RELIABILITY PANEL AEMC

REVIEW

Reliability Panel AEMC

FINAL REPORT

Annual market performance review 2015

1 September 2016

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About the Reliability Panel

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

Foreword

I am pleased to present this final report setting out the findings of the Reliability Panel's annual review of market performance. The Panel has reviewed the performance of the national electricity market (NEM) in terms of reliability, security and safety over 2014-15 in accordance with the requirements of the National Electricity Rules.

The NEM experienced very warm conditions in winter 2014, spring 2014 and summer 2014-15. Heatwaves occurred and it was the warmest spring on record for the second year running. By contrast, autumn 2015 was cooler than average. Average electricity consumption in the NEM has generally been declining in recent years although it appears to have plateaued in 2014-15.

Against this background, the Panel found that the reliability of the NEM continues to remain within the reliability standard as there was no unserved energy in 2014-15. However, there were some power system incidents that resulted in the loss of customer load. Similarly, there were a couple of incidents where frequency was outside the operating standards. These incidents were effectively managed and actions were taken, or are in the process of being completed, to address any issues identified.

Since June 2014, there have been some particularly significant events in the NEM relating to the South Australian and Tasmanian regions. As these events occurred during 2015-16 they will be assessed in detail in the 2016 review report, a draft of which is to be published for consultation later this year. This 2015 report provides a summary of these events for information.

More generally, the Panel is continuously reviewing the way in which it undertakes and reports on this annual review. To this end, some new or improved information arising from stakeholder comments during the 2014 review has been included in this report.

The preparation of this report could not have been completed without the assistance of the AEMO, the Australian Energy Regulator, 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 to date.

I would also like to acknowledge the work provided by Deloitte and Advisian in assisting the Panel carry out its annual review this year.

Finally, the Panel commends the staff of the Australian Energy Market Commission (AEMC) 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.

Neville Henderson, Chairman, AEMC Reliability Panel,

Commissioner, AEMC

Reliability Panel members

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Summary

This final report sets out the findings of the Reliability Panel's annual market performance review (AMPR) 2015 as required by the National Electricity Rules (NER) which is conducted in accordance with terms of reference issued by the Australian Energy Market Commission (AEMC). Covering 1 July 2014 to 30 June 2015, the AMPR 2015 includes observations and commentary on the reliability, security and safety performance of the power system. It follows a draft report released for public consultation on 16 June 2016. The Panel received one submission on the draft report.

Developments in the NEM during 2014-15

The NEM regions experienced very warm conditions in winter 2014, spring 2014 and summer 2014-15. Heatwaves occurred and it was the warmest spring on record for the second year running. By contrast, autumn 2015 was cooler than average. The warmer than average conditions meant that demand was higher than what it would have been if average conditions had occurred.

Against this backdrop, average operational consumption plateaued in 2014-15 following a decline in recent years.[1] The total growth in maximum demand continued to decline in 2014-15 and moderated in Victoria, South Australia, and Tasmania. These trends are as a result of an uptake in rooftop photovoltaic (PV) installations, increased energy efficiency, and changes in industrial plant operations.

Going forward, AEMO forecasts a gradual increase in operational consumption in the NEM over the next twenty years.[2] In the short term, maximum demand is expected to increase in Queensland, decrease slightly in NSW and remain relatively flat in other NEM regions.

The amount of generation capacity in the NEM in 2014-15 was similar to that in 2013-14. While a significant amount of generation capacity was withdrawn, a similar amount was installed during the year.

While the amounts were similar, the type of fuel source is different. Capacity that has been withdrawn or has been announced to be withdrawn uses coal or gas as a fuel source. In contrast, new and committed capacity during 2014-15 is typically wind or solar. As a result, the proportion of renewable generation in the NEM has been growing.

There have also been an increasing number of businesses providing a range of demand response services to enable customers to realise the value of their demand response capabilities in 2014-15. For example, Reposit Power offers a service designed to optimise the use of a consumer's solar PV and/or battery storage system. Similarly,

1 Operational consumption refers to electricity used over a period of time that is supplied by the transmission grid.

2 The forecasts referred to in this summary are taken from AEMO reports that were publicly available at the time of preparing the AMPR 2015 draft report.

Greensync offers a service to help businesses better manage their electricity to avoid costly peak times for example.

Another impact on generation has been the Federal Government's carbon pricing scheme. This scheme concluded at the start of 2014-15.

Interconnector capacity remained unchanged from the previous year in 2014-15. There were several outages on the Terranora interconnector between NSW and Queensland.

In 2014-15 a project was commenced by AEMO and ElectraNet to increase the capacity of the Heywood interconnector. This followed the completion of a regulatory investment test for transmission (RIT-T) on this investment in 2013. The increase in capacity is scheduled to be completed by the end of March 2017.

Reliability performance of the power system in 2014-15

The reliability of the power system refers to the system capacity to generate and transport sufficient electricity to meet consumer demand in the NEM. This requires both adequate supply of generation to meet customer demand, as well as a reliable network to transport electricity to end-use consumers.

The Panel's primary measure of the reliability of the power system is by reference to the reliability standard which measures maximum expected unserved energy at the generation and transmission level. In particular, the reliability standard requires that the maximum expected amount of unserved energy in any region not exceed 0.002 per cent of the regions annual energy consumption.

The Panel found that the reliability of the NEM continues to remain within the reliability standard in 2014-15. Specifically, there was no unserved energy for any NEM region in 2014-15. Consistent with this, AEMO was not required to issue any directions for reliability during 2014-15. Nor was it required to exercise the reliability and emergency reserve trader (RERT) mechanism during this period.

Going forward, AEMO forecasts the NEM to have adequate supply to meet projected electricity consumption over the next two years in all regions. As a result, AEMO is not expected to be called upon to undertake any reliability measures during this period.

With the current levels of generation capacity and committed generation capacity in mind it is expected that there will be sufficient capacity to maintain power system reliability above the reliability standard under both low and medium economic growth scenarios until at least 2022, for all regions except for South Australia. Due to South Australia's increased reliance on Victorian imports, AEMO has modelled two scenarios where there is a possibility that the reliability standard may be breached in that jurisdiction from 2019-20.

However, AEMO expects announcements to withdraw generation capacity will result in supply shortfalls beyond 2022-23 for all regions except Queensland and Tasmania under a medium economic growth scenario. Under a high economic growth scenario, it expects all regions except for Tasmania to experience a supply shortfall as soon as 2019-20.

The reliability outcomes experienced by electricity consumers are also impacted by the performance of the transmission and distribution networks. In the AMPR 2015, the Panel found that there is a continuing trend of consistent and improving transmission system reliability as experienced by consumers in all NEM regions. The reliability performance of distribution networks as experienced by consumers has fluctuated from year to year. However, the overall trend for the period has been steady.

Security performance of the power system in 2014-15

Security of the power system is achieved by managing all vital technical parameters such as voltage, equipment loading and power system frequency are all within design limits and that they are stable even following a credible event (an event which AEMO considers reasonably possible given the circumstances).

The Panel is required to develop and publish principles and guidelines that determine how AEMO should maintain power system security. Security issues are managed directly by AEMO and network operators in accordance with the applicable technical standards.

In relation to security performance during 2014-15:

- There has been an increase in the number of constraint changes in the NEM in recent years including in 2014-15. However, this is understandable and is the result of the commissioning of new wind farms and the withdrawal of synchronous generation from the NEM.
- There were two incidents where frequency was outside the operating standards in 2014-15. These incidents were effectively managed and actions were taken, or are in the process of being completed, to address the issues identified.
- There were no instances where secure voltage limits exceeded 30 minutes.
- AEMO did not draw on procured system restart ancillary services (SRAS) in 2014-15.
- AEMO issued two power system security directions in 2014-15, both of which were for Tasmanian generators. The low and declining number of power system security directions from AEMO in the last five years indicates that the power system has been operating in a secure manner.
- The number of operating incident reports published by AEMO in 2014-15 was lower than in 2013-14, although there is no evidence of a longer term decreasing trend.

Safety performance of the power system in 2014-15

The Panel's assessment of the safety of the NEM is focused on the consideration of the links between security of the power system and maintaining the system within relevant standards and technical limits. The Panel is not aware of any instances in 2014-15 where AEMO issued a direction and the directed participant elected not to comply on the grounds that complying with the direction would affect the safety of its equipment or personnel.

Recent incidents outside of the 2014-15 reporting period

Since the end of the 2014-15 reporting period, two major operating incidents have occurred in the NEM:

- the trip of the Heywood interconnector in November 2015; and
- the trip and outage of the Basslink interconnector in December 2015.

These incidents give rise to broader reliability and security developments. In particular, the implication of changes to the generation mix with increasing levels of large-scale intermittent generation.

South Australia is leading this change, with Australia's highest penetration of renewables. More than 40 per cent of the state's electricity generation now comes from renewables, primarily wind and solar. These renewable generation sources have technical characteristics that differ from the conventional plant they are replacing. One of the key impacts is on frequency. Traditional synchronous generators provide inertia that stabilise the movement of power system frequency. Non-synchronous generators such as wind and solar do not typically provide inertia.

Regions with high levels of non-synchronous generation, such as wind, are more reliant on interconnection with other regions of the NEM, and so can face increased risks if they are 'islanded', for example through a temporary fault in an interconnector. In the future, to manage these risks, more inertia and voltage support may be required. This could be provided in a range of ways, for example through designing and incentivising battery storage to provide inertia, using more rapid frequency control services by establishing new ancillary service requirements, and through grid-connected synchronous condensers and through changes in generator performance standards. There may also be other appropriate measures to manage these risks.

There are a number of parties who are currently considering such issues. Specifically, AEMO has an ongoing work program to investigate how the growing contribution of renewable technologies to Australia's energy supply mix is likely to affect wholesale market and power system operations and how any impacts should be managed. As part of this program, the Panel liaised with AEMO to assess the implications of the changing generation fleet on system security and reliability, and will continue to do so. In addition, the Panel also held discussions on the growing impact on system security with other parties including the AEMC and ElectraNet who are also considering these issues.

These challenges have wide ranging impacts. The Panel will continue to monitor developments in South Australia, as well as Basslink, with a more comprehensive analysis in the forthcoming 2016 AMPR.

Contents

1 Introduction

This report has been prepared as part of the Reliability Panel's (the Panel) annual market performance review (AMPR) 2015 covering the 2014-15 financial year. The review is a requirement of the 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 has a role to:

- monitor, review and report on the performance of the market in terms of reliability of the power system;[3] and
- 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.[4]

The Panel may also make recommendations on changes to the market or the rules and any other matters which it considers necessary.

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 calendar year and at other such times as the AEMC may request. The Panel must conduct its annual review in terms of:

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

3 Clause 8.8.1(a)(1) of the NER. In performing this function, clause 8.8.1 (b) 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.

4 Clause 8.8.1 (a)(5) of the NER.

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

- the guidelines referred to in clause 8.8.1 (a)(9).[7]

1.2 Purpose of the report

The purpose of this report is to set out the review's findings for 2014-15. In conducting this review, the Panel has considered publicly available information in addition to information obtained directly from relevant stakeholders and market participants.[8]

The Panel's findings include observations and commentary on the reliability, security and safety performance of the power system. It 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 review

The Panel is undertaking this review in accordance with the requirements in the NER and the terms of reference issued by the AEMC.[9]

The AEMC has requested that the Panel review the performance of the market in terms of reliability, security and safety of the power system. 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 sector, the transmission and distribution sectors and impacts on end-use customers where relevant information is available; and
  - significant power system incidents ("reviewable operating incidents") that have occurred in the previous year including the cause of the incident (a reliability or security event), the impact of the incident (on reliability or security) and the sector of origin (generation, transmission or distribution).

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6 The policies and guidelines referred to in clause 8.8 .1 (a)(4) govern how AEMO exercises its power to enter into contracts for the provision of reserves.

7 The guidelines referred to in clause 8.8.1 (a)(9) 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.

8 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.

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

- **Reliability performance of the power system:** The Panel has reviewed performance against the reliability standard for generation and bulk transmission. In doing so, it has considered:
  - actual observed levels of maximum expected unserved energy (USE) over 2014-15;
  - actual and forecast supply and demand conditions in order to form a view on whether any underlying changes to reliability performance have, or are expected to have, occurred; and
  - AEMO's use of the reliability safety net mechanisms over the previous financial year, including incidents of, and reasons for, the use of directions 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.
- **Safety performance of the power system:** Safety of the power system is closely linked to the security of the power system and relates primarily to the operation of assets and equipment within their technical limits. Therefore, the Panel has limited its consideration of this matter to maintaining power system security within the relevant standards and technical limits.

1.4 Draft report and review process

The Panel has carried out this review in accordance with the process set out in the NER and reflected in the AEMC's terms of reference.

The Panel published a draft report on 16 June 2016. Stakeholders were invited to comment on the draft report. They were also able to request a public meeting in relation to the draft report.

One submission on the draft report was received from AGL. This is available on the AEMC's website. The Panel has had regard to that submission in preparing this final report. There were no requests for the Panel to hold a public meeting on the draft report.

1.5 Structure of this report

The remainder of this report is set out as follows:

- **Chapter 2 – Key concepts and relevant standards and guidelines:** provides an explanation of key areas addressed by the AMPR, overview of the standards and guidelines published by the Panel and the operational guidelines that AEMO uses to manage the power system.

- **Chapter 3 - Reliability review:** provides an overview of the reliability performance of the NEM in 2014-15, historical performance and assessment of emerging trends.
- **Chapter 4 - Demand and reserve forecasting performance:** considers market information on demand and reserve forecasts as published by AEMO during 2014-15.
- **Chapter 5 - Security performance:** provides details of any security related issues that occurred during 2014-15.
- **Chapter 6 - Safety performance:** provides a more detailed analysis of the performance of the power system from a safety perspective.
- **Chapter 7 - Market reviews:** provides details of NEM market reviews and rule change requests completed during 2014-15.
- **Appendices**: provide detailed background information on various aspects of power system management and performance.

2 Key concepts and relevant standards and guidelines

The focus of this review is on the reliability, security and safety performance of the power system. These concepts are discussed below, with an explanation of the relevant standards and guidelines.

2.1 Reliability

Reliability is generally associated with ensuring there is enough capacity to generate and transport electricity to meet all consumer demand.[10]

Reliability is measured in terms of unserved energy (USE) which refers to an amount of energy that is required (or demanded) by customers but which cannot be supplied.[11] The current reliability standard is expressed in terms of the maximum expected USE, or the maximum amount of electricity expected to be at risk of not being supplied to consumers, per financial year. In particular, the current reliability standard requires that the maximum expected amount of unserved energy in any region not exceed 0.002 per cent of the regions annual energy consumption.

Compliance with the reliability standard is measured using the actual observed levels of USE for the most recent financial year.[12] The reliability of the NEM is reviewed each year to examine any incidents that have resulted in USE.

To assess performance against the reliability standard, the "bulk transmission" capacity of the NEM is taken to equate to the interconnector capability.[13] Consequently, only constraints in the transmission network that affect interconnector capability are considered when assessing the availability of reserves in a region.[14]

The reliability standard does not take into account USE that is caused by outages of local transmission or distribution elements that do not significantly impact the ability

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10 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 at all times; whereas security is a technical concept as discussed in section 2.2.

11 "Unserved energy" is a defined term in the NER.

12 This is different from the previous standard where compliance was measured against the moving average of the USE in the most recent ten financial years. The Panel made this change as a result of its review in 2010. The Panel considered that it was not appropriate to assign significant meaning to individual historical outcomes or to the average of a number of outcomes over a long period of time. Rather, the reliability of the NEM should be reviewed each year to examine any incidents that have resulted in USE. See AEMC Reliability Panel 2010, Reliability Standard and Reliability Settings Review, Final Report, 20 April 2010, Sydney.

13 The reason for this is that the reliability standard is measured on a regional basis, and the standard is met when sufficient generation capacity is available in a region. This capacity is calculated as the sum of local generation available within the region itself and of interstate generation available via an interconnector.

14 In the Comprehensive Reliability Review, the Panel clarified the definition of "bulk transmission". See AEMC Reliability Panel, 2007, Comprehensive Reliability Review, Final Report, Sydney, pp.32-33.

to transfer power into the region where the USE occurred. Failures of that type have not been catered for in setting the reliability standard and such events are outside the scope of the Panel's direct responsibility. However, the performance of distribution and transmission networks do influence the reliability outcomes experienced by electricity consumers. Therefore, consistent with the AEMC's terms of reference, the Panel has also set out the reliability performance of transmission and distribution networks.[15]

The reliability standard also does not consider any USE that is the result of non-credible (or multiple) contingency events. Interruption of consumer load in these circumstances is a controlled response to prevent power system collapse, rather than the result of insufficient generation or bulk transmission capacity being made available. These non-credible contingency events are formally classified as power system security issues and are addressed separately in this report.[16]

2.2 Security

While reliability relates to ensuring sufficient capacity to meet demand, security of the power system refers to the technical requirement of ensuring that power system equipment is maintained within its operating limits. Security issues are managed directly by AEMO and network operators in accordance with applicable technical standards.

Maintaining the security of the power system is one of AEMO’s key functions. The power system is deemed secure when all equipment is operating within safe loading levels and will not revert to an unsatisfactory operating state in the event of a single credible contingency. Secure operation depends on the combined effect of controllable plant, ancillary services, and the underlying technical characteristics of the power system plant and equipment.

The practices adopted by AEMO to manage power system security are defined in the operating procedures and guidelines, which have been developed from overarching guidelines defined by the Panel and obligations under the NER.

Operations consistent with those guidelines are intended to maintain system quantities such as voltage and frequency within acceptable performance standards, as well as providing that certain equipment ratings are not exceeded following credible contingencies.

A principle tool used by AEMO to maintain power system security is the constraint equations used in the market dispatch systems. Violations of constraint equations can indicate, among other things, periods where the power system is not in a secure state.

The Panel has reviewed power system security performance by considering the following matters:

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15 In reporting on distribution network performance the Panel has had regard to NER clause 8.8.1(b) as set out in section 1.1 of this report.

16 Power system incidents are discussed in Chapter 5.

- whether the power system has been operated consistent with AEMO's published procedures and guidelines;
- whether system parameters have been maintained within the range specified in the relevant standards;
- the frequency and extent of any violation of constraint equations; and
- the frequency and extent of any violations of equipment ratings.

In addition, the Panel has considered the various reviews of power system incidents reported by AEMO during 2014-15. This allows for an assessment of whether those incidents point to any emerging power system security issues or practices that might need to be revised to maintain future power system security.

2.3 Safety

While the general safety of the NEM, and associated equipment, power system personnel and the public is an important consideration under the National Electricity Law (NEL), in general terms, there is no national safety regulator for electricity. Instead, jurisdictions have specific provisions that explicitly refer to safety duties of transmission and distribution systems, as well as other aspects of electricity systems such as metering and batteries.[17]

There are strong linkages between maintaining power system security and operating the power system safely. For example, the transfer limits and ratings that define the secure operating envelope for the power system are set at levels that maintain safety; and safe clearances from conductors are maintained by setting the thermal rating of transmission lines at an appropriate level. Safety therefore can be managed by ensuring that the power system is operated within ratings and technical limits.

In this way, maintaining security of the power system could be considered as maintaining a "safe" power system to meet the requirements for safety in a general sense.[18]

In addition to considering the safety performance of the market as defined above, the Panel has included a summary of safety outcomes in each NEM jurisdiction by reference to jurisdictional safety requirements in Appendix G. This information may be useful for stakeholders.

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17 See section 2D(a) of the NEL.

18 Although it is noted that some system security considerations do not relate to safety, for the purpose of our considerations where the power system has been maintained in a secure state it is considered that it is also safe.

2.4 Standards and guidelines

The performance of the power system is measured against various standards and guidelines that form the technical standards framework. This framework is designed to maintain the security and integrity of the power system by establishing clearly defined standards for the performance of the system overall. The framework comprises a hierarchy of standards:

- **System standards** define the performance of the power system, the nature of the electrical network and the quality of power. These also establish the target performance of the overall power system. AEMO's obligations to manage the power system are included in Chapter 4 of the NER.

- **Access standards** specify the quantified performance levels that a plant or equipment (consumer, network or generator) must achieve to allow it to connect to the power system. Access standards define the range within which parties may negotiate with network service providers, in consultation with AEMO, for access to the network. AEMO and the relevant network service providers need to be satisfied that any access granted to the power system will not negatively affect the ability of the network to meet the relevant system standards, nor impact on other network users.

- **Plant standards** set out the technology specific standards that, if met by particular facilities allow compliance with the access standards. Plant standards can be used for new or emerging technologies where they are not covered by access standards. The standard allows a class of plant to be connected to the network if that plant meets some specific standard such as an international standard. To date, the Panel has not been approached to consider a plant standard.

The actual performance of all generating plant must also be registered with AEMO, and becomes known as a performance standard. Registered performance standards represent binding obligations on a generator. For generating plant to meet its registered performance standards on an ongoing basis, participants are also required to set up compliance monitoring programs. These programs must be lodged with the AER. It is a breach of the NER if the generating plant does not continue to meet its registered performance standards and compliance program obligations.[19]

19 The Panel developed a template in 2009 to assist generators in designing their compliance programs. This template was most recently updated by the Panel on 18 June 2015.

3 Reliability review

The reliability of the NEM can be influenced by the amount of available generation; the available capacity of the interconnectors; the maximum level of demand reached as compared to the forecast; and the performance of the transmission and distribution networks. This chapter considers these factors to provide a review of NEM reliability in 2014-15.

3.1 NEM regional reliability assessment

3.1.1 Generation capacity

As at 30 June 2015 the NEM's installed capacity of generation was 48,360 MW.[20] In terms of fuel source, this installed capacity comprised of 52 per cent coal, 22 per cent gas, 8 per cent wind, 17 per cent water, and 1 per cent other.[21]

South Australia has the largest amount of wind generation - it has 39 per cent of wind generation in the NEM. NSW has the largest amount of coal generation, with coal making up 41 per cent of NSW's generation capacity. Table 3.1 sets out generation capacity in the NEM by region and fuel type.

Table 3.1 Generation capacity by region and fuel type as at 30 June 2015

Region	Coal (MW)	Gas (MW)	Water (MW)	Wind (MW)	Other (MW)
Queensland	7,866	3,267	664	12	352
NSW (including ACT)	10,240	2,321	2,745	666	232
South Australia	546	2,632	3	1,473	133
Victoria	6,410	2,493	2,296	1,230	3
Tasmania	0	125	2,281	373	0
Total	**25,062**	**10,837**	**7,988**	**3,753**	**720**
(%) of total	**52%**	**22%**	**17%**	**8%**	**1%**

Note: Generation capacity includes existing capacity less withdrawn capacity. Totals may not add up exactly due to rounding.

Source: AEMO, *Electricity statement of opportunities for the National Electricity Market*, August 2015.

20 Existing generation capacity less capacity that has been withdrawn as reported by AEMO: AEMO, *Electricity statement of opportunities – for the National Electricity Market*, August 2015.

21 This only includes large scale generation. It does not include household solar PV for example.

New and committed generation

As set out in Table 3.2, 1,074 MW of generation capacity was commissioned[22] and 393 MW committed[23] in 2014-15. By comparison, 170 MW of new generation capacity was commissioned in 2013-14 and 523 MW in 2012-13.[24]

Another 97 MW of generation capacity was expected to be committed in the NEM during early 2016 comprising:

- 44 MW from CS Energy's Kogan Creek solar project; and
- 53 MW from AGL's Broken Hill solar project.[25]

The AGL Broken Hill solar project opened on 20 January 2016. CS Energy has announced that the Kogan Creek solar project will not proceed.[26]

Of the new generation capacity in the NEM committed in 2014-15 most of this was wind, with all of the 240 MW committed new generation capacity in Victoria being wind. There were also significant amounts of solar committed - specifically, 44 MW in Queensland and 109 MW in NSW. There was no new generation capacity committed in South Australia and Tasmania in 2014-15.

Table 3.2 provides a summary of total amount of capacity commissioned and committed during 2014-15 for each NEM region. For further details regarding the fuel source and the location of new or proposed generation capacity refer to Table A.1 in Appendix A.

22 The term commissioned is described in rule 5.8 of the NER. To be commissioned, the generator is responsible for providing evidence to AEMO and the relevant network service provider (NSP) that demonstrates the performance of the plant. These generators would generally be in full commercial operation.

23 Meet all five of AEMO's criteria covering site acquisition, contracts for major components, planning approval, financing, and the date for construction .

24 Reliability Panel, *Annual Market Performance Review 2014*, Final report, 16 July 2015.

25 AEMO, *Electricity Statement of Opportunities – for the National Electricity Market*, August 2014.

26 CS Energy, *Solar boost project will not be completed*, media release, 18 March 2016.

Table 3.2 New generation commissioned and committed during 2014-15

NEM region	Commissioned during 2014-15 (MW)	Committed during 2014-15 (MW)
Queensland	0	44
NSW (including ACT)	513	109
Victoria	291	240
South Australia	270	0
Tasmania	0	0
Total	**1,074**	**393**

Source: AEMO, *Electricity statement of opportunities – for the National Electricity Market*, August 2015.

Expected generation withdrawals

Since August 2014, there have been a number of changes to generation availability:

- Redbank power station, Morwell/EnergyBrix, Pelican Point Unit 2 and Tamar Valley CCGT have been retired;[27]
- Playford B, which is currently placed in dry storage[28], has been announced for full retirement by 2017;
- EnergyAustralia advised in November 2014 that unit 8 of Wallerawang power station would be retired.[29]
- Tamar Valley Peaking power station was classified as withdrawn although has since revised its status to be available and is currently in operation following the Basslink outage in late 2015.[30]

In addition, since 2011-12 Munmorah has been retired and Swanbank E has been placed in dry storage;[31] Collinsville, Daandine, Mackay GT, Mt Stuart, and Tarong are still operational but there have been announcements to retire them.[32]

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27 Redbank Energy Ltd advises that Redbank power station with a generating capacity of 143.8 MW fuelled by black coal, has been removed from service from August 2014 and shut down. There are no future plans at this stage for Redbank to return to service.

28 The term "dry storage" refers to the status of a generation facility that is not in a state of readiness to allow it to be dispatched in the NEM, but remains physically intact, and, after a limited period of restoration, would be capable of being returned to service. This state can also be referred to as "care and maintenance" or "mothballing".

29 Unit 7 was retired from the NEM on 20 June 2014. Both units comprising 1,000 MW of coal fired generation are now permanently closed and decommissioned.

30 AEMO, *Electricity Statement of Opportunities 2015*, August 2015.

31 Swanbank E may return to service if market conditions change.

In August 2015, the Anglesea 156 MW coal fired power station in Victoria was retired. It is important to note that generating plant capacity which has been placed in dry storage may be returned to service if market conditions change.

Table 3.3 summarises the amount of capacity withdrawn during 2014-15 and the amount of capacity that was announced to be withdrawn during 2014-15 but will be withdrawn after 2014-15. It shows that the largest amount of generation capacity withdrawn was in South Australia. South Australia also has the largest amount of generation capacity that is to be withdrawn after 2014-15. By comparison, there were no generation capacity withdrawals during 2014-15 in Queensland. Nor is there any capacity that has been announced to be withdrawn after 2014-15 in that jurisdiction. Three quarters of the generation capacity that is to be withdrawn after 2014-15 uses coal as a fuel source. The remaining capacity to be withdrawn uses gas as a fuel source. More information regarding generator details are in Table A.2 in Appendix A.

Table 3.3 Generation withdrawals

Region	Withdrawn in 2014-15	To be withdrawn after 2014-15
Queensland	0	0
NSW including ACT	144	2,171
Victoria	189	156
South Australia	479	1,026
Tasmania	266	120
Total	**1,078**	**3,473**

Source: AEMO, *Electricity statement of opportunities – for the National Electricity Market*, August 2015.

3.1.2 Interconnectors

Interconnector capacity

During 2014-15, no new interconnectors were commissioned. Similarly, there were no de-ratings of existing interconnector capacity.

From an operational point of view, the Terranora interconnector was the only interconnector which experienced extended service outages during 2014-15. This was due to outages of the high voltage direct current (HVDC) link for 58 days over three separate periods.

32 AEMO, *Electricity Statement of Opportunities 2015*, August 2015.

Heywood interconnector upgrade

In February 2011, ElectraNet and AEMO published a joint feasibility study that identified NEM benefits associated with upgrading Heywood Interconnector transfer capability, particularly for Victorian and South Australian energy consumers. This was followed by a joint regulatory investment test for transmission (RIT-T) which commenced in October 2011.

After considering a range of options to address the expected congestion of the Victoria to South Australia interconnector, and examining the merit of those options via a RIT-T assessment, AEMO and ElectraNet (as the Victorian and South Australian TNSPs respectively) identified a preferred option to increase the interconnector capacity by augmenting the Heywood interconnector. The preferred development would increase the transfer capability from Victoria to South Australia (and vice versa) by a notional 190 MW in each direction, that is, an increase from 460 MW to 650 MW each way.

AEMO and ElectraNet have subsequently progressed the upgrade of the Heywood interconnector. The upgrade consists of:

- installation of a third 500/275kV transformer at Heywood Terminal Station (HYTS) to remove the 460 MW thermal transfer limit. This was completed in late 2015.

- series compensation on the South East - Tailem Bend 275 kV (SESS – TBTS) lines to alleviate stability limits which is scheduled to be completed in July 2016.

Following the completion of the third HYTS transformer, AEMO began to progressively increase the transfer capability of the interconnector.[33] The transfer capacity upgrade project is scheduled for completion by March 2017.[34]

In light of the recent withdrawal of more than 1,500 MW of generation capacity in South Australia and in the absence of new additional generation capacity in that jurisdiction, there will be greater reliance on imports from Victoria to South Australia during peak demand periods.

Queensland - NSW interconnector upgrade

Powerlink and TransGrid have regularly been investigating whether a network development to increase the capacity of the Queensland - NSW interconnector (QNI) would be justified.

At the conclusion of the most recent investigation in 2014, Powerlink and TransGrid decided it was prudent to not recommend an upgrade. The cost-benefit analysis did not identify a preferred credible option and the market benefits delivered by each option were highly dependent upon the assumptions used and varied considerably

33 AEMO, *The Heywood Interconnector Overview of the Upgrade and Current Status*, August 2015.

34 AEMO, *Victoria – South Australia (Heywood) interconnector upgrade, Test program for inter-network tests*, Last revised on 6 November 2015, p.7.

between the scenarios modelled.[35] Developments in these assumptions will continue to be monitored.

Interconnector performance

Power transfer across an interconnector is limited by the capability of network elements which make up the interconnector (thermal limitations), or the ability to maintain the system in a secure state in the event of a contingency (transient or voltage stability limitations). These limits are applied in the form of constraint equations in the National Electricity Market Dispatch Engine (NEMDE) process.

During normal operation of the power system, transfer across an interconnector will ultimately be limited by constraints within the NEMDE dispatch process. However, the power system operates in a dynamic environment and there are instances where interconnector transfer can exceed their secure limit for a small period of time.

During 2014-15, the Panel has not been advised of any power system incidents where an interconnector was above its secure limit for more than one dispatch interval.

3.1.3 NEM regional reliability assessment

The reliability performance for each region in the NEM has been calculated by reference to the reliability standard. The NEM reliability standard requires that the maximum amount of unserved energy (USE) in any region not exceed 0.002% of the regions annual energy consumption.[36] Table 3.4 compares the regional performance against the reliability standard.

35 Further details can be found on Powerlink's website: www.powerlink.com.au, viewed 1 June 2016.

36 A 2014 review of the reliability standard determined that the existing standard should be retained in its current form beyond 1 July 2016. The 0.002% threshold has remained unchanged since 1998.

Table 3.4 Historical regional USE from 2005-06 to 2014-15

Year	Queensland (%)	NSW (%)	Victoria (%)	SA (%)	Tasmania (%)
2014-2015	0.0000	0.0000	0.0000	0.0000	0.0000
2013-2014	0.0000	0.0000	0.0000	0.0000	0.0000
2012-2013	0.0000	0.0000	0.0000	0.0000	0.0000
2011-2012	0.0000	0.0000	0.0000	0.0000	0.0000
2010-2011	0.0000	0.0000	0.0000	0.0000	0.0000
2009-2010	0.0000	0.0000	0.0000	0.0000	0.0000
2008-2009	0.0000	0.0000	0.0040	0.0032	0.0000
2007-2008	0.0000	0.0000	0.0000	0.0000	0.0000
2006-2007	0.0000	0.0000	0.0000	0.0000	0.0000
2005-2006	0.0000	0.0000	0.0000	0.0000	0.0000
10-year average reliability by region	**0.0000**	**0.0000**	**0.00040**	**0.00032**	**0.0000**

Source: AEMO.

As indicated in Table 3.4, there have only been two instances where the reliability standard has been breached on a regional basis. These breaches occurred, in Victoria and South Australia during 2008-09 on 29 and 30 January 2009 due to relatively high temperatures over a prolonged period. Notwithstanding the above, the long term 10 year average for all regions meets the reliability standard.

The Panel notes the following:

- Each region of the NEM met the reliability standard in 2014-15.
- There have only been a couple of instances over the past 10 years where the reliability standard was not met in a particular year.
- There is no trend emerging which indicates the reliability of the NEM has deteriorated based on the measured results, as shown by the 10-year average reliability by region.
- With the current levels of generating capacity, in addition to the committed generation discussed above the Panel considers that there will be sufficient capacity to maintain power system reliability above the reliability standard under a low economic growth scenario and a medium scenario until at least 2022 for all regions except for South Australia. Due South Australia's increased

reliance on Victorian imports, AEMO identified that under a medium and high growth scenario there is a possibility that the reliability standard may be breached in that jurisdiction from 2019-20.[37]

3.2 Network developments

3.2.1 Transmission network performance

The performance of transmission networks is the responsibility of the relevant transmission network service provider (TNSP). As noted in chapter 2, the frameworks which govern the way that electricity transmission reliability levels are set and delivered are currently the responsibility of each jurisdiction. Refer to Appendix B.1 for information regarding each region's TNSP reporting obligation.

The number of system minutes not supplied due to transmission outages provides an aggregate indicator of the reliability performance of transmission networks. Table 3.5 below shows the performance of the transmission networks as experienced by consumers in each region.

Table 3.5 Transmission networks unsupplied system minutes for 2014-15

	Calculated value in minutes	
Region	**2013-14**	**2014-15**
Queensland	0.24	2.70
NSW	0.64	0.31
Victoria	0.52	0.00
South Australia	5.83	0.35
Tasmania	2.90	2.63

Note: The calculated value in minutes is the amount of energy not supplied, divided by maximum demand, multiplied by 60.

Source: Queensland: Powerlink; NSW (inc. ACT): TransGrid; Victoria: AusNet Services; South Australia: ElectraNet; Tasmania: TasNetworks.

All regions except for Queensland experienced an improvement in transmission performance. South Australia's improvement was substantial while NSW, Tasmania and Victoria experienced modest improvements. Notably, Victoria did not observe any unsupplied system minutes in 2014-15. ElectraNet has advised the Panel that the change in transmission unsupplied minutes in 2014-15 from previous years is due to a reduction in the number of significant events that impacted the more meshed part of its network.

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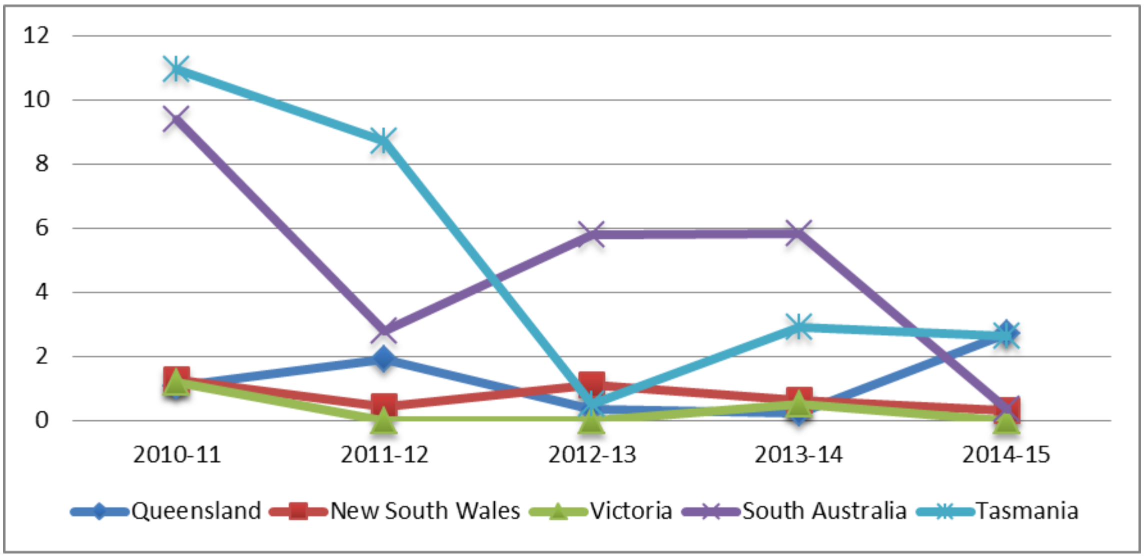
37 Refer to section 4.1 for a detailed analysis.

Figure 3.1 shows the transmission system minutes recorded in all regions since 2010-11. These results show a continuing trend of consistent and improving transmission system reliability across all regions of the NEM.

Figure 3.1 Transmission unsupplied minutes as reported in previous AMPRs



Source: Powerlink, TransGrid, AusNet Services, ElectraNet and TasNetworks.

3.2.2 Distribution network performance

The performance of distribution networks, and the reliability standards that must be met, fall within the responsibility of jurisdictions.

These reliability standards are often measured in terms of the system average interruption duration index (SAIDI). SAIDI is defined as the sum of the duration of each sustained customer interruption, divided by the number of customers. It is calculated for different parts of each distribution network service provider's (DNSP) network, such as central business district areas, urban areas, short rural feeder areas and long rural feeder areas.

Unplanned SAIDI relates to unplanned outages. These unplanned outages are typically caused by operational error or damage caused by extreme weather and damage by trees.

The average SAIDI figure for each NEM jurisdiction is in Table 3.6. 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.

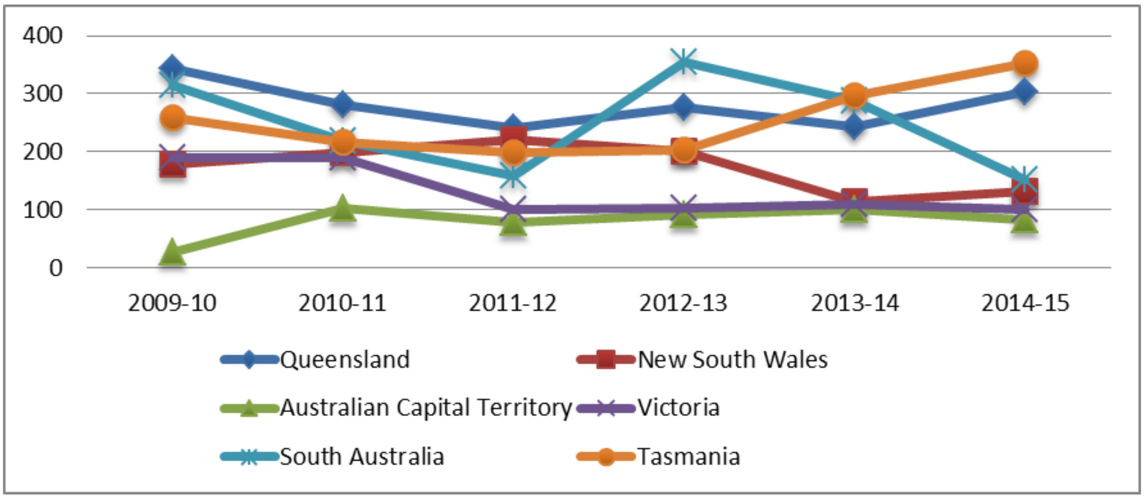
Table 3.6 Average distribution networks unsupplied system minutes per region

NEM jurisdiction	SAIDI (minute)	
	2013-14	**2014-15**
Queensland	243.44	**303.14**
New South Wales	113.50	**132.37**
Australian Capital Territory (ACT)	89.98	**82.56**
Victoria	110.27	**99.42**
South Australia	287.00	**151.90**
Tasmania	296.80	**353.20**

Source: Queensland: Queensland Department of Energy and Water Supply; NSW: Independent Pricing and Regulatory Tribunal; ACT: Independent Competition and Regulatory Commission; Victoria: Australian Energy Regulator; South Australia: Essential Services Commission of South Australia; Tasmania: Office of the Tasmanian Economic Regulator.

Figure 3.2 shows the historical distribution performance as reported in previous AMPRs. The chart shows that distribution network performance trend is generally steady over the last six years without any major improvement or deterioration. Distribution network performance appears to have declined in Tasmania in recent years. There appears to have been an improvement in performance in NSW and South Australia in recent years.

Figure 3.2 Distribution network SAIDI in minutes as reported in previous AMPRs



Source: Queensland: Queensland Department of Energy and Water Supply; NSW: Independent Pricing and Regulatory Tribunal; ACT: Independent Competition and Regulatory Commission; Victoria: Australian Energy Regulator; South Australia: Essential Services Commission of South Australia; Tasmania: Office of the Tasmanian Economic Regulator.

4 Demand and reserve forecasting performance

Chapter 4 considers market information on demand and reserve forecasts as published by AEMO in 2014-15 in various reports. The outlook periods for the forecasts range from the next trading day to ten years.

4.1 Reserve projections and demand forecasts

The Panel has previously noted the essential role played by energy and demand forecasts in the market and that these are used by key operational and investment decision makers. Electricity demand and usage forecasts are also important for transparency and to improve awareness in the energy markets. It is therefore critical that demand forecasts are as accurate as possible.

AEMO is required to produce electricity demand and energy forecasts for each NEM region as well as for the NEM as a whole. These forecasts can be found in the National Electricity Forecasting Report (NEFR) which provides forecasts for a 20-year outlook period.

Forecasts in the NEFR are used by AEMO:

- in the analysis of electricity supply and demand over a ten year outlook period, the results of which are published in the Electricity Statement of Opportunities (ESOO); and
- as inputs into longer-term transmission planning, the results of which are published in the National Transmission Network Development Plan (NTNDP).

The forecasts in the NEFR are also used by NSPs in their network planning along with more detailed transmission connection point forecasts that may be developed by either the NSP or AEMO.

Given the importance of accurate energy and demand forecasts for network planning, the NER stipulates that AEMO must:

- provide updated results whenever significant new information is made available;
- report on the accuracy of the previous year's NEFR;[38] and
- outline any improvements to the forecasting process which can be made for the preparation of future forecasts.[39]

38 The Forecast Accuracy Report is provided to the Panel, who publishes this on the AEMC Reliability Panel website.

39 These are disclosed in the NEFR Update Report, Forecast Accuracy Report, and NEFR Action Plan Implementation report, respectively.

As a result of the growing influence of emerging technologies such as battery storage and fuel switching, AEMO has also published a supplementary report to the NEFR, the Emerging Technologies Information Paper for the first time.

Further information relating to AEMO's demand forecasts and the different reports published by AEMO can be found in Appendix C and Appendix D.

4.1.1 2015 National Electricity Forecasting Report

The 2015 NEFR was published in June 2015 providing AEMO's 20 year electricity forecasts for the five NEM regions under high, medium, and low consumption growth scenarios.[40]

The results published in the 2015 NEFR have been obtained from a more sophisticated model than what was used in previous NEFRs. The model was changed, based on recommendations set out in the NEFR action plan for 2014.[41] The purpose of the changes was to capture recent trends such as the increasing uptake of household solar PV systems and other emerging technologies. The model changes are designed to provide more comprehensive energy and maximum demand forecasts. As a result of implementing these changes, the 2015 NEFR modelled residential and commercial PV separately for the first time.

The findings in the 2015 NEFR are set out below.

NEM overall annual operational consumption forecast results

Operational consumption[42] has been falling since 2008-09. This decline is due to:

- a reduction in industrial load (such as the closure of the Kurri Kurri and Point Henry aluminium smelters in NSW and Victoria respectively);
- curtailment of steel-making capacity in the Port Kembla steel mill in NSW;
- growth in rooftop PV installations; and
- general increases in energy efficiency.

Operational consumption was expected to be similar to the previous year in 2014-15. This outcome is attributed to the ramp up of LNG projects in Queensland, and recovery in residential and commercial consumption in NSW, which offset the closure of the Point Henry smelter in Victoria.

40 AEMO, *2015 National Electricity Forecasting Report for the National Electricity Market*, June 2015.

41 AEMO, *National Electricity Forecasting Report Action Plan for 2014*, November 2013.

42 Operational consumption is defined as the electrical energy supplied by scheduled, semi-scheduled, and significant non-scheduled generating units, less the electrical energy supplied by small non-scheduled generation.

Consumption in the residential and the commercial sector is expected to recover slightly over the short to medium term, although per capita consumption is still expected to decline in future owing to faster population growth. In summary, operational consumption throughout the NEM is forecast to grow at:

- 2.1% over the short-term (2014-15 to 2017-18);
- 0.5% over the medium term (2017-18 to 2024-25); and
- 1% over the long-term (2024-25 to 2034-35).

AEMO's forecasts take into consideration:

- population growth;
- structural shifts in the Australian economy away from energy-intensive industries;
- the closure and modest recoveries of some large industrial consumers;
- the ramp-up of consumption from Queensland’s LNG projects;
- consumer responses to higher prices, that is, a measure of demand elasticity;
- the advancement of energy efficiency for both residential and commercial purposes; and
- the response to government backed renewable energy schemes reducing demand from the grid, and increasing generation at the local level.

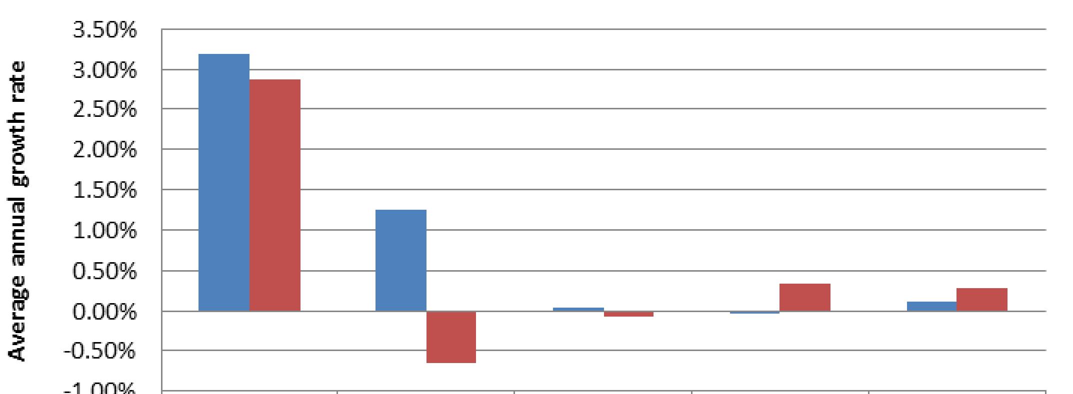
Region specific analysis is discussed in Appendix D.1.2.

Regional maximum demand forecasts

Figure 4.1 shows the change in the 10% maximum demand probability of exceedance (POE) forecasts from 2014-15 to 2017-18 as reported in the 2014 and 2015 NEFR[43]. Compared to the 2014 NEFR, the revised forecast maximum demand growth rates are lower for Queensland, NSW, and Victoria but higher for South Australia and Tasmania. AEMO notes that the changes made to the maximum demand POE forecasting model may have contributed to this revision.

43 Probability of exceedance (POE) is defined as the percentage that a maximum demand level will be met or exceeded (for example, due to weather conditions) in a particular period of time. For example, a 10% POE maximum demand for a given season means a 10% probability that the projected maximum demand level will be met or exceeded. The 10% POE is a conservative measure as it shows the projected maximum demand levels that are expected to be met or exceeded, on average, only one year in 10.

Figure 4.1 Comparison of forecast 10% POE maximum demand growth rates from 2014-15 to 2017-18 as reported in the 2014 and 2015 NEFR



	QLD	NSW	VIC	SA	TAS
2014 NEFR	3.19%	1.25%	0.04%	-0.04%	0.11%
2015 NEFR	2.88%	-0.65%	-0.08%	0.35%	0.29%

Source: AEMO, *2015 National Electricity Forecasting Report for the National Electricity Market*, June 2015; AEMO, *2014 National Electricity Forecasting Report for the National Electricity Market*, June 2014.

The following is a summary of AEMO's findings on maximum demand from the 2015 NEFR published by AEMO.

Maximum demand grew in most NEM regions between 2006-07 to 2010-11. However, since then growth has been consistently lower and has plateaued in Victoria, South Australia, and Tasmania as a result of an uptake in rooftop PV installations, increased energy efficiency, and changes in industrial plant operations.

Queensland, NSW, and South Australia have reported considerable movement in maximum demand growth in the past year. The movement in Queensland and South Australia is largely attributed to the short-term behaviour of large industrial loads, while the movement in NSW is largely attributed to revised solar PV uptake assumptions.

See Appendix D.1.4 for a more detailed regional analysis.

Maximum demand has historically been driven by demand from the residential sector, with its growth driven by changes in the level of income and population. It is primarily influenced by the weather, with high demand for cooling during hot days, and high demand for heating during cold days.

For most regions, maximum demand occurs during the summer months. The exception is Tasmania, where maximum demand occurs during winter months.

Maximum demand tends to occur in the late afternoon. However, the 2015 NEFR noted that the increased rooftop solar PV uptake is likely to shift the occurrence of maximum demand to the early evening. This effect has already been observed in South Australia, where the uptake of solar PV systems has been particularly strong. AEMO has forecast that the maximum demand in South Australia is expected to shift from around 5:30pm in 2014-15 to 6:30pm by 2023-24.

See Appendix E for a detailed analysis of prominent weather events during 2014-15.

2015 NEFR update report

AEMO provided an update to the 2015 NEFR in December 2015 on the basis that significant new information had been made available regarding Queensland's operational consumption and maximum demand forecasts, as well as Tasmania's maximum demand forecasts.[44]

The impact of this new information on Queensland's operational and maximum demand forecasts was not material. Similarly, there were no material changes to Tasmania's maximum demand and operational consumption forecasts.

2015 Forecast Accuracy Report

The 2015 Forecast Accuracy Report provides an assessment of the accuracy of the consumption and maximum demand forecasts in the 2014 NEFR for each NEM region, as well as any improvements that can be made to the forecasting process.

Table 4.1 reports the accuracy of operational consumption forecasts in 2013-14 and 2014-15 in the 2014 NEFR. In particular, it sets out the percentage difference between the values that were forecast for 2013-14 and 2014-15 in the 2014 NEFR with actual values as reported in the 2014 and 2015 Forecast Accuracy Reports.

Table 4.1 Difference between the operational consumption forecast for 2013-14 and 2014-15 in the 2014 NEFR with actual operational consumption

	NEM	NSW	Qld	South Australia	Tasmania	Victoria
Variance (2013-14)	2.30%	2.90%	4.80%	1.30%	0.90%	-0.50%
Variance (2014-15)	-2.65%	2.72%	-6.19%	0.74%	-0.62%	0.03%

Source: AEMO, *Forecast Accuracy report 2015 – for the National Electricity Forecasting Report*, November 2015; *AEMO, Forecast Accuracy report 2014 – for the National Electricity Forecasting Report*, November 2014.

Operational consumption was forecast with less accuracy in 2014-15 for the NEM as a whole, and with greater accuracy for all individual regions except for Queensland.

AEMO over-estimated annual consumption in Queensland by 4.8% in 2013-14 while under-estimating it by 6.2% in 2014-15. The under estimation was mainly due to higher than expected energy use requirements for several LNG projects and lower than

44 AEMO, *Update National Electricity Forecasting Report for the National Energy Market,* December 2015.

expected rooftop PV uptake resulting in an increase in residential and commercial consumption.[45] AEMO notes there was a higher than expected residential commercial and industrial consumption in NSW in 2014-15.

It is important to note that the econometric model was changed for the 2015 NEFR in order to provide a better analysis of the decline in electricity prices in some regions in recent years. In particular, AEMO adjusted the model to be more sensitive to region-specific trends.

Table 4.2 reports the accuracy of AEMO's maximum demand forecasts. Specifically, it shows the percentage difference between the maximum demand forecast in each region as per the 2014 NEFR and the observed maximum demand values for 2014-15 as reported in the 2015 NEFR.[46]

Table 4.2 Difference between the forecast and actual 10% POE maximum demand

	NSW	Queensland	South Australia	Tasmania	Victoria
Variance	5.80%	-7.02%	2.89%	0.11%	0.80%

Note: As maximum demand in Tasmania occurs in winter, the results for Tasmania are for the 2014 calendar year.

Source: AEMO, *2015 National Electricity Forecasting Report for the National Electricity Market*, June 2015; AEMO, *2014 National Electricity Forecasting Report for the National Electricity Market*, June 2014.

More detailed information on the accuracy of AEMO's operational consumption and 10% maximum demand POE forecasts is provided in Appendix D.2.

2015 NEFR action plan implementation

A number of improvements were made to the 2015 NEFR. The improvements identified by AEMO for implementation ahead of the 2016 NEFR are:[47]

1. Operational consumption:

- Historical data is not split according to residential and commercial consumption. Future NEFRs should split the forecasts where possible because this may increase their accuracy and identify trends between different consumer types. AEMO is continuing to investigate whether smart meter data can be utilised as well as data availability throughout the NEM.

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45 Lewis Grey Advisory prepared for AEMO, *Updated Projections of Gas and Electricity Used in LNG*, 26 October 2015.

46 The 2015 NEFR reports maximum demand for 2014-15 for all NEM regions except Tasmania as the maximum demand in these regions occurs in summer. In Tasmania, the maximum demand occurs in winter so the 2015 NEFR reports the maximum demand in Tasmania for the 2014 calendar year.

47 AEMO, *National Electricity Forecasting Report - Action Plan Implementation*, September 2015.

- Trends and recommendations regarding residential customer fuel switching in each NEM region will be considered in future NEFRs.
- Modelling of electric vehicles was not considered in previous reports due to data availability. In response to this, an electric vehicle user tool was developed that allows users to investigate annual consumption and daily demand. Future NEFRs will include a review of electric vehicle uptake as either government policy incentives are introduced or the capital costs drop significantly.
- Future NEFRs should categorise large industrial load forecasts by sector instead of by region since this would provide more granular demand forecasts. However, due to confidentiality, AEMO can only disaggregate regional large industrial load forecasts into 'Manufacturing' or 'Other'. This disaggregation would still be considered beneficial to stakeholders.

2. Maximum and minimum demand models:

- Extending the analysis to include both maximum and minimum demand forecasts for all regions would benefit both AEMO and NSPs. The 2015 NEFR contained minimum demand forecasts for South Australia, as this region has the largest concentration of rooftop PV in the NEM. As minimum demand forecasts help inform studies which examine network stability, future NEFRs should extend the minimum demand forecasts for all other regions.
- Currently industrial and non-industrial loads are modelled separately. In order to improve the accuracy of the POE forecasts, a maximum demand model that produces POEs for both industrial and non-industrial demand should be developed and its results published in future NEFRs.

3. Energy efficiency and rooftop PV forecasts:

- The 2014 NEFR only considered Federal energy efficiency and PV programs. The 2015 NEFR incorporated the impact of state and local government energy efficiency and PV schemes into their forecasts. Future NEFRs should also consider this information.

4. Battery storage:

- As part of the 2015 Emerging Technologies Information Paper,[48] AEMO modelled the potential uptake of integrated PV and battery storage systems. While this battery storage forecast was not included in the 2015 NEFR, the 2016 NEFR is to consider the potential impact of battery storage on the consumption and maximum demand forecasts.

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48 AEMO, *Emerging Technologies Information Paper – National Electricity Forecasting Report*, June 2015.

5. Communications:

- With regards to the NEFR publication, AEMO has developed a Forecasting Dynamic Interface that allows users to view graphs and key results, apply filters, and download data. This has the benefit of increasing data accessibility enabling stakeholders to tailor information to their interests and/or needs. AEMO will continue to explore, and implement where practical, improved ways to present published data.

Panel comments

There are often difficulties and complications associated with demand forecasting. The Panel considers there have been improvements in forecasting over time. It also acknowledges AEMO's continued commitment to prepare new forecasts such as operational minimum demand forecasts and improve its forecasting methods.

4.1.2 Electricity Statement of Opportunities 2015

AEMO publishes the ESOO in August each year. The 2015 ESOO provides an analysis of electricity supply and demand over a 10-year outlook period (2015-16 to 2024-25).[49] It includes historical information about the changing generation mix and recent trends in demand. The ESOO uses AEMO's electricity demand forecasts to assess supply adequacy for the 10-year outlook period.

While summarising the investment environment for each NEM region, including the supply-demand outlook and current interest in generation investment, the 2015 ESOO also highlighted NEM-wide generation and demand-side investment opportunities by analysing the key factors that influenced this.

The 2015 ESOO identified the following:

- No new generation capacity is required over the next 10 years in any NEM region to maintain supply adequacy under a low growth scenario.[50]

- Under a medium growth scenario all regions except for Queensland and Tasmania will experience a USE shortfall beyond 2022-23. Under a high growth scenario, all regions except for Tasmania will experience a USE shortfall as soon as 2019-20. The expected shortfalls are the result of announcements to withdraw generation capacity as discussed in section 3.1.1.

- The announcement of generation capacity withdrawals in South Australia will place a greater reliance on Victorian imports and will result in a possible breach of the reliability standard from 2019-20 under both a medium and high growth scenario.

49 For further information see the electricity statement of opportunities section under the electricity planning part of AEMO's website.

50 Supply adequacy is the ability to meet the reliability standard, 0.002% USE standard.

Further details regarding generation capacity changes are outlined in Tables A.1 and A.2 in Appendix A.

4.1.3 National Transmission Network Development Plan 2015

AEMO published the 2015 NTNDP in November 2015.[51] The purpose of the NTNDP is to facilitate the efficient development of the national transmission grid. It does this by providing a strategic view of the efficient development of the grid over a 20-year planning horizon. This includes consideration of forecast constraints on national transmission flow paths. A key consideration in the 2015 NTNDP is the impact of renewable energy and the expected increase in solar PV on the transmission networks.

Transmission network investment profile

A shift in the nature of transmission investment has occurred in conjunction with the recent decline in consumption per capita. There has been a movement away from augmenting network capacity to the replacement of aging assets. Transmission development has also been influenced by an increasing focus on the connection of large-scale renewable generation, driven by various climate change policy incentives.

The NTNDP notes that the total annual investment in transmission networks across the NEM has decreased from $1,282 million in 2008-09 to $745 million in 2014-15.[52] Out of this total investment, the proportion dedicated to increasing (augmenting) the network's capacity has fallen from 75% in 2008-09 to 15% in 2014-15.

As a reflection of the current environment, the NTNDP's projections for investments in new infrastructure to address transmission network capacity limitations have fallen significantly over the previous years. Only $800 million in new transmission infrastructure expenditure is projected over the next 20 years, which is a steep decline from the $8 billion which was forecasted in the 2010 NTNDP.

The changing environment

Since 2010, the large-scale renewable energy target (LRET) has been a major driver of network and generation development plans.

Currently the LRET is 33,000 GWh by 2020. Based on this LRET, the 2015 NTNDP forecasts between 4,200 MW and 6,700 MW of additional large-scale renewable generation will be installed across the NEM by 2020. The majority of this additional generation is expected to come from wind and large-scale solar PV sources and is expected to replace thermal synchronous generation such as coal and gas-fired generation. In light of these changes, transmission networks have had an increasing focus on how to best integrate renewable generation and the implications this has for the reliable, safe and secure operation of the networks.

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51 AEMO, *National Transmission Network Development Plan – For the National Electricity Market,* November 2015.

52 Nominal values are expressed in 2014-15 dollars.

The role of networks in future years is also expected to be influenced by residential battery storage. In order to forecast the amount of capacity to be storable in residential batteries by 2035, the 2015 NEFR modelled the rate of battery storage uptake under two scenarios, 'gradual evolution' and 'rapid transformation':

- under a 'gradual evolution' scenario, operational consumption continues to increase in line with the 2015 NEFR medium scenario and there is a gradual penetration of residential electricity storage to 8 GWh installed by 2035; while
- under a 'rapid transformation' scenario, operational consumption increases in line with the 2015 NEFR low scenario, and is reduced further by greater rooftop PV uptake,[53] which results in a 40% penetration of residential battery storage[54] by 2035.

Emerging challenges in managing the power system

As the level of wind and solar PV generation increases (along with potential battery storage), and thermal synchronous generation withdrawal continues, the secure operation of the transmission network will become more challenging. This is particularly when demand is low and output from renewable generation is high.

As a result of these changing conditions, the NTNDP notes the following challenges:

1. Less dispatchable generation: The increasing level of rooftop solar PV generation will reduce the proportion of generation controllable through the central dispatch process.

2. Inertia and frequency control requirements: Regions with high proportions of large-scale renewable and embedded generation may become more dependent on interconnection to other regions for inertia and network support services that maintain power system security.

3. Voltage stability during faults: Synchronous generators provide dynamic voltage support to the power system, particularly during and immediately following network faults. Withdrawal of these generators reduces voltage stability in the surrounding area, meaning will be larger voltage fluctuations during network faults.

Proposed work

AEMO is leading an ongoing program of work to evaluate the current and future impact of these challenges on power system operation. This work will also identify feasible solutions to assist in maintaining power system security and reliability. The 2016 NTNDP will present potential network and non-network options to address the emerging challenges identified in the 2015 NTNDP and renewable integration studies.

53 33.3 GW installed capacity by 2034-35, compared to 20.9 GW in the 'gradual evolution' scenario.

54 19.1 GWh installed capacity.

The 2015 NEFR also included, for the first time, a forecast for minimum demand for South Australia. It is intended that this minimum demand forecast analysis be applied to the other NEM regions. As rooftop PV and battery storage become more prevalent across the NEM, minimum demand forecasts will become more useful in examining network stability. Managing network voltages during these periods will also present challenges. To address this risk, increased use of network support and control ancillary services (NSCAS) may be required.

4.2 Energy adequacy assessment projection

AEMO is required to publish an energy adequacy assessment projection (EAAP) each quarter.[55] The EAAP is an information mechanism that provides the market with a two-year outlook on the effect of energy constraints in the NEM.[56]

The EAAP provides analysis of the potential effects of energy supply limitations for each region under three scenarios: low rainfall, short-term average rainfall, and long-term average rainfall, the outcome of which is potential periods of unserved energy. Monthly unserved energy projections for each region are provided, taking into consideration the changes in committed generating plant availability.

AEMO published an EAAP covering the period from 1 July 2014 to 30 June 2016.[57] This EAAP determined that the forecasted unserved energy is within the reliability standard of 0.002% for all regions, in both years, and for all scenarios.

An EAAP published in September 2015 considers the period from 1 October 2015 to 30 September 2017. The conclusion in this EAAP was that the NEM has adequate energy supply to meet projected electricity consumption over the next two years in all regions. Hence no unserved energy is expected to be observed under any scenario and for any region. A further EAAP was published in December 2015.

Following the Basslink outage, AEMO published two updates on the EAAP (in January and March 2016). Despite the outage and record low dam levels AEMO did not forecast any USE in Tasmania.

Additional background information on the EAAP is provided in Appendix C.3.

4.3 Medium-term projected assessment of system adequacy

Medium-term projected assessment of system adequacy (MT PASA) assesses the adequacy of supply to meet demand at the time of anticipated daily maximum demand, based on a 10-year POE for each day over the next two years. AEMO

55 On 26 May 2016, the AEMC made a rule reducing the frequency with which AEMO must publish an EAAP to annually. However, AEMO can still issue an EAAP when it is necessary. See the AEMC's website: www.aemc.gov.au, viewed 22 August 2016..

56 Energy constraints refer to fuel shortages or constraints that limit the ability to use a generator, such as access to water for cooling or for hydro generation.

57 Energy Adequacy Assessment Projection, June 2014 Update, June 2014.

publishes the MT PASA for each NEM region weekly.[58] See Appendix C.4 for further details.

As the MT PASA is continually being updated by AEMO, the Panel notes that it is difficult to identify any specific period that was at risk of not achieving an adequate reserve level during 2014-15.

Where the MT PASA identifies a reserve shortfall, these conditions usually elicit a response from generators to make generation available by shifting a planned network outage or possibly returning to service sooner than scheduled. In addition, a NSP may reschedule a planned outage in order to make additional network capacity available if required.

During 2014-15, AEMO did not invoke the reliability and emergency reserve trading (RERT) mechanism (see section 4.7 for an additional explanation) indicating adequate reserves were expected to be available for the whole period.

4.4 Short-term projected assessment of system adequacy

In addition to MT PASA reports, AEMO also publishes short-term projected assessment of system adequacy (ST PASA) reports. As compared to the MT PASA, which makes projections over a two-year period, the ST PASA makes projections for the following seven-day period on a half-hourly basis.

In the shorter forecast period of the ST PASA, the demand forecasts produced by AEMO become more critical to allow market participants to respond to any potential reserve shortfalls. The demand forecasts used in the ST PASA are the 50% POE for each region and half hour period. These forecasts are based on historical metering records and expected weather patterns. It has generally been accepted that four hours is required for large scheduled generators to be ready for dispatch. In addition a demand side response may also require several hours to be made ready to respond. See Appendix C. 5 for further details.

Table 4.3 shows the average ST PASA demand forecast accuracy for two, four, and six days ahead. Each element of the table is the percentage discrepancy between the actual and forecast demand for the respective forecast period.

58 For further information see the medium term outlook section under the electricity data part of AEMO's website.

Table 4.3 Accuracy of ST PASA forecasts 2014-15

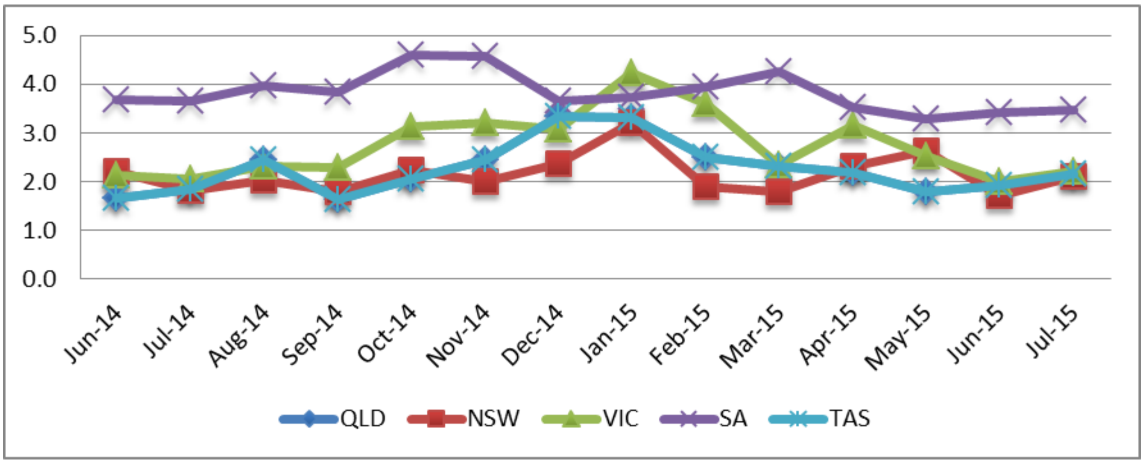
ST PASA demand forecast absolute percentage deviation	Queensland (%)		NSW (%)		Victoria (%)		South Australia (%)		Tasmania (%)	
	2013-14	2014-15	2013-14	2014-15	2013-14	2014-15	2013-14	2013-14	2013-14	2013-14
6 days ahead	2.60	2.84	2.50	2.78	4.50	3.54	3.90	7.63	7.00	4.68
4 days ahead	2.40	2.45	2.20	2.42	3.90	3.09	3.30	6.08	5.80	4.08
2 days ahead	2.10	2.26	2.00	2.15	2.90	2.73	2.00	5.17	5.20	3.82
12 hours ahead	1.90	1.88	1.70	2.02	2.60	2.47	2.30	4.40	4.70	3.47

Source: AEMO.

Typically, between 2013-14 and 2014-15, the forecast errors were fairly consistent for the Queensland, NSW and Victorian regions. The Panel notes improvements in the forecasts for Tasmania, and a deterioration in forecasts for South Australia. As expected, the shorter-time horizon forecasts were more accurate than the longer time forecasts.

Figure 4.2 displays the observed trends in the mean absolute percentage error for the two day ahead ST PASA over 2014-15.

Figure 4.2 Accuracy of 2-day ahead ST PASA forecasts 2014-15 (mean absolute percentage error)



Source: AEMO.

With reference to Figure 4.2, the mean absolute errors were higher for all regions during the summer months, except for South Australia, where the mean absolute error peaked during late spring, and remained consistently high. Typically, the mean absolute percentage error was lowest during the winter months.

4.5 Pre-dispatch

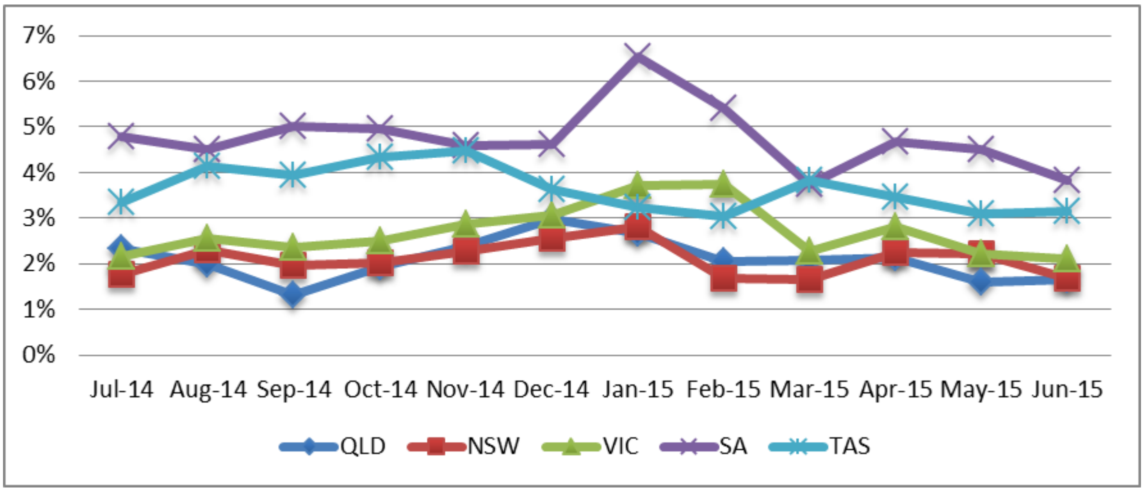
Pre-dispatch provides an aggregate supply and demand balance comparison for each half-hour of the next trading day. This information is provided to the relevant participants to assist with their operations management.

AEMO introduced a demand forecasting system in November 2011 to its market systems. AEMO currently uses this system to forecast electricity demand for the five NEM regions and 22 sub-regions. Originally, only four sub-regions were forecasted, however this number increased to 22 in early 2013.

The demand forecasting system generates half hourly forecasts for up to eight days, with these forecasts updated every half hour. The forecasting system has delivered greater accuracy for NEM regional demand forecasts in near real-time, compared to the previous manual forecasting process. The Panel notes that AEMO has indicated that the system has helped to improve alignment between dispatch and pre-dispatch. Furthermore, the system has also delivered greater accuracy for sub-regional demand forecasts up to eight days ahead compared to the previous method of deriving sub-regional forecasts by scaling NEM regional forecasts.

The Panel has considered the accuracy of the pre-dispatch demand forecasts on a 12-hour-ahead basis. Figure 4.3 below shows that the accuracy deteriorates during the summer months. The pre-dispatch demand forecast was the least accurate in the South Australian region.

Figure 4.3 Accuracy of 12-hour ahead pre-dispatch demand forecasts (mean absolute percentage error)



Source: AEMO.

The accuracy of 12-hour ahead pre-dispatch forecasts has been improving. However, perfect alignment between dispatch and pre-dispatch outcomes cannot be expected as the dispatch process utilises more complex constraint equations and real-time information whereas pre-dispatch uses less complex constraint equations and approximation of some terms in those equations. In addition, there may be differences between the dispatch and pre-dispatch outcomes in any case due to unexpected transmission or power station outages or unforeseen changes in demand for example.

Information has also been compiled regarding the performance of the four hour ahead pre-dispatch demand forecast during 2014-15. That supplementary information is provided in Appendix C.6.

The Panel notes that AEMO routinely reviews the performance of the pre-dispatch process in order to continuously implement updates and improvements to constraint information where possible.

4.6 Trading intervals affected by price variation

The Panel has considered the number of trading intervals affected by significant variations between pre-dispatch and actual prices during 2014-15 as well as likely reasons for the variations.[59] The data that the Panel has considered is disclosed in Table 4.4.

59 Significant price variations are defined in clause 3.13.7(a) of the NER. Under this clause, the AER must determine whether there is a significant variation between the spot price forecast and actual spot price. The AER must then review the reasons for the variation. The AER does this in each of its electricity weekly reports.

Table 4.4 Number of trading intervals affected by price variation

Price variation reasons	Queensland		NSW		Victoria		South Australia		Tasmania	
	No.	(%)	No.	(%)	No.	(%)	No.	(%)	No.	(%)
Demand	1,210	55.5	466	49.9	875	56.6	1,394	55.8	910	18.9
Availability	635	29.1	337	36.1	509	32.9	796	31.9	3,908	81.0
Combination	336	15.4	130	13.9	161	10.4	302	12.1	-	0.0
Network	-		0	0.0	2	0.1	5	0.2	5	0.1
Total intervals affected	2,181		933		1,547		2,497		4,823	
Total significantly affected intervals	1,775	10.1	820	4.7	1,426	8.1	2,107	12.0	4,730	27.0

Source: AER.

By way of example, Tasmania experienced 4,823 trading intervals that were affected by price variations in 2014-15. Of these trading intervals 4,730 were deemed significant representing 27% of all of the trading intervals in the NEM in 2014-15.[60] Of the trading intervals with significant price variations in Tasmania, 3,908 (81%) were due to changes in plant availability while 910 (18.9%) were due to changes in demand.

A comparison of the regions shows that Tasmania reported the highest number of significant price variations in 2014-15 with most of these variations caused by plant availability.

In contrast, typically demand was the major cause of affected trading intervals in other regions. The Panel notes that between 2013-14 and 2014-15, the number of trading intervals affected by price variations has deteriorated in every NEM region except for South Australia which posted a very minor improvement.

4.7 Reliability safety net

AEMO has the power to contract for the provision of reserves through the reliability and emergency reserve trader (RERT) to maintain power system security and reliability.[61] The RERT allows AEMO to contract for reserves up to nine months ahead of a period where reserves are projected to be insufficient to meet the reliability standard. During 2014-15, AEMO did not exercise the RERT or contract for any reserves.

AEMO may also direct a registered participant to take specific action in order to maintain or re-establish the power system to a secure operating state, a satisfactory operating state, or a reliable operating state.[62] Where a direction affects a whole region, intervention or 'what if' pricing would be required. Under 'what if' pricing, the spot price is determined as if the direction had not occurred. The purpose of 'what if' pricing is to preserve the market signals that would have existed had the intervention not been taken. In addition, it is used as the dispatch price and market ancillary services prices for the purposes of spot price determination and settlements. Section 5.4.1 of this report sets out information on power system directions issue by AEMO in 2014-15.

4.8 Wind forecasts

The Australian wind energy forecasting system was implemented by AEMO in a two stage process. 'Phase 1' of the project was implemented internally in 2008 and then 'Phase 2' was completed in June 2010. The development of the system was funded by the then Commonwealth Department of Resources, Energy and Tourism involving a

60 There were 17,520 trading intervals in the NEM in 2014-15.

61 The RERT is subject to a rule change request. See the AEMC's website: www.aemc.gov.au.

62 NER clause 4.8.9.

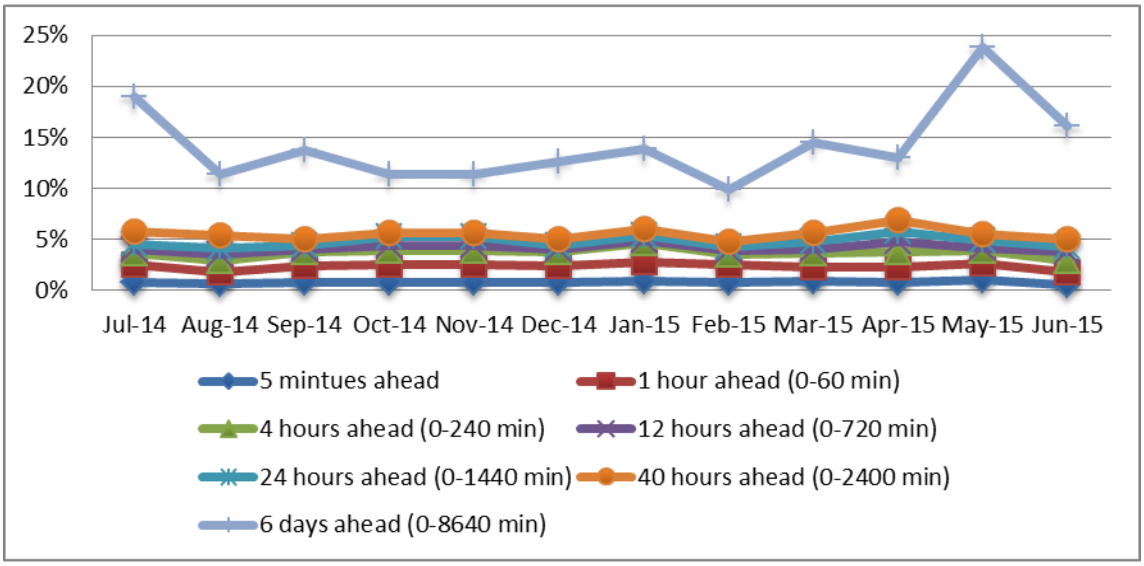
'world first 'integrated system designed specifically for the NEM by a European consortium[63].

The Australian wind energy forecasting system was developed by AEMO to fulfil its obligation under clause 3.7B of the NER, to prepare forecasts of the available capacity of semi-scheduled generators. It involves statistical, physical and combination models to provide wind generation forecasts using a range of inputs including historical information, standing data (wind farm details), weather forecasts, real time measurements and turbine availability information.

As set out in previous sections, the Panel recognises that wind generation capacity in the NEM is expected to continue to grow under Australia's LRET. On this basis, the Australian wind energy forecasting system will continue to be an important tool for promoting efficiencies in NEM dispatch, pricing, network stability and security management.

The Panel has considered the performance of Australian wind energy forecasting system based on the average percentage error across all regions in the NEM. The performance for 2014-15 is depicted in Figure 4.4. As could be expected, the accuracy of the forecasts deteriorates as the forecast horizon increases. The highest normalised absolute error values correspond to situations when forecasting is difficult, for example, when there is high or low wind speed.

Figure 4.4 Australian wind energy forecast system performance in 2014-15 (normalised mean absolute error)

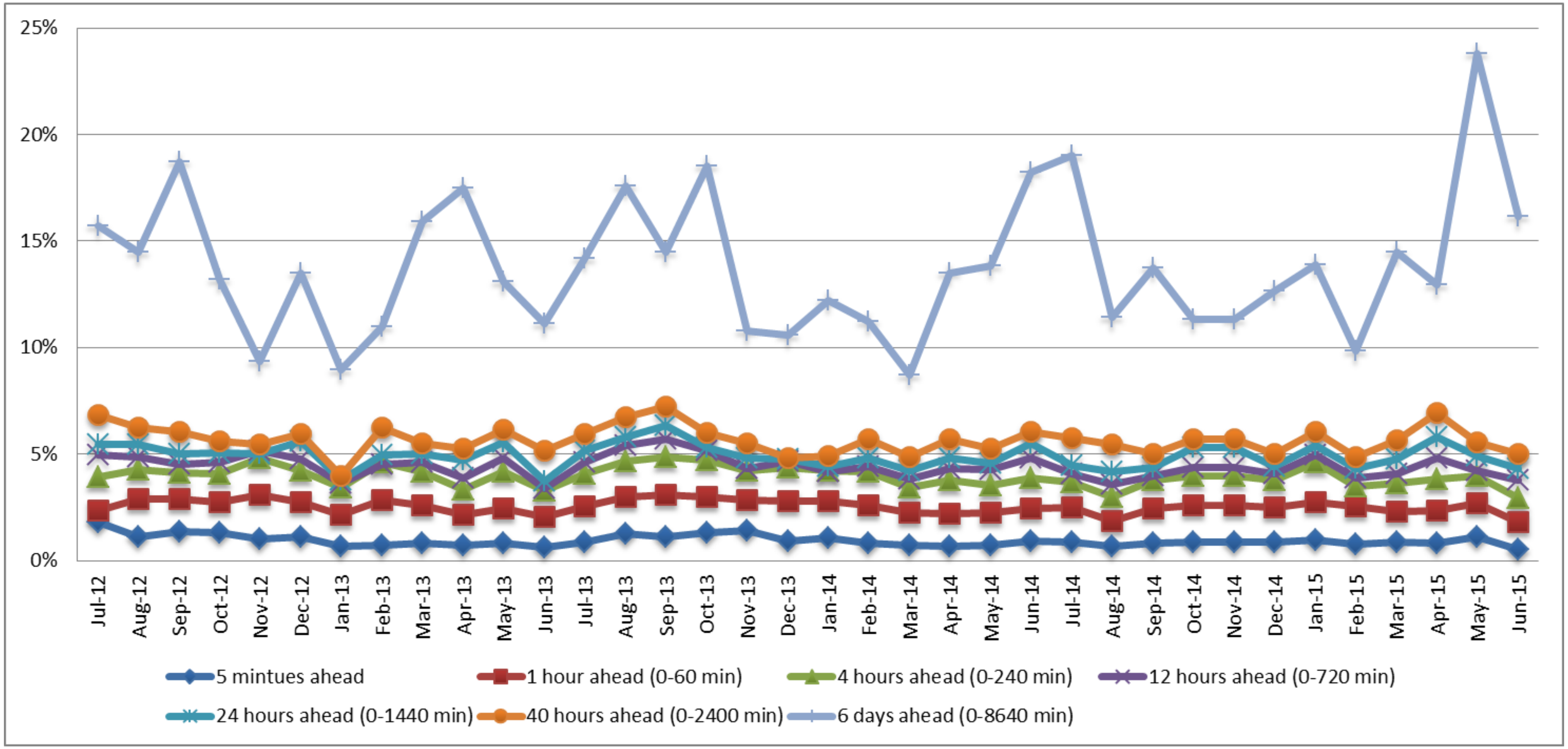


Source: AEMO.

63 AEMO, *Australian Energy Forecasting System (AWEFS)*, September 2014.

Figure 4.5 shows the performance of the system over a number of years, specifically from 2012-13 to 2014-15. It shows that the forecast error of Australian wind energy forecasting system has been relatively steady over the past three financial years. In particular, the addition of three extra wind farms in 2013 did not significantly affect forecast performance.

Figure 4.5 Australian wind energy forecasting system performance 2012-13 to 2014-15 (normalised mean absolute error)



Source: AEMO.

In the AMPR 2014 final report, the Panel agreed to look at ways to incorporate any new statistical parameters on the accuracy of AEMO's wind forecasts in response to a stakeholder comment.[64] The Panel has discussed this comment with AEMO and are of the view that the existing measures are the best statistical measures available at this moment.

However, the Panel notes that AEMO is currently consulting on changes to its wind and solar energy conversion model guidelines to resolve an identified issue with the accuracy of the wind forecasting system's dispatch forecasts.[65]

In general, the system has improved AEMO's ability to forecast wind energy dispatch which has assisted the reliability and security of the NEM.

4.9 Solar rooftop PV forecasts

This section of this report has been included following the recommendation made in the AMPR 2014 final report to include available information on PV forecasts in future AMPR reports.[66]

In response to the rapid expansion of solar generating capacity in the NEM, AEMO has forecast residential and commercial solar PV capacity separately for the first time, as outlined in the 2015 NEFR as well as the expected installed capacity for 2014-15.[67]

Table 4.6 shows the short-term (2017-18), medium-term (2024-25) and long-term (2034-35) forecast residential and commercial solar PV uptake outlook, as well as the installed capacity for 2014-15 forecast in the 2015 NEFR.

64 Reliability Panel, *Annual market performance review 2014, Final report*, 16 July 2015, p35.

65 See www.aemo.com.au/Consultations/National-Electricity-Market/Energy-Conversion-Model-Guidelines-Consultation-Wind-and-Solar-Farms, viewed 4 May 2015.

66 Reliability Panel, *Annual market performance review 2014, Final report*, 16 July 2015, p36.

67 PV systems with less than 10kW are classed as 'residential' whereas systems over 10kW are classed as commercial.

Table 4.5 Residential and commercial rooftop PV installed, and forecasted generation

	Residential PV		Commercial PV		Total	
	MW	GWh	MW	GWh	MW	GWh
2014-15	3,700	4,518	497	535	**4,197**	**5,053**
2017-18	5,550	6,949	1,149	1,363	**6,699**	**8,312**
2024-25	9,919	12,736	2,942	3,690	**12,861**	**16,426**
2034-35	15,083	19,504	5,808	7,398	**20,891**	**26,902**

Source: AEMO, *2015 National Electricity Forecasting Report for the National Electricity Market,* June 2015

In the 2015 NEFR, AEMO notes that:

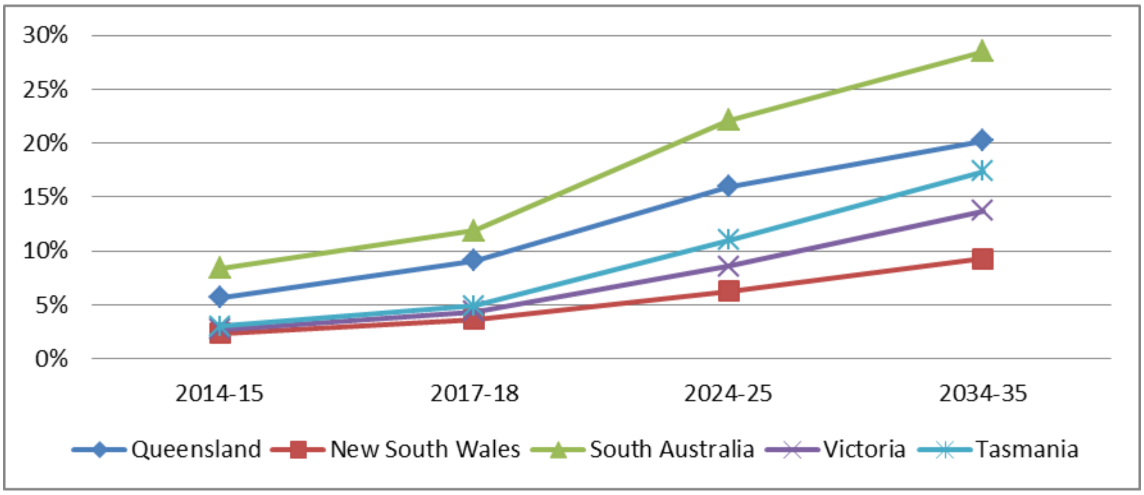
- Residential PV uptake continues to be driven by the federal small-scale renewable energy scheme (SRES) and the increasing economic viability of rooftop PV. The programs that incentivised historical uptake have helped to establish a local industry and drive reductions in the cost of PV technology and installation. AEMO forecasts that residential PV uptake will begin to slow after 2024-25 as it begins to reach saturation levels.

- Commercial sector PV uptake has occurred more recently. It has been driven by government initiatives such as the Clean Technology Investment Fund and SRES. In addition, the continued decrease in PV costs is making the business case more attractive. A continuing focus by businesses on sustainability initiatives and an increased marketing push by installers are also factors in the uptake. AEMO forecasts a continued increase in commercial sector PV uptake driven by stronger penetration of small commercial installations (between 10kW and 100kW of capacity).

AEMO also identifies that South Australia and NSW will continue to have the largest and lowest relative proportion of rooftop PV generation relative to total underlying consumption of all the NEM regions respectively.

Figure 4.6 shows the relative portion of rooftop PV generation to total residential and commercial consumption forecast by AEMO for each NEM region over time.

Figure 4.6 Proportion of rooftop PV generation relative to residential and commercial underlying consumption in each NEM region (%)



Source: AEMO, *2015 National Electricity Forecasting Report for the National Electricity Market,* June 2015

5 Security performance

Under clause 4.3.1 of the NER, AEMO has the principal responsibility for the secure operation of the power system. NSPs are required by the NER to assist AEMO in the discharge of its power system obligations.

This chapter presents the Panel's review of the market's performance from a power system security perspective for 2014-15. It reports on some of the critical physical elements of the power system such as voltage and frequency which impact on security.

5.1 Network constraints

The ability to transfer power across the system is limited by a number of factors including the capacity of the network.[68] Secure operation of the power system requires AEMO to maintain power flows within the capability of the network after allowing for credible contingencies.

NEMDE maximises the value of spot market trading in energy and ancillary services, subject to constraints designed to manage system security. Market participants make bids and offers to consume or produce electricity at various prices in each five minute dispatch interval in a day. Each generator's offers are combined into a merit order, and then dispatched by AEMO based on these bids, offers, constraints and other market conditions.

Where network constraints bind, generators may need to be dispatched from higher in the merit order, potentially resulting in increased wholesale prices. Constraints also represent the physical realities of the network, including network outages, which may affect customer's supply of electricity. Congestion is measured by the frequency and extent to which network constraints bind.

Increased congestion can result from a range of activities and does not necessarily indicate a reduction in network transfer capability. For instance, new generation located a significant distance away from a load centre may increase competition for existing transmission capacity, and so lead to increased congestion on the network.

AEMO publishes information on constraints in the NEM annually.[69] This section provides information about congestion patterns in the NEM over the previous five years.

68 The capability of the network to transfer power depends on a number of factors including the capacity of network elements as indicated by their thermal and fault rating and the availability of spare capacity to accommodate sudden load increases following contingencies and the availability and location of generation and reactive plant that define voltage and stability related power transfer limits.

69 AEMO, NEM constraint report 2014 – for the National Electricity Market, April 2015, p.6.

Network constraint changes

The total number of network constraint changes in a period gives an indication of how the power system is changing. It captures alterations to both the transmission network and the connected generation

Table 5.1 displays the yearly constraint changes since 2010 in NEMDE.

Table 5.1 Number of constraint changes in the NEMDE

Year	Constraint changes
2010 calendar year	6,250
2011 calendar year	4,776
2012 calendar year	4,130
2013 calendar year	5,817
2014 calendar year	8,121
2015 calendar year	11,967

Source: AEMO, *NEM constraint report 2015*, May 2016, p.1.

The annual number of constraints changes declined between 2010 and 2012. However, there was an increase from 2013, with a 40 per cent change in 2013 from the previous calendar year.

In 2014, there were 8,121 constraint changes - the largest number of changes since 2010. This was mainly due to:

- changes to connected generation in the NSW region, following the registering of three new large wind farms and de-registering of four existing generators.[70] These generation changes resulted in 4,817 constraint equation changes – the highest number ever for any NEM region and 53 per cent of all changes in the NEM in 2014; and

- the establishment of the Mt Mercer generator in Victoria (registered in 2013).[71]

Table 5.2 outlines the top five binding constraints impacting the NEM during 2014-15. Binding network constraints have an impact on market participants by constraining generation to ensure system security is maintained. Increasing levels of binding network constraints are an indicator that network augmentation may need to be assessed through the RIT-T to relieve those constraints. Binding constraints may also lead to customer load shedding in order for the network to remain in a secure state.

70 AEMO, *NEM constraint report 2015*, April 2015, p.6.

71 AEMO, *NEM constraint report 2015*, April 2015, p.6.

Table 5.2 Top five binding constraints impacting the NEM during 2014-15

Constraint	Hours binding	Description
N_X_MBTE_3A N_X_MBTE_3B	1,544	These outage constraints were invoked when all three Directlink cables were put out of service. In 2014-15, all three cables were unavailable for 58 days due to a rebuild of the Mullumbimby converter station.
V>>V_NIL_2A_R V>>V_NIL_2B_R V>>V_NIL_2_P	1,178	These are thermal limits which mainly restrict Victorian export to NSW across the F1 transformer at South Morang. AEMO (Victorian TNSP) is monitoring the market benefits of removing this constraint by installing a second transformer.
Q:N_NIL_AR_2L-G	1,096	This is a system normal transient stability constraint, which acts to limit Queensland's exports to New South Wales.
V:N_NIL_xxx	1,021	This is a system normal transient stability constraint, which acts to limit Victorian exports to the region as a whole. With an increase in Victorian generation, this constraint would bind more often.
Q>NIL_BI_FB	1,178	This is a system normal thermal constraint, which limits generation from Gladstone Power Station, predominantly from the units connected at 132 kV. During 2014-15, the 132 kV connected units generated more energy than in the prior three years.[72]

Source: AEMO.

72 Powerlink 2015 Transmission Annual Planning Report.

5.2 Market notices

Market notices are ad hoc notifications of events that impact the market, such as advance notice of low reserve conditions, status of market systems or price adjustments. They are electronically issued by AEMO to market participants to allow a more informed market response.[73]

AEMO issued 3,268 market notices during 2014-15, compared to 3,148 in 2013-14. The number and type of market notices issued by AEMO are summarised in Table 5.3.

Table 5.3 Market notices issued by AEMO in 2013-14 and 2014-15

	Number of notices	
Type of notice	**2013-14**	**2014-15**
Administered price cap	0	0
General notice	239	123
Inter-regional transfer	150	249
Market intervention	7	9
Market systems	117	86
Manual priced dispatch interval	0	0
NEM systems	0	1
Non-conformance	724	617
Power system events	85	87
Price adjustments	6	0
Prices subject to review	210	213
Prices unchanged	202	210
Process review	0	0
Reclassify contingency	1,040	1,440
Reserve notice	339	194
Settlements residue	29	20
Total	**3,148**	**3,268**

Source: AEMO, Market Notices: http://www.aemo.com.au/Electricity/Data/Market-Notices.

73 In accordance with rule 4.8 of the NER.

The Panel considers market notices to be an effective method of communicating with market participants and the wider public to inform them of real time operational matters.

5.3 Power system performance

AEMO has a number of on-line monitoring tools, which track the performance of the power system in real time and alert power system controllers when the power system is outside pre-determined parameters. These "excursions" vary in duration.

This section examines whether key power system quantities such as frequency and voltages were maintained at the levels required in system performance standards during 2014-15. The section also examines performance from the perspective of power system stability.

Appendix F provides further information of the systems standards including references to relevant clauses in the NER defining the standards.

5.3.1 Frequency

The control of power system frequency is a crucial element of managing power system security. The frequency of the power system reflects the balance between power system demand and adequacy of generation. For instance, if a generator were to suddenly trip and not be available then the frequency would fall as there would be insufficient generation to supply the demand.

Generally in the NEM, a single generator trip would not produce an event that would result in the frequency changing significantly. However if a group of generators were to trip then depending upon the amount of loss of generation the frequency may fall outside the frequency operating standards. Also if the demand were to increase without a corresponding increase in generation then the frequency would also fall.

If the frequency deviation was too low and remained outside the frequency operating band long enough, automatic protection systems would operate and trip load to bring the frequency back to within the frequency operating standards. Alternatively, if the frequency was too high for an extended period, generators would be tripped to bring the frequency back within operating standards.

The Panel has considered the number of times during 2014-15 where events have been outside the frequency operating standards. There are two separate operating standards in the NEM: one for the mainland; and one for Tasmania.[74]

Figure 5.1 shows that during 2014-15, both the mainland and Tasmania frequencies remained within the normal operating frequency band more than 99 per cent of the time. This is in accordance with the frequency operating standards.

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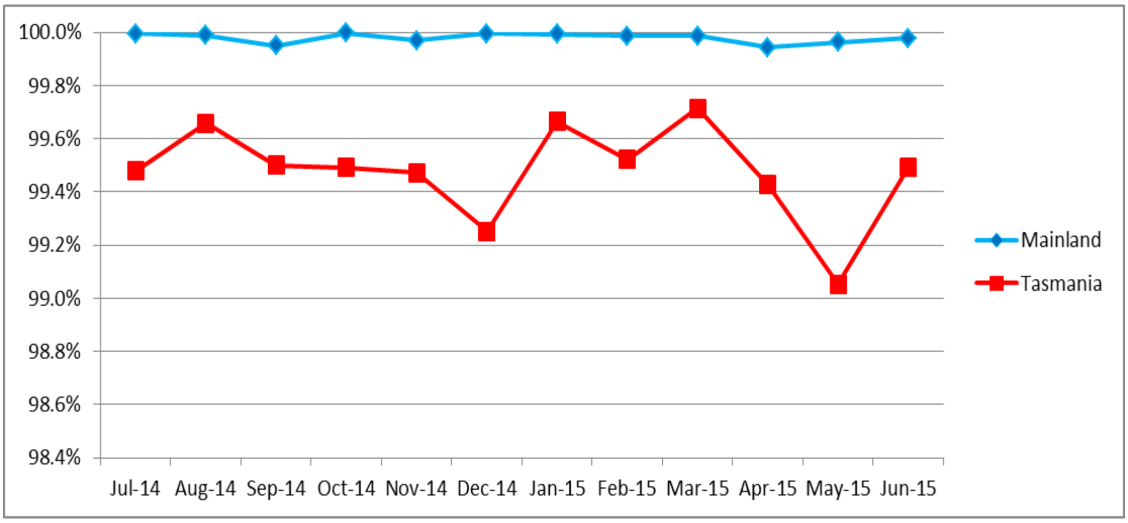
74 The mainland and Tasmanian frequency standards are outlined in Appendix F.

Figure 5.1 Percentage of time within the normal operating frequency band



Source: AEMO.

The percentage of time within the normal operating frequency band was less for both the mainland and Tasmania in 2014-15 than in 2013-14. For example, in the mainland there were 6,640 seconds outside the normal operating frequency band in 2014-15 compared with 2,656 in 2013-14. These results are further explained below.

Mainland NEM

There were no incidents during 2014-15 that resulted in the frequency operating standard not being achieved across the mainland NEM regions.

Tasmania

On two occasions in December 2014, and in February 2015, the Basslink high-voltage direct current (HVDC) link was interrupted due to faults in the Tasmanian 220kV system leading to tripping of industrial load in Tasmania.

The HVDC link was lost because multiple commutation failures were sustained, which had not occurred previously. After extensive modelling, AEMO reclassified certain contingencies in the Tasmanian networks, which arose as a temporary measure, in order to address any risks to system frequency that remained.

5.3.2 Voltage limits

Satisfactory voltage limits represent the minimum or maximum safe operating level of a network asset set by the asset owner and which should not normally be exceeded. A secure voltage limit is the normal minimum or maximum operating limit of a network asset such that, post contingency, voltage levels will not exceed the satisfactory limits.

It is possible for secure limits to be exceeded for short durations. In accordance with clause 4.8.15(a)(1)(iv) of the NER, AEMO must correct any breaches as soon as possible but within a maximum of 30 minutes. During 2014-15, there were no instances where secure voltage limits exceeded 30 minutes.

5.3.3 Power system stability

Transferring large amounts of electricity between generators and consumers over long distances can potentially compromise the stability of the power system. As system operator of the NEM, one of AEMO's obligations is to ensure that stability of the power system is adequately maintained. The primary means of achieving this is to carry out technical analysis of any threats to stability.

Generators and TNSPs are required to monitor indicators of system instability, such as responses to small disturbances, and report their findings to AEMO. AEMO is then responsible for analysing the data and determining whether the performance standards have been met. AEMO also uses this data to confirm and report on the correct operation of protection and control systems.

AEMO has a number of real-time monitoring tools, which help it meet its security obligations. These tools use actual system conditions and network configuration accessed in real-time from AEMO's electricity market management system. These tools include:

- Contingency analysis: an online tool used to ensure that all power system equipment remains within its designed capability and ratings.
- Phasor Point and Oscillatory Stability Monitor: Phasor Point is an online tool, which utilises phasor monitoring equipment installed at five locations across the NEM to detect underdamped oscillatory phenomena in the power system that could lead to a security threat.[75] The Oscillatory Stability Monitor uses the same measurements and produces parameter estimates of the three global oscillatory modes in the NEM based on a modal-identification algorithm. Data from both systems is stored to facilitate historical analysis of power system damping performances.
- Dynamic Security Assessment and Voltage Security Assessment Tool: this online security analysis tool simulates the behaviour of the power system for a variety of critical network, load and generator faults. The Dynamic Security Assessment undertakes transient stability analysis while the Voltage Security Assessment Tool is used for voltage stability analysis. Historical results are also stored for examination of power system performances as required.
- NEM-wide high-speed monitoring system that is installed and maintained by the TNSPs. This high-speed monitoring system provides visibility of the behaviour

75 Underdamped oscillatory phenomena refers to oscillatory stability or the ability of the power system to maintain synchronism after being subjected to a small perturbation without application of a contingency event.

of the power system during stability disturbances, which is particularly useful for post-event analysis.

AEMO's review of significant events in recent times shows that system damping and fault ride-through performances are generally within stipulated requirements. However, AEMO has highlighted the need to maintain adequate monitoring so that possible causes of instability can be located and addressed in a timely manner.

There have been a number of occasions, including in 2014-15, where these real-time monitoring tools have identified the need to reduce transfer capability.

On these occasions, the power system conditions at the time were used to review the transfer limits. This is because when the transfer limits were originally determined, these combinations of dispatch scenarios, power system configurations and faults may not have been considered due to their low likelihood of occurrence. In time, this analysis may lead to transfer limit functions being developed that could accurately deal with a broader range of more unusual power system configurations.

The Panel recognises that power system stability is a highly technical area that is not well understood by the market. AEMO has developed a number of analysis tools, as well as a program of installation monitoring tools to assist it monitor the stability of the power system. The NER also requires AEMO to co-operate with relevant NSPs to apply the power system stability guidelines.[76]

5.3.4 System restart standard

The Panel determines the system restart standard (SRS) that applies to the NEM.

The SRS sets out several key parameters for power system restoration, including the timeframe for restoration and how much supply is to be restored. The standard provides AEMO with a target against which it procures system restart ancillary services (SRAS) from contracted SRAS providers, such as generators with SRAS black start capability.

In the event of a major supply disruption, SRAS may be called on by AEMO to supply sufficient energy to restart power stations in order to begin the process of restoring the power system. AEMO's development of the System Restart Plan must be consistent with the Standard. The purpose of SRAS is to restore supply following an event that has a widespread impact on a large area – such as an entire jurisdiction.

The SRS does not relate to the process of restoring supply to consumers directly following blackouts within a distribution network or on localised areas of the transmission networks. In addition there is a separate process, developed with input of jurisdictional governments to manage any disruption that involves the operator on a network having to undertake controlled shedding of customers. Restoration of load from these localised or controlled events is not covered by the Standard.

76 NER clause 4.7.1(a).

AEMO has never drawn on procured SRAS, including in 2014-15. However, during the year it undertook a tender process for procuring system restart services for the period 1 July 2015 to 30 June 2018. In June 2015, AEMO announced the outcome of its procurement of SRAS for that period. As a result of this tender, the total amount AEMO expects to spend on the acquisition of SRAS dropped from $55 million a year in 2014-15 to $21 million a year in 2015-16, representing a reduction of 62 per cent, which is still higher than the cost of SRAS in the period before 2007-08.[77]

The current SRS was determined by the Panel in 2012. On 2 April 2015, the AEMC made a rule changing the requirements on AEMO relating to the procurement of SRAS and on the requirements for the standard. As a result of this rule change the AEMC require the Panel to review the SRS to meet the revised rule requirements. The Panel received terms of Rreference from the AEMC on 30 June 2015 to undertake this review.

The Panel also notes that, since 1 July 2015, AEMO is required to report annually on matters related to system restart services. This was requirement was placed on AEMO as part of the AEMC's system restart ancillary services final rule determination discussed in section 7.2.3.

5.4 Power system directions

Under clause 4.8.9 of the NER, AEMO has the power to either issue directions as a last resort measure; or to contract for the provision of reserves through the reliability and emergency reserve trader (RERT) mechanism, in order to maintain power system security and reliability.

5.4.1 Power system directions issued by AEMO in 2014-15

During 2014-15, AEMO issued two power system security directions, both of which were for Tasmanian generators.

Direction to Basslink and Tasmania generator (16 December 2014)

On 16 December 2014, AEMO reclassified the loss of the Gordon – Chapel Street No.1 and No.2 220 kV transmission lines and a radial power station in Tasmania as a credible contingency. This was a result of faults on the Tasmanian 220kV transmission system which resulted in the loss of the Basslink interconnector and the islanding of Tasmania from the NEM. This increased the requirement for contingency raise frequency control ancillary service (FCAS) to cover the loss of the power station and its enabled FCAS.[78]

Within an hour, AEMO reclassified the loss of the Basslink interconnector with any transmission line in Tasmania as a credible contingency, requiring all contingency

77 This tender process was completed on 2 July 2015: AEMO, *System restart ancillary services 2015, Tender process report*, 2 July 2015.

78 FCAS are those services required by a power system operator to ensure short-term supply and demand balancing throughout a power system.

FCAS to be locally sourced. To achieve this, AEMO directed Basslink to turn off its frequency controller. The local FCAS requirement for the Gordon – Chapel Street contingency was then violated for the next 14 dispatch intervals.

To remove these violations and restore power system security in Tasmania, AEMO issued a direction to a Tasmanian generator to reduce output from its power station and so lower the requirement for contingency FCAS.

Ultimately, AEMO withdrew the Gordon – Chapel Street reclassification and cancelled the direction shortly after. AEMO later found it should have withdrawn the classification earlier. Without the error, the direction to the Tasmanian generator would have been unnecessary.

AEMO cancelled the direction to Basslink on 19 December 2014.[79]

Direction to Tasmanian generator (23 February 2015)

On 23 February 2015, both the Basslink interconnector and the Gordon – Chapel Street No.2 kV transmission line in Tasmania simultaneously tripped due to lightening. The trip caused a local requirement for contingency raise FCAS that was determined by a radial power station, which tripped with the loss of the remaining Gordon – Chapel Street line.

AEMO then issued a direction to a Tasmanian generator to reduce output. The aim was to remove violations of the local contingency FCAS requirement and to restore power system security in Tasmania. AEMO cancelled the direction after Basslink returned to service later that day.

5.4.2 Historical summary of AEMO issued power system directions

Table 5.4 sets out the number of power system directions issued by AEMO in the last ten years. It shows that there have been a low number of power system security directions in the last five years indicating the power system has been operating in a secure manner. Indeed, the number of directions issued by AEMO has also been declining over this period – the first five years had a high number of directions; while in recent years there have only been one or two directions each year.

79 For further information see: AEMO, *NEM Event – Gordon – Chapel Street Reclassification Scheduling Error – 16 December 2014*, August 2015.

Table 5.4 Number of power system security directions issued by AEMO over the past 10 years

Financial year	Qld	New South Wales	Victoria	SA	Tasmania	Total
2014-15	0	0	0	0	2	**2**
2013-14	0	1	0	0	0	**1**
2012-13	0	0	0	0	1	**1**
2011-12	0	0	0	0	0	**0**
2010-11	0	0	0	0	0	**0**
2009-10	5	1	0	1	1	**8**
2008-09	2	1	5	4	0	**12**
2007-08	5	0	0	1	1	**7**
2006-07	3	0	6	1	0	**10**
2005-06	1	52	0	0	8	**6**

Source: AEMO.

5.4.3 Use of the reliability emergency reserve trader mechanism

The RERT is a mechanism that allows AEMO to contract for reserves up to nine months ahead of a period where AEMO projects there to be inadequate electricity generation capacity, such as during periods of high demand. AEMO is also able to, where practicable, dispatch these additional reserves should an actual shortfall occur. The RERT acts as a safety net, typically used in rare events where ordinary market mechanisms are unlikely to deliver adequate electricity supply to meet market demand.[80]

No reserve contracts were entered into during 2014-15.

5.5 Power system incidents

The Panel assesses the number and types of power system incidents in the NEM. The Panel also assesses how AEMO manages the process of identifying and reviewing incidents in order to identify if there are any ways this process can be improved.

80 The AEMC has recently completed a rule change request on the extension of the RERT. See the AEMC's website: www.aemc.gov.au, viewed 22 August 2016.

This section provides information on the requirement for AEMO to review system incidents, a summary of the operating incidents that were reviewed during 2014-15, and key findings from the most significant of these incidents.

5.5.1 Changes to the NER regarding reviewing operating incidents

Prior to 2012, under clauses 4.8.15(b) and 4.8.15(c) of the NER AEMO was required to investigate every "reviewable operating incident" which occurs in the power system. The Panel determined, in its review of the guidelines for reviewable operating incidents, that not every power system incident was "of significance to the operation of the power system".[81] As such, the guidelines were amended effective from the start of 2013 so that a key focus for AEMO is to review non-credible contingency events.[82] Credible contingencies are studied as part of the normal network planning and operation process.

The capability and performance of the power system are generally determined by analysing the results from the reviews into non-credible and credible contingency events.

In addition, the guidelines set out that a reviewable incident can also be any incident that:

- results in the power system being in an unsatisfactory operating state for more than five minutes;
- has AEMO's on-line oscillatory and transient stability monitoring systems detecting a potential instability for 30 minutes, continuously;
- occurs on a distribution network and impacts critical transmission elements;
- results in the operation of under frequency or over-frequency protection and control schemes;
- the Reliability Panel requests AEMO to investigate due to its potential to be a threat to system security; and
- AEMO considers is of significance to the operation of the power system.

5.5.2 Reviewable operating incidents during 2014-15

During 2014-15, there were 28 incidents that were reviewed in accordance with the new operating incident guidelines as set out in Table 5.5.[83] AEMO published a report

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81 AEMC Reliability Panel, *Review of the guidelines for identifying reviewable operating incidents*, Final report, 20 December 2012.

82 A contingency event which results in more than one transmission element trips.

83 The guidelines for identifying reviewable operating incidents can found on the AEMC Reliability Panel website: www.aemc.gov.au.

for each of these events. Of these events, AEMO classified 16 as multiple contingency events.

Table 5.5 Reviewable operating incidents during 2013-14 and 2014-15

Event description	Number of incidents (2013-14)	Number of incidents (2014-15)
Transmission related incidents (excluding busbar trips)	20	16
Generation related incidents	2	1
Combined transmission/generation incidents	5	2
Busbar related reviewable incidents	8	5
Power system security related	1	4

Source: AEMO.

The number of events in 2014-15 was lower than the previous financial year which experienced 36 reviewable operating incidents (with 18 of these being classified as multiple contingencies). However, the total number of incidents per annum fluctuates significantly each year and there is no evidence of any trend regarding the annual number of incidents.

There were a number of events that resulted in a loss of customer load:

- one event in Victoria resulted in the loss of a major industrial customer;
- three events in Tasmania resulted in the interruption of over 400 MW of customer load in order to maintain power system security and which are discussed below; and
- one event in far north Queensland resulted in the loss of approximately 234 MW of customer load, which is also discussed below.

All remaining incidents did not result in the loss of customer load.

5.5.3 Major incidents

Based on the Panel's review of the power system incident reports published by AEMO, the Panel has considered the trip of multiple transmission lines in far north Queensland, and the multiple trips of the Basslink interconnector in detail.

The Panel considers these incidents are more significant on the basis that they:

- resulted in material levels of load shedding and directly impacted consumer's experiences; and/or
- involved multiple generation/network elements and therefore may indicate issues requiring more serious attention.

Relevant details from the selected major incidents are summarised and discussed as follows.

Trip of multiple transmission lines in far north Queensland on 21 January 2015

The incident involving the loss of multiple transmission lines in far north Queensland resulted in the loss of approximately 234 MW of load and 71 MW of generation. AEMO noted that the network was returned to normal after approximately 10 seconds, and customer load was fully restored within 15 minutes.[84]

At 1205 hours on Wednesday 21 January 2015, the simultaneous trip of lines 857 and 858 was reclassified as a credible contingency due to lightning. At 1740 hours, the same day, the simultaneous trip of Chalumbin-Woree 876 and 877 275 kV transmission lines (lines 876 and 877) were also reclassified as a credible contingency due to lightning.

Should a lightning strike occur and trip either pair of these lines the most likely outcome is that the parallel 132 KV network would overload and then trip as this network is generally not of sufficient capacity to supply far north Queensland.

At 1930 hours, lines 857 and 858 tripped due to lightning. Simultaneously, and unexpectedly, lines 7301, 7139 and 7254 also tripped. Lines 7388 and 7132 should have tripped, but did not. As a result the far north Queensland network was disconnected as expected but not as per the contingency plan. Far north Queensland customer load was lost, and generating units at Kareeya and Barron Gorge power stations tripped on under frequency.

The Panel notes that the network was returned to normal after approximately 10 seconds, and customer load was fully restored within 15 minutes, with network elements operated within limits. Power system security was maintained over the course of the incident.

In response to this incident, a revised contingency plan was developed by Powerlink.

The Panel considers the six market notices issued by AEMO over the course of the incident were appropriate.

84 AEMO, *Disconnection of far north Queensland on 21 January 2015 – An AEMO Power System Operating Incident Report for the NEM*, September 2015.

Tasmanian incidents from December 2014 to February 2015

These three incidents involve the loss of the Basslink HVDC link due to faults in the Tasmanian 220kV system leading to the operation of the Frequency Control System Protection Scheme and the disconnection of industrial load in Tasmania.[85]

TasNetworks advised that the faults on the Tasmanian 220kV system were cleared in accordance with the System Standard, with network protection and control systems operating as designed. Basslink also confirmed its control and protection systems also operated as designed.

The HVDC link was lost because multiple commutation failures were sustained, which had not occurred previously for Basslink. After extensive modelling, AEMO has retained an operating policy to reclassify certain contingencies to maintain power system security, which required additional FCAS in Tasmania.

The Panel notes the modelling work undertaken by AEMO and TasNetworks to better understand the interaction between Basslink and the Tasmanian power system during network faults. This modelling has shown that a set of circumstances remains possible for some locations on the Tasmanian 220 kV system (particularly for faults at connection points of major generating units) where a fault would lead to loss of both a major generating unit and Basslink. The Panel encourages relevant parties to continue to investigate ways of removing the risk of concurrent Basslink and generation trips.

5.5.4 Recent incidents outside the 2014-15 reporting period

Since the end of the 2014-15 reporting period, two major operating incidents have occurred in the NEM. These are:

- the trip of the Heywood interconnector in November 2015; and
- the trip and outage of the Basslink interconnector in December 2015.

As these events occurred in the 2015-16 reporting period they will be discussed in detail in the 2016 AMPR. However, we include a brief summary of these events below.

Heywood interconnector trip on 1 November 2015

As part of the upgrade of the Heywood interconnector, ElectraNet's switchgear upgrade at the South East substation in South Australia required multiple planned network outages for the South East - Heywood No. 1 and No. 2 275 kV transmission lines, in turn, in October and November 2015. During each line outage there was a credible risk of synchronous separation between South Australia and Victoria.

85 The Frequency Control System Protection Scheme is an automated control scheme that rapidly disconnects either excess generation or contracted load immediately following the unexpected loss of Basslink. The December 2014 and February 2015 incidents occurred during period of Basslink flow south in excess of 400 MW.

Therefore, AEMO invoked constraint sets during the outages to obtain 35 MW of regulating raise and lower FCAS from within South Australia, to maintain power system security. AEMO determined it was necessary to procure regulating FCAS on a pre-contingent basis to keep the power system secure during the outages.[86]

On 1 November 2015, the South East - Heywood No. 1 275 kV transmission line tripped, with this occurring while the No. 2 transmission line was out of service for a planned outage. The incident involved:[87]

- the South Australian power system partially separating from the interconnected power system;
- the loss of 160 MW of customer load and 11 MW of generation;
- frequency control problems in operating the islanded South Australia power system.

This incident was a reviewable operating incident under the NER. The NER require AEMO to 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.

AEMO concluded that:[88]

- an incompatible protection relay configuration led to the unexpected tripping of line 1 that, in turn, islanded the South Australia power system;
- importantly, under frequency load shedding operated as expected for this type of incident;
- the frequency standard in South Australia was breached during the period of islanded operation; and
- the South Australia power system was not in a secure operating state during this incident but this was resolved when South Australia was reconnected to the interconnected system.

AEMO and the AER have both reported on the incident itself, as well as the FCAS prices that occurred during October and November 2015.

More broadly, AEMO and ElectraNet have been investigating the implications for operating the South Australian power system with high levels of renewable generation and low levels of conventional synchronous generation in operation.[89] These studies highlight the increasing importance of the Heywood interconnector in the secure and reliable operation of the South Australian power system. AEMO has not identified any

86 AEMO, *NEM - Market Event Report - High FCAS Prices in South Australia*, December 2015.

87 AEMO, *Load Shedding in South Australia on Sunday 1 November 2015*, February 2016.

88 AEMO, *Load Shedding in South Australia on Sunday 1 November 2015*, February 2016.

89 AEMO and ElectraNet, *Update to Renewable Energy Integration in South Australia*, February 2016.

issues with the management of power system security in South Australia provided that South Australia remains connected to the remainder of the NEM via the Heywood interconnector and sufficient synchronous generation is connected in the South Australian power system.

However, AEMO and ElectraNet have identified potential challenges for management of the South Australia power system in relation to AEMO's ability to meet the Frequency Operating Standards either during or following the loss of the Heywood interconnector, resulting in South Australia being separated from the remainder of the NEM. Similarly, AGL considers there is a need for further investigation into ways to manage frequency issues in a market moving to more renewable based generation.[90]

The Panel notes that these broader challenges have wide ranging impacts. We will continue to monitor developments in this area, with a more comprehensive analysis in the 2016 AMPR.

Basslink interconnector trip and outage on December 2015

On Sunday, 20 December 2015, a fault occurred on the Basslink Interconnector running between Victoria and Tasmania, separating Tasmania from the NEM. The interconnector was not returned to service until 13 June 2016.[91]

The outage along with low dam levels associated with low rainfall has led Hydro Tasmania to:

- return to service from dry-storage of the Tamar Valley CCGT, and the Tamar Valley peaking plant;
- install 200 MW of temporary diesel generation; and
- curtail major industrial load users.

The Panel notes that this outage has been a significant event with wide ranging impacts, and will continue to monitor the impact of this outage with a more comprehensive analysis in the 2016 AMPR.

90 AGL submission to draft report, 11 August 2016.

91 Basslink, *Basslink has returned to service,* media release, 13 June 2016.

6 Safety performance

Chapter 6 analyses the Panel's assessment of the performance of the electricity system from a safety perspective.

As outlined in Chapter 2, the scope of the Panel's consideration of performance for this review primarily relates to the bulk transmission system of the NEM. The Panel's assessment of the safety of the NEM is therefore limited to consideration of the links between security of the power system and maintaining the system within relevant standards and technical limits.

6.1 Reviewable operating incidents outcomes

As part of the Panel's assessment of the safety of the power system, this section analyses the responses to operating incidents which have occurred within the NEM during 2014-15. As operating incidents have implications for the overall safety of the system, the response to these incidents is a key indicator of safety performance. Examples of responses to operating incidents recommended by AEMO are outlined in Appendix H.

For 2014-15 the Panel reviewed the power system incident reports issued by AEMO. Based on publically available system event reports the Panel is not aware of any incidents 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.

Where AEMO issues a direction, the directed participant may choose not to comply on the grounds that complying with the direction would affect the safety of its equipment or personnel. The Panel notes that there were no instances in 2014-15 where this occurred. As set out in section 5.6, AEMO issued two direction notices in 2014-15, both relating to the Basslink Market Network Service Provider and the Gordon-Chapel Street No.2 220kV transmission lines.

7 Other relevant work

This chapter reports on other work that has been undertaken in 2014-15 by market institutions which is relevant to matters covered by the Panel's annual market performance reviews.

In particular, it includes information on:

- NEM market reviews completed by the Panel or the AEMC;
- rule changes made by the AEMC;
- AEMO pricing event reports; and
- market price information.

7.1 NEM market reviews

The Panel has provided a summary of what it considers as significant market reviews. These reviews are intended to outline the possible future changes to the market which may impact on issues covered by the Panel's annual market performance reviews.

7.1.1 Review of distribution reliability measures

The AEMC published the final report on its review of distribution reliability measures on 18 September 2014.[92] The review follows a request from the COAG Energy Council to develop common definitions for distribution reliability targets and outcomes.

In its final report the AEMC developed harmonised definitions which provide a menu of proposed distribution reliability measures to be applied by the AER and participating jurisdictions for their reporting, benchmarking and incentive schemes. It also recommended amending the NER to require the AER to develop, publish and maintain a guideline for the new definitions and consult with stakeholders in implementing the guideline.

In response to the review the COAG Energy Council submitted a rule change request to the AEMC. On 29 October 2015, the AEMC introduced new rules to give the AER responsibility for producing, maintaining and updating a guideline of common definitions of distribution reliability measures.[93]

92 AEMC, *Review of Distribution Reliability Measures*, Final Report, 5 September 2015.

93 AEMC, *Common definitions of distribution reliability measures*, Rule Determination, 29 October 2015.

7.1.2 Reliability standard and settings review

On 16 July 2014, the Panel published its final report for the reliability standard and reliability settings review 2014.[94] The final report contains the Panel's decision on the reliability standard and recommendations on the reliability settings (that is, the market price cap, cumulative price threshold and market floor price) that are to apply for the NEM from 1 July 2016.

The Panel's decision with respect to the reliability standard (unserved energy) and reliability settings (price mechanisms) is as follows.

Reliability standard

The Panel determined to retain the current form and level of the reliability standard to apply from 1 July 2016. That is:

- the reliability standard will remain in the form of an output-based measure expressed in terms of the maximum permissible unserved energy; and
- the level of the reliability standard will remain at 0.002 per cent of the annual energy consumption for the associated NEM region, or regions, per financial year.

Reliability settings

The Panel has determined that from 1 July 2016, no changes are to be made to the calculation or reliability settings, specifically:

- Market price cap (MPC). The MPC should continue to be indexed by the consumer price index, annually.
- Cumulative price threshold (CPT). The CPT should continue to be indexed by the consumer price index, annually.
- Market floor price. In addition, the market floor price should continue to be set in nominal terms (that is, the market floor price will not be indexed annually).

7.1.3 Last resort planning power – 2014 and 2015 review

The last resort planning power is provided for in the NER. It allows the AEMC to require one or more network service providers to apply the regulatory investment test for transmission to augmentation projects that are likely to relieve a forecast constraint on a national transmission flow path. The purpose of the power is to ensure timely and efficient inter-regional transmission investment when other mechanisms to provide for the planning of this investment appear to have failed.

94 Reliability Panel, *Reliability Standard and Reliability Settings Review 2014*, July 2014.

The NER require the AEMC to report annually on the matters it has considered during the year in deciding whether to exercise the last resort planning power.

The AEMC determined not to exercise its last resort planning power in 2014 and 2015. It did not find any inter regional constraints that were not being considered by TNSPs in their 2014 and 2015 transmission annual planning reports.

7.1.4 Barriers to efficient exit decisions by generators

On 16 June 2015, the AEMC published the 'Barriers to efficient exit decisions by generators' report.[95] It followed a request from the COAG Energy Council for advice from the AEMC on whether there are material barriers to orderly exit of generators from the NEM and from AEMO on pathways to ensure exit of generators does not jeopardise power system security.

The report provides a comprehensive review of the factors that generators may consider in deciding whether or not to exit the market. The advice concludes that there was nothing in the NEL or NER which would constitute a barrier to efficient exit decisions by generators.

The report notes that the decision to exit the market depends on the generator technology type, how the generator is structured, the generator's location and the stage of exit being considered by the generator. Stages of exit can vary from merely reducing dispatch to full decommissioning of the generator.

Furthermore, the report recognises that cost can be a barrier to entry if there is uncertainty surrounding the cost of exit, as greater uncertainty of the costs incurred upon exit is more likely to promote inefficient exit decisions. However, the level of uncertainty involved in these exit costs means it is difficult for policymakers to know what costs are faced by which generators upon exit, and therefore what would be efficient in terms of the timing or order of generator exit from the NEM.

The AEMC's view is that further work is not required on this issue unless significant changes occur in the market.

7.1.5 Template for generator compliance program review 2015

On 18 June 2015, the Panel published its final report for the template for generator compliance programs review 2015.[96] The template is designed to assist registered participants who own or operate plant to which performance standards apply, generally generators, with developing and designing their compliance programs to meet the relevant performance standard. It is also intended to assist the AER with the enforcement and monitoring of the generators' compliance with the technical requirements under the NER. Effective compliance with performance standards contributes to the delivery of reliable and secure electricity to customers in the NEM.

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95 AEMC, *Advice to the COAG Energy Council – Barriers to efficient exit decisions by generators*, June 2015.

The Panel's final report details amendments the Panel has made to the template to improve its clarity and to reflect changes in generation technology, new monitoring techniques and changes in plant operational modes.

The Panel also decided to submit a rule change request to the AEMC proposing to extend the review frequency period from "at least three years" to "at least five years" as a result of the review. On 3 December 2015, the AEMC made the rule proposed by the Panel.[97]

7.2 Rule changes made by the AEMC

This section provides a high level summary of the significant electricity rules changes that were completed during 2014-15 by the AEMC.

7.2.1 Governance arrangements and implementation of the reliability standard

On 19 March 2015, the AEMC made a final rule that strengthens the governance arrangements for the review and determination of the reliability standard and reliability settings.[98] These amendments were made to improve the process for determining the reliability standard and settings in order to provide greater certainty and transparency for market participants.

Specifically, the NER was amended to:

- require the AEMC to take on responsibility for setting the reliability standard, which is currently set by the Panel;
- shift the reliability standard and settings into a schedule to the rules and allow the AEMC to determine the reliability standard and settings through a process that is separate from the rule change process;
- require the AEMC to develop guidelines it must follow in reviewing and setting the reliability standard and settings;
- clarify that AEMO is responsible for making all reliability operational decisions and reviewing/amending processes to assess the adequacy of generation reserves to meet the reliability standard; and
- require AEMO to develop, consult on, and publish reliability standard implementation guidelines and reliability adequacy parameters, which will guide implementation of the reliability standard.

The rule commenced on 26 March 2015.

96 AEMC, *Amended template for generator compliance programs*, June 2015.

97 See the AEMC's website: www.aemc.gov.au, viewed 10 May 2015.

98 AEMC, *Governance Arrangements and Implementation of the Reliability Standard and Settings*, Final rule determination, March 2015.

7.2.2 Improving demand side participation information provided to AEMO by registered participants

On 26 March 2015, the AEMC made a rule that provides a process by which AEMO may obtain information on demand side participation from registered participants in the NEM.[99] It seeks to address the potential information deficiency experienced by AEMO.

Registered participants in the electricity market will be required to provide information on demand side participation to AEMO in accordance with guidelines as opposed to voluntary completing surveys regarding their knowledge of demand side participation that may occur in the NEM. This rule was made to improve the quality of information that AEMO receives in terms of demand side participation and hence help improve the quality of AEMO's electricity load forecasts. It commenced on 26 March 2015.

7.2.3 System restart ancillary services

In April 2015, the AEMC made a final rule determination to improve the arrangements for system restart ancillary services (or restart services) in the NEM.[100]

The final rule made by the AEMC:

- clarifies the roles and responsibilities of AEMO and the Panel;
- clarifies that the purpose of system restart ancillary services is that enough restart services should be procured so that each part of the system can be restored independently;
- helps to increase the degree of competition in the market for restart services; and
- requires system restart costs to be recovered on the basis of the regional benefits they provide.

As a result of this rule change, the Panel is currently reviewing the system restart standard.

7.3 Pricing event reports

AEMO publishes reports whenever a significant pricing event, that is, an unusual pricing outcome occurs in any NEM region. These reports contain information on the factors which contributed to these outcomes, whether outcomes were consistent with dispatch offers, the power system conditions, and the performance of pre-dispatch in forecasting abnormal outcomes. These pricing event reports provide a short

99 AEMC, *Improving demand side participation information provided to AEMO by registered participants*, March 2015.

100 AEMC, *System Restart Ancillary Services, Final rule determination*, April 2015.

description of the event and are targeted to be published within four business days of the event.[101]

Effective from 25 January 2015, these reports are produced whenever:

- the maximum daily spot price (trading interval price) in any region is more than $2000/MWh. AEMO will produce a brief summary report if the price is between $500/MWh and 2000/MWh;
- the minimum daily spot price for any region is less than -$100/MWh; and
- the maximum daily sum of Frequency Control Ancillary Services (FCAS) half hourly averaged prices exceed $150/MWh for all NEM regions except for Tasmania where this sum must exceed $3000/MWh.

During 2014-15, there were 108 separate extreme pricing events. The majority of these events were recorded in Queensland and South Australia. Out of these 108 extreme pricing events, ten were negative (below -$100/MWh), and 62 were greater than $2000/ MWh, hence these extreme pricing events would require a detailed report if they occurred after 25 January 2015. Furthermore, 21 of these occurrences occurred outside of peak demand time.[102] The full lists of these extreme pricing events are in Tables I.1a and I.1b in Appendix I.

Table 7.1 shows the top five highest prices, and the bottom two lowest prices which occurred throughout the NEM during 2014-15. Four of the top five highest spot prices during 2014-15 occurred in Queensland. One occurred in South Australia. Also, of the top five highest spot prices, four occurred during the summer, and one occurred during early March.

101 See http://www.aemo.com.au/Electricity/Resources/Reports-and-Documents/Pricing-Event-Reports for more information regarding the reporting guidelines and the reports themselves.

102 Peak demand time is 7:30am to 10:00pm each day.

Table 7.1 Highest five and lowest two observed prices throughout the NEM during 2014-15

Date	Region	Trading Interval (ending)	Price per MWh
Highest five observed prices			
Wednesday 17 December 2014	Queensland	20:00	$13,499
Thursday 5 March 2015	Queensland	20:30	$13,166
Thursday 15 January 2015	Queensland	20:00	$12,950
Tuesday 13 January 2015	Queensland	7:00	$4,543
Saturday 7 February 2015	South Australia	16:00	$4,527
Lowest two observed prices			
Saturday 5 July 2014	Queensland	14:30	-$328
Friday 13 February 2015	Victoria	10:30	-$319

Source: AEMO price event reports: www.aemo.com.au, viewed 1 June 2016.

The highest observed price occurred on 17 December 2014 in Queensland. AEMO notes that on this day, electricity demand in Queensland was the highest since 12 January 2012, peaking at 8,480 MW. This high demand was brought upon by hot temperatures in Brisbane, reaching up to 37.2 degrees. Compounding the effect of hot weather were generation limitations following the trips of the Yarwun power station and Roma unit 7. AEMO notes that rebidding and reduction of generation capacity by several units were the main reasons as to why this high price was observed.

The second highest observed spot price was $13,166 on 5 March 2015. AEMO attributed this occurrence to the unusually high demand brought upon by relatively hot weather as well as the steep supply curve, which was amplified by the constant re-bidding of generation capacity during the event. The next three observed highest prices were $12,950 on 15 January 2015; $4,543 on 13 January 2015; and $4,527 on 7 February 2015. These events also occurred as a result of relatively warm weather.

Of the ten observed prices below -$100/MWh, two were below -$300/MWh. These considerably low prices were observed in Queensland on 5 July 2014 (-$328.02), and in Victoria on 13 February 2015 (-$318.66). AEMO noted that the price in Victoria fell to this level because of an influx of generation capacity. This was a result of the export limits on the Murraylink and Heywood interconnector (both towards Victoria) being exceeded during trading intervals ending 1015 and 1020 hours, on this day. Further, AEMO noted that that the price in Queensland fell due to a sudden decline in demand in conjunction with a higher amount of generation capacity brought upon by a reduction in flow capacity from Queensland to NSW.

7.4 Market prices

The AEMC is responsible for calculating the MPC and the CPT each year to apply from 1 July each year as part of the NEM's reliability settings.

Since 1 July 2012, the NER have required the AEMC to annually update the values for the MPC and CPT by applying consumer price index information published by the Australian Bureau of Statistics.

The AEMC is required to publish these values by 28 February each year. For 2014-15, the values for MPC and CPT are tabulated in Table 7.2.[103]

Table 7.2 2014-15 market price cap and cumulative price threshold values

	From 1 July 2013 to 30 June 2014	From 1 July 2014 to 30 June 2015
MPC	$13,100 / MWh	$13,500 / MWh
CPT	$197,100	$201,900

Source: AEMC, *Schedule of Reliability Settings for 2014-15*, February 2014.

In the AMPR 2014 report the Panel considered there would be value in identifying periods in the AMPR report where the market achieved the MPC or CPT to assist the market understand if these periods were increasing. [104]

Market price cap

During 2014-15, the market price cap was reached 16 times in total: 11 times in South Australia; twice in Queensland; once in NSW; and once in Tasmania. The main reason was due to generator rebidding.[105]

Cumulative price threshold

The CPT was never reached during 2014-15. However, it was reached on 11 to 13 October 2015 and again on 15 to 26 October 2015 in the FCAS market, not the

103 AEMC, *Schedule of reliability settings*, 12 Feb 2015.

104 The following information is sourced from AEMO Pricing Event Reports available from www.aemo.com.au.

105 Typically rebidding occurs when there is limited availability or periods of high demand, for example during a network outage or at peak times on warm days. Note that the MPC may be reached during a 5-minute dispatch interval but the observed price for the half-hour trading interval may not be that high.

wholesale market. This was a result of the Heywood No.2 275kV transmission line planned outage.

Abbreviations

AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMPR	annual market performance review
CAIDI	customer average interruption duration index
CPT	cumulative price threshold
DNSP	distribution network service provider
EAAP	energy adequacy assessment projection
ESCOSA	Essential Services Commission of South Australia
ESOO	Electricity Statement of Opportunities
FCAS	frequency control ancillary service
HVDC	high voltage direct current
HYTS	Heywood Terminal Station
IPART	Independent Pricing and Regulatory Tribunal
LRET	large-scale renewable energy target
MPC	market price cap
MRL	minimum reserve level
MT PASA	medium-term projected assessment of system adequacy
NEFR	National Electricity Forecasting Report
NEL	National Electricity Law
NEM	national electricity market
NEMDE	National Electricity Market Dispatch Engine
NER	National Electricity Rules
NSCAS	network support and control ancillary services

NSP	network service provider
NTNDP	National Transmission Network Development Plan
POE	probability of exceedance
QNI	Queensland - NSW interconnector
RERT	reliability and emergency reserve trading
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SRAS	system restart ancillary services
SRES	small-scale renewable energy scheme
SRS	system restart standard
ST PASA	short-term projected assessment of system adequacy
TEC	Tasmanian Electricity Code
TNSP	transmission network service provider
USE	unserved energy

A NEM capacity changes

A.1 Increases in NEM capacity

As set out in chapter 2, 1,074 MW of generations was commissioned and 393 MW was committed during 2014-15. Table A.1 provides a granular analysis of this committed and commissioned generation capacity.

Table A.1 New generation commissioned and committed during 2014-15

Region	Status (during 2014-15)	Capacity (MW)	Power station	Fuel source
Queensland	Committed	44	Kogan Creek	Solar
New South Wales inc ACT	Commissioned	102	Nyngan	Solar
		20	Royalla	Solar
		113	Boco Rock Stage 1	Wind
		166	Gullen Range	Wind
		107	Taralga	Wind
		6	Wilga Park B	Gas
	Committed	56	Moree	Solar
		53	Broken Hill	Solar
Victoria	Commissioned	131	Mt Mercer	Wind
		47.2	Portland	Wind
		107	Bald Hills Phase 1	Wind
		6	Chepstowe	Wind
	Committed	240	Ararat	Wind
South Australia	Commissioned	270	Snowtown Stage 2	Wind
Tasmania		0		
Total commissioned		**1074**		
Total committed		**393**		

Note: Despite being labelled as committed, CS Energy has announced that the 44MW Kogan Creek project will not proceed. See CS Energy, *Solar boost will not be completed*, media release, 18 March 2016.

Source: AEMO, *Electricity statement of opportunities – for the National Electricity Market*, August 2015; AEMO, *Electricity statement of opportunities – for the National Electricity Market*, August 2014.

A.2 Reduction in NEM capacity

As at the end of the 2014-15, a total of 4,550.7 MW of capacity had been withdrawn during the year or announced to be withdrawn. The withdrawal of capacity is achieved either by the closure or mothballing of coal and gas fired power stations.

Table A.2 below sets out the total capacity that was withdrawn in 2014-15 or was announced to be withdrawn at the end of this period, that is it will be withdrawn after 2014-15. This is broken down by region, power station and fuel type.

Table A.2 Generation withdrawals during 2014-15 by region, power station and fuel type

Region	Status	Capacity (MW)	Power station	Fuel source
Queensland	N/A	0	N/A	N/A
New South Wales (including ACT)	Withdrawn during 2014-15	144	Redbank Power Station	Coal
	To be withdrawn after 2014-15	2,000	Liddell Power Station	Coal
		171	Smithfield Power Station	Gas
Victoria	Withdrawn during 2014-15	189	Morwell/Energy Brix Power Station	Coal
	To be withdrawn after 2014-15	156	Anglesea Power Station	Coal
South Australia	Withdrawn during 2014-15	239	Pelican Point Power Station Unit 2	Gas
		240	Playford B Power Station	Coal
	To be withdrawn after 2014-15	546	Northern Power Station	Coal
		480	Torrens Island Power Station A	Gas
Tasmania	Withdrawn during 2014-15	208	Tamar Valley CCGT Power Station	Gas
		58	Tamar Valley Peaking Power Station	Gas
	To be withdrawn after 2014-15	120	Bell Bay Three Power Station	Gas
Total withdrawn during 2014-15		**1,078**		
Total To be withdrawn after		**3,473**		

Region	Status	Capacity (MW)	Power station	Fuel source
2014-15				
Total		**4,551**		

Note: On 13 August 2015, Hydro Tasmania advised AEMO that Tamar Valley CCGT and Peaking unit is to return back to service in June 2016. On 6 June 2016, AGL announced the deferral of mothballing the four generating units at its 480 MW Torrens Island A station in Adelaide. See: www.aemo.com.au for further information.

Source: AEMO, *Electricity statement of opportunities – for the National Electricity Market*, August 2015; AEMO, *Electricity statement of opportunities – for the National Electricity Market,* August 2014.

B Network performance

This appendix includes an overview of relevant national and jurisdictional arrangements for managing the reliability performance of the NEM transmission and distribution networks.

B.1 Transmission network performance

This section provides an overview of national and jurisdictional arrangements for transmission network reliability performance.

B.1.1 National

There are some national requirements which impact on the reliability performance of the transmission network.

Part B of Chapter 5 of the NER includes planning requirements for transmission networks. TNSPs are required to carry out an annual planning review which must be reported in an annual market performance report. In addition, they must undertake a regulatory investment test for transmission where the estimated capital cost of the most expensive potential credible option to address an identified need is more than $6 million.[106]

Schedule 5.1 of the NER describes the planning, design and operating criteria that must be applied by TNSPs It also describes the requirements on TNSPs to institute consistent processes to determine the appropriate technical requirements to apply for each connection enquiry or application to connect processed by the TNSP. The objective is that all connections satisfy the requirements of this schedule.

In addition, TNSPs are subject to the AER's service target performance incentive scheme which provides financial incentives to maintain and improve performance, including reliability.

B.1.2 Queensland

For Queensland, in addition to the requirements in the NER above, mandated reliability obligations and standards are contained in the *Electricity Act 1994 (Queensland)*. As the TNSP in Queensland, Powerlink must adhere to these obligations and its connection agreements with other parties.

Powerlink plans future network augmentations in accordance with these requirements (among other things). It does this based on satisfying the following obligations:

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106 The AER recently increased the threshold from $5 million. See AER, *Cost thresholds review for the regulatory investment test,* Final determination, 5 November 2015.

- to ensure as far as technically and economically practicable that the transmission grid is operated with enough capacity (and if necessary, augmented or extended to provide enough capacity) to provide network services to persons authorised to connect to the grid or take electricity from the grid;[107]
- planning and developing its transmission network in accordance with good electricity industry practice such that the power transfer available through the power system will be such that the forecast of electricity that is not able to be supplied during the most critical single network element outage will not exceed either 50 MW at any one time; or 600 MWh in aggregate.[108]

B.1.3 New South Wales (including ACT)

In accordance with the direction issued by the NSW Government on 23 December 2010, TransGrid's network management plan sets out its planning approach to ensure the transmission design and reliability standard for NSW is met.

In general terms the standard requires TransGrid to plan and develop its transmission network on an "N–1" basis. This may be varied to accommodate AEMO's operating practices, distributor licence conditions or by agreement with distributors or other customers.

The standard requires that TransGrid's planning process be interlinked with licence obligations placed on distributors in NSW. In particular, TransGrid must ensure that their transmission network is adequately planned to enable distributor licence requirements to be met. The specific requirements are set out in TransGrid's network management plan.[109]

TransGrid is no longer required to have a network management plan since the Electricity Supply (Safety and Network Management) Regulation 2014 (NSW) commenced. However, TransGrid continues to use its network management plan to meet its obligations with the standard.

B.1.4 Victoria

AEMO is responsible for planning and directing augmentations of the Victorian electricity declared shared network in accordance with its obligations under the NER.

AEMO identifies the benefits of various network and non-network investment options. These benefits may, amongst other things, result from:

107 Section 34(2) of the *Electricity Act 1994 (Queensland)*.

108 Transmission Authority No. T01/98.

109 TransGrid's Network Management Plan can be located on TransGrid's website www.transgrid.com.au.

- a reduction in expected unserved energy;[110]
- a reduction in generation fuel costs;
- transmission loss reductions; and
- capital plant deferrals.

Using a probabilistic planning process, these benefits are then balanced against the cost of investments. If a transmission augmentation is selected AEMO proceeds with the credible option that delivers the highest net economic benefit out of the range of options.

AusNet Services owns and operates the majority of the transmission network in Victoria.

B.1.5 South Australia

As the TNSP in South Australia, ElectraNet is subject to the Electricity Transmission Code administered by the Essential Services Commission of South Australia (ESCOSA). The code sets specific reliability standards which are determined economically and expressed on a deterministic basis (for example, N, N–1, and N–2) for each transmission exit point.

ESCOSA is undertaking a review of the specific reliability standards set out in clause 2 of the Electricity Transmission Code. This review is scheduled to finish in the second half of 2016 in order to be reflected in ElectraNet's revenue proposal for the 2018-2023 regulatory control period.

B.1.6 Tasmania

TasNetworks is the TNSP in Tasmania. It is obliged to meet the requirements of its transmission licence, Electricity Supply Industry (Network Performance Requirements) Regulations 2007 (Tas), and the terms of its connection agreements.

The objective of the Electricity Supply Industry (Network Performance Requirements) Regulations 2007 (Tas) is to specify the minimum network performance requirements that a planned power system of a TNSP must meet in order to satisfy the NER. TasNetworks is required by the terms of its licence to plan and procure all transmission augmentations to meet these network performance requirements. TasNetworks publishes an Annual Planning Report, which includes discussion of any forecast supply shortfalls against the Electricity Supply Industry (Network Performance Requirements) Regulations 2007 (Tas), and proposed remedial actions.

110 AEMO calculates the benefits of reductions in expected unserved energy by applying a value of customer reliability. It considers a sector-specific value of customer reliability where the transmission constraint affects only a reasonably distinguishable subset of the load.

The Electricity Supply Industry (Network Performance Requirements) Regulations 2007 (Tas) set out:

- minimum network performance requirements in respect of electricity transmission services in Tasmania;
- the process for exemptions in respect of such requirements; and
- provisions in respect of Ministerial approval of certain augmentation in respect of such services.

B.2 Distribution network performance

All jurisdictions have their own monitoring and reporting frameworks for reliability of DNSPs. In addition, the Steering Committee on National Regulatory Reporting Requirements has adopted two main indicators of distribution network reliability that are widely used in Australia and internationally.[111] These are the system average interruption frequency index (SAIFI) and system average interruption duration index (SAIDI).

B.2.1 National

At a high level, the national requirements which impact on distribution reliability performance are broadly the same as those which impact on transmission networks.

Part B of Chapter 5 of the NER includes planning requirements for distribution networks. DNSPs are required to carry out an annual planning review which must be reported in an annual market performance report. In addition, they must undertake a regulatory investment test for distribution where the estimated capital cost of the most expensive potential credible option to address an identified need is more than $5 million.

Schedule 5.1 of the NER describes the planning, design and operating criteria that must be applied by DNSPs It also describes the requirements on D NSPs to institute consistent processes to determine the appropriate technical requirements to apply for each connection enquiry or application to connect processed by the DNSP. The objective is that all connections satisfy the requirements of this schedule.

In addition, DNSPs may be subject to an AER service target performance incentive scheme which provides financial incentives to maintain and improve performance, including reliability.

111 The Steering Committee on National Regulatory Reporting Requirements is a working group established by the Utility Regulators Forum; Utility Regulators Forum, *National regulatory reporting for electricity distribution retailing businesses*, discussion paper, 2012.

B.2.2 Queensland

The *Queensland Electricity Act 1994* and the Electricity Regulation 2006 define the arrangements for the Queensland DNSPs. Performance standards for Queensland DNSPs were introduced in September 2007.

The Queensland Electricity Industry Code requires that the Queensland Competition Authority to review the minimum service standards and guaranteed service level requirements to apply at the beginning of each regulatory period. These service levels were set following a review in early 2009. They have been applied to Ergon Energy and Energex since 1 July 2010.

The DNSPs report quarterly to the Queensland Competition Authority on their performance relative to their targets and on guaranteed service levels. The Queensland Competition Authority then reports this information to the Queensland Department of Energy and Water Supply.

Table B.1 details the performance of Energex and Ergon Energy against the minimum service standards set for 2014-15. It shows that Energex and Ergon met most of their SAIDI and SAIFI targets for the different feeder categories during 2014-15.

Table B.1 Performance of the Queensland DNSPs for 2014-15

DNSP	Feeder	SAIDI		SAIFI	
		Target	Actual	Target	Actual
Energex	CBD	15	3.70	0.15	0.16
	Urban	106	90.81	1.26	0.79
	Short-rural	218	178.59	2.46	1.55
Ergon Energy	Urban	149	133.66	1.98	1.27
	Short-rural	424	359.08	3.95	3.15
	Long-rural	964	1052.76	7.4	6.76

Note: SAIDI and SAIFI include planned and unplanned outages excluding major event days.

Source: Provided to the Panel by the Queensland Department of Energy and Water Supply.

B.2.3 NSW

The *Electricity Supply Act 1995* requires the NSW DNSPs to be licenced. Network performance standards for the NSW DNSPs have been set by the Minister for Energy through licencing conditions. These conditions were set in 2007 and are published on the Independent Pricing and Regulatory Tribunal's (IPART's) website.[112]

112 Conditions 14-19.

The performance of the NSW DNSPs against the performance standards is monitored by IPART by various means including:

- periodic self-exception reporting;
- compliance audits;
- Energy and Water Ombudsman's complaints;
- industry complaints; and
- media reports.

The DNSPs are required by the Electricity Supply (Safety and Network Management) Regulation 2008 to publish annual reports on network performance against their Network Management Plans. IPART also produces a licence compliance report, which from 2007 includes compliance with the reliability standards.

Table B.2 shows a summary of the performance of the NSW DNSPs overall and by feeder classification. All NSW DNSPs met their respective SAIDI and SAIFI targets in 2014-15. More detailed performance information is available from network performance reports published on each of the DNSPs websites.

Table B.2 Performance of the NSW DNSPs for 2014-15

DNSP	Feeder	Unplanned SAIDI (minutes)		Unplanned SAIFI (interruptions)	
		Maximum Target	Actual	Maximum Target	Actual
Essential Energy	Urban	125	72	1.8	0.97
	Short rural	300	207	3	2
	Long rural	700	489	4.5	3.28
	All	-	222	-	1.97
Ausgrid	CBD	45	8.73	0.3	0.09
	Urban	80	58.4	1.2	0.57
	Short rural	300	151.1	3.2	1.4
	Long rural	700	349.2	6	2.19
	All	-	71.4	-	0.69
Endeavour Energy	Urban	80	76.9	1.2	1
	Short rural	300	232.5	2.8	2.2
	Long rural	-	1,415	-	12
	All	-	103.7	-	1.2
NSW	CBD	-	8.7	-	0.09
	Urban	-	65.7	-	0.75
	Short rural	-	197.1	-	1.88
	Long rural	-	488.4	-	3.28
	All	-	117.1	-	1.14

Note: Unplanned SAIDI and SAIFI data excludes major event days.

Source: Provided to the Panel by the Independent Pricing and Regulatory Tribunal.

B.2.4 Australian Capital Territory

The *Utilities Act (2000)* underpins all codes and performance and compliance requirements for DNSPs operating in the ACT.

The Independent Competition and Regulatory Commission sets the performance standards for DNSPs operating in the ACT. These standards are available in the Electricity Distribution Supply Standards Code and in the Consumer Protection Code, which also has minimum service standards.

Table B.3 shows a summary of the performance of ActewAGL Distribution, the DNSP in the ACT, against the performance targets pertaining to each feeder classification for 2014-15. It shows that ActewAGL met its overall SAIDI and SAIFI target but did not meet the customer average interruption duration index (CAIDI) target. More detailed performance information is available from network performance reports published on ActewAGL's website.

Table B.3 Performance of ActewAGL for 2014-15

Feeder		SAIDI (minutes)		SAIFI		CAIDI	
		Target	Actual	Target	Actual	Target	Actual
Urban	Overall	n/a	81.4	n/a	0.85	n/a	95.17
	Distribution network – planned	n/a	47.33	n/a	0.21	n/a	223.06
	Distribution network – unplanned	n/a	33.81	n/a	0.64	n/a	52.8
	Normalised distribution network – unplanned	n/a	33.81	n/a	0.64	n/a	52.8
Rural short	Overall	n/a	85.48	n/a	0.76	n/a	112.21
	Distribution network - planned	n/a	54.56	n/a	0.23	n/a	237.24
	Distribution network - unplanned	n/a	30.92	n/a	0.53	n/a	58.14
	Normalised distribution network – unplanned	n/a	30.92	n/a	0.53	n/a	58.14
Network	Overall	91	82.56	1.2	0.82	74.6	100.31
	Distribution network - planned	n/a	49.69	n/a	0.22	n/a	227.94
	Distribution network - unplanned	n/a	32.87	n/a	0.61	n/a	54.33
	Normalised distribution network - unplanned	n/a	32.87	n/a	0.61	n/a	54.33

Note: Major event days have been excluded from the results.

Source: Provided to the Panel by the Independent Competition and Regulatory Commission.

B.2.5 Victoria

The *Electricity Industry Act 2000* and the *Essential Services Commission Act 2001* contain the network performance requirements for the Victorian DNSPs.

From 1 January 2009, responsibility for the compliance monitoring and enforcement of the DNSPs' distribution licence conditions was transferred to the AER from the Essential Services Commission of Victoria.

As part of its 2010 distribution regulatory determination, the AER sets SAIDI and SAIFI targets for the Victorian DNSPs for the 2011–15 regulatory period.[113] These targets are developed for the purpose of applying the AER's service target performance incentive scheme to the DNSPs.

Under the service target performance incentive scheme, the AER annually reviews the service performance outcomes and determines the resulting financial penalty or reward based on a DNSPs performance against the targets established at the time of a distribution determination.

Table B.4 shows a summary of the performance of the Victorian DNSPs including an overall target for each DNSP and the actual performance by feeder classification. It shows that AusNet Services met all of its SAIDI and SAIFI performance targets. CitiPower met all but one of its targets. The other DNSPs met fewer targets.

113 The AER released its distribution revenue and service determination for the 2016-20 period in May 2016.

Table B.4 Performance of the Victorian DNSPs for 2014-15

DNSP	Region	Unplanned SAIDI (minutes)		Unplanned SAIFI	
		Target	Actual	Target	Actual
Jemena	Urban	55.94	57.00	0.96	0.97
	Short-rural	93.52	94.27	1.28	0.67
	Whole Network		58.62		0.96
CitiPower	CBD	11.27	12.17	0.186	0.15
	Urban	22.36	42.50	0.45	0.49
	Whole Network		37.03		0.43
Powercor	Urban	82.467	79.61	1.263	1.07
	Short-rural	114.807	130.63	1.565	1.52
	Long-rural	233.759	338.03	2.54	2.49
	Whole Network		166.23		1.60
AusNet Services	Urban	101.803	101.30	1.448	1.23
	Short-rural	208.542	182.22	2.632	2.09
	Long-rural	256.578	246.12	3.378	2.64
	Whole Network		157.29		1.80
United Energy	Urban	55.085	72.55	0.899	0.95
	Short-rural	99.151	150.94	1.742	1.70
	Whole Network		77.94		1.00
Average			**99.4**		**1.2**

Note: Major event days are excluded from the results.

Source: Responses from the DNSPs to regulatory information notices available on the AER's website and DNSP revenue determinations and annual planning reports.

B.2.6 South Australia

The Essential Services Commission of South Australia (ESCOSA) continues to be responsible for setting elements of the service standard framework. For example, ESCOSA remains responsible for setting the South Australian jurisdictional service standards applying to SA Power Networks and guaranteed service levels.

ESCOSA has established annual standards for frequency and duration interruptions for seven geographic regions within SA Power Network's distribution network. These are specified by ESCOSA as 'best endeavour' annual targets in the Electricity Distribution Code. SA Power Networks must comply with the service standards set out in Chapter 1 of the Code.

While there are no annual state-wide targets specified for the entire network, there are implied state-wide targets based on the customer-weighted averages of the implied regional targets. For the 2010-11 to 2014-15 regulatory control period, these are 179 minutes per annum for duration interruptions and 1.68 interruptions per annum for frequency interruptions.[114]

The Code also establishes guaranteed service level payments in relation to the DNSPs timeliness. This includes timeliness of appointments, connections, and street light repairs. The Code also requires SA Power Networks to make specified payments to customers if the frequency of interruptions, or the duration of any single interruption exceeds the thresholds set out in the Code. Payments for the 2010-11 to 2014-15 regulatory control period range from $90 for a single outage of 12-15 hours duration, to $370 for a single outage exceeding 24 hours, and $90 for 9-12 interruptions per annum, to $185 for more than 15 interruptions per annum.

SA Power Networks also reports to ESCOSA on poorly performing segments of the distribution network, determined by reference to low reliability distribution feeders. This covers those feeders that have an individual SAIDI outcome greater than 2.1 times the SAIDI target for the region in which the feeder is located.

Reliability performance is reported to ESCOSA on a quarterly basis under Electricity Guideline 1. SA Power Networks and other regulated entities are required to provide verification of compliance with relevant regulatory obligations and codes on an annual basis under the requirements set out in Guideline 4. ESCOSA publishes the results in annual compliance and performance reports available on its website.

Table B.5 shows a summary of the performance of SA Power Networks Distribution for 2014-15 against the performance targets pertaining to each feeder classifications. Except for the SAIDI target for the Central feeder, SA Power Networks met all of the SAIDI and SAIFI targets. SAIFI and SAIDI results are published by ESCOSA.[115]

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114 The AER has determined revenues for the 2015-16 to 2019-20 regulatory control period but this determination is not relevant to the 2014-15 year covered in this report.

115 See: www.escosa.sa.gov.au, viewed 22 August 2016.

Table B.5 Performance of the SA Power Networks for 2014-15

Region	SAIDI (minutes)		SAIFI	
	Target	Actual	Target	Actual
Adelaide Business Area	25	10.9	0.25	0.151
Metro Business Areas	130	104.5	1.45	1.12
Central	260	279.7	1.8	1.364
Eastern Hills/ Fleurieu Pen.	295	229	2.8	1.576
Upper North & Eyre Pen.	425	353.8	2.3	1.431
South East	295	198.9	2.5	1.668
Kangaroo Island	450	266.4	N/A	N/A
Total Network	179	151.9	1.68	1.229

Source: Provided to the Panel by the Essential Services Commission of South Australia.

B.2.7 Tasmania

The network performance requirements for electricity distribution in Tasmania are prescribed in the Tasmanian Electricity Code (TEC).

On 1 January 2008, the Office of the Tasmanian Economic Regulator amended the TEC to incorporate new distribution network supply reliability standards, which were developed jointly by the Office of the Tasmanian Energy Regulator, the Tasmanian Office of Energy Planning and Conservation, and TasNetworks (previously Aurora Energy). These are designed to align the reliability standards more closely to the needs of the communities served by the network.

The distribution network supply reliability standards have two parts:

- minimum network performance requirements specified in the TEC for each of five community categories: Critical Infrastructure, High Density Commercial, Urban and Regional Centres, Higher Density Rural and Lower Density Rural; and
- a guaranteed service level supported by the TEC and relevant guidelines.

Further details on the standards are contained in Chapter 8 of the TEC.

Table B.6 shows a summary of the performance of TasNetworks for 2014-15, against the performance targets pertaining to each feeder classification. In 2014-15, the high density commercial category was the only category where performance was within both the frequency and duration limits as set out in the TEC.

In contrast, for the critical infrastructure category, performance exceeded both the frequency and duration limits. The other categories exceeded the duration limits only.

Table B.6 Performance of the TasNetworks (distribution) for 2014-15

Community category	SAIDI (minutes)		SAIFI	
	12 month category limit	Performance	12 month category limit	Performance
Critical Infrastructure	30	57	0.2	0.34
High Density Commercial	60	27	1	0.33
Urban and Regional Centres	120	169	2	1.25
Higher Density Rural	480	582	4	2.94
Lower Density Rural	600	931	6	4.04

Source: Provided to the Panel by the Office of the Tasmanian Economic Regulator.

C Reliability assessment

This appendix provides details on the information sources used to assess reliability in the NEM.

C.1 Reserve projections and demand forecasts

Market information is provided in a number of formats and time frames ranging from long-term projections (more than 10 years) that are published annually, through to the detailed five and thirty minute pre-dispatch price and demand projections. This information is published across a range of tailored reports, including:

- the National Electricity Forecasting Report (NEFR);
- the Electricity Statement of Opportunities (ESOO);
- the National Transmission Network Development Plan (NTNDP);
- the energy adequacy assessment projection (EAAP);
- the medium-term projected assessment of system adequacy (MT PASA);
- the short-term projected assessment of system adequacy (ST PASA); and
- ongoing market notices.

These documents together inform market participants on the state of the market and its potential evolution over the short and longer terms. This information can assist both existing and intending participants when identifying opportunities in the market. The following sections describe these information sources in more detail.

C.2 Planning information

National Electricity Forecasting Report (NEFR)

AEMO publishes the NEFR each June which provides AEMO's independent electricity consumption, maximum/minimum demand, and probability of exceedance (POE) forecasts for each of the five NEM regions (NSW includes the ACT). The report presents twenty year forecasts at an annual resolution and across high, medium, and low growth scenarios.

AEMO also publishes updates to the NEFR forecasts where new information becomes available. For example, AEMO published an update to the NEFR in December 2015 due to include new information regarding Queensland's LNG project status, and to include Tasmania's observed maximum demand which occurred after the original publication.

AEMO uses the NEFR forecasts as inputs into its other electricity planning publications identified in this section of this report.

Besides the NEFR, AEMO also publishes:

- NEFR Action Plan Implementation Plans, which outline how the activities proposed in the previous NEFR Action Plan Implementation report were implemented in the most recent NEFR. It also identifies actions requiring further investigation for the following NEFR.

- Forecast Accuracy Reports, aimed to report on the accuracy of the consumption and maximum demand forecasts disclosed in the relevant year's NEFR. In each Forecast Accuracy Report, the accuracy of the forecasts is determined by comparing actual values which those forecasted in the previous NEFR and/or previous NEFR Update. Based on the forecast accuracy results, AEMO then identifies focus areas and improvements which can be made for the following year's NEFR.[116]

Electricity Statement of Opportunities (ESOO)

The ESOO provides technical and market data and information, to the market. It assesses the adequacy of supply to meet demand over a ten year outlook period, highlighting changes to NEM-wide generation and demand side investment opportunities by analysing the factors which influence these types of investment.

The 2015 ESOO is reliant on the forecasts disclosed in the 2015 NEFR.

National Transmission Network Development Plan (NTNDP)

The NTNDP provides industry stakeholders such as the NSPs, AER, AEMC, and other policy makers with an independent strategic view for the efficient development of the national transmission network over a 20-year planning horizon.

In preparing the NTNDP, AEMO explores a range of scenarios to assess the impact of demand, fuel price, and policy settings on the optimal evolution of the transmission network. To achieve this, AEMO undertakes an annual consultation with stakeholders to establish the scope of the NTNDP, identify material issues for investigation, and seek feedback on the proposed methodology and modelling inputs.

C.3 Energy adequacy assessment projection (EAAP)

AEMO is required to publish the Energy Adequacy Assessment Projection (EAAP) each quarter. The EAAP provides information and analysis that quantifies the impact of energy constraints on energy availability (including water availability and other fuel supply limitations) over a 24 month period and under a range of scenarios. The energy constraints are based on information provided by scheduled generators and include information regarding planned outages, power transfer capability of the NEM, and

116 AEMO provides these reports to the Panel and are published on the AEMC's website.

demand forecasts that are provided by jurisdictional planning bodies for the purposes of the ESOO.

The June 2014 update considers the period from 1 July 2014 to 30 September 2016. Since June 2014 update there has been a September 2014 update, which considered the time period of 1 October 2014 to 30 September 2016, and a September 2015 update, which considered the period from 1 October 2014 to 30 September 2017. There has also been a December 2015 update which covered the period from 1 January 2016 to 31 December 2017. In addition, AEMO has published updates in January and March 2016 following the outage of the Basslink interconnector.

C.4 Medium-term projected assessment of supply adequacy (MT PASA)

The MT PASA, published by AEMO on a weekly basis, assesses the adequacy of supply to meet demand at the time of anticipated maximum demand, based on a 10% POE for each day over the following two years. This 10% POE maximum demand forecast is estimated using historical summer and winter, weekday 10% POE demand forecasts, and is provided at a daily resolution. The MT PASA also analyses region availability by providing an assessment of the projected impact of network outages on intra-regional and inter-regional power transfer capabilities, as well as constraint equation information. Generation and demand side daily estimates, as well as planned outage information are submitted by participants as required under clauses 3.7.2(d) and 3.7.2(e) of the NER, respectively.

C.5 Short-term projected assessment of supply adequacy (ST PASA)

The ST PASA, published by AEMO every two hours, assesses the adequacy of supply to meet demand for each half-hour of the following seven days (including the current day).

Each week participants must submit forecasts of generation and demand side availabilities as per clause 3.7.3(e) of the NER. Transmission outage programs are supplied by the TNSPs as per clause 3.7.3(g) of the NER. This information is used to assist participants in optimising short-term physical and commercial maintenance, production planning as well as load management activities.

C.6 Pre-dispatch

As part AEMO's market management assessment, pre-dispatch forecasts are prepared to provide:[117]

117 Pre-dispatch information is available at http://www.aemo.com.au/Electricity/Market-Operations/Dispatch/~/media/Files/Other/electricityops/0140-0040%20pdf.ashx.

- wholesale market participants with sufficient unit loading, unit ancillary service reserve and regional pricing information for them to make informed and timely business decisions relating to the operation of their dispatchable units; and
- the wholesale market operator (AEMO) with sufficient information to assist them in maintaining the power system in a reliable and secure operating state in accordance with the NER obligation.

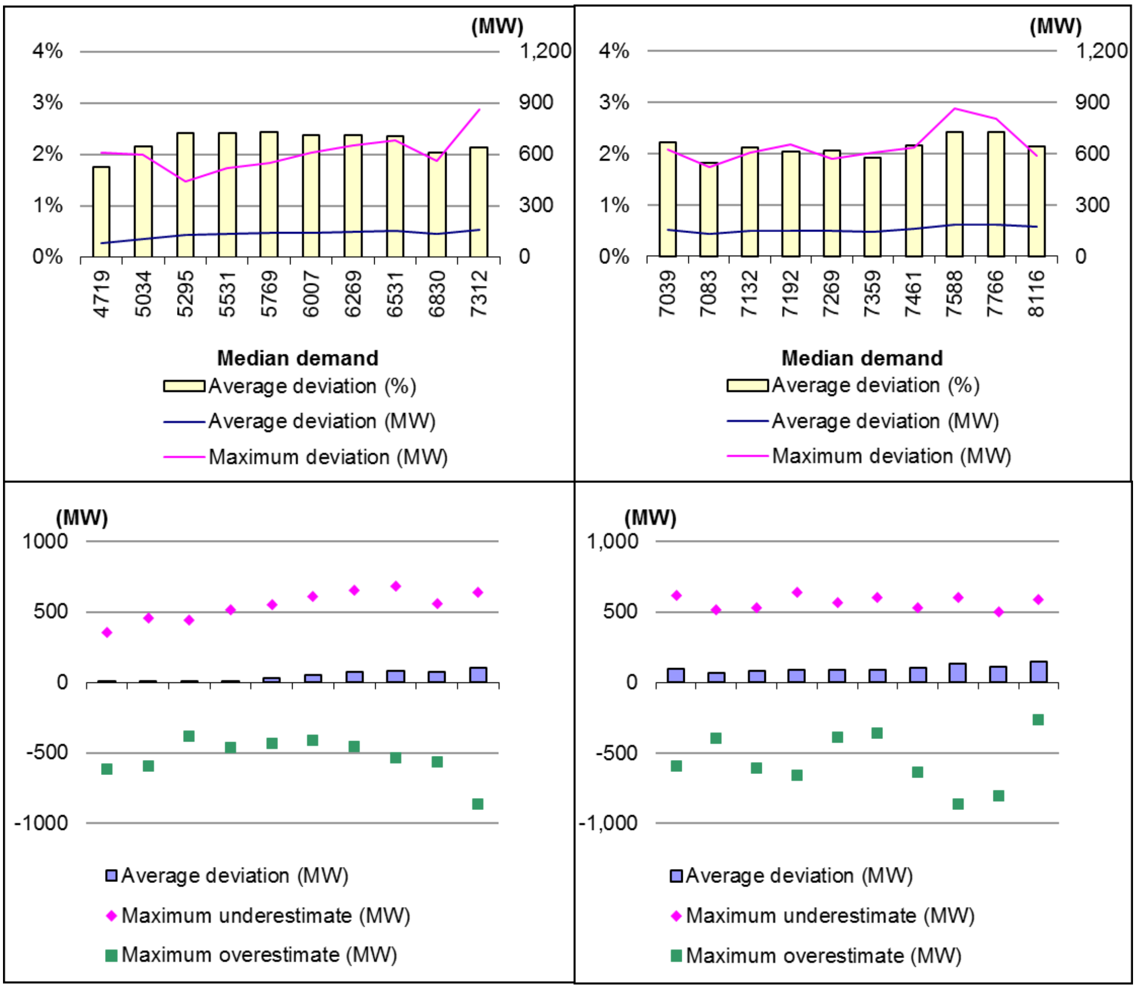
C.6.1 Demand forecast assessment

Figures C.1 to C.5 depict the four-hours-ahead demand forecasts for the summer 2014-15 period to assess whether forecast performance varies with levels of demand. Note that the horizontal axis in each graph denotes the median value of demand.

For each region there are four graphs used to explain forecast performance. The top-left graph examines the absolute deviations for equal sized samples of demand. Demand is grouped into samples of tenth percentile, with the median values of each grouped sample shown on the horizontal axis of the graph. For each group of demand samples, the average and maximum demand deviations are plotted.

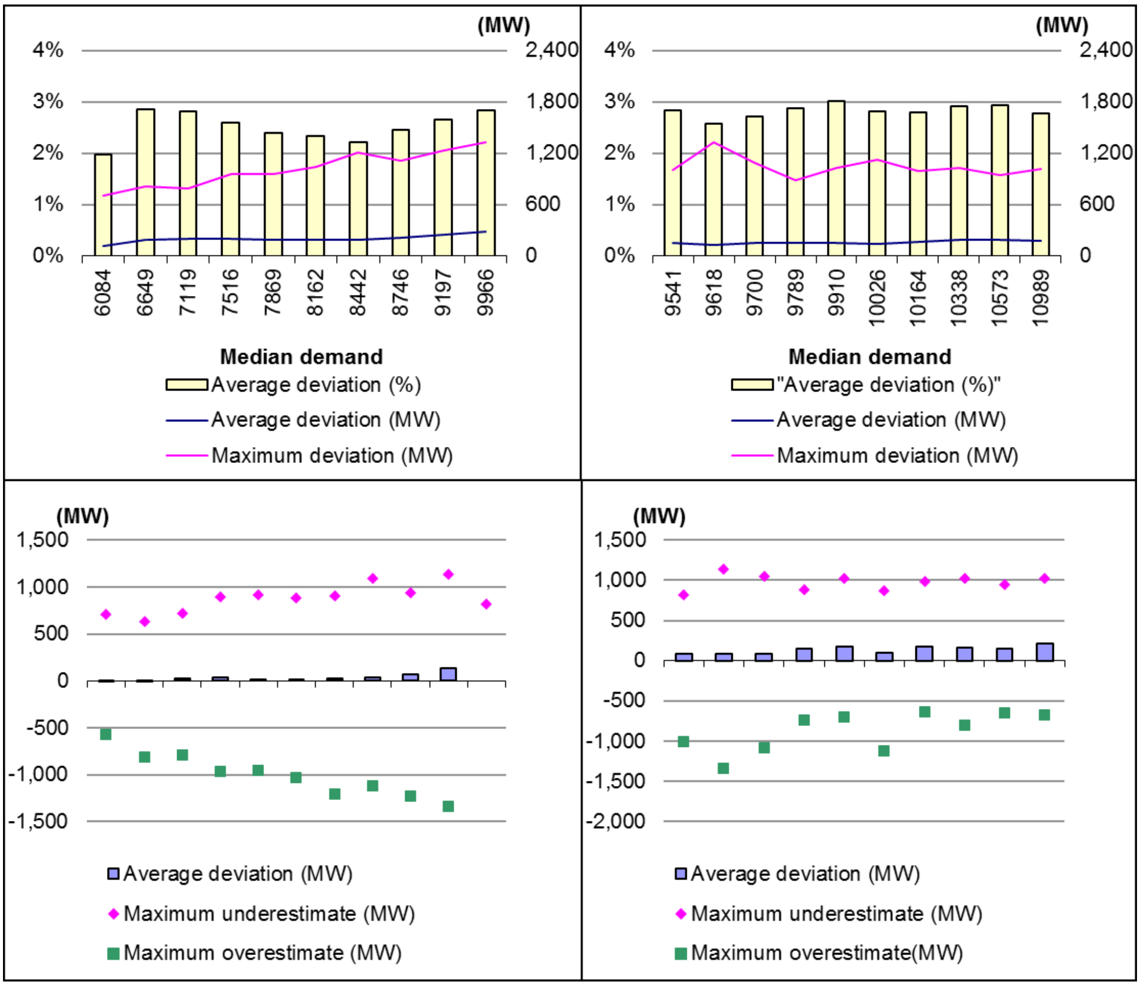
The top-right graph shows the top 10 per cent of actual demand in one percentage groupings. The bottom-left graph examines raw data deviations in tenth percentile groupings and plots the average raw deviation and maximum demand forecast deviation for each grouped sample. Similarly, the bottom-right graph plots the raw deviations in one percentile groups for the top tenth percentile demand level. Any underlying bias (imbalance of overs and unders) in forecasting would be expected to show up here. The graphs show that most deviations fall within two per cent and four per cent of forecast demand, with Tasmania displaying the highest demand deviations (up to six per cent of forecast demand level) and Queensland the lowest (just over two per cent of forecast demand level).

Figure C.1 Queensland median demand forecast deviation four hours ahead



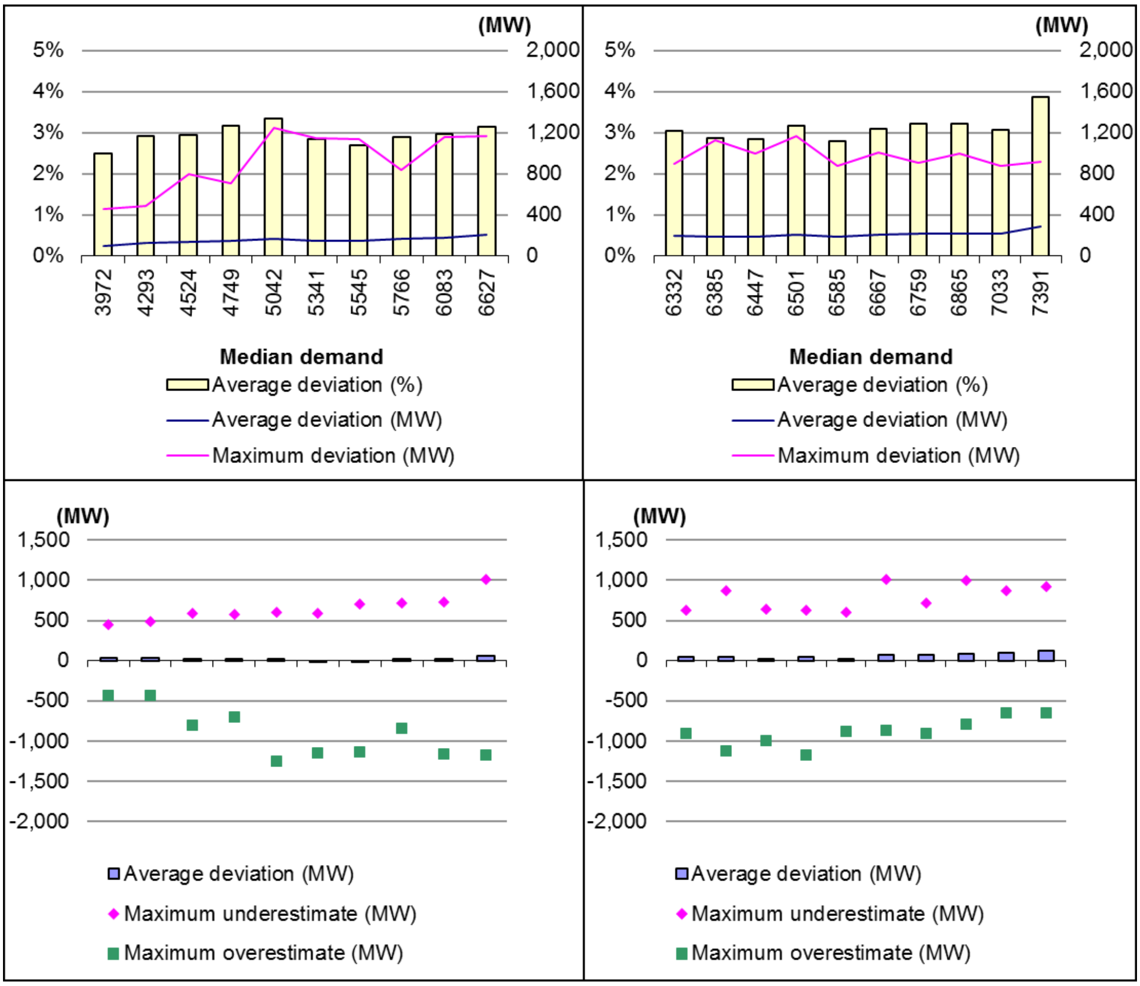
Source: AEMO.

Figure C.2 NSW median demand forecast deviation four hours ahead



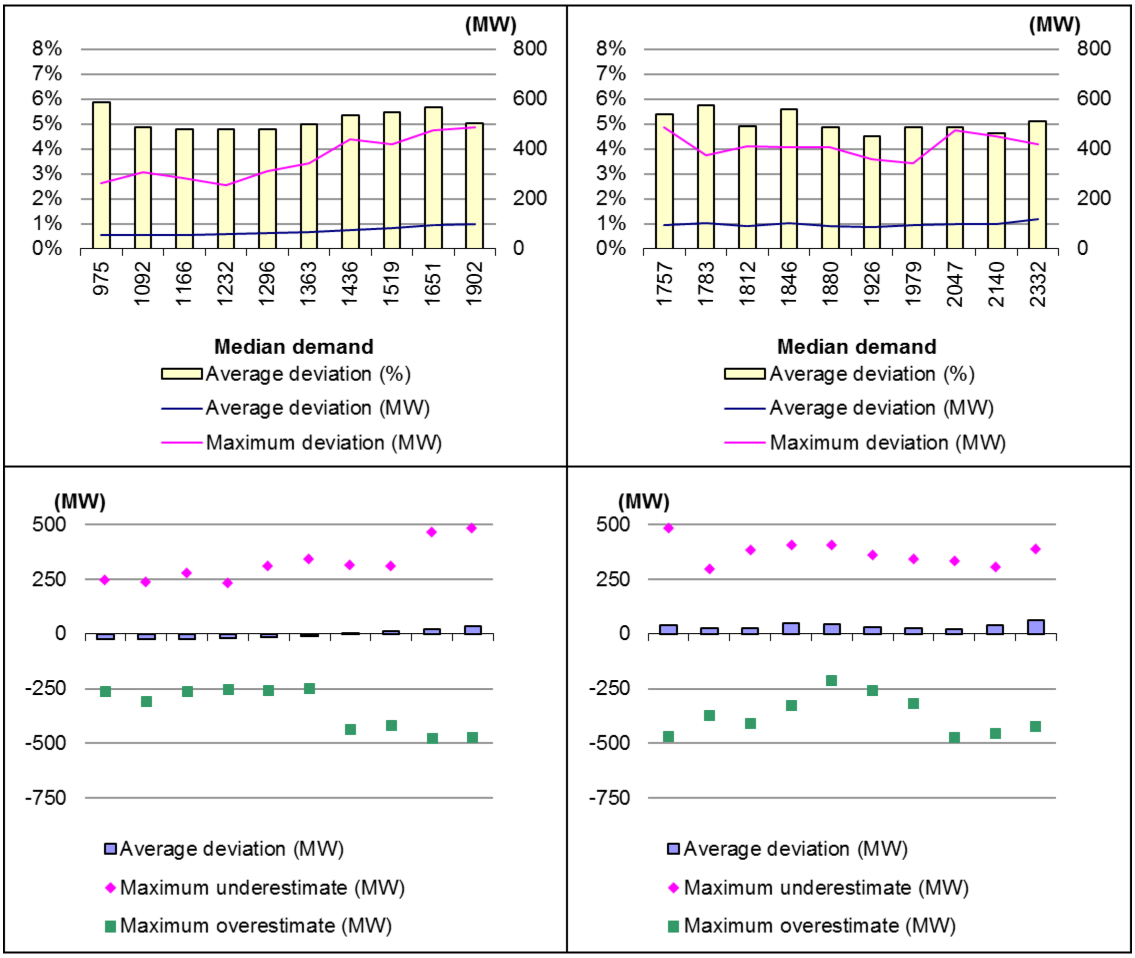
Source: AEMO.

Figure C.3 Victoria median demand forecast deviation four hours ahead



Source: AEMO.

Figure C.4 South Australia median demand forecast deviation four hours ahead



Source: AEMO.

Figure C.5 Tasmania median demand forecast deviation four hours ahead

Source: AEMO.

C.6.2 Minimum reserve levels

AEMO calculates minimum reserve levels to meet the reliability standard operationally where AEMO's objective is to maintain reserve levels above the minimum reserve levels.[118] These calculations take into account plant performance characteristics such as forced outage rates, the characteristics of demand including weather, market price sensitivity and the capability of the network.

As the market operator, AEMO takes the reliability standard as determined by the Panel (and which is expressed as percentage of energy consumption in GWh) and develops deterministic trigger levels that can be applied operationally. These trigger levels are expressed as the minimum reserve levels for each region. By convention, minimum reserve levels are expressed relative to a region's 10% probability of exceedance (POE) maximum demand, including any demand-side participation.

118 AEMO calculates the minimum reserve levels, which includes the use of a reserve sharing analysis that identifies the reserve requirement relationships between neighbouring regions. This could result in negative minimum reserve levels for some regions as shown in Table 14. Details of AEMO's calculation processes are outlined in AEMO's ESOO.

Minimum reserve levels are used in both medium and long-term supply-demand forecasts to assess whether the level of available capacity is sufficient to satisfy the reliability standard. Table C.1 provides a history of the values of the minimum reserve levels over the previous 10 years.[119]

Table C.1 Revised minimum reserve levels (MW)

	Queensland	NSW	Tasmania
2005-06	610	-290	144
2006-07	480	-1490	144
2007-08	560	-1430	144
2008-09	560	-1430	144
2009-10	560	-1430	144
2010-11	829	-1548	144
2011-12	913	-1564	144
2012-13	913	-1564	144
2013-14	913	-1564	144
2014-15	913	-1564	144

Source: AEMO, http://www.aemo.com.au/Electricity/Market-Operations/Reserve-Management

Table C.1 only presents data for three regions, Queensland, NSW (includes ACT), and Tasmania. This is because the minimum reserve levels MRLs in these regions are independent from one another.

The minimum reserve levels in Victoria and South Australia are dependent on one another. There are six constraints on the amount of reserves required for Victoria and South Australia. These are listed below:

VIC Reserve >= 205.00

5.88 * VIC Reserve + SA Reserve >= 1237.88

1.33 * VIC Reserve + SA Reserve >= 228.00

0.43 * VIC Reserve + SA Reserve >= -40.53

0.23 * VIC Reserve + SA Reserve >= -147.55

SA Reserve >= -368.00

119 This data is sourced from AEMO's reserve notice MT PASA publication, which is published at the end of each calendar year.

D Demand forecasts

D.1 National Electricity Forecasting Report

D.1.1 Purpose

AEMO reports operational consumption and maximum demand forecasts in the NEFR. The 2015 NEFR provides AEMO's annual, independent electricity forecasts for the five NEM regions to 2034-35 (twenty years out) across high, medium, and low consumption growth scenarios. AEMO uses these forecasts as an input into its electricity planning publications, including the ESOO.

D.1.2 Energy consumption and maximum demand modelling improvements

Based on the recommendations listed in the 2014 NEFR, the following improvements were implemented in the 2015 NEFR:

Residential and commercial

- factored in different drivers for each region to reflect regional market differences; and
- modelled asymmetric price elasticities where possible, capturing different consumer responses to price increases and decreases.

Rooftop PV

- forecast residential and commercial PV separately for the first time, to capture the different drivers in each sector; and
- included commercial PV projects greater than 100 kW in the modelling for the first time.

Energy efficiency

- incorporated updated data on federal programs; and
- included new data from NSW schemes.

Large industrial loads

- increased the sample size of large industrial customers surveyed, from 93 to 115; and
- applied an economic sectoral approach in the medium to longer term forecasts.

Maximum demand

- included industrial demand in the maximum demand model to allow for operational demand to be modelled as a whole;
- allowed variable selection for the demand model to vary with time of day. This improved accuracy by allowing the demand model to be tuned to morning, afternoon and evening periods rather than only the afternoon period;
- separate models for working days and non-working days. Hierarchical modelling such as this is known to improve accuracy; and
- more sophisticated reconciliation with AEMO's annual consumption forecasts.

Operational minimum demand

For the first time in 2015, operational minimum demand forecasts have been developed for South Australia to investigate the impact on the network of residential and commercial rooftop PV. South Australia was considered first because it has the highest penetration of rooftop PV. AEMO is planning to extend the minimum demand analysis to other regions in future NEFRs.

Emerging technologies

The 2015 NEFR forecasts do not explicitly include emerging technologies and trends such as battery storage, electric vehicles and fuel switching. Instead, AEMO has developed a set of forecasts and user tools that demonstrate the potential impact of emerging technologies on operational consumption and maximum demand forecasts. These were released as a supplementary Emerging Technologies Information Paper in June 2015.[120]

D.1.3 Regional operational consumption

The 2015 NEFR notes the following in regards to operational consumption within each NEM region.

Queensland

In Queensland, the NEFR notes that operational consumption has remained relatively flat in the 10 years to 2014-15. AEMO forecasts a recovery in operational consumption in the short-term, under a medium growth scenario, driven by the ramp up in LNG projects and a stronger population growth than in the previous year. Excluding LNG, operational consumption is expected to remain flat in the short-term and then increase slightly in the longer-term.

Despite the increase in solar PV installations, which offsets consumption from the grid, consumption did recover over the last period, perhaps owing to a longer and warmer

120 AEMO, *Emerging Technologies Information Paper*, June 2015.

summer period. Based on existing and future government programs, residential PV installations are expected to continue to increase until they reach saturation levels in the longer-term. Commercial PV installations are forecast to continue to grow over the entire forecast period. This is a contributing factor to the forecast decline in per capita consumption from the grid.

NSW (including ACT)

The bulk of the overall consumption of electricity comes from the residential and commercial sector. The growth in residential and commercial energy demand is largely driven by population growth. NSW is the only NEM region that reported a slight increase in per capita consumption growth. This coincides with the fact that NSW has the lowest proportion of household PV installations of all the NEM regions. AEMO has forecast modest consumption growth over the short, medium and longer term assuming medium income and population growth.

AEMO forecasts growth in residential and commercial solar PV over the entire forecast period. On the basis that NSW's commercial installation growth is the highest in the NEM region, NSW is forecast to have the highest installed capacity of commercial solar PV of the NEM regions.

South Australia

In the four years to 2014-15, operational consumption has steadily declined owing to reductions in residential and commercial consumption as a result of higher electricity prices as well as the implementation of household PV systems and a general increase in energy efficiency. Despite this, AEMO forecasted a slight increase in industrial consumption as the Port Pirie smelter returned to pre-2014 levels.

AEMO forecasts a continuing decline in per capita consumption; with population growth keeping operational consumption relatively flat over the long-term period. The reported decline in per capita consumption has slowed as a result of slower growth in solar PV uptake. AEMO forecasts that solar PV uptake will reach a saturation point over the long-term. Under the medium growth assumption, any recovery in underlying consumption, driven by economic factors, is expected to be offset by solar PV systems and energy efficiency in the short to medium term.

Victoria

AEMO notes that although there has been a recovery in consumption from the residential and commercial sector, consumption per capita has continued to decline. This is despite the fact that Victoria has the lowest proportion of solar PV relative to its load in the NEM. Over the short-term, consumption per capita is expected to decrease slightly. However, the total underlying residential and commercial consumption is forecast to increase as a result of lower electricity prices and population growth.

Like NSW, residential and commercial solar PV is expected to grow over the entire forecast period without reaching the saturation point. Despite this continued uptake, rooftop PV still only offsets a small portion of total Victorian underlying consumption.

Tasmania

Operational consumption in Tasmania has been declining over the past five years. It is expected to continue recover slightly in the short-term but then decline and plateau over the medium and long-term, respectively. Under the medium-growth assumption underlying those forecasts, the recovery in operational consumption is not expected to reach the previous historical high in 2007-08. The underlying short-term recovery is driven by falling electricity prices in the short-term. In the medium and long-term, the increase in electricity consumption due to population and income growth is expected to be offset by the growth in residential and commercial solar PV uptake and energy efficiency gains. AEMO also forecasts a decline in consumption per capita for the same reasons.

D.1.4 Regional maximum demand

Table D.1 shows the change in the forecasted 10% maximum demand POE forecasts for the short-term period from 2014-15 to 2017-18 as reported in the 2014 and 2015 NEFR.

Table D.1 Comparison of forecast maximum demand growth rates reported in the 2014 and 2015 NEFRs

		NEM Region				
		QLD	NSW	VIC	SA	TAS
2014 NEFR	**2014/15 (predicted)**	8,621	13,438	10,114	3,277	1,756
	2017/18 (predicted)	9,722	14,112	10,132	3,272	1,764
	% Change	12.8%	5.0%	0.2%	-0.2%	0.5%
	Average % change per year	3.19%	1.25%	0.04%	-0.04%	0.11%
2015 NEFR	**2014/15 (Actual)**	9,465	14,265	10,034	3,185	1,754
	2017/18 (predicted)	10,282	13,985	10,011	3,218	1,769
	% Change	8.63%	-1.96%	-0.23%	1.04%	0.86%
	Average % change per year	2.88%	-0.65%	-0.08%	0.35%	0.29%

Source: AEMO, *2015 National Electricity Forecasting Report for the National Electricity Market*, June 2015; AEMO, *2014 National Electricity Forecasting Report for the National Electricity Market*, June 2014.

AEMO notes that the revision in the short-term 10% maximum demand POE is due to region specific factors.[121]

Queensland

In both years Queensland has reported the highest growth rates of 10% POE maximum demand for the period from 2014-15 to 2017-18, albeit the forecast was revised down slightly in the 2015 NEFR. This relatively high growth rate is attributed to the commencement of several LNG projects which increased demand from the industrial sector.

NSW (including ACT)

The NSW 10% POE maximum demand forecast changed considerably between the 2014 and 2015 NEFR. The 10% POE forecast is expected to decrease in the short-term. AEMO notes that the maximum demand level was relatively high in 2014-15 and despite continued population and gross state product growth. Maximum demand is not expected to reach the level observed in 2014-15 over the short-term.

South Australia

In South Australia, the 10% POE maximum demand forecast was also relatively constant. Growth in the forecast is largely attributed to increases in population and income growth. AEMO notes that the increase in this forecast can also be attributed to the return of the Port Pirie smelter.

Victoria

The 10% POE maximum demand forecast for Victoria changed the least between the two years. Growth forecasts have remained steady since the significant reduction in industrial demand as a result of the closure of the Port Henry aluminium smelter, and car manufacturing plants in August 2014.

Tasmania

Tasmania is the only NEM region which records its maximum demand in winter rather than summer. The growth in the forecast is predominantly due to population growth and income growth.

D.2 Forecast Accuracy report

D.2.1 Purpose

AEMO published the 2015 Forecast Accuracy report in November 2015.[122] The purpose of this report is to assess the accuracy of the operational consumption and

121 AEMO recognised that the changes made to the maximum demand POE forecasting model may have also contributed to this revision.

122 AEMO, *Forecast accuracy report 2015*, November 2015.

maximum demand forecasts in the 2014 NEFR. This is achieved by comparing 2014-15 forecasts in the 2014 NEFR with actual results for 2014-15. The 2015 Forecast Accuracy report also discussed changes made to the forecasting methodology which was used in the 2015 NEFR. In particular, the changes made to the econometric model in order to capture recent consumption patterns and to become more sensitive to region-specific trends.

D.2.2 Regional energy forecast accuracy

Variances between forecast and actual operational consumption ranged between 0.7 and 6.2per cent. Table D.2 summarises this variance.

Table D.2 Variance between forecast operational consumption for 2014-15 in the 2014 NEFR and actual consumption

Region	Forecasted (GWh)	Actual (GWh)	Variance (GWh)	Variance (%)
NSW	65,321	67,145	-1,824	-2.7
Queensland	45,362	48,356	-2,994	-6.2
South Australia	12,560	12,468	92	0.7
Victoria	42,586	42,574	12	0.0
Tasmania	9,862	9,924	-62	-0.6
NEM	175,691	180,467	-4,776	-2.65

Source: AEMO, *Forecast Accuracy report 2015 – for the National Electricity Forecasting Report*, November 2015; AEMO, *Forecast Accuracy report 2014 – for the National Electricity Forecasting Report*, November 2014.

The 2015 Forecast Accuracy report noted the reasons for these variances are as follows:

Queensland

The forecast error in Queensland was the largest in the NEM. The operational consumption forecast was 6.2 per cent below than the actual consumption level. The main reasons for this underestimation are:

- higher than expected large industrial consumption;
- higher than expected residential and commercial consumption (excluding the impact of rooftop PV output);
- higher than expected transmission losses; and
- lower than expected rooftop PV output, increasing residential and commercial consumption from the grid.

NSW (including ACT)

NSW also reported a relatively high forecast error at -2.7 per cent. The main reasons for this are:

- higher than expected residential and commercial consumption (excluding the impact of PV output);
- higher than expected large industrial consumption; and
- higher than expected PV production.

South Australia

South Australia reported a slight overestimation of operational consumption. This was attributed to slightly lower than expected large industrial consumption occurring.

Victoria

Although there was virtually no difference between forecast and actual consumption, AEMO notes that there was variation between the estimation components. Specifically, AEMO notes:

- lower than expected residential and commercial consumption;
- higher than expected large industrial consumption; and
- higher than expected transmission losses.

Tasmania

Tasmania also reported a slight overestimation of operational consumption. The main reasons for this are:

- higher than expected rooftop PV output, reducing residential and commercial consumption from the grid; and
- higher than expected industrial consumption.

D.2.3 Regional 10% maximum demand POE forecast accuracy

The 10% maximum demand POE is a maximum demand value that is expected to be exceeded once every 10 years. The variance between the forecasted 10% maximum demand POE and the actual 10% maximum demand POE, as reported in the 2014 and 2015 NEFR respectively is outlined in Table D.3. Here the actual value (as reported in the 2015 NEFR) is used to indicate that actual economic and weather data has been used to calculate the 10% maximum demand POE.

Table D.3 Variance between forecast 10% POE maximum demand in the 2014 NEFR and actual 10% POE maximum demand

Region	Forecasted (GWh)	Actual (GWh)	Variance (GWh)	Variance (%)
NSW	13,438	14,265	-827	-5.8
Queensland	8,461	9,100	-639	-7.0
South Australia	3,277	3,185	92	2.9
Victoria	10,114	10,034	80	0.8
Tasmania	1,756	1,754	2	0.1

Note: Numbers for Queensland exclude the impact of LNG. As maximum demand in Tasmania occurs in winter, the results for Tasmania are for the 2014 calendar year.

Source: AEMO, *Forecast Accuracy Report 2015 – for the National Electricity Forecasting Report,* November 2015.

The 2015 Forecast Accuracy Report noted the reasons for these variances are as follows.

Queensland

Queensland has the largest discrepancy between the forecasted and actual 10% maximum demand POE. AEMO attributes this to higher than expected LNG demand and warmer than average summer months. Both of these factors contributed to higher than expected residential and commercial demand.

NSW (including ACT)

Likewise, AEMO notes that the warmer than average summer months contributed to higher than expected residential and commercial demand.

South Australia

AEMO notes the lower than expected large industrial demand contributed to the overestimation of the 10% maximum demand POE. Furthermore, AEMO notes that a change made to the 2015 maximum demand modelling methodology was also a likely contributor to this variance.

Victoria

AEMO notes that the forecasted and actual 10% maximum demand POE are in good agreement as there is only 0.8 per cent difference between the two.

Tasmania

AEMO notes that the forecast and actual 10% maximum demand POE are in good agreement as there is only 0.1 per cent difference between the two. It is important to note that Tasmania's maximum demand occurs during the winter months and different methods are used to forecast maximum demand POE.

E Weather summary 2014-15

E.1 Season weather summary

This section provides a review of the weather across the NEM region for 2014-15 and how it impacted on the NEM. In particular, it reports on those extreme weather events that had an impact on the NEM and consumer responses.

The weather can have a significant impact on the delivery of electricity. During periods of hot weather, demand for electricity can be very high and the heat can restrict the ability of generating plants to operate at rated generation levels. In addition, hot weather and bushfires can adversely affect transmission and distribution network capability.

High demand for electricity can also occur during cold weather and ice and snow can adversely affect overhead transmission and distribution line capability.

Long periods of drought can also seriously affect generation availability as hydro generators require sufficient reservoir levels and some thermal generators require water for cooling. While storms and floods may have an immaterial effect on demand levels, they can cause supply interruptions through damage to the transmission and distribution networks, through lightning strikes to transmission lines or trees falling on distribution lines.

Below is a summary of the climate for 2014-15 by each season.[123]

E.1.1 Winter 2014

Average temperatures were above average in all areas of the NEM region during July and August 2014. Tasmania had an equal sixth highest winter temperature on average. Rainfall was below average for all areas of Australia.

E.1.2 Spring 2014

Spring 2014 was the warmest spring on record for Australia for the second year running. South Australia recorded their highest mean temperature on record. All maximum temperatures were significantly above the average with significant anomalies in NSW, Victoria and South Australia regions. All areas across the NEM region recorded significantly lower than average rainfall for spring 2014, with NSW experiencing its lowest rainfall since 2002.

123 Information in this appendix has been obtained from the Australian seasonal climate summary archive of the Australian Bureau of Meteorology.

E.1.3 Summer 2014-15

The summer was warmer than the average for Australia as a whole and was the fifth-warmest on record. All of the regions within the NEM recorded above average temperatures for summer.

February was a very warm month across the NEM, producing a pattern of persistent warmth with numerous records broken. Most notably, Australia recorded the fourth highest maximum temperature on record. Between the 8 and 10 of February, the Australian area-averaged maximum temperature exceeded 38 degrees, this is only the second time this has occurred, with the previous three day period back in 1983.

The Australian area-averaged rainfall for the summer period was seven per cent above the long-term Australian average as a whole. This is a result due largely in part to the significant deviation from the long-term average rainfall in NSW and Victoria. However, Queensland and Tasmania both experienced rainfall less than the average long term mean in each area.

E.1.4 Autumn 2015

Autumn 2015 was colder than average for Australia. The majority of geographical locations including Victoria, Tasmania and South Australia were also below the long term average.

E.2 Notable hot periods during 2014-15

Sydney's warmest days were Saturday 1 November 2014 and Sunday 1 March 2015 with maximum temperatures of 36.4 degrees and above. On 1 November 2014 demand reached 9,485 MW. However, for the NSW region the maximum demand was 11,883 MW on 21 November 2014.[124]

On Thursday 2 January and Friday 3 January 2015, Melbourne experienced maximum temperatures of 38.8 degrees and 38.2 degrees respectively. Demand reached 7,676 MW. This was lower than expected given it was the holiday season. On 22 January 2015, another notably hot day occurred in Melbourne reaching a maximum temperature of 35.8 degrees. No date in 2014-15 reached the 40 degree mark in Melbourne, unlike January 2014 which exceeded 40 degrees on four consecutive days.

Brisbane's hottest day was Sunday 16 November 2014 which reached 38.9 degrees. The maximum demand in summer for Queensland was 8,831 MW on 5 March 2015 although January was the warmest month in Brisbane for 2014-15.

Adelaide's maximum temperature was 44.1 degrees which occurred on Friday 2 January 2015. This was the 6th day in a row with temperatures above 30 degrees. Hobart's highest maximum temperature was 37.1 degrees on 22 February 2015.

124 Electricity demand information has been obtained from AEMO, *2015 National Electricity Forecasting Report*.

E.3 Notable cold periods during 2014-15

Sydney's coldest days were Sunday 12 July and Monday 3 August 2015 where minimum temperatures were 6.4 and 5.5 degrees, respectively. July 2014, on average, recorded the lowest daily minimum average temperature for 2014-15 in Sydney.

Melbourne's coldest days were on 3 and 4 August 2014 with temperatures of 1.2 and 1.7 degrees, respectively. August 2014 was the coldest month within Melbourne recording a lowest daily minimum average temperature of 7.6 degrees.

Brisbane's coldest day was 12 July 2014 with a minimum temperature of 2.6 degrees.

Adelaide's coldest days were between 2 and 6 August 2014 with temperatures ranging from 0.9 to 3.3 degrees.

Hobart's coldest days were between 19and 23 June 2015 (when temperatures ranged between 0.3 and 2 degrees) and had a minimum temperature recording of 0.3 degrees on Monday 22 June 2015.

F Security performance

Appendix F provides a detailed analysis of the power system's security management, and the measurement of the power system's security performance. The complete review of the power system's performance is discussed in Chapter 5.

F.1 Security management

Maintaining the security of the power system is one of AEMO's key obligations. The power system is deemed secure when it is in a satisfactory operating state and will return to a satisfactory operating state following the occurrence of any single credible contingency event.

A satisfactory operating state is achieved when:

- the frequency is within the normal operating frequency band;
- voltages at all energised busbars at any switchyard or substation are within relevant limits;
- the current flows on all transmission lines of the power system are within the ratings;
- all other plant forming part of or impacting on the power system is operating within its rating; and
- the configuration is such that the severity of any potential fault is within the capability of circuit breakers to disconnect the faulted circuit or equipment.

A secure or satisfactory operating state depends on the combined effect of controllable plant, ancillary services, and the underlying technical characteristics of the power system plant and equipment.

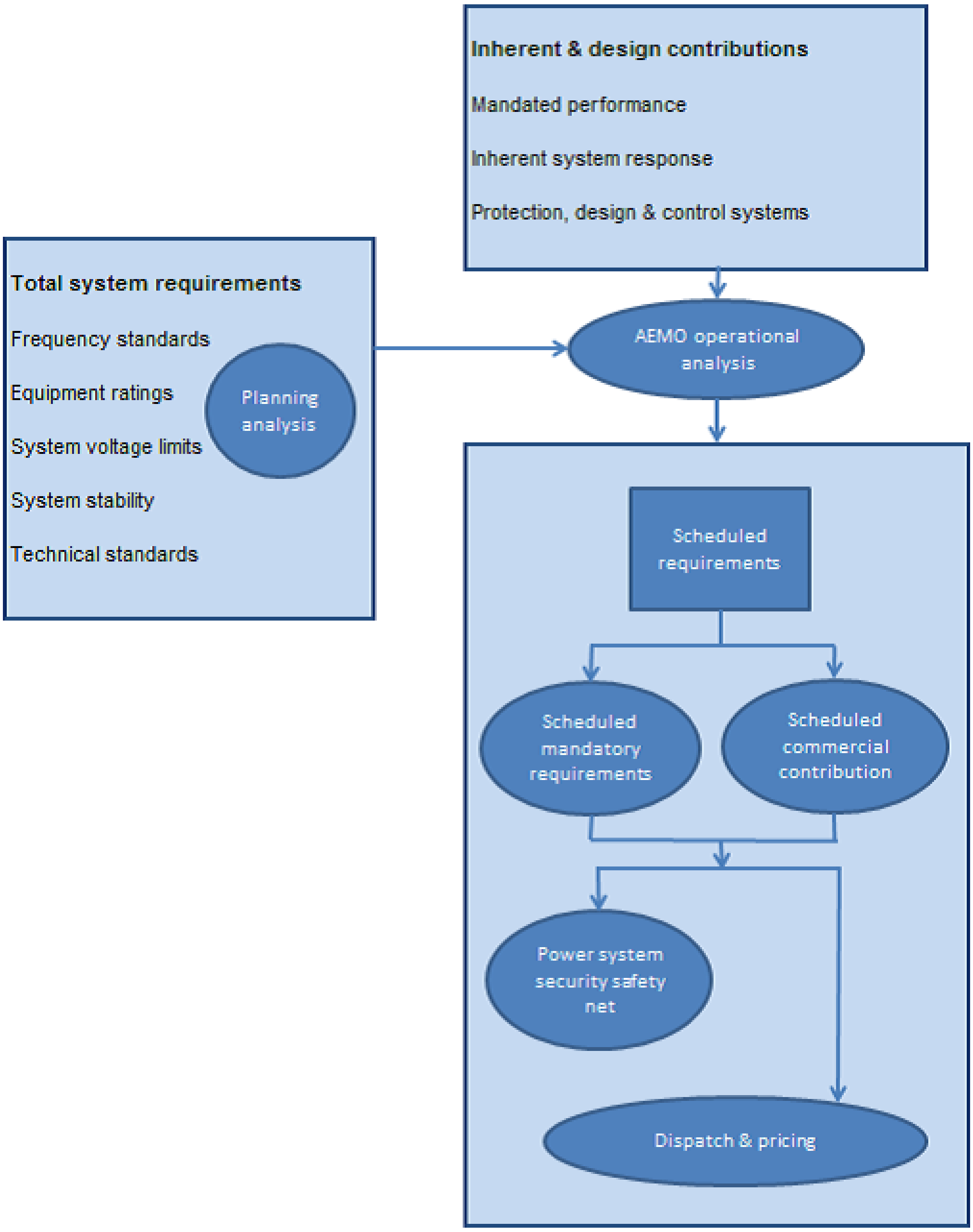
AEMO determines the total technical requirements for all services needed to meet the different aspects of security from:

- the Panel's power system security and reliability standards;
- market rules obligations and knowledge of equipment performance as supplied by the TNSPs; and
- design characteristics and modelling of the dynamic behaviour of the power system.

This allows AEMO to determine the safe operating limits of the power system and associated ancillary service requirements.

Figure F.1 illustrates the overall arrangements for security. The operation of each element is explained and analysed in this section.

Figure F.1 Security model



Source: AEMO.

F.2 System technical requirements

To meet the power system security standards, a number of technical requirements must be satisfied. They include the technical standards, frequency operating standards, equipment ratings, system voltage limits, system stability criteria, and generator performance standards. These requirements are addressed by AEMO as part of its planning and operational activities and are discussed below.

F.3 System restart standard

The Panel also determines the system restart standard for the acquisition of system restart ancillary services.[125]

The SRS sets out several key parameters for power system restoration, including the timeframe for restoration and how much supply is to be restored. The standards provides AEMO with a target against which it procures system restart ancillary services (SRAS) from contracted SRAS providers, such as generators with SRAS black start capability. In the event of a major supply disruption, SRAS may be called on by AEMO to supply sufficient energy to restart power stations in order to begin the process of restoring the power system. AEMO’s development of the System Restart Plan must be consistent with the standard. The purpose of SRAS is to restore supply following an event that has a widespread impact on a large area – such as an entire jurisdiction.

The SRS does not relate to the process of restoring supply to consumers directly following blackouts within a distribution network or on localised areas of the transmission networks. In addition there is a separate process, developed with input of jurisdictional governments to manage any disruption that involves the operator on a network having to undertake controlled shedding of customers. Restoration of load from these localised or controlled events is not covered by the standard.

AEMO has never drawn on procured SRAS, including in 2014-15. However, during the year it undertook a tender process for procuring system restart services for the period 1 July 2015 to 30 June 2018. In June 2015, AEMO announced the outcome of its procurement of SRAS for that period. As a result of this tender, the total amount AEMO expects to spend on the acquisition of SRAS dropped from $55 million a year in 2014-15 to $21 million a year in 2015-16, representing a reduction of 62 per cent, which is still higher than the cost of SRAS in the period before 2007-08.[126]

The current SRS was determined by the Panel in 2012. On 2 April 2015, the AEMC made a rule changing the requirements on AEMO relating to the procurement of SRAS and on the requirements for the standard. As a result of this rule change request the AEMC require the Panel to review the SRS to meet the revised rule requirements. The Panel received terms of reference from the AEMC on 30 June 2015 to undertake this review.

The Panel also notes that, since 1 July 2015, AEMO is required to report annually on matters related to system restart services. This was requirement was placed on AEMO as part of the AEMC's system restart ancillary services final rule determination discussed in section 7.2.3.

125 NER clause 8.8.1(a)(1a) and AEMC Reliability Panel, System restart standard, *Electricity guidelines and standards*, 1 August 2013.

126 This tender process was completed on 2 July 2015: AEMO, *System restart ancillary services 2015, Tender process report*, 2 July 2015.

F.4 Technical standards framework

The technical standards framework is designed to maintain the security and integrity of the power system by establishing clearly defined standards for the performance of the system overall.

The framework comprises a hierarchy of standards:

- System standards define the performance of the power system, the nature of the electrical network and the quality of power supplied.
- Access standards specify the quantified performance levels that plant (consumer, network or generator) must have in order to connect to the power system.
- Access standards specify the quantified performance levels that plant (consumer, network or generator) must have in order to connect to the power system.

These system standards establish the target performance of the power system overall.

The access standards define the range within which power operators may negotiate with network service providers, in consultation with AEMO, for access to the network. AEMO and the relevant network service provider need to be satisfied that the outcome of these negotiations is consistent with their achieving the overall system standards. The access standards also include minimum standards below which access to the network will not be allowed.

The system and access standards are tightly linked. For example, the access standard is designed to meet the frequency operating standards, which is a system standard. In defining the frequency operating standards, consideration would need to be given to the cost of plant in meeting the required access standards.

The plant standards can be used for new or emerging technologies, such as wind power. The standard allows a class of plant to be connected to the network if that plant meets some specific standard such as an international standard. To date, the Panel has not been approached to consider a plant standard.

F.5 Registered performance standards

The performance of all generating plant must be registered with AEMO as a performance standard. Registered performance standards represent binding obligations. To ensure a plant meets its registered performance standards on an ongoing basis, participants are also required to set up compliance monitoring programs. These programs must be lodged with AEMO. It is considered a breach of the rules if plant does not continue to meet its registered performance standards and compliance program obligations.

The technical standards regime, which came into effect in late 2003, "grandfathered" the performance of existing plant. This established a process to specify the registered standard of existing plant as the capability defined through any existing derogation, or connection agreement or the designed plant performance.[127]

Once set, a plant's performance standard does not vary unless an upgrade is required. Where that occurs, a variation in the connection agreement would be needed.

F.6 Changes to performance standards

The AEMC has conducted a number of reviews, resulting in some changes to the process where the performance standards of a generator are registered. They include:

- Review into the enforcement of and compliance with technical standards.[128]
- Technical standards for wind and other generator connections rule change.[129]
- Resolution of existing generator performance standards rule change.[130]
- Performance standard compliance of generators rule change.[131]
- Reliability Panel technical standards review.[132]

In addition, the Panel undertook and completed a review into a program for generator compliance. This culminated in the construction of a template for generator compliance programs that was published by the Panel in July 2009. The Panel performed its first review of the template in 2011-12 and adopted a template with minor amendments in its June 2012 final report.[133]

The Panel undertook a further review of the template for generator compliance, which was completed in June 2015.[134]

127 While the changes to the rules were introduced in March 2003, the period between November 2003 and November 2004 allowed for all existing generators to register their existing performance with National Electricity Market Management Company Limited (now AEMO).

128 AEMC, *Review of enforcement of and compliance with technical standards*, Report, 1 September 2006, Sydney.

129 AEMC, *National Electricity Amendment (Technical Standards for Wind and other Generator Connections) Rule 2007, Rule Determination*, 8 March 2007, Sydney.

130 AEMC, *National Electricity Amendment (Resolution of existing generator performance standards) Rule 2006 No. 21, Rule Determination*, 7 December 2006, Sydney.

131 AEMC, *National Electricity Amendment (Performance Standard Compliance of Generators) Rule 2008 No. 10*, 23 October 2008, Sydney.

132 AEMC Reliability Panel, *Reliability Panel Technical Standards Review, Final Report*, 30 April 2009, Sydney.

133 The Panel's final report is available on the AEMC website under the project reference: "REL0047".

134 See: www.aemc.gov.au, viewed 22 August 2016.

F.7 Frequency operating standards

Control of power system frequency is crucial to security. The Panel is responsible for determining the frequency operating standards that cover normal conditions, as well as the period following critical events when frequency may be disturbed. The frequency operating standards also specify the maximum allowable deviations between Australian Standard Time and electrical time (based on the frequency of the power system). The frequency operating standards 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.

The frequency operating standards require that during periods when there are no contingency events or load events, the frequency must be maintained within the normal operating frequency band (49.85 Hz to 50.15 Hz in both Tasmania and the NEM mainland) for no less than 99 per cent of the time. The frequency operating standards also require that following a credible contingency event, the system frequency should not exceed the normal operating frequency excursion band for more than five minutes on any occasion. Following either a separation or multiple contingency event, the system frequency should not exceed the normal operating frequency excursion band for more than ten minutes.

F.7.1 NEM mainland frequency operating standards

The frequency operating standards that apply on the NEM mainland to any part of the power system other than an island are shown in Tables F.1 to F.3.

Table F.1 NEM mainland frequency operating standards (except "islands")

Condition	Containment	Stabilisation	Recovery
Accumulated time error	5 seconds	n/a	n/a
No contingency event or load event	49.75 to 50.25 Hz100	49.85 to 50.15 Hz within 5 minutes	
	49.85 to 50.15 Hz		
	99% of the time		
49.85 to 50.15 Hz within 5 minutes	49.5 to 50.5 Hz	49.85 to 50.15 Hz within 5 minutes	
Network event	49 to 51 Hz	49.5 to 50.5 Hz within 1 minute	49.85 to 50.15 Hz within 5 minutes
Separation event	49 to 51 Hz	49.5 to 50.5 Hz within 2 minutes	49.85 to 50.15 Hz within 10 minutes
Multiple contingency event	47 to 52 Hz	49.5 to 50.5 Hz within 2 minutes	49.85 to 50.15 Hz within 10 minutes

Source: The Panel's website: www.aemc.gov.au, viewed 16 June 2015.

Table F.2 NEM mainland frequency operating standards for “island” conditions

Condition	Containment	Stabilisation	Recovery
No contingency event or load event	49.5 to 50.5 Hz		n/a
Generation event, load event or network event	49 to 51 Hz		49.5 to 50.5 Hz within 5 minutes
The separation event that formed the island	49 to 51 Hz or a wider band notified to AEMO by a relevant Jurisdictional Coordinator	49.0 to 51.0 Hz within 2 minutes	49.5 to 50.5 Hz within 10 minutes
Multiple contingency event including a further separation event	47 to 52 Hz	49.0 to 51.0 Hz within 2 minutes	49.5 to 50.5 Hz within 10 minutes

Source: The Panel's website: www.aemc.gov.au, viewed 16 June 2015.

Table F.3 NEM mainland frequency operating standards during supply scarcity condition

Condition	Containment	Stabilisation	Recovery
No contingency event or load event	49.5 to 50.5 Hz		
Generation event, load event or network event	48 to 52 Hz (Queensland and South Australia)	49.0 to 51.0 Hz within 2 minutes	49.5 to 50.5 Hz within 10 minutes
	48.5 to 52 Hz (New South Wales and Victoria)		
Multiple contingency event or separation event	47 to 52 Hz	49.0 to 51.0 Hz within 2 minutes	49.5 to 50.5 Hz within 10 minutes

Source: The Panel's website: www.aemc.gov.au, viewed 16 June 2015.

On 18 December 2008, the Panel submitted its final report outlining the amended frequency operating standards to apply in Tasmania to the AEMC for publication.[135] The amended frequency operating standards for Tasmania took effect on 28 October 2009. The frequency operating standards that apply in Tasmania to any part of the power system other than an island are shown in Tables F.4 and F.5.

135 AEMC, *Review of Frequency Operating Standards for Tasmania, Final Report*, 18 December 2008, Sydney.

Table F.4 Tasmanian frequency operating standards (except "islands")

Condition	Containment	Stabilisation	Recovery
Accumulated time error		15 seconds	
No contingency event or load event	49.75 to 50.25 Hz,	49.85 to 50.15 Hz within 5 minutes	
	49.85 to 50.15 Hz		
	99% of the time		
Load and generation event	48.0 to 52.0 Hz	49.85 to 50.15 Hz within 10 minutes	
Network event	48.0 to 52.0 Hz	49.85 to 50.15 Hz within 10 minutes	
Separation event	49.85 to 50.15 Hz within 10 minutes	48.0 to 52.0 Hz within 2 minutes	49.85 to 50.15 Hz within 10 minutes
Multiple contingency event	47.0 to 55.0 Hz	48.0 to 52.0 Hz within 2 minutes	49.85 to 50.15 Hz within 10 minutes

Source: The Panel's website: www.aemc.gov.au, viewed 16 June 2015.

Table F.5 Tasmania frequency operating standards for "island" conditions

Condition	Containment	Stabilisation	Recovery
No contingency event or load event	49.0 to 51.0 Hz		
Load and generation event	48.0 to 52.0 Hz	49.0 to 51.0 Hz within 10 minutes	
Network event	48.0 to 52.0 Hz	49.0 to 51.0 Hz within 10 minutes	
Separation event	47.0 to 55.0 Hz	48.0 to 52.0 Hz within 2 minutes	49.0 to 51.0 Hz within 10 minutes
Multiple contingency event	47.0 to 55.0 Hz	48.0 to 52.0 Hz within 2 minutes	49.0 to 51.0 Hz within 10 minutes

Source: The Panel's website: www.aemc.gov.au, viewed 16 June 2015.

F.8 System stability

Transferring large amounts of electricity between generators and consumers over a wide area presents technical challenges to the stability of the power system. One of AEMO's core obligations is to ensure that stability of the power system is maintained. The primary means of achieving this is to carry out technical analysis of threats to stability. Under the rules, generators and TNSPs monitor indicators of system instability and report their findings to AEMO. AEMO then analyses the data to determine whether the standards have been met. AEMO also uses this data to confirm and report on the correct operation of protection and control systems.

AEMO has a number of real-time monitoring tools which help it meet its security obligations and which provide valuable feedback on the planning process. These tools include the state estimator, power flow, contingency analysis and stability monitoring software.

Monitoring equipment that detects oscillatory disturbances on the power system has been installed at a number of locations in the NEM. This equipment, set up by AEMO in conjunction with Powerlink, measures small changes in the power flow on key interconnectors and analyses these changes to determine the state of the power system.[136]

A system upgrade in 2006-07 permitted a larger number of locations to be observed simultaneously and to enhance historical analysis of power system oscillatory stability.

AEMO monitors power system stability in real- time using two security analysis tools. The Dynamic Security Analysis tool monitors transient instability on the power system and the Voltage Security Assessment tool monitors voltage instability. Both the Dynamic Security Analysis tool and Voltage Security Assessment tool use real-time data from the AEMO energy management system to simulate the behaviour of the power system for a variety of critical network, load and generator faults. This type of analysis has traditionally been performed by off-line planning staff. The Dynamic Security Analysis tool and Voltage Security Assessment tools use actual system conditions and network configuration to automatically assess the power system.

In addition, AEMO has been working with TNSPs to develop a NEM-wide High-speed Monitoring System. This system would complement AEMO's existing oscillatory stability monitoring capability by enhancing observability of power system disturbances in operational timeframes and for post-contingency analysis. High-speed monitoring systems are owned and operated by each of the TNSPs and AEMO has access to their data.

AEMO's review of significant events in recent times showed system damping times were generally within the stipulated requirements. However, AEMO has highlighted the need to maintain adequate monitoring using high speed monitors and advanced analysis techniques to ensure that causes of poor damping can be located and addressed in a timely manner.

There have been a number of occasions (including difficult to predict, unlikely and unknown cases) when these real-time monitoring tools identified the need to reduce transfer capability. On these occasions, the power system conditions at the time were

136 Further information is available at www.gegridsolutions.com/alstomenergy/grid/Global/OneAlstomPlus/Grid/PDF/NMS/Successes-Powerlink.pdf.

used to review limits and constraints. It is important for transparency and predictability in dispatching the market, to ensure that these more restrictive limits are fed back into the processes for determining limits, and constraint equations are used to manage those limits.

Some dispatch scenarios and power system configurations were not considered when system limits were originally determined. Online real time monitoring allows for these scenarios to be defined and fed back to the relevant TNSP. This real time monitoring is an important tool for circumstantial indication of security in particular cases. However, it might not concur that a significant increase in analysis for the '–1' condition would be of greater benefit. A higher level of 'N-X' limit analysis might mean an exponential increase in the amount of work to derive and implement and even then, might result in a very conservative market impact.

G Safety framework

As noted in Chapter 6, NSPs and other market participants have specific responsibilities to ensure the safety of personnel and the public. The electrical system is designed with extensive safety systems to ensure the protection of the system itself, workers and the public. Each NEM region is subject to different safety requirements as set out in the relevant jurisdictional legislation. State and territory legislation governs the safe supply of electricity by network service providers and broader safety requirements associated with electricity use in households and businesses.

Examples of the different jurisdictional safety arrangements are provided below. The Panel considers it is of benefit to provide an overview of some of the jurisdictional arrangements to provide context to issues that may be relevant to stakeholders. The Panel notes this is not an exhaustive summary of safety requirements in each region.

G.1 Queensland

In Queensland, the Electrical Safety Office is the electrical safety regulator that undertakes a range of activities to support electrical safety with the key objective of reducing the rate of electrical fatalities in Queensland. The *Electrical Safety Act 2002 (Qld)* places obligations on people who may affect the electrical safety of others. This stand-alone legislation fundamentally changed Queensland's approach to electrical safety, establishing a Commissioner for Electrical Safety, an Electrical Safety Board and three Board committees to advise the Minister on electrical safety issues. Additionally, an independent state-wide electrical safety inspectorate was established to administer and enforce the new legislative requirements.

One of the responsibilities of the Electrical Safety Board is the development of a five year strategic plan for improving electrical safety in Queensland. The Electrical Safety Plan for Queensland 2014–2019 was published in 2013 and sets out strategies designed to achieve the Board's goal of eliminating all preventable electrical deaths in Queensland by 2019.

G.2 NSW

In NSW, IPART is the safety and reliability regulator for electricity networks under the *Electricity Supply Act 1995 (NSW)* and the Electricity Supply (Safety and Network Management) Regulation 2014 (NSW). IPART strives to ensure safe and reliable supply of electricity for the benefit of the NSW community (including employees of the network operators) and the environment.

IPART has been granted new compliance and enforcement powers with an overall objective to:

- maintain safety standards within electricity networks; and
- meet relevant reliability standards set by government.

Electricity networks continue to have the ultimate responsibility for network safety and reliability. IPART holds these utilities accountable by developing an effective risk based compliance and enforcement framework.

The NSW Fair Trading monitors the safety of customer electrical installations under the *Electricity (Consumer Safety) Act 2004 (NSW)* and Electricity (Consumer Safety) Regulation 2015 (NSW). SafeWork NSW monitors the safety of work places under the *Work Health and Safety Act 2011 (NSW)* and Work Health and Safety Regulation 2011 (NSW). The NSW Department of Industry authorises accredited service providers under the *Electricity Supply Act 1995 (NSW)* and the Electricity Supply (General) Regulation 2014 (NSW).

G.3 ACT

The ACT Planning and Land Authority administers the *Electricity Safety Act 1971 (ACT)* and Electricity Safety Regulation 1971 (ACT) in the ACT. This legislation ensures electrical safety, particularly in relation to:

- the installation, testing, reporting and rectification of electrical wiring work for an electrical installation and its connection to the electricity distribution network (the Wiring Rules are the relevant standard);
- the regulation and dealings associated with the sale of prescribed and non-prescribed articles of electrical equipment;
- the reporting, investigation and recording of serious electrical accidents by responsible entities;
- enforcement by the ACT Planning and Land Authority and its electrical inspectors (including inspectors' identification, entry powers, seizing evidence, disconnection of unsafe installations and articles, powers to collect verbal and physical evidence and respondents' rights);
- the appeals system; and
- miscellaneous matters such as certification of evidence.

G.4 Victoria

Electricity safety in Victoria is regulated by Energy Safe Victoria. The role of Energy Safe Victoria involves overseeing the design, construction and maintenance of electricity networks across the state and ensuring every electrical appliance in Victoria meets safety and energy efficiency standards before it is sold. Energy Safe Victoria oversees a statutory regime that requires major electricity companies to submit and comply with their Electricity Safety Management Scheme, submit bushfire mitigation plans annually for acceptance and electric line clearance management plans annually for approval, and to actively participate in Energy Safe Victoria audits to test compliance of their safety systems.

G.5 South Australia

In South Australia, the Office of the Technical Regulator is responsible for the administration of the *Electricity Act 1996 (SA)* and *Energy Products (Safety and Efficiency) Act 2000 (SA)*. The primary objective of these Acts is to ensure the safety of workers, consumers and property as well as compliance with legislation, technical standards and codes in the electricity industries.

The principal functions of the Office of the Technical Regulator under the *Electricity Act 1996 (SA)* are:

- monitoring and regulation of safety and technical standards in the electricity supply industry;
- monitoring and regulation of safety and technical standards relating to electrical installations;
- administration of the provisions of the Act relating to clearance of vegetation from power lines; and
- fulfilling any other function assigned to the Technical Regulator under the Act.

G.6 Tasmania

Until 1 June 2010, several safety functions were vested with the Office of the Tasmanian Economic Regulator under the *Electricity Industry Safety and Administration Act 1997 (Tas)* and the *Electricity Supply Industry Act 1995 (Tas)*. The *Electricity Industry Safety and Administration Act 1997 (Tas)*:

- provides for electrical contractors and workers to be appropriately qualified and regulated;
- establishes safety standards for electrical equipment and appliances; and
- provides for the investigation of electrical safety accidents in the electricity industry.

Safety-related responsibilities were transferred to Workplace Standards Tasmania via an amendment to the *Electricity Industry Safety and Administration Act 1997 (Tas)* in 2009.

H Examples of AEMO recommendations for reviewable operating incidents

Table H.1 AEMO recommendations for reviewable operating incidents 2014-15

Participant responsible	AEMO recommendation
AusNet Services	• AusNet to replace flashed insulators on No.1 Line. • AusNet to investigate the reason why the White Phase of the capacitor bank opened and submit the investigation findings to AEMO by 30 September 2014.
AEMO	• In relation to the Post Contingent overload on the 132 kV transmission lines between Waterloo and Robertstown on 4 March 2015, AEMO has reviewed and revised the outage assessment process to ensure all relevant constraints are included in the outage constraint set. This action was taken to prevent this incident from occurring in the future.

Source: AEMO.

I Pricing review

Tables I.1a and I.1b summarise the occurrence of extreme pricing events throughout the NEM during 2014-15.

Table I.1a Pricing event notices for July 2014 to December 2014

Period	Date	Region	Trading Interval (ending)	Price per MWh
July 2014	Tuesday 1 July 2014	South Australia	8:30	$1,966.12
	Saturday 5 July 2014	Queensland	3:00	-$126.76
			14:30	-$328.02
	Sunday 6 July 2014	South Australia	19:30	$2,275.88
	Monday 14 July 2014	South Australia	20:00	$1,884.35
			20:30	$1,587.98
	Friday 18 July 2014	South Australia	19:00	$2,107.93
	Sunday 20 July 2014	South Australia	19:30	$2,288.13
			18:30	$2,088.28
	Tuesday 22 July 2014	South Australia	19:30	$2,412.12
August 2014	Monday 4 August 2014	South Australia	19:30	$1,923.30
	Monday 11 August 2014	South Australia	0:00	$1,822.01
	Wednesday 20 August 2014	South Australia	13:30	$2,284.78
		Tasmania	18:30	$815.43
	Thursday 21 August 2014	Tasmania	18:00	$2,277.62
	Saturday 30 August 2014	Tasmania	18:00	$1,532.72
September 2014	Thursday 4 September 2014	South Australia	17:30	$2,281.98
	Monday 8 September 2014	South Australia	0:00	$656.02

Period	Date	Region	Trading Interval (ending)	Price per MWh
	Tuesday 16 September 2014	Queensland	18:00	$2,296.92
	Thursday 25 September 2014	Queensland	6:00	-$150.62
October 2014	Saturday 25 October 2014	South Australia	0:00	$1,670.35
		Victoria	0:00	-$148.63
	Monday 27 October 2014	Tasmania	3:30	$4,405.84
	Tuesday 28 October 2014	Tasmania	6:30	$1,731.78
November 2014	Saturday 15 November 2014	Queensland	17:00	$2,304.32
	Tuesday 18 November 2014	Queensland	18:30	$1,146.24
	Wednesday 19 November 2014	Queensland	14:00	$1,965.95
			16:30	$2,379.64
	Monday 24 November 2014	Queensland	16:30	$1,156.28
	Tuesday 25 November 2014	Queensland	15:00	$2,296.88
	Saturday 29 November 2014	South Australia	15:30	$2,365.96
			16:30	$2,279.32
December 2014	Monday 8 December 2014	Queensland	13:30	$1,144.99
			16:30	$2,289.55
	Tuesday 9 December 2014	Queensland	12:30	$1,417.37
			15:30	$2,324.2
	Wednesday 10 December 2014	Queensland	14:30	$2,302.53
			17:00	$4,519.92
	Thursday 11 December 2014	Queensland	13:00	$2,351.52
	Tuesday 16 December 2014	Queensland	13:30	$3,172.31

Period	Date	Region	Trading Interval (ending)	Price per MWh
	Wednesday 17 December 2014	Queensland	14:00	$2,299.47
			20:00	$13,499.00
	Thursday 18 December 2014	Queensland	15:00	$2,282.63
			16:00	$1,139.96

Source: AEMO, http://www.aemo.com.au/Electricity/Resources/Reports-and-Documents/Pricing-Event-Reports

Table I.1b Pricing event notices for January 2015 to June 2015

Period	Date	Region	Trading Interval (ending)	Price per MWh
January 2015	Wednesday 7 January 2015	South Australia	14:00	$1,138.18
	Thursday 8 January	Tasmania	6:00	$714.69
	Thursday 8 January	Queensland	23:00	$1,797.48
	Friday 9 January 2015	Tasmania	17:30	-$139.08
		Queensland	23:00	$2,265.96
	Saturday 10 January 2015	Queensland	23:00	$2,269.81
	Sunday 11 January 2015	Queensland	10:00	$2,270.85
	Monday 12 January 2015	Queensland	8:30	$2,277.98
	Tuesday 13 January 2015	Queensland	7:00	$4,543.29
	Wednesday 14 January 2015	Queensland	19:00	$2,282.40
			20:00	$2,391.85
	Thursday 15 January 2015	Queensland	15:00	$1,783.73
			20:00	$12,950.00
	Friday 16 January 2015	Queensland	16:00	$2,230.95
			17:30	$4,523.27

Period	Date	Region	Trading Interval (ending)	Price per MWh
	Saturday 17 January 2015	Queensland	17:00	$2,209.01
		South Australia	16:30	$2,067.68
		Victoria	21:00	-$148.26
	Monday 19 January 2015	Queensland	8:30	$2,367.16
		Queensland	9:30	$553.25
	Monday 26 January 2015	Queensland	17:00	$2,278.01
			18:00	$2,274.37
February 2015	Saturday 7 February 2015	South Australia	16:00	$4,526.63
	Friday 13 February 2015	South Australia	10:30	$4,342.64
		Victoria		-$318.66
	Sunday 22 February 2015	South Australia	18:00	$1,988.35
		Tasmania		$2,295.52
	Sunday 22 February 2015	South Australia	0:00	$2,265.06
		Victoria		-$151.90
	Tuesday 24 February 2015	Queensland	17:00	$2,325.20
March 2015	Tuesday 03 March 2015	Queensland	7:00	$2,369.86
	Thursday 5 March 2015	Queensland	14:00	$2,212.64
			20:30	$13,166.27
			22:30	$1,034.50
	Sunday 8 March 2015	Queensland	19:00	$510.92
	Monday 9 March 2015	Queensland	17:00	$570.96
			19:00	$2,300.87
	Thursday 19 March 2015	Queensland	19:00	$2,349.73
	Friday 20 March 2015	Queensland	16:00	$1,841.38
			17:30	$2,100.65

Period	Date	Region	Trading Interval (ending)	Price per MWh
April 2015	Thursday 02 April 2015	Tasmania	6:30	$1,958.65
	Thursday 16 April 2015	South Australia	10:00	$2,282.19
	Friday 17 April 2015	South Australia	14:00	$1,845.63
	Tuesday 21 April 2015	Queensland	14:00	-$148.42
	Sunday 26 April 2015	South Australia	0:00	$2,289.40
	Tuesday 28 April 2015	South Australia	9:00	$552.39
	Wednesday 29 April 2015	South Australia	9:00	$502.77
		Tasmania	13:00	$1,009.16
		South Australia	15:30	$566.66
May 2015	Friday 01 May 2015	New South Wales	9:00	$1,792.03
		Victoria		$505.44
		Tasmania		-$137.27
	Thursday 21 May 2015	South Australia	0:00	$2,287.83
	Saturday 23 May 2015	South Australia	18:30	$2,327.67
	Tuesday 26 May 2015	Tasmania	7:00	$2,045.46
	Tuesday 26 May 2015	South Australia	0:00	$2,289.00
June 2015	Wednesday 10 June 2015	South Australia	12:30	$2,277.98
			15:30	$2,417.48
	Thursday 11 June 2015	South Australia	8:00	$2,318.91
			10:00	$1,834.76
	Friday 12 June 2015	South Australia	8:30	$2,306.02
			9:00	$2,314.94

Period	Date	Region	Trading Interval (ending)	Price per MWh
	Monday 15 June 2015	South Australia	12:30	$2,287.03
			14:30	$2,276.71

Source: AEMO,
http://www.aemo.com.au/Electricity/Resources/Reports-and-Documents/Pricing-Event-Reports

J 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; and a • 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	These are instructions AEMO issues to participants under clause 4.8.9 of the rules 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 clause 3.8 (NER), 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.
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.
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 or rules)	The NER came into effect on 1 July 2005, replacing the National Electricity Code.
National electricity system	The generating systems, transmission and distribution networks and other facilities owned, controlled or operated in the states and territories participating in the National Electricity Market.
Network	The apparatus, equipment and buildings used to convey and control the conveyance of electricity. This applies to both transmission networks 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. satisfactory operating state 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); and • the severity of any potential fault is within the capability of circuit breakers to disconnect the faulted circuit or equipment.
Secure operating state	The power system is in a secure operating state when: • it is in a satisfactory operating state; and • it will return to a satisfactory operating state following a single credible contingency event.
Reliable operating state	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 clause 4.8.9 (NER); • no load shedding is occurring or expected to occur anywhere on the power system under clause 4.8.9 (NER); and • 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	Under clause 4.2.7 of the rules, the power system is assessed to be in a reliable operating state when: • AEMO has not disconnected, and does not expect to disconnect, any points of load connection under clause 4.8.9 of the rules; • no load shedding is occurring or expected to occur anywhere on the power system under clause 4.8.9 of the rules; and • 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.
Reliability of supply	The likelihood of having sufficient capacity (generation or demand-side response) to meet demand (the consumer load).
Reliability standard	The Panel's current standard for reliability is that there should be sufficient generation and bulk transmission capacity so that, over the long term, no more than 0.002 per cent of the annual energy of consumers in any region is at risk of not being supplied, or to put it another way, so that the maximum permissible unserved energy (USE) 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	Explanation: • excursions outside the normal operating frequency band but within normal operating frequency excursion band; • the voltage magnitudes at all energised busbars at any switchyard or substation of the power system are within the relevant limits set by the relevant network service providers in accordance with clause S5.1.4 of Schedule 5.1 (of the rules); • the current flows on all transmission lines of the power system are within the ratings (accounting for time dependency in the case of emergency ratings) as defined by the relevant network service providers in accordance with Schedule 5.1 (of the rules); • all other plant forming part of or impacting on the power system is being operated within the relevant operating ratings (account for time dependency in the case of emergency ratings) as defined by the relevant network service providers in accordance with Schedule 5.1 (of the rules); • the configuration of the power system is such that the severity of any potential fault is within the capability of circuit breakers to disconnect the faulted circuit or equipment; and • the conditions of the power system are stable in accordance with requirements designated in or under clause S5.1.8 of Schedule 5.1 (of the rules).

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	Under clause 4.2.4 of the rules, the power system is defined to be in a secure operating state if, in AEMO's reasonable opinion, taking into consideration the appropriate power system principles (described in clause 4.2.6 of the rules): • 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 and reliability standards.
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.
Short term projected assessment of system adequacy (ST PASA) (also see MT PASA)	The PASA in respect of the period from two days after the current trading day to the end of the seventh day after the current trading day inclusive in respect of each trading interval in that period.
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 rules.
Spot price	The price for electricity in a trading interval at a regional reference node or a connection point.
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 cannot be supplied because there are insufficient supplies (generation) to meet demand