum demand and demand response

Forecasts of maximum annual demand are strongly driven by weather, and occur at different times in different regions. Meanwhile, changing forecasts of minimum demand are driven increased volumes of rooftop PV in the NEM all producing electricity during the day.

Projected changes in maximum demand are illustrated in Figure 2.13 and Figure 2.14. These figures are characterised by the following trends which were presented in AEMO's 2019 ESOO:

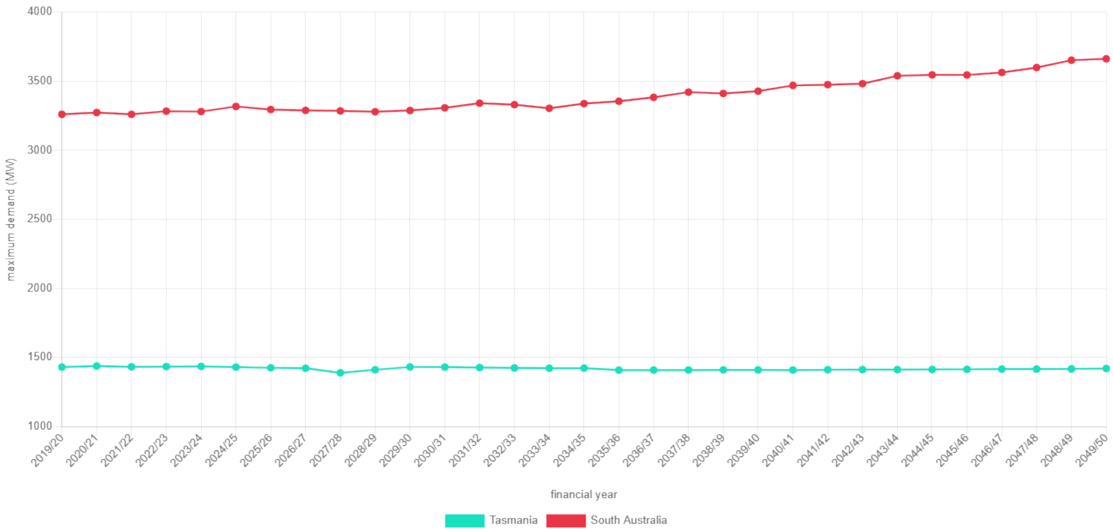
- Although record high maximum demand days are being observed, load factors and operational consumption growth have been decreasing.
- AEMO has forecast maximum demand in most regions to remain relatively flat over the short to medium term.
- However, with growing electrification, AEMO is forecasting regional maximum demands to continue to grow over the long term.
- The timing of maximum demand is expected to be pushed into later in the evening as rooftop PV reduces demand during the day.

Figure 2.13: Maximum demand forecasts over time in New South Wales, Queensland and Victoria



Source: Data from AEMO, *2019 Electricity statement of opportunities*, August 2019.
Note: The data for this chart is available in the [AMPR data portal](#).

Figure 2.14: Maximum demand forecasts over time in South Australia and Tasmania



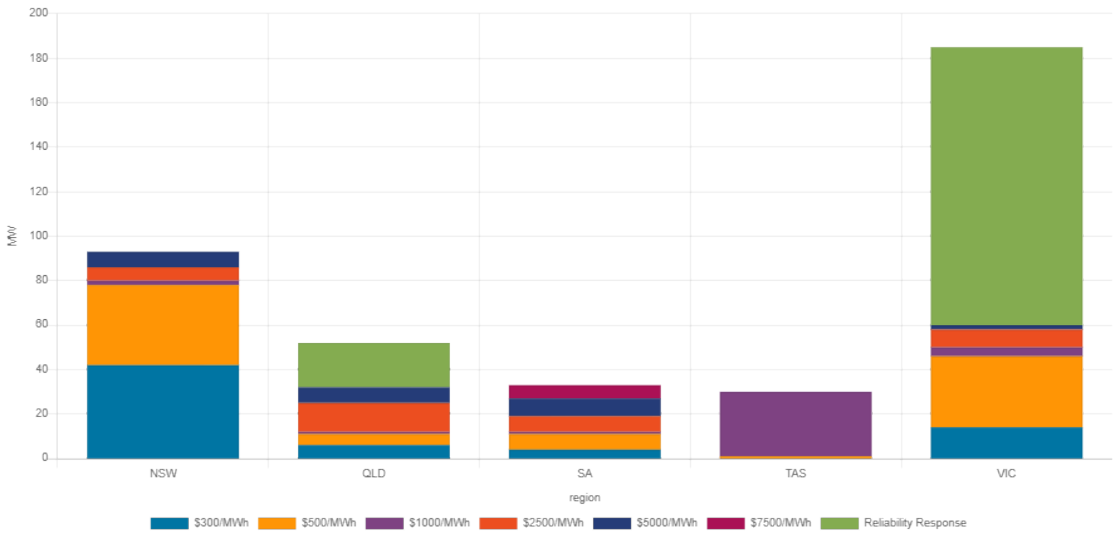
Source: Data from AEMO, *2019 Electricity statement of opportunities*, August 2019.
Note: The data for this chart is available in the [AMPR data portal](#).

Of increasing importance to operational outcomes in the NEM is the impact of declining minimum demand.[36] In relation to minimum demand in the NEM, AEMO has forecast:

- Minimum demand is forecast to decline over the next 3-5 years in New South Wales, Victoria, South Australia, and Queensland.
- In the long term, forecast minimum demand in Queensland continues to decline, due to continual projected growth in rooftop PV and PVNSG capacity.
- Minimum demand is forecast to approach the middle of the day within the next couple of years, except for Tasmania, which given its relatively larger proportion of business load compared to the other regions, experiences minimum demand overnight or after sunset.

Figure 2.15 shows the level of wholesale demand side response that AEMO considered to be currently available in the NEM at the time of publishing its 2018 ESOO. These estimates capture the magnitude of the response by industrial users, and consumer response through programs run by retailers, aggregators, or network service providers. The figure below considers the amount of demand response that would be expected at certain wholesale prices i.e. how much would demand change if these wholesale prices were reached. These figures exclude any demand response providing emergency reserves through the RERT.

Figure 2.15: Amount of expected wholesale demand response in NEM, per region



Source: AEMC analysis of AEMO, *2019 Electricity statement of opportunities*, August 2019.
Note: The data for this chart is available in the AMPR data portal.

2.4.3 Trends in distributed energy resources uptake

The electricity sector is undergoing a major transformation, and distributed energy resources, such as solar panels, battery storage and electric cars, are fundamentally changing the way consumers engage with energy markets. Consumer uptake of DER increased significantly

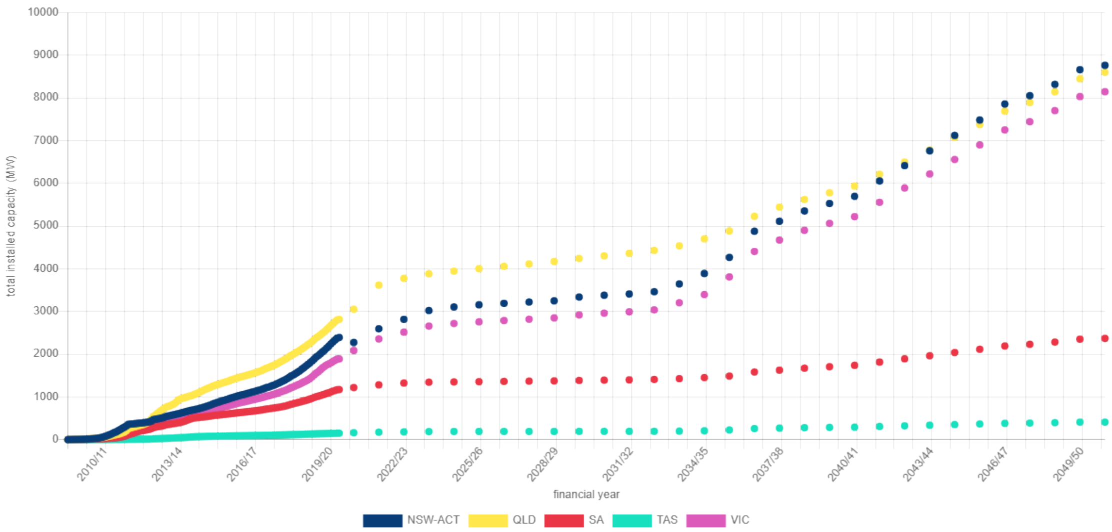
36 These impacts are explored in detail in the security assessment chapter.

with the installation of roof-top solar PV systems in the late 2000s and this trend has continued to the present. Consumers have also started to adopt new forms of DER, such as embedded battery storage, as they become available to help better manage their electricity usage. Consumer uptake of DER is expected to continue to increase as costs decline and availability increases.

Figure 2.16 illustrates the following trends in rooftop solar PV uptake:

- Rooftop PV has continued to grow over 2018 and early 2019, leading to approximately 1.4 GW of new installations and bringing the total capacity to about 8.1 GW.
- Relatively strong growth in rooftop PV systems is forecast over the next five years while pricing support remains from high retail prices and government subsidies such as the small-scale technology certificates (STC).
- After this, future growth in PV uptake is projected to be slower, due to a combination of declining incentives and easing of retail electricity prices.

Figure 2.16: Actual and forecast uptake of rooftop solar PV



Source: AEMC analysis of AEMO and CER data.
Note: The uptake of rooftop solar PV is forecast to almost triple between now and 2048.
Note: The data for this chart is available in the AMPR data portal.

Australia is leading the way with the installation of battery storage, with approximately one quarter of global battery installations by capacity expected to be installed in Australia during 2019.[37] Battery storage can provide consumers with more active control and ways to use electricity. These could include:

- selling stored energy when energy prices are high
- providing network support

37 Bloomberg New Energy Finance, 22 January 2019, *Australia to be Largest Residential Storage Market in 2019*, viewed 28 August 2019.

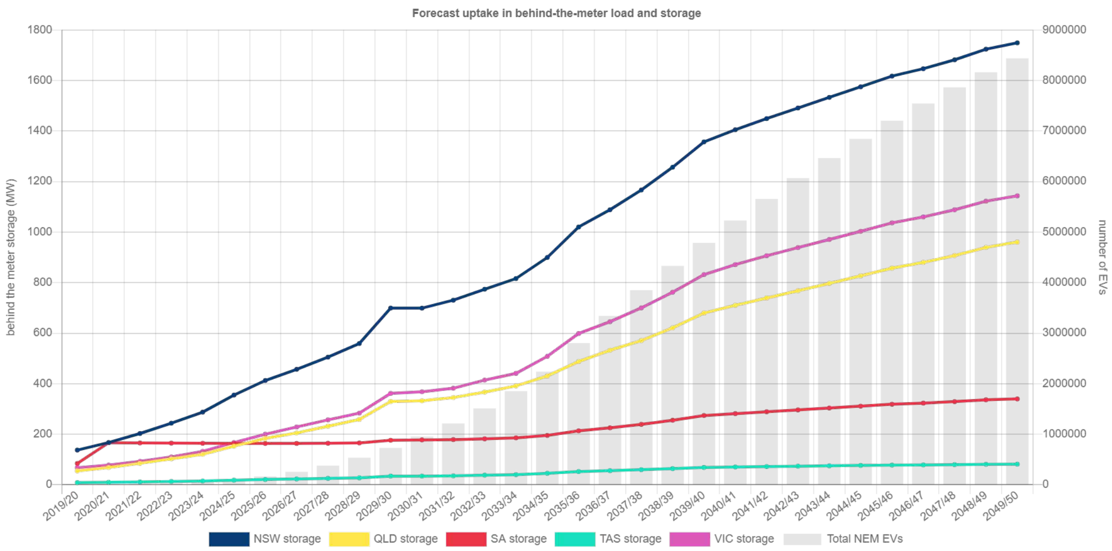
- storing solar energy for later use.

Another form of energy storage is electric vehicles. Consumer uptake of EVs has been lower than that of solar PV and battery storage in Australia. Major factors that have inhibited EV uptake thus far include concerns regarding the distance that can be travelled per EV charge, the purchase cost when compared to petrol or diesel vehicles, the accessibility of charging infrastructure and the reliability of electric vehicle technology.[38]

Figure 2.17 illustrates the forecast uptake of both household embedded battery storage systems and electric vehicles in the NEM. AEMO's forecasts for household battery storage and electric vehicles show:

- Battery uptake is expected to grow steadily, and then forecast to slow briefly as battery price reductions are expected to stabilise around 2030.
- Uptake of EVs will reach 4% in the next decade, up from current levels of 1%.
- After 2028-29, EV ownership is projected to start increasing faster, due to greater model choice, charging infrastructure availability, and falling costs through economies of scale and fuel savings.

Figure 2.17: Forecast uptake in behind-the-meter load and storage



Source: AEMC analysis of AEMO ESOO 2019 data.
Note: The data for this chart is available in the AMPR data portal.
Note: Minor corrections were made to this chart after publication to amend axis labels

2.4.4 Implications of DER uptake

Growing amounts of rooftop PV is reducing the total amount of electricity consumption that is drawn through the networks.

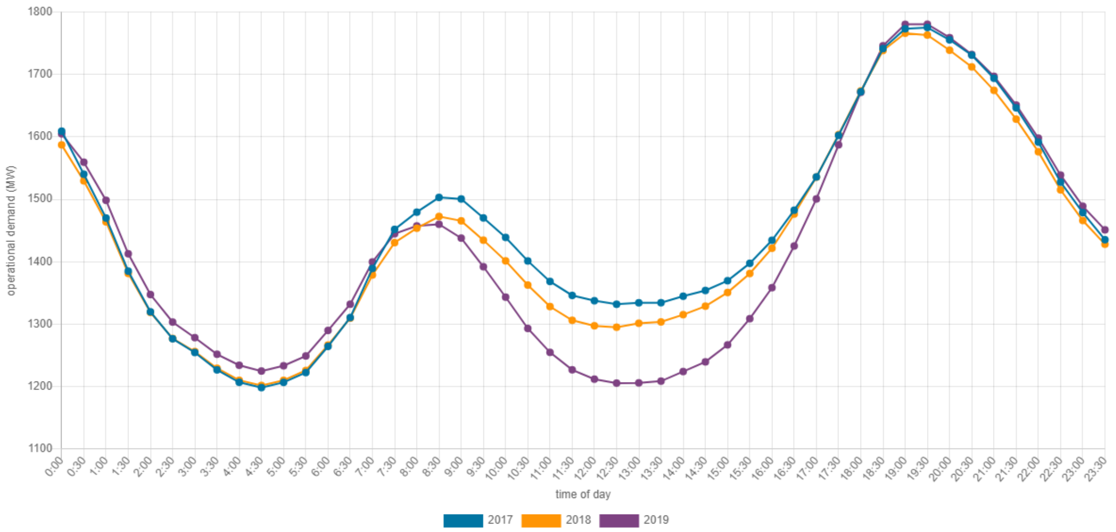
38 ClimateWorks Australia, *The state of electric vehicles in Australia*, June 2018, p. 18.

This results in decreasing minimum demand levels and also the need for wholesale generators to respond to a later and steeper ramp up to meet evening peak demand.

This trend is most prominent in South Australia but emerging in other states like Queensland, as the proportion of solar PV grows. Figure 2.18 and Figure 2.19 show this trend:

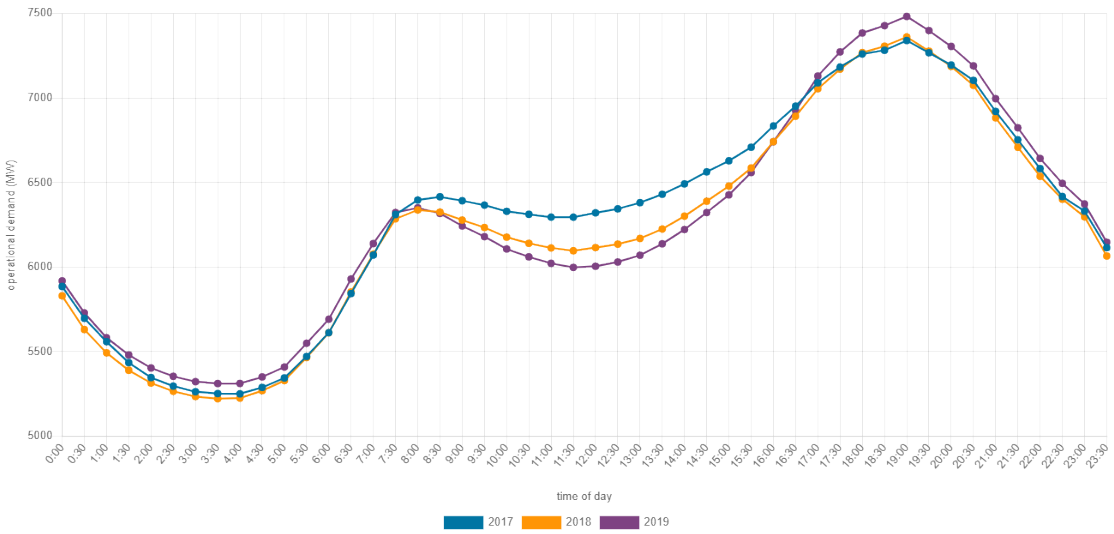
- In South Australia, the lowest level of minimum demand is forecast to become negative by 2026/27. This means that distributed generation output in the region would demand, mainly driven by output from residential rooftop PV.
- the effects of increased residential rooftop PV, and DER more generally, can present a number of operational and system security challenges, including:
  - system strength risks
  - voltage and frequency control issues
  - challenges for protection and control schemes operation, including emergency frequency control schemes.

Figure 2.18: Change in operational demand in SA driven by increasing rooftop solar PV



Source: AEMC analysis of AEMO data.
Note: The data for this chart is available in the AMPR data portal.

Figure 2.19: Change in operational demand in QLD driven by increasing rooftop solar PV



Source: AEMC analysis of AEMO data.
Note: The data for this chart is available in the AMPR data portal.

The AEMC's *Electricity network economic regulatory framework review*,[39] identified that the potential benefits of efficient integration of DER for all customers are substantial and the timely development of a supportive regulatory framework is essential. However, it also identified that consumers will bear the cost of DER not being integrated into the electricity system efficiently if such a transition isn't appropriately managed. For example, these costs may include or arise from:

- Consumers facing increased costs for products and services if the power system does not provide consumers with choice or reward supportive behaviours
- the risk of increased electric vehicle and battery consumption adding to peak demand instead of smoothing it
- rooftop PV being constrained
- prices becoming more volatile.

The Panel notes the importance of managing the increased uptake of distributed energy resources so that the associated value can be captured and shared with consumers. The Panel also notes the importance of coordinating reforms so that the uptake of DER doesn't adversely impact on reliability and security outcomes in the NEM.

The Panel notes that the Commission has identified the following 'tools' that are crucial in integrating DER and optimise benefits for all customers:

- customer reward pricing

39 AEMC, *Electricity network economic regulatory framework review 2019*, September 2019.

- distribution system access and connections
- information to enable decision-making
- maintaining security and reliability.

2.5 Network trends

BOX 3: SUMMARY OF NETWORK TRENDS

The Panel notes the following key network capacity trends emerging or continuing in the NEM:

- Over the past ten years across the whole of the NEM, the vast majority of blackouts have been caused by breakdowns in the grid's poles and wires.
- AEMO's generation information page notes that there is over 60GW of generation proposing to connect to the NEM. However, not all of this generation is expected to necessarily progress to commitment stage and be developed.
- New transmission infrastructure is needed to support this investment in generation
- A similar trend is occurring at the distribution level. AEMO's ISP shows that by 2040 distributed energy generation capacity is expected to double or even triple.
- In this future, the network will become a platform for consumers to buy *and* sell energy and demand response services in a more dynamic way – in response to prices and their own preferences.

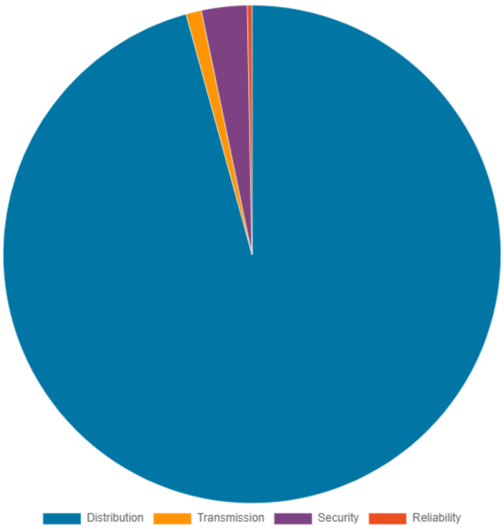
2.5.1 Sources of supply interruptions

While customers' experience of power supply interruptions tends to be the same irrespective of the cause, interruptions are classified based on what part of the power system caused the interruption. This is because different parts of the power system have differing planning frameworks, are regulated by different bodies and require different solutions.

Figure 2.20 and Figure 2.21 below shows the total number of megawatt hours of supply interruptions customers experienced due to different types of supply outage at a national level. Given the chart is measure in megawatt hours of supply interruptions, outages that affect many people or over longer durations will show up more prominently in the chart.

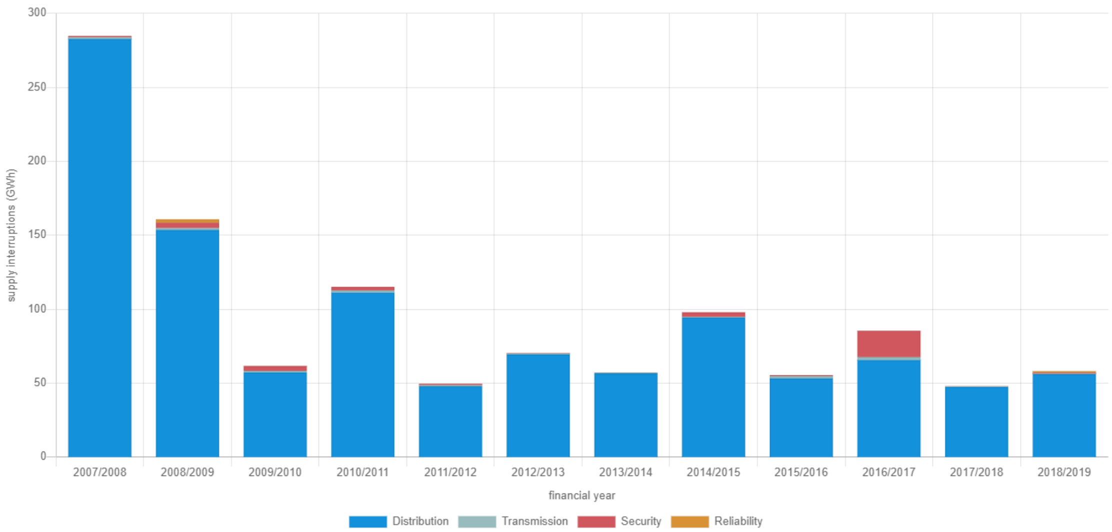
Over the past ten years across the whole of the NEM, the vast majority of blackouts have been caused by breakdowns in the grid's poles and wires.

Figure 2.20: Sources of supply interruptions over the decade (2008/09-2018/19)



Source: AEMC analysis and estimates based on publicly available information from AEMO's incident reports and the AER's RIN economic benchmarking spreadsheets.
Note: The data for this chart is available in the AMPR data portal.

Figure 2.21: Sources of supply interruptions in the NEM 2008/09 to 2018/19



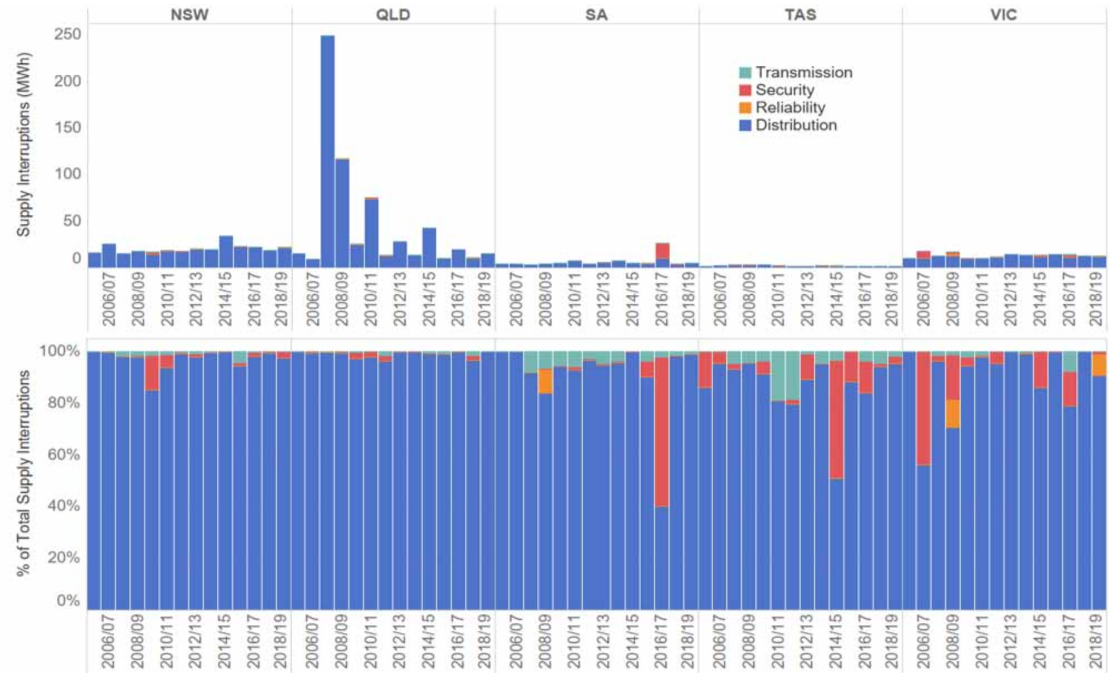
Source: AEMC analysis and estimates based on publicly available information from AEMO's incident reports and the AER's RIN economic benchmarking spreadsheets.
Note: The data for this chart is available in the AMPR data portal.

While the figures above show the source of supply interruptions across the NEM. On a regional basis, we can observe some trends that are specific to each state.

Figure 2.22 below shows how the *number* of megawatt hours of supply interruptions in each state (top half) and the *percentage* of total supply interruptions in each state (bottom half), separated by the cause of the supply interruption. These two charts highlight that:

- when aggregated across the NEM, distribution network outages in states where demand is highest (New South Wales and Queensland) tend to outweigh the of impact transmission and security-related outages have had in smaller states (South Australia, Tasmania and Victoria).
- On a regional basis, South Australia, Victoria and Tasmania have been more effected by transmission, security and reliability related supply interruptions.
- Reliability-related outages impacted South Australia in 2008/09, 2016/17 and 2018/19 and Victoria in 2008/09 and 2018/19.

Figure 2.22: Sources of supply interruption in each state from 2008/09 to 2018/19



Source: AEMC analysis and estimates based on publicly available information from AEMO's incident reports and the AER's RIN economic benchmarking spreadsheets.
Note: This chart shows megawatt hours of interrupted supply for each year of the last decade, by state.
Note: The data for this chart is available in the AMPR data portal.

These charts demonstrate that the causes of supply interruptions have varied by state and over time. Understanding what caused the interruption allows for identification of where further actions may be needed, in order to improve outcomes for consumers in the future. It is also important to understand the cause so any solution can be targeted to the problem.

2.5.2 Trends in transmission networks

When the NEM started trading, it was limited to large players because the generation was only cost effective at a large scale and technology and communications required to participate was too costly to impose on smaller players. Transmission infrastructure was built between a handful of generation and load centres and this was sufficient to support the delivery of electricity to customers.

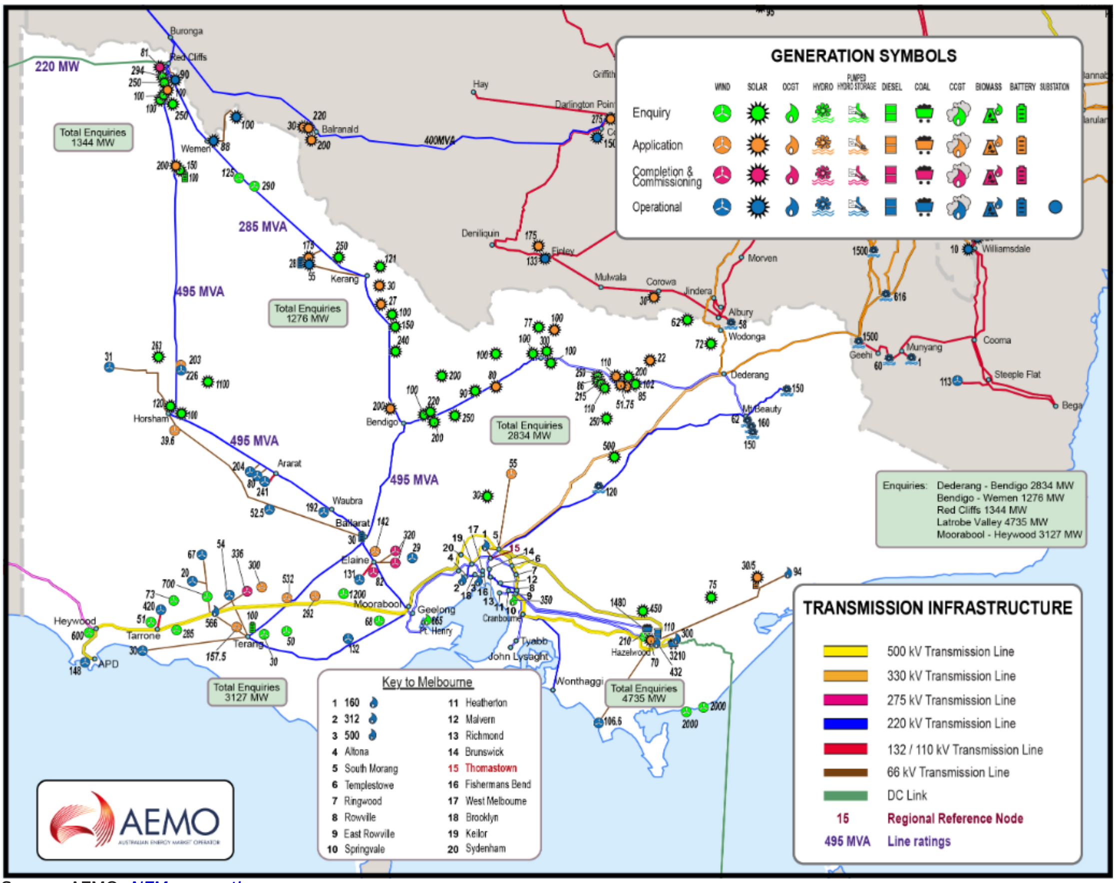
Today, the NEM is currently undergoing a significant transformation, with an unprecedented level of generators seeking to connect to the system. AEMO's Generation Information page lists that there is approximately 60 GW of generation proposing to connect to the NEM.[40] Unlike the existing fleet, the new generation comes from lots of relatively small and geographically dispersed generators. This generation is likely to be connected in sunny or windy areas at the edges of the grid, where the network is less strong.

Generators currently have no right to be dispatched in the wholesale market. Therefore, there is no guarantee that the network will have the capacity to get the energy to market even once connected. In contrast, transmission businesses have an obligation to meet jurisdictionally-set reliability standards for their networks, and so are focussed on making investments to reliably supply consumers. Given that a significant amounts of this new capacity is seeking to locate (often at the edges of the network), there is an increasing need to invest in and build transmission to reliably connect these generators and get their energy to market.

Figure 2.23 shows illustrates the scale of the change underway in Victoria.

40 However, the Panel notes that not all of this generation will become committed and be developed.

Figure 2.23: Volumes of connection interest in Victoria



Source: AEMO, NEM generation maps.

Currently, decisions on where to locate, and how to operate generation are not always aligned with decisions on how much and where transmission investment should be. This is slowing the pace transition. The Panel notes that there is a significant program of work underway to coordinate generation and transmission investment across the NEM to support the huge amount of investment that will occur in the energy sector in coming years.

This includes AEMO's Draft 2020 Integrated System Plan, which identifies over 15 projects to augment the transmission grid to provide a "least-regret, dynamic, resilient and transparent roadmap for the NEM."[41] The ISP will be supported by the AEMC's transmission access reforms that incentivise generators to locate in places where transmission infrastructure can be used most effectively to get energy to market. Together, these reforms will facilitate new technologies accessing the grid, promoting reliability and security.

41 AEMO, *Draft 2020 Integrated System Plan*, December 2019

2.5.3 Trends in distribution networks

The uptake of distributed energy resources in Australia has increased significantly in the last decade, driven mainly by consumers. The NEM saw nearly 6,000 MW of small-scale solar PV systems installed between 2010 and 2018. The trend in DER uptake is likely to continue. AEMO's ISP shows that by 2040 distributed energy generation capacity is expected to double or even triple. This will make Australia one of the most decentralised electricity systems in the world.

This high level of uptake means that DER is likely to be a significant part of the Australian electricity system in the future, and will play an important role in an electricity system that is diverse and flexible.

It also means that the distribution network is moving away from a one-way supply chain model to a platform for local energy production, consumption, storage and trading. Networks still largely charge for energy consumed and do not necessarily value the services consumers now require and this is slowing down the transition.

The future distribution level market will see consumers buy and sell energy and demand response services in a more dynamic way. Network businesses also need to be enabled and incentivised to provide the new services that are valued by users of the network. Consumers may interact with the electricity system in one or a combination of the following ways:

- Drawing electricity from the grid.
- Generating electricity for their own consumption only (becoming less reliant on grid supply).
- Buying, trading or selling energy, either to a retailer or through other platforms such as peer-to-peer trading.
- Participating in new services markets such as providing demand response, network support or ancillary services to the wholesale energy market.
- Supplying energy (or other services) to community projects such as a community battery.

These changes will benefit everyone on the grid – not just those with solar panels or other distributed energy resources. It'll mean lower costs for consumers and a secure and reliable power system.

2.6 Wholesale market trends

BOX 4: SUMMARY OF WHOLESALE MARKET TRENDS

The Panel notes the following key wholesale market trends emerging or continuing in the National Electricity Market:

- For many regions in the NEM, 2018/19 was characterised by the highest wholesale electricity prices on record.
- Prices in the range of $100-200/MWh are a growing proportion of total electricity costs.

- Price spikes occurred in South Australia and Victoria over the reporting period but were not observed in other regions.
- Negative prices were experienced in Queensland and Victoria, driven mostly by high renewable output during the day.

The spot market is the mechanism that AEMO uses to match the supply of electricity from power stations with real time consumption by households and businesses. All electricity in the spot market is bought and sold at the spot price. The spot price tells generators how much electricity the market needs at any moment in time to keep the physical power system in balance.

The NEM is currently undergoing a significant transition involving the adoption of generation technologies such as wind, solar and energy storage at the same time as the age-based retirement of existing thermal generation. Flexible technologies are playing an increasingly important role in supporting the intermittent output of wind and solar generators. Supply side flexibility is currently provided by hydro, gas peaking, and diesel fuel generators and to some extent by coal-fired generators.

The generation mix will change further as technology advancements improve the economics of faster and more flexible demand and supply solutions. Wholesale prices directly influence the type, scale and location of technology installed, in response to changing power system conditions. They also provide a signal for the efficient consumption of electricity and efficient investment in generation and demand side technologies.

The trends that underpin wholesale market patterns impact on the financial viability of existing market participants, and the signals to invest for new and existing participants.

This section observes three key areas:

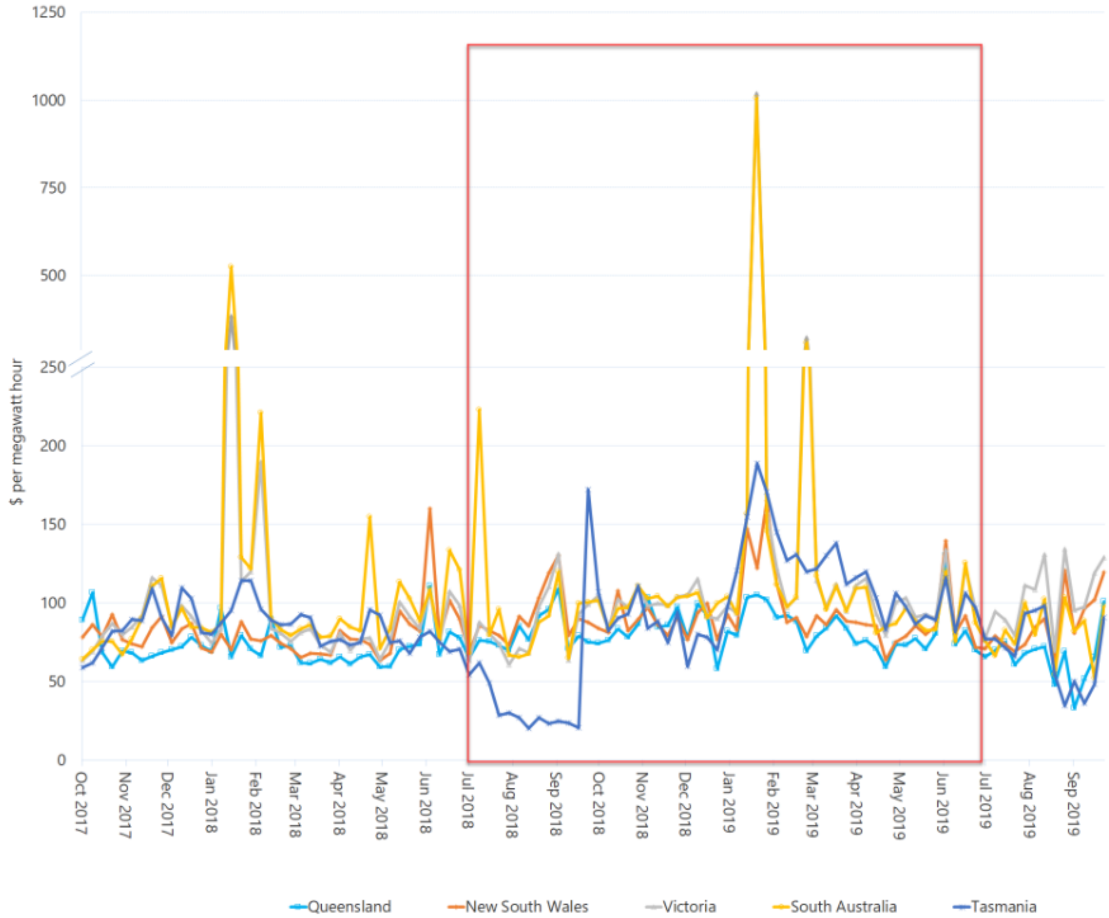
- trends in spots prices
- trends in contract prices
- trends in price banding.

2.6.1 Trends in spot prices

The Panel observes a number of trends in weekly average weighted spot prices illustrated in Figure 2.24:

- The Panel has identified the box in red as the reporting period.
- Prices become increasingly volatile towards the middle or the reporting period during the summer months, which is typically characterised by high demand during hot weather. This likely reflects the fact that reserves are tight at these times, and prices are increasing to signal scarcity to the market.
- Most regions remain in a relatively stable band during other parts of the year other than Tasmania, which experienced some volatility in September during shoulder months.

Figure 2.24: **Weekly volume weighted average spot prices**



Source: AER, *Wholesale statistics page*.
Note: This figure shows weekly spot price movements. It shows a trend starting where prices spike in summer given high demand during hot weather, and reflecting the fact that reserves are tight at these times.

2.6.2 Trends in contract prices

To manage their financial risks and have more certainty over wholesale energy costs, wholesale market participants enter into various wholesale hedging contracts.

Both buyers and sellers in the wholesale market are exposed to variations in the spot price in the wholesale market. They appreciate that large swings in spot prices have a similar but opposite effect on their costs and revenue and, consequently, their profits and share price. This encourages both buyers and sellers to agree to contracts that convert volatile spot revenues and costs for a more certain cash flows or to help underwrite further investment in both generation and retail assets (vertical integration), which are generally expensive, long-term investments in a more uncertain investment environment.

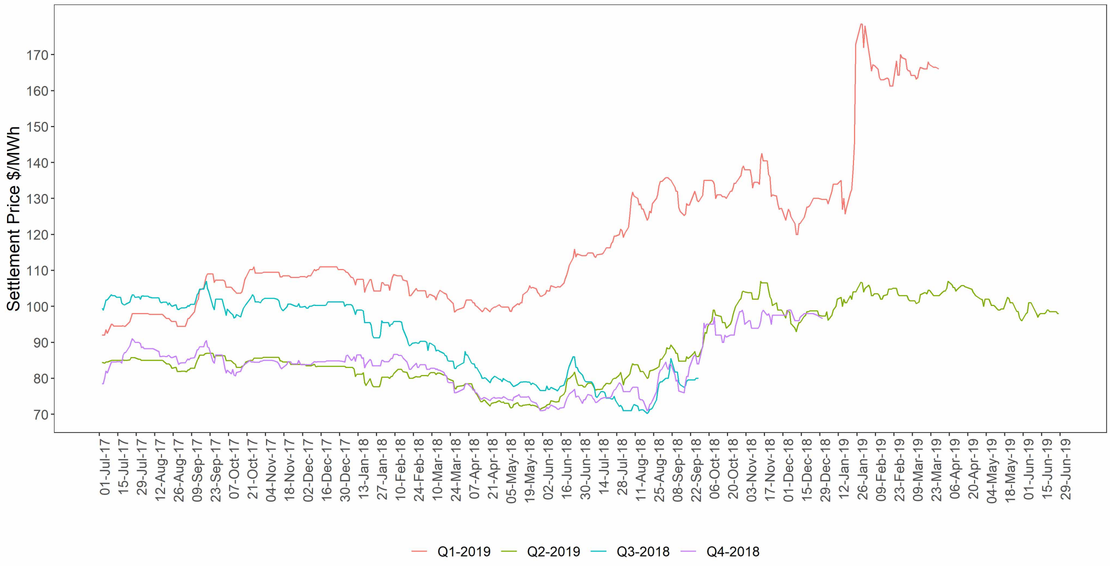
While its primary role is to smooth the cash flows of buyers and sellers to manage these risks, contracts can be considered simply as another means of expressing the price of the same underlying product - electrical energy - meaning that spot and contract prices are intrinsically linked. The price of hedging contracts reflects the balance of expectations as to the level and volatility of future wholesale spot price outcomes, and therefore supports reliability by informing both investment and operational decisions.

Contracts in the national electricity market are traded either on the ASX or bilaterally, and their prices for Victoria and Queensland over the 2018/19 are shown in Figure 2.25 and Figure 2.26 respectively. All regions exhibited a similar long-term trend in contract prices over the course of the period.

These charts illustrate:

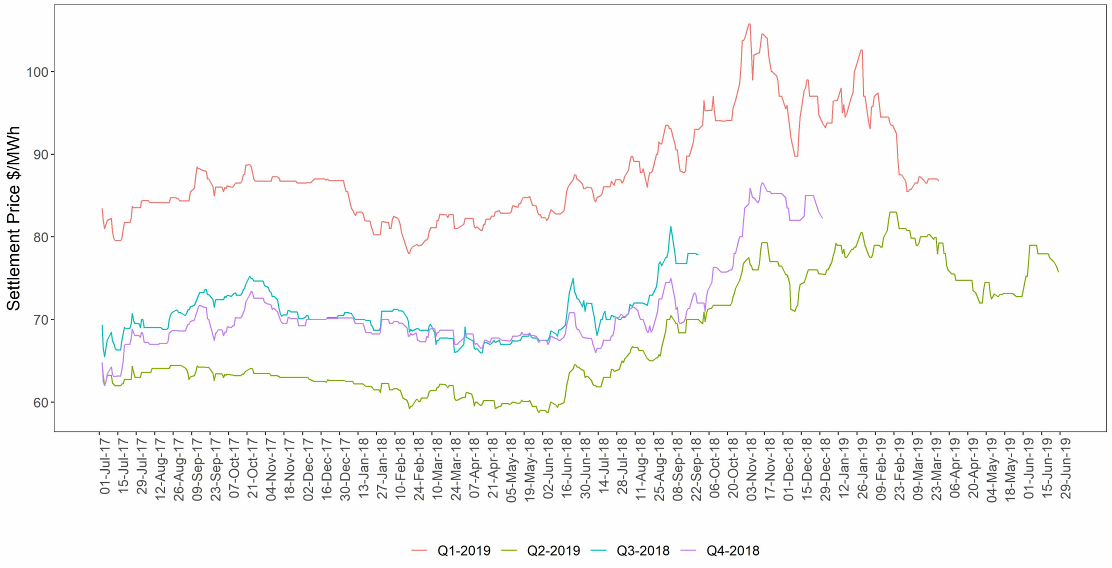
- Contract prices for all quarters remained steady until January 2018, when they began trending downwards.
- Contract prices remaining low for Q2 2019, Q3 2018 and Q4 2018 throughout June over 2018, while prices for Q1 2019 contracts beginning to rise in anticipation of a tight supply/demand balance.
- Price spikes for Q12019 contracts in all regions coinciding with the 24 and 25 January load shedding events in Victoria.

Figure 2.25: ASX settlement prices of 2018/19 financial year base load strips - VIC



Source: AEMC analysis of ASX data.

Figure 2.26: ASX settlement prices of 2018/19 financial year base load strips - QLD



Source: AEMC analysis of ASX data.

2.6.3 Trends in price banding

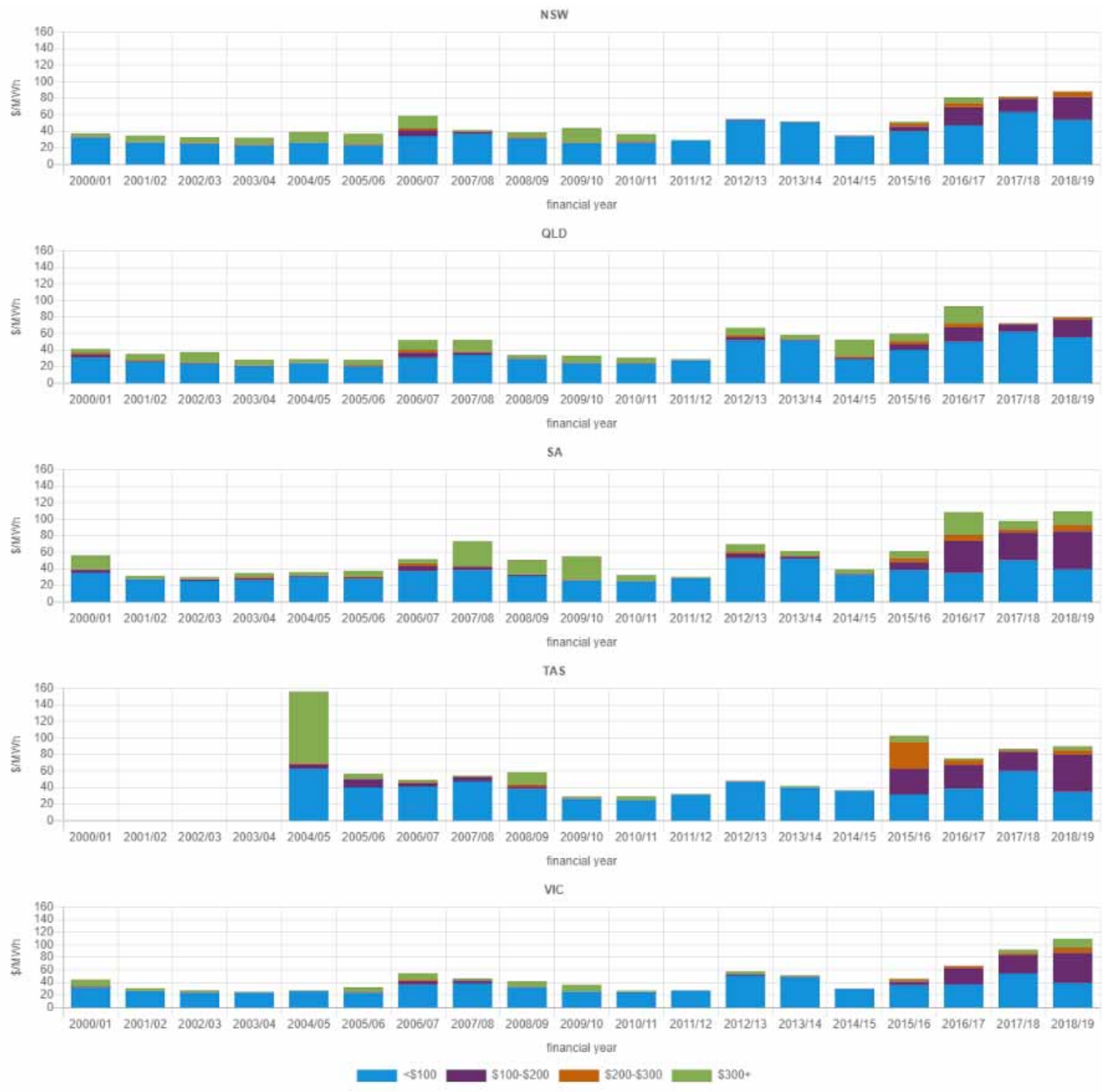
The Panel notes that trends in supply and demand are effecting wholesale market dynamics. On the supply side, the changing generation mix has driven changes in the dynamics of the market, altering the bidding behaviour of market participants. Figure 2.27 shows changes to the prices for electricity in the wholesale market.

The chart shows a trend of an increase in the wholesale prices in the $100 - $200 per MWh band in all NEM regions since 2015/16. These prices are significant contributors to the overall prices in the spot market. The Panel attributes this to:

- Increasing penetration of renewable generation with low short run marginal costs, which is variable and poorly correlated with demand, tends to bid capacity into the wholesale market at low or negative prices.
- As penetration increases, variable plant is likely to increasingly become price setters and price volatility will increase.
- For non-variable plant to recover their long-run costs, spot prices have to be higher when variable generators are not setting the prices, typically at times of higher demand.
- As such, non-variable plant is increasingly recovering long run costs in the $100-$200 bracket of spot prices.

Overall, price periods across the NEM in the $100 - $300 range contributed about 38% to the overall average price in 2018/19, compared in 17% in 2015/16. This has been accompanied by a drop in the impact of larger price spikes (i.e. exceeding $300/MWh), which made up a 6% share in 2018/19 compared to a 17% share in 2014/15.

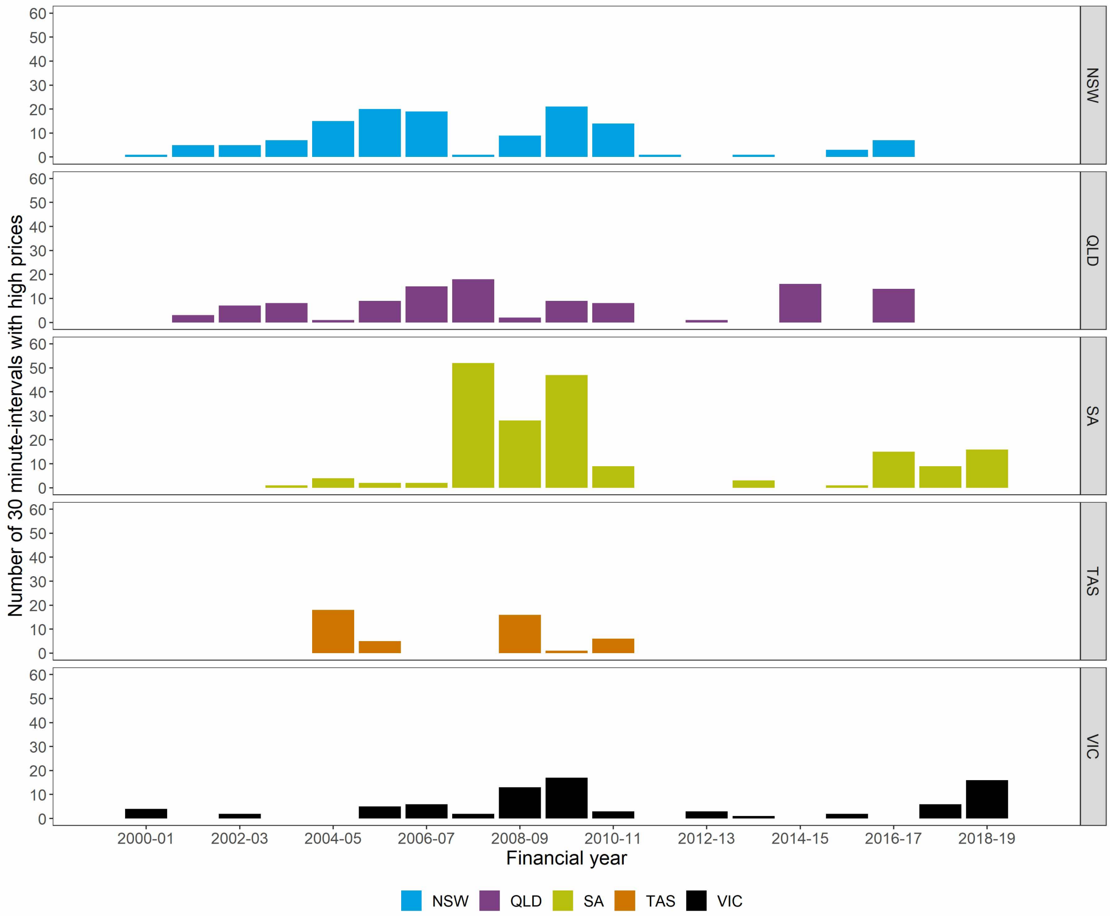
Figure 2.27: Price band contribution to spot prices from 2000/01-2018/19



Source: AEMC analysis of AEMO data.
Note: The data for this chart is available in the AMPR data portal.

Meanwhile, the number of 30 minute intervals where price exceed $5000 has increased in Victoria and South Australia This may reflect a tighter supply-demand balance in these regions, particularly on coincident peak demand days when generation resources can not be appropriately shared across the Heywood interconnector. Other regions have not experienced prices exceeding $5000/MWh over the reporting period.

Figure 2.28: Count of 30 minute price intervals >$5,000

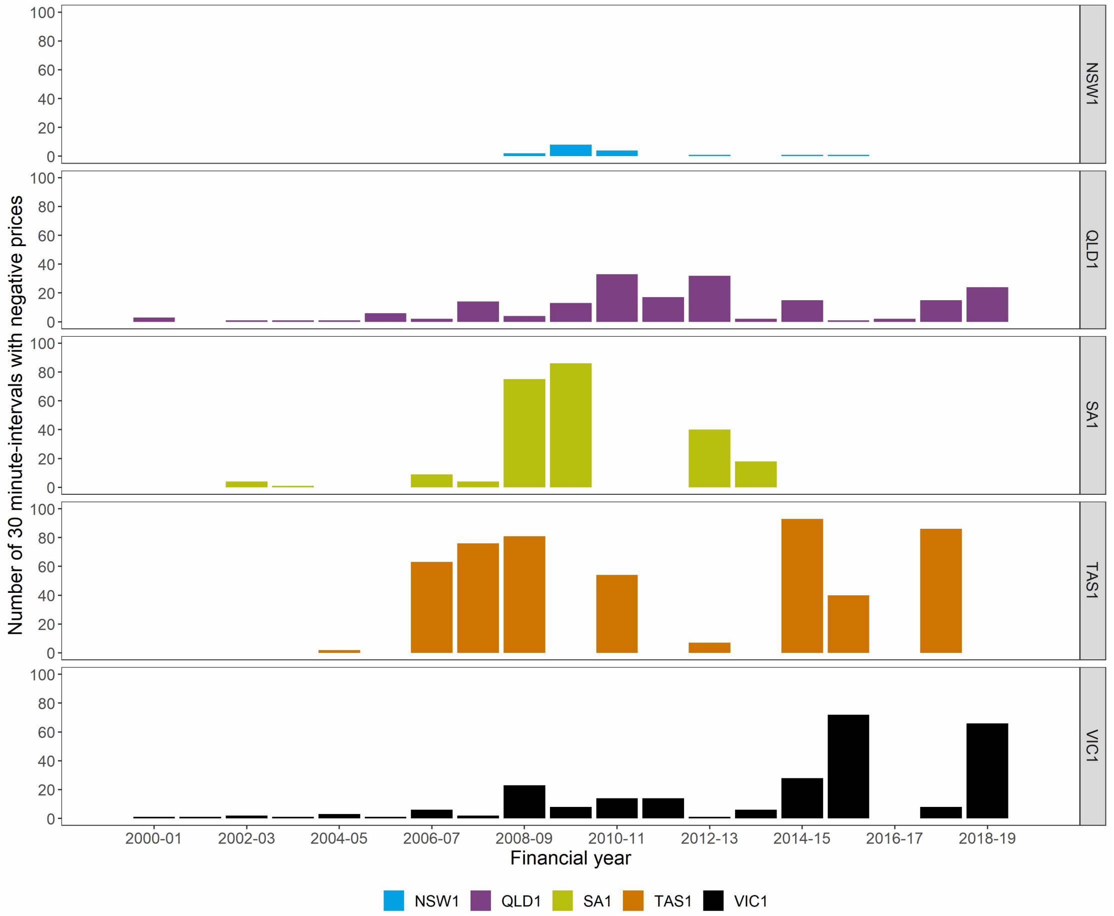


Source: AEMC analysis of AEMO data.
Note: High spot price events occur more frequently in South Australia and Victoria. This reflects the tighter supply and demand balance and also, perhaps, coincident high demand days.
Note: The data for this chart is available in the AMPR data portal.

Trends associated with the number of 30 minute price intervals where prices have been negative are significant in two regions.

- Only Victoria and Queensland experience 30-minute intervals with negative prices in 2018/19.
- Frequently, these negative price periods are either driven by period of high renewable output where traders have not yet adapted to bidding more actively, or it is reflective of instances where interconnection assets are constrained and this leads to an oversupply of least-cost electricity in one region given is unable to export across the interconnector.

Figure 2.29: Count of 30-minute intervals with negative prices



Source: AEMC analysis of AEMO data.
Note: The data for this chart is available in the AMPR data portal.

2.7 Cost of operating the system

The NEM functions primarily to enable the matching of supply and demand for electricity. The wholesale market is where this energy is bought and sold, and is also where the majority of the financial trade in the NEM occurs. In order to provide for a secure and reliable power system, a number of additional costs are incurred, including but not limited to:

- maintaining power system frequency
- having services available to restart the power system if needed
- emergency reserves for maintaining power system reliability
- other services needed to maintain the secure operation of the power system
- costs incurred from intervening in the market, including costs of compensating affected participants

- costs of running and administering the market.

In the reporting period for 2018/19:

- $176m was paid through FCAS markets
- $35.7m was paid for the providers of system restart ancillary services
- $34.2m was paid following the exercise of the RERT.
- $10.6m was paid for network support and control ancillary services.

While these costs are small relative to the total value transacted through the wholesale market, they do represent costs that have to be recovered from market participants, and ultimately consumers. The Panel intends to investigate the extent of these costs, and the trends in these over time, in future AMPRs.

3 RELIABILITY

Reliability in the electricity sector means that the power system has enough capacity to meet consumer needs.[42] That is, the system has sufficient capacity (including generation, demand response and interconnectors) to produce and transport electricity to meet consumer demand.

A reliable power system requires the following:

- efficient investment, retirement and operational decisions by market participants resulting in an adequate supply of capacity to meet demand, plus a sufficient level of reserve or buffer, so demand and supply can be kept in balance, even in the face of shocks to the system
- a reliable transmission and distribution network
- the system being in a secure operating state.[43]

One of the Panel's key responsibilities, set out in National Electricity Law (NEL), is to monitor, review and report on the reliability of the national electricity system and provide advice in relation to the reliability of the national electricity system, at the request of the AEMC. This chapter considers the reliability performance of the NEM over the 2018/19 financial year in line with the Panel's NEL obligations[44] and the review's terms of reference.

This chapter sets out:

- What is power system reliability
- How reliability is delivered
- The reliability performance of the NEM in 2018/19
- Panel insights: challenges to reliability and the work underway to address these

The Panel plays an important role in determining standards to deliver a reliable power system in the most efficient way to minimise costs for consumers. The Panel will use its assessment of reliability to inform its future work plan.

3.1 What is power system reliability?

Reliability issues occur when the balance of demand and supply in a region is tight and there may not be enough generating or network capacity to meet all end user demand for electricity. Historically the NEM has generally provided a high level of reliability as generation and network capacity has been sufficient to meet customer needs, even at times of peak demand. However, there is concern that the power system may be less able to deliver reliable supply under the broader range of scenarios expected in the future.

42 Reliability is an economic construct to the extent that it must be cost-effective for generators and networks to have enough capacity to meet demand.

43 That is, one where the power system is in, or will return to, the NER requirement of a satisfactory operating state within 30 minutes. The "satisfactory operating state" is a defined term under clause 4.2.2 of the NER.

44 Section 38 of the NEL.

The Panel has assessed the reliability performance of the power system in this chapter identified relevant trends going forward.

Discussions about reliability generally focus the power system's capacity to meet peak demand. Peak demand occurs in summer in the majority of the NEM although some jurisdictions, such as Tasmania, experience peak demand in winter. Outside of Tasmania, reliability is predominantly a challenge on hot days, as hot weather can affect both demand and supply. On hot days:

- People tend to use more electricity. Air conditioners in offices and homes substantially increase electricity demand, especially during the working week. The difference between electricity demand on a very hot weekday afternoon, compared to a mild weekday afternoon, can be considerable - and increase exponentially as it gets hotter.
- Electricity generators and the infrastructure used to transport electricity to our homes and offices are put under stress. Many generators become less efficient in hot weather; it is harder to cool thermal plants, and solar and wind plants may produce lower output outside optimal operating temperatures. Some older, more unreliable generators and infrastructure may trip off, or be removed from service especially with accumulated stress from longer-than-usual periods of operation.

The effects of extreme weather on both the supply and demand side are exacerbated when it occurs on consecutive days or in more than one region at once. The 2018/19 summer was the warmest on record for Australia and unusual warmth persisted across March and April.[45] This chapter looks at some of these hot weather events and how they tested the NER's reliability frameworks.

There is also an emerging concern that periods of tightening reserves are starting to coincide with traditional 'shoulder periods'. Generators and TNSPs often schedule maintenance for shoulder periods as temperatures are generally mild and demand during these times is generally lower. However, temperature and demand are remaining higher for longer and shoulder periods are getting shorter. The Panel has considered reserve levels during these milder periods to understand whether there is an increasing risk to reliability when available supply is lower while generators and lines are out of service for scheduled maintenance.

While customers' experiences of power supply interruptions may be the same irrespective of the cause, policy-makers classify supply interruptions based on the cause of the interruption. There are separate frameworks for delivering wholesale reliability and network reliability (these concepts are distinguished below). This AMPR focusses mainly on wholesale level reliability - that is the bulk production and transfer of electricity - as this is most closely related to the Reliability Panel's jurisdiction. It does consider network reliability at a high level at the end of the chapter.

3.1.1 Different types of reliability

Having enough generation and network capacity to meet customer demand does not mean consumers are protected against all power outages - see section 3.1.1. Interruptions can

45 Bureau of meteorology, *Annual climate statement 2019*, temperature section

originate anywhere in the power system—from not having enough generation or storage assets (generation reliability), in the poles and wires that transport power across states and within regions, or in towns and suburbs' power networks that distribute electricity to homes (network reliability). Sometimes supply interruptions can occur due to a technical fault or disturbance (power system security).

The two main types of reliability assessed in this section are:

- Wholesale reliability: Wholesale reliability is one way of referring to power outages caused by insufficient generation or demand response. These are very rare; less than 1 per cent of blackouts to date were caused by wholesale reliability events. When customers experience supply interruptions specifically because demand is higher than available supply, we call the demand that went unmet 'unserved energy'.
- Network reliability: Network reliability is about having enough operational network capacity available to transport electricity to customers who need it. Historically, just over 95 per cent of all interruptions to the power supply have been caused by sudden breakdowns in the grid's poles and wires, typically at distribution level. For example, when a power pole is knocked down in a storm or power lines are damaged in a bushfire.

3.1.2 Links between reliability and system security

A reliable power system will always be secure, however a secure power system will not necessarily be reliable. Power system security is therefore relevant but distinct to power system reliability. Power system security is be explored in chapter 4 however this section introduces security issues as they relate to the Panels' consideration of reliability.

A secure power system is one that operates within defined technical limits. Around 4 per cent of supply interruptions are caused by events that disrupt the frequency and voltage balance in the system. A system security event is generally related to a sudden unexpected failure or removal from service of a power system element (such as a generator or network element). These are known as 'contingency events[46] and the power system is designed and operated to remain secure and reliable during contingency events that occur often enough to be considered credible. If a contingency event occurs that is due to rare combinations of non-credible or unexpected incidents, like large storms removing transmission lines from service coupled with generators tripping off, load may be shed in order to protect the system from a cascading failure, a major supply disruption or black system event.

This chapter focuses mainly on the generation reliability performance and unserved energy. Power system security is discussed in detail in chapter 4**.**

3.2 How is reliability delivered in the NEM

The core objective of the existing reliability framework in the NEM is to deliver efficient reliability outcomes through market mechanisms to the largest extent possible. These mechanisms provide strong financial incentives for participants (generators, retailers,

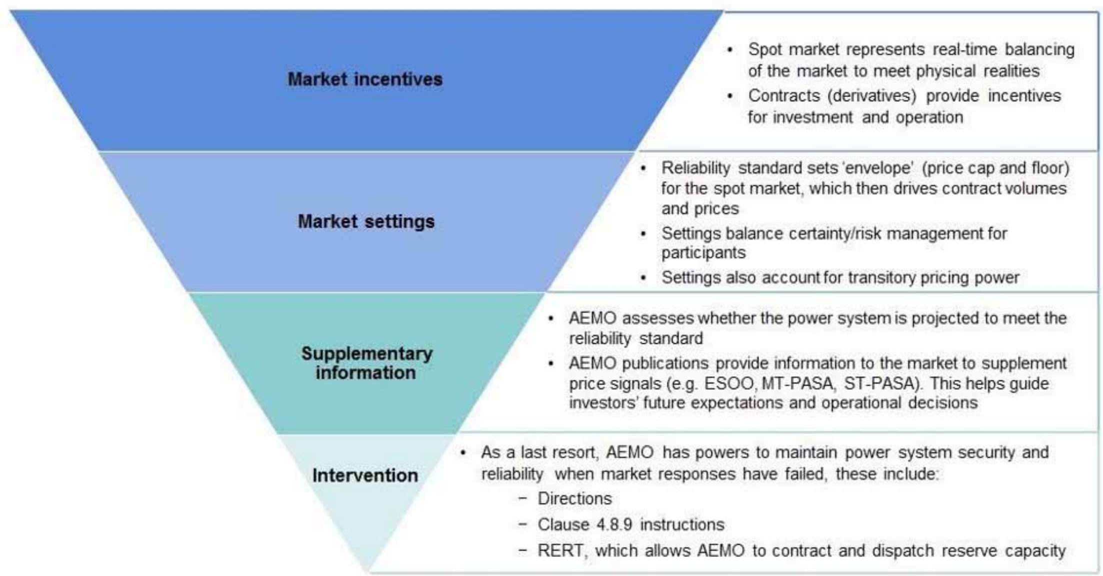
46 A contingency event is defined in clause 4.2.3.(a) of the NER.

aggregators and customers) to make investment, retirement and operational decisions that support reliability.

The NEM is designed specifically with reliability in mind. It is a gross pool market which does not specifically reward capacity, and instead utilises a high market price cap to incentivise operating and investment decisions decision during times of supply scarcity (when reliability is likely to be an issue). The design of the NEM also incorporates a series of standards and settings to guide and inform participant decisions, as well as tools AEMO can use to intervene when needed to maintain reliability.

Figure 3.1 below illustrates how the reliability in the NEM is largely driven through market participants responding to financial incentives and information provided about the need for resources. Interventions are used as a last resort.

Figure 3.1: Reliability framework with escalating series of interventions.



Source: AEMC, *Reliability frameworks review*, July 2018, p. 14.

This chapter will consider the regulatory setting and tools used to underpin the NEM's reliability performance in the 2018/19 financial year.

Some of the key elements of the reliability framework relevant to the Panel's consideration of reliability in this AMPR are explained below including:

- The reliability standard and settings to set expectations
- Spot and contract prices to incentivise investment
- Information to guide decisions
- Interventions as a safety net

Each of these elements are relevant to the outcomes presented in this chapter.

3.2.1 The reliability standard and settings

The reliability standard is a key element of the NER's reliability framework and acts as the overarching objective for the operation of related frameworks. A key role of the reliability standard is to guide various decisions made by AEMO in its day-to-day operation of the market and in turn inform market participant decisions about how to invest and operate their assets. AEMO has the flexibility to evolve and adapt its approach for how it operationalises the reliability standard over time.

The reliability 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 reliability standard is:[47]

> a maximum expected unserved energy (USE) in a region of 0.002 per cent of the total energy demanded in that region for a given financial year.

The reliability standard provides for a limited amount of unmet energy in each year. The standard involves a trade-off between the prices paid for electricity and the cost of not having energy when it is needed. Power systems cannot plan for 100 per cent reliability at all times. There will always be some chance of a security or reliability event and associated unserved energy. Even attempting to achieve 100 per cent reliability would be prohibitively expensive and exceed the value placed on it by consumers.

The reliability standard is an objective which is operationalised in the market through the reliability standard settings. The reliability settings - the market price cap, cumulative price threshold, administered price cap and market floor price - are closely linked to the reliability standard. They form a price envelope for spot prices and protect the long term integrity of the market by limiting the extent to which prices can rise and fall. They are set at a level so as not to interfere with the price signals needed for investment. The reliability price settings for 2018/19 are set out in Table 3.1 below. Details on the determination of these settings can be found in the Reliability Panel's *Reliability standard and settings review 2018.*[48]

Table 3.1: Reliability price settings 2018-19

	VALUES
market price cap	$14,500/MWh
cumulative price threshold	$216,900
administered price cap	$300/MWh
market price floor	-$1,000/MWh

Source: AEMC, *Schedule of reliability settings*, February 2018.

Note: Since 1 July 2012, the NER have required the AEMC to update the values for the market price cap and cumulative price threshold each year by applying consumer price index information published by the Australian Bureau of Statistics. The market price floor has remained at -$1,000 since December 2000.

Note: Descriptions of each price setting can be found in the Reliability Panel's *Reliability standard and settings review*, April 2018, p. 4.

47 Clause 3.9.3C(a) of the NER.

48 On 30 April 2018 the Reliability Panel published a final report for its four yearly review of the reliability standard and settings in the NEM.

3.2.2 Spot and contract prices to incentivise investment

The design of the NEM uses market signals to incentivise operational and investment decisions that allow the reliability standard to be met. The buying and selling of electricity in the wholesale market and in related contract markets is therefore the main mechanism through which reliability is delivered in the NEM.

Spot market prices can currently range between negative $1000 and $14,500/MWh. This wide range of potential prices is part of the NEMs design and supports reliability by allowing for very strong signals for investment in additional capacity during high priced periods.

Market participants use contract markets to manage financial risk by 'hedging' against this spot market volatility. The degree of volatility affects the demand for and value of hedge contracts and, in turn, this provides incentives for investment or retention of plant that is best able to capitalise on that volatility, such as peaking plant and storage solutions. Spot price volatility, and the resulting contract prices therefore creates incentives for an efficient mix of technologies to be deployed to meet the needs of the NEM.

As the supply/demand balance tightens, spot and contract prices will rise within the price envelope defined by the market price cap and floor specified in Table 3.1. These price signals are meant to encourage new investment and increased generation which consequently help relax the tight supply/demand balance.

3.2.3 Information to guide decisions

AEMO publishes various materials to help inform market participants and any other interested parties on matters pertaining to the reliability standard. This information is an important part of the reliability framework that helps guide and inform market participants' expectations of the future, enabling more efficient investment and operational decisions.

For example, AEMO is required to publish the electricity statement of opportunities (ESOO) which considers the supply and demand balance in the NEM over a 10-year period.[49]

AEMO also publishes shorter term forecasts including short and medium term projected assessment of system adequacy and pre-dispatch pricing forecasts that help participants and AEMO assess reserve margin and the adequacy of generation capacity to meet demand. The Panel discusses these in more detail in section 3.4.6.

Another important part of the information provided to the market also comes in the form of AEMO notices signalling low reserves through LOR notices. During the 2018/19 financial year, lack of reserves were calculated under a new framework that allows the AEMO to use either the existing contingency-based deterministic approach, or one that is probabilistic and can reflect the changing nature of the power system.[50] There are three levels which inform the market of increasing severity of reliability challenges and the likely actions AEMO will take in responding to them. These are:

49 AEMO, *Electricity statement of opportunities*, August 2019

50 The key parts of the Declaration of lack of reserve conditions rule, including AEMO's Reserve level declaration guidelines, were introduced in January 2018.

- LOR1 is the bigger of the size of the two largest credible contingency events as a minimum and the forecast uncertainty measure (FUM) - explained in section 3.4.3.
- LOR2 is the bigger of the largest credible contingency event and the FUM.
- LOR3 which means that there is insufficient supply to meet demand. An actual LOR3 represents load shedding.

LOR conditions in 2018/19 are explored in this chapter as are a number of intervention events that rely on the LOR framework.

3.2.4 Interventions as a safety net

While the reliability standard and market design use market prices and commercial incentives to drive reliability outcomes, AEMO can intervene to maintain a reliable power system if the market does not look likely to provide enough supply to meet demand. AEMO has a range of tools it uses when intervention becomes necessary.

Prior to formally intervening in the market AEMO's first step is generally to engage in informal negotiations with market participants to alleviate any supply shortfalls. As a last resort AEMO may have no other choice but to intervene in the market more directly to deal with actual or forecast shortages. Interventions include:

- Reliability and Emergency Reserve trader (RERT) allowing AEMO to contract for reserves ahead of forecast breach of the reliability standard.
- Directions under NER clause 4.8.9 allowing AEMO to direct a generator to increase its output, direct a large energy user to temporarily disconnect its load or reduce demand, or instruct load shedding.
- Instructions, under NER 4.8.9 including involuntary customer load shedding as a last resort to avoid the risk of a wider system blackout, or damage to generation or network assets.

Direct intervention by AEMO is a last resort as it may distort market prices and the signals used by market participants to make operating and investment decisions relevant to reliability. For this reason, AEMO's interventions are designed to minimise market distortion. In certain circumstances, intervention pricing is applied to preserve market incentives.

The Panel notes that following the 2018/19 financial year, the Retailer reliability obligation (RRO) was introduced to assist in delivering reliable supply. The RRO requires retailers to contract for or invest in dispatchable and 'on demand' resources if AEMO forecasts a reliability gap three years ahead.[51] The Panel will explore the impact the RRO is having on reliability outcomes in next years' AMPR.

3.3 Summary of reliability outcomes in 2018/19

51 Participants do not have to "deliver" the reliability Standard to comply with the RRO.

BOX 5: SUMMARY OF RELIABILITY OUTCOMES IN 2018/19

Reliability outcomes

- The reliability standard was not breached in any region.
- There was unserved energy in Victoria and South Australia[i]
- There was one major reliability event across 24 and 25 January 2019 where the RERT was used and load shedding was instructed.
- The number of lack of reserve notices issues by AEMO was lower than in previous years. Of the notices issued, the majority were in summer when demand levels are typically higher. About half of the reserve notices were issued because of uncertainty relating to the forecast output of intermittent generation. A majority of forecast lack of reserve conditions did not eventuate, which may indicate the market responding to forecast tight supply/demand conditions.
- AEMO had to call on emergency reserves (i.e. reserves procured through the RERT) twice in the reporting period. AEMO has had to increasingly use emergency reserves to maintain a reliable power system. The price of the reserves procured through the RERT decreased compared to last year.
- Over the reporting period, AEMO did not direct any market participants for reliability purposes. However, AEMO did issue instructions for load to be shed on 24 and 25 January 2019.
- Intervention pricing was used for reliability purposes as part of RERT activation (twice) and an administered price cap (APC) was put in place after the cumulative price threshold (CPT) was triggered.
- Centrally determined forecasts of demand and intermittent generation output, which are key components of the reliability framework, are as accurate as they were in past years. Given the growth of intermittent generation, it is important that these forecasts remain accurate.
- Over the reporting year, a number of new reporting requirements came into effect. These including the introduction of a DER register, and two rule changes, one to require generators to provide three years notice before closing and one to improve transparency relating to the connection of new projects. The information provided through these avenues will assist participants in making investment and operation decisions, and help AEMO operate the power system reliability.

Panel insights

- While the reliability standard has not been breached, reliability is becoming more challenging to maintain as the supply/demand balance tightens.
- There have been large influxes of new intermittent generation, however, due to the variable nature of this, not all of this generation is necessarily available to help meet consumer demand when they need it. In addition, over the reporting period, a number of thermal generators were not available at times of tights supply and demand balance.

- The Panel is concerned that AEMO is having to increasingly relying on tools like emergency reserves to maintain power system reliability as this indicates the market is not delivering enough supply to meet consumer demand.
- Market incentives and community concern are signalling for new investment in generation and demand response that can be available at times of peak demand, however private sector investment in response to these signals is not as strong as might be expected.
- The Panel notes that to support reliable outcomes into the future, focus should be given to:
  - **Adapting to changing power system conditions and community expectations:** as the power system changes, the approach to delivering reliable supply may also need to change. For example the most recent summer has seen the NEM draw on all options to withstand storms, drought, bushfires and higher and higher temperatures.
  - **Improving coordination and total system thinking:** the investment pipeline is robust with over 60GW [i] [i] of committed or proposed generation on the books. The challenge is to encourage investment in a range of different technologies and locations so that the total system costs are minimised and the benefits for customers maximised.
  - **Fostering regulatory and policy certainty:** alongside technological change, regulatory reforms and government policies will continue to transform the power system, influence private sector investment and impact on reliability outcomes into the future. Regulatory and policy certainty wherever possible, including integrating emissions and energy policy, will help smooth the power system transition.
- Focusing on these three areas will be a step towards encouraging the new wave of investment necessary to underpin reliability in the NEM.

Note: [i]There was no actual load shedding in South Australia, but under the pain sharing arrangements set out in the NER, 25 per cent of the load shedding need in January 2019 was allocated to South Australia - more detail in section 3.4.1 below.

Note: [iiii] [i]The Panel notes that a significant proportion of "proposed" generation will not progress to committed stage or ultimately connect to the power system.

3.4 Reliability outcomes in 2018/19

The Panel has considered the following metrics as a way of assessing how the power system performed in terms of reliability in the 2018/19 financial year:

- **The reliability standard and unserved energy:** whether the standard was met and the amount of customer demand in 2018/19 that was not supplied within a region due to a shortage of generation or interconnector capacity, and the forecasts for unserved energy in the future.[52]

52 Unserved energy excludes demand for energy that was not met due to security related issues or due to failures of the intraregional transmission and distribution networks.

- **Reliability events:** the number of occasions in 2018-19 where customers experienced supply interruptions specifically because demand was higher than available supply
- **Energy market reserve levels:** the amount of spare capacity that was available in 2018-19, giving consideration to amounts of generation, forecast demand, demand response and scheduled network service provider capability.[53]
- **Use of AEMO interventions and powers:** whether AEMO intervened in the market in order to maintain reliable supply using the three key intervention mechanisms related to reliability: the RERT, directions and instructions, [54] and controlled load shedding.
- **Accuracy of forecasts and information:** how accurate forecasts and other information have been. Forecasts help inform operational and investment decisions to deliver reliability.
- **Network performance:** outage minutes, upgrades and other performance outcomes from interconnectors, transmission networks and distribution networks.

As in previous AMPRs, these indicators have been examined to assess the overall reliability of the NEM.

3.4.1 The reliability standard and unserved energy

While customers can experience supply interruptions for a variety of reasons, this section focuses on incidents where supply interruptions occur because there is not enough supply to meet demand. As discussed in section 2.5.1 reliability-related outages have been responsible for less than 1 per cent of supply interruptions over the last decade. Reliability-related outages are known as 'unserved energy'.

Unserved energy is measured against the reliability standard.[55] The standard is expressed as the maximum expected level of unserved energy of 0.002% in a region for a given financial year.[56]

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

53 Reserves are defined in Chapter 10 of the NER. There are two types of reserves in the NEM: Market reserves that participate in the market and, at a high level, can be expressed as the balance of supply over demand; (ii) Out-of-market reserves (for example, the RERT) are one of the available interventions permitted to be used by AEMO when it identifies, through a series of processes set out in the rules, that the market will not deliver enough market reserves to meet the reliability standard.

54 An instruction differs from a direction in the types of market participants AEMO can require to take action and the nature of the action taken. AEMO issues directions to generators to increase (or decrease) their output or a scheduled load to decrease (or increase) consumption. Instructions generally involve AEMO requiring a network service provider or a large energy user to shed load.

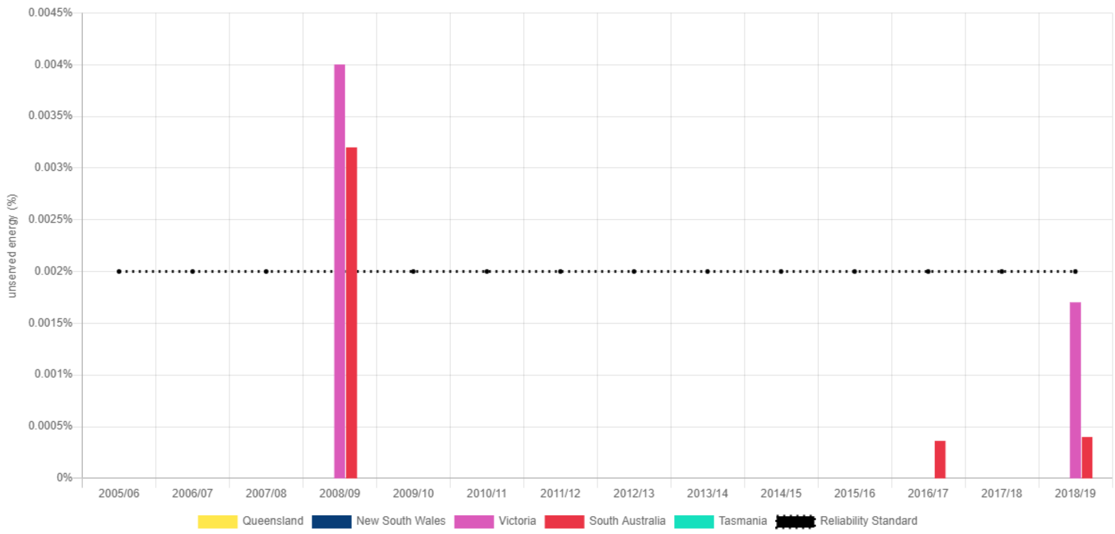
55 Unserved energy is expressed as a percentage of the total annual energy consumed in each region.

56 Clause 3.9.3C of the NER.

Setting the level of the reliability standard involves a trade-off, made on behalf of consumers, between the prices paid for electricity and the cost of not having energy when it is needed.[57]

Historically, there has been very little unserved energy in the NEM. However, in recent years significant changes occurred on the supply side of the NEM due to the integration of large volumes of intermittent renewable generation, while peak demands have not changed materially. Figure 3.2 illustrates the NEM's overall reliability performance by comparing unserved energy in each region in the NEM over the past decade, to the reliability standard.

Figure 3.2: Unserved energy in the NEM



Source: AEMC analysis of AEMO data.
Note: The data for this chart is available in the AMPR data portal.

As show in Figure 3.2 the reliability standard was met in all regions in 2018/19, however there was unserved energy observed in Victoria (0.0017%) and in South Australia (0.0004%). The unserved energy in both regions can be attributed to the load shedding in Victoria on 24 and 25 January 2019, detailed in section 3.4.2. For the purposes of measuring the reliability standard, unserved energy is allocated using the pain sharing arrangements set out in the NER.[58] Under these arrangements, any load shedding must be proportional to the aggregate demand of the effected regions. On this occasion, approximately 75 per cent of the load shedding need on 24 January 2019 was to be met by Victoria and 25 per cent by

57 A higher reliability standard (that is, expected unserved energy less than 0.002 per cent) would in turn derive a higher market price cap (all things equal) which in turn should incentivise a supply- or demand-side response such as investment and operational decisions in generation, improving reliability. This may also improve liquidity in the contract market, as participants potentially would be exposed to higher risks and would prefer to have more certainty through entering into contracts. However, a higher market price cap would expose consumers that participate directly in the market, and retailers, to higher average spot prices. In turn, in a competitive market, retailers will recover these higher average spot prices from end consumers. The trade-off is therefore between two sets of costs, both of which are ultimately borne by consumers.

58 Under clause 4.8.9 (i) of the NER, AEMO must implement any necessary load involuntary shedding in an equitable manner, in accordance with guidelines established by the Reliability Panel - the *Guidelines for management of electricity supply shortfall events,* December 2009.

South Australia. In practice, given the reserve need was met by shedding one large customer in Victoria, South Australia did not actually experience any load shedding during this event.

For the purpose of calculation of the reliability standard, the shortfall amount in each region is used, rather than the actual load shed.

In the past decade, there have been two occasions where levels of unserved energy exceeded the reliability standard. These events occurred in Victoria and South Australia in 2008/09.

Forecast unserved energy

AEMO publishes the ESOO on an annual basis.

The ESOO includes projections of future expectations of unserved energy (USE). These projections of USE are provided to the market with the intention of eliciting a response from market participants to address any projected shortfall.

AEMO published the 2019 ESOO in August 2019. As required under clause 3.13.3(q) of the NER, the ESOO includes projections of aggregate demand and energy requirements for each region, generating capabilities of existing and planned units, anticipated generator retirements and operational and economic information.[59]

The 2019 ESOO identified key insights for the 2019/20 summer, including:

- a tightly balanced supply and demand in several NEM regions for summer 2019/20, with all regions other than Victoria expected to meet the current reliability standard of expected USE not exceeding 0.002%
- unplanned outages of Loy Yang A2 (500 MW) and Mortlake 2 (259 MW) pose a significant risk of insufficient supply that could lead to involuntary load shedding.

Figure 3.3 below is taken from AEMO's 2019 ESOO and shows forecast unserved energy in the next 10 years in Victoria, New South Wales, and South Australia. This forecast is based on the neutral scenario demand forecasts. The Panel notes that this forecast assumes no new generation projects being developed beyond those that are currently committed.

59 From 2019 and onwards, the ESOO will include reliability forecasts identifying any potential reliability gaps for each of this financial year and the following four years, as defined according to the Retailer Reliability Obligation, and an indicative reliability forecast of any potential reliability gaps for each of the final five years of the 10-year ESOO supply adequacy forecast.

Figure 3.3: Forecast unserved energy outcomes 2019-20 to 2028-29

Source: AEMO, *2019 Electricity Statement of Opportunities*, August 2019, p. 10.

The 2019 ESOO forecast, in the absence of an appropriate market response, that there would be:

- challenges to reliability and meeting retailer reliability obligation requirements following the closure of Liddell Power Station in NSW.[60]
- expected unserved energy in New South Wales, rising to 0.0017% in 2023/24 and remain at this level until later in the decade, where expected unserved energy will rise again in 2028-29 as projected EV uptake puts upward pressure on demand
- expected unserved energy in South Australia which increases slightly as the two remaining units of Torrens A are mothballed from 2020/21 and Osborne Power Station is decommissioned in 2023/24.
- contributions from new renewable generation entering the market that deliver only a small improvement to the reliability outlook. Victoria will remain susceptible to uncontrollable, high impact events like prolonged or coincident generator outages in the short term, but expected unserved energy is forecast to steadily decline as new generation fleet are commissioned to meet the Victorian Renewable Energy Target (VRET)[61]

60 The 2019 ESOO modelling incorporates the announced retirements of the Torrens Island A Power Station in South Australia (480 MW, between 2020 and 2021), Liddell Power Station in New South Wales (450 MW in April 2022 and 1,350 MW in April 2023), and Osborne Power Station in South Australia (172 MW in 2023/24).

61 The VRET was increased to 50 per cent by 2030 in October, 2019. The VRET is part of a suite of policy packages that seek to deliver energy investment in Victoria, including the Victorian Renewable Energy Auction Scheme (VREAS), which supported 6 new renewable projects totalling 928 megawatts in September 2018. More information can be found at: https://www.energy.vic.gov.au/renewable-energy/victorian-renewable-energy-auction-scheme

- growth in forecast demand in Queensland starts to see some risk of unserved energy, but well below the levels forecast for other mainland regions.
- Tasmania has no forecast unserved energy across the entire modelling horizon.

Forecast unserved energy is a direct indicator of future reliability. The Panel notes that the challenges ahead are driven in large part by the retirement of Australia's aging thermal fleet and the need for sufficient replacements to enter the market to meet the needs of consumers.

While the reliability standard and unserved energy are an important method for assessing reliability performance in the NEM, it is not the *only* way. In the rest of this chapter, the Panel examines *how* reliability is being provided, rather than just the total sum of unserved energy.

3.4.2 Reliability events in 2018/19

A reliability event for the purposes of this report is one where there was insufficient generation, demand response or interconnector capacity to meet consumer demand.

In 2018/19, there was one reliability event that occurred across two consecutive days.[62] Prior to this, there had only been three other reliability-related events in the last decade: in South Australia in 2008/09 and 2016/17, and in Victoria in 2008/09 and 2018/19.

The event is described briefly in this section. The use of intervention mechanisms to manage the event are explored in section 3.4.4 and section 3.4.5 below.

25-25 January 2019 reliability events in Victoria

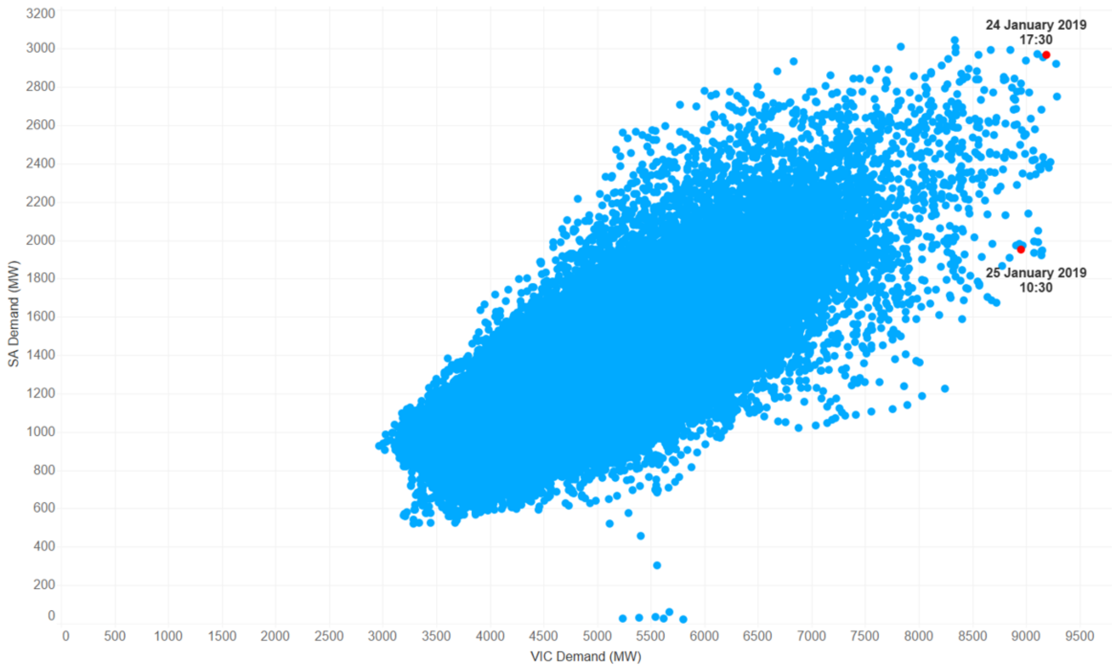
On 24 January 2019, temperatures reached 41ºC in Melbourne and 48ºC (a new record) in Adelaide. This resulted in high electricity demand in Victoria and South Australia, especially in the late afternoon when air conditioner usage reached its peak. On 25 January 2019 temperatures stayed high in Victoria reaching 43ºC and pushing demand higher than had been forecast. On both days there were several generator outages (planned and unplanned due to unexpected equipment failures and urgent maintenance activity). Reduced generation capacity meant there was not enough power generation in the South Australia and Victoria regions to meet customer demand.

This combination of higher than expected demand along with generator outages resulted in a reliability event as there was insufficient supply available to meet consumer demand.

Figure 3.4 below compares South Australian and Victorian demand across all intervals between July 2014 and July 2019, highlighting the level of demand in the half hour interval before the RERT was activated on each day.

62 It is AEMO's role to determine whether an event is defined as a security or reliability event.

Figure 3.4: Coincident South Australian and Victorian demand 1 July 2014-1 July 2019



Source: AEMC analysis.
Note: This chart highlights (in red) the level of demand in SA and Victoria half an hour before the RERT was activated on 24 and 25 January 2019.

Figure 3.4 shows that on 24 January 2019 demand was close to historic highs in both regions. On 25 January 2019, while demand in South Australia was much lower than its historical peak, it remained at close to peak demand in Victoria. The extreme heat on consecutive days was a significant challenge for reliability both in terms of the stresses placed on the physical elements making up power system but also for the frameworks in the NER that are designed to maintain reliability on such occasions. It was particularly challenging to have high coincident demand in both regions as this meant market reserves could not be easily shared between the regions.

Detailed event reporting can be found on AEMO[63] and the AER's websites.[64]

In this AMPR the Panel has focussed on the following tools within the reliability framework that were used to maintain power system reliability during this event. These are explored in detail in relevant sections below and included:

- RERT contracts were activated in response to the forecast tight supply and demand conditions. More detail is available in section 3.4.4.

63 AEMO, Load Shedding in Victoria on24 and 25 January 2019 operating incident report, April 2019.

64 The AER has published separate reports relating to the 24 January 2019 and 25 January 2019 pricing events.

- An actual lack of reserve 3 condition was declared which resulted in controlled load shedding and led to intervention pricing being implemented. More detail on lack of reserve conditions is available in section 3.4.5 and on load shedding in section 3.4.5.
- The cumulative price threshold was breached due to sustained high prices on both days, and an administered price cap was put in place. More detail of these intervention pricing events is available in section 3.4.5.

The load shedding event in Victoria on 24-25 January 2019 resulted from the fact that there was insufficient capacity to meet customer demand. It was the only reliability-related event for the 2018/19 reporting period.

The Panel notes that the conditions experienced on 24 and 25 January 2019 were extreme and presented significant challenges for the operation of the power system. Unfortunately, under extreme conditions the supply of electricity to consumers can be effected. Notwithstanding the impact this event had on customers, it also demonstrated that the reliability framework operated as it should have and a combination of market reserves, emergency reserves and load shedding used by AEMO meant that the reliability standard was not breached despite the extreme conditions.

3.4.3 Market reserve levels

Market reserve levels refer to the amount of spare capacity available given amounts of generation, demand and demand response at any point in time. In simple terms, market reserves can be thought of as the "buffer" that is made available by the market as part of the usual operation of the power system.

A market reserve level indicates the difference between available resources in the market to meet demand for energy, and the level of energy demanded. Market reserves help manage unplanned system developments, such as the loss of a large generator or a sudden increase in demand.

AEMO uses its medium-term projected assessment of system adequacy (MT-PASA) reports to provide regular assessments of any projected shortage of market reserves that may result in a failure to meet the reliability standard. This enables market participants to make decisions about supply, demand and outages of transmission networks for periods up to two years in advance.

In the short-term (from real time to seven days ahead of real time), AEMO conducts its short-term PASA process which includes forecasts of the lack of reserve (LOR) conditions to inform the market of a potential market shortage. This can encourage a response from market participants to provide more capacity into the market. For example, generators may offer in more supply, or consumers can reduce their demand. Both responses have the effect of improving market reserve margins, and helping to maintain power system reliability.

As real time approaches, and greater certainty is available to AEMO regarding demand and supply conditions, AEMO may declare that there is an actual LOR condition in effect. These actual LOR notices signal to the market there is either a present or potential future shortage of market reserves.

A new LOR framework was introduced in February 2018,[65] which included a move to a probabilistic approach to assessing low reserve levels. Under the new framework AEMO is also required to report on the implementation of the guidelines, and to provide analysis of how the LOR framework is operating during the relevant reporting periods. The reports are published within one month following each calendar quarter, and must specifically include:

- AEMO's observations of any trends in when and why LOR conditions are being declared under the reserve level declaration guidelines
- a summary of the leading factors or causes of any LOR conditions declared.

The 2018/19 reporting period is the first where such LOR reports are available for the full duration of the reporting period.[66]

Total actual LOR notices

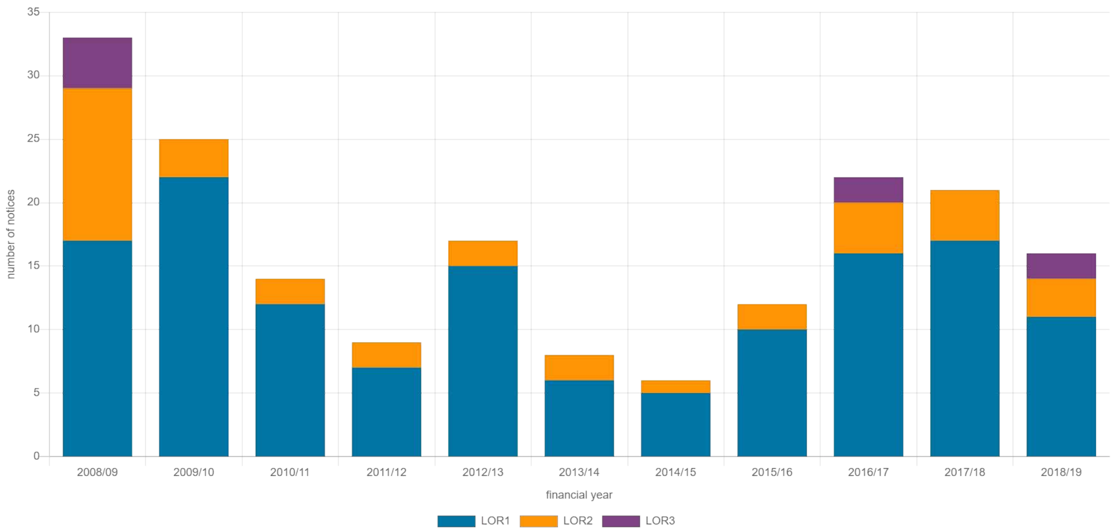
Figure 3.5 shows the number of actual LOR notices issued in the NEM since 2008/09. This figure shows that:

- there were 16 LOR notices issued over the reporting period, down from the 21 notices issued in 2017/18.
- there was a drop in the number of actual LOR1 market reserve notices issued (from 17 in 2017-18 to 11 in 2018-19)
- There was a slight drop in the number actual LOR2 market reserve notices issued (from 4 in 2017-18 to 3 in 2018-19)
- there was an increase in actual LOR3 conditions (from 0 in 2017-18 to 2 in 2018-19), reflecting load shedding that was instructed in this reporting period.

65 AEMC, *Declaration of lack of reserve conditions - final determination*, December 2017.

66 Quarterly lack of reserve framework reports can be found on the AEMO website here: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Power-system-operation/NEM-Lack-of-Reserve-Framework-Quarterly-Reports

Figure 3.5: Number of actual lack of reserve notices



Source: AEMO, *NEM Lack of reserve framework quarterly reports*.
Note: The data for this chart is available in the AMPR data portal.

Lack of reserve forecasts and the forecast uncertainty measure

In the 2018/19 reporting period, AEMO started publishing its NEM Lack of Reserve Framework quarterly reports which provide information on the use of AEMO's Forecast Uncertainty Measure (FUM) in declaring LOR conditions.

The FUM introduces a probabilistic element into the determination of LOR levels alongside the traditional deterministic approach which allows for the impact of estimated reserve forecasting uncertainty in the prevailing conditions when calculating the LOR levels.[67] These estimates are made on the basis of modelling past reserve forecasting performance for demand, output of intermittent generation and availability of scheduled generation.

Accounting for the FUM, LOR levels are now calculated as follows:[68]

- LOR1 is the bigger of the size of the two largest credible contingency events as a minimum and the FUM
- LOR2 is the bigger of the largest credible contingency event and the FUM
- LOR3 is unchanged.

AEMO's NEM LOR framework quarterly reports provide a detailed summary of the forecast, actual and cancelled lack of reserve notices issued to the market, the time and date they were issued, the required and available megawatt reserves at the time of the time, and whether the notice level was issued by breaching the reserves required as measured

67 With the addition of the FUM, LOR levels are triggered on the basis of the largest of the distinct credible contingency based approach and the forecast uncertainty measure.

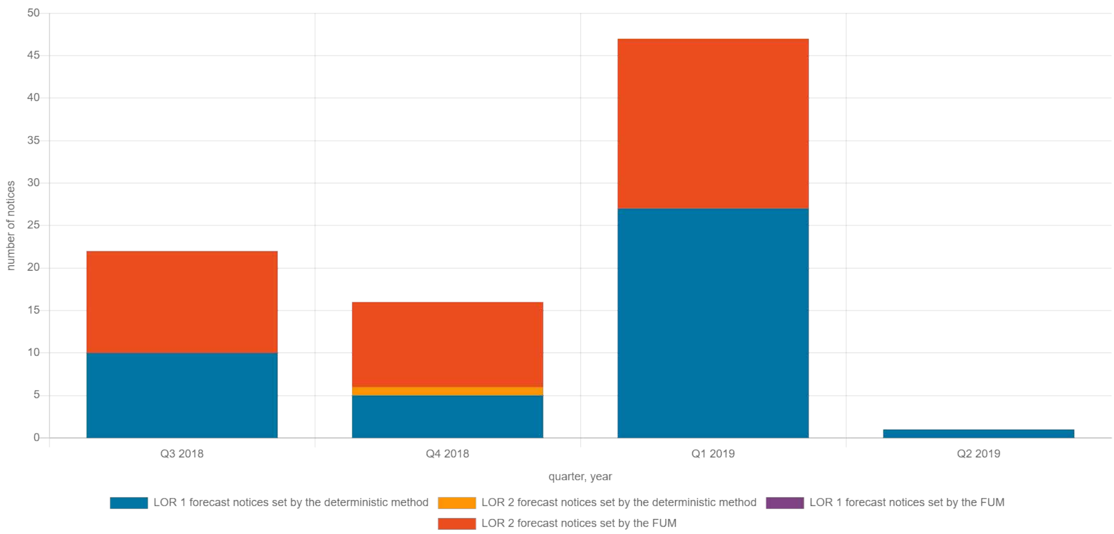
68 AEMO's Reserve level declaration guidelines, including the three conditions, were introduced in January 2018.

deterministically (single and two largest credible contingencies in each region) or probabilistically (by the FUM).

Figure 3.6 illustrates which measure set the LOR level. Over the course of the 2018-19 reporting period, 44 forecast notices were set deterministically based on credible contingencies, while 42 were set probabilistically using the FUM.

Of the 44 notices set deterministically, 43 were for LOR1 levels and 1 was for an LOR2 level, while of the 42 set probabilistically, all were for LOR2 levels.

Figure 3.6: Forecast notices set by the deterministic method vs the Forecast Uncertainty Measure



Source: AEMO, *NEM Lack of reserve framework quarterly reports*.
Note: The data for this chart is available in the AMPR data portal.

The Panel notes that these results show that uncertainties including intermittent generation, weather, demand and scheduled generation, exceed the deterministic forecast of required market reserves almost half of the time in the reporting period. This is likely to become increasingly prominent as greater amounts of intermittent generation enter the market. This marks a potential shift in the operation of the reliability framework. Previously, it was the potential loss of large generating units that signalled a potential shortage of market reserves. This new dynamic suggests that it will increasingly be short term variability of intermittent generation output that could result in shortages in market reserves. This highlights the importance of continuing to improve the understanding of the short term operation of intermittent generation for maintaining a reliable power system. In section 3.4.6 of this report, the Panel looks at the accuracy of forecasts of wind and solar output.

As this is the first year that the FUM has been in effect, the Panel will use future AMPRs to observe trends relating to the FUM and the declaration of LOR conditions.

Lack of reserve notifications and market response

LOR notices are an important market signal. They notify the market on a short term basis when more reserves may be required to maintain the reliability of the system and due to a potential tightening of supply and demand, spot prices are likely to be high.

AEMO's LOR framework quarterly reports provide information on why forecast notices of LOR conditions were cancelled. AEMO lists a variety of different reasons why a LOR notice may be cancelled, predominantly due to changed conditions in the market. These reasons for cancellations have been grouped in Table 3.2.

Table 3.2: **Reasons issued for cancelling LOR notices**

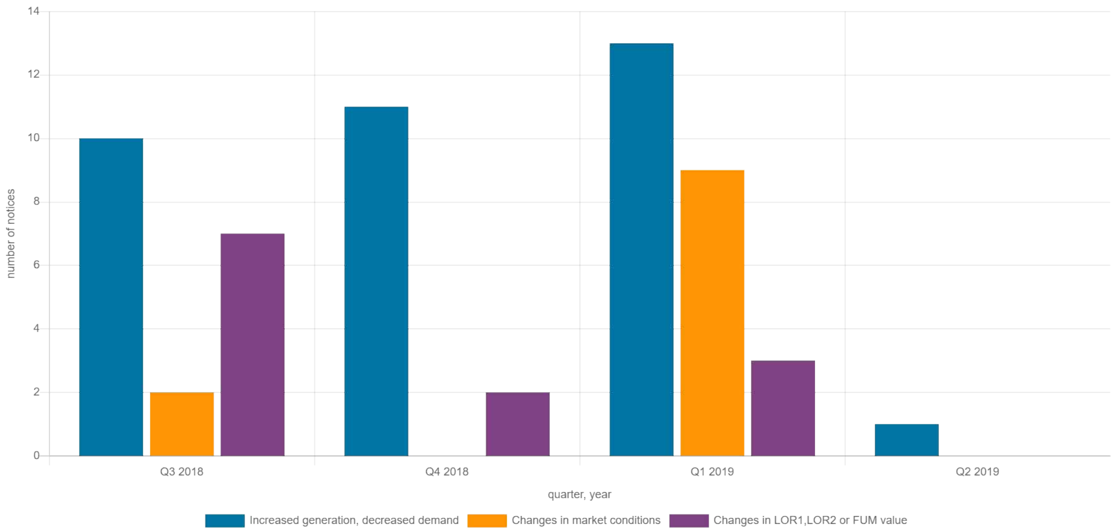
CANCELLED DUE TO A CHANGE IN MARKET CONDITIONS	CANCELLED DUE TO CHANGE IN LOR LEVEL CLASSIFICATION THRESHOLD	CANCELLED DUE TO OTHER REASONS
Increase in generation plant availability	Reduction in the FUM value	Cancellation of actual conditions
Decrease in forecast demand	Reduction in LCR1/LCR2 value	
Decrease in forecast demand and increase in generation availability	Level reclassification	
Inter-regional effects		

Source: AEMO, *NEM Lack of reserve framework quarterly reports*.

Using this information, the Panel has assessed whether there was a potential market response following the issuing of a lack or reserve notice. Notices that were cancelled due to "increase in generation plant availability" or "decrease in forecast demand and increase in generation availability" may indicate instances where the market responded to forecast tight supply/demand conditions. This was compared against the number of cancellations issued due to a reclassification of the LORs required either deterministically or probabilistically, and the number of cancellations due to other changes in market conditions, such as decreases in forecast demand, or inter-regional effects on interconnectors.

Figure 3.7 shows the most common reason for cancellation of a forecast LOR notice in each quarter was due to a market response. While these are relatively broad categorisations of why LOR conditions were cancelled, it does reflect the operation of the reliability framework, which seeks to provide market participants with information that informs operational decisions they may make approaching real time. This indicates that, over short-term periods, market participants are responsive to market signals currently established under the reliability framework in a manner that improves market reserve levels.

Figure 3.7: Reasons for cancellations of lack of reserve notices



Source: AEMO, *NEM Lack of reserve framework quarterly reports*.
Note: The data for this chart is available in the AMPR data portal.

Reserve levels during shoulder periods

As noted in section 3.1, reliability issues are generally associated with peak load conditions.

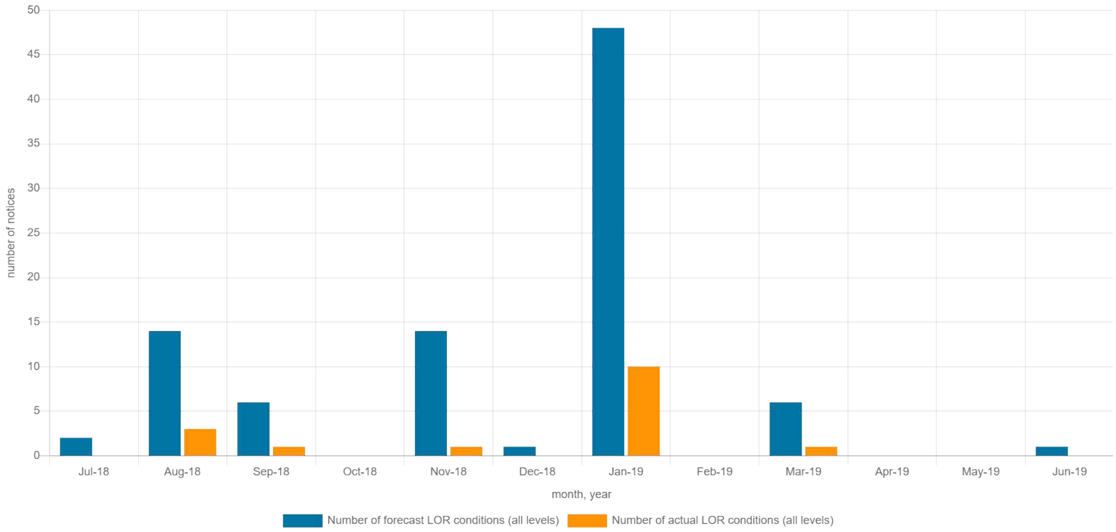
However the Panel investigated whether periods of tightening reserves are also coinciding with traditional 'shoulder periods'. Generators and TNSPs often schedule maintenance for shoulder periods as temperatures are generally mild and demand during these times is generally lower. However temperature and demand are remaining higher for longer and shoulder periods are getting shorter. There is an emerging concern that tight reserve conditions may occur more often during these times when available supply is lower while generators and lines are out of service for scheduled maintenance.

Figure 3.8 shows that most of the forecast and actual LOR conditions in the reporting period occurred in January, alongside high temperatures and associated high demand. It also shows that there were lack of reserve conditions occurring outside of summer when demand is usually lower.

The Panel intends to investigate this further in future AMPRs as more data becomes available. For example, the Panel may consider:

- looking at year on year trends in forecast and actual LOR conditions by month
- identify how many forecast and actual LOR conditions in traditional shoulder periods are attributed to 'planned transmission outages'
- identify instances where scheduled maintenance periods of major generation units coincide with 'planned transmission outages' identified in LOR reports.

Figure 3.8: Forecast and actual lack or reserve notices per month



Source: AEMO, *NEM Lack of reserve framework quarterly reports*.
Note: The data for this chart is available in the AMPR data portal.

3.4.4 Use of the Reliability and emergency reserve trader mechanism

The RERT is an intervention mechanism that allows AEMO to contract for additional, emergency reserves such as generation or demand response that are not otherwise available in the market when a supply shortfall is forecast.RERT reserves are contracted in addition to the "buffer" that is already made available by the market as part of the usual operation of the power system. These emergency reserves are used as a safety net to avoid or reduce the need for involuntary load shedding when the market hasn't provided for sufficient reserves.[69]

The RERT is activated when there is insufficient market reserves to keep the power system in a reliable operating state. In 2018/19, the RERT was activated twice in response to the forecast lack of reserve conditions in Victoria on 24 and 25 January 2019.

Procurement of RERT reserves

The RERT guidelines for the 2018-19 reporting period, which are made and reviewed by the Panel, specify three types of RERT based on how much time AEMO has to procure the RERT prior to the projected reserve shortfalls occurring:

- long-notice RERT: between ten weeks' and nine months' notice[70] of a projected reserve shortfall.

69 From 26 March 2020, new arrangements will come into place under the *Enhancement to the Reliability and Emergency Reserve Trader* rule change. These new arrangements clarify when and how the RERT can be used and include additional reporting requirements that commenced in October 2019.

70 Under the *Enhancement to the Reliability and Emergency Reserve Trader* final rule this has been extended to 12 months and will take effect on 26 March 2020.

- medium-notice RERT: between ten weeks' and one week's notice of a projected reserve shortfall.
- short-notice RERT: between seven days' and three hours' notice of a projected reserve shortfall.

Under the NER, AEMO may enter into reserve contracts to ensure that supply in a region meets the reliability standard for that region. Typically, AEMO sets up a RERT panel of providers for both the medium-notice and short notice RERT and only triggers the procurement contract when it has identified a potential shortfall and after seeking offers from RERT panel members. There is no panel for the long-notice RERT; rather, contracts are signed following the close of a public tender process.

Use of RERT on 24 and 25 January 2019

Prior to the 2018/19 summer, and based on a risk identified in its 2018 ESOO,[71] AEMO contracted 40 MW[72] of long notice RERT reserves in Victoria and South Australia. With lack of reserve conditions forecast on 24 and 25 January 2019, AEMO entered into seven short term RERT contracts in South Australia and Victoria totalling 365 MW for 24 January and 596 MW for 25 January.[73] All contracts were for demand response from customers.

On 24 and 25 January 2019, in light of the high demand for electricity in Victoria, generator outages, and insufficient market response to lack of reserve notices, AEMO activated all contracted RERT reserves, reducing demand in Victoria and South Australia to balance supply and demand. This was only the third and fourth times the RERT has been used since the NEM commenced. Key elements of the RERT events are listed in the tables below.

Table 3.3: Summary of 24 and 25 January 2019 RERT events

	24 JANUARY 2019	25 JANUARY 2019
RERT contracts activated	396 MW in total. Seven short notice contracts totalling 365 MW and one 31 MW long notice contract	625 MW in total. Seven short notice contracts totalling 595 MW and one 30 MW long notice contract
RERT reserves activated - cumulative total	1,621 MWh	1,472 MWh
Time RERT activated	16:30-22:30	09:30-16:30
Number of trading intervals during which RERT was activated	13 trading intervals	15 trading intervals

71 AEMO, *2018 Electricity Statement of Opportunities*, August 2018.

72 AEMO, *RERT contracted for summer 2018/19*, November 2019.

73 AEMO, *RERT contracted for 24 and 25 January 2019*, January 2019.

Source: AEMO, *Load shedding in Victoria on 24 and 25 January* *operating incident report* and *RERT report for 2018-19*.
Note: *AEMO issued market notices to inform the market that it had intervened by activating RERT and to declare that intervention pricing arrangements would commence. Price intervention was in place from 1600 until 2230 on 24 January 2019 and again from 0905 until 1630 on 25 January 2019. AEMO, *Load shedding in Victoria on 24 and 25 January 2019*, April 2019, p. 37.

A necessary consequence of using emergency reserves is that there are associated costs that end up on consumer bills. The table below summarises the costs associated with the use of RERT on this occasion.

Table 3.4: Costs of Victorian RERT event

COMPONENT	COST
Total cost of RERT contracts ($)	$30.6 million
Cost of compensation to market participants** ($)	$3.6 million
Cost of reserves ($/MWh)	$10,000 per MWh
Cost of RERT to typical commercial and industrial customer* (annual average $/MWh)	$0.79 per MWh in Victoria $0.16 per MWh in South Australia
Cost of RERT to typical residential customer^ (average annual $/customer)	$3.20 in Victoria $0.80 in South Australia
Estimated value of avoided load shedding ($)	$52 million

Source: AEMO, *Load shedding in Victoria on 24 and 25 January* *operating incident report* and *RERT report for 2018-19*.
Note: *using typical commercial and industrial energy usage rates for the 2018 calendar year noting that the costs of RERT to commercial and industrial customers are provided as a typical guide only. Actual costs billed by retailers may vary significantly based on a number of factors including individual rates, consumption profiles, and contractual terms.
Note: **When the RERT is activated, AEMO applies intervention pricing known as "what-if" pricing. "What-if" pricing seeks to preserve price signals by setting the price as if the intervention, in this case the activation of the RERT contracts, had not occurred. AEMO also determines compensation for specified categories of 'affected participants' and market customers that would return them to the position they would have been had the intervention not taken place.
Note: ^ using typical residential customer energy tariffs and usage rates over the 2018 calendar year.

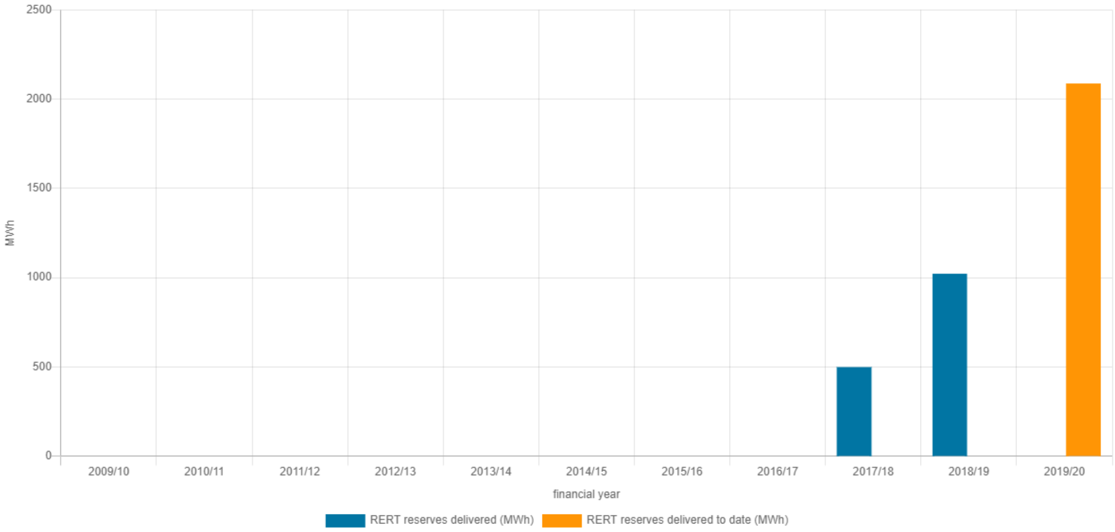
The Panel makes the following observations about the use of the RERT on this occasion:

- the use of the RERT, as part of the overall response to the lack of reserve, meant the reliability standard was not breached and assisted in keeping the power system in a secure operating state throughout the period. This indicates the RERT, and the reliability framework more broadly, operated effectively over the reporting period.
- While the cost of using the RERT and compensating participants was $34.2 million, AEMO states that the value of avoided load shedding amounted to around $52 million. This indicates that the benefits of activating the RERT outweighed the costs of the avoided load shedding.

Use of RERT over time

AEMO reports on the amount of RERT delivered each year[74]. This is shown in the Figure 3.9 below and shows increasing amount of RERT reserves delivered each year.

Figure 3.9: RERT reserves delivered



Source: AEMO *Activation of unscheduled reserves* reports for 30 November 2017 and 19 January 2018, *Operating incident* report for 24/25 January 2019 and *RERT activation estimates* reports for 30 December 2019, 4 January, 23 January, and 31 January 2020.
Note: The data for this chart is available in the AMPR data portal.

The Panel is concerned that there has been an increasing need for and use of the RERT to be able to deliver reliable supply in recent years. This means that, over the past few years, the market has not delivered enough supply to meet demand at these times, and this is one indicator that reliability in the NEM is becoming more challenging to maintain.

To date, the RERT has only been activated on a handful of summer days when temperature and demand are very high. On these days, for a variety of reasons, the market has either not been able or not been willing to deliver enough supply to meet demand.[75]

The Panel notes that the RERT was designed to be used circumstances such as these, when a number of factors converge and result in unexpected challenging conditions for the power system. The Panel also notes that in 2018/19, while load shedding was ultimately used to maintain the supply and demand balance, the use of RERT lessened the load shedding needed.

74 In AEMO's RERT and incident reports, various metrics are used to report on the amount and type of RERT contracts for each year and each event. The Panel has used "RERT delivered" as this is consistently reported for each event

75 30 November 2017 the RERT was used following unseasonably warm weather and generation unavailability, 19 January 2018 the RERT event followed a period of hot whether, the derating of Basslink, the trip of a major generating unit in Victoria and the threat of bushfire in southwest Victoria. The RERT was also used in 2019/20; however, these incident reports have not yet been published. High temperatures and demand, thermal outages and bushfires have played a role.

However, the Panel is still concerned that there are an increasing number of times each when the market is not delivering enough supply to meet demand and emergency reserves are being called upon through the RERT to keep the system in balance. This is emblematic of a broader concern regarding the levels on investment in additional generation or demand response capacity needed to meet the supply gap particularly on very hot days when not only is demand very high, but aging thermal generators and renewable energy generators are sometimes not able to generate at maximum capacity. The RERT is an important tool for maintaining the reliability of the power system

Cost of using RERT resources over time

A necessary consequence of using emergency reserves is that there are associated costs paid for by consumers.

The total cost of RERT for 2018/19 was $34.5 million, as shown in Figure 3.10 below. This was a decrease compared to 2017/18. The cause of this decrease was predominantly because AEMO secured RERT resources in 2018/19 on a usage only basis (without availability charges), reducing RERT costs in 2018/19 to around 65% of the 2017/18 costs.[76] Given the volume of RERT activated in 2018/19 was greater than the previous year, activation costs increased from $3.2 million[77] in 2017/18 to $18.85 million[78] in 2018/19. In 2019/20 the amount of RERT reserves activated have again increased with an associated increase in total costs.[79] Figure 3.10 below shows that the costs associated with delivering RERT reserves during the four events to date in 2019/20 RERT are slightly more than the total costs over the 2018/19 financial year.

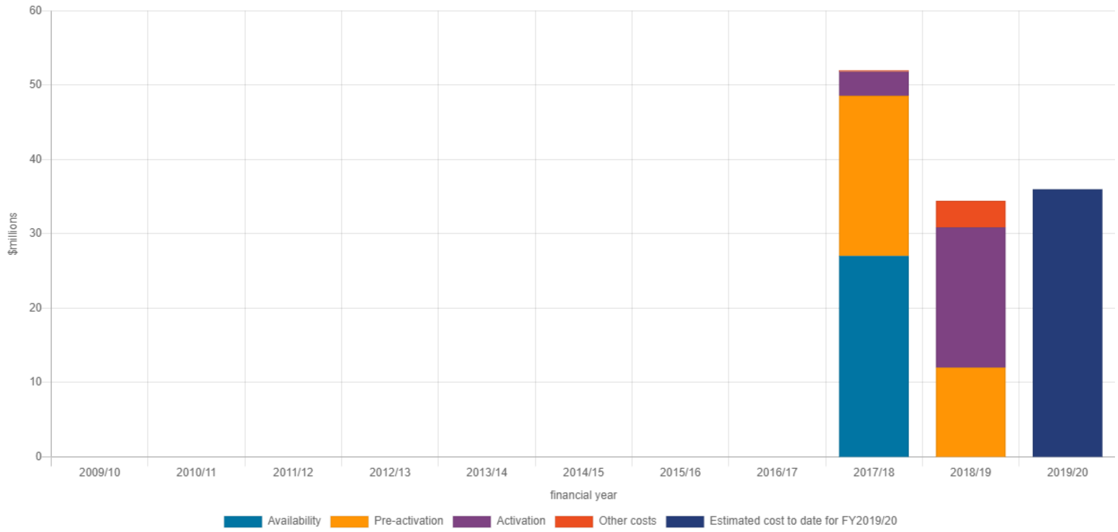
76 AEMO, *Load shedding in Victoria on 24 and 25 January 2019*, p. 35.

77 AEMO, *RERT 2017/18 cost update*.

78 AEMO, *RERT Report for 2018/19*.

79 RERT activation estimates for 30 December 2019, 4, 23 and 31 January 2020 are published on AEMO's RERT reporting page.

Figure 3.10: Costs of RERT use



Source: AEMO *Activation of unscheduled reserves* reports for 30 November 2017 and 19 January 2018, *Operating incident* report for 24/25 January 2019 and *RERT activation estimates* reports for 30 December 2019, 4 January, 23 January, and 31 January 2020.

Note: The RERT was activated twice in 2017/18, twice in 2018/19 and, to date, four times in 2019/20.

Note: This chart only includes publicly available costs taken from incident and event reports. AEMO does not publish information about individual RERT provider activations and costs. From 31 October 2019 AEMO is required to report on RERT activity each year with the first report of this kind, covering Q4 2019, published in February 2020.

Note: 'Other costs' includes compensation paid to market participants as a result of the intervention.

Note: The data for this chart is available in the AMPR data portal.

Costs of using the RERT can also be broken down by the cost per megawatt hour of delivered RERT reserves. AEMO's incident report notes the average cost of RERT payments for 24 and 25 January was approximately $10,000 per MWh.

The Panel notes that all RERT reserves contracted in 2018/19 were from demand response providers. When deciding whether to provide reserves through the RERT, these demand response providers would be expected to compare the price they can get from reducing demand through the RERT to the price they would pay to purchase that electricity from the market at that time. These types of resources can represent a cost-effective source of RERT reserves as demonstrated by the $10,000/MWh cost of RERT reserves in 2018/19. This is a lower cost per MWh than the market price cap and price of wholesale energy at the time of load shedding, $14,500 per MWh.[80]

RERT contracts vary in terms of pre-activation and activation lead times, as well as response times (i.e. an industrial load responding to a request to reduce load under the RERT may need several hours to prepare its plant or undertake safe shut down) and minimum

80 RERT costs that exceed the market price cap have the potential to distort the price incentives of market participants. For example, AEMO's procurement of the RERT may lead market participants to withdraw capacity from the market to provide RERT instead, in the hope of higher or more certain returns. The RERT rules in place at the time of the 24-25 January event sought to mitigate this risk by requiring that RERT providers cannot participate in RERT if in the market for the trading intervals to which contract relates.

continuous run times. Due to the fast response times of some RERT contracts, AEMO can defer activation of these contracts until after an LOR 3 condition arises, which enables AEMO to avoid activation costs until or unless additional reserves are required in real time.

Prior to the 2018/19 year, consumers had expressed concerns with the lack of transparency about the procurement and use of emergency reserves and its impact on electricity bills, the high costs of emergency reserves and low predictability of these costs associated with the use of the RERT.

In 2018/19 AEMO has provided information on the costs of RERT during 2018/19 through incident reports and a brief RERT costs summary for 2018/19 to address this concern. Additional reporting requirements were introduced into the RERT framework and commenced on 31 October 2019.[81] More detail on this is provided in section 3.5.2. The first comprehensive quarterly report was published in February 2020 and the Panel will consider this and future quarterly reports in next year's AMPR.

Evolving use of RERT

The increased use of RERT reflects changing system needs, including:

- growing amount of variable renewable generation
- aging fleet of thermal generation
- tightening supply-demand balance
- peakier demand
- growing risks of extreme weather and climate outcomes, including increasing temperatures and cyclonic activity.

Using emergency reserves more frequently has also meant increased costs to customers in RERT affected jurisdictions.

As the power system changes, there will need to be continuous consideration of the tools available to AEMO and market participants to help maintain the reliability of the power system. However, stakeholders have raised concerns around the transparency of RERT events, and the emergency reserve framework more broadly. During the reporting period, the AEMC made new rules to enhance the operation of the RERT[82] to provide AEMO with tools to manage extreme conditions while also increasing transparency to the rest of the market regarding how these resources are procured and used.

The Panel notes this includes additional reporting requirements so that all interested parties have access to clear, timely and meaningful information to help them manage operational and investment decisions. The Panel welcomes the first quarterly RERT report[83] and looks forward to seeing these reports become more informative for stakeholders over time.

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81 The implementation of the *Enhancement to the Reliability and Emergency Reserve Trader* final rule is staggered. Specific reporting requirements commenced 31 October 2019, while all the remaining elements of the final rule commence on 26 March 2020. As such, the changes to the RERT made in the *Enhancement to the Reliability and Emergency Reserve Trader* were not in effect during the 2018/19 reporting period.

82 AEMC, *Enhancement to the Reliability and Emergency Reserve Trader rule change - final determination,* May 2019, commencing 31 October 2019 (reporting) and 26 March 2020 (remainder of rule)

83 AEMO's first quarterly RERT report was published on 13 Feb 2020 and covers Q4 2019.

3.4.5 Use of AEMO interventions

AEMO can intervene in the market to help maintain and/or re-establish the reliability and security of the NEM.

Intervention mechanisms enable AEMO to deal with actual or potential supply shortages or system security issues by intervening in the market in certain limited circumstances. Intervention mechanisms are an acknowledged and important feature of the market design. However, the use of such mechanisms requires careful consideration as to the flow-on effects for investment signals, as well as costs to consumers.

This section talks about when and how interventions were used in 2018/19, and considers whether the intervention mechanisms available adequately supported the delivery of reliable supply. The Panel has already explored the use of RERT in the section above. In this section the Panel considered the use of these other interventions in 2018/19:

- Reliability directions to generators
- Instructions and load shedding
- Wholesale prices in periods where AEMO is intervening in the market.

Each is considered in separate section below.

Reliability-related directions

AEMO may issue a direction to registered participants where it is necessary to do so to maintain or return the power system to a secure, satisfactory or reliable operating state.[84]

AEMO can issue directions to generators to increase (or decrease) their output or a scheduled load to decrease (or increase) its consumption.

Historically, AEMO has rarely used directions to manage reliability-related events. Over the last five years, the vast majority (99%) of directions have been issued for security-related events. In 2018/19 there were no reliability-related directions issued in the NEM.

Instructions: controlled load shedding

An instruction differs from a direction in the types of market participants AEMO can require to take action and the nature of the action taken.

Instructions often involve AEMO requiring a network service provider or large energy user to shed load.

AEMO gave instructions to maintain reliability on 24 and 25 January 2019 to direct load shedding to keep supply and demand in balance after all other options - including the RERT - had been exhausted.

Controlled load shedding, or involuntary disconnection of customer supply for reliability purposes may be implemented when there is a shortage of electricity supply to meet customer demand or when demand cannot be satisfied while also keeping the power system in a secure state. Load shedding for reliability purposes is manually initiated as a last resort

84 Clause 4.8.9(a)(1) of the NER.

response to bring power flows into balance. Under manual load shedding a relatively small amount of load shedding for a short period (generally on a rotational basis) reduces the potential for more widespread and prolonged customer supply interruptions.

As mentioned, the 24-25 January 2019 were extreme temperature days and as a result customer demand was very high. Supply was tight given a number of planned and unplanned generator outages. In the lead up to the load shedding event, AEMO noted in its incident report that it had already:

- signalled a lack of reserve to the market but did not receive sufficient response
- directed on a synchronous condenser in New South Wales to maximise flows into Victoria across VNI
- activated RERT contracts to reduce demand in Victoria and South Australia.

The purpose of load shedding on this occasion was to reduce the flow towards Victoria from New South Wales to balance demand with the available supply and maintain the power system in a secure operating state. Key elements of the load shedding events are listed in the table below.

Table 3.5: Summary of Victorian load shedding event

	24 JANUARY 2019	25 JANUARY 2019
Requested load shed	75 MW	251 MW
Actual load shed	266 MW	271 MW
Time of load shedding and load restoration	1800-2032 hrs	1100 hrs: 108.8 MW was shed 1130 hrs: 162 MW were shed 1325 hrs: 50 MW load restored 1350 hrs: remaining 221 MW restored.
Duration of load shedding	2 hours, 32 minutes	50 MW unmet for 2 hours 25 minutes 58.8 MW unmet for 2 hours 50 minutes 162 MW unmet for 2 hours 20 minutes
Customers effected	1 - Alcoa Portland smelter^	Approximately 80,000* homes in Victoria

Source: Load Shedding in Victoria on 24 and 25 January 2019 operating incident report, 16 April 2019
Note: ^On 25 January 2019, the Portland aluminium smelter was not available to be switched off again until 1300hrs for technical reasons.
Note: *Exact numbers of customers effected by the 25 January load shedding event are not known as network businesses conduct outages on a rotational basis. This can sometimes mean more customers without power, but for shorter (usually half hour) periods of time.

The Panel makes the following observations about the use of load shedding:

- The use of load shedding was necessary for keeping the power system in a secure operating state throughout the period. Load shedding is an important, if regrettable, last option in the reliability framework and in this instance, it operated effectively.
- Load shedding was required and affected around 80,000 residential customers. However, load shedding was directed only after all other options were exhausted. All available contracted RERT had been activated to meet the expected reserve shortfall, and AEMO had taken other actions within its control to reduce constraints and maximise grid capacity by adjusting power system conditions. According to AEMO, participants took all reasonable steps to comply with instructions and directions issued by AEMO leading up to and during the load shedding event and that load shedding was achieved in a manner that was as consistent as reasonably practicable with AEMO's instructions.
- AEMO noted in its incident report that registered participants took all reasonable steps to comply with instructions and directions issued by AEMO leading up to and during the load shedding events.[85]
- This event increased public awareness of the impact extreme weather days can have on our transitioning power system. AEMO noted that since the load shedding events, it has also received additional interest from potential alternative source of RERT[86] with successful offers included on RERT panels after a second open expression of interest process.[87]

Breach of cumulative price threshold with an administered price cap put in place

During the reporting period, the cumulative price threshold (CPT) was breached and an administered price cap (APC) was put in place at midday on 25 January 2019.

The CPT is one of the reliability settings and seeks to maintain the overall integrity of the NEM by limiting market participants' exposure to sustained high prices which could threaten the financial viability of market participants. The CPT caps the aggregate market price that can occur over seven consecutive days. While this is intended to protect market participants, and ultimately customers from paying excessively high prices, the cap is also set at a level so that prices over the long term can still incentivise enough new investment in generation so the reliability standard is expected to be met.

85 AEMO, *Load shedding in Victoria on 24 and 25 January 2019*, April 2019.

86 Ibid, p. 35.

87 Call for expressions of interest at https://www.aemo.com.au/energy-systems/electricity/emergency-management/reliability-and-emergency-reserve-trader-rert/rert-tendering

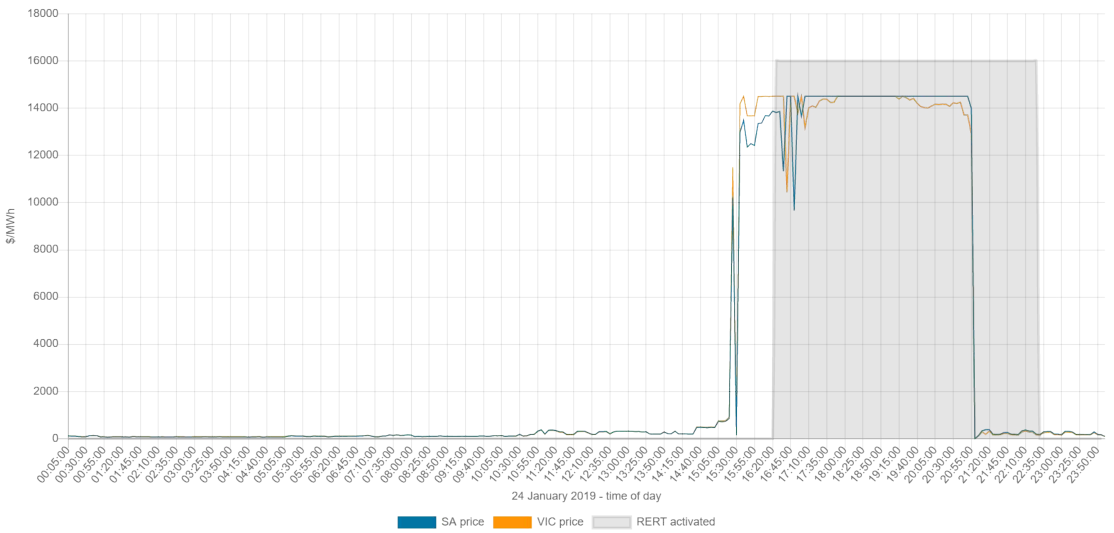
For 2018/19 the CPT was $216,900[88]. Once the CPT is triggered, an APC of $300/MWh is put in place and remains until the seven-day moving average drops below CPT again.

On this occasion, the combination of unexpected generator outages, and higher than expected demand due to consecutive days of record temperatures, meant that the supply demand balance was much tighter anticipated by AEMO. While generation in Victoria and the majority of available generation in South Australia was priced low this still wasn't enough to satisfy the level of demand and high priced generation was required from South Australia leading to high prices in both regions. Intervention pricing was put in place for the periods where the RERT was activated, so that the dispatch price and ancillary service prices are set at the value which AEMO, in its reasonable opinion, considers would have applied had the intervention event not occurred.

The sustained high prices across both regions led to a cumulative price threshold being triggered, with administered price cap put in place - overriding the intervention pricing that had been in place while RERT was activated - from midday 25 January until 1 February 2019.

Figure 3.11 below shows spot prices in Victoria and South Australia over the two days and highlights the periods when intervention "what-if" pricing was in place while the RERT was activated, and the point at which the CPT was triggered.

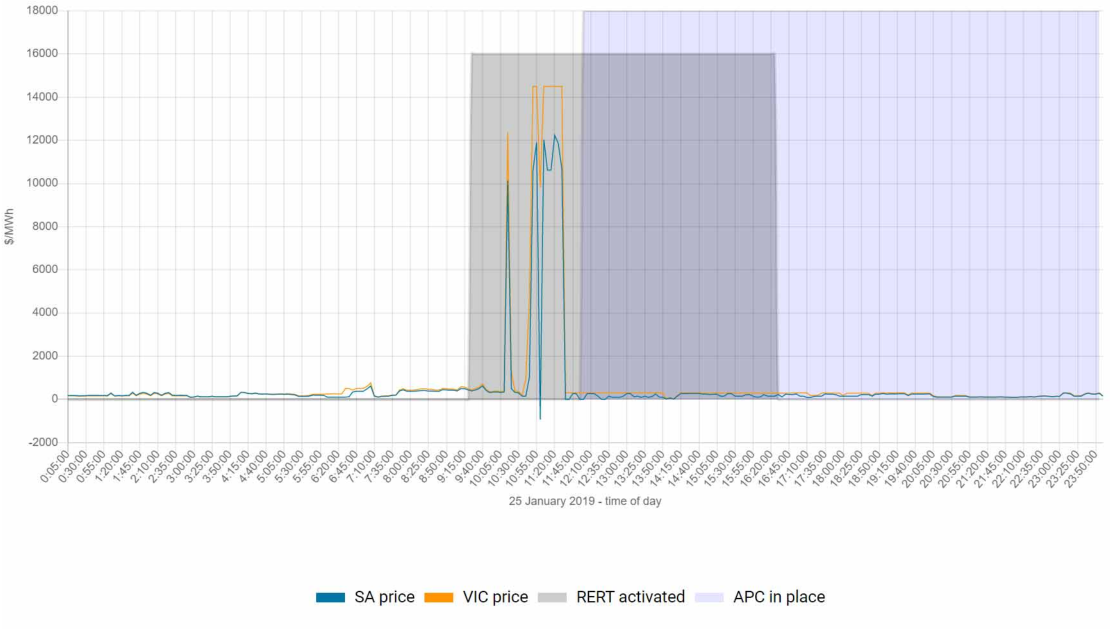
Figure 3.11: Prices in Victoria and South Australia on 24 January 2019



Source: AEMC analysis.
Note: AER found that rebidding from low to high prices did not contribute to high price outcomes.
Note: The data for this chart is available in the AMPR data portal.

88 Under the NER, and as part of the schedule of reliability settings, the AEMC calculates the market price cap and cumulative price threshold each year, in line with the consumer price index

Figure 3.12: Prices in Victoria and South Australia on 25 January 2019



Source: AEMC analysis.
Note: AER found that rebidding from low to high prices did not contribute to high price outcomes.
Note: The data for this chart is available in the AMPR data portal.
Note: Minor corrections were made to this chart after publication to indicate when the APC was in place.

As shown in Figure 3.11, on 24th January 2019:

- the spot price reached the MPC of $14,500/MWh in Victoria at 6.30 pm and 7 pm and in South Australia from 5.30 pm to 8.30 pm.
- the spot price for electricity exceeded $5,000/MWh over 11 trading intervals from 4 pm to 9 pm inclusive in Victoria and South Australia.
- these sustained high prices in both states pushed the cumulative prices to just below the CPT at around $204,000.

As shown in Figure 3.12, on 25th January 2019:

- the spot price reached $7,433/MWh at 11 am and the market price cap at 11.30 am in Victoria
- the spot price for electricity reached $3,817/MWh at 11 am and $11,340/MWh at 11.30 am in South Australia,
- as a result of the previous days high prices, the cumulative price threshold was triggered in both states by 12pm and the administered price cap of $300/MWh applied to all trading intervals thereafter.

Cumulative prices fell below the threshold on 31 January in South Australia and Victoria at 4.30 pm and 7.30 pm respectively, and the administered price period ended at the end of that trading day (i.e. at 4 am on 1 February).

The Panel makes the following observations about the use of the administered price cap:

- The administered price cap played a role in keeping prices within levels that limited the exposure of market customers.
- Some customers were responding to high prices in the market by reducing demand, assisting to address the reliability challenge up the point that the APC was applied. After it was applied, these customers increased demand, arguably making maintaining reliability more challenging.

The Panel notes that the CPT, the APC, and the impact these signals have on participant behaviour warrants further consideration and will consider the effectiveness of the administered price cap and cumulative price threshold shortly, in light of recent events. This is particularly relevant as in-market demand response plays an increasingly important role in responding to reliability challenges.

3.4.6 Forecast accuracy and information that helps deliver reliable supply

It's important to have accurate and regular information about the performance of the power system and market, and forecasts about what is expected both over the short and long term. This helps inform the investment and operational decisions of AEMO and market participants.

In this section, the Panel considers how the accuracy of forecasts can impact the reliability of supply. It does this by looking at AEMO's 2019 forecast accuracy report as well as four different forecasts specifically related to planning for and delivering enough supply to meet demand - i.e. the delivery of *reliable* supply. This includes:

- Accuracy of ST-PASA and MT PASA
- Wind energy forecasting system and solar energy forecasting system across different time periods and different states.

AEMO's 2019 forecast accuracy report

Annually, AEMO publishes an assessment of forecast accuracy. AEMO's report primarily assesses the accuracy of its annual ESOO which provides forecasts over a 10-year period. A summary of AEMO's assessment of its forecast accuracy for 2018/19 is shown in Figure 3.13 below.

Figure 3.13: AEMO's forecasting accuracy summary by region 2018/19

Forecast Component	NSW	QLD	SA	TAS	VIC	Comments
Drivers of demand	Orange	Orange	Orange	Orange	Orange	Growth in new household connections and distributed PV slower than projected in most regions.
Energy consumption	Green	Orange	Green	Green	Red	QLD above forecast due to LNG/CSG VIC below forecast due to differences not explained by variations in input assumptions
Summer maximum demand	Green	Orange	Green	Green	Green	QLD actual above forecast.
Winter maximum demand	Green	Orange	Green	Green	Orange	QLD actual above forecast. VIC actual below forecast.
Annual minimum demand	Orange	Green	Orange	Orange	Orange	Most actuals above forecast due to the overforecast of distributed PV.
Installed generation capacity	Green	Orange	Green	Green	Green	New variable renewable energy capacity installations were lower than predicted, particularly in QLD.
Summer supply availability of dominant fuel	Green Coal	Green Coal	Green Gas	Green Hydro	Orange Coal	VIC Coal generation availability below expectation due to more forced outages than forecast.

Source: AEMO, *forecast accuracy report*, December 2019, p. 3.

Note: Green = forecast has performed as expected, orange = Inaccuracy observed in forecast is explainable by inputs and assumptions. These inputs should be monitored and incrementally improved, provided the value is commensurate with cost, red = Inaccuracy observed in forecast needs attention, and should be prioritised for improvement.

AEMO has identified a comprehensive register of proposed improvement to forecasting.[89] There are two improvements that AEMO identified as the highest priority to be implemented for the 2020 ESOO to improve forecast accuracy:

- Energy forecast methodology: AEMO will develop a multi-model ensemble for energy consumption forecasts is proposed per region, incorporating monthly time-series energy consumption forecasts for the next three years. This is expected to better-align operational consumption history and forecast trends to improve year ahead forecast accuracy.
- PV forecasts: AEMO intends to work more closely with the Clean Energy Regulator and consultant forecasters to ensure insights and short-term trends from the DER register and cleaned historical installations are better captured.

The Panel notes AEMO's continuing assessments and future work program will improve stakeholder and market participant understanding of the changing supply and demand dynamics, a fundamental part of supporting investment, operational and policy decisions that underpin reliability.

Projected assessment of system adequacy

The projected assessment of system adequacy is the principal method of indicating to AEMO and market participants a forecast of the overall balance of supply and demand for electricity.

89 AEMO, *forecast accuracy report*, December 2019, p. 78.

PASA is conducted over short and medium-term horizons. This section considers the forecast accuracy of both.

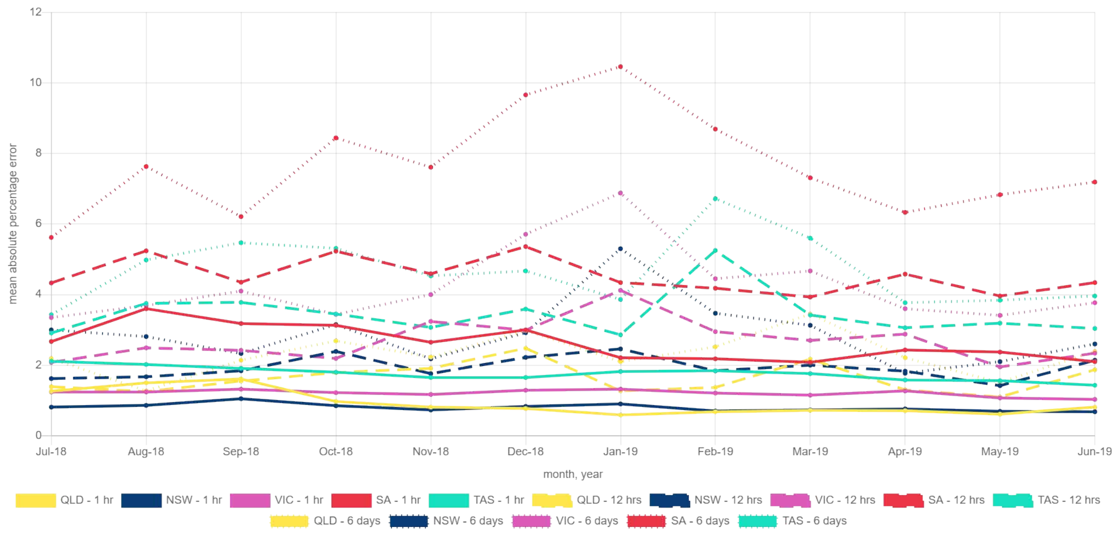
Short-term projected assessment of system adequacy

ST-PASA provides information to market participants on the expected level of short term capacity reserve and hence the likelihood of interruptions due to a shortage of power. In can also provide a benchmark for AEMO to intervene in the market. It covers 6 trading days from end of the trading day covered by most recent pre-dispatch schedule with a half hourly resolution.

Figure 3.14 below shows the percentage error of load forecasts in 2018/19, one hour and 12 hours ahead of the relevant dispatch interval. The Panel notes that:

- Accuracy of load forecasts appear to have slightly improved throughout the year in all states.
- As in previous years, South Australian load was typically forecast with the least accuracy, whereas load in Queensland and New South Wales was the most predictable.
- As expected, the one-hour ahead load forecasts were generally more accurate than the 12-hour ahead forecasts.

Figure 3.14: Load forecasting error, one hour, 12 hours ahead and six days



Source: AEMC analysis of AEMO data.
Note: The data for this chart is available in the AMPR data portal.

Medium-term projected assessment of system adequacy

In addition to ST-PASA reports, AEMO also publishes MT-PASA reports. MT-PASA assesses of the adequacy of expected electricity supply to meet demand across a two-year horizon through regular assessment of any projected failure to meet the reliability standard.

MT PASA collects and analyses information to assess medium-term power system security and reliability of supply prospects enabling participants to make decisions about supply, demand and outages of transmission networks for periods up to two years in advance.

Each week, scheduled market participants (e.g. generators) must submit forecasts of their availability (total MW capacity available for dispatch) to AEMO for the period covering the next 24 months, commencing eight days (i.e. Sunday) after the publication date of the MT-PASA report. The report is published every week as a minimum. AEMO publishes the MT-PASA every Tuesday at 16:00 AEST with outcomes of the PASA process as well as input variables. Scheduled generators or market participants are required to submit PASA availability of each scheduled generating unit, load or network service and energy constraints for each scheduled generating unit or load.[90] Network service providers must provide planned network outage information.[91]

Australian wind energy forecasting systems

The Australian Wind Energy Forecasting System (AWEFS) produces wind generation forecasts for all semi-scheduled and non-scheduled wind generators in the NEM.[92] These forecasts are used for the dispatch, pre-dispatch, ST-PASA and MT-PASA processes.

AWEFS produces forecasts from the following inputs:

- Real time SCADA measurements from the wind farms.
- Numerical weather predictions from weather forecasters from around the world.
- Standing data from the wind farms.
- Availability information provided by the wind farms, that includes turbines under maintenance and upper MW limit on the wind farm.

Due to the variable nature of wind and solar, there is potential for material variations in energy availability from these generators, which may have reliability implications for the system. At times of peak demand, even small variations within a tight timeframe can create reliability issues, especially if dispatchable generation is not available to replace this capacity.

The accuracy of forecasting is therefore a key factor in the effective integration of variable renewable generation into the NEM. On this basis, forecasting systems are an increasingly important tool for promoting efficiencies in NEM dispatch, pricing, system reliability and security, as renewable generation continues to make up a larger share of the generation mix.

The Panel has looked at the degree of difference between wind forecasts and actual output, over different timeframes. As Figure 3.15 shows, the accuracy of forecasts of wind generation generally improves closer to real time. AEMC analysis of historic forecasting accuracy also shows that the level of deviation between actuals and forecasts has generally remained steady over time. However, accurate forecasting has become more complex due to

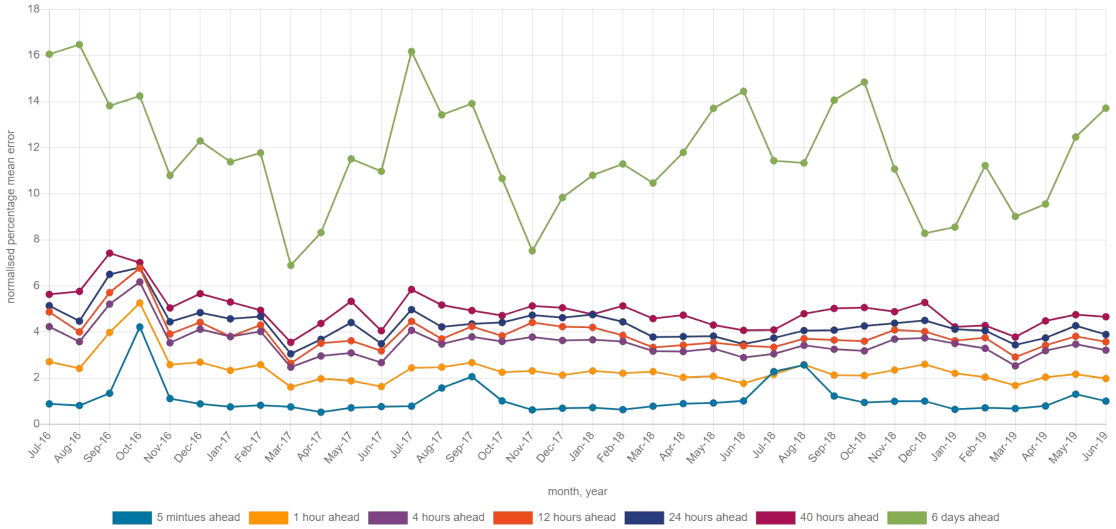
90 In accordance with clause 3.7.2(d) of the NER.

91 In accordance with clause 3.7.2(e). This clause is classified as a civil penalty provision.

92 AEMO is required to prepare forecasts of the available capacity of semi-scheduled generators such as larch scale wind and solar farms, in order to schedule sufficient generation in the dispatch process (NER clause 3.7B) and to be used in the PASA processes for reserve assessment purposes (NER clause 3.7.1(c)(2)).

greater volumes of variable renewable energy generation entering the NEM. Forecasting of variable renewable generation beyond a six-day time horizon is hard and, as could be expected, there is a significant degree of difference that can occur between forecast and actual variable renewable generation output.

Figure 3.15: Accuracy of wind energy forecasting in the NEM, July 2016-July 2019

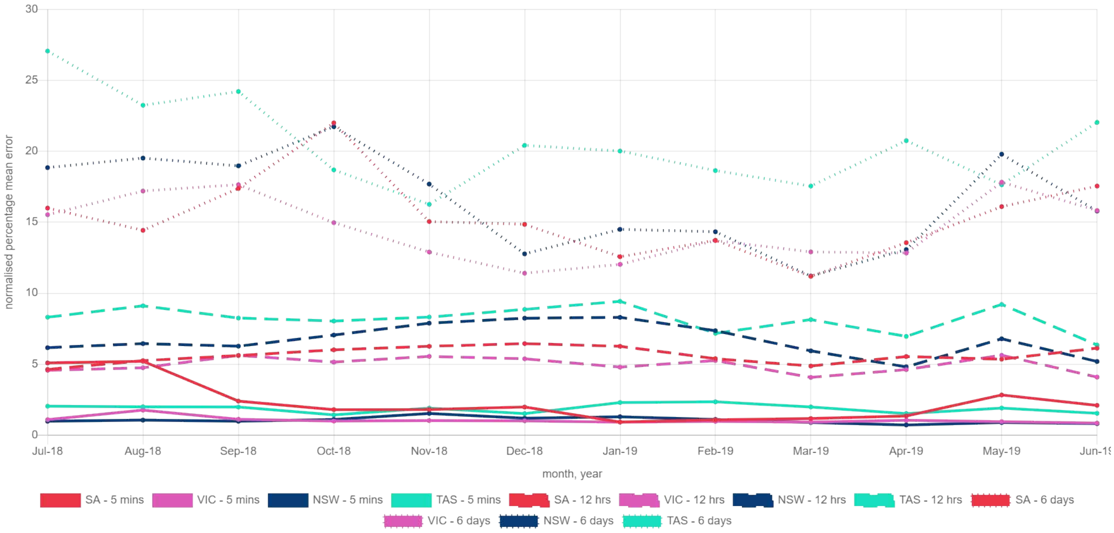


Source: AEMC analysis of AEMO AWEFS data.
Note: The data for this chart is available in the AMPR data portal.

Forecast accuracy also varies across regions. Figure 3.16 below compares the accuracy of wind energy forecasts in each state (excluding QLD, because it currently has much less installed wind when compared to the other regions in the NEM) for 2018/19 and shows the forecast five minutes, 12 hours and six days ahead of the relevant dispatch interval. The Panel makes the following observations:

- As expected the forecast accuracy improves in all states approaching real time with five-minute ahead forecasts generally within 2 per cent of the actual output.
- Victoria generally has the most accurate forecasts across the three intervals. Tasmania is generally less accurate than the other states up to 12 hours ahead of the dispatch interval but remains within 2 per cent of actual output five minutes ahead.
- South Australia has a mean absolute error ranging between 1 per cent and 5 per cent five minutes ahead. Forecast accuracy tends to be slightly lower in winter months.

Figure 3.16: Accuracy of wind energy forecasts in 2018/19 by state



Source: AEMC analysis of AEMO AWEFS data
Note: QLD is not included in the wind energy forecasting system data because it currently has much less installed wind when compared to the other regions in the NEM.
Note: The data for this chart is available in the AMPR data portal.

Australian solar energy forecasting system

Australian Solar Energy Forecasting System (ASEFS) is designed to produce solar generation forecasts for large solar power stations and small-scale distributed PV systems, covering forecasting timeframes from 5 minutes to 7 days.

ASEFS produces forecasts from any solar farms greater than or equal to 30 MW registered capacity, and any solar farms that AEMO is required to model in network constraints for power system security reasons, as well as small-scale distributed PV systems

AEMO started forecasting from large scale solar farms on 30 May 2014. It uses the following inputs to produce solar generation forecasts for large solar power stations:

- Real time SCADA measurements from the solar power station.
- Numerical weather prediction data from multiple weather data providers.
- Standing data from the solar power station as defined in the ASEFS energy conversion model[93]
- Additional information provided by the solar power station, including inverters under maintenance and upper MW limit on the solar farm.
- Imagery from Himawari-8 satellite

Forecasts of large-scale output are used in dispatch, pre-dispatch and ST PASA processes.

93 Available on AEMO's website.

Forecasts of small-scale distributed PV systems (less than 100 kW system capacity) commenced more recently on 30 March 2016. It uses the following inputs to produce aggregated regional solar generation forecasts for small-scale PV systems:

- Numerical weather prediction data from multiple weather data providers.
- Output measurements and static data from selected household rooftop PV systems from PvOutput.org and Solar Analytics.
- Aggregate kilowatt capacity by installed postcode for small-scale solar systems as recorded by the Clean energy Regulator[94]
- Imagery from Himawari-8 satellite.

Small scale solar forecasts are used in the pre-dispatch and ST PASA demand forecasts.

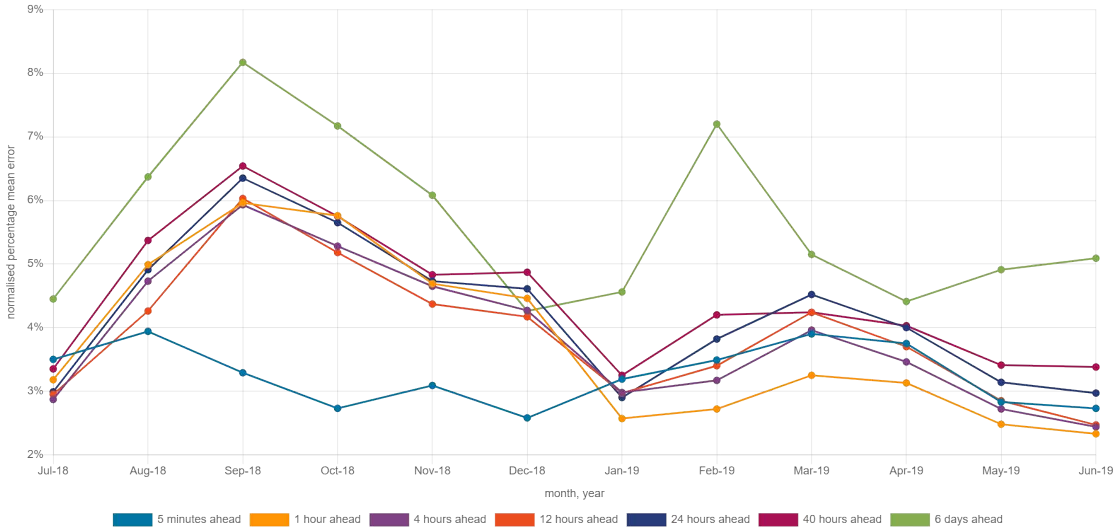
In 2018/19 solar energy forecasts remained within a 10 per cent error margin even six days and more ahead of real time. This contrasts to wind energy forecasts that can have errors of up to 30 per cent six days out and 10 per cent just 12 hours ahead.

Figure 3.17 below shows the percentage error of large scale-solar energy forecasts across seven intervals leading up to dispatch. The Panel makes the following observations:

- Solar forecasting does not seem to follow the expected pattern of getting more accurate as the relevant interval approaches. The total range of error across the different timeframes is small, particularly from 24 hours out.
- The percentage error for solar energy forecasts made five minutes ahead ranged between 2.5 and 4 per cent. This is greater than percentage errors for wind energy forecasting.

94 This data is available on the CER's website.

Figure 3.17: Accuracy of large-scale solar energy forecasts in the NEM for 2018/19



Source: AEMC analysis of AEMO ASEFS data.
Note: The data for this chart is available in the AMPR data portal.

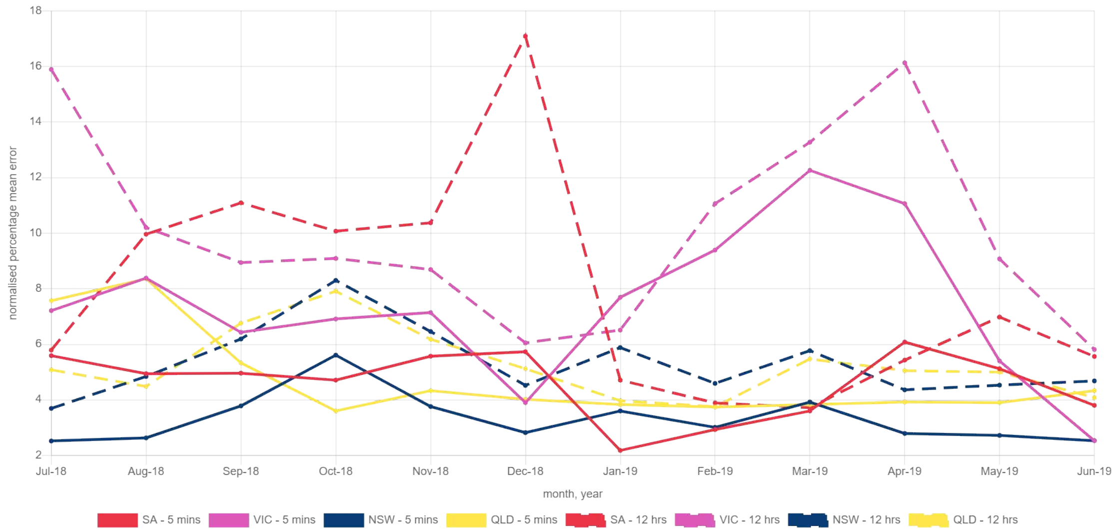
When comparing forecast accuracy for solar energy across states, Figure 3.18 shows that New South Wales tends to have the most accurate solar energy forecasts five minutes and 12 hours ahead of the relevant dispatch interval but that Queensland is also fairly consistent. The percentage errors for South Australia and Victoria were more varied across months in 2018/19. In particular, for more than half the year, Victoria's forecasts were seven per cent or more in error compared to actual output.

The regional accuracy is derived from a comparison of aggregated output and aggregated forecasts. This comparison can produce uncharacteristically high errors on occasion due to commissioning and hold-point testing of individual farms when the regional installed capacity is relatively low. For example, in South Australia (December 2018) and Victoria (July 2018).

The Panel expects solar energy forecasting to improve over time as more information becomes available about how small and large-scale solar performs under different scenarios, and as the register of distributed energy resources provides more visibility over where small scale solar PV is located in the grid.

In early 2018, AEMO and ARENA began undertaking a self-forecasting to test the potential benefits to operation of the power system of wind and solar generator self-forecasting. It is anticipated that the use of self-forecasting will deliver system wide benefits by reducing generation forecast error and providing greater autonomy to existing semi-scheduled generators. The Panel supports this trial and notes that any learnings could be pursued through rule change requests to the AEMC.

Figure 3.18: Accuracy of solar forecasts 2018/19 by state



Source: AEMC analysis of AEMO ASEFS data.
Note: Tasmania is not included in ASEFS forecasts because there is no large scale solar in Tasmania.
Note: The data for this chart is available in the AMPR data portal.

3.4.7 Network performance

In assessing network performance in the NEM in 2018/19, the Panel has considered:

- Performance of interconnectors
- Performance of transmission networks
- Performance of distribution networks.

Interconnector performance

In this section the Panel considers the current performance as well as future development of interconnection in the NEM.

Six interconnectors currently transport electricity between adjacent NEM regions. The Queensland-New South Wales (QNI) interconnector, Victoria-New South Wales (VNI) interconnector and Heywood interconnector between South Australia and Victoria are high voltage alternating current links while Terranora (NSW/QLD), Murraylink (VIC/SA) and Basslink (TAS/VIC) are high voltage direct current links. A seventh 330 kilovolt interconnector between South Australia and New South Wales - known as Project EnergyConnect - is in the latter stages of planning and has an estimated delivery time of 2022 to 2024.[95]

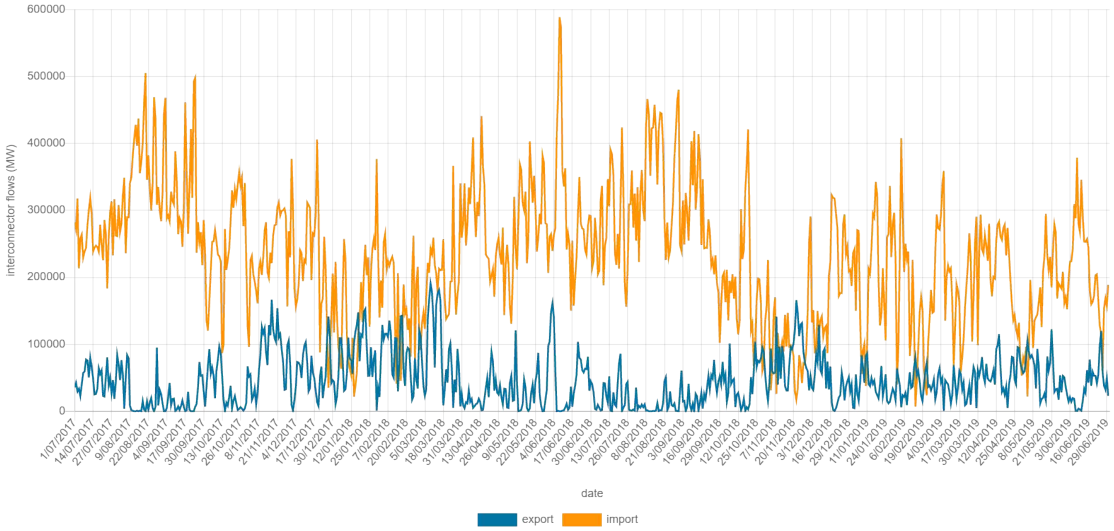
Interconnection between regions can be a way for one region to "back-up" another in lieu of more local generation, and can also be used more strategically to enable competitive sharing

95 Delivery time depend on the time taken to gain environmental and other necessary approvals - more information is available in Project EnergyConnect's project assessment conclusions report, February 2019.

of resources across regions, and allow the market to deliver the technological requirements for the evolving power system.

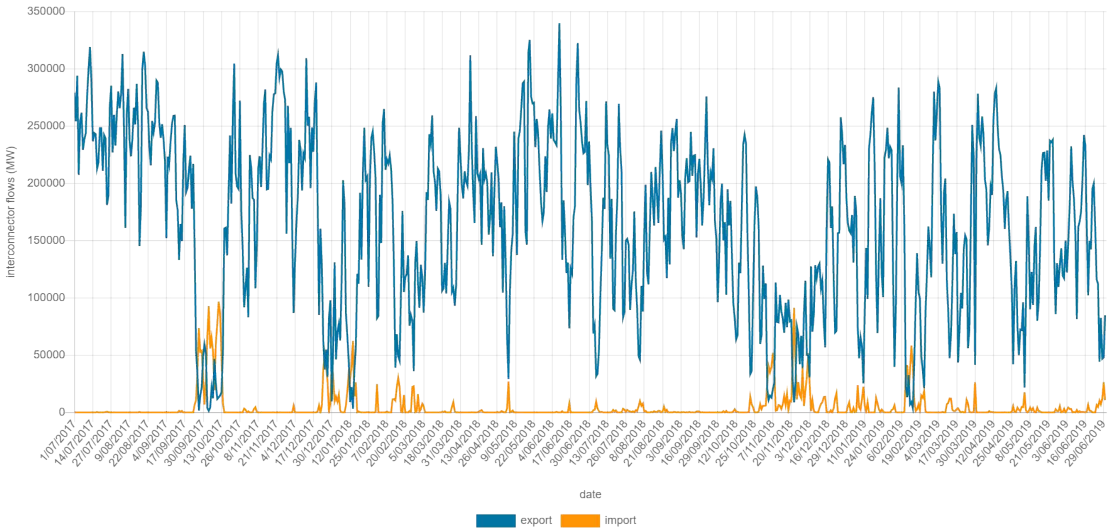
The figures below shows the interregional flows across interconnectors in 2018/19 compared to 2017/18. The blue indicates when and how much a jurisdiction is importing, the purple, indicates when how much electricity a region is exporting.

Figure 3.19: Interconnector flow July 2017 - July 2019 - New South Wales



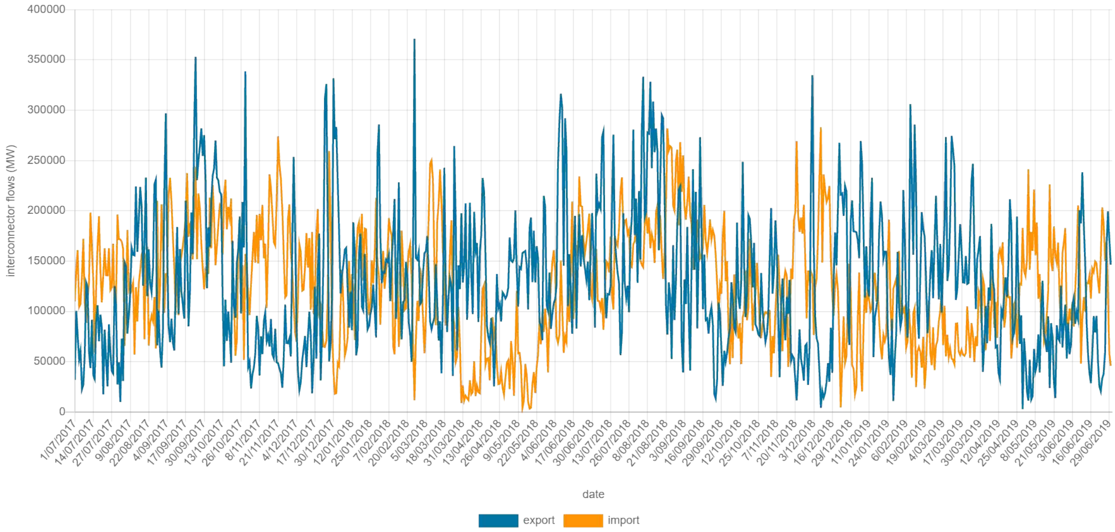
Source: AEMC analysis.
Note: The data for this chart is available in the AMPR data portal.

Figure 3.20: Interconnector flow July 2017 - July 2019 - Queensland



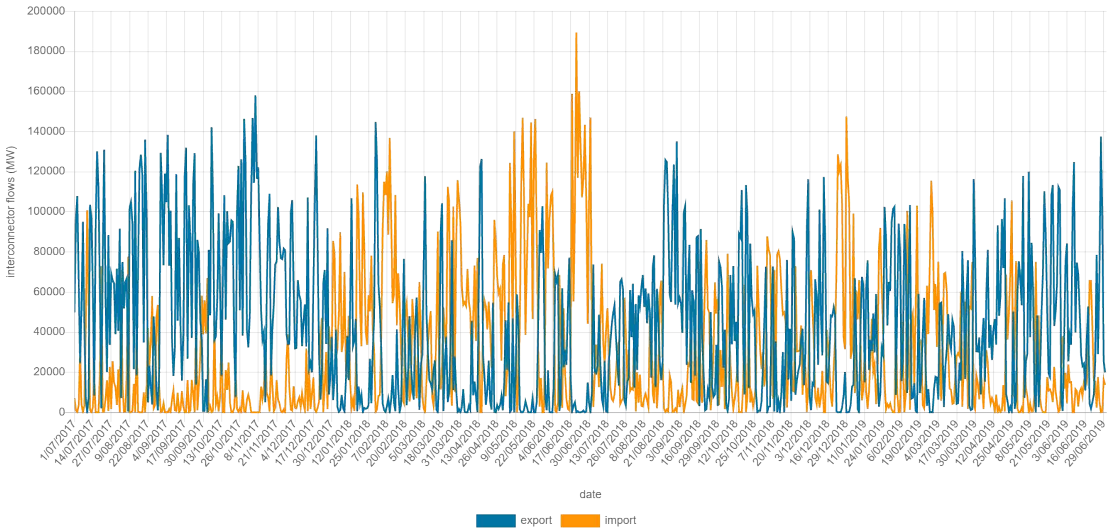
Source: AEMC analysis.
Note: The data for this chart is available in the AMPR data portal.

Figure 3.21: Interconnector flow July 2017 - July 2019 - Victoria



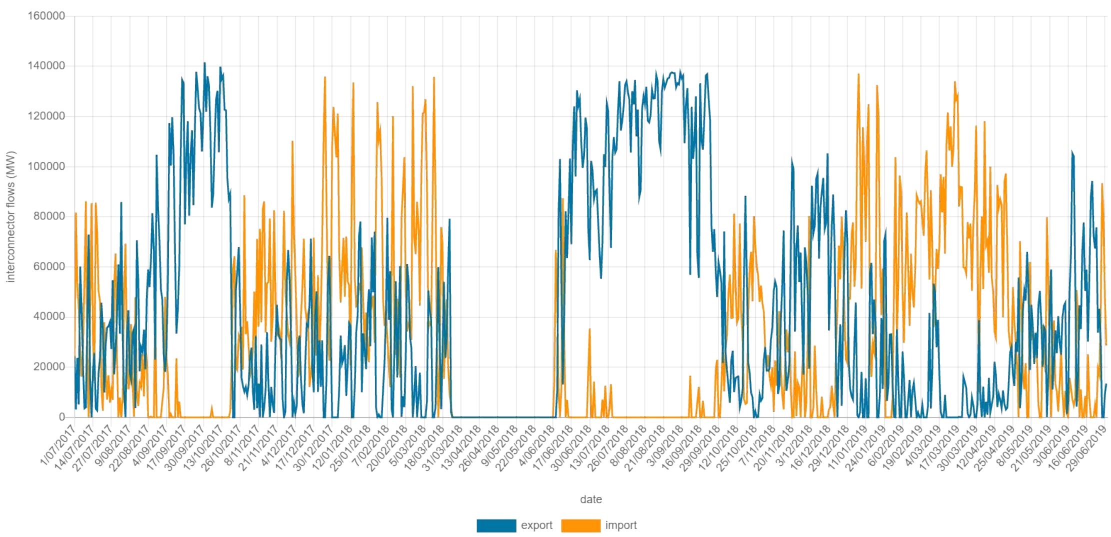
Source: AEMC analysis.
Note: The data for this chart is available in the AMPR data portal.

Figure 3.22: Interconnector flow July 2017 - July 2019 - South Australia



Source: AEMC analysis.
Note: The data for this chart is available in the AMPR data portal.

Figure 3.23: Interconnector flow July 2017 - July 2019 - Tasmania



Source: AEMC analysis.
Note: The data for this chart is available in the AMPR data portal.

Some key points to note in relation to interregional flows include:

- As the power system transforms and generators exit, and enter in new parts of the grid, interconnectors are likely to be used more frequently to provide system support services and market benefits through lower prices, as well as simply providing additional capacity for a neighbouring region. As shown in the figures above, interconnectors flowed both ways throughout the 2018/19 period so that even if the 'net' position of a jurisdiction was as an importer, there were still significant periods when it was an exporter as well.
- In 2018/19 Victoria remained a net exporter with the equivalent of only 0.5 per cent of its regional energy consumption exported across interconnectors. This is steep decline in exports following the retirement of Hazelwood power station.
- South Australia is increasingly a net exporter along with Tasmania and Queensland. NSW was the only net importer in 2018/19.[96]
- The same trends in the direction of flow across interconnectors also impacts flow rates and binding constraints between regions. Binding constraints represents the physical realities of the network and the limits needed to maintain the power system in a secure operating state. Network congestion can be measured by the frequency and extent to which network constraints bind. The charts below show the extent to which binding played a role for each region during 2018/19.

96 Net export figures were taken from AER's Wholesale Statistics page - *Annual interregional trade as a percentage of regional energy consumption.*

- There continues to be a lot of focus on inter-regional congestion and interconnector capability. Congestion on the transmission network can be influenced by events occurring far away from the physical line that is constrained. Consequently, flows across the interconnectors and the capacity for inter-regional trade in the NEM is not only influenced by the limits of the physical assets that cross region boundaries, but also by constraints occurring in parts of the network further removed from the actual interconnector infrastructure. During 2018-19 there has been significant progress made to 'action the ISP'. Updates on the progress of ISP transmission projects (QNI and VNI upgrades and Project EnergyConnect) are included below.

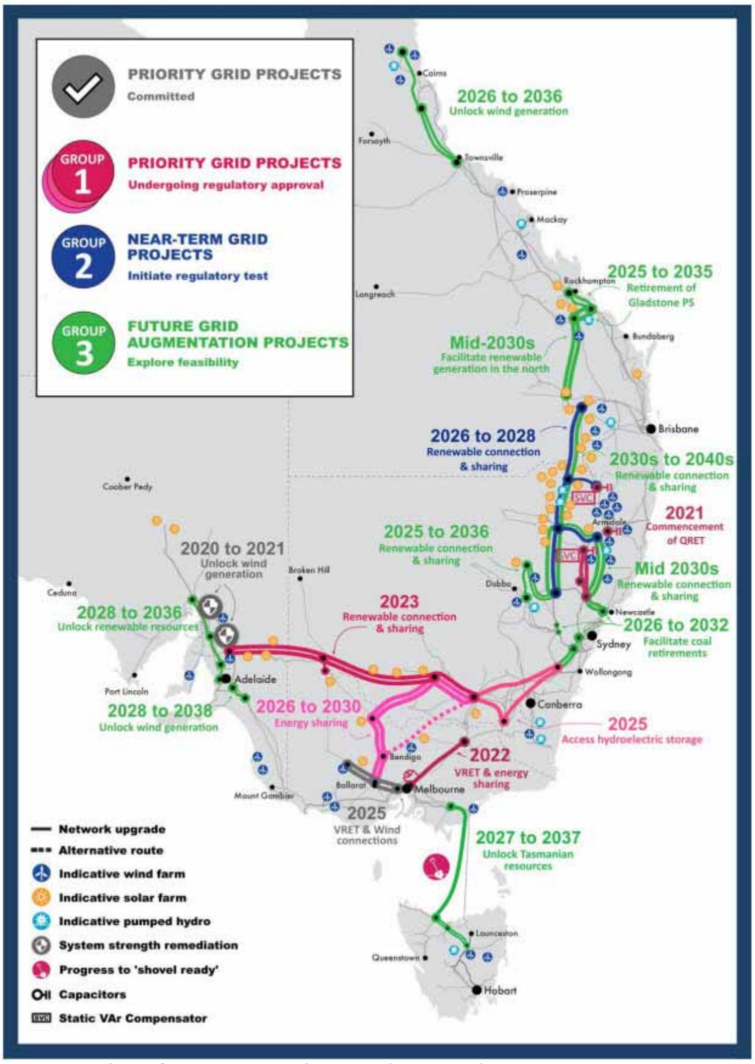
While some regions are net exporters (Queensland, South Australia) and others are net importers (New South Wales), all states benefit from interconnection between regions. For example, each region may rely at some time on electricity produced across borders either for reliability and security purposes, or to access electricity at a lower price than would otherwise be available in their region. The Panel notes that as the generation mix changes, the capacity for energy resources to be shared efficiently, securely and at low cost, is likely to become more important.

There have been a number of work programs progressed over the last year that are relevant to the development of interconnector capability in the NEM.

In July 2018, AEMO published its inaugural Integrated system plan (ISP). The next ISP 2020 is due for publication in June 2020 with a draft currently out for consultation[97] In the ISP, AEMO forecasts the overall transmission system requirements for the NEM over the next 20 years. It identifies a potential plan of the transmission investments that AEMO believes will be necessary to support the long term interests of consumers for safe, secure, reliable electricity, at the least cost, across a range of plausible futures. The ISP groups investments identified in the plan into three phases as shown in Figure 3.24 below.

97 AEMO, *Draft 2020 Integrated system plan*, December 2020.

Figure 3.24: Draft 2020 ISP development pathways



Source: AEMO's *Draft 2020 Integrated system plan*, December 2019, p. 14.

The Panel notes that priority projects are well progressed, supported by rules to streamline the implementation of ISP priority projects[98] An update on relevant projects is provided in the sections below.

The Panel has included some analysis below on the performance of some of these interconnectors, focussing on the QNI, VNI, Heywood and Basslink interconnectors over 2018/19.

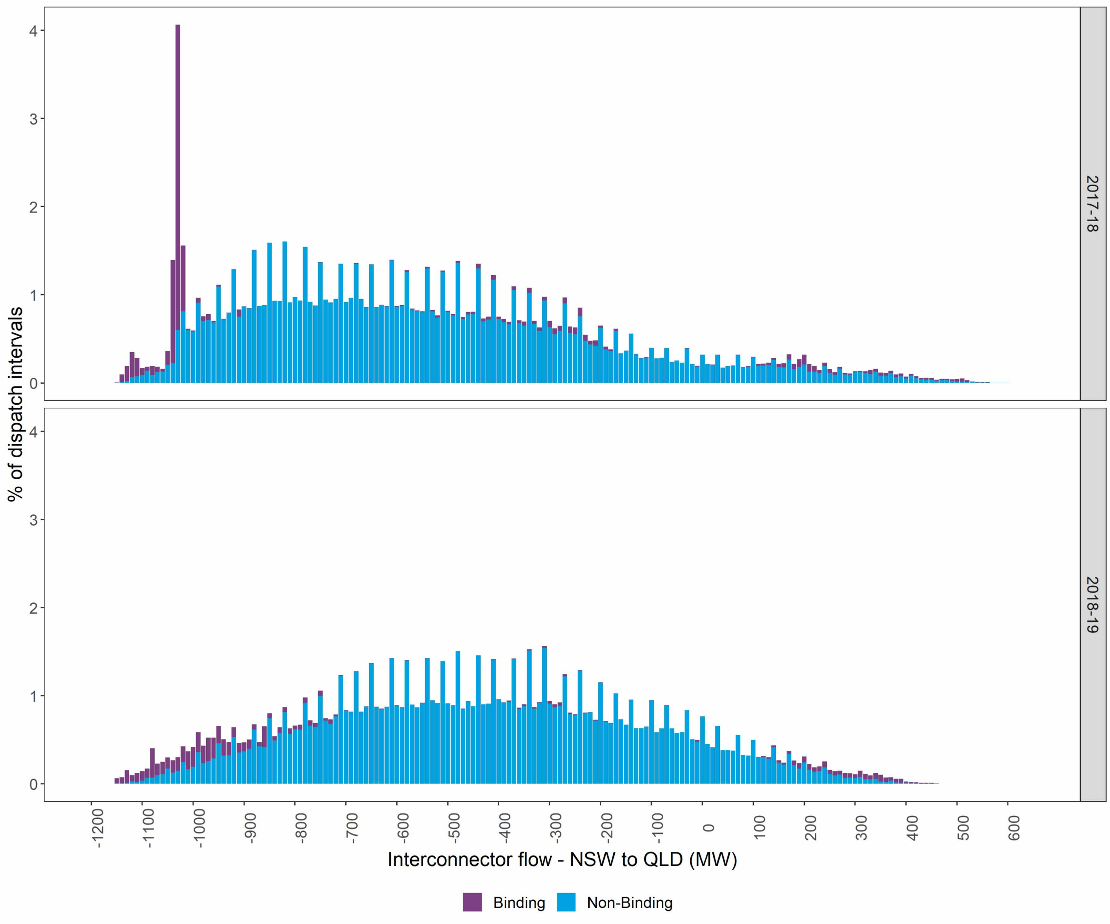
98 AEMC, *Early implementation of ISP priority projects final rule*, April 2019.

Interregional flow across QNI

QNI runs between Bulli Creek in Queensland and Dumaresq in New South Wales. QNI currently has a nominal capacity of about 300-600 MW from New South Wales to Queensland and 1,080 MW from Queensland to New South Wales.

Figure 3.25 shows that the trend of increasing flows from Queensland to New South Wales across QNI.

Figure 3.25: Interregional flow across QNI



Source: AEMC analysis.
Note: The left-hand side of the chart shows flows from Queensland to New South Wales the right-hand side shows flows from New South Wales to Queensland.
Note: The data for this chart is available in the AMPR data portal.

In 2018/19:

- New South Wales imports across QNI generally bound more often at higher flow levels, and also bound more frequently near the nominal capacity limit of 1,080 MW. This continues a trend observed in last year's report but has softened compared to last year.

- There are fewer instances of New South Wales imports frequently binding below 300 MW than in the previous two years.

To improve flows on QNI, TransGrid and Powerlink (the respective NSW and QLD TNSPs) have submitted a proposal to the AER outlining a preferred option to extend capacity to 690 MW (NSW-QLD) and to 1,120 MW (QLD-NSW).[99] This one of the group one projects identified in AEMO's ISP and is expected to be completed in 2021/22.

On 28 October 2019, the Commonwealth and NSW Governments announced they would each contribute $51 million (i.e. $102 million in total) to underwrite the early works required for the preferred QNI upgrade. TransGrid considers this underwriting a key facilitator of delivering the upgrade in the timeframes specified.[100]

Interregional flow across VNI

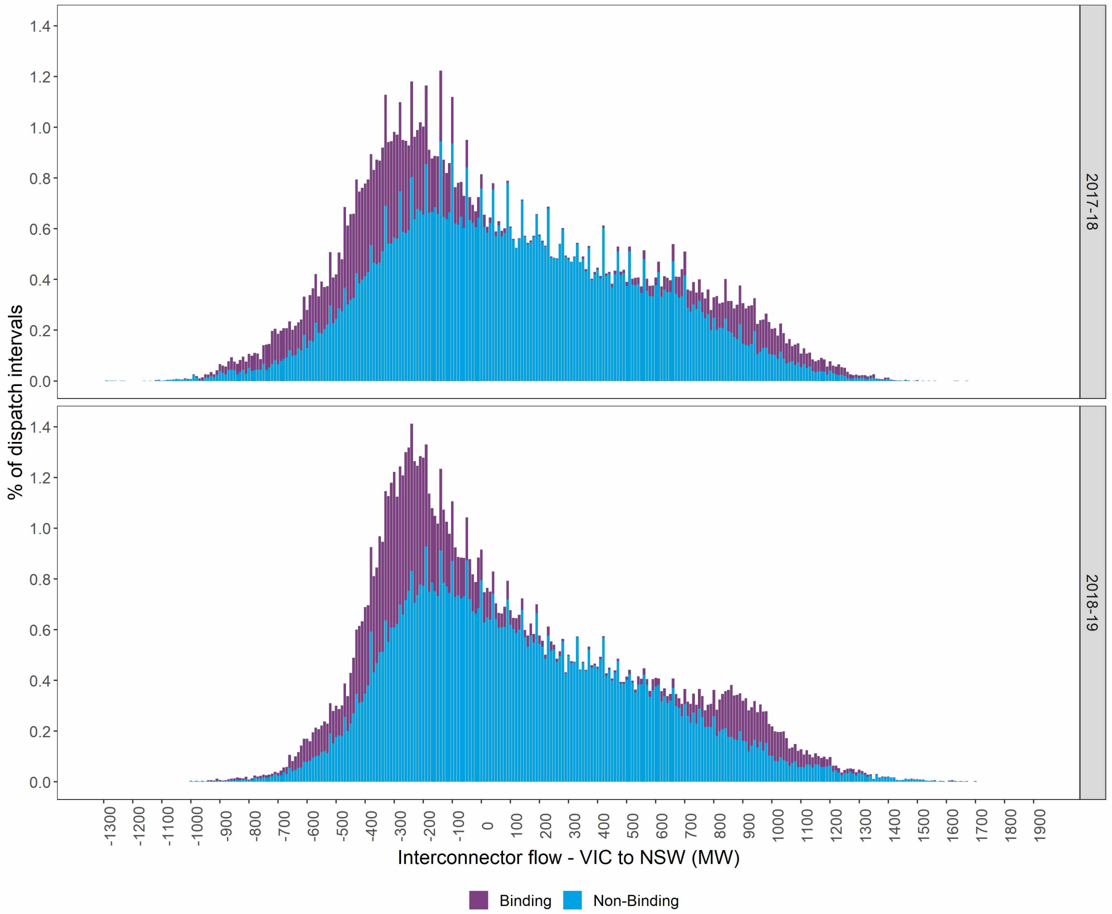
VNI connects northern Victoria with southern New South Wales. VNI currently has a nominal capacity of 700-1,600 MW from Victoria to New South Wales and 400-1,350 MW from New South Wales to Victoria. AEMO and TransGrid are currently finalising a RIT-T process to expand the interconnector capacity between Victoria and New South Wales.

Figure 3.26 shows a trend of increasing flows from New South Wales to Victoria that was observed in 2017/18 and continues in 2018/19.

99 This involves uprating the Liddell to Tamworth lines and installing new dynamic reactive support at Tamworth and Dumaresq and shunt capacitor banks at an estimated capital cost of $230 million. More information is available in the PACR, December 2019.

100 More information in the PACR, December 2019

Figure 3.26: Interregional flow across VNI



Source: AEMC analysis.
Note: The left-hand side of the chart shows flows from New South Wales to Victoria, the right-hand side shows flows from Victoria to New South Wales.
Note: The data for this chart is available in the AMPR data portal.

Flows from New South Wales to Victoria continued to bind bound more often at both high and low flow levels in 2018/19 compared to both 2017/18 and 2016/17.[101] Victoria to New South Wales flows bound frequently in 2018/19 above 800MW.

Proposed upgrades to VNI could improve flows. The preferred option outlined in AEMO's Project Assessment Conclusions Report (PACR) recommends a combination of minor upgrades to existing infrastructure and major transmission works – including a new terminal station north of Ballarat and long-distance high voltage transmission lines between Bulgana and Sydenham terminal stations – staged over several years, with the final component expected to be in operation by 2025[102]

101 Reliability Panel, *Annual market performance review 2018*, p. 58.

102 AEMO, *Western Victorian regulatory investment test for transmission - the preferred investment option.*

Interregional flow across Heywood

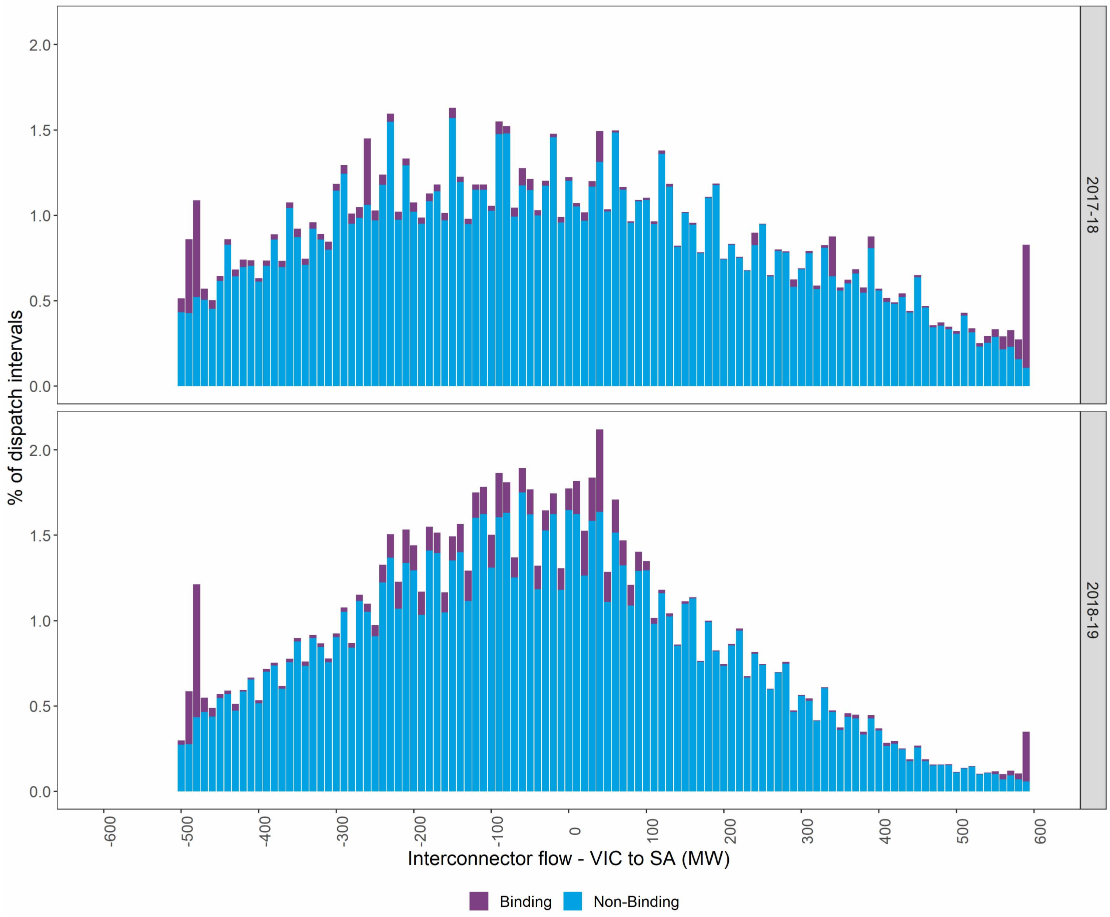
The Heywood interconnector has a nominal capacity of 600 MW from Victoria to South Australia and 500 MW from South Australia to Victoria[103]. The Heywood interconnector connects Heywood in Victoria to the south-east of South Australia. ElectraNet has recently carried out upgrades on the Heywood interconnector to increase the interconnector's nominal transfer capacity to 650 MW in either direction of flow. The limits on the Heywood interconnector currently remain below 650 MW in order to manage system security issues, including a potential stability issue at high levels of transfer from Victoria to South Australia.

Figure 3.27 shows a similar trend from 2017/18 to 2018/19 with approximately equal flow between regions. Before this recent trend, energy typically flowed from Victoria to South Australia. There are more instances of the interconnector binding across flow levels below 250 MW (SA to VIC) and below 100MW (VIC to SA) compared to 2017/18; however, these flows are binding significantly less than in 2016/17.[104]

103 AEMO, *Interconnector capabilities*, November 2017, p. 6.

104 Reliability Panel, *Annual market performance review 2018*.

Figure 3.27: Interregional flows across Heywood



Source: AEMC analysis.

Note: The left-hand side of the chart shows flows from South Australia to Victoria, the right-hand side shows flows from Victoria to South Australia.

Note: AEMO will increase the Heywood limit from SA to Vic (from the current 500 MW) to 550 MW and the combined (Heywood and Murraylink) SA to Vic limit from 650 to 700 MW at 1000 hrs on 18 Dec 2019.

Note: The data for this chart is available in the AMPR data portal.

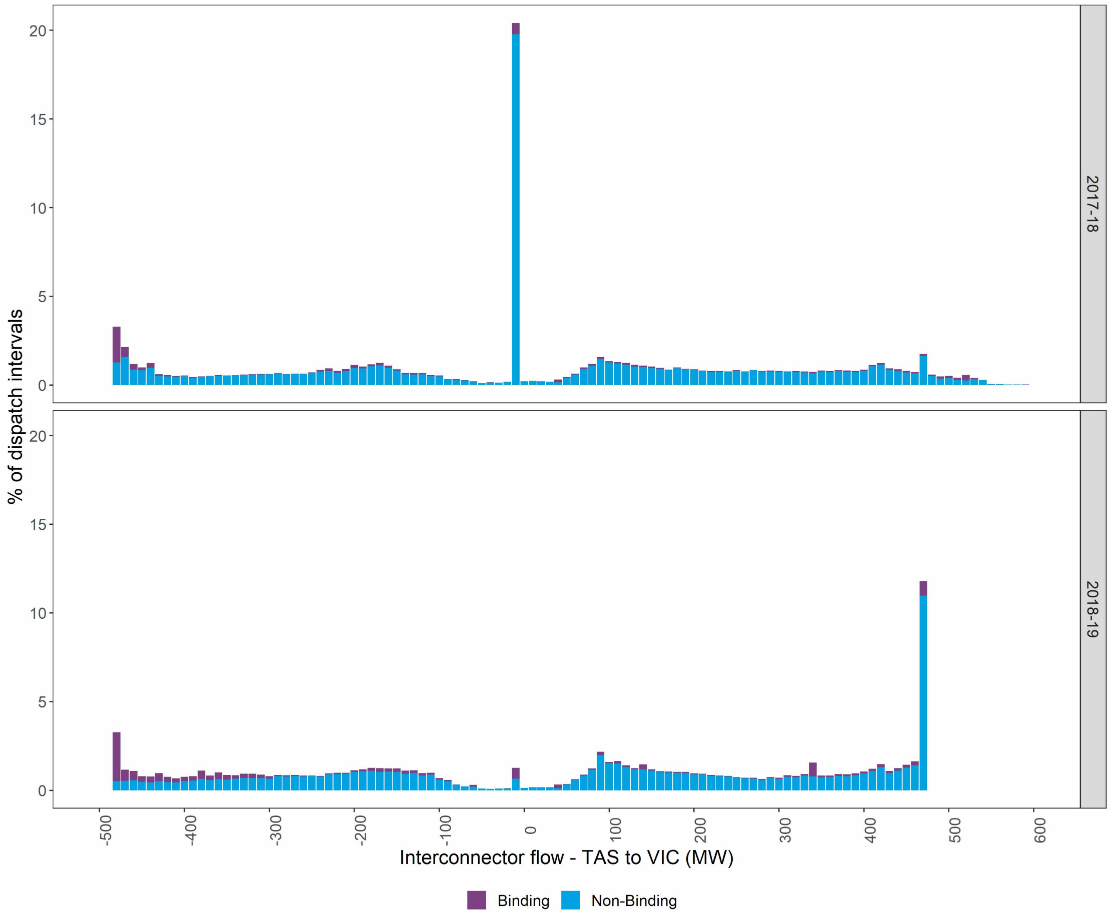
Interregional flows across Basslink

The Basslink Interconnector is a sub sea HVDC interconnector between Victoria tand Tasmania. Basslink's capacity is rated at 500 MW of energy on a continuous basis in either direction and up to 630MW export from Tasmania for limited periods.

Figure 3.28 shows the flows between Victoria and Tasmania in 2017/18 and 2018/19. The most notable feature is the amount of time in 2017/18 with zero flow. This can be attributed to an event on 24 March 2018, where a third-party damaged Basslink equipment during routine maintenance at its Victorian transition station. Basslink resumed normal operations on 5 June 2018. The outage meant the availability of Basslink in 2017/18 was 79.77 per cent[105]

With no major outages for Basslink in 2018/19, the interconnector operated more consistently throughout the year. Tasmania remained a net exporter into Victoria with a large number of intervals. As shown in Figure 3.28 below, when flows from Victoria to Tasmania increase, Basslink binds more often.

Figure 3.28: Interregional flow across Basslink



Source: AEMC analysis.
Note: The left-hand side of the chart shows flows from Victoria to Tasmania, the right-hand side shows flows from Tasmania to Victoria.
Note: The data for this chart is available in the AMPR data portal.

Transmission network performance

This section provides a summary of transmission network network performance in 2018/19. The Panel has considered both unplanned network outages and the resulting market impacts.

105 Office of the Tasmanian economic regulator, *Energy in Tasmania report 2017-18*.

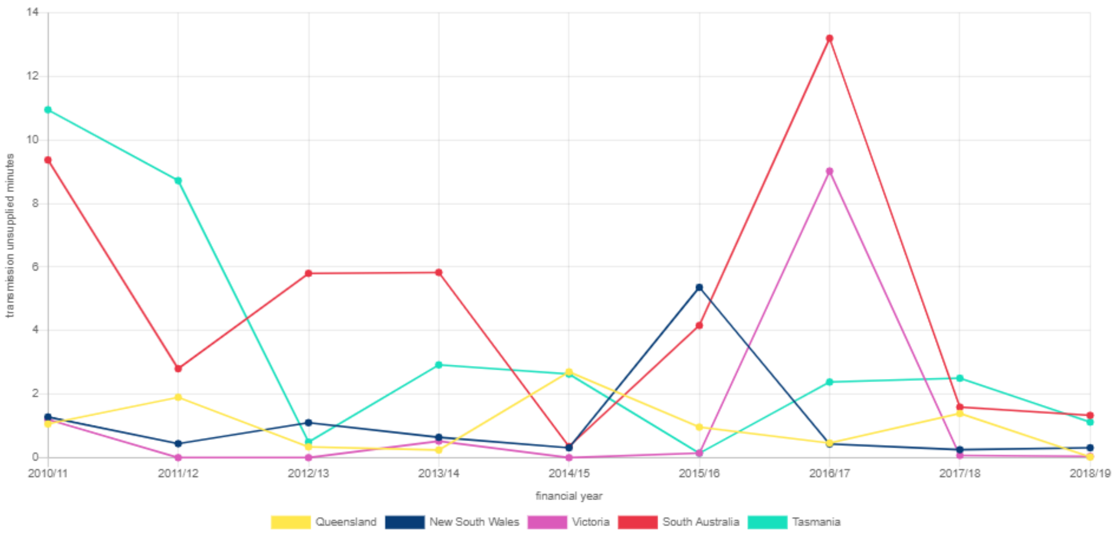
The Panel has also discussed some of the changes underway at the transmission level including the increased number of generator connections, and changing loss factors.

Transmission network outages

Unplanned network outages result in lost load which is not counted towards unserved energy for the purposes of the reliability standard. This is because unserved energy is only demand not met due to insufficient generation and bulk transfer, which does not include interruptions to supply caused by disturbances on intra- regional transmission and distribution networks.

Figure 3.29 shows the performance of the transmission networks as experienced by consumers in each region.

Figure 3.29: Transmission unsupplied minutes



Source: Information provided by: Queensland - Powerlink; New South Wales - TransGrid; Victoria - AusNet Services; South Australia - ElectraNet; Tasmania - TasNetworks

Note: For South Australia, the 28 September 2016 black system event did not contribute to the unsupplied minutes calculations as this was considered to be a force majeure.

Note: Outages on the transmission network are measured in system unsupplied minutes which is the amount of energy not supplied, divided by maximum demand, multiplied by 60.

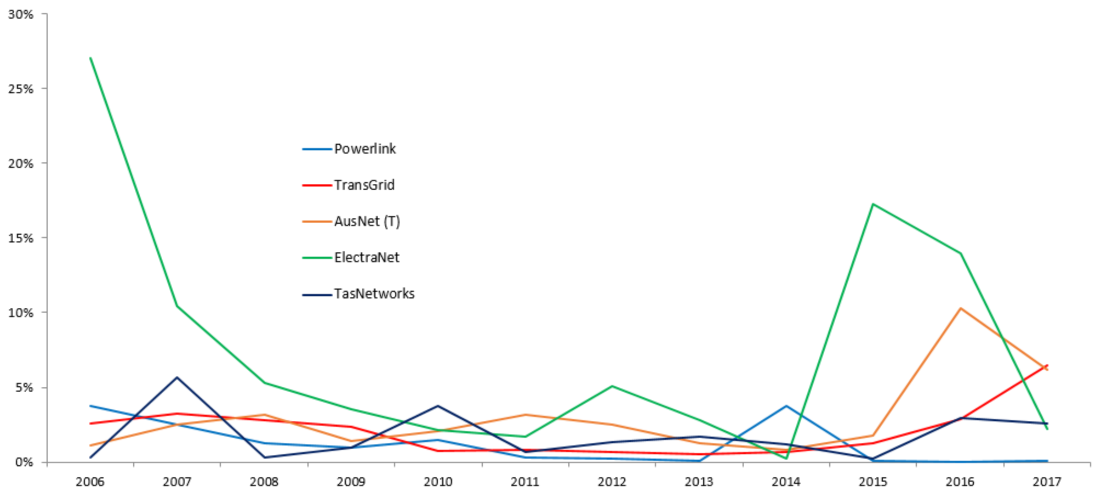
Note: The data for this chart is available in the AMPR data portal.

In 2018/19 all states except New South Wales experienced fewer transmission unsupplied minutes than in 2017/18, and all networks delivered fewer than two minutes of system unsupplied minutes.

When transmission assets are withdrawn from service, it can impact system demand and the ability for generators to sell electricity into the wholesale market. Therefore, transmission outages can effect customers by impacting the energy price in the NEM.

While the number of unsupplied minutes is at or close to the lowest they have been, percentage of dispatch intervals where a transmission outage had a market impact, that is, had an impact on the energy price is increasing. This is shown below. In this figure, if an outage increases the energy price by more than $10/MWh it is counted in the market impact measure.

Figure 3.30: Percentage of dispatch intervals where a transmission outage impacted the electricity price



AER, Transmission performance data 2006-2018.

Note: The data excludes outages caused by force majeure events, resulting from third party systems, required to maintain personal safety or security, and other specific exclusions.

Transmission planning and congestion

The electricity sector transition that is currently underway is changing the dynamics of the power system. Along with the change in generation mix and profile, networks across the NEM are becoming more meshed and interconnected (both within and across regions). This is combining with increased inter-regional trade and sharing of reserves between jurisdictions (see section 3.4.3 above).

The transmission sector will continue to evolve as significant amounts of new generation connect to the grid in coming years. Unlike the existing power system, the system of the future is likely to be characterised by numerous relatively small and geographically dispersed generators.

AEMO's 2018 ISP 'neutral with storage' modelling scenario shows that by 2030 over 6 GW of existing generation is expected to close and be replaced by approximately 22 GW of renewable generation and 6 GW of storage.[106]

Instead of locating where there is substantial existing transmission to serve them, these generators may instead connect in sunny or windy areas at the edges of the grid, where the

106 Note the 2020 draft ISP does not have a "neutral with storage' scenario.

network is less strong. In addition, these new types of generation can be built more quickly than transmission infrastructure. As a result, these generators may experience significant congestion on the transmission network after connecting.

Transmission businesses are already experiencing congestion across their networks and this is forecast to increase. Substantial and timely transmission infrastructure is therefore likely to be required and the scale and speed of change means that there is a need to have a better way of co-ordinating generation and transmission investment decisions in order to better facilitate the development.

As well as the whole-of-system plan set out in AEMO's ISP, the Panel notes that regulatory change is also needed to underpin the next wave of investment needed to deliver secure and reliable power system.

The AEMC is conducting its COGATI review which proposes a comprehensive reform package that seeks to provide better locational signals to generators, resulting in more effective use of the transmission network; as well as giving generators an ability to manage risks associated with congestion and changing losses.[107]

The Panel notes that a number of the recommendations in that report have been implemented and others are underway.

- Changes to regulatory frameworks are being made to directly link investment decisions by transmission businesses to AEMO's ISP.[108]
- New rules have also been made to streamline regulatory approval processes for these strategic projects.[109]
- A process is underway through the COGATI access review[110] to develop a new access model to better coordinate generation and transmission investment through the introduction of locational marginal pricing and financial transmission rights in the NEM. The proposed new access model seeks to provide certainty about the operation and revenue of assets. It also seeks to improve signals for investment in generation and transmission to locate in areas of the network that are more beneficial for the power system.
- A rule change request has been submitted to the AEMC[111] by AEMO seeking to make it easier for large-scale storage systems to connect to the network by creating a new registration category to support seamless integration.

107 AEMC's *Coordination of generation and transmission investment review, final report,* December 2018.

108 The ESB has consulted on draft ISP rules to convert the ISP into action. A final ISP Rule change package will be provided to the COAG Energy Council at its March meeting. The ESB is undertaking this Rule change process in accordance with section 90F of the NEL.

109 In April 2019, the AEMC made new rules to streamline regulatory processes for three projects (upgrades to QNI and VNI, and the proposed interconnector between South Australia and New South Wales – Project EnergyConnect) identified by the AEMO in its inaugural ISP.

110 The AEMC's Coordination of generation and transmission investment implementation – access and charging project was initiated in March 2019.

111 AEMO, *Integrating energy storage systems into the NEM rule request*, August 2019.

These changes all seek to create a framework where investment and operational decisions deliver the most efficient outcomes for customers at the same time as maintaining a secure power system even in light of the technological change underway.

Governments have also taken action to facilitate transmission upgrades including:

- The South Australian and New South Wales governments provided financial support to underwrite early works on the proposed SA/NSW interconnector, Project EnergyConnect.
- The federal and NSW governments are jointly underwriting early works to upgrade to an electricity interconnector between New South Wales and Queensland.
- Outside of the Panel's reporting year in February 2020, the Victorian Government introduced the *National Electricity (Victoria) Amendment Bill 2020 (Bill)*. If passed, the Bill would amend Victoria's application act for the NEL to enable the Victorian Minister, by Order, to modify or disapply certain provisions of the NEL and NER to "facilitate or expedite" the implementation of specified transmission system augmentations, non-network service and services related to a specified transmission system augmentation.

Transmission losses

Transmission losses, their method of calculation, and recent volatility in loss factor values have attracted attention during 2018/19 in terms of investability of certain plant.

Transmission losses are the portion of power lost as heat energy when transferred through the transmission network. These losses increase as more generation connects in locations that are distant from load centres, and the power produced has to travel further to the load centre. Losses are also impacted by changes in power system flows, for example where generation retires in a region and requires more power to be imported from other regions.

It is necessary to account for these losses when operating the power system and the market. In the NEM, this is done by representing these losses with marginal loss factors (MLFs), which are calculated and applied annually by AEMO to the processes of generation dispatch and wholesale market revenue settlement.

MLFs are used to adjust the price of electricity in a NEM region, relative to the regional reference node, in a calculation that aims to recognise the difference between a generator's output and the energy that is actually delivered to consumers. Generally speaking, generators with higher MLF values (that is a value that is close to one, or greater than one) will be dispatched first, and will receive a settlement payment for energy that is closer to the regional reference price.

Historically, MLFs did not change markedly from year to year. However, various factors, including recent changes in the power system, has resulted in significant year to year changes in some MLFs in some parts of the power system. In 2018/19 AEMO outlined the following major changes in load and generation patterns driving changes in MLFs:

- increased renewable generation, particularly in north Queensland, central Queensland, north-west Victoria, and northern South Australia.

- decrease in projected generation from coal and gas fired power stations across the NEM. Increased consumption forecast in southern Queensland, in particular forecast increased liquefied natural gas (LNG) processing load.
- decreased regional consumption forecast in Queensland, New South Wales, Victoria, and SouthAustralia.
- increased regional consumption forecast in southern Tasmania and increased generation on the west coast.
- forecast increased Basslink power transfers from Victoria to Tasmania.

These changes drove significant changes in MLFs in 2018/19 compared to 2017/18. The major changes in regional loss factors were:

- A large reduction in MLFs at connection points in central and northern Queensland, and an increase in MLFs at connection points in south-east and south-west Queensland.
- A reduction in MLFs at connection points in northern and southern New South Wales.
- A reduction in MLFs at connection points in central Victoria, western Victoria and north-west Victoria, and an increase in MLFs at connection points in northern Victoria.
- An increase in MLFs at connection points in south-east and the Riverland area in South Australia, and a reduction in MLFs at connection points in northern South Australia.
- A general increase in MLFs at connection points in Tasmania.

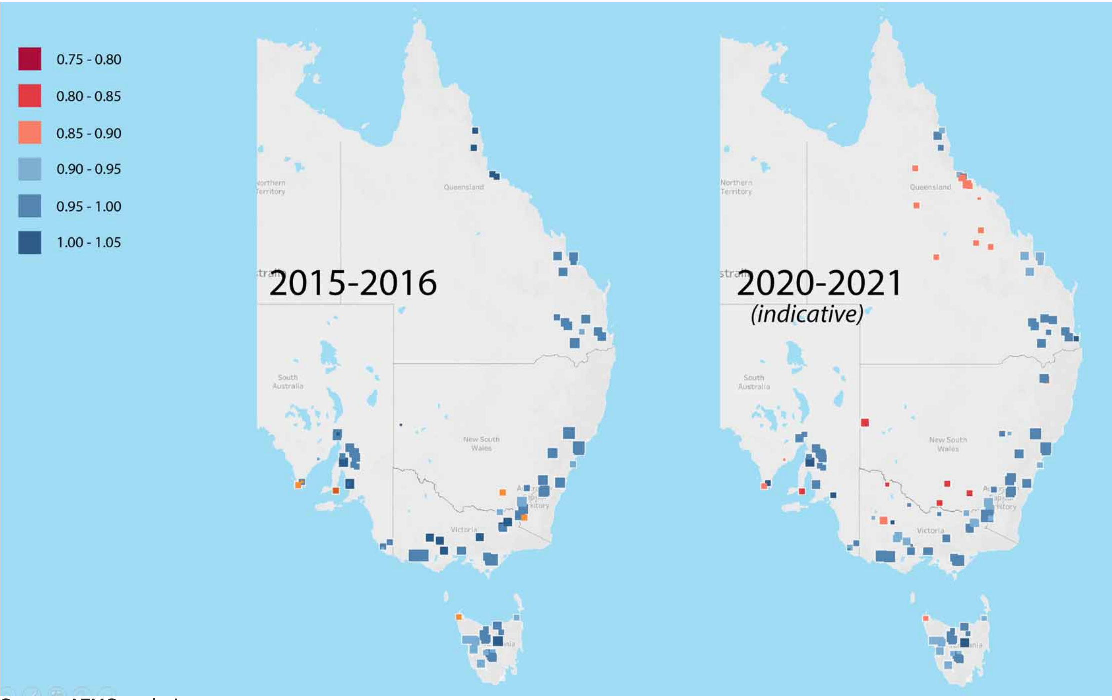
Changes between the 2018/19 MLFs and the 2019/20 MLFs continue to be driven by the large volume of new generation projects connecting to the NEM. When determining the 2019/20 MLFs, AEMO accounted for approximately 4,500 MW of new capacity. While not in the Panel's reporting year, the Panel notes that in general, MLFs declined between 2018/19 and 2019/20. In summary:

- Reduction in MLFs at connection points in central and northern Queensland.
- A very large reduction in MLFs at connection points in south-west New South Wales
- A very large reduction in MLFs at connection points in north-west Victoria
- Increase in MLFs at connection points in the south-east and Riverland area in South Australia
- A general decrease in MLFs at connection points in Tasmania.

AEMO has recently published its draft MLFs for 2020/21.[112] The Panel will consider these in next year's report however Figure 3.31 below shows the areas in the NEM impacted most by lower MLFs in 2020/21 compared to 2015/16.

112 AEMO, *Draft marginal loss factors 2020-21*, March 2020

Figure 3.31: Change in transmission loss factors 2015/16 to 2019/20 (indicative)



Source: AEMC analysis.

The emerging pattern is that changes in MLFs are increasingly driven by the unprecedented number of new generation connections expected to connect to the NEM. The vast majority is variable renewable generation intending to connect to electrically weak areas of the network that are remote from the regional reference node, resulting in MLFs falling by large margins.

On 27 February 2020, the AEMC published a final determination in relation to marginal loss factors. The final determination set out that the existing marginal loss factor methodology would be retained. The final determinations highlights the importance of maintaining clear signals for efficient dispatch and future investment in the market. The AEMC considers the marginal loss factor methodology is the most efficient way of accounting for losses, and continuing to set these loss factors on an annual, forward-looking basis remains the most appropriate approach given the existing broader market design.

As discussed above, AEMO has recommended transmission augmentation as part of the ISP which, if implemented, will increase transfer capability and reduce network losses.

Distribution network performance

The performance of distribution networks, and the reliability standards that must be met, fall within the responsibility of each jurisdiction. All jurisdictions have their own monitoring and reporting frameworks for reliability of distribution network service providers (DNSPs).[113]

There are two main indicators of distribution network reliability:

- System average interruption *duration* index (SAIDI)
- System average interruption *frequency* index (SAIFI).

DNSP performance in 2018/19 in relating to each of these, is discussed below.

System average interruption duration index

SAIDI indicates the average number of *minutes* of outages that each customer served by the DNSP experienced, specifically, the sum of the duration of each sustained customer interruption, divided by the number of customers, excluding certain events that are not within the control of the distribution network.[114] SAIDI is an indicator of how long it took to respond to and restore power after an outage.

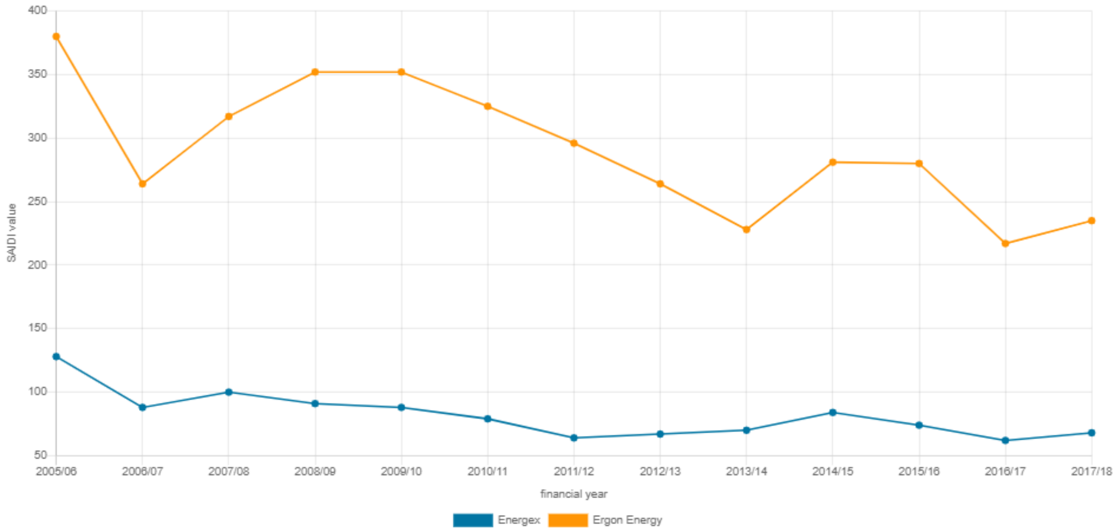
Network reliability standards are often measured in terms of the SAIDI. It is calculated for different parts of each DNSP's network for example the reliability on long rural lines is calculated differently to reliability of CBD networks. The reliability targets for these different parts of the network are also different.

The average SAIDI figure for each DNSP in the NEM is shown in Figure 3.32. As shown in the figure, DNSPs that largely serve urban customers such as Ausgrid, Energex and CitiPower have experienced SAIDI outage rates of around 100 minutes or less. DNSPs such as Essential Energy, Power & Water and Ergon Energy which have larger proportions of rural customers have experienced the highest SAIDI outage rates. Distribution networks that have predominately rural customers also had outage rates with the highest variability, possibly reflecting the vulnerability of these rural networks weather events. DNSPs with urban customers tended to have more consistent outage rates.

113 Jurisdictional arrangements are summarised in appendix B of the Reliability Panel's *Annual market performance review 2018*.

114 For a more detailed list of exclusions, see AER, *Distribution Reliability Measures Guideline*, November 2018, p. 8.

Figure 3.32: DNSP system average interruption duration index - Queensland

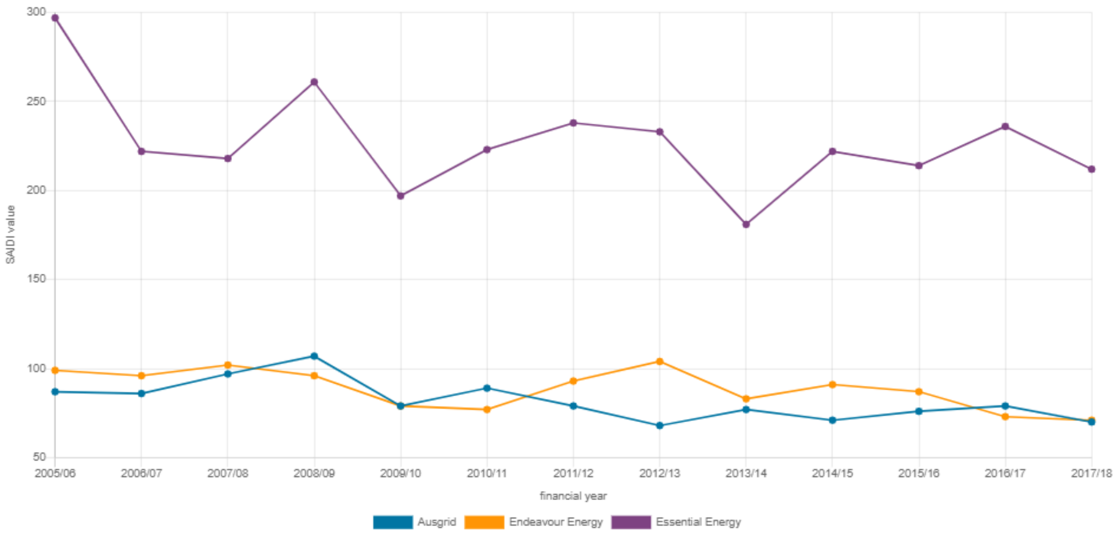


Source: AEMC analysis of AER data.

Note: This figure was used in the AEMC's Economic regulatory framework review for 2019. The Panel notes different exclusion methodologies, variances in customer numbers by feeder and different geographical conditions may apply in each jurisdiction. These averages are therefore to represent a summary only. Additionally, the average SAIDI provided for each jurisdiction is calculated on a different basis and therefore, averages should not be directly compared between jurisdictions.

Note: The data for this chart is available in the AMPR data portal.

Figure 3.33: DNSP system average interruption duration index - New South Wales

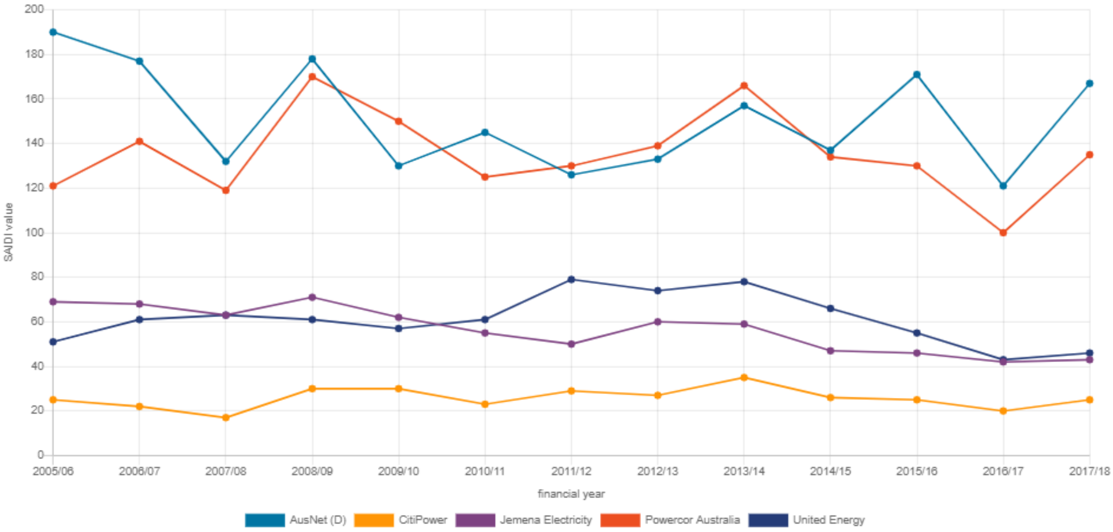


Source: AEMC analysis of AER data.

Note: This figure was used in the AEMC's Economic regulatory framework review for 2019. The Panel notes different exclusion methodologies, variances in customer numbers by feeder and different geographical conditions may apply in each jurisdiction. These averages are therefore to represent a summary only. Additionally, the average SAIDI provided for each jurisdiction is calculated on a different basis and therefore, averages should not be directly compared between jurisdictions.

Note: The data for this chart is available in the AMPR data portal.

Figure 3.34: DNSP system average interruption duration index - Victoria

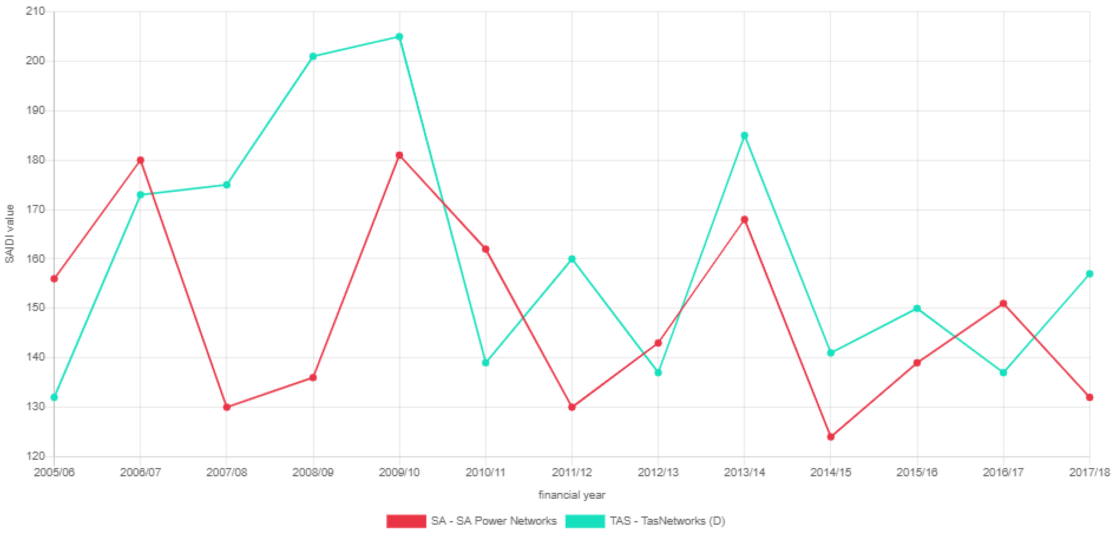


Source: AEMC analysis of AER data.

Note: This figure was used in the AEMC's Economic regulatory framework review for 2019. The Panel notes different exclusion methodologies, variances in customer numbers by feeder and different geographical conditions may apply in each jurisdiction. These averages are therefore to represent a summary only. Additionally, the average SAIDI provided for each jurisdiction is calculated on a different basis and therefore, averages should not be directly compared between jurisdictions.

Note: The data for this chart is available in the AMPR data portal.

Figure 3.35: DNSP system average interruption duration index - South Australia and Tasmania



Source: AEMC analysis of AER data.

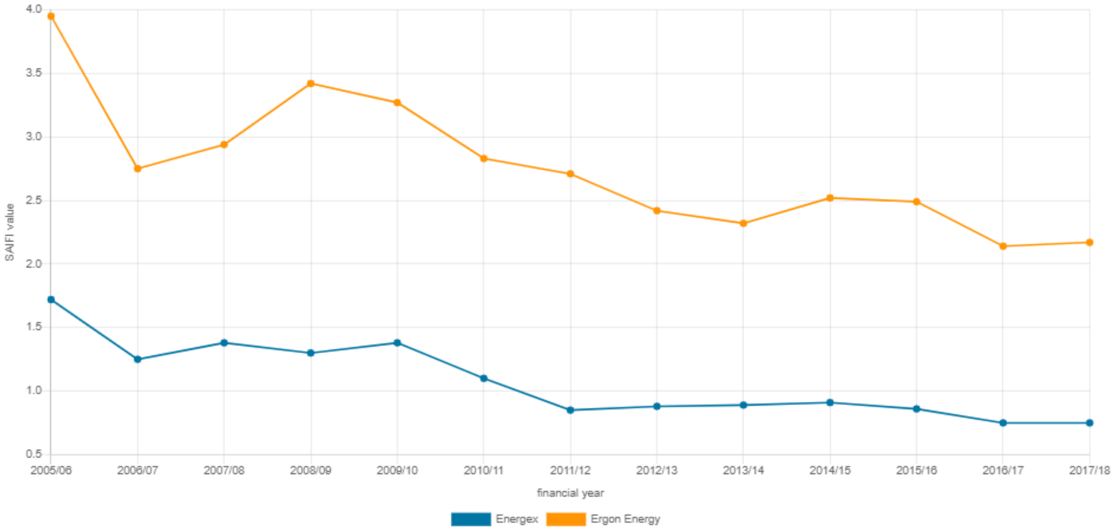
Note: This figure was used in the AEMC's Economic regulatory framework review for 2019. The Panel notes different exclusion methodologies, variances in customer numbers by feeder and different geographical conditions may apply in each jurisdiction. These averages are therefore to represent a summary only. Additionally, the average SAIDI provided for each jurisdiction is calculated on a different basis and therefore, averages should not be directly compared between jurisdictions.

Note: The data for this chart is available in the AMPR data portal.

System average interruption frequency index

SAIFI indicates the average *number* of outages for each customer served by the DNSP. Figure 3.36 shows the SAIFI, which indicates the average *number* of outages for each customer served by the DNSP.

Figure 3.36: DNSP system average interruption frequency index - Queensland

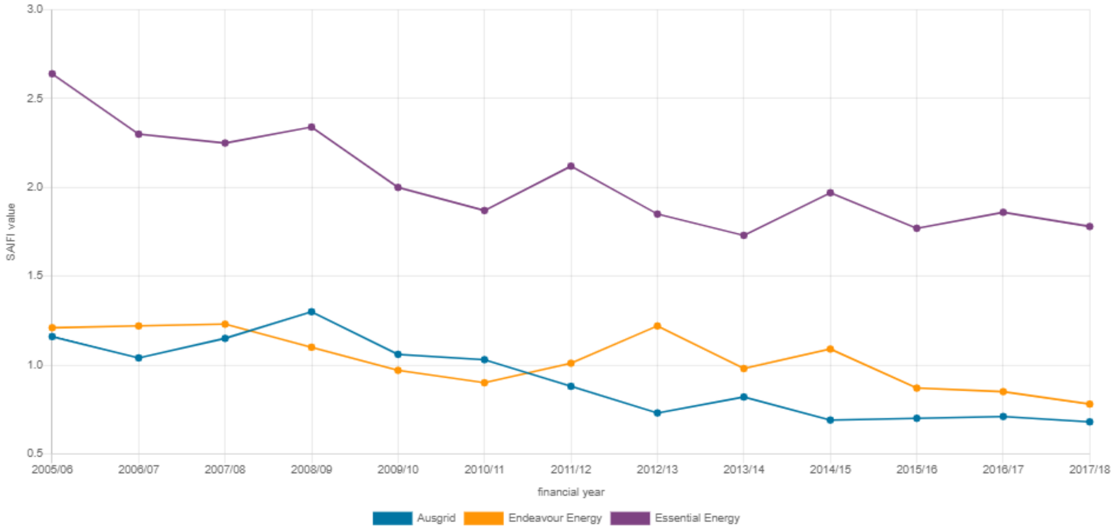


Source: AEMC analysis of AER data

Note: This figure was used in the AEMC's Economic regulatory framework review for 2019. The Panel notes different exclusion methodologies, variances in customer numbers by feeder and different geographical conditions may apply in each jurisdiction. These averages are therefore to represent a summary only. Additionally, the average SAIFI provided for each jurisdiction is calculated on a different basis and therefore, averages should not be directly compared between jurisdictions.

Note: The data for this chart is available in the AMPR data portal.

Figure 3.37: DNSP system average interruption frequency index - New South Wales

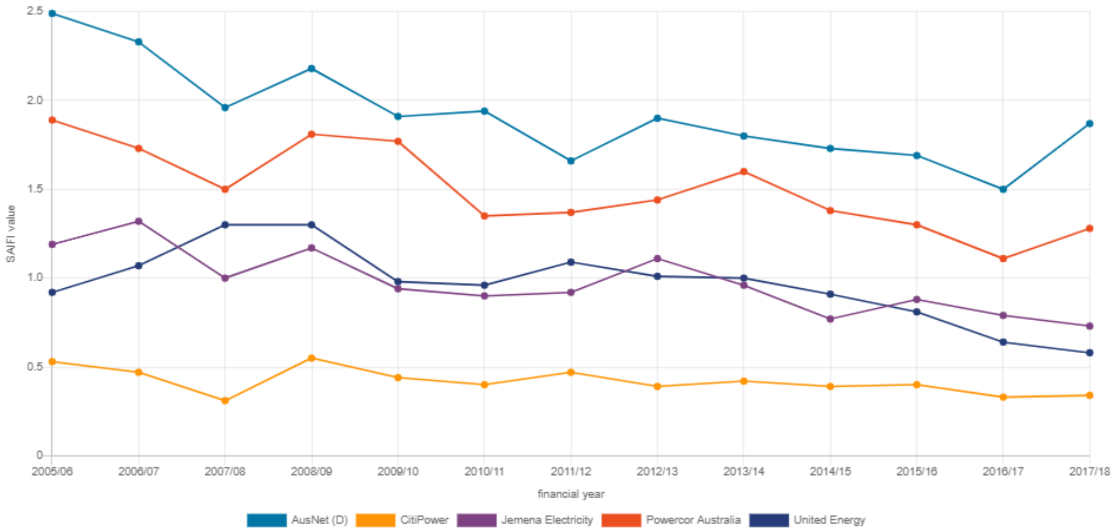


Source: AEMC analysis of AER data.

Note: This figure was used in the AEMC's Economic regulatory framework review for 2019. The Panel notes different exclusion methodologies, variances in customer numbers by feeder and different geographical conditions may apply in each jurisdiction. These averages are therefore to represent a summary only. Additionally, the average SAIDI provided for each jurisdiction is calculated on a different basis and therefore, averages should not be directly compared between jurisdictions.

Note: The data for this chart is available in the AMPR data portal.

Figure 3.38: DNSP system average interruption frequency index - Victoria

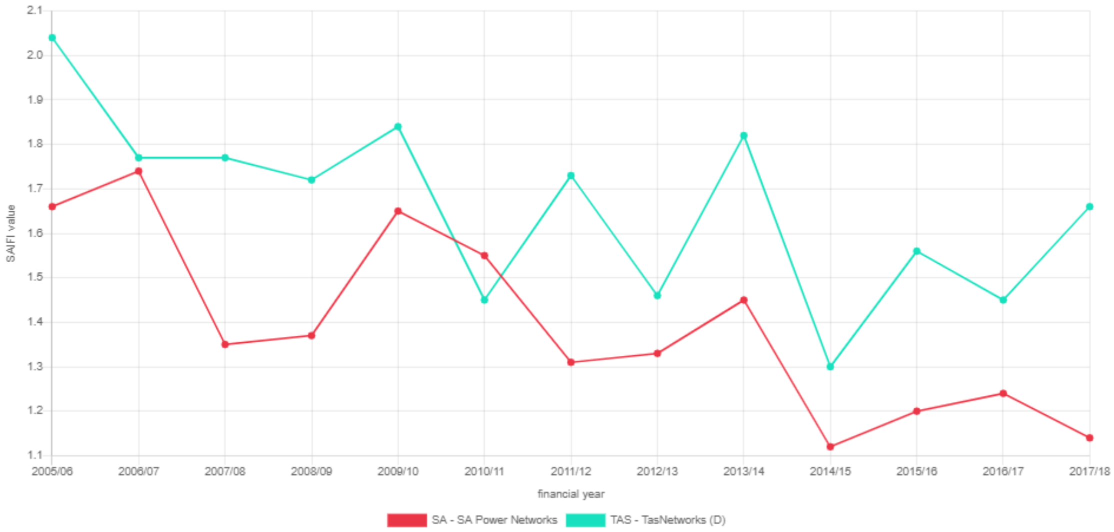


Source: AEMC analysis of AER data.

Note: This figure was used in the AEMC's Economic regulatory framework review for 2019. The Panel notes different exclusion methodologies, variances in customer numbers by feeder and different geographical conditions may apply in each jurisdiction. These averages are therefore to represent a summary only. Additionally, the average SAIDI provided for each jurisdiction is calculated on a different basis and therefore, averages should not be directly compared between jurisdictions.

Note: The data for this chart is available in the AMPR data portal.

Figure 3.39: DNSP system average interruption frequency index - South Australia and Tasmania



Source: AEMC analysis of AER data.

Note: This figure was used in the AEMC's Economic regulatory framework review for 2019. The Panel notes different exclusion methodologies, variances in customer numbers by feeder and different geographical conditions may apply in each jurisdiction. These averages are therefore to represent a summary only. Additionally, the average SAIDI provided for each jurisdiction is calculated on a different basis and therefore, averages should not be directly compared between jurisdictions.

Note: The data for this chart is available in the AMPR data portal.

Beyond performance metrics around outages for distribution networks, there are a number of emerging challenges that will be crucial in overcoming if DNSPs are to continue to be able to deliver reliable supply to customers on their network. These include:

- achieving greater visibility of their networks. Traditionally, DNSPs have had limited visibility of electricity flows and voltage levels on their networks. This was less necessary but is becoming more important as more generation and demand response is embedded in the distribution network.
- the integration of growing amounts of distributed energy resources, particularly rooftop solar PV. These distributed energy resources can affect network flows and voltages. DNSPs will soon also need to incorporate electric vehicles and embedded storage.
- growing peak demand, particularly driven by residential air conditioning.

3.5 Key changes to reliability frameworks in 2018/19

As the power system itself changes, so too must the regulatory framework that supports reliability outcomes. During the 2018/19 financial year, a range of changes were made to adapt existing tools, introduce new one, or improve the information and signals that drive reliability outcomes in the NEM. The Panel has explored the key changes below and provided commentary on the impact these rules have had during the year or, where its too early to tell, the expected impact of the new arrangements.

Key changes to reliability frameworks in 2018/19 include:

- Changes to lack of reserve framework
- Enhancement to the RERT
- New rules to inform investment and operational decisions
- Improvements to forecasting.

3.5.1 Changes to lack of reserve frameworks

The LOR declaration framework has existed since the start of the NEM. Its primary function is to inform the market of the risk of involuntary load shedding, that is potential shortfalls in reserves may occur in the next seven days.

At certain risk levels, AEMO will seek to alleviate the potential shortfalls in reserves by calling for a market response. It does this by informing market participants of the potential of lack of reserve conditions through publishing a market notice.

On 19 December 2017, the AEMC made a new rule that promotes short-term reliability in the NEM by modifying the framework for the declaration of lack of reserve conditions to be more flexible and transparent.

The new arrangements introduced a more flexible way for AEMO to declare lack of reserve conditions using the existing deterministic approach, or a new probabilistic calculation that allows for the impact of estimated reserve forecasting uncertainty in the prevailing conditions when calculating the LOR levels. The new arrangements include a more robust consultation process and reporting regime.

The key features of the new arrangements are:

- the removal of the three levels of contingency-based LOR definitions descriptions from the NER and replacement with a high-level description of lack of reserve condition
- the introduction of an obligation for AEMO to develop and publish reserve level declaration guidelines that set out how AEMO will determine a lack of reserve condition
- minimum requirements for the guidelines, including obliging AEMO to declare at least three probability levels that indicate an increasing level of probability
- the introduction of the factors that AEMO must take into account when assessing how to declare an LOR
- a requirement for AEMO to use an amended version of the rules consultation procedures when amending the guidelines
- a requirement for AEMO to report on the operation of the LOR framework every quarter.

The new arrangements improve the LOR framework since it will better predict the risk of insufficient market reserves, which should lead to more efficient outcomes on short-term reserves and promote reliability for consumers.

The LOR declaration framework is an important information tool that promotes efficient market responses to tight demand-supply conditions. 2018/19 was the first full year the new arrangements have been in place and the Panel will use the LOR results reported in section

3.4.3 as a baseline to explore the impact of a probabilistic framework for forecasting lack of reserve conditions.

However, in the meantime, the Panel notes that in a world that is changing, it is possible for a reserve shortfall risk to be larger than the largest credible contingency, particularly on extreme weather days. There will continue to be intermittent generators connecting to the NEM that may not individually add significant forecast uncertainty, but in aggregate these generators will increasing set the threshold for short term uncertainty. The Panel agrees that the previous LOR contingency-based framework was no longer fit for purpose and that forecasting LORs using a more flexbile probabilistic approach reflects the dynamic nature of supply and demand in the NEM today and into the future.

3.5.2 Enhancement to the RERT

The AEMC made the *Enhancement to the Reliability and Emergency Reserve Trader* final rule in May 2019. The final rule provides AEMO with flexibility in using emergency reserves while also seeking to minimising the associated costs. The final rule:

- links the RERT procurement trigger and volume to the reliability standard, which provides transparency to market participants of when and how emergency reserves will be used
- provides flexibility to AEMO as to how much emergency reserves it can procure
- provides flexibility and discretion as to how the reliability standard is incorporated in its day-to-day operations, particularly through its modelling and forecasting of power system risk
- increases the procurement lead time from 9 to 12 months, which will broaden the pool of RERT providers, allowing emergency reserves to be procured at lower cost for consumers. It also promotes consistency with the Retailer Reliability Obligation.

Alongside these changes, the final rule also recognised that intervening in the wholesale market has the potential to distort efficient outcomes and potentially adversely impact on consumers. As a result, the final rule also:

- clarifies the out-of-market provisions so that reliability is more likely to be delivered at minimal cost to consumers, including by reducing the risk of gaming by reserve providers
- provides additional guidance to AEMO when assessing the appropriate costs of entering into emergency reserve contracts
- allocates the cost of emergency reserves to, where possible, those customers who caused the need for the RERT
- increases transparency and reporting, to assist market participants and consumers in planning for RERT costs.

On 8 October 2019, the AEMC received a rule change request from the Victorian Government seeking a jurisdictional derogation for Victoria to allow the AEMO to contract for RERT reserves on a multi-year basis in that state. Specifically, the proposal is to enable AEMO to procure long-notice RERT contracts of up to three years' duration in response to a short-term reliability problem in Victoria. The AEMC published a final determination on 12 March 2020.

The Panel notes the RERT has been activated each year for the last three years in a row indicating that as the power system transitions, AEMO is relying more on these intervention mechanisms to balance supply and demand. The enhanced RERT framework will assist AEMO in discharging its responsibilities to balance supply and demand to keep the power system reliable. The Panel notes that these interventions mechanisms have associated costs and the additional reporting requirements will be an important part of addressing stakeholder concerns about the use and cost of RERT. The information reported will give stakeholders access to clear, timely and meaningful information to help them manage operational and investment decisions.

The Panel will continue to monitor how the RERT is used and the associated costs in future AMPRs.

3.5.3 New rules to inform operational and investment decisions

In the 2018/19 year under review, a number of new pieces of information were made available to the market to inform investment and operational decisions. The Panel has considered how these new pieces of information are supporting reliability outcomes, including:

- generator notice of closure register
- register of distributed energy resources
- values of customer reliability
- transparency of new projects - noting this came into effect after the 2018/19 reporting year

Generator three year notice of closure register

The Panel notes that on 8 November 2018 the AEMC made a new rule[115] to promote reliability in the NEM by requiring generators to advise the AEMO of the expected closure year for all their scheduled and semi-scheduled generation units. It also requires generators to give AEMO at least three years' notice of their intention to permanently close a generating unit unless they are granted an exemption by the AER. This information will assist in managing the market impacts of the retirement of coal-fired generators as they reach the end of their economic lives and help market participants respond to possible future shortfalls in electricity generation, for example by building replacement capacity.

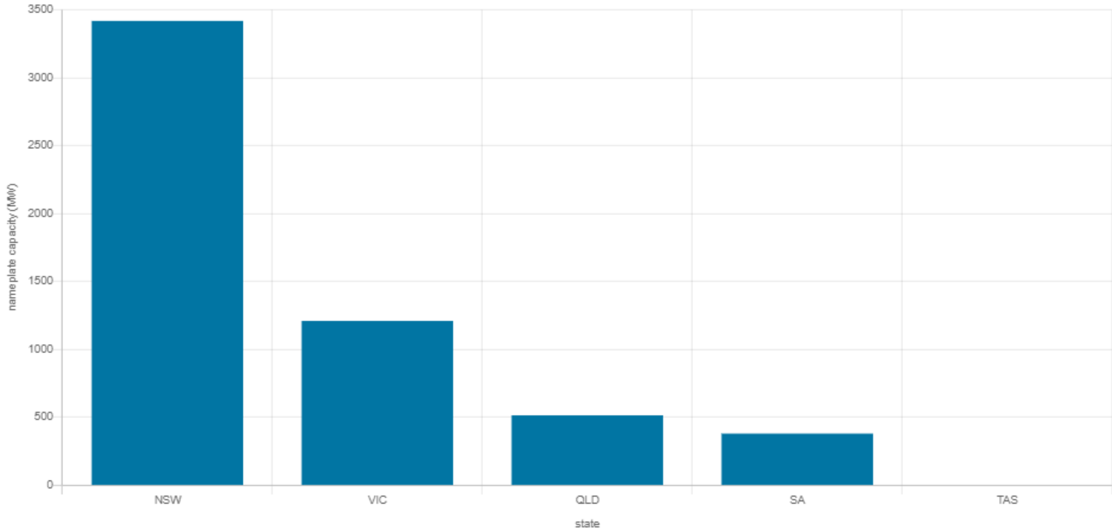
Expected closure years can now be found in the *generating unit expected closure year file* on AEMO's generator information page.[116] This will be updated regularly by AEMO.

As of 8 November 2019, all generators captured by the new requirement had registered a closing date with AEMO. Between now and 2030, more than 5,000 MW of capacity is expected to close. The capacity exiting, broken down by state and by fuel type, is shown in Figure 3.40 and Figure 3.41 below.

115 AEMC, *Three year notice of closure*.

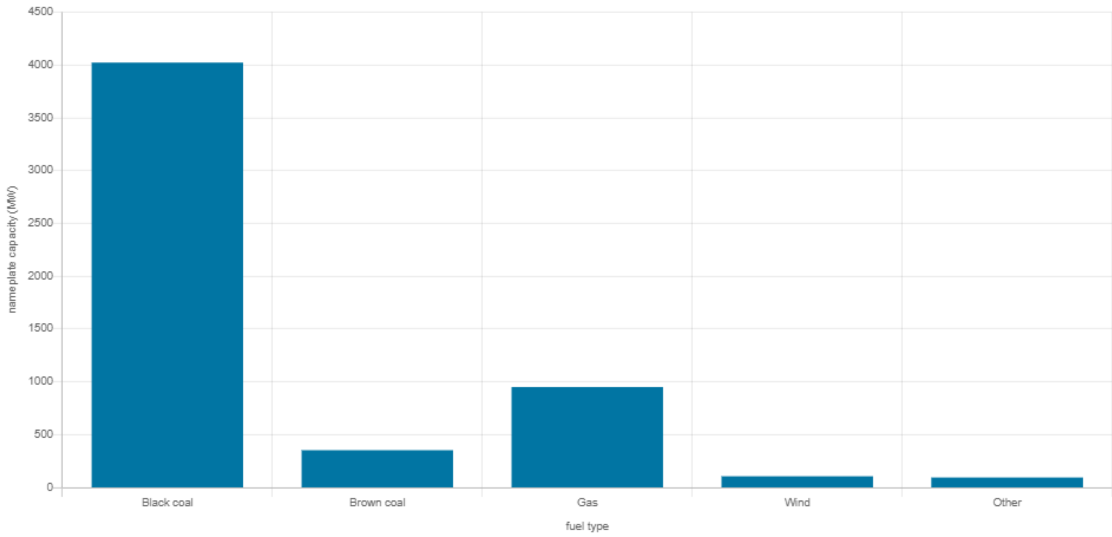
116 AEMO, *Generation information page*.

Figure 3.40: Generator capacity closing before 2030 - by state



Source: AEMC analysis of AEMO data from Generation information page.
Note: Gas includes landfill gas, waste coal mine gas, natural gas, coal seam gas, other includes diesel and biofuels.
Note: The data for this chart is available in the AMPR data portal.

Figure 3.41: Generator capacity closing before 2030 - by fuel



Source: AEMC analysis of AEMO data from Generation information page.
Note: Gas includes landfill gas, waste coal mine gas, natural gas, coal seam gas, other includes diesel and biofuels.
Note: The data for this chart is available in the AMPR data portal.

Governments and market participants are responding to the risks and opportunities resulting from upcoming generator closures. Responses include:

- 5,000MW of upgrades and committed new generation, and a further 60,000MW of proposed new generation listed on AEMO's generator information page as options to replace retiring capacity in coming years
- NSW and Federal Governments Liddell Taskforce that was established in August 2019 to look at how closing Liddell will change New South Wales' power supply and its effect on local businesses and families. The taskforce will also explore ways to keep electricity affordable and reliable.
- AGL (the owner of the Liddell Power Station) has announced plans to replace Liddell with a range of different resources, including gas peaking plants, demand response, a utility scale battery and renewable energy.[117]

In addition, market participants are likely to be factoring the expected closure of these plants into investment decisions that are not yet made public.

Register of distributed energy resources

On 13 September 2018 the AEMC made a new rule[118] requiring AEMO to establish a register of distributed energy resources such as small scale battery storage systems and rooftop solar. The DER Register is a database that stores information about all[119] DER devices installed on-site at residential or business locations. The information collected by NSPs from electrical contractors and solar installers and provided to AEMO.

The register will give network businesses and AEMO visibility of where distributed energy resources are connected to help in planning and operating the power system as it transforms.

AEMO has noted that the data held securely in the DER Register will enable it to:

- forecast, plan and operate the grid more efficiently, ensuring the system and market can deliver energy at an efficient price for all customers,
- be more prepared for major disruptions to the system with a greater understanding of how DER assets will behave during these events,
- prepare the grid for major innovations with DER such as virtual power plants, and enabling customers to consider and participate in new markets with their DER, and
- allow networks to make better informed decisions about network investment options in the future as demand changes and DER increases.

DER installers and electrical contractors have been required to provide information for the DER Register since December 2019 and that AEMO launched the DER register on 1 March 2020. The register has not been in place long enough to understand how it is contributing to the security and reliability of the power system; however, the Panel acknowledges the need for NSPs and AEMO to have greater visibility over DER and expects the DER register to play an increasingly important role in delivering a reliable and secure power system.

117 AGL, NSW Generation Plan, December 2017.

118 AEMC, *Register of distributed energy resources - final determination*, September 2018.

119 Generators or batteries that are only used as standby or back-up power, and generators or energy storage that registers with AEMO for market participation are exempt.

Transparency of new projects

The Panel notes that a new *transparency of new projects* rule[120] was made after 2018/19 reporting year to improve publicly available information about new grid-scale generation projects.

Increasing penetration of renewable generation such as wind and solar mean that TNSPs are receiving an unprecedented volume of generation connection enquiries with a significant amount of new generation- of proposed (mainly renewable) projects in various stages of development.

The Panel notes that this new rule and new information will support the energy market transition by making it easier and quicker for developers to assess the viability of proposed projects. It will also mean market participants are better informed of proposed connections which may assist them with their operational and investment decision-making.

From a reliability perspective this information will complement the information about generator closures schedules and underpin new investment needed across the NEM to deliver reliable supply. AEMO has published interim generation information guidelines on AEMO's website and has published key connection information about current proposed connections[121]

Values of customer reliability

On 5 July 2018, the Commission made a final rule to make the AER responsible for calculating values of customer reliability (VCR) estimates. This rule required AER to develop a VCR methodology, and calculate the first VCR estimates under that methodology, by 31 December 2019.

VCR estimates play an important role in balancing the need to deliver secure and reliable electricity supplies and maintain reasonable costs for electricity consumers. VCRs seek to reflect the value different types of customers place on a reliable electricity supply, and the level at which they are set reflect a trade-off between electricity reliability and affordability. Knowing how different customers value reliability in different parts of the grid helps inform policy-makers and network planners on how to most efficiently meet the demands of customers without over or under investing in assets that deliver electricity to their homes and businesses. VCRs expressed in dollars per kilowatt-hour.

On 18 December 2019, the AER released their final report on the Values of Customer Reliability, which set out the VCR values for unplanned outages of up to 12 hours in duration (i.e. standard outages) for the NEM and the Northern Territory. It was the largest VCR study ever conducted in Australia with over 9,000 residential, small business and industrial energy customers completing the survey.[122]

The survey sought to understand customer preferences across a range of outage situations considering:

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120 AEMC, *Transparency of new projects final determination*, October 2019.

121 AEMO, *Generation information page*.

122 More information can be found on the AER website here: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/values-of-customer-reliability-vcr

- how widespread an outage is
- how long the outage lasts
- whether the outage occurs during peak or off-peak times
- whether the outage occurs during summer or winter
- whether the outage occurs on a weekday or the weekend.

Very large businesses that reached peak demands of higher that 10 MVA were asked instead to answer a survey that placed a value on the direct costs they incur from outages of different durations.

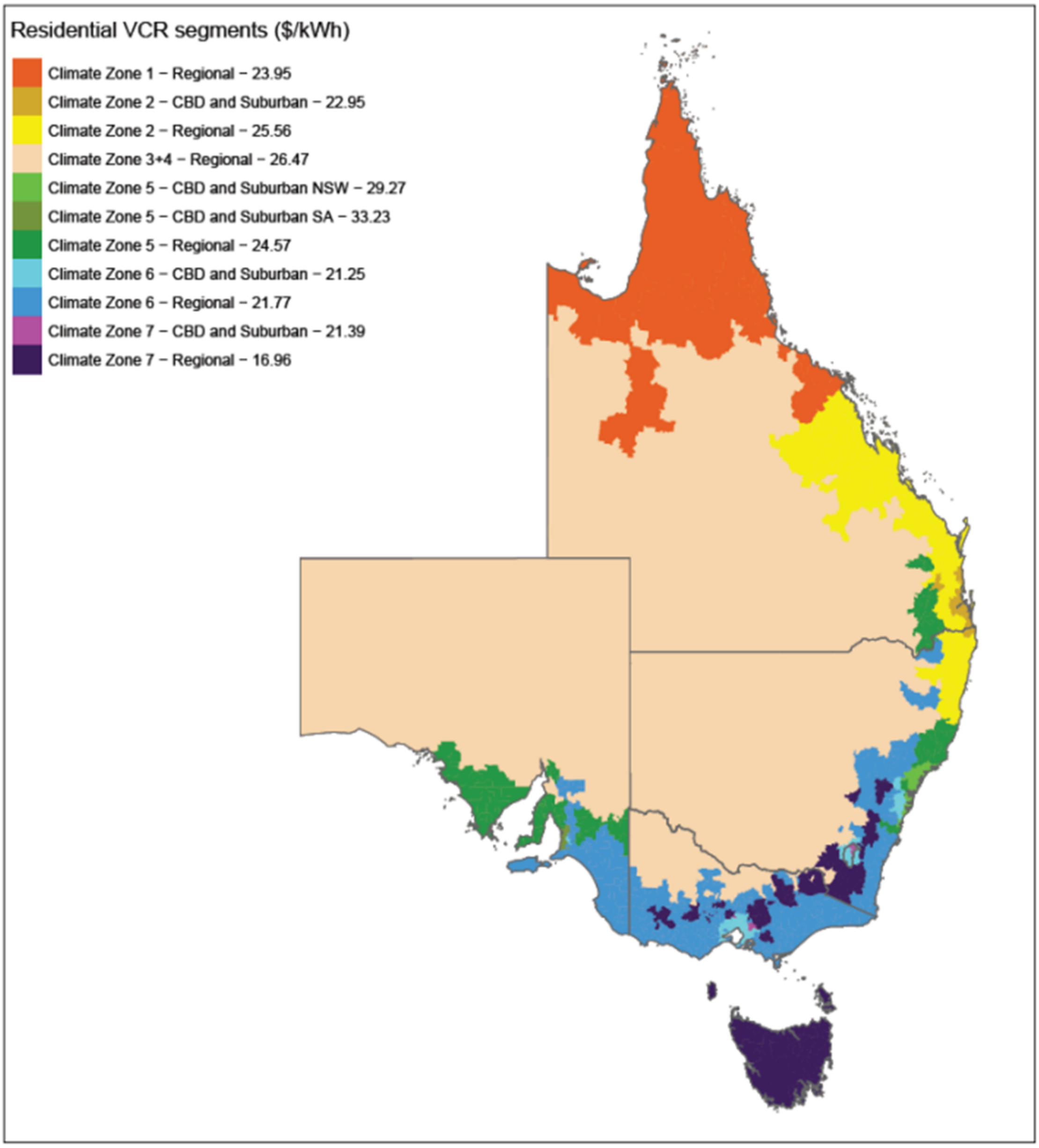
Findings

The AER found that:

- in general, VCR values are similar between the two survey years, 2014 (the last time the survey was undertaken) and 2019
- business customer VCRs continue to be higher than residential customer VCRs
- residential customers continue to value reliability and have a preference to avoid longer outages, and outages which occur at peak times. However, residential values are lower in 2019 than in 2014 with the exception of customers in suburban Adelaide
- the 2019 VCR values are lower than the 2014 results for agricultural and commercial customers, and higher for industrial customers
- the higher industrial VCR value has driven a small increase in the NEM and state VCR values compared to 2014. This is because proportionally, industrial customers use more energy relative to other customer segments and so, have a greater influence on load weighted VCR numbers
- the direct cost survey results show that VCR values amongst the approximately 300 business sites that consume the most energy in the NEM can vary greatly depending on the sector.

As shown in Figure 3.42, the AER considered climatic zone and remoteness to be key drivers of reliability preferences for residential customers, rather than other available divisions such as state boundaries.

Figure 3.42: Value of customer of reliability by climate zone



Source: AER, *Values of customer reliability - Final decision*, p. 15.

For business customers using less than 10 MVA peak demand, VCR values were derived for the same business sectors (agriculture, commercial and industrial) as AEMO in 2014. These are listed in Table 3.6 below. The AER's VCR values for very large businesses (reaching above 10 MVA peak demand) are not directly comparable to AEMO's 2014 values because a wider range of businesses were included in the survey sample compared to AEMO in 2014.

Table 3.6: Business customers Value of Customer Reliability numbers

Business < 10MVA peak demand per annum, VCR values (real $2019)		
Business customer segment	AER 2019 business VCR ($/kWh)	AEMO 2014 business VCR ($/kWh) real $2019
Agriculture	37.87	51.34
Commercial	44.52	48.16
Industry	63.79	47.45
Business customers with a peak demand of 10MVA or more (very large business customers) VCR values, ($/kWh) by sector		
Segment	$/kWh VCR values	
Services	10.54	
Industrial	117.99	
Metals	19.86	
Mines	35.16	
Business customers with a peak demand of 10MVA or more (very large business customers) VCR values, ($/kWh) by network connection		
Segment	$/kWh VCR values	
Transmission	26.44	
Distribution	56.69	

Source: AER,*Values of customer reliability - Final decision*

The AER is currently continuing work on VCRs for widespread and long duration outages and intend to publish the results, including the underlying model, in early 2020. The Panel has been engaging closely in the process and welcome the AER's work.

3.5.4 Challenges and improvements in forecasting

It's important to have accurate and regular information about the performance of the power system and market, and forecasts about what is expected both over the short and long term. This supports informed decision-making market bodies and governments. AEMO produces a wide range of forecasts over different time periods to understand the different elements impacting supply and demand.

Challenges in forecasting and modelling

The Panel acknowledges the challenges involved in accurately forecasting given the increasing complexity of the power systems. These forecasts are impacted upon by the actions of market participants as well as a range of external factors including the climate and government policies. Some of the factors making forecasting and modelling more challenging include:

- more variable and extreme weather outcomes
- generator performance under a range of scenarios, particularly older generation and performance under more extreme temperatures
- customer behaviour, particularly as technological developments enable them to become more price responsive
- the smaller windows for undertaking necessary planned outages
- availability of information from the increasing number of distributed, decentralised generation assets
- number and range of risks has increased and is increasingly uncertain, such as the risk of tail events occurring.

Greater uncertainty generally makes it more difficult to operate the power system in a secure and reliable manner. As such, it is important that steps are continually taken to:

- understand and assess potential risks to the power system so they can be incorporated into the reliability frameworks
- gain greater information or transparency where this improves outcomes at a reasonable cost
- improve forecasting methods, including placing the responsibility for forecasting on the party best placed to make this forecast.

There have been several recent examples of forecasting and modelling methods being improved.

- AEMO and ARENA are currently undertaking a self-forecasting trial with ARENA in which some intermittent generators are submitting their own forecasts.
- The VPP demonstrations being led by AEMO are considering how forecasts of VPP output can be incorporated into broader demand forecasts.

It is important to understand and to try and mitigate some of the uncertainty in modelling and forecasting where possible. This uncertainty has detrimental impact on reliability as it increases risk, which in turn tends to decrease the appetite for market participants to make important investment. Further, in an operational timeframe, it can lead to participants making more conservative decisions when operating their equipment which can lead to more inefficient outcomes for consumers.

Improvements to ESOO forecasts

The ESOO modelling uses a statistical approach, which calculates an average USE over a number of maximum and minimum demand outcomes and supply availability forecasts, weighted by likelihood of occurrence, to determine the probability of any supply shortfalls. These shortfalls have been expressed in terms of the expected unserved energy and compared to the NEM reliability standard.

The 2019 ESOO, like the 2018 ESOO, has modelled reliability performance under three scenarios: central, slower and a 'step change;' pace of change. The ESOO scenarios assess supply adequacy of existing and committed generation, storage and transmission projects, under three different demand projections driven by faster or slower transformative change in the NEM.

Comparing to 2018 ESOO, among others, AEMO introduced a number of modelling improvements in 2019 ESOO. Demand side forecasting improvements included:

- improved business sector consumption modelling
- large industrial loads modelling informed by interviews and sector surveys
- energy efficiency savings modelling has included consideration of energy efficiency savings from manufacturing small to medium enterprises
- maximum/minimum demand forecasting has added an extreme value approach, focusing on high/low demand points only.
- more nuanced forecasts incorporating the impacts of battery charging and EV forecasts
- energy efficiency impacts on maximum demand
- improvements to the way demand traces are developed to meet the annual maximum demand targets.

Supply forecasting improvements included:

- forced outage rate modelling that better captures the variability within each technology type
- variable renewable generation has been modelled using historical reference years which use the historical correlation between demand and wind and solar generation
- additional sensitivity analysis in the short term – the 2019 ESOO incorporated a number of sensitivities into its base case outlook. This resulted in a more realistic view of the range of possible conditions which will impact reliability in Victoria this summer.

From 2019 and onwards, the ESOO will include:

- reliability forecasts identifying any potential reliability gaps for each of this financial year and the following four years, as defined according to the Retailer Reliability Obligation
- an indicative reliability forecast of any potential reliability gaps for each of the final five years of the 10-year ESOO supply adequacy forecast.

3.6 Panel insights: challenges to reliability and work underway to address these

A reliable power system requires the following:

- efficient investment, retirement and operational decisions by market participants resulting in an adequate supply of capacity to meet demand and with a buffer available to respond to shocks
- a reliable transmission and distribution network
- the system being in a secure operating state.

The Panel notes that all three elements are becoming more difficult to achieve as the power system becomes more complex and uncertain. Operating a power system involves knowing what is happening in real time, and anticipating what is likely to happen in the future so supply and demand can be matched at all times. As the power system becomes more complex and uncertain, it becomes more challenging to predict and plan for what is going to happen in the coming minutes, hours, days, and years.

This chapter has focused on whether, in the face of these challenges, the market and regulatory frameworks are operating in a way that delivers enough supply to meet demand and enough network capacity to deliver it to customers.

Based on the metrics explored in this chapter, the reliability performance of the NEM has been satisfactory with the framework operating to support reliable delivery of electricity to customers during 2018/19**:**

- The reliability standard was met in all regions, and when used, intervention mechanisms delivered the outcomes they were expected to.
- The regulatory frameworks are delivering strong signals about when and where additional generation, demand response capacity and network capacity is needed. For example:
  - forecast unserved energy in New South Wales and Victoria suggests that there is likely to be future tight supply/demand conditions and associated high wholesale prices.
  - continued use of emergency RERT reserves suggests there is a need for flexible capacity that is available in summer months
  - triggering of the cumulative price threshold for energy suggests that there are strong financial incentives to be available on extreme demand days.
- Network investment is occurring in places where it's needed to get more supply to market.

However, the Panel notes that the concern around the NEM's ability to deliver reliable supply has increased.

To contribute to the concern, private sector investment in response to market and regulatory signals is not as strong as might be expected under the current market conditions. There may be a number of reasons for this within the regulatory framework including:

- some of the current price settings, such as the cumulative price threshold and administered price cap, may not provide sufficient incentives for new investment in peaking generation and demand response
- delays to connection resulting from system strength and grid congestion related issues are deterring investment.

The Panel notes that some investment in flexible capacity is not as transparent to the market as investment in peaking generation. For example, a number of retailers have started commercialising demand response programs aimed at getting their customers to reduce consumption during high wholesale prices.

It may also be a consequence of the broader changing external environment. It may be that pressures or uncertainty from outside the energy regulatory framework may outweigh the strong signals for new investment. This could include uncertainty in the cost and availability of fuel, future state and federal government policy, or consumer sentiment.

In sections below, the Panel has outlined some proposed responses to key challenges to reliability.

3.6.1 Adapting to changing power system conditions and community expectations

When the NEM was established, there was an oversupply of generation in the market resulting from state governments overbuilding. The reliability frameworks set up sought to deliver an efficient amount of generation i.e. enough to meet consumers expectations without encouraging over-building. The nature of the challenge facing the NEM is changing.

- the amount of variability in the NEM has increased due to the effects of and responses to climate change
- consumer confidence that there will be enough generation to supply their consumption has waned
- general uncertainty and the number and range of risks facing the power system have increased.

As the power system changes, the approach to delivering reliable supply may also need to change. For example the most recent summer has seen the NEM draw on all options to withstand storms, drought, bushfires and higher and higher temperatures.

The reliability standard has been a key regulatory feature since the NEM's inception in 1998. The Panel considers that changes in our physical power system, the climate, and increased planning and operational complexity, mean it is timely to examine this fundamental feature of the NEM framework.

The question is, how much of a buffer is cost effective? How tightly can we run a transitioning system so that we can deliver reliable energy to consumers with a high degree of confidence across multiple scenarios? The COAG Energy Council has tasked the ESB with reviewing the reliability standard as a way of testing these questions.

The Panel acknowledges the increasing concern regarding the reliability of the NEM. The Panel agrees that heightened concern about reliability is warranted, given the increasing use of regulatory levers to maintain reliability within the current standard. The Panel acknowledges that with ongoing changes in power system conditions and to expectations of what the power system should deliver, there may be a need to rethink how reliability can be delivered into the future. This is being considered by the ESB currently, and the Panel appreciates the ability to input and work with the ESB on these issues.

3.6.2 Improving coordination to minimise total system costs and maximise consumer benefits

The Panel's view is that to encourage more investment in the NEM thereby improving reliability outcomes for consumers, efforts should be made to better coordinate to deliver total system benefits and reduce the costs of transition.

The investment pipeline is robust with over 60GW of committed or proposed generation on the books[123]. The aim should be to encourage investment in a range of different technologies and locations so that the total system costs are minimised and the benefits for customers maximised.

This will need to include new generation and demand response that offer dispatchable and flexible capacity that is available during system peaks - usually very hot summer days when there is coincident high temperatures, and therefore demand in more than one region.

When it comes to network capacity, the Panel is confident that processes are in place to deliver the immediate term transmission needs of the power system through ISP priority projects. the AEMC's COGATI seeks to support the next wave of transmission investment by introducing price signals to incentivise new generation to locate in areas where the transmission network can support the connection as well as giving generators an ability to manage risks associated with congestion and losses.

3.6.3 Fostering regulatory certainty to support a smoother power system transition

Uncertainty tends to increase risks, and make it harder to anticipate and manage risks, for market participants and consumers. It also tends to decrease investment, particularly in high capital cost, long-term investments.

Some of the key factors in the NEM that are contributing to uncertainty about for investment decisions are:

- The supply side becoming more variable as the NEM shifts from a system dominated by large thermal power stations, to a system with many more power generators of various sizes and technologies. This can increase the uncertainty relating to real time outcomes in the wholesale market and make it more challenging to operate in the NEM generally.
- The demand side is becoming more variable as customers use energy differently and become more active participants in the power system and market. In many cases customers are now producers as well as consumers. This also adds uncertainty to real time outcomes and, without visibility of price-responsive customers, this is making demand forecasting more difficult.
- The physics of the power system are changing with increasing amounts of non-synchronous generation like batteries, wind and solar and the exit of synchronous generators like coal and gas. This means the way the power system is operated must also change to account for lower levels of inertia and system strength being provided as by-products and a growing proportion of generation unable to match output to demand.
- The power system is becoming increasingly decentralised with more and more generation and demand response occurring behind the meter. This creates challenges in understanding what is happening and how it is impacting the power system, but huge opportunities if we can understand and leverage it.

123 The Panel notes that a significant proportion of "proposed" generation will not progress to committed stage or ultimately connect to the power system.

- An increasing number and range of risks, particularly weather-related risks that result from climate change.
- There is more interconnectedness and more interrelationships between power system equipment and participants so that challenges can multiply.

The Panel's view is that to encourage more investment in the NEM thereby improving reliability outcomes for consumers, efforts should be made to foster regulatory certainty wherever possible. The Panel's notes that efforts to improve certainty should be focussed on the following two areas:

1. **Regulatory and policy actions that impact reliability outcomes:** efforts should be made by regulators and governments to clarify the timing and scope of reforms, policies and the actions to implement them. This includes government actions to support investment in generation, demand response or transmission infrastructure, and policies to deliver emissions reductions. These policies will continue to transform the power system, influence private sector investment and impact on reliability outcomes into the future. Clear direction will help support a smoother and lower cost transition.
2. **Transmission infrastructure to support new investment:** ISP priority projects have been identified and progressed with the support of rule changes, expedited regulatory process and in some cases' government funding. The next wave of transmission investment will be just as important in facilitating new generation capacity to get to market as the current fleet retires. The Panel notes that work is underway to improve coordination between generation and transmission investment and supports these efforts. Taking advantage of transmission infrastructure that supports new connections will also allow for a smoother and lower cost transition.

Reducing uncertainty in these two areas will be a step towards encouraging the new wave of investment necessary to underpin reliability in the NEM.

3.6.4 Work underway to improve reliability

The Panel notes that a number of regulatory changes seeking to improve reliability came into effect during the 2018/19 reporting year. This included:

- New requirement for large generators to give at least three years' notice before closing. This commenced in December 2018
- New rules to streamline the regulatory processes for key time-critical projects identified in AEMO's Integrated System Plan. This commenced in May 2019.
- New rules to enhancement, clarify and strengthen the RERT framework. These commenced in October 2019

A more extensive list of rules that came into effect in 2018/19 is included in appendix a**.**

The panel also acknowledges the reforms completed since the end of the Panel's reporting year and the substantive work programs underway through the market bodies, ESB, the COAG Energy Council and individual governments to address the reliability issues raised here. The Panel particularly notes:

- **Market body and ESB actions to coordinate investment in new generation and transmission infrastructure:** This includes AEMO's Draft 2020 ISP, which identifies over 15 projects to augment the transmission grid to provide a "least-regret, dynamic, resilient and transparent roadmap for the NEM."[124] The ISP is being supported by the AEMC's transmission access reforms that propose changes to incentivise generators to locate in places where transmission infrastructure can be used most effectively to get energy to market. The ESB has also been working on rules to action the ISP by embedding the process into the regulatory framework. Together, these reforms will facilitate new technologies connecting to the grid.
- **The ESB March advice to the COAG Energy Council on the reliability standard:** The COAG Energy Council tasked the ESB with reviewing the reliability standard. The Council asked that the advice reflect community expectations that electricity supply will remain reliable during a "1 in 10" year summer and that existing mechanisms should be used where possible. This advice will be provided to the COAG Energy Council meeting on 20 March 2020.
- **The ESB Post-2025 market design advice:** The COAG Energy Council requested the ESB advise on a long-term, fit-for-purpose market framework to support reliability, modifying the NEM as necessary to meet the needs of future diverse sources of non-dispatchable generation and flexible resources including demand side response, storage and distributed energy resource participation.

A more extensive list of current reliability-related work streams is included in appendix a.

124 AEMO, *Draft 2020 Integrated System Plan*, 2019

4 SECURITY

One of the Panel's key responsibilities, set out in National Electricity Law, is to monitor, review and report and provide advice on the security of the national electricity system, at the request of the AEMC. This chapter considers the security performance of the NEM over the 2018/19 financial year in line with the Panel's NEL obligations[125] and the review's terms of reference.[126]

This chapter outlines:

- What is power system security
- How system security is delivered in the NEM
- System security performance of the NEM in 2018/19
- Security-related rules that came into effect during 2018/19 and their impact
- Current challenges to system security and work underway to address them

In assessing the system security performance of the NEM, the Panel has looked at a number of indicators. Power system security involves keeping the power system within a technical envelope across a range of characteristics. Often, an event will impact on a number of these characteristics. For example, if a generating unit was to trip, it can have impacts on the local voltage levels, while also impact on the power system frequency across the entire NEM.

The Panel plays an important role in determining standards that are required to deliver a secure, reliable and safe power system in the most efficient way in order to minimise costs for consumers. The Panel will use its assessment of system security to inform its future work plan.

4.1 What is power system security?

The national electricity system is a large scale complex machine made up of thousands of different elements each with specific technical characteristics and operating requirements. Power system security involves maintaining these components within their allowable equipment ratings, and maintaining the system as a whole in a stable condition, within defined technical limits, and returning the power system to operate within normal conditions following a disturbance.[127]

In a secure power system technical parameters such as power flows, voltage and frequency remain stable during normal operations and are returned even after a significant change in power system conditions, such as the loss of a major transmission line or large generator. A secure power system is one that, among other things:

125 Section 38 of the NEL.

126 AEMC, *Annual market performance review term of reference*, September 2018.

127 Power system security is defined in Chapter 10 of the NER as the safe scheduling, operation and control of the power system on a continuous basis in accordance with the power system security principles. The power system is defined to be in a secure operating state if the power system is in a satisfactory operating state and the power system will return to a satisfactory operating state following the occurrence of any credible contingency event in accordance with the power system security standards.

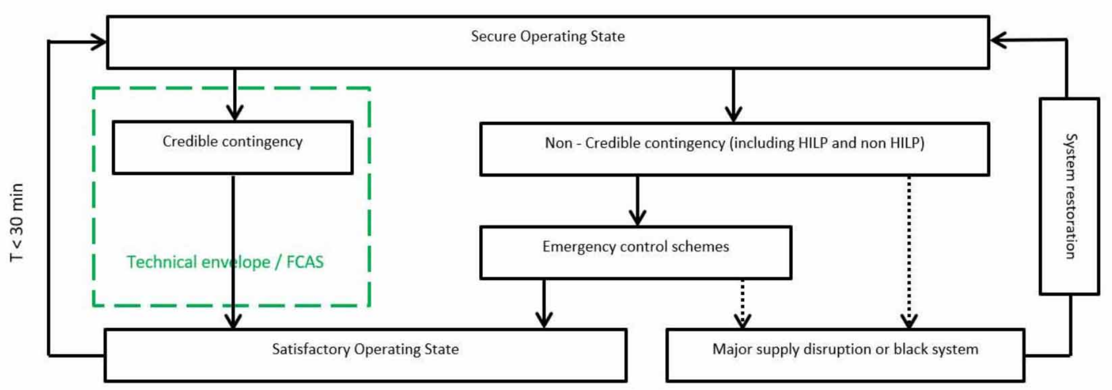
- A power system that is in a secure operating state is able to maintain a satisfactory operating state following the occurrence of a credible contingency event.[128]
- A satisfactory operating state is achieved when power system frequency, voltage, current, and plant operation all remain within appropriate limits as specified by the power system security standards.[129]

In practice, a power system is in a secure state if it remains within its technical parameters following a credible contingency event.

In order to keep the system in a secure state, AEMO dispatches generation within a technical envelope to try to make sure that when a credible disturbance occurs, the power system remains stable, no load is shed, and voltage and frequency are able to be bought within normal operating parameters within 30 minutes.[130]

The framework in the NER for achieving and maintaining a secure power system involves a range of tools and operating practices. In Figure 4.1 below the green box indicates when the power system is 'secure'. The rest of the diagram is about responding to disturbances to return the power system back to a secure state.

Figure 4.1: Existing system security arrangements



AEMC, review of South Australian black system event, December 2019, p.26

4.2 How is power system security delivered in the NEM?

Large, distributed power systems like the NEM are routinely subject to a range of disturbances, of varying severity and frequency. Power system security is delivered through

128 Clause 4.2.4 of the NER.

129 Clause 4.2.2 of the NER.

130 For a more detailed explanation of power system security refer to chapter 3 of the AEMC's *Mechanisms to enhance resilience in the power system - review of the South Australian black system event*, December 2019.

market and regulatory frameworks that aim to resist, respond to and then recover from disturbances that pose a risk to, or uncertainty in, the stability of the power system.[131]

The NER contains a set of system security frameworks. These frameworks involve maintaining the power system in a secure state with no load shedding to disturbances which are sufficiently likely to be considered 'credible'.[132] Credible disturbances, also known as contingencies, occur regularly with AEMO operating the power system to anticipate the loss of any single generation or network element under normal conditions.

For severe load probability disturbances the NER requires AEMO and NSPs to implement energy control schemes to shed load rapidly in order to prevent a major supply disruption. In the case of a black system event, the NER requires AEMO to procure system restart ancillary services to re-energise the power system.[133]

Regulatory frameworks set out the broad technical parameters of the power system, including standards for allowable ranges for voltage and frequency given certain types of disturbances, requirements for generators and NSP equipment connected to the power system to withstand disturbances, and roles and responsibilities for AEMO to manage the power system in anticipation of, and in response to disturbances of varying levels of severity.

The NER places primary responsibility for managing system security with AEMO. The Panel also has a key role in system security as the party responsible for developing some system security standards under the NER.

AEMO is ultimately responsible for maintaining power system equipment is within its designed capability and ratings, performance standards have been met, protection and control systems have operated correctly, and, if necessary, AEMO is responsible for using regulatory tools to intervene to ensure the power system remains secure.

AEMO also uses a variety of measures such as constraining the dispatch of generation or parts of the network, procuring system services under regulatory frameworks or intervening in the market by directing participants or instructing load shedding. These measures enable the system to survive, respond to and recover from minor disturbances as well as more severe and unexpected events to avoid load shedding, cascading failure and black outs.

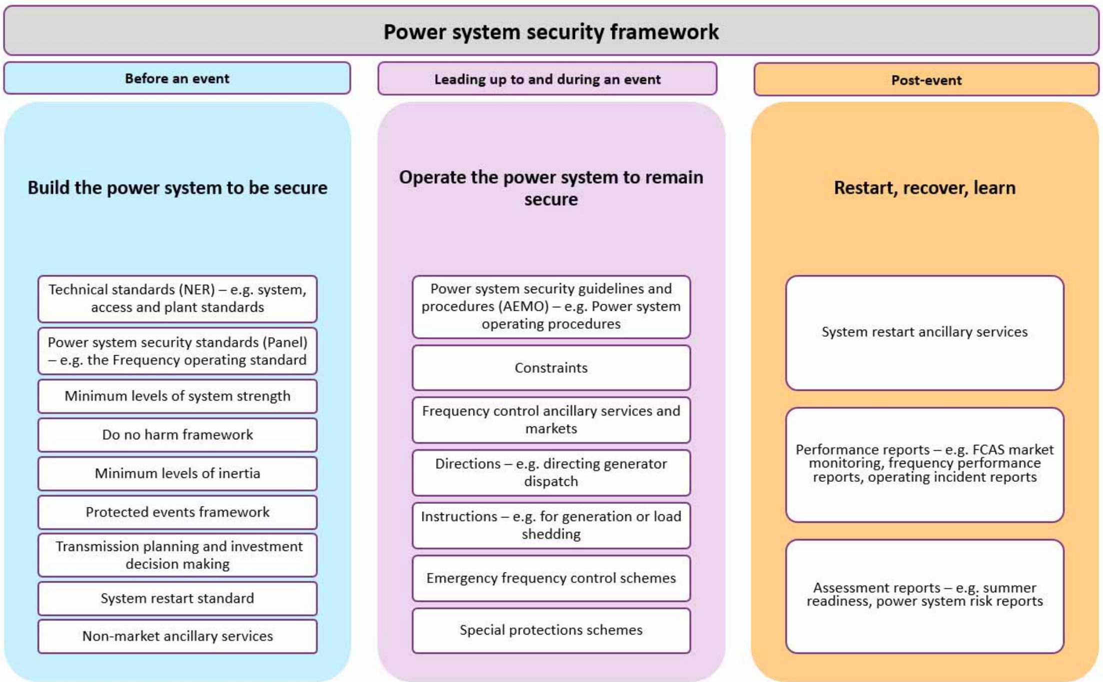
Figure 4.2 illustrates, at a high level, the key regulatory instruments and tools used to deliver power system security in the NEM.

131 Contingency events are defined in clause 4.2.3(a) of the NER as events affecting the power system which AEMO expects would likely involve the failure or removal from operational service of one or more generating units and/or transmission elements. More information about the concept of contingency events can be found in AEMC's *Mechanisms to enhance power system reslience - review of the South Australian black system event*, December 2019, chapter 3

132 Clause 4.2.4 of the NER.

133 Clause 4.3.1(p) of the NER.

Figure 4.2: System security framework



Source: AEMC.

4.3 Summary of security outcomes in 2018/19

The Panel's objectives in assessing the NEM's performance are set out in terms of reference provided by the AEMC.[134] This chapter assesses the system security performance of the NEM in 2018/19 by considering:

- **Key security-related events:** the power system and markets' response to a number of security events that occurred during 2018/19.
- **Voltage management:** the ability to maintain voltages on the network within acceptable limits. In this section the Panel considers power system performance in relation to voltage control and system strength and looks at some of the market and regulatory mechanisms to manage them.
- **Frequency management:** the ability to set and maintain system frequency within acceptable limits. In this section, the Panel considers inertia levels, provision of frequency control ancillary services, performance against the frequency operating standard and emergency frequency control schemes.

134 AEMC, *Annual market performance review - AEMC terms of reference to the Reliability Panel,* September 2018. Available at: https://www.aemc.gov.au/sites/default/files/2018-09/Terms%20of%20Reference.pdf

Box 6 presents a summary of the Panel's assessment of the NEM's security performance in 2018/19.

BOX 6: SYSTEM SECURITY PERFORMANCE IN 2018/19

Security outcomes

- The Panel considered three reviewable operating incidents that raised particular issues of concern in relation to power system security:
  - Islanding of Queensland and South Australia: this event suggested that the power system may be becoming less resilient to large disturbances. It also highlighted the importance of greater understanding of the operation of protection systems and distributed energy resources under these conditions.
  - Sudden reduction in wind output: this event highlighted the significant impact of sudden changes in generation availability.
  - Not updating Tailem Bend solar farm in Emergency Management System: this event highlighted the growing administrative complexity of running security-constrained dispatch.
- Voltage control: as large thermal generators withdraw and more inverter-connected generators (i.e. wind and solar) connect, system strength continues to deteriorate and over time, without action, will manifest in greater challenges in keeping system voltages in acceptable ranges.
  - Currently, AEMO is predominantly managing system strength and voltage control challenges through greater use of interventions. That is, issuing directions, reconfiguring the network and applying constraints to generators and transmission elements.
  - The existing framework provides for system strength obligations on networks, do no harm provisions and performance standard requirements for generators. There is potential for system strength and voltage control issues to spread across the NEM without system-wide solutions.
  - The Panel supports the AEMC's Investigation into system strength in the NEM that it is currently undertaking and highlights the importance of long term solutions being developed.
- Frequency control: the distribution of frequency during normal operation in the NEM has continued to flatten in the reporting period. This means there is a higher risk of frequency leaving the normal operating band. Frequency left the normal operating range more times in the mainland and Tasmania when compared to last year.
  - there was a small increase in total FCAS costs in 2018/19 when compared to 2017/18. This trend has continued into 2019/20. The price increases were driven by increased cost of regulating FCAS. The price of contingency FCAS services fell relative to 2017/18.

- FCAS prices coupled with technological developments have driven new types of FCAS providers to enter the market. This includes demand response, virtual power plants, wind farms and utility scale batteries. These new entrants demonstrate that new technologies and business models will have an increasingly important role is assisting with maintaining power system security.
- There were more emergency managements and special protection schemes installed: over the reporting period, there was a significant increase in the number of these schemes, particularly those installed to address system strength concerns.

Panel insights

- Power system security continues to be a challenge to maintain. The Panel expects these challenges to continue given the NEM is at the global forefront when it comes to integrating renewable energy into the power system. Integration of new technologies is occurring as risks to the power system are increasing driven by climactic change, increasing temperatures and the likelihood of extreme weather events.
- However, significant work has been undertaken to understand what is needed for the secure operation of the power system. This will assist us in meeting the challenges and embracing the opportunities that come with a new generation mix.
- In terms of ongoing work to address system security issues, the Panel notes the importance of:
    - **Defining system service needs:** clearly articulating the type and level of services required is a critical step is designing regulatory frameworks that can provide for these needs.
    - **Incentivising investment in system services:** each of the required system services has different characteristics, and may need different approaches to valuing and procuring them. The Panel notes progress has been made in relation to some services for example frameworks are in place to provide for system strength and inertia and a rule change is underway looking at the provision of primary frequency response.
    - **Leveraging the opportunities associated with new technologies:** in this transition, there are going to be challenges that test the system security frameworks. However, there is also an opportunity for new technologies to assist with maintaining the secure operation of the power system.
- The Panel acknowledges that some solutions may only be temporary fixes and other solutions may take time to mature and become effective.

4.4 Events impacting on power system security

One of the indicators of power system security in the NEM is how many security-related operating incidents occurred during the year.

AEMO has a responsibility to investigate and review all major power system operational incidents and publish detailed incident reports. A 'reviewable operating incident' is an incident identified, in accordance with guidelines determined by the Reliability Panel under NER, to be of significance to the operation of the power system or a significant deviation from normal operating conditions.[135] The NER require AEMO to report on every reviewable operating incident and assess the adequacy of the provision and response of facilities or services, and the appropriateness of actions taken to restore or maintain power system security.[136]

AEMO is required to report on the following categories of incidents as reviewable operating incidents:

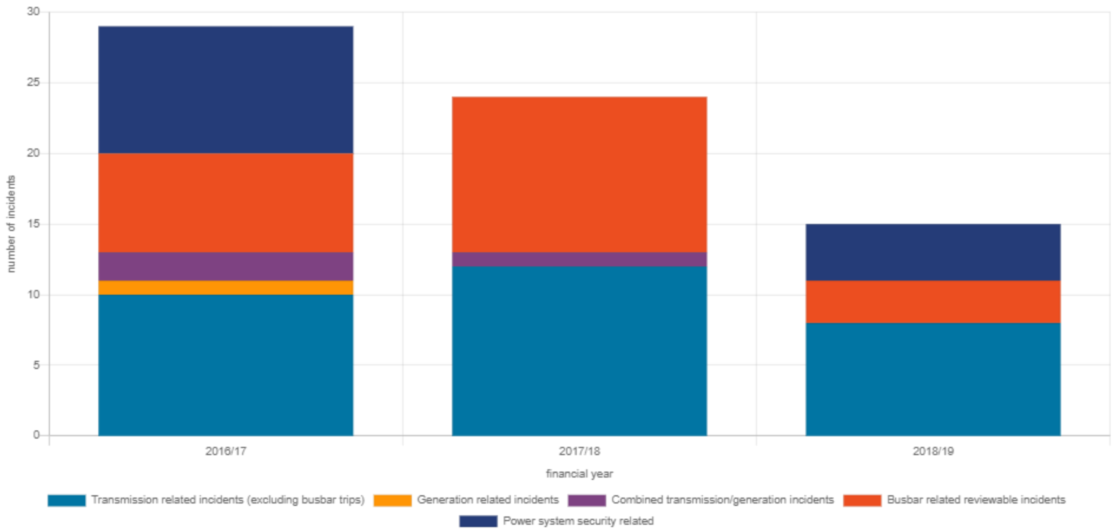
- a non-credible contingency event or multiple contingency events on the transmission system,
- a black system condition,
- an event where the frequency of the power system is outside limits specified in the power system security standards,
- an event where the power system is not in a secure operating state for more than 30 minutes; or
- an event where AEMO issues a clause 4.8.9 instruction for load shedding.

Figure 4.3 shows the type of incidents that have occurred in recent years. During the 2018/19 financial year there were 15 reviewable operating incidents. This compares to 24 incidents in 2017/18 and 29 incidents in 2016/17. Four of the incidents in 2018/19 resulted in the power system not being in a secure operating state for more than 30 minutes. In the figure below, these events are categorised as "power system security related'.

135 Clause 4.8.15(a) of the NER.

136 More information on AEMO's power system operating incident reports can be found on AEMO's website.

Figure 4.3: Number and type of reviewable operating incidents



Source: AEMC analysis of AEMO data.
Note: reviewable operating incidents don't necessarily provide a holistic view of power system or asset risks as not all events are reviewable
Note: The data for this chart is available in the AMPR data portal.

The Panel is encouraged by the fact that the number of reviewable operating incidents is declining.[137]

The Panel notes, however, that some of the incidents indicate areas of concern for power system security. In this section three incidents where the power system was not in a secure state for more than 30 minutes have been explored:

- The Queensland and South Australia system separation on 25 August 2018.
- The power system in South Australia not being in a secure operating state when wind generation in the northern area of South Australia unexpectedly reduced to zero or near zero output, causing voltage levels in the area to rise on 5 May 2019.
- Power system in South Australia not in a secure operating state when Tailem Bend solar farm was not constrained by AEMO during planned outages of transmission equipment on 14 May 2019.

These events highlight security matters that are of particular interest to market participants, and symptomatic of the security-related trends and challenges emerging in the power system which are detailed elsewhere in this section.

137 However, the Panel notes that the total number of incidents is likely to increase for the 2019/20 reporting period. This will be covered in the next annual market performance review.

4.4.1 The Queensland and South Australia system separation on 25 August 2018

On Saturday 25 August 2018, a single lightning strike caused the simultaneous "double back" flashover[138] across two insulators of the QLD – NSW interconnector (QNI). After two seconds QNI tripped, separating the Queensland region from the rest of the NEM. This led to the loss of the interconnector between South Australia and Victoria (Heywood) and the separation of the South Australia region from the rest of the NEM. This in turn resulted in under-frequency load shedding (UFLS) in the New South Wales, Victoria, and Tasmania regions.

This event created three separate frequency islands on the mainland NEM and demonstrates the present challenges of controlling frequency in the NEM and keeping the power system in a secure state, particularly following non-credible contingency events. In its incident report, AEMO noted that the event highlights a deficit of primary frequency control response from NEM generation, compared with historic levels and with other power systems around the world. The following summary draws heavily on the relevant AEMO incident report, published 10 January 2019.[139]

Key details

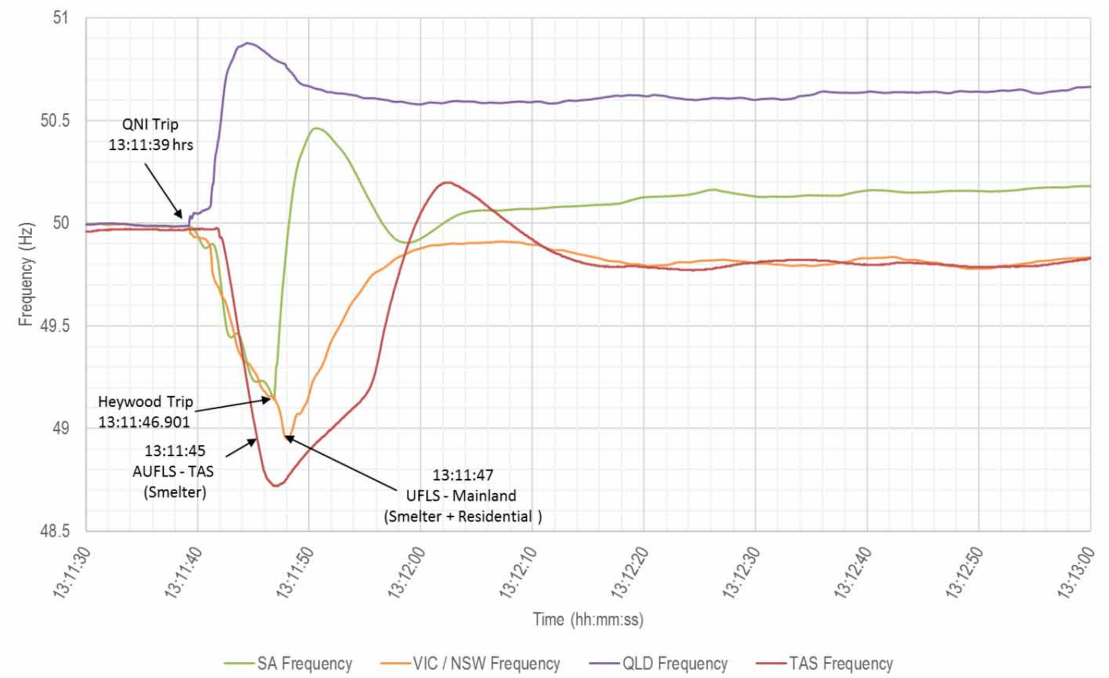
- On Saturday 25 August 2018, there was a single lightning strike on a transmission tower structure supporting the two circuits of the 330 kV QNI lines. The lightning strike triggered a series of reactions creating faults on each of the two circuits of QNI at 13:11:39. The Queensland and New South Wales power systems then lost synchronism, islanding the Queensland region two seconds later, at 13:11:41
- When this occurred, 870 MW of power was flowing from Queensland to New South Wales. The tripping of the QNI interconnector caused Queensland to experience an immediate supply surplus, resulting in an over frequency condition in Queensland. The remainder of the NEM experienced a supply deficit, resulting in a reduction in frequency (shown in Figure 4.4)
- The frequency controller on the Basslink interconnector responded to the reduction in frequency by immediately increasing flow from Tasmania to Victoria. This created a supply deficit in Tasmania, causing the disconnection of contracted interruptible load to rebalance the Tasmania power system at 13:11:46 (shown in Figure 4.4)
- At the same time, the reduction in frequency caused the South Australia-Victoria interconnector at Heywood to experience rapid changes in power system conditions that triggered the protection settings on the interconnector that separated South Australia and Victoria at 13:11:47. At this time, South Australia was exporting power across the Heywood interconnector.

138 When lightning strikes a transmission tower it can result in very high voltages being produced on the tower. When the voltage on the tower is larger than the withstand voltage of the insulator that supports one of the transmission line circuits, lightning can flash over from the tower to the transmission line, ionising the air around the insulator. The ionised air around the insulator provides a path for the current on the transmission line to transfer to the tower and into the tower earthing system, creating a phase to ground fault. The QNI transmission towers support 6 lines, which comprise each of the three phases of the dual circuit transmission lines. A double circuit fault can occur when one phase on each circuit will "flash over" at the same time, this is known as a 'double back' flashover.

139 AEMO, *Final report - Queensland and South Australia system separation on 25 August 2018*, January 2019.

- When South Australia and Victoria separated, there was a supply surplus, causing frequency to rise in South Australia. The resulting supply deficit in Victoria caused frequency to fall below 49 Hz, triggering UFLS to rebalance supply and demand across those regions.
- The SA-VIC interconnection was restored at 13:35 on 25 August 2018, and QNI at 14:20. The interrupted Tasmania load commenced restoration at 13:40 and the NSW and Victoria smelters were permitted to reconnect at 13:33 and 13:38 respectively. All NSW consumer load was restored by 15:28.

Figure 4.4: QNI and Heywood interconnector trips on 25 August 2019



Source: AEMO, *Final Report - Queensland and South Australia system separation on 25 August 2018,* January 2019.

Comparison with 2008 separation event

The last time Queensland separated from the rest of the NEM was on 28 February 2008. In this earlier event, Queensland separated from the NEM through the loss of the QLD-NSW DC interconnector, Directlink, followed by the loss of QNI. At the time, Directlink was transporting 113 MW from QLD to NSW and QNI was transporting 978 MW from Queensland to New South Wales. This resulted in a total loss of power transfer from Queensland to NSW of 1,091 MW as compared to the loss of 870 MW on 25 August 2018.

In 2008, the Queensland frequency rose to 50.62 Hz, compared to 50.9 Hz on 25 August 2018, and the remaining NEM frequency dipped to a minimum of 49.55 Hz, compared to 48.95 Hz on 25 August 2018. No additional regions separated, and no load was shed in 2008. This is compared to 997 MW of UFLS on 25 August 2018.

A comparison of key outcomes between the 2008 and 2018 events is provided in Figure 4.5. This figure shows that the magnitude of the initiating events in each case was fairly similar (about 200 MW higher in 2008) but that a much larger deviation in frequency was experienced in 2018 relative to 2008. In addition, while 1078 MW of load shedding occurred in 2018, none occurred in 2008. This contrast suggests that the power system is more vulnerable to non-credible contingency events and could be considered to show a reduction in the resilience of the power system since 2008.

Figure 4.5: Comparison between 2008 and 2018 NSW-QLD separation events

	2008	2018
Net loss of supply QLD to NSW	1,091 MW	870 MW
Other regions separated	NIL	South Australia
Maximum frequency QLD	50.62 Hz	50.9 Hz
Minimum frequency NSW	49.55 Hz	48.85 Hz
Load interrupted	NIL	997.3 MW (UFLS) 81 MW (contracted)

Source: AEMO, *Rule change request - Mandatory primary frequency response*, p. 11.

Panel observations

The Panel notes that AEMO has reviewed the event thoroughly and recommended a range of actions to address the security issues identified. AEMO, the AEMC and market participants are working to progress these recommendations so the power system is in a better position to respond to future events like this and the Panel notes the importance of this work.

Given the key components of this event were not related to the changing generation mix (around 90 per cent of generation in Queensland at the time of the event was synchronous thermal plant) the Panel notes that there are a range of broader power issues that are worth exploring. Of the issuing arising from this event, the Panel notes that the issues warrant further attention are:

- There were much higher levels of load shedding than in 2008. There are intricacies that make comparing two power system events directly difficult; however, it remains concerning that almost 1GW of load shedding occurred in the 2018 separation. This suggests that the power system may be less resilient to these large disturbances than it used to be. As noted in the AEMC's *Review of the System Black Event in South Australia on 28 September 2016*[140] the power system has always faced risk from a range of sources. These risks and uncertainties reflect both the characteristics of the elements making up the power system, the types of disturbances which may occur and the systems' response to these disturbances - all of which are changing in today's NEM. The

140 Available at: https://www.aemc.gov.au/sites/default/files/documents/aemc_-_sa_black_system_review_-_final_report.pdf

Panel notes that uncertainty, along with increasing interconnectedness and interrelationships between power system elements, the power system needs to be appropriately 'resilient' to unexpected outcomes from unexpected events.

- Solar PV "shake-off" was not necessarily expected, but helped contain the frequency spike in QLD. AEMO's operating incident report includes detailed analysis of the response of rooftop PV to the disturbance in Queensland, New South Wales and Victoria, and South Australia. In summary, the analysis undertaken by AEMO highlights that a subset of distributed PV appears to have responded in a manner that is neither consistent with AEMO's expectations nor compliant with the Australian Standard.[141] During this event, the implications were manageable, if not helpful. For example in Queensland, 15 per cent of old inverters disconnected in response to the over-frequency against expectations and previous results. However, a portion of new inverters in each state did not reduce output as expected. Given the growing size of rooftop PV as a proportion of the overall mix, understanding and incorporating these responses into the planning and operational system security frameworks will become increasingly important as the amount of installed distributed energy resources grow.
- Over the course of this event, FCAS costs associated with the event were more than $10 million. This highlights that, during disturbances like islanding of regions, these services often become extremely valuable for maintaining system security. FCAS costs have been considered in more detail in section 4.6.3.
- The very fast response to frequency changes in South Australia of utility-scale batteries contributed to separation of South Australia and Victoria.[142] This suggests that protection schemes need to be recalibrated in light of the responses available from newer technologies.[143]

4.4.2 Unexpected reduction of wind generation in South Australia to zero causing voltage level rises

On 5 May 2019 there was an event in the northern region of South Australia where the power system was not in a secure operating state for 75 minutes.[144] This was due to a combination of forecasting errors of semi-scheduled generator performance and localised voltage management.

In the NER, the 'General principles for maintaining power system security' require AEMO, following a contingency event, to take all reasonable actions to adjust, wherever possible, the operating conditions with a view to returning the power system to a secure operating state as soon as it is practical to do so, and, in any event, within 30 minutes.[145]

Key details

141 AS4777 - Grid connection of energy systems via inverters.

142 The emergency Alcoa Portland tripping scheme is designed to prevent Portland smelter load in Victoria form remaining to an islanded SA system. It is designed to separate South Australia from Victoria when it detects a rapid increase in power flow from SA to VIC in combination with an under-frequency condition.

143 AEMO, *Final report - Queensland and South Australia system separation on 25 August 2018*, p. 7.

144 AEMO,*Power system in South Australia not in a secure operating state on 5 May 2019*, January 2020.

145 Clause 4.2.6(b)(1) of the NER.

- On 5 May 2019, between 1030 hrs and 1145 hrs, the power system was not in a secure operating state. Voltage levels at Blyth West, and Willalo substations in the northern part of SA were found to have exceeded the satisfactory operating voltage limit of 303kV.
- In the period prior to this incident, the wind farms in the northern area of South Australia, including North Brown Hill, Bluff, Willogoleche, Hallet Hill, Hallett, Hornsdale, Snowtown North, and Snowtown South wind farms, were forecast to be generating at low, but above zero outputs.
- However, from approximately 1015 hrs on 5 May 2019, the output of the Northern area wind farms reduced to zero or near zero. This significantly reduced their ability to absorb reactive power to limit voltages in the area.
- This was exacerbated by capacitor banks running at Willogoleche and Snowtown North wind farms that contributed to a net rise in reactive power.
- This resulted in voltages increases in the area.
- At 1107 hrs, AEMO requested ElectraNet to open circuit breaker 8001 at Blyth West to reduce voltages at BlythWest substation to acceptable levels
- With advice from ElectraNet, AEMO switched out these capacitors and also requested the Hornsdale Battery be switched from power factor control mode to voltage control mode and the voltage setpoint be lowered to reduce voltages in the area
- At 1522 hrs, studies indicated that the voltages were now low enough to allow the Hornsdale Battery to return to normal operation in power factor control mode.

In its report on the event, AEMO found that[146]:

> The incident represents a combination of different power system challenges which are becoming more pronounced in the NEM. The concurrent nature of these challenges, namely system strength, reactive power and the accuracy of forecasting, combined with the effectiveness of the Hornsdale battery to provide voltage control, makes this emblematic of an event that may grow more frequent as the power system transitions.

In response to the event AEMO has updated its operating procedures to provide additional information on the available voltage control actions for wind and solar farms and battery installations. This information will enable AEMO to manage these type of voltage control issues during similar events of low wind generation.

Panel observations

The Panel considers this incident to illustrate a range of challenges which are arising in the transitioning power system:

- This event demonstrates the range of factors involved in integrating variable renewable energy sources into the power system.
- Declining system strength makes it more challenging to keep technical parameters within their technical envelope in normal operating conditions.

146 AEMO, Power system in South Australia not in a secure operating state on 5 May 2019, January 2020.

- Generally, semi-scheduled generation are not required to follow dispatch instructions.[147] This creates challenges in balancing supply and demand when forecasts change. Even small changes in forecast output can have system security consequences, even if the energy supply consequences are not significant.
- Storage technologies (in this case Hornsdale battery) are becoming increasingly important in managing system security because of their versatility and responsiveness.

4.4.3 Incident during planned outages of transmission equipment when Tailem Bend was not constrained

On 14 May 2019 the power system in South Australia was not in a secure operating state for 100 minutes with voltages below the required limits. This resulted from a process issue associated with AEMO's Energy Management System (EMS) that meant the low voltage was not detected immediately.

Key details:

- On 14 May 2019 between approximately 1159 hours and 1339 hours, the power system in South Australia was not in a secure operating state, with voltages on the 132 kV network around the Tailem Bend and Keith substations below the required limits.
- Prior to and during this incident, parts of the network at the Tailem Bend were out of service for planned work by ElectraNet.
- Due to the planned works, if there was an outage on the Mobilong – Tailem Bend line, this would have resulted in very low voltage levels and potentially would have led to a voltage collapse in the area.
- At around 1320 hrs on, staff monitoring South Australia observed that there was an inconsistency between the EMS in the Sydney and Brisbane offices – with one showing potential voltage violations for the loss of the Mobilong – Tailem Bend line.
- AEMO determined the potential violations related to generation at the Tailem Bend solar farm. The Tailem Bend solar farm was constrained down, and all violations ceased.
- The reason for inconsistencies between AEMO's EMS's was that one showed Tailem Bend solar farm to be out of service. As such, EMS assumed there was no generation from the Tailem Bend solar farm.
- The modelling issue was corrected at 1345 hrs, and the broader process issues to make sure the status of new equipment is updated on both EMS's once commissioned, have also been rectified.

Panel observation

The Panel notes that while the physical implications of this event were not significant, it does highlight the importance of good process and accurate modelling tools in managing the increasingly complex power system.

147 Except when the semi-scheduled generator has been issued a semi-dispatch cap. This cap means a semi-scheduled generators is required to follow its dispatch target, often for system security reasons.

4.5 Voltage control and system strength

This section talks about how the power system and market performed in terms of voltage management, that is, the ability of the power system and market to maintain voltages within acceptable limits.

AEMO uses a number of tools in order to maintain voltages for system security purposes, including:

- Liaising with NSPs regarding the operation of their networks and providing for the availability of sufficient reactive power and voltage control capabilities
- Using **network constraints** to organise dispatch so it meets both economic and physical requirements
- **De-energisation of lines** to plan and manage over-voltages during low demand periods
- Negotiating **technical performance standards** which set the levels of reactive power and voltage control capacity and performance for equipment connecting to the power system
- Interventions such as **directing generators** to come online to inject reactive power to manage voltage.

The Panel has considered the NEM's performance in 2018/19 in relation to each of these areas below.

4.5.1 What is voltage control and system strength and why are they important?

Voltage control

Maintaining power system voltages within acceptable limits is important for the proper operation assets connected to the power system.

Acceptable limits are defined by the NER as being +/- 10% of normal voltage for normal operating conditions with voltages during disturbances required to remain with the levels specified in the system standard.[148]

Excessive over or under voltages can result in major system security challenges, including major supply disruptions. Maintaining stable voltage is a key element of power system security. If voltages are not stable, this can jeopardise the ability of generators and other equipment to operate correctly and increase the difficulty of managing power system stability.

Voltages in the power system are determined by, and controlled through adjusting the amount of reactive power. Reactive power is the power required to create electric and magnetic fields in transmission lines and end user equipment (such as motors) that allow electrical energy to be transported from the source of generation to the point of end use. Too little reactive power means voltages may be too low while too much reactive power means voltages may be too high.

148 Clause 5.1A.4 of the NER.

Generators or network equipment either inject or absorb reactive power to maintain voltages within acceptable limits resisting changes in voltage and responding to changes when they occur. In the NEM this is achieved by:

- obligations on networks to install equipment and control to maintain network voltages within acceptable limits
- obligations on generators to control voltage and reactive power to the level specified in their connection standards
- requirements for AEMO to monitor and co-ordinate the actions of generators and NSPs in maintaining voltages within acceptable limits.

System strength, discussed below, helps resists changes in voltage. AEMO's obligations for the control of system voltages include:

- AEMO must determine the adequacy of the capacity of the power system to produce or absorb reactive power in the control of the power system voltages.[149]
- AEMO, in consultation with Network Service Providers, must assess and determine the limits of the operation of the power system associated with the avoidance of voltage failure or collapse under any credible contingency event or protected event scenario[150]
- The limits of operation of the power system must be translated by AEMO, in consultation with Network Service Providers, into key location operational voltage settings or limits, transmission line capacity limits, reactive power production (or absorption) capacity or other appropriate limits to enable their use by AEMO in the maintenance of power system security.[151]

System strength

An AC power system requires minimum levels of system strength to remain stable and secure. Insufficient system strength can lead to a range of system security challenges which include, but are not limited to, maintaining stable voltages particularly in response to disturbances that occur.

As the power system changes, existing synchronous generating systems retire, and asynchronous and inverter connected system connect, system strength is becoming a significant challenge. To date, asynchronous, inverter connected generating systems have not historically provided material levels of fault current to support system strength, although we understand there are current participants looking at this. At a given location system strength is usually determined by two factors:

- the number of synchronous machines connected nearby
- the number of transmission lines or distribution lines (or both) connecting synchronous machines to the rest of the network.

System strength is greater in parts of the power system that are more interconnected and have more online synchronous generating systems. Areas of the network with lower levels of

149 Clause 4.5.1(a) of the NER.

150 Clause 4.5.1(b) of the NER.

151 Clause 4.5.1(c) of the NER.

transmission capacity and few synchronous generating systems have lower levels of system strength.

System strength is relevant to the control of voltages as the amount of available reactive power required to accurately control voltages depends on the levels of system strength in an area. The relationship between system strength and voltage control is illustrated by the one approach to defining levels of system strength which is the relative change in voltage for a change in load or generation at a connection point.

System strength involves complex interactions between many network components, including synchronous machines, asynchronous generation (and their protection and control systems) and other electrical and mechanical elements within the power system. Low levels of system strength makes the power system more vulnerable to disturbances and makes it harder to manage power system stability.

System strength is supported by synchronous generating systems or other equipment, such as synchronous condensers.

The NER includes arrangements for ensuring the provision of minimum levels of system strength that is required for AEMO to maintain the power system in a secure state:

- AEMO has an obligation to assess the power system's need for system strength and define minimum levels at a set of nodes across the system.
- NSPs are required to increase system strength where a gap exists between the needs of the system and available levels given existing connections and network. An NSP is responsible if the retirement of an existing synchronous generator leads to system strength falling below minimum levels.
- Generators who are seeking to connect new generating systems are required to remediate the impact of their connection if it results in system strength levels falling below minimum levels necessary for the operation of the system, or if it would negatively impact the stable operation of other participants, when existing system strength requirements are met. This is known as the 'do no harm' requirement.

Why are they important?

Maintaining voltages within appropriate bounds is a key element of power system security. If voltages are not stable, this can jeopardise the ability of generators and other equipment to operate correctly and increase the difficulty of managing power system stability. This is exacerbated by reduced system strength. Reduced system strength in certain areas of the network may mean that generators are no longer able operate properly and may be unable to remain connected to the power system at certain times.

Therefore, providing for sufficient voltage control and system strength is integral to maintaining power system security.

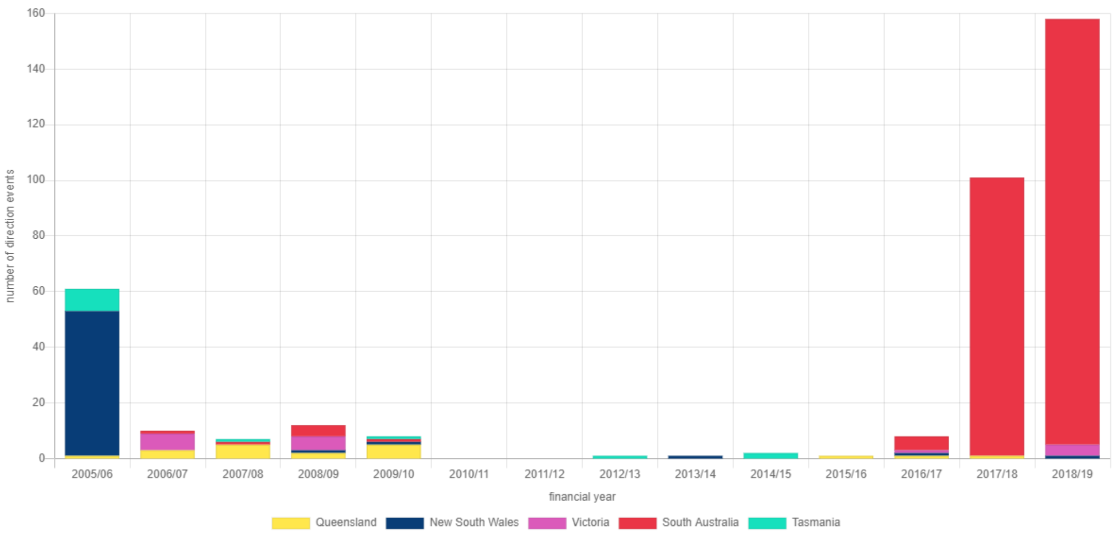
4.5.2 Directions to maintain system security

AEMO has the power to direct market participants to manage power system security.[152] It can direct participants to manage voltage and system strength.

Currently, most directions given by AEMO are to synchronous gas fired generators to ensure adequate system strength in South Australia. This started in early December 2016, when AEMO announced that at least two large synchronous generating units should be online at all times to maintain system strength in South Australia. Usually, directions are required when spot prices fall to levels that are not sufficient to cover gas fired generators' short run costs (typically during periods of high wind output and low to moderate demand).

During 2018/19, 158 directions were issued by AEMO, 153 of which were to maintain system strength above minimum levels in South Australia. This compares to 101 directions issued in 2017/18, and eight in 2016/17. For the first time, AEMO also issued a direction to a generator in Victoria to maintain adequate system strength in November 2018. The increasing use of directions is illustrated in Figure 4.6 below.

Figure 4.6: Number of power system security directions issued by AEMO in last decade

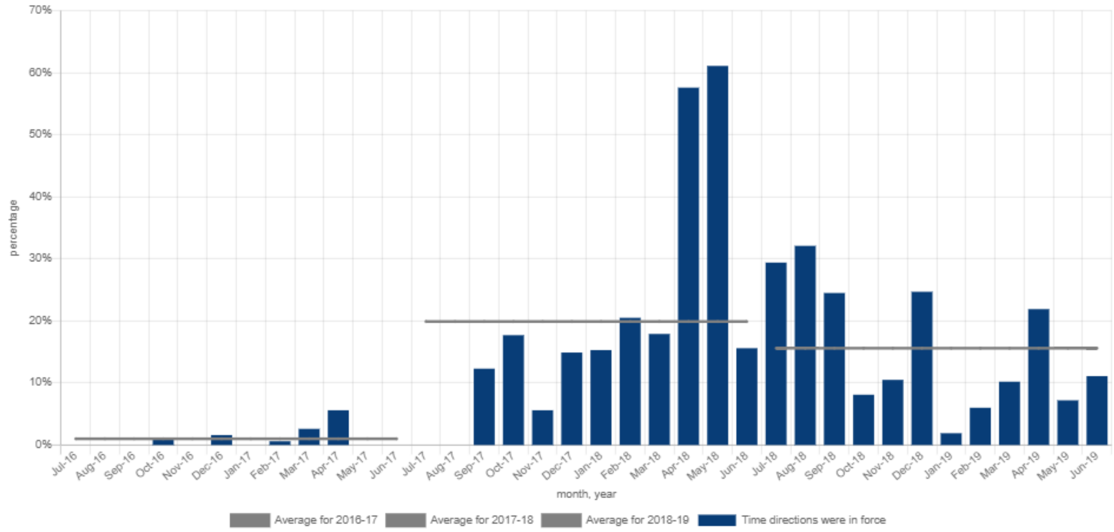


Source: AEMC analysis of information provided by AEMO.
Note: The data for this chart is available in the AMPR data portal.

Further, the proportion of time in which directions have been in place in the NEM continues to be far above the levels experienced two years ago. Figure 4.7 shows that in 2018/19, a direction was in place in the NEM (most often in South Australia) approximately 16 per cent of the time. This is slightly down from 20 per cent in 2017/18 but still represents a significant increase from the 1 per cent experienced in 2016/17.

152 Clause 4.8.9 of the NER.

Figure 4.7: Percentage of time when system strength directions were in force in NEM



Source: AEMC analysis of information provided by AEMO.
Note: The data for this chart is available in the AMPR data portal.

The Panel notes that AEMO's approach of using directions to maintain system strength in South Australia is likely to continue until ElectraNet's synchronous condensers are commissioned at the end of 2020. The Panel notes that AEMO may also need to increase its use of directions for system strength elsewhere in the NEM as network augmentations to address low level of system strength often take time to build.

Price impact of directions for system strength

The use of directions has an impact on price. When a direction is in force, intervention pricing is used as a way of setting the dispatch price and ancillary services price at the value which AEMO, in its reasonable opinion, considers would have applied had the AEMO intervention event not occurred. For this reason, intervention pricing is often referred to as "what if pricing" – what would the price have been if the intervention had not occurred?

In its consultation paper on Intervention mechanisms in the NEM,[153] the AEMC looked at the degree to which interventions in South Australia may have affected spot price outcomes in South Australia and other regions for the 2018 calendar year. It found that the impact of intervention pricing on spot prices was most marked in South Australia but that it can also have significant effects across the NEM when the volume of energy traded in larger regions is considered. Across the NEM, the price uplift of intervention pricing was $164M.[154] For South Australia specifically, intervention pricing resulted in wholesale prices that were $71M higher than they would have been had intervention pricing not been applied.[155] The chief recipients

153 AEMC, *Investigations into intervention mechanisms and system strength in the NEM - Consultation paper*, April 2019, p 60.

154 Ibid, p. 60.

155 This is total amount averaged over the 2018 year. The AEMC noted that this estimate represents an upper limit of the impact,

of higher spot prices during system strength directions are wind generators (who do not provide system strength), together with any gas fired generators who are operating without being directed to do so. Gas fired generators who are operating pursuant to a system strength direction do not receive the spot price. Instead, they are compensated based on the 90th percentile price.

Given the increasing use of directions to maintain adequate system strength in South Australia, intervention pricing has been implemented for around 16 per cent of the hours in the 2018/19.

The Panel notes that changes to the NER relating to intervention pricing commenced after the reporting period in December 2019. This included rules relating to:

- Intervention pricing: the final rule for the *Application of the regional reference node test to the reliability and emergency reserve trader (RERT)* rule change clarified when intervention pricing should apply. This includes removing the use of intervention pricing for interventions to obtain services not traded in the market, such as system strength and voltage control.[156]
- Affected participant compensation: under the final rule for the *Application of compensation in relation to AEMO interventions* rule change, affected participant compensation is no longer payable in connection with interventions which do not trigger intervention pricing, for example system strength directions.[157]
- Compensation threshold: the final rule for the *Threshold for participant compensation following market intervention* rule change changed the $5,000 compensation threshold for directed and affected participants so it applies per event rather than per trading interval.[158]

The new rules seek to increase clarity and consistency, reduce market distortion and costs to consumers, and strike a better balance between the interests of market participants and consumers.

The Panel notes that the use and therefore cost of directions should decrease over time as the system strength framework matures. The following actions are also likely to improve system strength and the operation of system strength frameworks, therefore reducing the need for AEMO to intervene and use directions:

- Strength remediation projects already underway in areas where a shortfall has been identified including ElectraNet's South Australia system strength remediation project to install four synchronous condensers by the end of 2020, and AEMO's Western Victoria Transmission Network Project which will be a novel technical solution, developed by 2021 in consultation with stakeholders.

and that higher spot prices typically do not translate immediately or directly into higher prices for consumers. Ibid, pp. 60-61.

156 More information can be found on the Application of the regional reference node test to the reliability and emergency reserve trader (RERT) rule project page.

157 More information can be found on the Application of compensation in relation to AEMO interventions rule project page.

158 More information can be found on the Threshold for participant compensation following market intervention rule project page.

- ISP transmission upgrades currently progressing through the regulatory approvals process, particularly Project EnergyConnect[159] expected to be completed by in 2023-24 but also VNI Minor upgrade in 2022-23[160] and QNI Minor upgrade in 2021-22.[161] These upgrades are expected to reduce impedance, thereby improving system strength.
- The potential development of renewable energy zones which may also coordinate infrastructure to provide system strength for generators connecting in that zone.
- Changes to system strength frameworks that may result from the AEMC's investigation of the application of the system strength framework.[162]

4.5.3 System strength

The rapid scale and pace of new inverter-based renewable generators connecting to the NEM is leading to and increasing need for more system strength particularly in remote areas or at the edge of the network. As this transition continues, AEMO has indicated that additional system strength will be required to maintain the secure and stable operation of the power system.[163]

Declining levels of system strength can have both localised and broader power system impacts. The potential challenges for the power system associated with decreasing levels of system strength include:[164]

- Steady state voltage management: greater deviations in voltages make it difficult to maintain secure operating voltages. For example larger voltage step changes can occur with the switching in/out of reactive devices and high voltages can occur during light load periods.
- Voltage dips: in a weak network area, voltage dips are deeper, more widespread, and can last longer than in a strong network.
- Fault ride-through: where the impact of a network fault is widespread, a large amount of inverter-based resources can enter fault ride-through during the brief period before a fault is isolated, resulting in a power imbalance.
- Power quality: voltage harmonics and imbalance are generally higher in weak systems than in strong systems. High voltage harmonics and imbalance diminish power quality.
- Operation of protections: as system strength declines, fault current is reduced, which makes it more difficult for protection systems to detect and isolate faults.

The Panel has included examples in the sections below of where declining levels of system strength are impacting NEM operations.

159 For more information, see: https://www.projectenergyconnect.com.au/
160 AEMO and TransGrid, *Victoria to New South Wales interconnector upgrade - Project Assessment Draft report*, August 2019.
161 TransGrid, *QNI Minor Upgrade Project - Contingent project application*, January 2020.
162 More information can be found on the Investigation into system strength frameworks in the NEM project page.
163 AEMO's *System strength requirements methodology* , 1 July 2018, p. 12.
164 AEMO, *Notice of inertia and fault level shortfalls in Tasmania*, November 2019, p. 10.

Minimum system strength levels

A minimum level of system strength is required for the power system to remain stable under normal conditions and to return to a steady state condition following a system disturbance.

Starting 1 July 2018, new rules came into effect requiring AEMO to determine minimum three-phase fault at each node in the power system and to identify any regions where there is a shortfall in system strength. Under these rules the TNSP is responsible for maintaining minimum levels of system strength.[165] A new generator must "do no harm" to the security of the power system to which it connects, including remediating any adverse system strength impact caused by its connection.

As at 30 June 2018, AEMO had determined the minimum system strength levels at fault level nodes for all regions in the NEM.[166]

System strength shortfalls in South Australia in 2018/19

Each year AEMO assesses whether there is an emerging risk of a system strength shortfall in any region, for example if typical patterns of dispatched generation do not maintain previously determined fault levels, or if increased asynchronous generation penetration results in fault levels no longer being adequate to ensure a secure operating state.

During the 2018/19 reporting year the only shortfall identified by AEMO was in South Australia.[167] The primary concern in South Australia is a sudden loss of generation resulting in the disconnection of the Heywood interconnector and a state-wide frequency or voltage collapse (that is, a state-wide blackout).

Under the new system strength framework, TNSPs are required to provide the necessary system strength to remedy the existing fault level shortfall.

While ElectraNet's proposed solution to install two synchronous condensers each at the Davenport and Robertstown 275 kV connection points received formal technical approval from AEMO in March 2019, the commissioning of these synchronous condensers is not expected to commence until mid-late 2020. In the interim, AEMO has been, and will continue to issue directions (see more detail in section 4.5.2 below) to ensure that sufficient synchronous generators are operating in order to keep the power system secure. In the absence of AEMO's directions, the fault level shortfall could be as much as 840 MVA in certain areas of the state.[168]

The Panel notes that it will be important to observe the extent to which the installation of synchronous condensers in South Australia constitute a cost-effective remediation to system strength issues.

165 At the same time, rules were implemented that created a similar framework for inertia.

166 More information on how AEMO determines minimum fault levels and identifies shortfalls can be found in AEMO's *2018 System strength requirements methodology*.

167 In December 2016, AEMO's National Transmission Network Development Plan (NTNDP) identified an NSCAS gap for system strength in South Australia. Subsequently, AEMO declared a system strength NSCAS gap in South Australia in October 2017 and confirmed the exact extent of the gap.

168 AEMO, system strength requirements methodology, July 2018, p. 23.

Emerging system strength shortfalls

The Panel following the 2018/19 reporting period, system strength shortfalls have also declared in Tasmania[169] and Victoria.[170]

Tasmania

The fault level shortfall in all regions in Tasmania (combined with an inertia shortfall discussed in more detail in section 4.6.5 below) reflects a change in Tasmania's generation when there is low demand from the grid, combined with high imports from Victoria over Basslink. During these periods Tasmania has the potential to experience low levels of synchronous generator unit dispatch. This is expected to occur more often following the commissioning of two large (asynchronous) wind farms over the next 12 months. AEMO and TasNetworks have agreed to address system strength shortfall by 1 April 2020 noting that new connecting wind farms will also have obligations to remediate their individual impacts under the 'do no harm' framework (see section 4.5.4 below). TasNetworks has proactively sought expressions of interest to provide system strength and inertia services in Tasmania. In the meantime, operational arrangements will be used if necessary to securely operate the power system. AEMO will continue to monitor the system strength requirements in Tasmania, with a specific focus on:

- commitment status of new generation (e.g. new wind farms)
- changes to rainfall and operation of the hydroelectric fleet
- generator maintenance requirements and system operability.

Victoria

Red Cliffs is in a remote area of the grid in the North West of Victoria on the Murray river.

The fault level shortfall of 312MVA at Red Cliffs in Victoria reflects both a change in the required minimum fault level from 600 MVA in June 2018 to 950 MVA in December 2019, due to the large volumes of inverter-based wind, solar and energy storage resources connecting in remote outer grid areas requiring higher levels of system strength in those areas to operate stably. AEMO will seek system strength services to address this shortfall by 1 January 2021.

The adjustment to minimum fault levels and the resulting shortfall in system strength was identified when AEMO modelled voltage instability in the area following a contingency event.

While Red Cliffs is an area which is seeing significant connection of new generation, the fault level shortfall in this instance is due to generation that had connected in the area prior to the do-no-harm regime coming into place. The TNSP is therefore responsible for increasing fault levels in the area to achieve the minimum requirement identified by AEMO.[171]

169 AEMO, *Notice of inertia and fault level shortfalls in Tasmania*, November 2019. AEMO assessed that there is a fault level shortfall at the fault level nodes of George Town (530MVA), Burnie (180MVA), Waddamana (310MVA) and Risdon (320MVA) in Tasmania.

170 AEMO, *Notice of Victorian fault level shortfall at Red Cliffs*, December 2019. AEMO declared a fault level shortfall of 312 MVA at Red Cliffs.

171 Under NER framework for addressing low levels of system strength, and new connecting generators are now required to remediate any system strength impacts.

In response to this gap identified by AEMO power system security is currently being managed by constraints that limit the generation of five solar farms in the area. These constraints limit the output and online inverters of these solar farms to a level that minimises the occurrence of voltage oscillations should an initiating fault occur. Until new operating parameters are verified, approved and implemented by the solar plants, AEMO believes the only prudent course is to postpone final approvals for new generators due for commissioning or registration in the impacted area.[172]

While AEMO is addressing this problem in the immediate term by limiting generation levels from these solar farms, a range of short, medium, and long terms solutions has been identified to address the systemic issues that exist in this part of the network. These include:

- short term: control system tuning of constrained solar plant. The five solar generators are working with AEMO, Powercor and TransGrid to adjust the performance of their systems to maintain stable operation in the low system strength environment. Once these changes have been verified, approved and implemented these solar plants should be able to increase the amount they can generate without compromising power system security. AEMO expects these changes to be made and tested in early 2020.
- medium term: system strength gap remediation which is the responsibility of the TNSP and may include additional investments made to increase system strength in the area. These investments could include synchronous condensers.
- long term: augmentation of the transmission system connecting western Victorian with generation centres in other parts of the NEM. This is a longer term investment solution which will be assessed as part of AEMO's ISP.

System strength is likely to remain a challenge given the large number of inverter connected renewable generating systems seeking to connect in western Victoria.

This will be considered in further in more detail in AMPR 2020.

4.5.4 Generator 'do no harm' arrangements

In 2018, an obligation on new connecting generators to 'do no harm' to the level of system strength necessary to maintain the security of the power system in that area or to pay remediation costs when connecting.

This puts an incentive on connecting generators to connect to the NEM in a location where there is either sufficient system strength, or a location where the generator is willing to fund the remediation of system strength to accommodate their connection.

New connecting generators in South Australia have been assessed under the 'do no harm' framework and have been incorporated into dispatch constraint equations are currently used to manage system strength impacts at a local generating system and system-wide level in South Australia.

Elsewhere in the NEM, a number of non-synchronous generating systems, have been required to pay remediation costs where an assessment by the relevant TNSP identifies an

172 AEMO, *Power System Limitations in North Western Victoria and South Western New South Wales*, December 2019.

adverse system strength impact. Connecting generators can undertake a range of actions to remediate the impact of their connections. These actions must be approved by AEMO but can include installing synchronous condensers, funding NSP actions or contracting with other generators to provide system strength services.

As the information contained in connection agreements is largely confidential, information about the actions taken by individual generators are not publicly available. The Panel notes that some new connecting generators have reported costs of up to $40 million to remediate their system strength impacts.[173]

The Panel acknowledges stakeholder concerns that system strength remediations required by each new generator may result in a piecemeal solution that may not address the long-term system strength needs of the NEM fully, efficiently or at least cost, but notes that providing clear signals to generators about their potential impact on system strength is an important component of maintaining system strength and ultimately a secure power system.

The Panel notes that the AEMC is currently investigating the application of the system strength frameworks to date to determine whether any improvements could be made to more effectively and efficiently address system strength issues in the NEM. A discussion paper for the *Investigation of system strength frameworks in the NEM* is expected to be published in late March 2020 that, among other things, will seek stakeholder feedback on whether improvements could be made to system strength frameworks. The Panel supports the AEMC's review and looks forward to reporting on the outcomes in next year's AMPR. In the meantime, the Panel remains of the view that existing frameworks provide appropriate incentives for new generators to connect in locations with spare transmission capacity, while maintaining system strength.

4.5.5 Constraints to manage voltage and system strength

AEMO operates the system to balance supply and demand for power using the most economic resources available, while also maintaining a secure and reliable system. To do so, the NEM is operated within a technical envelope of constraints that aim to prevent the power system from operating in a state that is vulnerable to supply disruptions in response to a credible contingency event.

Network constraints are developed from TNSP limit advice and are used by AEMO in the NEM dispatch process to ensure that plant remains within rating, and power transfers remain within stability limits, so that the power system is in a secure operating state.

As the power system transitions from one dominated by a limited number of large synchronous generating systems, located in areas with strong transmission connections, to a system dominated by inverter connected renewable generation connecting is weaker parts of the network, the number of constraint changes is likely to increase to reflect this complexity. Constraint equations are changed or added to for a number of reasons including:

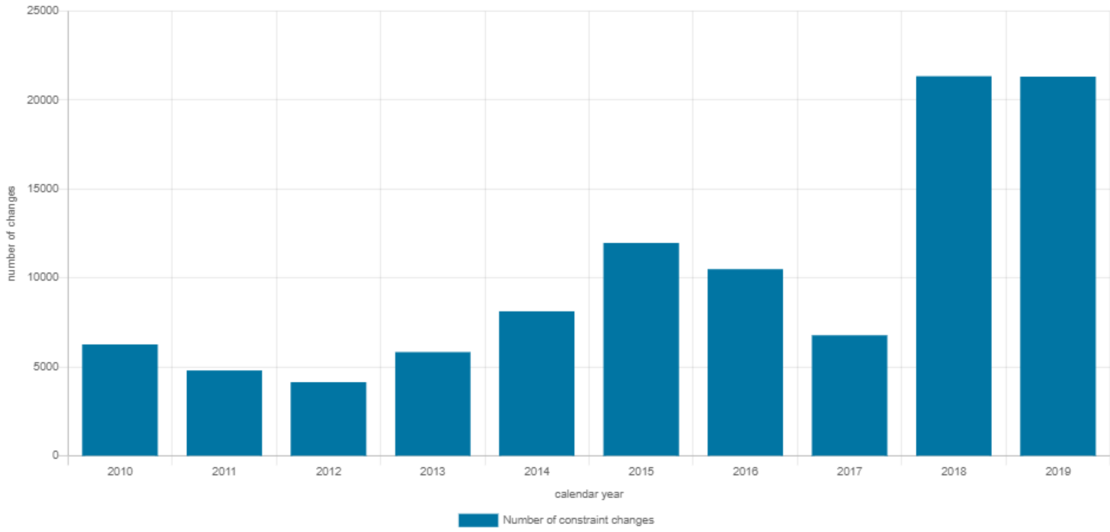
- new advice from the TNSP

173 Kiamal Solar Farm (200MW) has signed connection contracts including installation of Synchronous Condenser (estimated cost $30-40m) to remediate system strength. For more information see: https://kiamalsolarfarm.com.au/?page_id=1472

- an item of plant (such as a generator) was commissioned or decommissioned
- adjustments were made to improve the performance of the constraint equation
- power system studies identified a new condition that needs to be managed by a constraint equation
- a new FCAS requirement was identified.

In 2018/19 there were 21,317 constraint changes which is similar to last year but a large increase on previous years as shown by Figure 4.8 below.

Figure 4.8: Constraint changes in NEMDE 2010-2019



Source: AEMC analysis of AEMO data.
Note: The data for this chart is available in the AMPR data portal.

The Panel notes that this large increase in the number of constraint equation changes is driven by a number of factors. However, it does reflect an increasingly complex optimisation process being run by AEMO.

Binding constraints

A constraint equation is binding when the power system flows managed by it have reached the applicable thermal, voltage or stability limit.

The application of constraint equations to the process of dispatch can have an impact on pricing in the electricity market. AEMO publishes a report every year which examines some key impacts from the application of these constraints in dispatch. The top five binding constraints are listed in the table below.

Table 4.1: **Top five binding network constraints in 2018/19**

CONSTRAIN DESCRIPTION	REGION/TYPE	2018 MARGINAL VALUES	2018 HOURS
Upper limit (1460 to 1295 MW) for South Australian non-synchronous generation for minimum synchronous generators online for system strength requirements. Automatically swamps out when required HIGH combination is online.	SA/NIL	13,582,752.5	1,094.4
Out = NIL, avoid pre-contingent O/L of the Derby to Scottsdale Tee 110 kV line, feedback	Tas/NIL	1,518,119.6	118.1
Out = Nil, avoid voltage collapse at Darlington Point for loss of the largest Vic generating unit or Basslink	NSW/NIL	1,000,022.8	1,166.1
Discretionary upper limit for Snowtown North and South Windfarms of 190 MW	SA/Outage	777,639.0	121.6
Out = Nil, Raise 5 min requirement for a NEM Generation Event	FCAS/NIL	757,552.5	5,581.2

Source: AEMO.
Note: Two constraints, the Port Lincoln NSA and Silverton constraints, have been excluded as they only affect a single plant. The marginal value or hours binding are more reflective of the cost on the single generator affected and not a guide to congestion in the market as a whole or even regionally.

The most significantly binding constraint in the NEM is the South Australian minimum synchronous generation level constraint which was discussed in more detail in section 4.5.2.

Tools to manage system security when constraints are not enough

In the event AEMO is unable to manage secure and satisfactory limits through the use of network constraints, it will use the following options in suggested priority order.

1. **Revision to plant thermal ratings:** The TNSP provides to AEMO a revised plant thermal rating if available and AEMO inputs these revised plant rating into the operational systems to limit dispatch of certain generating systems in the case of a system security issue.
2. **Revision to power system limits:** The TNSP provides AEMO with revised power system limits together with any associated conditions. AEMO will perform a 'due diligence' of the revised limit to ensure that the advice is reasonable and that the power system remains in a satisfactory operation state following the credible contingency event indicated in the limit advice.
3. **Implement agreed plan:** Between AEMO and relevant registered participants, for example, contingency plan, Network Support Agreement (NSA).
4. **Reconfigure network:** Consider network re-arrangements, including where possible: switching of network elements, providing additional reactive support, reconfiguration or return to service of plant. Switching reconfiguration options may include sacrificial switching. This is discussed in more detail below in section 4.5.6.
5. **Use the RERT:** Under RERT, if there is sufficient notice, AEMO may dispatch or activate suitable reserve contracts to address a power system security event. This is discussed in more detail in chapter 3.
6. **System security direction or instruction:** Identify any options for power system security directions or instructions under section 116 of the NEL and NER clause 4.8.9. This is discussed in more detail in section 4.5.2.
7. **Reduction of FCAS risk:** Through system security constraints or a direction or clause 4.8.9 instruction (depending on whether there is insufficient raise or lower FCAS). This discussed in more detail below in section 4.6.3.
8. **Involuntary load shedding:** AEMO will instruct load shedding at the effective connection points. This is discussed in more detail in chapter 3.

4.5.6 De-energising lines to manage overvoltage in Victoria

In a secure power system, voltages are maintained within acceptable ranges during normal operation, and must be recovered to acceptable levels following a disturbance. AEMO maintains voltage levels across the transmission network within the relevant limits specified in the NER and to a target voltage range specified by the TNSP.[174]

The number of overvoltage incidents have increased in parts of the Victorian network, driven by a combination of:

174 Schedule 5.1a of the NER.

- Lower minimum demand levels: minimum demand has decreased by 520 MW or 15 per cent in the last five years. Transmission lines inject reactive power under very low demand conditions leading to an increase in voltage unless sufficient resources are available to absorb this additional reactive power.
- Mothballing or retirement of synchronous generation: Hazelwood closure removed 1600MW and reactive capability from the grid. The closure of Hazelwood reduced the capability of the Victorian network to absorb reactive power to address the additional needs due to low demand conditions.
- Transformation of the generation mix: expected increase in large scale renewables and withdrawal of thermal plant in coming decades.

The Panel identified this as an emerging issue in 2017/18 and committed to monitoring the issue.

There are several methods of voltage control available for managing overvoltage on transmission lines including:

- changing the voltage ratio of a transformer to offset any higher or lower input voltages
- actively injecting or absorbing reactive power at connection points or other locations within the network
- network reconfiguration or line switching.

One option for AEMO to manage the over voltage conditions associated with low demand periods in Victoria is to remove transmission lines from service thereby reducing the network's contribution to reactive power absorption requirements. During 2018/19, operational measures such as de-energising transmission lines, have become necessary during these periods to maintain voltages within operational limits. In addition to de-energising a single 500 kV transmission line in Victoria, there is also one NMAS contract in place[175] that was invoked on 11 occasions during the year to suppress high voltages in Victoria in 2018/19:

- twice in March for a total of 13.5 hours
- five times in April for a total for 33.5 hours
- four time in May for a total of 24 hours.

This contract was typically activated overnight, when demand is at its lowest.

Network re-configuration, by withdrawing transmission lines from service, is a valid approach to managing the circumstances in Victoria. There are however some significant drawbacks and network reconfiguration should not be excessively utilised to manage over voltage conditions during low demand periods. The Panel notes that continued reliance on network reconfiguration could:

- place additional stress on the system by requiring network assets to be used in ways outside their original design specifications

175 This is a Voltage Control Ancillary Services contract between AEMO and a VCAS provider.

- reduce flow path redundancy on the main transmission system if more lines are switched off, making the system more vulnerable to unexpected shocks
- impact on the ability of the transmission system to effectively transport energy within and between regions over time resulting in higher costs to consumers.

AEMO notes in its *Power system security guidelines*[176] if voltage issues are experienced during real time operation, one transmission line per region may be de-energised for voltage control. If further actions are required, AEMO will consider directing participants to inject or absorb power. If no direction options are available, more transmission lines may be de-energised.

AEMO is currently undertaking a Regulatory Investment Test for Transmission (RIT-T)[177] to deliver a long-term solution to a need for voltage control issues during times of minimum demand in Victoria. The preferred option is to install shunt reactors at Keilor Terminal Station in 2021/2022, a synchronous condenser at South Morang Terminal Station in 2022 and two shunt reactors at Moorabool Terminal Station in 2023.

The Panel notes that this seeks to deliver a long-term solution to address these voltage control issues. However, in the interim, there is a need for absorbing reactive power which can suppress the high voltages on the Victorian transmission network during these low demand periods.

AEMO is seeking tenders for the provision of Non-Market Ancillary Services from NEM registered participants with generating units, dispatchable load, storage or any other equipment located around Moorabool, South Morang, Geelong, Sydenham or Keilor terminal stations during times of minimum system demand.

The Panel is encouraged by these near and long term activities to address over-voltages in Victoria and notes that similar action may need to be taken as forecast reductions in minimum demand over the next 10 years emerge in other areas of the network.

4.6 Frequency control and inertia

This section talks about how the power system and market performed in terms of frequency, that is, the ability of the power system and market to maintain frequency at or close to 50 Hertz (Hz) and in line with the NER's power system security requirements set out in the Panel's Frequency Operating Standards (FOS).

A number of factors are involved in managing frequency in the NEM including:

- Performance of **power system frequency** against the FOS.
- Levels of **inertia** which act to dampen or resist changes in system frequency. Inertia is usually provided by generators with large spinning turbines that are synchronised to the frequency of the power system, like hydro, coal and gas.

176 AEMO, *Power system security guidelines*, September 2019.

177 For more information see AEMO's website.

- Generators helping to control system frequency by automatically changing power output in response to locally detected variations in frequency - known as **primary frequency control**.
- Availability and use of **frequency control ancillary services** which are procured by AEMO or market participants to increase or decrease active power over a timeframe that meets the requirements of the frequency operating standards - discussed in detail in section 4.6.3.
- Elements of the **technical standards framework** which relate to frequency control and inertia. These include generator technical performance standards which require generators to remain in continued uninterrupted operation for frequency disturbances of a certain magnitude - discussed in section 4.6.2**.**
- Operation of **emergency frequency control schemes** which help restore power system frequency in the event of extreme power system events.

In this section the Panel considers the NEM's performance in 2018/19 in relation to primary frequency control and emergency management and special protection schemes.

4.6.1 What is frequency control and inertia, and why are they important?

Frequency control

Controlling or maintaining stable frequency is a key element of power system security. All generation, transmission, distribution and load components connected to the power system are standardised to operate at a nominal system frequency of 50 Hz. The power system must therefore stay at or close to this level for equipment to stay connected to the system and continue to operate within technical bounds.

To maintain a stable system frequency at or close to 50Hz, AEMO must balance the supply of electricity into the power system against consumption of electricity at all times. When there is more generation than load, the frequency will tend to increase. When there is more load than generation, the frequency will tend to fall.[178] The dispatch process is the main way of achieving this balance, but AEMO also relies on frequency control services, which are mostly designed to inject or remove power from the grid to restore the balance of supply and demand, discussed more in section 4.6.3**.**

Frequency performance in the NEM is assessed against the frequency operating standard which defines the range of allowable frequencies for the electricity power system under different conditions, including normal operation and following contingencies.

Inertia

The amount of inertia in the NEM has been decreasing as synchronous generators exit, and are replaced by technology that either cannot or does not presently provide inertia. With less inertia in the NEM, it is harder to manage frequency and keep it within the normal operating band (49.85-50.15 Hz).

178 A more detailed explanation of power system frequency and frequency variation is provided in Appendix C of the AEMC's *Frequency control frameworks review* draft report p. 187.

The frequency of the power system varies whenever the supply from generation does not precisely match customer demand and losses. Inertia is a measure of the ability of the power system to resist changes in frequency due to sudden changes in supply or demand.

Inertia in the power system is associated with the rotational kinetic energy stored in the spinning turbine masses. This kinetic energy is released when there is an instantaneous imbalance between power demand and generation which acts to slow the rate of change of frequency.

Power systems with high inertia can resist large changes in frequency and limit the amount and rate of frequency change after a disturbance. Power systems with lower levels of inertia limit the rate of change of power system frequency in vulnerable regions. Systems with low inertia also require greater coordination and use of FCAS and, if necessary, emergency frequency control schemes to respond to sudden frequency changes.

At present, AEMO does not dispatch inertia, instead it is provided in the NEM by synchronous generators such as coal, hydro and gas power stations as part of their normal operations. In some regions however AEMO uses constraint equations to maintain a sufficient number of synchronous generators in operation to provide levels of inertia sufficient to limit the rate of change of frequency in a vulnerable region. AEMO also acts to limit the potential size of the imbalance in power demand and use by limiting the size of the potential contingency that can occur. This can be by constraining the output of large generators or interconnectors.

Why are they important?

Uncontrolled changes in frequency can cause cascading failures leading to major supply disruptions or black system events. To protect against this, it is important there are sufficient measures in place to provide for frequency control and inertia.

4.6.2 Performance against the frequency operating standard

AEMO is required to keep the power system stable and securely operating at a frequency close to 50 Hz. Where frequency deviates from 50Hz, there are acceptable limits defined for different scenarios.

Figure 4.9: Frequency bands for the NEM and Tasmania

	NORMAL (HZ)		ISLAND (HZ)		SUPPLY SCARCITY (HZ)
	MAINLAND	TASMANIA	MAINLAND	TASMANIA	MAINLAND[1]
normal operating frequency band	49.85 – 50.15		49.5 – 50.5	49.0 – 51.0	49.5 – 50.5
normal operating frequency excursion band	49.75 – 50.25		49.5 – 50.5	49.0 – 51.0	49.5 – 50.5
operational frequency tolerance band	49.0 – 51.0	48.0 – 52.0	49.0 – 51.0	48.0 – 52.0	48.0 – 52.0
extreme frequency excursion tolerance limit	47.0 – 52.0	47.0 – 55.0	47.0 – 52.0	47.0 – 55.0	47.0 – 52.0

Source: Reliability Panel, Frequency operating standard.

Note: The Reliability Panel has not determined separate frequency bands for periods of supply scarcity in Tasmania. Where a state of supply scarcity exists for the Tasmanian power system, the frequency bands set out in the "normal" column apply for an intact power system, and the frequency bands set out in the "island" column apply for an island with the Tasmanian power system.

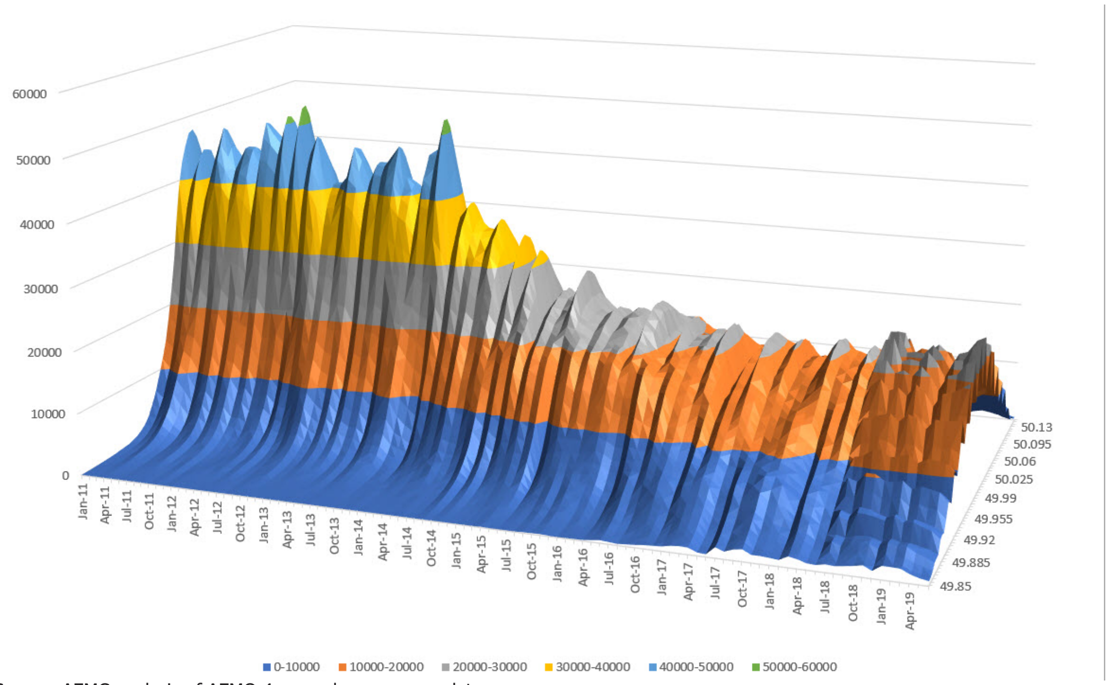
Note: The Panel updated the FOS on 14 November 2017 to accommodate the new emergency frequency control scheme and the new category of protected contingency event. The FOS was updated again on 18 April 2019 to limit on the size of the largest generation event in the Tasmanian power system and improve the structure and consistency of the FOS.

Note: The Panel made it clear in its recent review, that it may need to revisit the FOS again in the short to medium term to accommodate any recommended changes to the frequency control philosophy that are necessary to specify the power system security requirements as the NEM evolves.

The FOS also provides that in the absence of a contingency event, AEMO should maintain system frequency within the applicable normal operating frequency excursion band and should not exceed the applicable normal operating frequency band (NOFB) for more than five minutes on any occasion and not for more than 1% of the time over any 30-day period. AEMO calculates the percentage of time spent inside the NOFB on a daily rolling average.

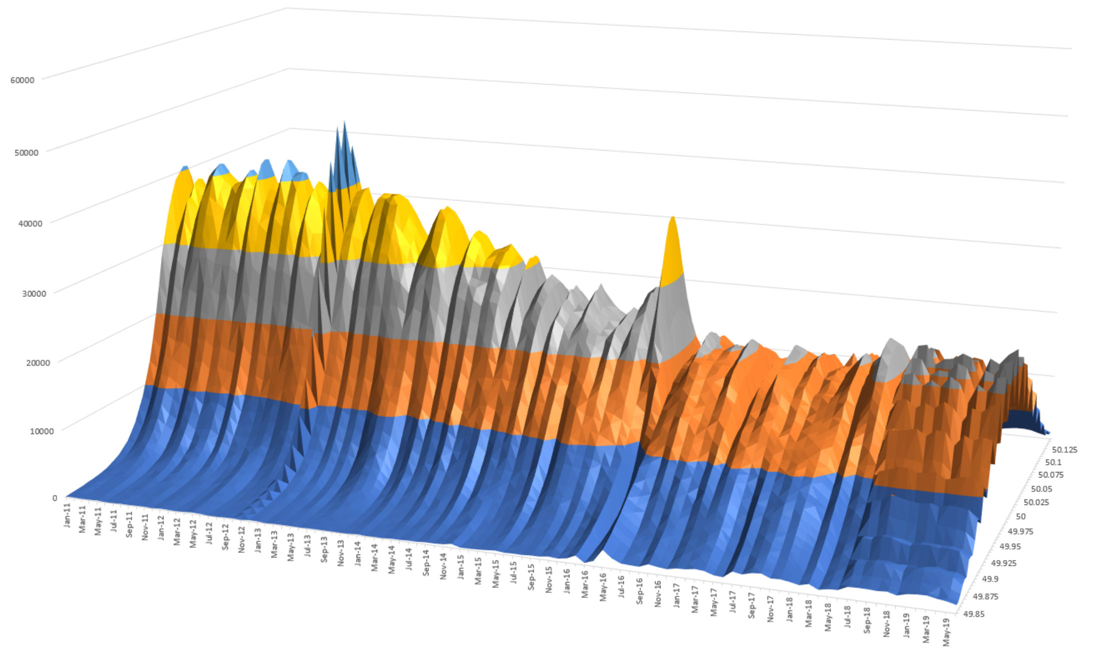
Frequency performance under normal operating conditions has been deteriorating in recent times. That is, there has been a flattening of the distribution of frequency within the normal band, as shown in for the NEM mainland in Figure 4.10 and for Tasmania in Figure 4.11 below. In practice, this means that the power system is increasingly operating at frequencies further away from the ideal operating frequency, increasing the risk that a disturbance will cause frequency to move outside the tolerance limits.

Figure 4.10: Frequency distribution on NEM mainland



Source: AEMC analysis of AEMO 4-second causer pays data.
Note: The data for this chart is available in the AMPR data portal.

Figure 4.11: Frequency distribution in Tasmania



Source: AEMC analysis of AEMO 4-second causer pays data.
Note: The data for this chart is available in the AMPR data portal.

A key indicator of the frequency performance of the NEM is the extent to which system frequency has met the requirements of the FOS. The FOS is determined by the Reliability Panel and sets out the specific frequency requirements that AEMO must meet under different power system conditions. They are the basis for determining the level of quick acting response capabilities, or ancillary service requirements necessary to manage frequency. Tasmania has separate frequency operating standards to the mainland NEM as set out in Figure 4.9 above.

Performance against the FOS in 2018/19

Frequency performance of the NEM showed mixed performance in the 2018/19 financial year. The FOS specifies outcomes that should be achieved during normal operation, as well as a number of system frequency outcomes following specified conditions.

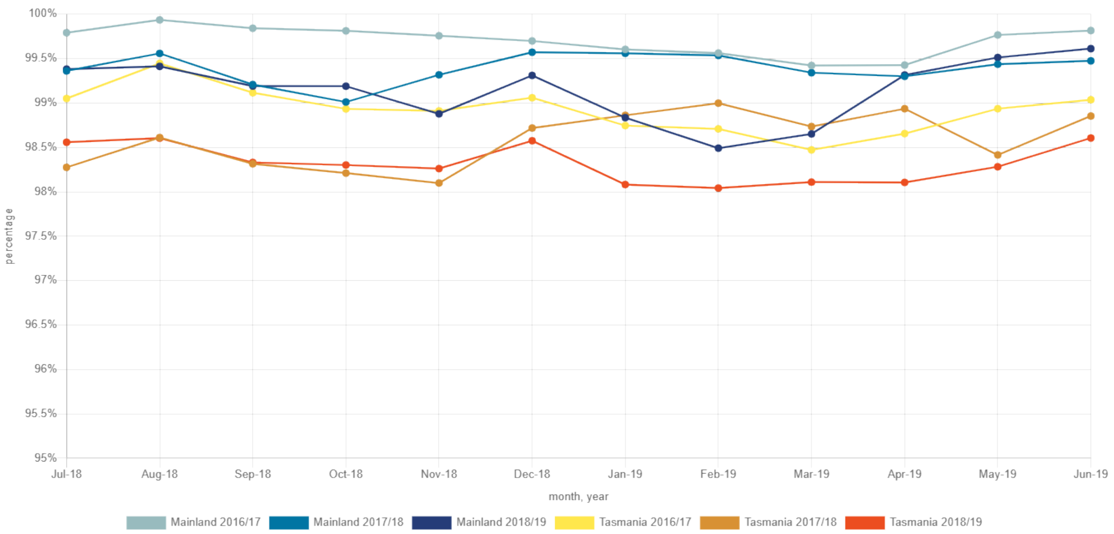
AEMO provides quarterly reports[179] on the NEM and Tasmanian power systems' performance against the FOS. According to AEMO's reports, Tasmania failed to meet this requirement for every 30 day period across the 2018/19 financial year, and the NEM on only met it from June to October 2018, and in May and June 2019.

179 These reports are available at: https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/ancillary-services/frequency-and-time-deviation-monitoring

Figure 4.12 below shows:

- frequency performance over the course of the report period was generally steady
- the 2018/19 outcomes are part of an emerging trend where the percentage of time spent in the normal operating band each month has been deteriorating.

Figure 4.12: Percentage of time in normal operating band on mainland and in Tasmania.

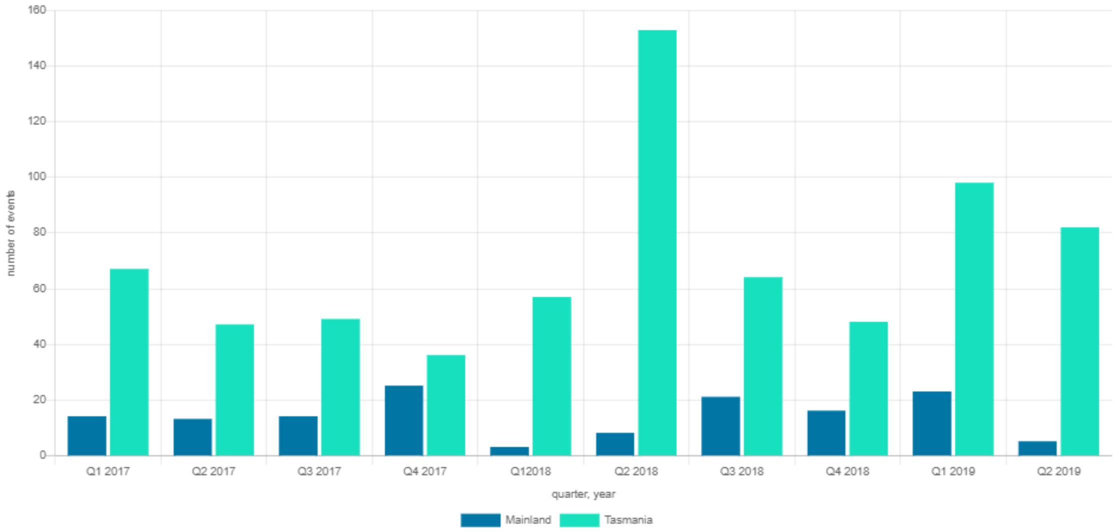


Source: AEMC analysis of AEMO data.
Note: The data for this chart is available in the AMPR data portal.

Other elements of the FOS include a requirement that if the power system frequency deviates outside the normal band, it must be returned to the normal band within five minutes. The number of frequency events outside these FOS requirements in 2018/19 financial year is shown in Figure 4.13 below.

The Panel notes that there is no clear trend emerging in relation to the number of events outside the frequency operating standard. On the mainland the number was greater overall (65) in 2018/19 than the previous reporting period (50). In Tasmania the number was around the same in each year (292 in 2018/19 and 295 in 2017/18) but with Q2 2018 showing significantly more events than all other quarters.

Figure 4.13: Events outside the frequency operating standard



Source: AEMC analysis of AEMO's quarterly Frequency and time deviation monitoring report.
Note: This includes events that either exceed the allowable duration in the FOS or where the frequency was outside the normal operating frequency excursion band (NOFEB) for a reason other than a contingency event or a load event.
Note: The data for this chart is available in the AMPR data portal.

Figure 4.14 and Figure 4.15 below shows the number of frequency excursions on the mainland and Tasmania respectively.

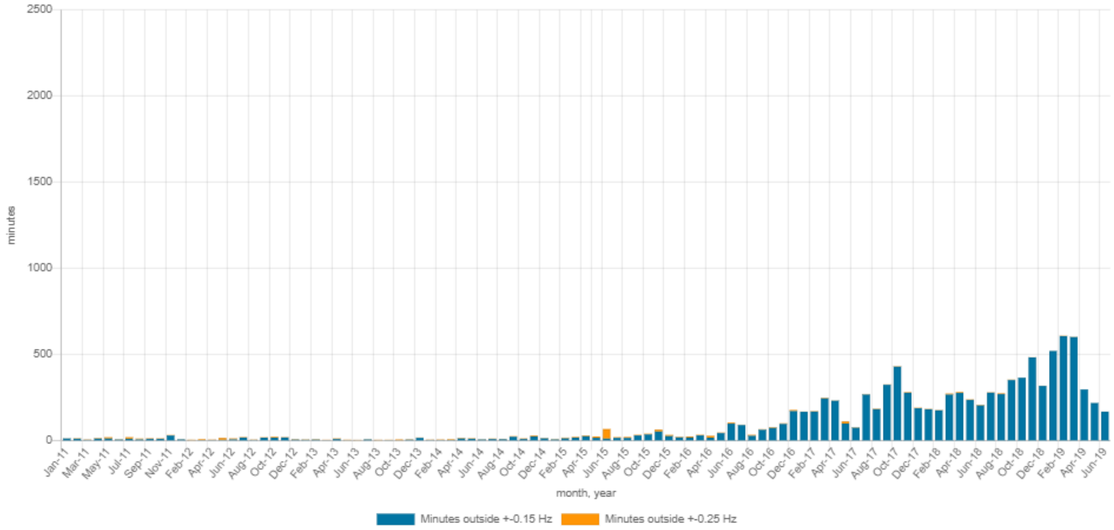
On the mainland:

- While frequency excursions vary month to month, there has been an overall and exponential increase in excursions on the mainland continuing the trend of the last four years.
- This continues to be a concern for the security of the power system.

In Tasmania:

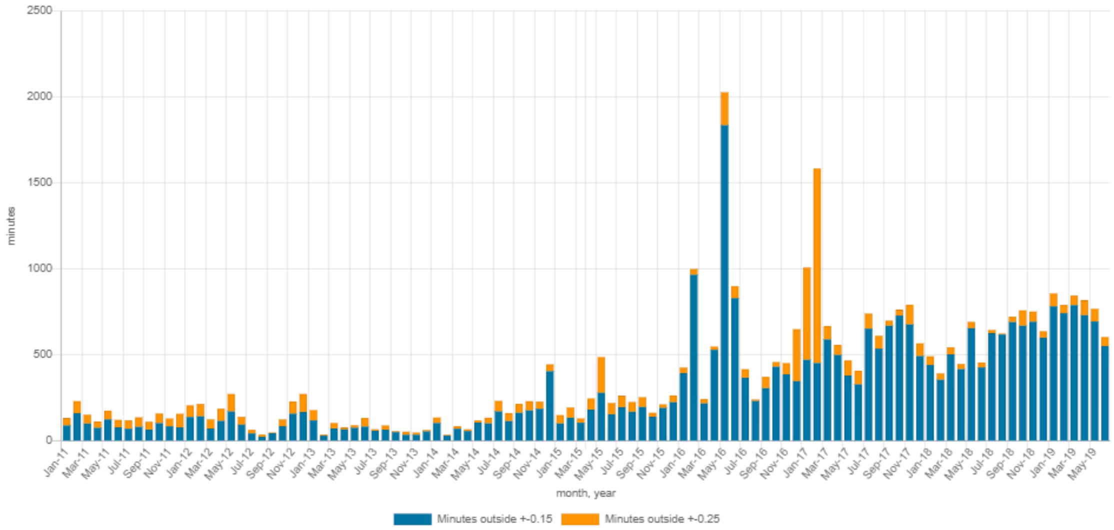
- the number of frequency band exceedances is much greater than on the mainland; however, it is more consistent in 2018/19 compared to previous years
- system frequency has exceeded the more severe +/-0.25Hz band significantly more often than in the mainland, though this has lessened in recent years.

Figure 4.14: Frequency excursions in the NEM



Source: AEMC analysis of AEMO Frequency and time deviation monitoring data.
Note: The data for this chart is available in the AMPR data portal.

Figure 4.15: Frequency excursions in Tasmania



Source: AEMC analysis of AEMO Frequency and time deviation monitoring data.
Note: The data for this chart is available in the AMPR data portal.

The Panel notes that actions taken by AEMO as a result of the increase include an increase in base mainland regulation FCAS (see section 4.6.3) and reduction of assumed mainland load relief. The Panel remains concerned that the performance of the mainland and Tasmanian power systems against the FOS continues to deteriorate. In light of this, the Panel highlights the importance of the work program underway to improve the frequency performance in the NEM. This work program is discussed in section 4.7.4.

4.6.3 Performance of frequency control ancillary service markets

Ancillary services are essential to the management of power system security in the NEM to facilitate orderly trading in electricity, and to ensure the supply is of acceptable quality. These services maintain key technical characteristics of the system, including standards for frequency, voltage, network loading, and system restart processes. FCAS are intended to work together to maintain a steady frequency during normal operation, and to stabilise and restore the frequency by reacting quickly and smoothly to contingency events that cause frequency deviations.

AEMO operates eight separate markets for the delivery of FCAS and purchases Network Support Control Ancillary Services (NSCAS) and System Restart Ancillary Services (SRAS) under agreements with service providers. Payments for ancillary services include payments for availability and delivery of the services. Ancillary service costs are dependent upon the amount of service required at any particular time and, as these amounts can vary significantly from period to period, costs will also vary.

The ongoing transformation of the power system presents both opportunities and challenges for AEMO's ability to manage power system frequency.

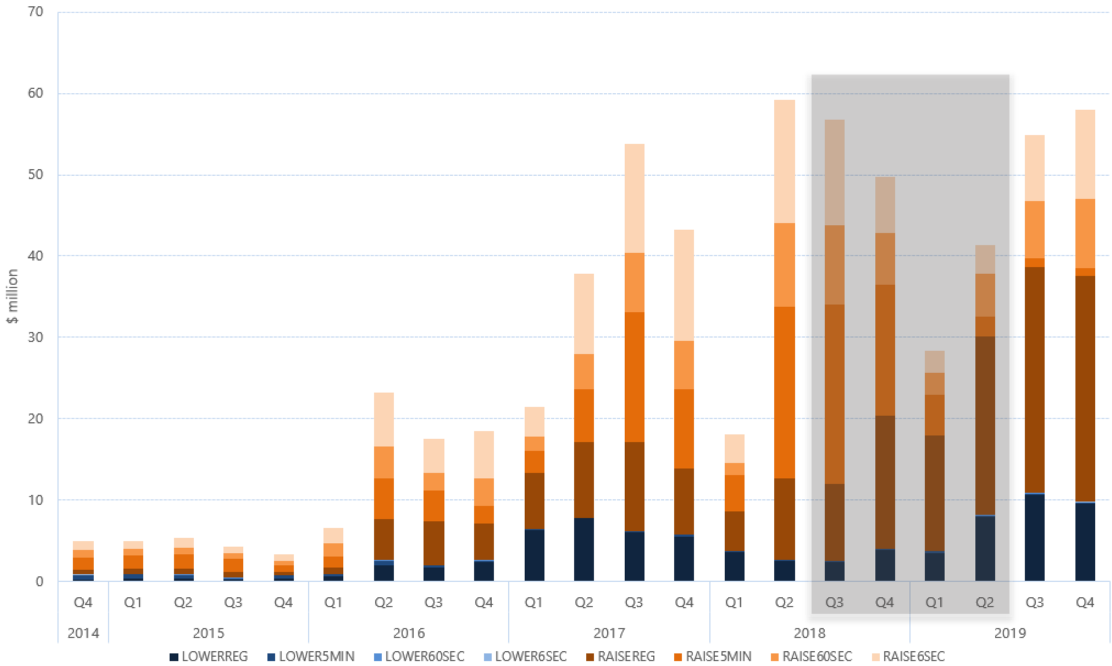
Further changes to the market and regulatory frameworks may be required to meet the challenges in maintaining effective frequency control arising from, and harness the opportunities presented by, the changing generation mix.

FCAS markets

FCAS services are used to raise system frequency if it has fallen (by increasing generation or reducing load) and to lower system frequency if it has risen (by decreasing generation or increasing load). FCAS are intended to work together to maintain a steady frequency during normal operation, and to stabilise and restore the frequency by reacting quickly and smoothly to contingency events that cause frequency deviations.

The AER monitors FCAS prices to understand the impact the use of these services have on the total cost of running the power system. Overall, FCAS costs increased slightly from $174.2 million in 2017/18 to $176 million in 2018/19. Costs of raise services make up a large portion of regulation raise service increasing its share of the costs over the year and other raise services decreasing their share. The cost of regulation lower services also increased throughout the year.

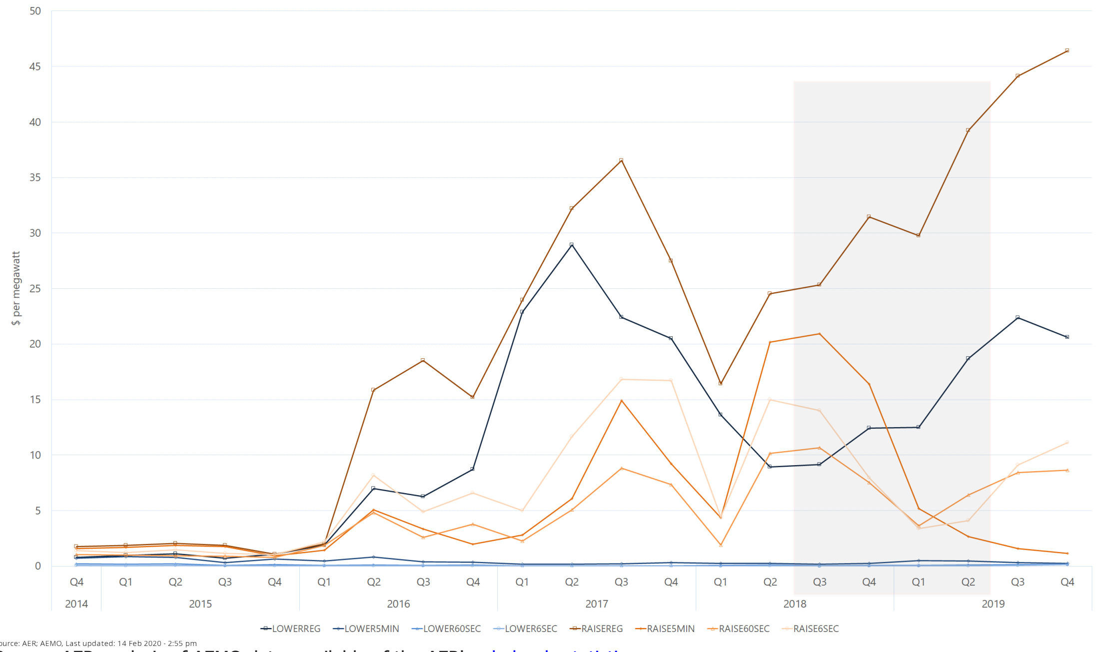
Figure 4.16: Quarterly global FCAS costs by services



Source: AER analysis of AEMO data, available of the AER's wholesale statistics page.
Note: This figure shows the quarterly costs for each global FCAS service across the NEM for the past five years. These include costs for both raise and lower regulation services, and raise and lower contingency services.

The price of FCAS services has also changes in response to changing market conditions. Prices for regulation raise and lower services trended up during the reporting period while all other services trended downwards.

Figure 4.17: Quarterly global FCAS prices by services

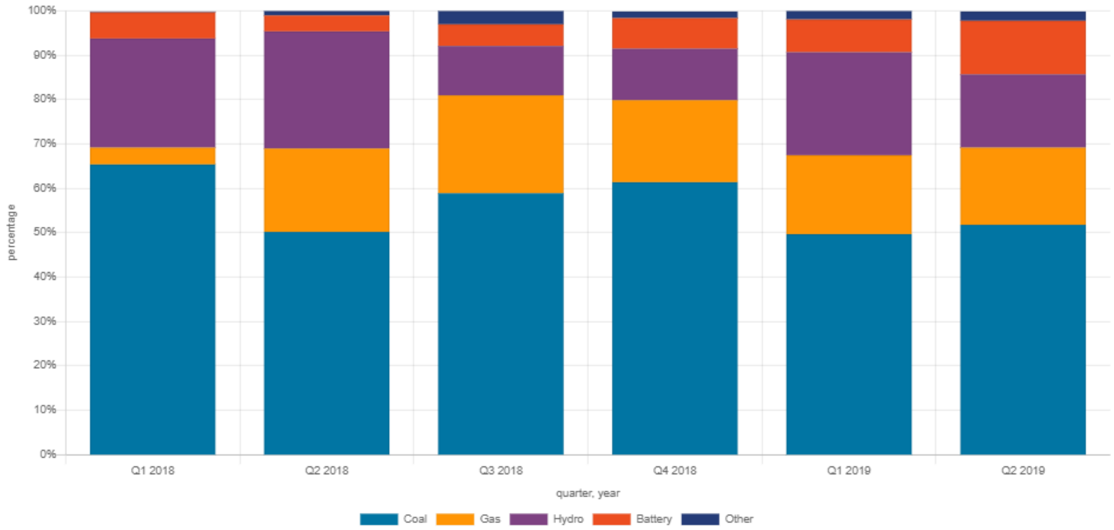


Source: AER analysis of AEMO data, available of the AER's wholesale statistics page.

New providers of FCAS

A notable change in FCAS markets during 2018/19 is the increase in new participants. Figure 4.18 below shows the amount of FCAS provided by batteries and "other" (which includes demand response, wind farms and virtual power plants) has increased significantly even within the reporting year. At the same time, the amount of FCAS provided by coal-fired power plants decreased over the year.

Figure 4.18: Percentage of 'raise' FCAS provision by fuel type



Source: AEMC analysis of AEMO data.
Note: The data for this chart is available in the AMPR data portal.

This highlights that there is an important role for new technologies in the system security frameworks, particularly as these services become more valuable. As thermal generators retire from the NEM, they will cease to be able to provide services such as FCAS. Advances in technology and the continued entrance of new generators means these new entrants will increasingly be able to replace these services. It will be important to make sure these frameworks enable the provision of these services from non-traditional sources.

An example of this is the provision of FCAS from aggregated distributed energy resources. This is an important development for the system security frameworks. Increasingly, generation in the NEM will be dispersed through the distribution network. While this generation can present challenges, it also represents an opportunity as a new source of important services. The Panel commends the work undertaken to integrate this non-traditional sources of FCAS into the framework and notes it is important that this work continues.

Procurement of System Restart Ancillary Services

System restart ancillary services enable the recovery of the power system following a major disturbance, where large parts of the power system have collapsed to a "black system" condition. SRAS is currently provided by generators with the capability to start, or remain in service, without electricity being provided from the grid. Once an SRAS provider has restarted its own plant, it provides energy to restart other generators and commence the processes required for system restoration. There is an additional cost involved to equip generating plant with this capability and not all generators have it.

The Panel is responsible for determining the system restart standard, which specifies the level of supply restoration for which AEMO is to procure system restart services. The system restart standard specifies the parameters for restoring generation and transmission system operations after a major supply disruption including a black system event. This generation capability can then be used to restart other generators and these can subsequently restore supply to consumer load. The parameters included in the standard are:

- the maximum time in which a specified level of generation capability must be restored in each sub-network
- the aggregate level of reliability of restart services in each sub-network, that is, the overall reliability of the SRAS procured for the sub-network rather than just for any individual source of SRAS.

AEMO must use its reasonable endeavours to acquire sufficient SRAS for each defined electrical sub-network to meet the requirements of the system restart standard. The NER sets out a framework for how the restoration of the system should be managed. Careful planning and clear communication between these various parties is critical to the effective restoration of supply to customers.

The current system restart standard was determined in December 2016 following a year-long public consultation process with energy users, industry, jurisdictional system security co-ordinators and state and territory governments, and came into effect on 1 July 2018.[180] The new standard has a more stringent process for procurement of restart services which is tailored to the specific requirements of each electrical sub-network and made recommendations to improve testing and load restoration.

Under the new standard:

- the level and time components are now tailored for each electrical sub-network to reflect the speed at which the generation can be restored, the characteristics of the transmission network and the economic circumstances that apply to the sub-network
- it minimises the costs of the SRAS that will need to bought by specifying the minimum level of generation and transmission capacity to be restored by SRAS in each sub-network in accordance detailed economic assessment of procuring different levels SRAS
- it includes aggregate reliability of the SRAS procured for each of the electrical sub-networks. This requirement better-specifies the performance of the procured SRAS, and includes a requirement for AEMO to consider the reliability and damage to the transmission network, following a major supply disruption, when it calculates aggregate reliability.

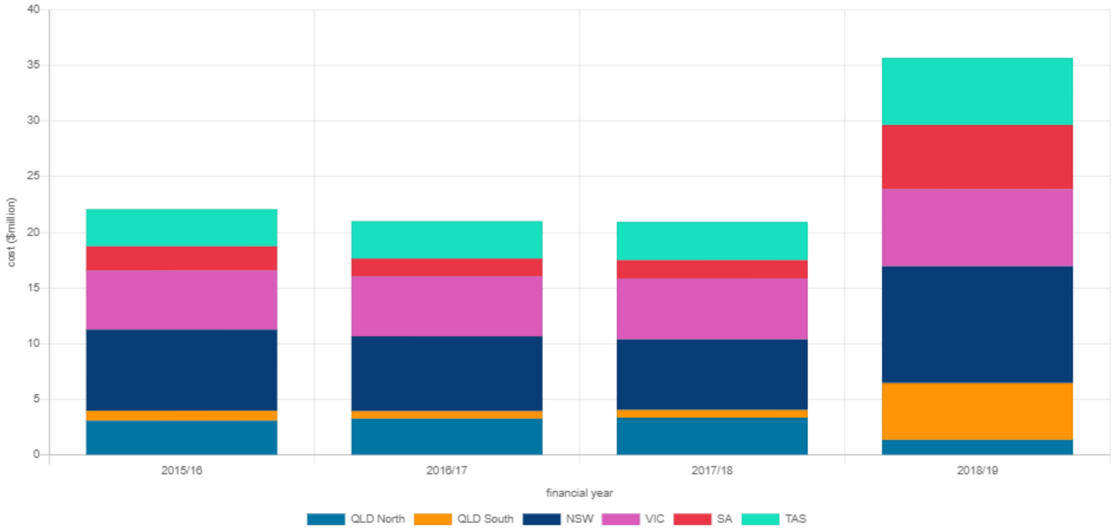
For the 2018/19 year AEMO had 12 SRAS contracts - two in each of New South Wales, Victoria, South Australia and Tasmania, two for Queensland south and two for Queensland north. [181] The cost of SRAS, which had remained relatively stable since August 2013,

180 The current System Restart Standard was determined by the Reliability Panel in accordance with clauses 8.8.1(a)(1a) and 8.8.3 of the NER. The previous standard was determined in August 2013 and remained in effect until 30 June 2018.

181 Under clauses 3.11.10 and 3.13.5(b) and (c) of the NER, AEMO reports annually on the quantities and costs of system restart ancillary services and network support and control ancillary services and the process AEMO followed to acquire SRAS for subsequent financial years.

increased in 2018/19 from approximately $21 million to $35.7 million. The increase in costs is due to new requirements under the new standards that commenced on 1 July 2018. AEMO has estimated SRAS costs will increase again in 2019/20.

Figure 4.19: SRAS costs



Source: AEMC analysis of AEMO non-market ancillary services cost and quantity annual reports.
Note: The data for this chart is available in the AMPR data portal.

AEMO and the AER have identified a number of challenges arising under the existing frameworks governing the procurement, testing and deployment of SRAS, and have proposed a rule change to address these. Key elements of the rule request and draft determination made in December 2019 include:

- Traditional sources of SRAS are declining in some NEM regions, and those that remain are potentially less capable of restoring the power system. This issue can be at least partly addressed by expanding the definition of SRAS, to allow new parties and new technologies to offer these services.
- The definition of SRAS currently only encompasses black start capability and does not refer to other ancillary services that are needed to support the stable restoration of the power system. Defining these new services will allow AEMO to source them as necessary to deliver an effective restoration of the power system.
- Existing modelling and generator-level testing of contracted SRAS sources may not be sufficient, by themselves, to accurately determine whether the SRAS acquired by AEMO is capable of effectively restoring the power system to meet the requirements of the system restart standard. Physical testing of restart paths is needed to complement this modelling and generator-level testing.
- The NER do not provide sufficient clarity and delineation between the roles of AEMO, transmission network service providers (TNSPs) and other parties involved in system restoration, particularly in relation to the communication processes needed to facilitate an

effective response to a major supply disruption. Clarifying these roles and responsibilities will enhance the effectiveness of the system restoration process generally.

A final determination is expected in April 2020.

4.6.4 Primary frequency control

The Panel acknowledges that there are various drivers of this degradation of frequency performance. One of these is a reduction in generator frequency response during normal operation.

Generators can help to control system frequency by automatically changing power output in response to locally detected variations in frequency. However, generators that are not enabled to provide frequency control through the ancillary service markets have been decreasing or removing their responsiveness to correct frequency deviations on a voluntary basis. Under the current arrangements, frequency response is only required by those market participants that are enabled to provide FCAS through the related ancillary service markets.

An increase in the provision of primary frequency response (PFR) from generators will improve the security of the national electricity system for the benefits of consumers and will assist AEMO to maintain the power system in a secure operating state and enhance the overall resilience of the power system. PFR will also enhance AEMO's ability to predict the dynamic behaviour on the power system during events and successfully manage power system security accordingly.

The Panel notes that the AEMC has made a draft rule to introduce a mandatory requirement for generators to provide PFR. The AEMC considers that this is likely to address the immediate need identified by AEMO for improved frequency control in the NEM.

The Panel recognises that a mandatory requirement for narrow band PFR is likely to assist power system frequency control but is not a complete solution and, on its own, will not incentivise the provision of primary frequency response over the long term. The Panel notes that AEMO's view is that all of the generation fleet needs to provide primary frequency response in order to be effective in managing system security.

The Panel notes that further work needs to be done to understand the power system requirements for maintaining good frequency control. This future work will also need to consider the appropriateness of the mandatory requirement for narrow band PFR and other alternative and complementary measures, including the potential for new market and incentive-based mechanisms for frequency control which will be considered through the AEMC's Removal of disincentives to primary frequency response rule change process. The Panel looks forward to working with the AEMC on frequency issues, including a potential revision of the frequency operating standard (if required) in the future.

4.6.5 Inertia levels

As discussed earlier in this chapter, the amount of inertia in the NEM has been decreasing as synchronous generators exit, and are replaced by technology that either cannot or does not presently provide inertia.

This reduction in inertia is increasing the susceptibility of the system to rapid changes in frequency that arise as a result of system disturbances, which can lead to blackouts. The NEM requires a minimum level of inertia to keep it secure.

During the 2018-19 financial year, new rules came in to help manage the rate of change of power system frequency by requiring TNSPs to provide inertia network services up to a minimum level set by AEMO for each sub-network. TNSPs will have an obligation to provide inertia network services if an inertia shortfall has been identified.

Setting minimum levels of inertia

AEMO calculated the inertia requirements for each inertia sub-network in June 2018. Each region is considered a sub-network for the purposes of the assessment.[182] The minimum levels and shortfalls determined by AEMO are available on its website.[183]

Inertia shortfalls

On 21 December 2018, AEMO published its 2018 National Transmission Network Development Plan (NTNDP) and declared an inertia shortfall in South Australia. AEMO has assessed an inertia shortfall of 6,000 MW.s will arise in South Australia when AEMO stops directing synchronous generation to remain online for system strength purposes.

AEMO's declared inertia shortfall requires ElectraNet to use reasonable endeavours to procure at least 4,400 MW.s of synchronous inertia services to meet the 'minimum threshold level of inertia when the South Australian region is at credible risk of islanding. ElectraNet may address the balance of the 6,000 MW.s shortfall by contracting generation, batteries and other equipment capable of fast frequency response to provide inertia support to meet the 'secure operating level of inertia' under islanded conditions.

ElectraNet's approved solution[184] is to install four high inertia synchronous condensers on the South Australian transmission network. The inertia capability of these machines means the system strength gap discussed in section 4.5.3 is addressed and the inertia shortfall declared by AEMO.

Inertia shortfalls were not declared in any other regions for the 2018/19 reporting period.

However, the Panel notes that in November 2019, AEMO declared an inertia shortfall in Tasmania. The shortfall risk is during periods of low demand from the grid, combined with high imports from Victoria over Basslink. During these times, Tasmania has the potential to experience low levels of synchronous generator unit dispatch. This is expected to occur more often following the commissioning of two large (asynchronous) wind farms over the next 12 months. The Panel understands that TasNetworks has proactively sought expressions of interest to provide inertia and system strength in Tasmania, and will monitor the status of its activities in next years AMPR.

182 AEMO's Inertia requirements methodology and inertia requirements and shortfalls, June 2018.

183 Ibid.

184 More information is available on the AER's website.

4.6.6 Emergency management and special protection schemes

If frequency moves significantly outside of the normal ranges, automatic protection systems operate to trip load (under-frequency load shedding (UFLS) schemes) or generation (over-frequency generation shedding (OFGS)) schemes to bring the frequency back to within the normal operating standards. These emergency frequency control schemes are the last line of defence to maintain the power system following a major disturbance (non-credible event) and are central to keeping the power system secure.

In June 2018, AEMO published the final report of its inaugural *2018 Power system frequency risk review,*[185] which recommended material changes to emergency frequency control schemes for South Australia and Queensland. These changes were made during the 2018/19 financial year and include:

- In Queensland: amending the existing SPS for central Queensland to south Queensland, to be effective for higher southerly flows that are anticipated as generation projects connect in North Queensland.
- In South Australia: implementing an upgrade to the SIPS to reduce the likelihood that a loss of multiple generators in South Australia will lead to separation and a black system. This was progressed as part of the protected event emergency frequency control scheme (see below).

The Panel understands that AEMO's *Power system frequency risk review* will be updated as needed. The Panel notes that this may involve creating a new risk review process, a General Power System Risk review, to allow AEMO, networks and market participants to work together to identify new risks and develop solutions as recommended in the AEMC's review into the black system event in South Australia.[186]

Protected events

The protected event framework is another component of managing frequency in emergency events. Protected events are a relatively new category of non-credible contingency event for which there are net economic benefits from AEMO taking some pre-emptive action to manage, for example by purchasing FCAS, constraining generation dispatch or using emergency load or generation shedding schemes. Protected events may be declared by the Panel in response to a request from AEMO.[187]

On 5 November 2018, AEMO submitted a request to the Reliability Panel seeking to declare the risk to South Australia's power system from destructive winds as a 'protected event.'

On 20 June 2019 the Panel published a final determination declaring a protected event in accordance with AEMO's request. The Panel's final determination supports AEMO's recommended option for managing the protected event, which includes:

- upgrading the existing system integrity protection scheme (SIPS) in South Australia

185 AEMO, *Power system frequency risk review report*, June 2018.

186 AEMC, *Review of the system black event in South Australia on 28 September 2016*, December 2019.

187 Clause 8.8.4 of the NER.

- limiting imports across the Heywood interconnector during periods of forecast destructive wind conditions.

The Panel's declaration will provide a more cost-effective, fit-for-purpose mechanism for managing the risks associated with the protected event than previous arrangements employed by AEMO, and provide the market with more transparency about how AEMO will manage the protected event.

Special protection schemes

Special protection schemes and emergency frequency management schemes are designed to shed load, generation or trip network elements in order to arrest the progress of a cascading outage. Given the changing power system and increased uncertainties and risks, they play and increasingly important role for both AEMO and participants to manage and protect equipment from damage, and the power system from uncontrolled responses to disturbances.

In December 2019 the AEMC completed a review into the South Australian black system event.[188] Throughout the process of compiling the review, stakeholders identified the uncoordinated proliferation of special protection schemes throughout the NEM may have detrimental effects on system security. It was noted that unexpected outcomes from, and adverse interactions between, special protection schemes and plant control and protection settings represent a material risk.

The Panel, in collaboration with AEMO, have sought to assess the magnitude of this proliferation in this review. Figure 4.20 illustrates the number and type of special protection schemes that have been added to the NEM in 2018/19.

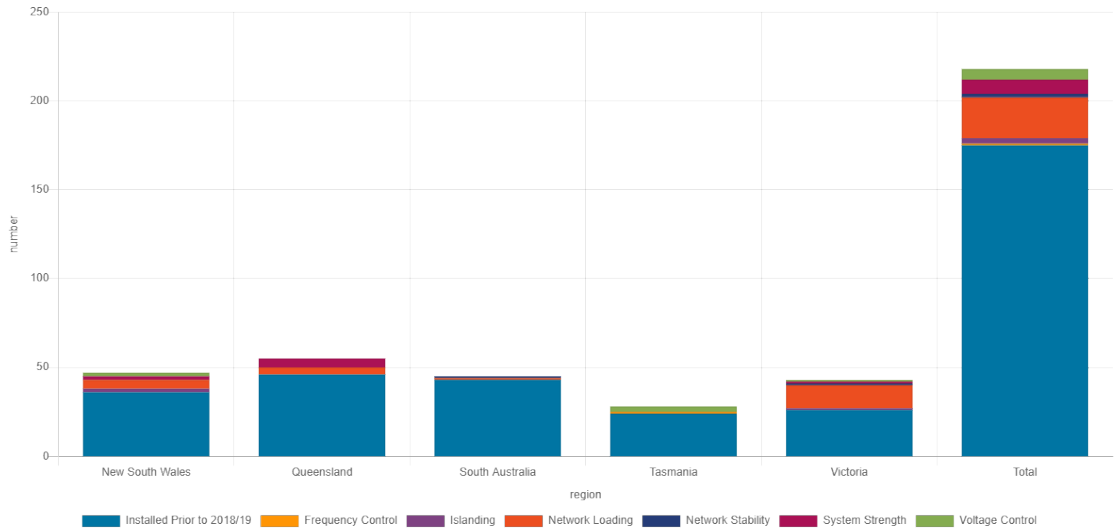
AEMO categorises different protection schemes by their function; different schemes serve different purposes, and the increase in one type compared to another is indicative of the challenges being faced presently by market participants, and how they are choosing to manage it.

Figure 4.20 shows a notable increase in the number of schemes used to manage network loading and system strength. The increase in network loading schemes in 2018/19 (23 added) represents a 30% increase in this type of special protection scheme in one year (73 to 98), compared to the number of all network loading schemes in the NEM prior to 2018/19. Most of the network loading schemes were added in Victoria (13).

There was also a significant increase in the number of special protection schemes for managing system strength, with 8 added in 2018/19 to the 1 scheme that was installed prior to 2018/19. Most of these schemes were installed in Queensland (5).

188 AEMC, *Review of the system black event in South Australia on 28 September 2016*, December 2019.

Figure 4.20: Number of Special Protection Schemes added to the NEM in 2018/19



Source: AEMC analysis of AEMO data.
Note: Data is valid as at January 2020 and represents current control schemes in the transmission and distribution network that have the potential to impact power system security.
Note: The data for this chart is available in the AMPR data portal.

Overall, 43 special protection schemes were added in 2018/19, taking the total number of special protection schemes in the NEM to 2018. This represents a 20% increase in the number of schemes that are managing different system security challenges emerging in the NEM, indicating a growing reliance on them.

The Panel notes the importance of greater understanding of the performance and interaction of these protection schemes. As demonstrated in the islanding of South Australia in August 2018, the unknown interactions of these protection settings can lead to adverse outcomes. There is a continuing need to monitored the ongoing performance and interaction of the special protection schemes as system conditions continue to change.

4.7 Panel insights: challenges to system security and work underway to address them

As shown in the assessment of power system security in this AMPR, power system security continues to be a challenge to maintain. Transitioning to a low emissions electricity sector means the NEM will continue to be at the global forefront for integration of renewable energy. This is also occurring as risks to the power system are being driven by climactic change, increasing temperatures and the likelihood of extreme weather events.

The Panel expects these challenges to continue and notes that new challenges are likely to manifest themselves. However, significant work has been undertaken to understand what is needed for the secure operation of the power system. This will assist us in meeting the challenges and embracing the opportunities that come with a new generation mix.

Transition presents challenges for system security

Historically, many of the services needed for power system security were provided by synchronous generation, such as coal, gas and hydro. These services were often provided for free as a by-product of producing energy. These services included inertia and fault level.

The NEM is experiencing a significant and rapid change in its generation mix. The vast majority of the generation that has connected to the NEM in the past five years has been inverter-connected renewable energy. This is likely to continue. As a result:

- A number of the necessary services and characteristics of a secure power system are not being provided as by-products
- Services that may not have been needed previously will become more and more important to support this transition.

Changes in weather and climate will add to challenges

Security events are often caused by weather related factors. For example, prolonged extreme temperatures, cyclones and bushfires. As the climate changes and these extreme events become more frequenct and pronounced, the challenge of maintaining the secure operation of the power system will grow.

Understanding the nature of these risks and operating the power system with resilience will be important to preserving power system security.

Assessment suggests maintaining power security will get harder before it gets easier

The assessment in this AMPR suggest that maintaining power system security is more difficult. Compared to last report:

- There were more directions for system security.
- There were more times when the power system was not in a secure operating state
- Frequency performance degraded.

However, this also reflects a greater awareness of the operational needs of the power system. For example, a greater understanding of system strength may manifest itself in AEMO directing more participants to maintain system security.

The work underway is helping

There has been significant work undertaken to understand the technical needs of the power system and how to respond to the immediate issues - see appendix a.

The NEM is at the global forefront of dealing with these issues. This means is it important to acknowledge some solutions may only be temporary fixes. Other solutions may take time to mature and become effective.

In terms of ongoing work to address system security issues, the Panel notes:

- The importance of expanding the understanding of the characteristics of a power system that are needed for secure operation, including how the power system responds to various disturbances and learning for previous experiences. This will help define the system service needs of the NEM.

- Providing these characteristics may require different approaches for each service. Considering these differences will help in designing frameworks that incentivise investment in system services.
- As the power system transitions to a low emissions future, there will be challenges that emerge; however, these challenges will be able to be embraced and addressed and opportunities will arise. New technologies and business models will play an important role in this.

These are discussed in more detail below.

4.7.1 Defining system service needs

While the power system is being transformed, the laws of physics that determine electrical flows do not change. To maintain a secure and reliable system, a range of interdependent technical and operational needs must be met at all times. Having a clear, articulated assessment of these system needs is a critical step to making sure the regulatory frameworks can provide for these needs.

The Panel notes AEMO published documents on power system requirements[189] and the AEMC has a number of projects underway looking at system strength and frequency control.

In defining the system needs, it will be important to consider the implications of the broader system trends, such as:

- more generation connected to weaker, lower voltage parts of the NEM
- growing penetrations of rooftop PV
- greater numbers of electric vehicles.

It will also be important to take the opportunity to learn from disturbances on the power system. While these events often have unfortunate consequences, they are also often revealing regarding what it takes to keep the power system secure. For example, the islanding of Queensland and South Australia in this reporting period highlighted the complex interactions between rapid responses to frequency and protection settings. It also highlighted the response of distributed energy resources. As the amount of distributed energy resources grow, it will change what is needed to keep the power system secure.

4.7.2 Incentivising investment in system services

With a clearer understanding of what the power system needs, setting up regulatory frameworks that provide for them will be critical.

The Panel notes that this is already happening. For example, there are frameworks in place to provide for system strength and inertia to be provided by network service providers. There is also a rule change underway looking at the provision of primary frequency response.

189 AEMO, *Power system requirements,* March 2018.

The Panel notes that if each of the required system services has different characteristics, it is unlikely a one-size-fits-all approach would work. Each service will need to be assessed on its merits and provided for accordingly and within the context of longer-term market design.

4.7.3 There are opportunities associated with the transition

In this transition, there are going to be challenges that test the system security frameworks. However, there is also an opportunity for new technologies to assist with maintaining the secure operation of the power system.

For example, there has been a significant growth in the number of FCAS providers in the NEM. FCAS is a service that has traditionally been provided only by synchronous generators. However, residential consumers through to wind farms have increasingly been able to participate in FCAS market and provide these services. The ESB is also looking at security matters through its 2025 work.

Setting up frameworks that allow for new entrants to participate will be key to encouraging and capturing the opportunities presented by these new generators entering the market.

4.7.4 Work underway to improve power system security

The Panel notes that a number of regulatory changes seeking to improve power system security came into effect during the 2018/19 reporting year. This included:

- A Managing power system fault levels rule that requires AEMO to set minimum levels of system strength and identify any shortfalls across the NEM, and makes TNSPs responsible for providing services to meet these. It also requires new connecting generators to 'do no harm' to the level of system strength necessary to maintain the security of the power system or remediate impact. The new arrangements commenced in South Australia on 13 October 2017, and on 1 July 2018 in the rest of the NEM.
- A Managing the rate of change of power system frequency rule requiring AEMO to set minimum levels of inertia and identify any shortfalls across the NEM. TNSPs are responsible for providing inertia services to meet any gaps. These arrangements commenced in July 2018.
- New Generator technical performance standards for connecting generators and a new process for negotiating them. These arrangements commenced in October 2018.

A more extensive list of rules that came into effect in 2018/19 is included in appendix a.

The panel also acknowledges the reforms completed since the end of the Panel's reporting year and the substantive work programs underway through the market bodies, ESB and the COAG Energy Council and individual governments to address the system security issues raised in this chapter.

The Panel particularly notes the AEMC's work program to procure the technical services required to keep the power system secure which includes:

- A draft rule to introduce mandatory **primary frequency control** requirements and a rule change considering incentives for generators to deliver primary frequency control.[190]
- An investigation into the application of the **system strength frameworks** to date to determine whether any improvements could be made to more effectively and efficiently address system strength issues in the NEM. This includes looking at the minimum system strength and 'do no harm' frameworks.[191]
- A rule change seeking to improve the provision of **system restart ancillary services** updating the arrangements under which the services that "jump start" the power system after a system black are provided, including more rigorous testing processes.[192]

A more extensive list of current security-related work streams is included in appendix a**.**

190 More information can be found at https://www.aemc.gov.au/rule-changes/mandatory-primary-frequency-response

191 More information can be found at https://www.aemc.gov.au/market-reviews-advice/investigation-system-strength-frameworks-nem

192 More information can be found at https://www.aemc.gov.au/rule-changes/system-restart-services-standards-and-testing

5 SAFETY

This section covers the Panel's assessment of safety of the power system in 2018/19. The Panel notes that its safety role for the purposes of this report relates primarily to the operation of assets and equipment with their technical limits.

5.1 What is safety for the purposes of this review?

The safety of the national electricity system can be understood to mean that:

- the transmission and distribution systems and the generation and other facilities connected to them are safe from damage (safety in the technical safety sense) or
- the transmission and distribution systems and the generation, and other facilities connected to them are not a source of injury and danger (safety in the public safety sense).

Safety performance of the power system: The National Electricity Law and rules set out the functions and powers of the Reliability Panel, which include a function to monitor, review and report on safety in accordance with the rules. However, the NER do not specify additional requirements in relation to safety performance reporting.[193] However, the Panel also has the function of advising in relation to the safety of the national electricity system at the request of the AEMC.[194] The terms of reference for the *2018 Annual market performance review*, as they relate to safety, were considered by the Panel as a request for advice from the AEMC.[195] In accordance with the terms of reference issued by the AEMC, for the purposes of the safety assessment the Panel has considered the maintenance of power system security within the relevant standards and technical limits.

The terms of reference issued by the AEMC direct the Panel to focus on technical safety (power system security) rather than public safety in the 2018 AMPR.[196] The Panel's assessment of the safety of the NEM is therefore limited to consideration of the links between the security of the power system and maintaining the system within relevant standards and technical limits.

5.2 How is a safe power system delivered?

The safety of the power system, and associated equipment, power system personnel and the public is covered in general terms under the NEL.[197]

193 Instead, the functions of the Reliability Panel under clause 8.8.1 of the NER provide that the functions of the Panel is to, among other things, monitor, review and report on the performance of the market in terms of reliability of the power system, report to the AEMC and jurisdictions on overall power system reliability matters and undertake a number of functions relating to the security of the power system. The reliability and security focus of the Panel under the NER is reflected in the scope of the annual market performance review that the Panel is required to undertake under clause 8.8.3(b) of the NER.

194 If the AEMC requests such advice, the Panel is required to provide it (section 38(4) of the NEL).

195 Under section 38(2)(b) of the NEL.

196 It is open to the AEMC to request advice from the Panel on either or both technical safety of the national electricity system (power system security) or public safety issues relating to the national electricity system or specific aspects of those types of safety as it considers appropriate. Terms of reference are available at: https://www.aemc.gov.au/sites/default/files/2018-09/Terms%20of%20Reference.pdf

197 Part 8 of the NEL. Section 2D(1)(a) of the NEL also has a specific provision in relation to the obligation of NSPs in relation to safety of their systems (transmission and distribution) with references to external legislation.

However there is no national safety regulator specifically for electricity. Instead, state and territory legislation governs safety generally which includes the safe supply of electricity and the broader safety requirements associated with electricity use in households and businesses. Each jurisdiction has its own approach to setting out obligations relating to safety in the power system, and enforcing these obligations. Network service providers and other market participants also have specific responsibilities to provide for the safety of personnel and the public.

Examples of the different jurisdictional safety arrangements are provided below however the Panel notes this is not an exhaustive summary of safety requirements in each region.

The electrical system is also designed with extensive safety systems to provide for the protection of the system itself, workers and the public. Network constraints, developed from TNSP limit advice, are used by AEMO in the NEM dispatch process to make sure that plant remains within rating and power transfers remain within stability limits so that the power system is in a secure operating state[198] Should AEMO not be able to manage secure and satisfactory limits through the use of network constraints, the following options will be used. These options are listed in AEMO's suggested priority order and may not all be available under all circumstances:

- Revision to generator thermal ratings.
- Revision to power system limits.
- Implement plan agreed between AEMO and relevant registered participants (e.g. Contingency plan, Network Support Agreement (NSA)).
- Reconfigure network.
- Dispatch or activation of reserve contracts to address a power system security event.
- System security direction or instruction issued under clause 4.8.9 of the rules.
- If sufficient raise FCAS are unavailable, use system security constraints to reduce the size of the largest generation at risk. If sufficient lower FCAS are unavailable, issue a direction under section 116 of NEL for a reduction in the size of the largest load at risk.
- Instruct involuntary load shedding.

5.3 Safety performance of the power system in 2018/19

The Panel has reviewed AEMO's power system incident reports and consulted with AEMO to understand if there were any instances where actions to maintain the power system within relevant standards and technical limits resulted in technical safety issues. Operating incidents are covered in detail in section 3.4.2 and section 4.4 but can have implications for the overall safety of the system. The response to these incidents is a key indicator of safety performance.

The Panel is not aware of any incidents during the 2018/19 reporting period where AEMO's management of power system security has resulted in a safety issue with respect to maintaining the system within relevant standards and technical limits.

198 AEMO, *Power system security guidelines*, December 2018.

The Panel also notes that there were no instances in 2018/19 where AEMO issued a direction and the directed participant did not comply on the grounds that complying with the direction would be a hazard to public safety, or materially risk damaging equipment or contravene any other law.[199]

5.4 Challenges in maintaining a safe power system and work underway to address these

The electrical system is designed to provide for the protection of the power system itself, workers and the public.

The Panel notes that the challenges in maintaining a safe power system, one that operates within the technical limits it has been designed for, are the same as those discussed in section 2.2 and section 4.7. Broadly, these challenges relate to the fact that in power system is becoming more complex, with more uncertainty on the supply and demand side. This means the number and range of potential risks has increased, and the ability to predict them has become harder.

Work underway to address the current challenges in keeping the power system within its technical limits are covered in detail in appendix a.

199 Directions issued to maintain the power system in a secure operating state are discussed in section 4.3.

ABBREVIATIONS

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
Commission	See AEMC
COAG	Council of Australian Governments
ESB	Energy Security Board
MCE	Ministerial Council on Energy
NEL	National Electricity Law
NEO	National electricity objective
NERL	National Energy Retail Law
NERO	National energy retail objective
NGL	National Gas Law
NGO	National gas objective

GLOSSARY

Available capacity	The total MW capacity available for dispatch by a scheduled generating unit or scheduled load (i.e. maximum plant availability) or, in relation to a specified price band, the MW capacity within that price band available for dispatch (i.e. availability at each price band).
Busbar	A busbar is an electrical conductor in the transmission system that is maintained at a specific voltage. It is capable of carrying a high current and is normally used to make a common connection between several circuits within the transmission system. The rules define busbar as 'a common connection point in a power station switchyard or a transmission network substation'.
Cascading outage	The occurrence of a succession of outages, each of which is initiated by conditions (e.g. instability or overloading) arising or made worse as a result of the event preceding it.
Contingency events	These are events that affect the power system's operation, such as the failure or removal from operational service of a generating unit or transmission element. There are several categories of contingency event, as described below: • credible contingency event is a contingency event whose occurrence is considered "reasonably possible" in the circumstances. For example: the unexpected disconnection or unplanned reduction in capacity of one operating generating unit; or the unexpected disconnection of one major item of transmission plant • non-credible contingency event is a contingency event whose occurrence is not considered "reasonably possible" in the circumstances. Typically a non-credible contingency event involves simultaneous multiple disruptions, such

	as the failure of several generating units at the same time.
Customer average interruption duration index (CAIDI)	The sum of the duration of each sustained customer interruption (in minutes) divided by the total number of sustained customer interruptions (SAIDI divided by SAIFI). CAIDI excludes momentary interruptions (one minute or less duration).
Directions	Under s. 116 of the NEL, AEMO may issue directions. Section 116 directions may include directions as issued under clause 4.8.9 of the NER (e.g. directing a scheduled generator to increase output) or clause 4.8.9 instructions (e.g. instructing a network service provider to load shed). AEMO directs or instructs participants to take action to maintain or re-establish the power system to a secure operating state, a satisfactory operating state, or a reliable operating state.
Dispatch	The act of initiating or enabling all or part of the response specified in a dispatch bid, dispatch offer or market ancillary service offer in respect of a scheduled generating unit, a scheduled load, a scheduled network service, an ancillary service generating unit or an ancillary service load in accordance with NER rule 3.8, or a direction or operation of capacity the subject of a reserve contract as appropriate.
Distribution network	The apparatus, equipment, plant and buildings (including the connection assets) used to convey and control the conveyance of electricity to consumers from the network and which is not a transmission network.
Distribution network service provider (DNSP)	A person who engages in the activity of owning, controlling, or operating a distribution network.
Emergency Frequency Control Schemes (EFCS)	Facilities for initiating automatic load shedding (Under Frequency Load Shedding) or automatic generation shedding (Over Frequency Generation Shedding) to prevent or arrest uncontrolled increases or decreases in frequency (alone or in combination)

	leading to cascading outages or major supply disruptions
Forecasting uncertainty measure (FUM)	The FUM is the number of MW representing the quantity of error in reserves for which AEMO determines, at a certain confidence level, that the error will not exceed this value. In other words, it is the size of the adjustment to be made based on AEMO's modelling of reserve errors.
Frequency control ancillary services (FCAS)	Those ancillary services concerned with balancing, over short intervals, the power supplied by generators with the power consumed by loads (throughout the power system). Imbalances cause the frequency to deviate from 50 Hz.
Interconnector	A transmission line or group of transmission lines that connect the transmission networks in adjacent regions.
Jurisdictional planning body	The transmission network service provider responsible for planning a NEM jurisdiction's transmission network.
Lack of reserve	This is when reserves are below specified reporting levels.
Load	A connection point (or defined set of connection points) at which electrical power is delivered, or the amount of electrical power delivered at a defined instant at a connection point (or aggregated over a defined set of connection points).
Load event	In the context of frequency control ancillary services, a load event: involves a disconnection or a sudden reduction in the amount of power consumed at a connection point and results in an overall excess of supply.
Load shedding	Reducing or disconnecting load from the power system either by automatic control systems or under instructions from AEMO. Load shedding will cause interruptions to some energy consumers' supplies.
Low reserve condition (LRC)	This is when reserves are below the minimum reserve level.

Momentary average interruption frequency index (MAIFI)	The total number of customer interruptions of one minute or less duration, divided by the total number of distribution customers.
Medium term projected assessment of system (MT PASA) (also see ST PASA)	A comprehensive programme of information collection, analysis and disclosure of medium-term power system reliability prospects. This assessment covers a period of 24 months and enables market participants to make decisions concerning supply, demand and outages. It must be issued weekly by AEMO.
Minimum reserve level (MRL)	The minimum reserve margin calculated by AEMO to meet the reliability standard.
Ministerial Council on Energy (MCE)	The MCE is the national policy and governance body for the Australian energy market, including for electricity and gas, as outlined in the COAG Australian Energy Market Agreement of 30 June 2004.
National Electricity Code	The National Electricity Code was replaced by the National Electricity Rules on 1 July 2005.
National electricity market (NEM)	The NEM is a wholesale exchange for the supply of electricity to retailers and consumers. It commenced on 13 December 1998, and now includes Queensland, New South Wales, Australian Capital Territory, Victoria, South Australia, and Tasmania.
National Electricity Law (NEL)	The NEL is contained in a schedule to the National Electricity (South Australia) Act 1996. The NEL is applied as law in each participating jurisdiction of the NEM by the application statutes.
National Electricity Rules (NER)	The NER came into effect on 1 July 2005, replacing the National Electricity Code.
Network	The apparatus, equipment and buildings used to convey and control the conveyance of electricity. This applies to both transmission and distribution networks.
Network capability	The capability of a network or part of a network to transfer electricity from one location to another.
Network control ancillary services (NCAS)	Ancillary services concerned with maintaining and extending the operational efficiency and capability of the network within secure

	operating limits.
Network event	In the context of frequency control ancillary services, the tripping of a network resulting in a generation event or load event.
Network service providers	An entity that operates as either a transmission network service provider (TNSP) or a distribution network service provider (DNSP).
Network services	The services (provided by a TNSP or DNSP) associated with conveying electricity and which also include entry, exit, and use-of-system services.
Operating state	The operating state of the power system is defined as satisfactory, secure or reliable, as described below. The power system is in a **satisfactory** operating state when: • it is operating within its technical limits (i.e. frequency, voltage, current etc are within the relevant standards and ratings) • the severity of any potential fault is within the capability of circuit breakers to disconnect the faulted circuit or equipment. The power system is in a **secure** operating state when: • it is in a satisfactory operating state • it will return to a satisfactory operating state following a single credible contingency event. The power system is in a **reliable** operating state when: • AEMO has not disconnected, and does not expect to disconnect, any points of load connection under NER clause 4.8.9 • no load shedding is occurring or expected to occur anywhere on the power system under NER clause 4.8.9 • in AEMO's reasonable opinion the levels of short term and medium term capacity

	reserves available to the power system are at least equal to the required levels determined in accordance with the power system security and reliability standards.
Participant	An entity that participates in the national electricity market.
Plant capability	The maximum MW output which an item of electrical equipment is capable of achieving for a given period.
Power system reliability	The measure of the power system's ability to supply adequate power to satisfy demand, allowing for unplanned losses of generation capacity.
Power system security	The safe scheduling, operation and control of the power system on a continuous basis.
Probability of exceedance (POE)	POE relates to the weather/temperature dependence of the maximum demand in a region. A detailed description is given in the AEMO ESOO.
Reliable operating state	Refer to operating state.
Reliability of supply	The likelihood of having sufficient capacity (generation or demand-side response) to meet demand (the consumer load).
Reliability standard	The Reliability Panel's current standard for reliability is that there should be sufficient generation and bulk transmission capacity so that the maximum expected unserved energy is 0.002 per cent.
Reserve	The amount of supply (including available generation capability, demand side participation and interconnector capability) in excess of the demand forecast for a particular period.
Reserve margin	The difference between reserve and the projected demand for electricity, where: Reserve margin = (generation capability + interconnection reserve sharing) – peak demand + demand-side participation.
System average interruption duration index (SAIDI)	The sum of the duration of each sustained customer interruption (in minutes), divided by the total number of distribution customers. SAIDI excludes momentary

	interruptions (one minute or less duration).
System average interruption frequency index (SAIFI)	The total number of sustained customer interruptions, divided by the total number of distribution customers. SAIFI excludes momentary interruptions (one minute or less duration).
Satisfactory operating state	Refer to operating state.
Scheduled load	A market load which has been classified by AEMO as a scheduled load at the market customer's request. A market customer may submit dispatch bids in relation to scheduled loads.
Secure operating state	Refer to operating state.
Separation event	In the context of frequency control ancillary services, this describes the electrical separation of one or more NEM regions from the others, thereby preventing frequency control ancillary services being transferred from one region to another.
Special Protection Scheme (SPS)	Special Protection Schemes, or emergency control schemes are typically considered to be equipment configured as emergency controls that respond consistently with specification set out in S5.1.8 of the National Electricity Rules. They typically deployed to deal with system stability issues, such as maintaining synchronism of the system, or damping power system oscillations.
Short term projected assessment of system adequacy (ST PASA) (also see MT PASA)	The ST PASA has the following objectives: • Provide a benchmark for AEMO to intervene in the market through the reserve trading provisions of the National Electricity Rules, and then commit extra capacity (either scheduled generation or loads) into the spot market. • Provide information to market participants on the expected level of short term capacity reserve and hence the likelihood of interruptions due to a shortage of power.
Spot market	Wholesale trading in electricity is conducted as a spot market. The spot market allows

	instantaneous matching of supply against demand. The spot market trades from an electricity pool, and is effectively a set of rules and procedures (not a physical location) managed by AEMO (in conjunction with market participants and regulatory agencies) that are set out in the NER.
System Restart Ancillary Services (SRAS)	A service provided by facilities with black start capability which allows: • energy to be supplied; and • a connection to be established, sufficient to restart large generating units following a major supply disruption
Supply-demand balance	A calculation of the reserve margin for a given set of demand conditions, which is used to minimise reserve deficits by making use of available interconnector capabilities.
Technical envelope	The power system's technical boundary limits for achieving and maintaining a secure operating state for a given demand and power system scenario.
Transmission network	The high-voltage transmission assets that transport electricity between generators and distribution networks. Transmission networks do not include connection assets, which form part of a transmission system.
Transmission network service provider (TNSP)	An entity that owns operates and/or controls a transmission network.
Unserved energy (USE)	The amount of energy that is required (or demanded) by consumers but which is not supplied due to a shortage of generation or interconnection capacity. Unserved energy does not include interruptions to consumer supply that are caused by outages of local transmission or distribution elements that do not significantly impact the ability to transfer power into a region.
Value of Customer Reliability (VCR)	In dollar terms, the Value of Customer Reliability (VCR) represents a customer's willingness to pay for the reliable supply of electricity. The values produced are used as a proxy, and can be applied or use in revenue

regulation, planning, and operational purposes in the National Electricity Market (NEM).

A SECURITY AND RELIABILITY WORK PROGRAM

In this section the Panel has listed the current and recently completed projects that relate to reliability and power system security in the NEM. It includes some of the key projects led by each of the three market bodies and the Energy Security board. The list is not exhaustive but aims to provide stakeholders with a better understanding of market body and ESB actions to address the security and reliability challenges facing the NEM.

The Panel notes that many governments are also taking action to improve security and reliability outcomes in their jurisdictions. Government actions are not captured in the list below.

A.1 Energy security board (ESB)

- **Post 2025 market design**: The COAG Energy Council requested the ESB advise on a long-term, fit-for-purpose market framework to support reliability, modifying the NEM as necessary to meet the needs of future diverse sources of non-dispatchable generation and flexible resources including demand side response, storage and distributed energy resource participation. The ESP published a consultation paper in September 2019 and is developing its advice for Ministers.
- **Interim advice on Reliability Standard**: As an interim part of its post-2025 market design advice, the ESB was also tasked with reviewing the reliability standard. The Council asked that existing mechanisms be used where possible. This advice is being considered by Ministers at the March 2020 COAG Energy Council meeting.
- **Health of the NEM**: Each year the ESB delivers a *Health of the National Electricity Market* report to the Council that tracks the performance of the system, the risks it faces, and the opportunities for improvement. The ESB has reported on the health of the NEM annually since December 2017. The 2019 report was published in February 2020. It noted that overall, NEM performance improved on the previous year but that the issue of most concern to the ESB is security.
- **Actioning the ISP**: The ESB is undertaking a process to action the ISP and embed it in the regulatory framework. The ESB-recommended rules seek to make transmission investment more streamlined, while still maintaining the checks and balances on investment to protect consumers.
- **Renewable energy zones**: COAG Energy Council requested the ESB provide interim advice by March 2020 on options to implement Renewable Energy. The market bodies are involved in this work.

A.2 Australian Energy Market Commission (AEMC)

Table A.1: **Security-related rules - current and recently completed**

RULE	STATUS	DESCRIPTION
Frequency control frameworks review	Published Jul 2018	Final report and recommendations to support better frequency control in the long term. Included three rule

RULE	STATUS	DESCRIPTION
		change requests to improve information/transparency around frequency control and frequency control markets. Also includes a work plan, developed collaboratively by the AEMC, AEMO and the AER.
Managing the rate of change of power system frequency	Commenced Jul 2018	Makes TNSPs responsible for procuring minimum required levels of inertia or alternative frequency control services to meet minimum levels set by AEMO.
Managing power system fault levels	Commenced Oct 2017 - SA, Jul 2018 - NEM	Makes TNSPs responsible for maintaining minimum levels of system strength. Should a shortfall be identified by AEMO, the TNSP must procure system strength services to maintain the fault levels determined by AEMO. Also introduces 'do no harm' for new connecting generators.
Generating system model guidelines	Commenced Sept 2018	Requires detailed information on how generators and networks perform to help AEMO plan for contingency events.
South Australian protected event	Declared Jun 2019	The Panel declared a protected event during periods of forecast destructive wind conditions in South Australia.
Generator technical performance standards	Commenced Oct 2018	Updates the technical performance standards for connecting generators and the process for negotiating them.
Investigation into intervention mechanisms and system strength in the NEM	Published Aug 2019	Final report and recommendations for changes to the interventions and compensation frameworks including two draft determinations to improve the interventions' framework including Application of the regional reference note test to the RERT and Threshold for participant compensation following market suspension.
Register of distributed energy resources	Commenced Dec 2019	Makes AEMO responsible for establishing a register of distributed energy resources in the national electricity market, including small scale battery storage systems and rooftop solar.
Application of the regional reference note test to the RERT	Commenced Dec 2019	Clarifies when intervention pricing should apply. This includes removing the use of intervention pricing for interventions to obtain services not traded in the market, such as system strength and voltage control.
Application of compensation in relation to AEMO interventions	Commenced Dec 2019	Affected participant compensation is no longer payable in connection with interventions which do not trigger intervention pricing, for example system strength directions. This rule actions a recommendation in the AEMC's final report on its Investigation into intervention mechanisms in the NEM.

RULE	STATUS	DESCRIPTION
Threshold for participant compensation following market suspension	Commenced Dec 2019	Changes the $5,000 compensation threshold for directed and affected participants so it applies per event rather than per trading interval.
Review of the System Black Event in South Australia on 28 September 2016	Published Dec 2019	Final report and recommendations that are designed to enhance the resilience of the power system.
Updated Generator compliance template	Commenced Dec 2019	Reliability Panel incorporated recent changes to generator technical performance standards and improved clarity and usability.
Reliability Panel review of the frequency operating standard	Commenced Jan 2020	The standard has been restructured and consolidated to avoid duplication and improve the obligations it places on AEMO to manage the power system frequency
Investigation into system strength frameworks in the NEM	Consultation paper expected Mar 2020	The Commission is considering whether improvements could be made to more effectively identify and address low levels of system strength as they arise in NEM regions; increase the transparency and efficiency for remediating the impact of new connecting generators; and allow for the provision of increased levels of system strength to enable greater output from lower cost generation sources.
Mandatory primary frequency response	Final determination Apr 2020	Proposed new rules requiring generators to respond automatically to changes in power system frequency.
System restart services, standards and testing	Final determination Apr 2020	Seeks to enhance the frameworks for system restart and restoration. System restart services contribute to the overall resilience of the power system by enabling recovery following a major blackout.
Incentives for primary frequency response	Draft determination Sep 2020	Seeking to develop mechanisms or arrangements to increase the provision of primary frequency response to help manage frequency deterioration.
Monitoring and reporting on frequency control framework	Commenced Jan 2020	Established ongoing reporting requirements on AEMO in relation to frequency and frequency control performance; and on the AER in relation to the performance of frequency control ancillary services (FCAS) markets.

RULE	STATUS	DESCRIPTION
Frequency control work plan	Ongoing	AEMC working with AEMO and the AER on designing new, coordinated and lowest-cost ways to deliver frequency control services.
Maximum reactive current during a fault	Pending	Seeks change the maximum reactive current value to correctly align the frame of voltage control in remote/weak grids.
Removal of obligation to counteract during intervention	Pending	Seeks to remove the requirement that AEMO endeavours to minimise the number of affected participants, and the effect on interconnector flows, during an intervention.
Removal of intervention hierarchy	Pending	Seeks to remove the requirement for AEMO to exercise the RERT before issuing directions or instructions and replace it with a principle requiring AEMO to endeavour to minimise the costs and maximise the effectiveness of an intervention in the NEM.
Synchronous services markets	Pending	Seeks to address the shortage of inertia and related services in the NEM by integrating their dispatch with the existing spot and frequency control ancillary services markets.
Removal of mandatory restrictions framework	Pending	Seeks to remove the mandatory restrictions framework from the rules. Mandatory restrictions are a market intervention mechanism whereby demand restrictions are imposed by a jurisdictional government (under state legislation) in anticipation of, for example, significant supply shortfalls. If this occurs, the rules set out a process of capacity contracting and pricing which is designed to integrate restrictions into the market to ensure delivery of a reliable and secure supply. This contracting and pricing process was included in the NER in 2001 but has never been used.
Compensation for scheduled loads affected by interventions	Pending	Seeks to change the definition of the term of "BidP" in the formula for calculating affected participant compensation for a scheduled load.
Affected participant compensation for FCAS losses	Pending	Seeks to include FCAS prices as an additional clause amongst other factors to be considered in determining affected participant compensation.
Compensation following directions for services other than energy and	Pending	Seeks to change the way directed participants are compensated when they are directed to provide services other than energy and market ancillary services.

RULE	STATUS	DESCRIPTION
market ancillary services		

Source: AEMC

Table A.2: **Reliability related projects - current and recently completed**

RULE	STATUS	DESCRIPTION
Declaration of LOR conditions	Commenced Dec 2017	New framework to allow AEMO to use a probabilistic approach when declaring lack of reserve conditions, and to report every quarter.
Reporting of aggregate generation capacity for MT PASA	Commenced May 2018	New arrangements for AEMO reporting on aggregate generation capacity to signal whether electricity supply is projected to meet demand in the medium-term.
Values of customer reliability	Commenced May 2018	New rules to make AER responsible for establishing and regularly updating the values of customer reliability.
Reinstatement of long-notice RERT	Commenced Jun 2018	Eanbles AEMO to contract up to nine months ahead of a projected shortfall under the RERT.
Transmission connection and planning arrangements - connections aspects of the rule	Commenced July 2018	The connection aspects of this rule provide more choice, control and certainty for connecting parties, while at the same time making it clear that the incumbent TNSPs are accountable for providing a safe, reliable and secure transmission network.
Participant compensation following market suspension	Commenced Nov 2018	Establishes a new compensation framework so that certain market participants who incur a loss during a market suspension event can be compensated.
Generator three year notice of closure	Commenced Dec 2018	New requirement for large generators to give at least three years notice before closing.
Coordination of generation and transmission investment	Published Dec 2018	Final report and recommendations for a comprehensive reform package that better coordinates investment in renewable generation and transmission infrastructure. This includes actions to embed the ISP, streamline regulatory arrangements for priority transmission projects, facilitate renewable energy

RULE	STATUS	DESCRIPTION
		zones and develop phased reforms to change how generators access and use the network.
Early implementation of ISP priority projects	Commenced May 2019	New rules to streamline the regulatory processes for key time-critical projects identified in AEMO's Integrated System Plan.
Enhancement to the RERT	Commenced Oct 2019, Mar 2020	New rules to enhancement, clarify and strengthen the RERT framework.
Transparency of new projects	Commenced Nov 2019	Enhances publicly available information about new generation projects, as well as allowing developers of these projects to register with AEMO to get access to key technical information such as network modelling data.
Short term forward market.	Final determination Mar 2020	Decision not to introduce a short term forward market given there is currently limited demand for short term hedge products in the market and that demand is sporadic and bespoke.
Wholesale demand response mechanism	Second draft determination Mar 2020	Proposes a new mechanism to enable more wholesale demand response by introducing a new category of registered participant, a demand response service provider (DRSP), that would be able to bid demand response directly into the wholesale market as a substitute for generation.
Victorian jurisdictional derogation – RERT contracting	Published March 2020	New arrangement to provide a derogation for Victoria to allow the Australian Energy Market Operator to contract for reserve electricity capacity under the Reliability and Emergency Reserve Trader mechanism on a multi-year basis.
Improving transparency and extending duration of MT PASA	Commences May-Aug 2020	Improves transparency of the MT PASA process, makes market information available when it is most needed and extends the period generation availability is published from two to three years.
Demand management incentive scheme and innovation allowance for TNSPs	Commences Mar 2021	Introduces demand management incentives for transmission businesses.

RULE	STATUS	DESCRIPTION
AEMC/AEMO/AER VPP trial	Ongoing	Trial will inform changes to frameworks and operational processes so VPPs can play a bigger role in the energy market. Learnings may be submitted as rule change requests.
Coordination of generation and transmission investment - access and charging	Ongoing	Proposal to introduce locational marginal pricing and financial transmission rights, which will send better locational signals to make sure the transmission network is more effectively used as well as offering generators a way to manage risks associated with congestion and losses.
Energy storage systems	Pending	Seeks to efficiently accommodate increasing numbers of connections where bi-directional electricity flows occur and business models where there are a mix of technology types are connecting behind a connection point.
Threshold for generator registration	Pending	Seeks to reduce threshold for generator registration the from 30 to 5 MW.
Transparency of unserved energy calculation	Pending	Seeks to clarify and simplify the definition of unserved energy used in post-event analysis of supply interruptions.
Recovering affected participant compensation for RERT activation	Pending	Seeks to clarify the basis for recovering costs associated with compensating participants affected by the exercise of the RERT.

Source: AEMC

A.3 Australian Energy Market Operator (AEMO)

The Panel notes that AEMO has a significant amount of work underway across the board to address security and reliability challenges as they emerge and over the long term. The Panel has included a selection of projects that are part of AEMO's broader work program.

- Electricity Statement of Opportunities: The Electricity Statement of Opportunities (ESOO) provides technical and market data that informs the decision-making processes of market participants, new investors, and jurisdictional bodies as they assess opportunities in the National Electricity Market (NEM) over a 10-year outlook period. The NEM ESOO incorporates a reliability assessment against the reliability standard defined in the National Electricity Rules (NER) clause 3.9.3C and AEMO’s Reliability Forecast under the Retailer Reliability Obligations (RRO).
- Integrated Systems Plan: The Integrated System Plan (ISP) is a whole-of-system plan that provides an integrated roadmap for the efficient development of the National Electricity Market (NEM) over the next 20 years and beyond. Its primary objective is to

maximise value to end consumers by designing the lowest cost, secure and reliable energy system capable of meeting any emissions trajectory determined by policy makers at an acceptable level of risk. AEMO published the inaugural Integrated System Plan (ISP) for the National Electricity Market (NEM) in 2018, and it will be updated every two years.

- Renewable Integration Study: AEMO's Renewable Integration Study is the first stage of a multi-year plan to support a secure and reliable NEM with a high share of renewables. The study will focus on quantifying the technical renewable penetration limits of the power system for a projected generation mix and network configuration in 2025. The insights from the Renewable Integration Study will complement existing ISP processes and form a basis for future work, including Western Australian system planning and operation. The Renewable Integration Study report is planned for Q1 2020.
- Quarterly Energy Dynamics (QED): AEMO's Quarterly Energy Dynamics reports (QED) detailed market dynamics, trends and outcomes in Australia's electricity and gas markets. It is produced quarterly. Geographically, the report covers the National Electricity Market – which includes Queensland New South Wales, the Australian Capital Territory, Victoria, South Australia and Tasmania – and the gas markets operating in the same states (except Tasmania). The latest QED, which covers the period 01 October to 31 December 2019, tracks the market impacts of extreme heat, generator and transmission line outages, and the shifting supply mix as we enter a critical new year for the energy sector.
- Distributed Energy Resource Register: The DER Register is a database of information about DER devices, and stores information about a DER device installed on-site at a residential or business location. This information will be requested by Network Services Providers (or network operators) from qualified electrical contractors and solar installers at the time of the DER installation. The DER Register launched on 1 March 2020.
- Summer 2019-20 Readiness Plan: Annually, AEMO prepares a summer readiness plan, collaborating with generation and transmission network providers, federal and state governments, and key agencies to actively manage the heightened risks to power system operations and to to provide information about its preparations for the summer period. These preparations were designed to minimise the risk of customer supply disruption in the National Electricity Market during the periods of highest demand for electricity from the grid.
- Five Minute Settlement and Global Settlement: The Australian Energy Market Operator (AEMO) is working with industry to implement changes arising from an Australian Energy Market Commission (AEMC) Final Determination to implement Five-Minute Settlement (5MS) in the National Electricity Market (NEM), and a final rule that requires a move to a Global Settlement (GS) framework for the demand side of the wholesale electricity market. The full commencement of 5MS, and the soft start of GS, both begin on 1 July 2021.
- Consumer Data Right: The Consumer Data Right (CDR) reform – as well as broader government 'consumer choice' policies – are designed to offer Australians greater control over their energy data, and empower Australia's energy consumers to choose from a range of tailored and innovative products and services. During 2021, it is anticipated that the CDR will commence in the National Electricity Market (NEM). The CDR Program seeks

to offer Australian energy consumers with easy access to their energy consumption data, so they can readily choose, compare or switch their energy retailer, and make more informed decisions on the right investments in energy-efficient appliances and distributed energy resources (or DER) - such as rooftop solar PV and battery storage devices. It is being progressed in consultation with various stakeholders in government, industry and the community.

- Western Victoria Regulatory Investment Test for Transmission: In its role as the transmission network planner for Victoria, AEMO recently completed a Regulatory Investment Test for Transmission (RIT-T) to assess the technical and economic viability of increasing transmission network capacity to address current limitations in the Western Victoria transmission network, in accordance with the National Electricity Rules (NER).
- Interconnector West (VNI West) Regulatory Investment Test for Transmission: In its role as the jurisdictional transmission network planners for Victoria and NSW, AEMO and Transgrid are jointly undertaking a RIT-T to assess the technical and economic viability of expanding interconnector capacity between Victoria and New South Wales, to address current limitations, in accordance with the NER.

A.4 Australian Energy Regulator (AER)

The Panel notes that AER has a range of work underway that relate to security and reliability. The Panel has included a selection of recent projects that are part of AER's broader work program.

- Values of customer reliability: VCR estimates play an important role in balancing the need to deliver secure and reliable electricity supplies and maintain reasonable costs for electricity consumers. VCRs seek to reflect the value different types of customers place on a reliable electricity supply, and the level at which they are set reflect a trade-off between electricity reliability and affordability. Knowing how different customers value reliability in different parts of the grid helps inform policy-makers and network planners on how to most efficiently meet the demands of customers without over or under investing in assets that deliver electricity to their homes and businesses. On 18 December 2019, the AER released their final report on the Values of Customer Reliability, which set out the VCR values for unplanned outages of up to 12 hours in duration (i.e. standard outages) for the NEM and the Northern Territory.
- Developing guidelines for Retailer reliability obligation (RRO): the AER is responsible for developing a number of Guidelines on certain aspects of the RRO including the *Reliability Instrument Guideline, Market Liquidity Obligation (MLO) Guideline, Contracts and Firmness Guideline, Forecasting Best Practice Guideline* and the *Opt-in Guideline.* Interim guidelines are in place and consultation is underway to finalise guidelines between June and December 2020.
- Compliance and enforcement relating to RRO: If the RRO is triggered due to an identified reliability gap, the AER is responsible for compliance and enforcement of liable entities. The RRO commenced on 1 July 2019.

- South Australian RRO trigger: On 9 January 2020, the South Australia Minister for Energy and Mining triggered the RRO in South Australia for the first quarters of 2022 and 2023. The AER has a monitoring and compliance role to ensure that Origin, AGL and ENGIE offer appropriate products on the ASX as required under the market liquidity obligation.
- Approval of RIT-T for SA-NSW interconnector: In January 2020, the AER approved the SA-NSW interconnector RIT-T. The AER noted that the proposed interconnector will facilitate the long term transition of the energy sector to low emission energy sources and enhance power system security in South Australia.