Reliability Panel
AEMC

REVIEW

Reliability Panel AEMC

FINAL REPORT

Annual Market Performance Review 2014

16 July 2015

Reference: REL0055
Final Report

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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 report setting out the findings of the Reliability Panel's annual review of market performance. The Panel carried out this review in accordance with the requirements of the National Electricity Rules where we have reviewed the performance of the National Electricity Market (NEM) in terms of reliability, security and safety over the 2013-14 financial year.

The NEM regions experienced the warmest spring on record for Australia in 2013. Temperatures were warmer than average for Australia over summer and autumn with a number of heat waves affecting Victoria, South Australia and Tasmania during January 2014. Temperatures in winter 2013 were average across the NEM regions. Average demand continues to decline and long-term demand projections were revised down. On a number of occasions, bushfires and lightning activity impacted power generation that had ramifications for the power system across the NEM.

Our report provides the Panel's considerations and comments on specific events that occurred in the stated year, as well as an assessment of the performance of the NEM against various reliability and security measures. To provide a comprehensive overview of reliability and security issues, our report also includes details provided to us about the reliability performance of transmission and distribution networks.

The Panel is continuously reviewing the way in which we undertake, and report on, this annual review. To this end, we sought comments on the draft report from stakeholders, including comments concerning the information and format of the report. One submission was received from GDF SUEZ Australian Energy (GDFSAE) highlighting several areas where GDFSAE considers the Panel could provide additional clarification or consideration. Where appropriate, GDFSAE's comments have been incorporated into the final report.

The preparation of this final report could not have been completed without the assistance of the Australian Energy Regulator, the Australian Energy Market Operator, network service providers, and the State and Territory 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 assistance provided by GHD Hill Michael in helping the Panel to carry out its annual review this year, and for its assistance in preparing the draft report that formed the basis of this final report.

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

Neville Henderson Chairman,

AEMC Reliability Panel

Commissioner, AEMC

Reliability Panel members

Neville Henderson, Chairman and AEMC Commissioner

Trevor Armstrong, Chief Operating Officer, Ausgrid

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1 Introduction

This report has been prepared under the Reliability Panel's (the Panel) annual market performance review (AMPR or review). The review is a requirement of the National Electricity Rules (NER or rules), where the Panel must carry out an annual review of the performance of the national electricity market (NEM) in terms of reliability, security and safety of the power system.

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;[1] and
- report to the 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.[2]

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);[3]

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1 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.

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

3 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 policies and guidelines referred to in clause 8.8.1 (a)(4);[4] and
- the guidelines referred to in clause 8.8.1 (a)(9).[5]

1.2 Purpose of the report

The purpose of this report is to set out the review's findings for the 2013-14 financial year. In conducting this review, the Panel has considered publicly available information in addition to information obtained directly from relevant stakeholders and market participants.[6]

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 Australian Energy Market Commission (AEMC or Commission).[7]

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**

  To provide a comprehensive overview of the performance of the power system, and where relevant information is available, the Panel has considered performance in terms of reliability and security, and from the perspective of the transmission and distribution sectors, in addition to the generation sector. The Panel's review of overall power system performance has also included consideration of the impact on end-use customers.

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4 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.

5 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.

6 The data and information gathered has been provided by a number of organisations including AEMO, network service providers, the Australian Energy Regulator and state-based 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.

The Panel has considered significant power system incidents ("reviewable operating incidents") which have occurred in the previous year. Consideration has also been given to 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).

- **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 the previous financial year. Consideration has been given to actual and forecast supply and demand conditions to assist the Panel to form a view on whether any underlying changes to reliability performance have, or are expected to have, occurred.

  The Panel has also considered 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 consultation process

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

The Panel published the draft report for this review on 13 May 2015. Submissions closed on 24 June 2015 and the Panel received one stakeholder submission from GDF SUEZ Australian Energy (GDFSAE). This is available on the AEMC website. The Panel has had regard to that submission in preparing this final report.

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

1.5 Structure of this report

This report documents the 2013-14 AMPR and incorporates a number of revisions compared to previous AMPR reports. These revisions are designed to improve the relevance of the AMPR through enhancing the accessibility of information and providing greater clarity regarding the outcomes from the AMPR.

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 the 2013-14 financial year, historical performance and assessment of emerging trends.
- **Chapter 4 – Forecast of reliability**: provides a review of published reports on the projected adequacy of capacity to deliver NEM reliability requirement.
- **Chapter 5 – Security performance**: provides details of any security related issues that occurred during the 2013-14 financial year.
- **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 undertaken during the year.
- **Appendices**: the 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.[8]

2.1 Reliability

Reliability is generally associated with ensuring there is enough capacity to generate and transport electricity to meet all consumer demand.[9]

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.[10] 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.

Compliance with the reliability standard is measured using the actual observed levels of USE for the most recent financial year.[11] The reliability of the NEM is reviewed each year to examine any incidents that have resulted in USE.

To assess against the reliability standard, the "bulk transmission" capacity of the NEM is taken to equate to the interconnector capability.[12] Consequently, only constraints in the transmission network that affect interconnector capability are considered when assessing the availability of reserves in a region.[13] The reliability standard does not

8 In its submission to the AMPR draft report, GDFSAE suggested that the Panel consider including in the AMPR report a set of “traffic lights” for simplified communication and navigation. The Panel has considered this suggestion and notes the importance of ensuring that the information and data presented in the AMPR report is clear and as user friendly as possible. The Panel will therefore give further thought to how it presents information and data in future AMPR reports, including the merits of incorporating a set of traffic lights as suggested by GFDSAE.

9 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.

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

11 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.

12 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.

13 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.

take into account USE that is caused by outages of local transmission or distribution elements that do not significantly impact the ability 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 considered the impact of transmission and distribution networks on reliability. As transmission and distribution network reliability performance requirements are set at a state level, the AMPR presents information on trends in aggregate reliability contributions from networks, but does not provide a detailed assessment against state-based reliability standards. Summaries of the transmission and distribution network reliability in the NEM have been provided to the Panel by the relevant network service provider or jurisdictional body and are included in Appendix D of this report.

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.[14]

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 their 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 objectives. 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 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 and should make certain equipment ratings are not exceeded following credible contingencies. A

14 Power system incidents are discussed in chapter 5.

principal tool used by AEMO to maintain power system security is implementing constraint equations in the market dispatch systems. Violations of constraint equations can signal periods where the power system is not in a secure state.

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

- 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 2013-14. 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 safety of the NEM and safety of 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. Jurisdictions have specific provisions that explicitly refer to safety duties of transmission and distribution systems.[15]

There are strong linkages between maintaining power system security and operating the power system safely. The transfer limits and ratings that define the secure operating envelope for the power system are set at levels that maintain safety. 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. The Panel notes that this is a narrow definition of safety. The Panel has deliberately limited the definition of safety for the purpose of this review given the scope of this work under the rules.[16]

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

16 The scope of this review is discussed in chapter 1.

Under this limited scope, 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.[17]

The Panel has included an overview of some of the jurisdictional safety provisions in Appendix F of this report.

2.4 Standards and guidelines

The performance of the power system is measured against various standards and guidelines which form the 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 technical standards 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. The system standards establish the target performance of the overall power system. AEMO’s obligations to manage the power system are also included in Chapter 4 of the NER.

- **Access standards** specify the quantified performance levels that plant (consumer, network or generator) must achieve to allow it to connect to the power system. Access standards define the range within which generators 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. 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 performance of all generating plant must also be registered by AEMO as a performance standard. Registered performance standards represent binding obligations. 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 AEMO. It is a breach of the NER if the

17 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.

generating plant does not continue to meet its registered performance standards and compliance program obligations.[18]

18 The Panel developed a template in 2009 to assist generators in designing their compliance programs and this template was reviewed by the Panel in 2011-12.

3 Reliability review

The reliability of the NEM can be influenced by the performance of generating plant, the maximum level of demand reached (as compared to the forecast) and the performance of the network. This section provides a review of NEM reliability in 2013-14 by considering the performance of each of these factors. Performance trends are also considered to assess changes over time.

3.1 Generation reliability

3.1.1 Changes in generation capacity

A total of 170 MW of new generation capacity (including new registrations and increases in capacity of existing plant) was commissioned[19] across the NEM in 2013-14.[20] Of this new capacity, 168 MW is located in Tasmania, 1.5 MW in Victoria and 0.13 MW in New South Wales.[21] This compares with a total of 522.7 MW of new generation capacity that was added to the NEM in 2012-13.[22]

In addition to new generation capacity, as at December 2014, there were 10 newly committed generation projects in the NEM totalling 648.5 MW. This capacity was split between wind (58 per cent) and large-scale solar (42 per cent).[23] This newly committed generating plant is expected to be commissioned in the next two years.[24]

Unit 7 of Wallerawang C Power Station was retired from the NEM on 20 June 2014. In addition to this retirement, a decision to place 385 MW of generation in dry storage was announced in 2013-14.[25]The affected generation related to the 385 MW gas-fired Swanbank E Power Station in Queensland, which was withdrawn from service in December 2014. Generating plant placed in dry storage may be returned to service if market conditions changed.

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19 The term commissioning is described in rule 5.8 of the NER. It outlines the overall approach to commissioning to be undertaken by a generator and the requirements to cooperate with AEMO and the relevant NSP. The generator is responsible for specifying and undertaking commissioning tests and providing evidence to AEMO and the relevant NSP that demonstrates the performance of the plant.

20 The new capacity includes scheduled/semi-scheduled and non-scheduled plant with the bulk of new capacity coming from wind farms.

21 Details of generator changes that have occurred since the last AMPR are included in Appendix I.

22 AEMC Reliability Panel, *Annual Market Performance Review 2013 – Final report*, 7 May 2013, p.7.

23 AEMO reference to committed projects.

24 Further information on the capacity of new committed generation can be found in Appendix I of this report.

25 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”.

Furthermore, Energy Australia advised in November 2014 that in addition to Unit 7, Unit 8 of the Wallerawang C power station would be removed from service and both units would be permanently closed and decommissioned.

3.1.2 Generator performance

The performance of generation as experienced by consumers in each region has been calculated with reference to the reliability standard. With reference to Table 3.1, the Panel notes that there were no instances of USE for 2013-14 in any region of the NEM.

Table 3.1 Generation performance for 2013-14

Region (generation)	Per cent of unserved energy	
	Standard	Actual
Queensland	0.002	0.000
New South Wales	0.002	0.000
Victoria	0.002	0.000
South Australia	0.002	0.000
Tasmania	0.002	0.000

The Panel notes the following:

- Although there was a reduction in overall generation capacity in the NEM due mainly to the dry storage of generation, the generator performance as measured with reference to the reliability standard was not impacted and has been unchanged for a number of years.
- The Panel does not consider, based on the above evidence, that the reduction in generation capacity during 2013-14 has resulted in reliability being reduced to a level below the reliability standard.
- With current levels of generating capacity, in addition to the committed generation capacity identified by AEMO, the Panel considers that there will be sufficient capacity to maintain power system reliability above the reliability standard.

3.2 Network developments

There were no major interconnectors commissioned during the 2013-14 financial year. Neither was there de-rating of any existing interconnector capacity. However, from an operational viewpoint, Directlink was out of service for an extended period (158 days) of time during 2013-14, which reduced the overall transfer capability between NSW and Queensland.

3.2.1 Planned interconnector upgrades

Heywood interconnector[26]

After considering a range of options to address expected congestion on the Victoria to South Australia interconnector and examining the merit of those options via a RIT-T assessment, AEMO (as the Victorian TNSP) and ElectraNet 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 South Australia to Victoria by a notional 190 MW in each direction.

As part of the RIT-T process, ElectraNet and AEMO submitted their preferred option to the AER. The AER undertook a formal assessment of the preferred option, confirming in September 2013 that the interconnector upgrade was justified and that it satisfied the requirements of the RIT-T process. As a result of the AER's decision, AEMO and ElectraNet were able to progress upgrade of the Heywood interconnector with funding in ElectraNet's revenue determination. Upgrade of the interconnector is expected to be completed by mid-2016.

Queensland – New South Wales Interconnector[27]

Powerlink and TransGrid have been investigating a network development to increase the capacity of the Queensland NSW interconnector. In November 2014 they announced there was uncertainty in the net benefits of the potential augmentation options.

The market benefits delivered by each option were highly dependent upon the assumptions used and varied considerably between the scenarios modelled. No option was identified that consistently delivered a net market benefit under all scenarios. Therefore the recommendation was that the project would no longer proceed under the current planning timeframe.

3.2.2 Interconnector performance

While the power system operates in a dynamic environment, there are instances where interconnectors exceed their secure limit for small periods of time; however, this is generally corrected within a dispatch interval. Typically an interconnector may exceed its secure limits when there is a loss of generation in a region resulting in a large increase in generation import across the interconnector.

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26 For further information see the regulatory tests for transmission section of AEMO's website under electricity planning.

27 TransGrid, *TransGrid and Powerlink Queensland: Summary of Project Assessment Conclusions Report*, Development of the Queensland – NSW Interconnector, 13 November 2014.

Transmission lines operating above secure limits are reported through AEMO's online management system. AEMO’s on-line staff then invoke network constraints to manage the power system within its secure limits.

The Panel has not been advised by AEMO of any power system incidents in the 2013-14 financial year where an interconnector was above its secure limit for more than one dispatch interval.

3.2.3 Transmission network performance

The performance of transmission networks is the responsibility of the relevant network service provider (NSP). 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.

The number of system minutes not supplied due to transmission outages provides an aggregate indicator of the reliability performance of transmission networks.

Table 3.2 shows the performance of the transmission network as experienced by consumers in each region. This information was supplied by TNSPs.

Table 3.2 Transmission networks unsupplied system minutes for 2013-14

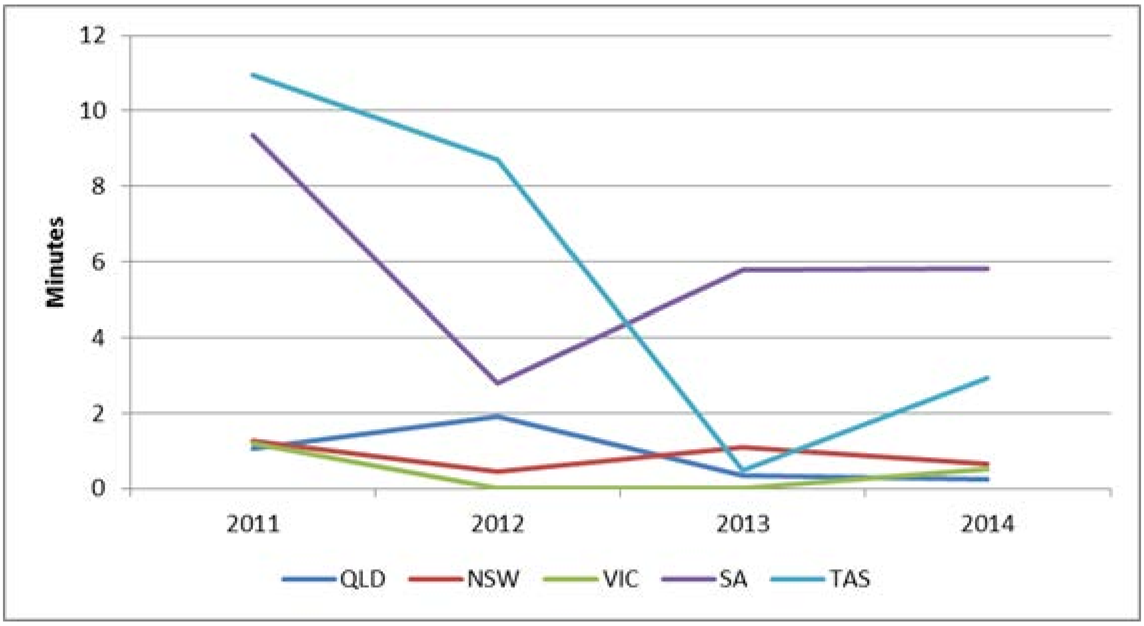
Region (transmission)	Calculated value in system minutes (amount of energy not supplied, divided by maximum demand, multiplied by 60)	
	2013-14	2012-13
Queensland	0.24	0.34
New South Wales	0.64	1.10
Victoria	0.52	0.00
South Australia	5.83	5.80
Tasmania	2.92	0.49

Victoria recorded an increase in unsupplied system minutes due to transmission contingencies between 2012-13 and 2013-14. With the exception of Victoria, during 2013-14, the mainland regions of the NEM recorded levels of unsupplied system minutes similar to those recorded in 2012-13.

Tasmania experienced a reduction in performance with the transmission system minutes increasing from 0.49 minutes in 2012-13 to 2.92 minutes in 2013-14. The reason for the deterioration in the unsupplied system minutes was not requested from TasNetworks.

Figure 3.1 shows the transmission system minutes recorded in all regions since 2011. These results show a continuing trend of fairly consistent and improving transmission system reliability across all regions of the NEM.

Figure 3.1 Transmission unsupplied minutes as reported in previous AMPR's



3.2.4 Distribution network performance

The performance of distribution networks, and the reliability standards that must be met fall within jurisdictions. The reliability standards are measured in terms of the system average interruption duration index (SAIDI) amongst other indices.

SAIDI is the sum of the duration of each sustained customer interruption, divided by the total number of customers. It is calculated for different categories, such as: central business district (CBD); urban; short rural; and long rural. Unplanned SAIDI relates to unplanned outages. These outages may result from operational error and damage caused from extreme weather and trees.

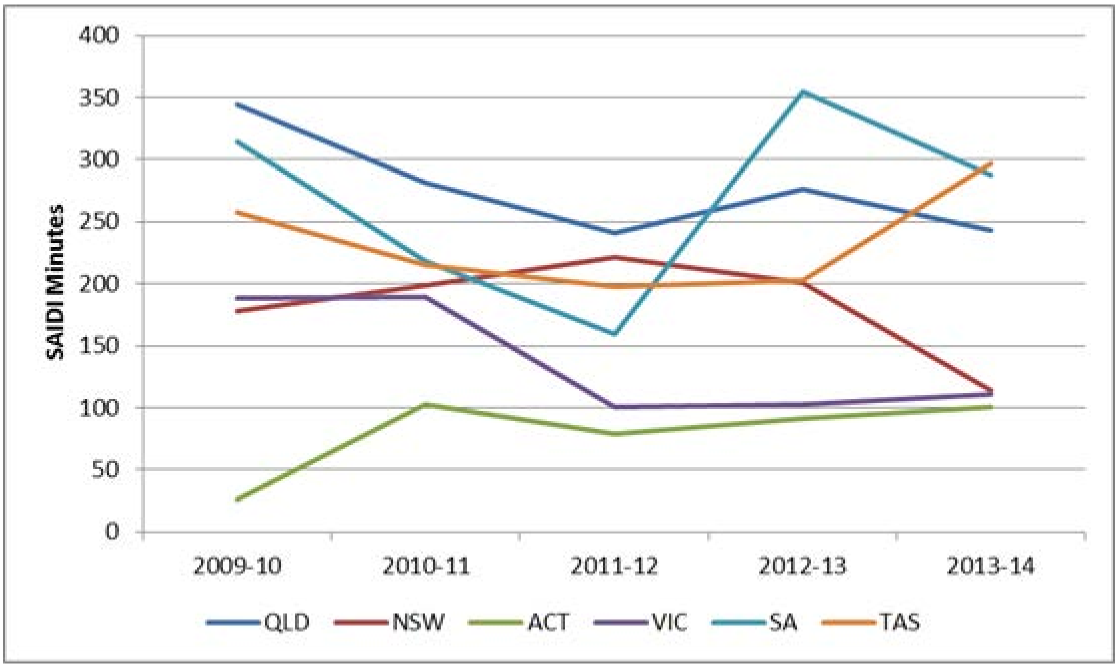
The Panel has calculated an average SAIDI figure for each region, as set out in Table 3.3. The Panel understands different exclusion methodologies, variances in customer numbers by feeder and different geographical conditions apply, and that these averages are to represent a summary only.

Table 3.3 Distribution network unsupplied system minutes for 2013-14

Region (distribution)	System average interruption duration index (SAIDI) in minutes (sum of the duration of each sustained customer interruption, divided by the total number of customers)	
	2013-14	2012-13
Queensland	243.44	276.39
New South Wales	113.50	200.22
Australian Capital Territory	99.98	90.90
Victoria	110.27	102.98
South Australia	287.00	355.01
Tasmania	296.80	202.80

Figure 3.2 shows the historical distribution performance as reported in previous AMPRs. The chart shows that distribution network performance has been generally consistent over the past five years. The general trend for distribution networks is an improvement in the SAIDI minutes. However, for South Australia, there is no clear trend with a high degree of variability. Tasmania also experienced a significant increase in SAIDI minutes in 2013-14 compared with the previous year.

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



DNSPs have a number of reporting requirements in relation to reliability performance. These include reporting requirements to the AER and state-based regulators. Further information on the more granular measures of reliability performance applied to individual distribution networks is provided in Appendix D.

The Panel notes the following regarding network performance during 2013-14:

- The transmission system delivered reliability performance comparable with historic performance. The unsupplied minutes due to the transmission system has remained relatively stable over time.
- The development of the Heywood interconnector will improve the Victoria-South Australia interconnector capacity once it is commissioned. It is not likely to result in any significant change in transmission minutes not supplied.
- The distribution reliability performance aggregated at a state level, shows relatively consistent reliability performance over time as viewed from the perspective of overall power system reliability.

3.3 Reliability assessment

3.3.1 Details of USE in each region

To assess the performance of the NEM in the 2013-14 financial year against the reliability standard, the Panel has reviewed the USE experienced in each region of the NEM. Table 3.4 shows the performance of each NEM region against the reliability standard for the past 10 years.

Table 3.4 Regional USE for the past 10 years

Year	Queensland	New South Wales	Victoria	South Australia	Tasmania[28]
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%

28 Tasmania joined the NEM in May 2005.

Year	Queensland	New South Wales	Victoria	South Australia	Tasmania[28]
2005-2006	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
2004-2005	0.0000%	**0.00005%**	0.0000%	0.0000%	0.0000%
10-year average reliability by region	**0.0000%**	**0.0000%**	**0.0004%**	**0.0003%**	**0.0000%**

Source: AEMO

GDFSAE recommended that Table 3.4 be updated to show those instances where the reliability standard was not met in an individual year and insert a new line for the 10-year average reliability by region. GDFSAE considered that this would further highlight the sustained reliable performance of the NEM. The Panel considers that these amendments better show the historical performance of the NEM regions with respect to the reliability standard and indicates those instances where the reliability standard was not met in a particular financial year.

The Panel notes:

- Each region of the NEM met the USE standard in 2013-14. Therefore the NEM as a whole met the reliability standard.
- There have been only a few instances over the past 10 years where the USE standard was not met within a particular financial 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.

4 Forecasts of reliability

While Chapter 3 considered the historic reliability performance of the NEM, this Chapter considers market information on demand forecasts as published by AEMO in various forms, with outlooks ranging for the next trading day to 10 years. In this Chapter, the Panel considers those forecasts published during the 2013-14 financial year. Background information providing detailed explanation of each type of forecast to provide market information is outlined in Appendix I.

Energy and demand forecasts play an essential role in the market. They are used to make key operational and investment decisions. Demand forecasts are also a key input into network planning. To facilitate these business functions, it is critical that the demand forecasts are as robust and reliable as possible. Electricity forecasts are also important to end-use customers to provide transparency and improve awareness of energy use and other market issues.

4.1 Reserve projections and demand forecasts

Various bodies produce electricity demand and energy forecasts covering different portions on the NEM. Network service providers often produce forecasts for the area of the NEM served by their network and those forecasts are used by the network businesses when planning their networks.[29] In Victoria and South Australia, AEMO produces the state wide forecasts used for transmission network planning. AEMO is also required to produce a demand forecast for each NEM region and also produces a NEM wide energy forecast. Obligations under the NER require AEMO to publish the Electricity Statement of Opportunities each year, which includes both demand and energy forecasts for a twenty year outlook period.[30] AEMO also publishes the National Electricity Forecasting Report (NEFR) each year that contains demand and energy forecasts.

The Panel has previously noted the essential role played by electricity energy and demand forecasts in the market and that they are used by key operational and investment decision makers.[31]

The Panel notes that there are often difficulties and complications associated with demand forecasting. This AMPR is based on statistics collected from AEMO and based on these results the Panel considers that there have been improvements in forecasting over time. The Panel also notes AEMO's continued commitment to improve its forecasting methods.

29 NSP electricity forecasts are published in their respective transmission and distribution annual planning reports.

30 Clause 3.13.3(q) NER.

31 For further information see the Reliability Panel section of the AEMC's website.

4.1.1 Electricity statement of opportunities

AEMO publishes the ESOO in August each year. The 2014 ESOO provides an analysis of electricity supply and demand over a 10-year outlook period (2014-15 to 2023-24).[32] It includes historical information about the changing electricity generation mix and trends in electricity demand, which is combined with information from energy market participants and AEMO's latest electricity demand forecasting, 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 generation investment interest, the ESOO also highlights NEM-wide generation and demand-side investment opportunities by analysing the key factors influencing this type of investment.

Under a medium economic growth scenario, the 2014 ESOO identified the following:

- No new generation capacity is required over the next 10 years in any NEM region to maintain supply adequacy under low and medium growth scenarios. Supply adequacy is assessed in terms of the ability to meet the 0.002% USE standard.[33]
- Under the high growth scenario with no further investment there is a risk that Queensland experiences a small amount of USE beyond 2023-24. Without further investment, USE of 34 MWh or 0.0001% which is below the 0.002% USE standard could be experienced.
- More than 7,500 MW of supply capacity would need to be removed from the market to affect supply-adequacy in 2014-15. Approximately 90% of this capacity would need to be in New South Wales, Queensland and Victoria.
- Even with 10 years of consumption growth by 2023-24, between 1,000 and 3,400 MW of capacity could still be withdrawn from each of New South Wales, Queensland and Victoria without breaching the reliability standard.
- The long term outlook to 2023-24 indicates that there is unlikely to be any USE. As noted by AEMO this is one of the first instances where the ESOO has identified there is no requirement for additional generation to meet the forecast ten year demand.

4.1.2 National Electricity Forecasting Report

The 2014 NEFR was published in June 2014 providing AEMO’s 20 year electricity forecasts for the five NEM regions under high, medium, and low consumption

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

33 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, which is equivalent to 0.002% USE.

scenarios.[34] It highlights the continuing decline in actual and forecast demand and energy supplied from the NEM which has been a consistent trend over the past several years.

The 2014 NEFR also identified the following:

- The consumption of electricity supplied through the NEM has been declining since 2008-09 and is forecast to continue to decline through 2014-15. Under the medium growth scenario energy consumption is forecast to grow in Queensland, albeit at a relatively low rate. All other regions are forecast to experience flat or reducing energy consumption.

- In combination the following factors have contributed to reduce NEM-wide electrical energy consumption in the medium growth scenario:

    - Declining residential and commercial consumption due to changes in consumer behaviour as a result of rising electricity prices;

    - Declining industrial consumption, particularly as a consequence of the closure of the Kurri Kurri aluminium smelter in New South Wales and Point Henry aluminium smelter in Victoria; and

    - Strong growth in rooftop PV generation (which offsets grid supplied energy); and

    - Energy efficiency measures especially affecting appliances such as air-conditioners, refrigerators and electronics.

- In Queensland in the medium growth scenario, the increased energy consumption from LNG projects, strong population and state income growth is expected to exceed reductions in energy consumption due to increased installation of PV, energy efficient measures and the closure of the Bulwer Island refinery. This results in forecast growth in the consumption of NEM supplied electricity.

- In NSW in the medium growth scenario the increased energy consumption from population and state income growth is expected to match reductions in energy consumption from industrial loads, increased installation of PV and energy efficient measures delivering relatively constant forecast electricity consumption.

- In Victoria, strong population and income growth is expected to be balanced by increased installation of PV, energy efficiency savings and closure of manufacturing plant and an aluminium smelter delivering relatively constant electricity consumption under the medium growth forecast.

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34 AEMO, *2014 National Electricity Forecasting Report for the National Electricity Market*, June 2014.

- In Tasmania, consumption is forecast to continue to decline, as a result of high levels of rooftop PV installation, low population and state income growth and energy efficiency savings.

- The forecast maximum demand growth rates in the 2014 NEFR are lower than the 2013 forecasts for all regions other than Tasmania. Figure 1 shows the average four year growth rates in forecast demand in the 2014 NEFR, compared with the 2013 NEFR. The factors identified previously as driving energy growth forecasts are also the primary factors influencing the forecast demand growth.

The coloured bars in Figure 4.1 differentiate between the four year average maximum demand growth rate reported in the 2014 and 2013 NEFR. A tabulated comparison is shown at the bottom of the Figure.

Figure 4.1 Comparison of forecast demand growth rates reported in 2014 and 2013 NEFR

	Qld with LNG 2015-16	Qld without LNG 2021-22	NSW 2022-23	Vic Beyond 2033-34	SA Beyond 2033-34	Tas Beyond 2033-34
2013 NEFR	5.5%	2.7%	0.8%	1.2%	-0.3%	-0.9%
2014 NEFR	4.0%	0.0%	0.5%	-1.1%	-1.1%	0.9%

Source: AEMO, *2014 National Electricity Forecasting Report for the National Electricity Market*, June 2014, p.iv.

Weather has a significant influence on the maximum demand reached in any year. Appendix A provides a summary of the weather patterns experienced during peak demand conditions in 2013-14. Further detailed analysis of the influence of weather on electricity demand is reported in NSP Annual Planning Reports. With the exception of South Australia the maximum temperature periods during 2013-14 occurred during the early January holiday period or at weekends, contributing to reduced demand compared to levels that would have been expected if the same weather patterns occurred on working days outside of the holiday period.

An update to the 2014 NEFR was issued in December 2014.[35]

The 2014 NEFR update suggests that the trend towards falling electrical energy consumption may be coming to an end. The update reported that, for the period July –October 2014, the electrical energy consumed in all NEM regions (apart from Victoria) was above the 2014 NEFR forecast. This was not in line with previous updates which showed actual energy consumption falling below forecast. Table 4.1 tabulates the difference between actual energy consumption and the level forecast in the 2014 NEFR.

The Panel notes that although the update was outside the reporting period for the 2014 AMPR report, the need for an update demonstrates the continuing uncertainty regarding forecast electricity consumption that has triggered the need for frequent revision of forecasts in recent years.

The Panel considers that recent changes to the NER relating to a requirement for market participants to provide AEMO with more demand side participation information should improve the quality of load forecasts going forward. The new rules should provide AEMO with more accurate and granular information to allow improvements in both short term forecasts such as five minute pre-dispatch (looking out one hour ahead), and long term forecasts such as the ten year forecasts in the NEFR.[36]

Table 4.1 Regional operational consumption variance (July to October 2014)[37]

	NEM	New South Wales	Queensland	South Australia	Tasmania	Victoria
Variance	+2.3%	+2.9%	+4.8%	+1.3%	+0.9%	-0.5%

It is notable that the material change to electricity consumption that gave rise to a NEFR update did not trigger either a review of summer maximum demand in the affected region of Queensland, or a corresponding update to the ESOO.

Forecast accuracy report

The NER also require AEMO to produce a Forecast Accuracy Report for the Reliability Panel each year. The report assesses the accuracy of the consumption and maximum demand (MD) forecasts in the previous year's NEFR for each NEM region. It also details any improvements that will apply to the forecasting processes for the next statement of opportunities.[38]

35 AEMO, *2014 National Electricity Forecasting Report Update for the National Electricity Market*, December 2014.

36 Further information on this rule change request can be found in section 7.2.1 of this report.

37 ibid, p.3.

38 NER cause 3.13.3(u).

AEMO's Forecast Accuracy Report 2014 was provided to the Reliability Panel in November 2014. The improvements identified by AEMO for implementation ahead of the 2015 NEFR were as follows:[39]

- Splitting Victorian residential and commercial consumption using smart meter data to assess the practicality and value of using this data;
- Publishing summer and winter minimum demand forecasts for South Australia, where minimum demand is critical due to the large level of wind penetration and consider this for other regions in the 2016 NEFR;
- Capturing the impact of local, state and federal energy efficiency programs on forecasts, as opposed to only federal programs at present;
- Investigating the possible impact of battery storage along with key policy and economic drivers; and
- Exploring and implementing new ways to better communicate published data.

The Panel notes the following with respect to demand and energy forecasting:

- Forecasting is dependent upon a number of key inputs including (but not limited to) weather, economic outlook and consumer behaviour. These factors are highly variable and difficult to forecast. The relationships between electricity consumption, maximum demand and the key inputs are complex and inexact and can only be approximated. As such parties should carefully consider the level of reliance that should be placed on any forecast.
- AEMO noted a number of changes to its 2014 NEFR forecasting methodology in the Forecast Accuracy Report 2014 to the Panel. These changes are not explicitly linked to any previously identified deficiency. Further enhancements suggested by the 2014 report are noted for actioning in the 2015 NEFR.
- The approach undertaken by AEMO to update the forecasts between annual NEFRs is appropriate when AEMO has identified a reasonable variation from the forecasts.
- The importance of the forecasts to generation investment in the market, and the operation of the market. These ultimately impact on the security and reliability of supply.

4.1.3 National Transmission Network Development Plan

AEMO publishes the annual National Transmission Network Development Plan (NTNDP) in its role as the national transmission planner.[40] The purpose of the

39 AEMO, *Action plan – For the 2015 National Electricity Forecasting Report*, November 2014, p.3.

40 For further information see the National Transmission Network Development Plan section under the electricity planning part of AEMO's website.

NTNDP is to facilitate the development of an efficient national electricity network that considers forecast constraints on national transmission flow paths. The NTNDP provides industry participants, AER, AEMC and policy-makers with an independent, strategic view for the efficient development of the national transmission network, over a 20-year planning horizon.

The 2014 NTNDP considers the challenges and opportunities for transmission network development over the next 20 years. It focusses on the transmission network assets connecting large-scale generation to population and industrial centres in the NEM.

The current environment

The consumption of electricity sourced from transmission networks in the NEM has been declining since 2009. Maximum demand growth has slowed over this period and is forecast to slow over the next decade.[41] This is attributed to structural shifts in the Australian economy away from energy-intensive industries, consumer response to high prices, energy efficiency initiatives, and increasing generation at the local level.

Transmission network investment profile

Historically, transmission development has been driven by forecast demand growth and prescriptive transmission network reliability standards in a number of NEM jurisdictions. More recently, reliability standards across the NEM have begun to converge towards an approach which explicitly considers customers' reliability needs.

Future transmission network development plans reflect slowing forecast maximum demand growth. Transmission network augmentation needs are reducing and transmission network asset replacement is becoming the most common form of network development. 60 per cent of the $11.9 billion of transmission network investment over the past decade was driven by the need to augment network capacity to meet expected maximum demand growth. AEMO forecasts that over the next 20 years, transmission businesses may invest between $9 billion and $18 billion in network infrastructure. It is estimated that 75 to 85 per cent of this expenditure will go towards replacing ageing assets rather than augmenting existing transmission network capacity.[42]

The significantly lower proposed augmentation investment over the next five years reflects current expectations of slower maximum demand growth and is likely to see reinvestment as assets reach end of life as the biggest investment driver for network companies.

The changing environment

Emerging technology such as battery storage and rooftop photovoltaic (PV) are expected to influence transmission network development in the medium to long-term.

41 AEMO, *2014 National Electricity Forecasting Report for the National Electricity Market*, Chapter 2 – NEM Forecasts, pp.2.1-2.3, June 2014.

42 AEMO, *National transmission network development plan*, December 2014, p.3.

AEMO modelled the impact of combining a time-of-use tariff with solar PV and residential energy storage (RES) installations on a typical household's demand for grid delivered electricity. This modelling shows that:[43]

- Adding a 5 kWh RES system to an existing solar PV system reduces the household maximum demand by 45 per cent in summer and 23 per cent in winter;
- Households with battery storage could be self-sufficient for 60 per cent of the time in summer and 40 per cent in winter; and
- The penetration of battery storage technology may further defer the need for network augmentation and may affect the size and scope of required asset replacement.

AEMO modelled the potential impact of battery storage on the load profile at a typical transmission substation during the maximum demand day in 2013. Under the high storage penetration scenario, plausible within the next 10 years, applying a critical peak capacity tariff could reduce maximum substation demand by up to 30 MW.

4.2 Power system adequacy - two year outlook

AEMO published its 2013 Power System Adequacy (PSA) report on 13 August 2012.[44] AEMO has decided that the PSA report will no longer be produced as the publication of other forecasting tools provides sufficient information to the market on the short term supply adequacy situation across the NEM.

The PSA covers the period from 1 July 2013 to 30 June 2015 and outlines the expected impact on medium-term power system security and reliability. The PSA complements the ESOO, which provides an outlook for the supply-demand balance for the ten years from 2014-23.

The PSA looks at scenarios which assess key aspects of the power system's capability and took into account the Commonwealth Government's Clean Energy Future Plan announced on 10 July 2011.[45]

The 2013 PSA established the following key points:[46]

- The reserve capacity and energy adequacy assessment indicates that the power system will have sufficient supply capacity to meet the NEM reserve requirements, and (as at the time of publication) AEMO is not expecting to

43 ibid, pp.4-5.

44 For further information see: AEMO, *Power system adequacy report 2013*, August 2012.

45 The price on carbon legislated in the Clean Energy Future Plan was repealed in parliament and removed on 1 July 2014.

46 ibid, p.iii.

invoke the (Reliability and Reserve Trader) RERT tender process to maintain supply reliability in the NEM.

- The operational capacity assessment indicates that significant new operational issues are unlikely.

- An area of possible concern involves the adequacy of frequency control during periods of high wind generation and the electrical separation of parts of the transmission network. AEMO is currently working to address this issue, which involves the design of over-frequency generator shedding (OFGS) schemes to ensure frequencies in the affected regions remain within the operating standards. The preliminary design phase of the OFGS schemes for the Queensland and South Australian regions are complete and currently under final review.

- Renewable energy generation could increase by approximately 1,000 MW in the next two years, comprising 956 MW of wind generation and 44 MW of solar generation. Current planned large-scale solar installations fall outside the two-year timeframe of this report. The increase in renewable energy generation is identified to have potential impacts on contingency frequency control ancillary services and interconnector capability, especially in the South Australian and Tasmanian regions.

The Panel notes:

- The 2013 PSA assessment found that there would be sufficient supply capacity to meet the NEM reserve requirement standard for the outlook period.

- That during periods of high wind generation it was possible for separation of parts of the transmission network and over-frequency generator shedding (OFGS) may be required to maintain frequencies within the frequency operating standards.

- AEMO and ElectraNet have undertaken a joint study to consider the impact on the power system of the high rate of renewable penetration in South Australia.[47] South Australia has the highest wind and PV generator penetration of any NEM region. Currently there is 1,470 MW of installed wind generation and 540 MW of solar PV installed. It has been forecast that an additional 1,000 MW of wind and 500 MW of solar PV will be added in SA by 2020. There are a number of short term and long term operational reviews and possible changes which have been identified by AEMO and ElectraNet.

- The level of wind generation in Tasmania increased due to the commissioning of the Musselroe Windfarm. Along with Basslink and the Woolnorth Windfarm there is a high level of non-synchronous generation in Tasmania. The Panel is unaware of any reduction in reliability in Tasmania due to commissioning of the Musselroe Windfarm.

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47 AEMO, *Renewable energy integration in South Australia – Joint AEMO and ElectraNet study*, October 2014, p.4.

4.3 Energy adequacy assessment projection (EAAP)

As required by the NER, since March 2010 AEMO has published the EAAP each quarter.[48]The EAAP provides information about the impact of fuel and water availability on energy availability over a 24 month period under a range of scenarios. The energy constraints are based on information provided by scheduled generators including information on planned outages, power transfer capability of the NEM and demand forecasts that are provided by jurisdictional planning bodies for the purposes of the ESOO.

The EAAP reports provide USE projections for each region under three scenarios: low rainfall, short-term average rainfall and long-term average rainfall. USE projections for each region are also provided for each month in the forecast period.

EAAP consists of a public report and private report for each generator who owns scheduled generating units or hydro power schemes.

The June 2012 EAAP covered the study period from 1 July 2012 to 30 June 2014, which includes the 2013-14 financial year, relevant for this AMPR. The 2012 EAAP determined that the forecast unserved energy is within the Reliability Standard of 0.002 per cent for all regions for both years (1 July 2012 to 30 June 2014) in the three scenarios.[49]

The March 2014 EAAP is the most recent publicly available EAAP relevant to this report, which covers the study period from 1 April 2014 to 31 March 2016.[50]This EAAP determined that, for the 2014 and 2015 calendar years, the forecast unserved energy falls within the Reliability Standard of 0.002 per cent for all regions for both years for the three scenarios considered. USE is observed in South Australia and Victoria in the 2015 calendar year under the low rainfall scenario, but remains within the 0.002 per cent reliability level.[51]

The Panel notes:

- The forecast availability of energy outlined in the two EAAP reports indicates that the reliability standard for supply adequacy will be met for all NEM regions.

- The EAAP functions as an additional source of information for the market regarding when and where energy constraints may impact on energy availability.

48 NER rule 3.7C.

49 AEMO, *Energy Adequacy Assessment Projection Report Update*, June 2012.

50 AEMO, *Energy Adequacy Assessment Projection – March 2014 update*, March 2014.

51 ibid, pp.8-9.

4.4 Medium-term projected assessment of system adequacy (MT PASA)

MT PASA assesses the adequacy of supply to meet demand at the time of anticipated daily maximum demand, based on a 10 per cent probability of exceedance (POE) for each day over the next two years.[52]

MT PASA information is provided:

- to assist participants in planning for maintenance, production planning and load management activities over the medium-term (over a two-year period); and
- to inform of any intervention decisions by AEMO, for example invoking the Reliability and Emergency Reserve Trader (RERT) mechanisms.

Demand forecasts used in the MT PASA are prepared by AEMO. Generation and demand-side daily availability estimates are submitted by participants under clause 3.7.2(d) of the NER. In addition, planned network outages are submitted to AEMO by network service providers under clause 3.7.2(e) of the NER.

AEMO publishes the MT PASA forecasts at least weekly on its website for each region in the NEM.[53]

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 2013-14. Further, with the level of available generation and current demand forecasts the Panel does not expect the MT PASA forecasts to identify a reserve shortfall over the forecast two-year period.

Where MT PASA identifies a reserve shortfall, these conditions usually elicit a response from generators to make them available by shifting a planned outage or possibly returning to service sooner than scheduled. In addition a network service provider may reschedule a planned outage in order to make additional network capacity available if required. During 2013-14, AEMO did not invoke the RERT mechanism, therefore adequate reserves were available for the whole period.

4.5 Short-term projected assessment of system adequacy (ST PASA)

In addition to MT PASA reports, AEMO also publishes ST PASA reports. As opposed to MT PASA, which makes projections over a two-year period, ST PASA makes projections over 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

52 Probability of exceedance refers to the likelihood that a maximum demand projection will be met or exceeded.

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

reserve shortfalls. For instance 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 need several hours to be made ready to respond.

Table 4.2 shows the average ST PASA demand forecast accuracy for two, four, and six days ahead. For example, the table shows that on average, the 12-hours-ahead forecasts were within 4.7 per cent of the actual demand outcomes for Tasmania.

The ST PASA demand forecasts for 2013-14 show:

- On average across the four forecast categories, Tasmania marginally reduced in accuracy, e.g. for six-days-ahead ST PASA, demand forecast accuracy deteriorated from 5 per cent in 2012-13 to 7 per cent in 2013-14;
- There was a general improvement for the South Australian region across all forecast periods; and
- There was a marginal deterioration in forecasts for other mainland regions.

Table 4.2 Accuracy of ST PASA forecasts 2013-14

ST PASA demand forecast absolute percentage deviation	Queensland	New South Wales	Victoria	South Australia	Tasmania
6 days ahead	2.6%	2.5%	4.5%	3.9%	7.0%
4 days ahead	2.4%	2.2%	3.9%	3.3%	5.8%
2 days ahead	2.1%	2.0%	3.7%	2.9%	5.2%
12 hours	1.9%	1.7%	3.4%	2.6%	4.7%

Source: AEMO

The Panel observes that demand forecasts were relatively consistent for New South Wales, Queensland and South Australia where the absolute percentage deviation for each of the four forecasts was around two to four per cent for the duration of the year. The absolute percentage deviations were slightly higher in Victoria and highest for Tasmania.

Figure 4.2 Accuracy of ST PASA forecasts 2013-14

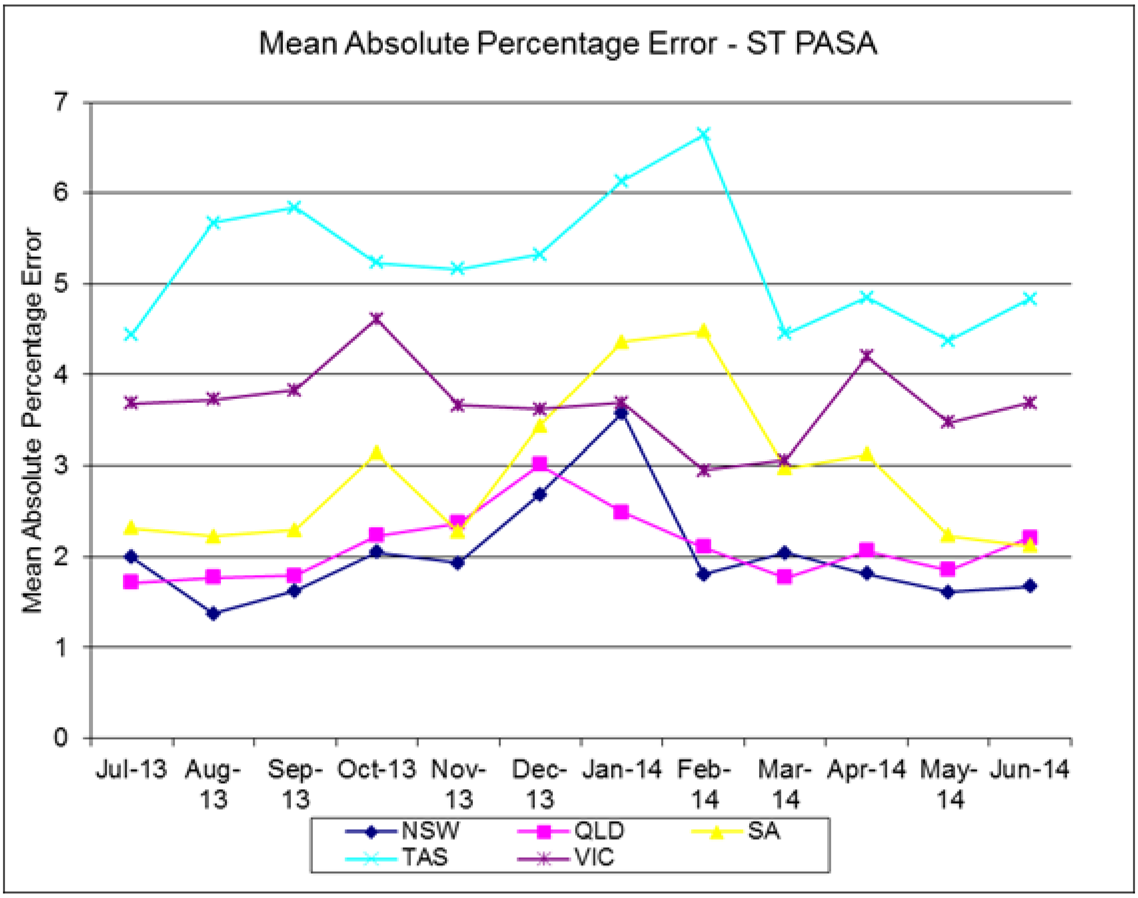


Figure 4.2 displays the observed trends in the mean absolute percentage error for the two day ahead ST PASA over the 2013-14 financial year. With reference to this figure, the mean absolute errors were higher for all regions over the summer months and early autumn, most notably for South Australia where the errors peaked at 4.5 per cent in January and February 2014. Similarly, the mean absolute errors were highest in Tasmania in spring and autumn, corresponding to September 2013 and March 2014.

4.6 Pre-dispatch

Pre-dispatch provides an aggregate supply and demand balance comparison for each half-hour of the next trading day. The information is provided to relevant participants to assist with their operations management. The demand forecasts used in the ST PASA are the 50 per cent Probability of Exceedance (PoE) for each region for each half hour period. These forecasts are based on historical metering records and expected weather patterns.

AEMO introduced a Demand Forecasting System (DFS) on 15 November 2011 to its market systems. AEMO is currently forecasting electricity demand for the five NEM regions and 22 sub-regions using the DFS. Originally four sub-regions were forecast, this was expanded to 22 in early 2013.

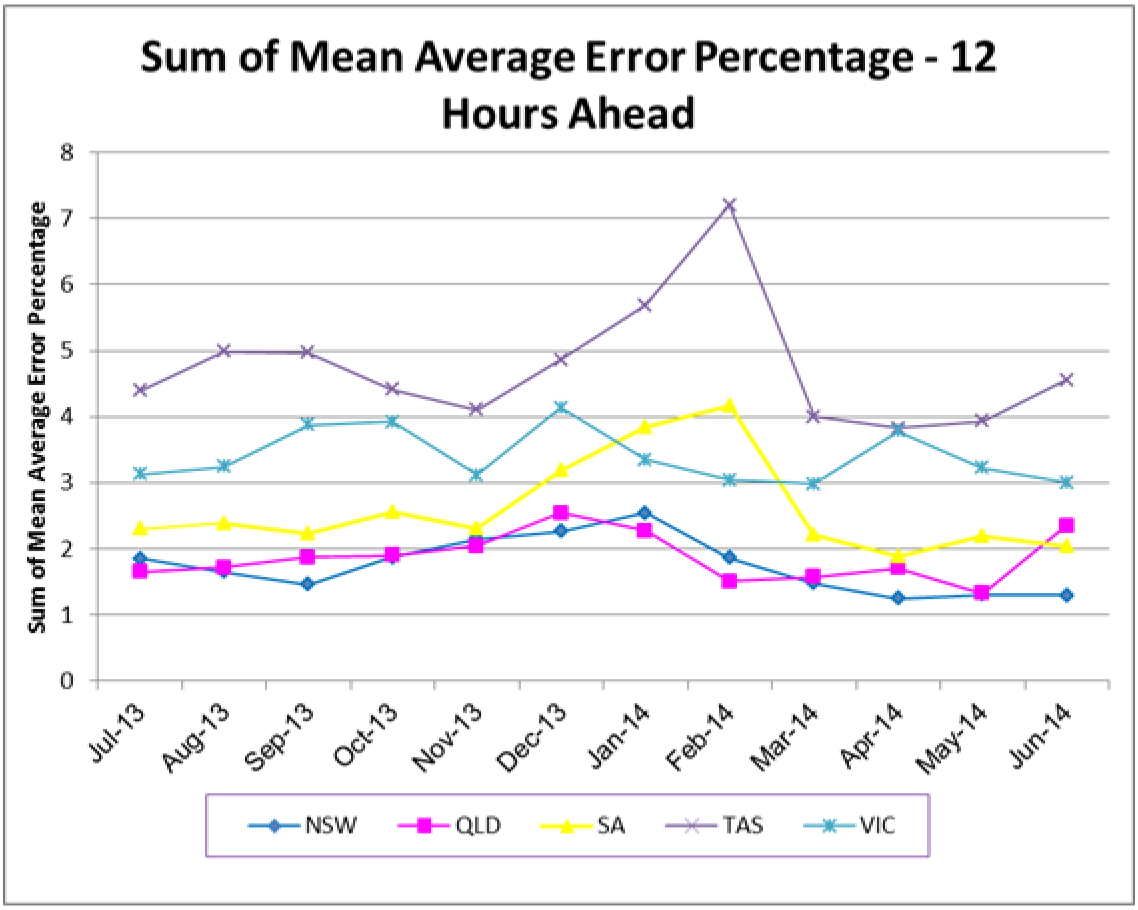
The DFS generates half hourly forecasts, updated every half-hour, up to eight days ahead. The DFS has delivered greater accuracy for NEM regional demand forecasts in the near-real-time, compared to the previous manual forecasting process. The Panel notes that AEMO has indicated that the DFS has helped to improve the alignment between dispatch and pre-dispatch.

The DFS 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-hours-ahead basis. Figure 4.3 below shows the accuracy deteriorated slightly in 2013-14 compared with 2012-13.

Information has also been compiled on the performance of the 4 hour ahead pre-dispatch demand forecast during 2013-14. That supplementary information is provided in Appendix C and reveals that the accuracy of the 4 hour ahead forecast achieved during 2013-14 varied between regions with errors rates of between 2 and 6 per cent reported.

Figure 4.3 Accuracy of Pre-dispatch Demand Forecasts 12-hours-ahead[54]



54 Absolute percentage deviation - actual demand compared to 12-hours-ahead forecast.

The Panel notes the following:

- The accuracy of the demand forecasts used by AEMO in the pre-dispatch process is an important determinant of the accuracy of the pre-dispatch outcomes overall.
- 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. The quality of the forecasts is important but obtaining better forecasts will only improve the alignment between dispatch and pre-dispatch.
- AEMO routinely reviews the performance of the pre-dispatch process in order to continuously implement updates and improvements to constraint information where possible.

4.7 Trading intervals affected by price variation

The Panel has considered the number of trading intervals affected by statistically significant variations between pre-dispatch and actual prices during the 2013-14 financial year, as well as the most probable reasons for the variations.

Table 4.3 Trading intervals affected by price variations 2013-14

Price variation reasons	Number of trading intervals with price variations (%)									
	Queensland		New South Wales		Victoria		South Australia		Tasmania	
Demand	905	60%	244	58%	479	55%	1132	64%	562	25%
Availability	253	17%	75	18%	196	22%	332	19%	1687	75%
Combination (for example, changes in plant availability, demand rebidding activities)	357	24%	98	23%	197	23%	302	17%	0	0%
Network (for example, network outages)	2	0%	1	0%	2	0%	4	0%	15	1%
Total trading intervals affected	1232	7%	346	2%	703	4%	1467	8%	2162	12%

The data that the Panel has considered is set out in Table 4.3. The table shows that for Tasmania, a total of 2,162 trading intervals in 2013-2014 were affected by significant price variations which represents 12 per cent of trading intervals in total for that year. Of the 2,162 trading intervals, 75 per cent were due to changes in plant availability and 25 per cent were due to variation in demand values.

The Panel considers that pre-dispatch has been working satisfactorily as an indicator of reliability and security. Its utility to the market however, will always be affected by the accuracy of demand forecasts. The Panel notes that load forecasting is a continuing challenge. The Panel expects that pre-dispatch should be able to achieve higher accuracy forecasts given the relatively small time difference between periods covered by the pre-dispatch outlook and current dispatch interval.

The Panel notes the following changes from 2012-13 to the 2013-14 financial year:

- the number of trading intervals affected by statistically significant variations between pre-dispatch and actual prices has improved; and
- with respect to the number of total trading intervals affected by price variation there was a general improvement in all areas across all regions apart from Tasmania.

4.8 Reliability safety net

AEMO has the power to issue directions as a last resort measure, or to contract for the provision of reserves through the Reliability and Emergency Reserve Trader (RERT) mechanism to maintain power system security and reliability.

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.[55] 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.

In 2013, the ESOO and MT PASA forecast that there would be no need for additional generation in the NEM regions for both the 2-year and 10-year outlook period. Consequently, during 2013-14 AEMO did not exercise the RERT mechanism as additional reserves were not required.

4.9 Wind forecasts

The Australian Wind Energy Forecasting System (AWEFS) was implemented by AEMO where 'Phase 1' of the project was implemented internally in 2008 and then 'phase 2' was completed in June 2010. The development of the AWEFS was funded by the then Commonwealth Department of Resources, Energy and Tourism involving a

55 NER clause 4.8.9.

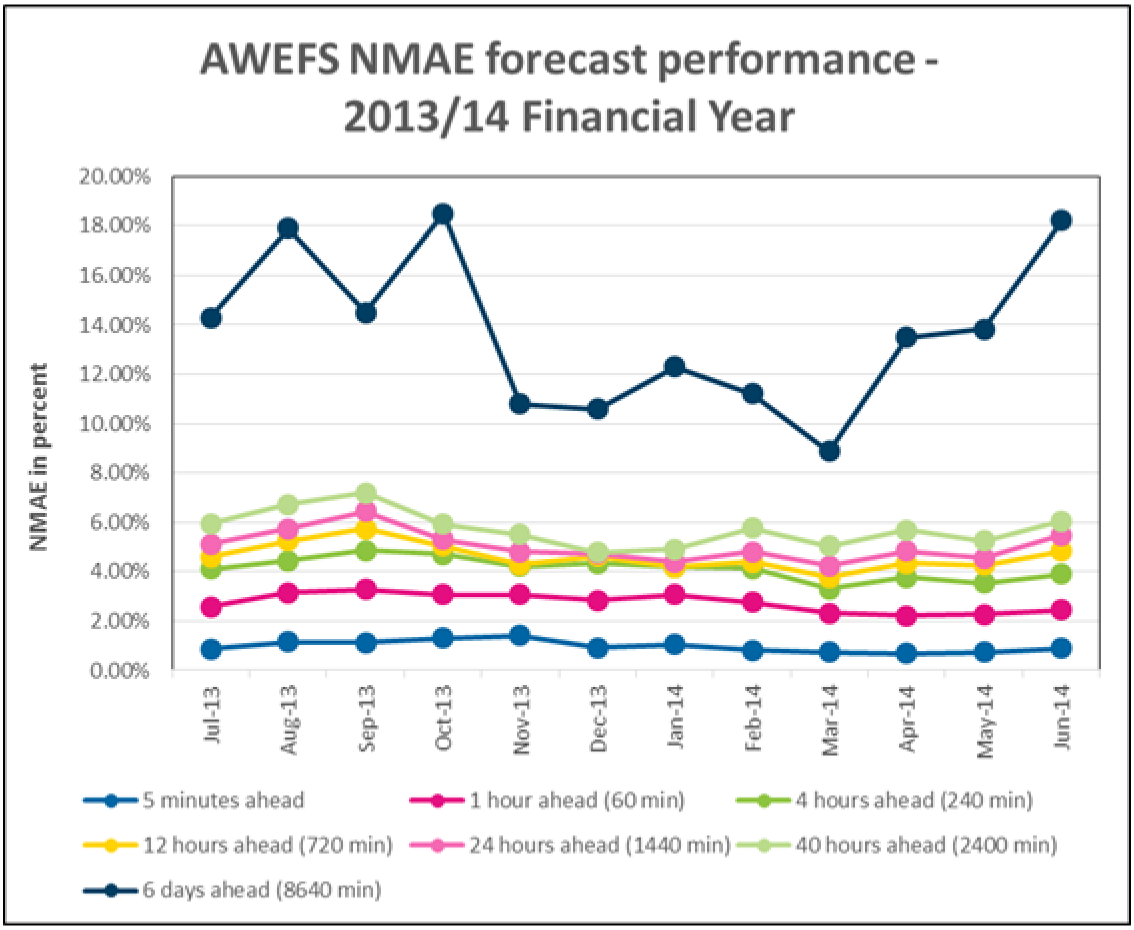
'world first' integrated system designed specifically for the NEM by a European consortium.[56]

The AWEFS 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.

The AWEFS was established in response to the growth in intermittent generation in the NEM and the increasing impact this growth was having on NEM forecasting process. The Panel recognises that wind generation capacity in the NEM is expected to continue to grow under Australia's Renewable Energy Target and the AWEFS will continue to be an important tool for promoting efficiencies in NEM dispatch, pricing, network stability and security management.

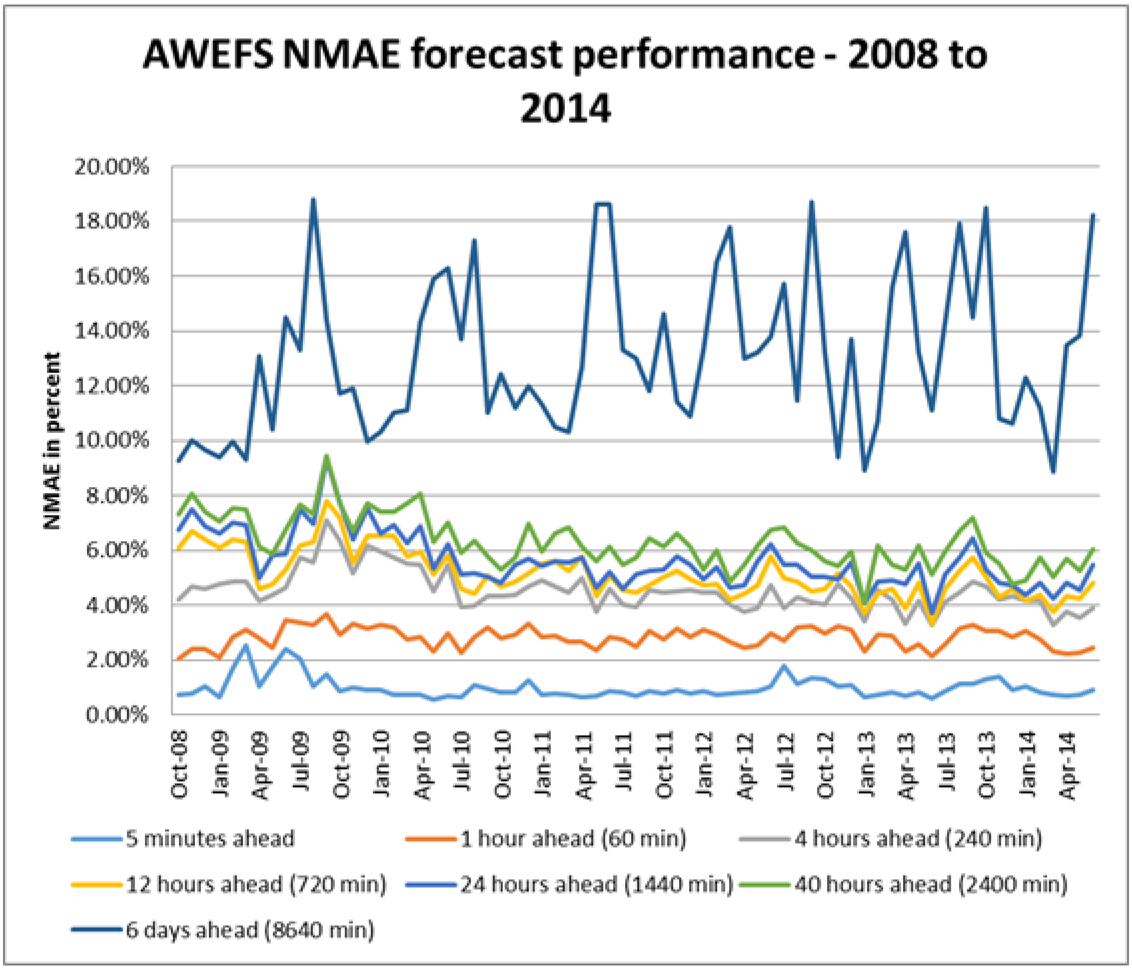
The Panel has considered the performance of AWEFS based on the average per cent error across all regions in the NEM across various timeframes. The performance is shown in Figure 4.4.

Figure 4.4 Accuracy of AWEFS (normalised mean absolute error)



56 AEMO, *Australian energy forecasting system (AWEFS)*, September 2014.

Figure 4.5 AWEFS NMAE Forecast Performance 2008 - 2014



In response to the draft report, GDFSAE suggested that, in addition to the above charts, it would be helpful to provide statistical parameters regarding noted improvements and/or maintenance of forecast accuracies. These parameters could include a measure of statistical significance for any changes in forecasting performance.[57] The Panel notes the suggestions from GDFSAE and will look at ways to incorporate any new statistical parameters in the AMPR going forward.

In relation to Figure 4.4 and Figure 4.5, the Panel notes that:

- as could be expected, the accuracy of the forecasting improves as the forecast horizon shortens;
- the highest normalised absolute error values correspond to situations when forecasting is difficult, i.e. periods with very high or very low wind speeds;
- from the graphs it can be seen that the forecast accuracy of AWEFS is stable; and
- three new wind farms have been added to AWEFS since June 2013 without any noticeable change in forecast performance.

57 GDFSAE, Draft report submission, p.1.

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

Further in relation to forecasting renewable generation, GDFSAE noted that the penetration of photovoltaic (PV) generation has increased significantly in recent years and contributed to changing the load shape. As such, from a market transparency perspective, it would be useful to include a PV output forecasting module in AEMO processes in a manner similar to wind forecasting. GDFSAE questioned whether the Panel had a view in relation to forecasting PV and whether this could be reflected in the annual report.[58]

The Panel has considered this comment from GDFSAE. It considers that it could be useful to include information on forecasting renewable generation in the NEM, including photovoltaics. The Panel notes that AEMO has, in its 2015 NEFR, modelled residential and commercial PV separately for the first time – and energy efficiency measures. In the NEFR overview report, published in June 2015, AEMO also notes its intention to release a supplementary Emerging Technologies Information Paper (also in June 2015) setting out a set of forecasts and user tools that demonstrate the potential impact of emerging technologies and trends (such as battery storage, electric vehicles and fuel switching) on operational consumption and maximum demand forecasts.[59]

Further, AEMO has advised that it has already implemented the Australian Solar Forecasting System (ASEFS) for utility scale solar farms. ASEFS is the solar equivalent to the AWEFS wind forecasting system which has been operational for a number of years now. ASEFS is now in operation with the commissioning of the Nyngan solar farm. AEMO has also advised that it is currently developing a system for short-term forecasting of rooftop PV generation, which will feed into their short-term demand forecasting system. AEMO advised that it anticipates making an announcement on a go-live date for the rooftop PV forecasting system later in 2015.

The Panel will consider available information regarding PV forecasts in AMPR reports going forward.

58 ibid, p.2.

59 AEMO, 2015 National Electricity Forecasting Report Overview for the National Electricity Market, June 2015, p.19.

5 Security performance

This Chapter presents the Panel's review of the market performance from a power system security perspective for the 2013-14 financial year. It reports on some of the critical physical elements of the power system including voltage and frequency which impact on power system security.

Section 5.1 provides an overview of the systems used to manage power system security. Section 5.2 presents an overview of performance during the year in terms of frequency, voltage and stability. Section 5.3 reviews system incidents reported during the year.

5.1 Power system security operations

Under the NER, AEMO has the principal responsibility for the secure operation of the power system.[60] Network service providers are required by the NER to assist AEMO in the discharge of its power system obligations. This section provides details of power system security operations during the 2013-14 financial year.

5.2 Network constraints

The ability to transfer power across the power system is limited by a number of factors including the capacity of the network.[61] Secure operation of the power system requires AEMO to maintain power flows within the capability of the network after allowing for credible contingencies. The capability of the network is reflected in the national dispatch systems via network constraints.

When network constraints bind, generation may need to be dispatched from higher priced offers. In extreme cases (for example, where alternative generators are not available), binding network constraints may affect the ability to supply electricity to customers. Congestion is measured by the frequency and extent to which network constraints bind, restricting NEM dispatch.

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

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60 NER clause 4.3.1.

61 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.

AEMO publishes the NEM Constraint Report annually based on the calendar year.[62] It provides information about congestion patterns over the previous five years.

While the total number of network constraints in the NEM has been declining in recent years, as shown in Table 5.1, during 2013 there was a significant increase in the number of active network constraints in the NEM Dispatch Engine (NEMDE). This increase was mainly due to due to changes in the Tasmanian region resulting from commissioning of Musselroe Windfarm.

AEMO noted the following in relation to commissioning of the Musselroe Windfarm:

- discretionary limits on the output of Musselroe Windfarm to manage system security during commissioning to reflect safe operating limits;
- limits imposed on Musselroe Windfarm to manage the reactive requirements required for the operation of the windfarm; and
- limits to manage the thermal line ratings in the vicinity of the windfarm due to increased line flows

Table 5.1 Number of constraint changes in NEMDE

Year	Constraint changes
2009	8594
2010	6250
2011	4776
2012	4130
2013	5817

Source: AEMO

However, of more importance to the market are the number of binding constraints and the duration of those constraints.

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.

Table 5.2 outlines the top five binding constraints impacting the NEM during 2013. The first two constraints identified in the table are temporary and are not expected to occur in the future:

62 AEMO, *NEM constraint report 2014 – for the National Electricity Market*, April 2015.

- As noted earlier, the Musselroe windfarm constraint was a product of the commissioning process.

- The constraint related to the Directlink interconnector resulted from the extended period of time in which its cables were out of service. They are planned to be returned to service within the next 12 months.

In relation to the other constraints identified, the overloading of the Heywood transformer is expected to continue to bind for long periods of time until the Heywood upgrade is completed in 2016.

Further, the constraint to manage voltage collapse in Queensland following the trip of the largest generator in Queensland is likely to continue to impact the market. This is expected to continue until a credible network or non-network solution which satisfies the RIT-T is developed to relieve this power system condition.

Table 5.2 Top five binding constraints for 2013-14

Constraint	Hours binding 2013 (Hours binding 2012)	Description
N_X_MBTE_3A N_X_MBTE_3B	3,773 (503)	Constraint activated to reflect all three Directlink cables being out of service for 158.1 days in 2013 compared to 20.9 days in 2012.
#MUSSELR1_E	1,107 (0)	Constraint activated temporarily to manage Musselroe Windfarm commissioning.
V>S_NIL_HYTX_HYTX	992 (48)	This constraint acts to avoid overloading of remaining Heywood 275/500 kV transformer in the event of the other transformer tripping. The Heywood upgrade project reported in section 5.6.1 will make this constraint less likely to bind.
V>>S_NIL_SETB_SGKH	652 (0)	Constraint activated to be able to limit the output of Musselroe Wind Farm to 100 MW.
N^^Q_NIL_B1, 2, 3, 4, 5, 6 & N^Q_NIL_B	531 (103)	Constraint acts to avoid voltage collapse following a trip of the largest generator in Queensland.

The Panel acknowledges the information that AEMO provides to the market on the performance of network constraints.

In its submission to the draft report, GDFSAE referred to Table 5.1 and noted that, given there had been little network development taking place and the network topology is almost static, the Panel may wish to consider the following questions:

- whether the large number of constraint changes in the 2013-14 financial year signalled inefficiencies in the current representation of the network;
- whether a more effective network representation be used; and
- whether this data could be contrasted with other electricity markets.

The Panel has considered the questions raised by GDFSAE and notes that the number of constraint changes in NEMDE in 2013 was consistent with the average number of constraint changes experienced over the preceding five years.

In addition, as noted above, many of the changes relate to the commissioning of Musselroe. The Panel notes that adding a new generating system that isn't contained in existing constraints will lead to changes in all affected constraints, in order to include that generating system.

Further, that there have been a number of constraint changes does not necessary imply that there are errors or inefficiencies in AEMO's current representation of the network. The Panel understands that AEMO tests new constraints (off-line) before they are included in NEMDE. In addition, AEMO has other tools that determine if system security is being breached (such as Contingency Analysis and some real-time stability simulations), which would detect if an error in the constraint risks system security.

The Panel has notified AEMO of GDFSAE concerns in relation to the number of constraint changes in NEMDE in 2013.

5.3 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 them a more informed market response.[63]

AEMO issued 3,148 market notices during the 2013-14 financial year. These notices are summarised by type in Table 5.3.

Table 5.3 Market notices

Type of notice	Number of notices
Administered price cap	0
General notice	239
Inter-regional transfer	150
Market intervention	7
Market systems	117

63 NER rule 4.8 in relation to power system security operations.

Type of notice	Number of notices
Manual priced dispatch interval	0
NEM systems	0
Non-conformance	724
Power system events	85
Price adjustments	6
Prices subject to review	210
Prices unchanged	202
Process review	0
Reclassify contingency	1040
Reserve notice	339
Settlements residue	29
Total	3,148

Source: AEMO

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.

5.4 Power system performance

The section examines whether key power system quantities such as frequency and voltages were maintained at the levels required in system performance standards during 2013-14.[64] The section also examines performance from the perspective of power system stability.

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. Some of these "excursions" are of short duration while others are more sustained. There are power system events which have been classified by the AEMC as "reviewable operating incidents". These are generally power system incidents which are not classified as "credible contingency events". Credible contingency events are defined in the NER.[65] AEMO publishes reports on power system incidents in accordance with AEMC Panel guidelines.[66]

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

65 NER clause 4.2.3 (b).

66 AEMC Reliability Panel, *Guidelines for identifying reviewable operating incidents*, 1 April 2013.

5.4.1 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 power system frequency would fall as there would be insufficient generation to supply the demand.

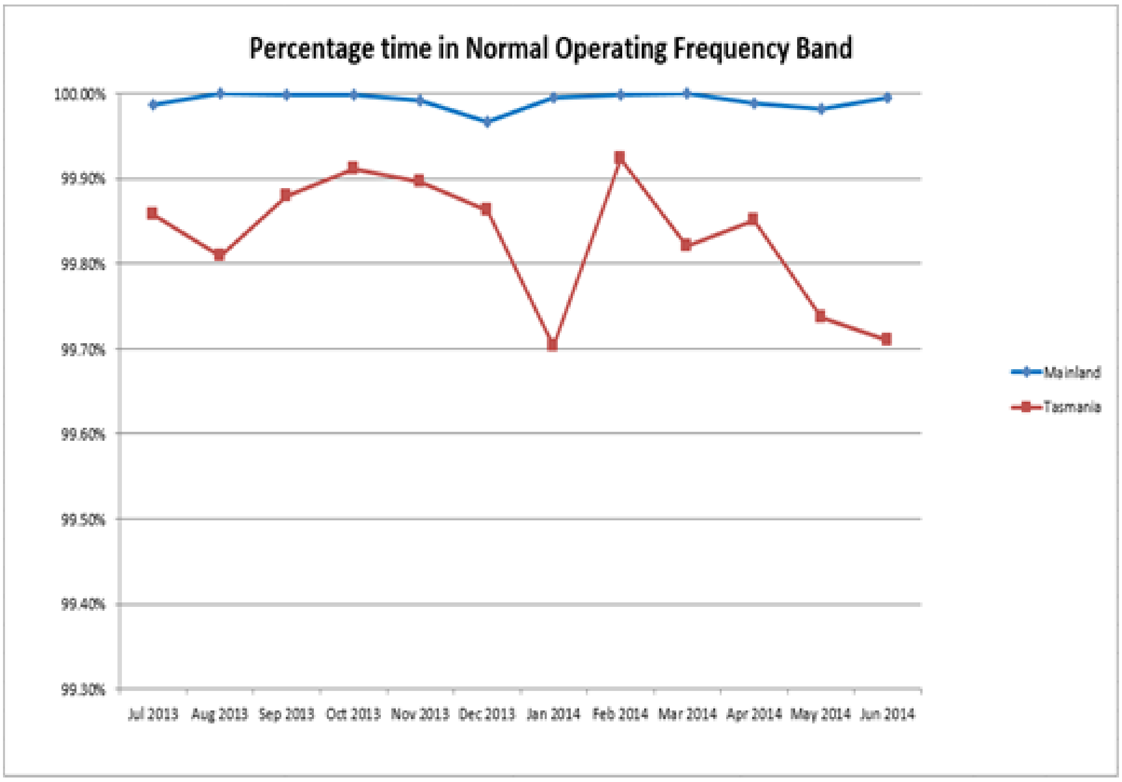
Generally in the NEM, a single generator trip would not produce an event that would result in the power system frequency changing appreciably. However if a group of generators were to trip then depending upon the amount of loss of generation the power system frequency may fall outside the frequency operating 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 then generators would be tripped to bring the frequency within the operating standards.

The Panel has considered the number of times in the 2013-14 financial year where events have been outside the frequency operating standards. The mainland and Tasmanian frequency operating standards are outlined in Appendix E.

Figure 5.1 shows that during 2013-14, both the mainland and Tasmania frequencies remained within the normal operating frequency band more than 99 per cent of the time. This result is in accordance with the respective frequency operating standards. The percentage of time frequency was outside the normal operating frequency band was similar for the mainland in 2013-14 and 2012-13, but less for Tasmania in 2013-14 than in 2012-13. These results are further explained below.

Figure 5.1 Percentage time in normal operating frequency band



Mainland NEM

There was one frequency event on the mainland in the 2013-14 financial year that did not comply with frequency operating standards. The Panel notes that this is one fewer than in 2012-13. The Panel also notes that this was a low frequency excursion event, during which the frequency was outside the normal operating frequency band for more than 300 seconds. The event was caused by the trip of the Vales Point Unit 6 in NSW on 22 December 2013 while generating 553 MW. This resulted in the system-wide frequency falling to 49.78 Hz for a period of 476 seconds (approximately 7.9 minutes).

This event is classified as a generation event in the mainland frequency operating standards. AEMO considered this event to be non-compliant as the duration of the frequency excursion was not in accordance with the frequency operating standards.[67]

AEMO did not investigate this event further, as it was not considered to be critical, or warrant any detailed investigation to determine the cause of the event.

On no occasion did a high-frequency excursion violate the mainland frequency operating standard in 2013-14.

Tasmania

The frequency operating standards that apply in Tasmania are detailed in Appendix E. These standards were most recently updated in October 2009.

67 AEMO, *Frequency and time error monitoring - 4th quarter 2013*, 3 February 2014, pp.8-9.

There were 12 frequency events in Tasmania in the 2013-14 financial year that did not comply with the frequency operating standards.[68] This was one fewer than in 2012-13.

The Panel notes the following information provided by AEMO:

- Nine of the events were high frequency excursions, two were low-frequency excursions, and one exhibited both high and low-frequency excursions.
- No contingency was identified for 11 of the 12 events and a network event was identified for the remaining event.
- For 10 of the 12 events, the frequency stabilised inside the normal operating frequency band within five minutes. The remaining two events took more than 10 minutes to stabilise.
- The primary causes for these events were generation not meeting dispatch targets, sudden load change, and Basslink's Georgetown transformer thermal rating limiting dispatch. A secondary cause was Frequency Control Ancillary Services (FCAS) being unmet.
- The durations of Tasmanian non-compliant frequency events were distributed approximately uniformly in 2013-14. During 2012-13, 70 per cent of the non-compliant frequency events were less than one minute in duration and the remainder exceeded two minutes.

The Panel notes that these events illustrate the challenge of controlling the Tasmanian frequency when Basslink is not available for frequency control. AEMO has since developed tools to better monitor the delivery of regulation FCAS, which will assist in the investigation of similar events that occur in the future. The Panel will continue to review these types of incidents in Tasmania.

5.4.2 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 the NER, AEMO must correct this as soon as possible but within a maximum of 30 minutes.[69]

For the 2013-14 year, there were no instances where secure voltage limits exceeded 30 minutes.

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68 For further information on these events, see AEMO's frequency and time deviation monitoring reports for the 3rd and 4th quarters of 2013 and 1st and 2nd quarters of 2014 within the electricity resources, reports and documents part of AEMO's website.

69 NER clause 4.8.15(a)(iv).

However, in one instance, a satisfactory voltage limit was exceeded. In this case, the Kangaroo Valley – Dapto 330 kV transmission line in NSW opened at the Dapto end only, resulting in an over-voltage of 1.6% on the Kangaroo Valley busbar for nine minutes.

No power system incident report was issued by AEMO, as it was considered as minor and not a threat to system security or the reliability of the power system. The Panel agrees that not every power system incident that AEMO identifies should be investigated. This is due to the resources required to undertake such a task.

Overall, the Panel notes that AEMO managed the power system within the voltage limits specified.

5.5 Power system stability

Transferring large amounts of electricity between generators and consumers over long distances can 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 threats to stability.

Under the NER, generators and TNSPs monitor indicators of system instability and report their findings to AEMO who then analyses the data to determine 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 in meeting its security obligations and provide valuable feedback on the planning process. These tools use actual system conditions and network configuration accessed in real-time from AEMO's energy management system. These tools include:

- Contingency analysis: contingency analysis is 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 different regions in the NEM to detect underdamped oscillatory phenomena in the power system that could lead to a security threat. 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: These online security analysis tools simulate 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.

In addition, AEMO has been working with transmission businesses to develop a NEM-wide high speed monitoring system. This will enhance visibility of the behaviour 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 to ensure that possible causes of instability can be located and addressed in a timely manner.

There have been a number of occasions during 2013 -14 and previous years where these real-time monitoring tools have identified the need to reduce transfer capability.

On these occasions, power system conditions at the time were used to review the transfer limits. This is because when transfer limits were originally determined, these unlikely 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 can accurately deal with a broader range of 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 and developed a program of installing monitoring tools to assist it monitor the stability of the power system. The NER also requires AEMO to co-operate with relevant network businesses to apply the power system stability guidelines.[70] However, it is difficult for the Panel to assess the performance of power system stability as it currently applies in the NEM.

5.6 Power system directions

AEMO has the power to issue directions as a last resort measure, or to contract for the provision of reserves through the reliability and emergency reserve trader (RERT) mechanism to maintain power system security and reliability. AEMO's powers of direction are set out in clause 4.8.9 of the NER

On 16 January 2014, AEMO directed the Broken Hill Gas Turbine Station on for system security reasons. At the time, supply from Victoria to Red Cliffs and Broken Hill was limited due to the forced outage of a 220 kV transmission line in the Victorian region. Supply from Murraylink was also limited by constraints in South Australia. Flow from NSW then reached a voltage collapse limit, whilst local load was continuing to increase.

70 NER clause 4.7.1(a).

AEMO's options were to either direct local generation at Broken Hill or load shed parts of Broken Hill.

The Broken Hill Gas Turbine Station plant operator advised that the station was physically available to generate, but would require a direction to do so. AEMO exercised the option to direct local generation.

The Panel notes that the low number of power system security directions indicates that the power system has been operating in a secure manner with a low number of directions over the past four years.

Table 5.4 Number of power system security directions issued by AEMO

Financial year	Queensland	New South Wales	Victoria	South Australia	Tasmania	Total
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	61
2004-05	8	0	0	34	0	42

5.7 Power system incidents

The Panel is required to publish guidelines under clause 8.8.1 (a)(9) of the NER. These guidelines are used by AEMO to identify power system incidents which need to be reported to the market. The Panel reviews these reports to assess how AEMO manages this process and to identify if there are any issues which arise whereby this process can be improved. In particular the Panel is interested in the numbers and types of power system incidents to determine if there is an increase thereby indicating that the power system is less secure.

The requirement for AEMO to review system incidents is discussed in the next section; with subsequent sections presenting a summary of the reviews completed during 2013-14 and key findings from the most significant incidents.

5.8 System operating incident guidelines

Under clauses 4.8.15(b) and 4.8.15(c) of the NER, AEMO is required to investigate every "reviewable operating incident" in the power system and report its findings. Given the number of reviewable operating incidents and the time and resources required by AEMO to investigate these incidents, AEMO requested the Panel undertake a review of the guidelines in December 2012.[71]

As part of the review process, the Panel determined that not every power system incident was "of significance to the operation of the power system". As such, the guidelines were amended to focus reviews on those incidents of significance to the operation of the power system.[72]

One of the key changes was the introduction of the term "critical transmission elements". Critical transmission elements are defined as those with a minimum voltage of 220 kV or elements of a lower voltage that have been identified by AEMO as critical for the supply of electricity in or between regions. AEMO has published a list of these critical transmission elements.[73]

When reviewing operating incidents a key focus for AEMO is to review non-credible contingency events.

The NEM planning framework requires that credible contingencies are studied as part of the normal network planning and operation processes. The capability of the power system is generally defined from the results of these studies.

However, as non-credible contingency events are not considered to the same extent in normal operational and planning activities, a review of these rare events provides a valuable opportunity to assess the performance of the power system. Therefore, AEMO assesses the adequacy of, and the provision and response of, facilities or services in its investigations and the subsequent appropriateness of any actions taken to restore or maintain power system security.[74]

5.8.1 Contingency events

In the 2013-14 financial year, there were 36 contingency events that were reviewable under the operating incident guidelines.[75] AEMO published a report for each event. Of these contingency events, AEMO classified 18 as multiple contingency events.[76]

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

72 ibid.

73 For further information, see the power system operating incident reports under the electricity resources part of AEMO's website.

74 ibid.

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

The Panel notes that the number of events was lower than the previous financial year which experienced 46 reviewable contingency events (with 20 of these being classified as multiple contingencies). The categorisation and number of contingency events are set out in Table 5.5.

Table 5.5 Reviewable operating incidents 2013-14

Event description	Number of incidents[77]
Transmission related incidents (excluding busbar trips)[78]	20
Generation related incidents	2
Combined transmission/generation incidents	5
Busbar related reviewable incidents	8
Power system security related	1

Source: AEMO

None of the events resulted in customer load interruptions in order to maintain power system security. There were also no load interruptions due to power system reliability issues.

Part of AEMO's review process involves considering whether further actions should be recommended for relevant participants to undertake. These recommendations can help to directly or indirectly reduce the likelihood of recurrence of an incident.

Examples include recommending that a transmission business investigate and conduct site testing to resolve inappropriate functioning of equipment; recommending a generator modify a protection scheme; or recommending AEMO provide further simulation training to control room operators to improve awareness and responses to future situations.

As a result of AEMO's review of incidents that occurred in 2013-14, ten actions were recommended for completion within a specific time frame.[79] As at April 2015, eight recommended actions had been completed, one was overdue for completion, and one was yet to be completed.[80]

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

77 Some events are included in more than one category.

78 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'.

79 AEMO, *Progress on power system operating incident report recommendations February–December 2014*, January 2015.

80 ibid, pp.4-7.

Based on the advice from AEMO, the Panel considers this process is being effectively managed and is supportive of AEMO's recent introduction of quarterly reporting on the progress of recommended actions. The Panel expects this formal tracking process will support timely implementation of recommendations and accountability for actions to reduce incident recurrence.

5.8.2 Major incidents

Based on the Panel's review of the power system incident reports published by AEMO, the Panel has considered the trip of the Bannaby to Mount Piper transmission line, and trip of the Torrens Island generators, in detail. The Panel considers these incidents are more significant on the basis that they:

- may have resulted in material levels of load shedding and therefore would have more 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 Bannaby–Mount Piper 500 kV transmission line and Bayswater Unit 4 generator transformers on 19 March 2014

Type of event

This event resulted in a major 500 kV transmission line and heavily loaded generator tripping at the same time. No customer load was lost as a result of this incident. This event was classified as a non-credible event as generators generally should not trip as a consequence of a system fault.

Summary of event details

A system event occurred which resulted in the 500 kV Bannaby–Mt Piper 5A7 transmission line (line 5A7) being tripped by protection systems and reclosing to clear the fault and restore the faulted line.

At the same time the Bayswater Unit 4 generator transformers 4A and 4B tripped, disconnecting Bayswater Unit 4 and removing 625 MW from the market.

During power system faults, generators are expected to remain connected to the power system while protection systems operate and isolate the faulted equipment. Tripping of the generator for a power system fault was therefore a non-credible contingency and may have resulted in the non-compliance of Mt Piper Unit 4 with its generator performance standards.

TransGrid's investigation identified that a lightning strike was the most probable cause of the incident. The transmission line protection operated correctly for this type of incident. Macquarie Generation's investigation found that the X protection relay operated and the associated tripping operated correctly. However no fault was recorded in the area which should have required the relay to operate.[81]

The Panel's comments and observations

The Panel notes that these incidents, although rare, do occur and may potentially impact on consumers. Some of these incidents are difficult to attribute to a cause and rely on the correct operation of protection systems. Therefore ongoing routine maintenance is critical such that problems of this nature do not occur more frequently.

The power system remained in a secure operating state throughout the incident.

Trip of Torrens Island Units B3 and B4 on 14 July 2014

Type of event

This event relates to the loss of two 200 MW generating units caused by problems associated with a new burner management system. This incident was classified as a non-credible contingency event under the NER.

Summary of event details

Two units at Torrens Island (B3 and B4) simultaneously tripped disconnecting 400 MW of generation. As a result, the power flow across the Victoria – South Australia (Heywood) interconnector increased above its secure operating limit for approximately 4.5 minutes. Both units should not have tripped simultaneously, as generating units should operate independently and not be affected by the operation of other units. Because both generators tripped simultaneously, this event was classified as a non-credible contingency.

Torrens Island B4 tripped due to an instrument error which determined an incorrect gas heating value. Torrens Island B3 then tripped 10 seconds later due to a fuel-rich protection trip caused by a transient gas pressure change. In both cases, the instruments relating to the incident had recently been adjusted.

During the power system incident:

- The Victoria–South Australia interconnector limit was exceeded for approximately 4.5 minutes. Therefore the power system was in an insecure operating state for this period.
- Power system frequency fell during this period, but remained within the frequency operating standards.
- The power system returned to a satisfactory operating state within 4.5 minutes.

81 Generators have redundant protection systems referred to a X and Y protection.

- Following the incident, AEMO reclassified the simultaneous trip of Torrens Island B3 and B4 as a credible contingency and invoked a constraint equation limiting the collective output of the two units to 273 MW. Reducing the collective output of the generating units limited the impact of the contingency to be no greater than the trip of the largest generating unit in South Australia.

AGL informed AEMO on 18 July 2014 that the cause of the trip had been resolved and AEMO revoked the constraints on the Torrens Island units.

The Panel's comments and observations

The Panel notes that AEMO classified this event as a credible contingency until AGL reported that it had fixed the cause of the problem. This had an impact on the wholesale market by restricting the available output of the two Torrens Island units, which had the potential to limit the amount of available generation in South Australia.

The power system was in an insecure operating state for a period of 4.5 minutes directly following the incident. This resulted in a fall in the system frequency, but not an incursion of the frequency operating standards.

While the incident does not reflect a broader power system security issue, there were power system security issues that had to be managed by AEMO for a period of time. The incident highlights how changes to generator instrumentation and controls may make those units more susceptible to unforseen tripping events. As a result, there may be an increased risk of supply loss following significant plant changes.

6 Safety performance

This Chapter sets out the Panel's assessment of the performance of the system from a safety perspective.

As discussed in Chapter 2, the scope of the Panel's consideration primarily relate to the bulk transmission system of the NEM, which for this report means interconnectors. 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.

For the 2013-14 financial year, the Panel reviewed the power system incident reports issued by AEMO. Based on the publicly issued power 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.

The Panel notes that 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. As noted in section 5.7, one direction notice was issued by AEMO in 2013-14. This related to directing the Broken Hill Gas Turbine to start generating to maintain power system security.

AEMO may alternatively have been able to ensure the power system was operated safely without directing the Broken Hill Gas Turbine to generate. This would have involved the shedding of load around Broken Hill. Therefore, the operation of the gas turbine was classified as a power system direction rather than a requirement for safety reasons.

Network service providers 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 in Appendix F.

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.[82]

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82 Unless stated otherwise, the information in Appendix F has been drawn directly from the websites of the relevant jurisdictional entities.

7 Market reviews

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 relevant to the AMPR.

7.1.1 Advice on linking the reliability standard and reliability settings with VCR

On 20 December 2013, the AEMC published its final advice to the Standing Council on Energy and Resources (SCER) on linking the reliability standard and reliability settings in the wholesale electricity market with a value of customer reliability (VCR).[83]

The AEMC's preferred approach is similar to the current process for determining the wholesale electricity market reliability standard and reliability settings. The key difference is the inclusion of a requirement for a VCR, estimated for the customers most affected by a supply shortfall, to be used as a cross-check on the reliability standard.

This approach provides for the level of supply reliability to customers from the generation and bulk-transmission sectors of the NEM to broadly reflect the value that customers place on receiving a reliable supply of electricity. This will promote efficient market outcomes that are at least consistent with those delivered by the NEM's current reliability standard and settings.

7.1.2 Distribution reliability measures

On 30 January 2014, the AEMC received a request from the COAG Energy Council to develop common definitions for expressing distribution reliability targets across the NEM. The COAG Energy Council considers this would be a useful tool to facilitate efficient investment, increase transparency and improve regulatory outcomes.[84]

The AEMC published the final report on its review of Distribution Reliability Measures on 18 September 2014. The report presents common definitions for distribution reliability targets and outcomes that could be applied across the National Electricity Market (NEM). The report proposes the use of these common definitions to increase transparency and consistency of distribution reliability measurements and improve stakeholder confidence.

83 AEMC, *Advice to SCER on linking the reliability standard and reliability settings with VCR*, Final Report, 20 December 2013.

84 AEMC, *Review of Distribution Reliability Measures*, Final Report, 5 September 2014.

The report proposes the use of these common definitions to increase transparency and consistency of distribution reliability measurements and improve stakeholder confidence.

The AEMC has worked with the AER, relevant electricity distribution businesses, jurisdictional regulatory bodies and governments in the development of the common definitions.

7.1.3 Optional firm access - design and testing

The SCER directed the AEMC to undertake a detailed design and testing of the optional firm access model. Under the proposed optional firm access model generators would drive much of the transmission investment in return for more certainty of access to the networks.[85] This would also drive locational price signals to assist generators to determine where they are located. In the longer term the alignment of generation and transmission investment would potentially minimise prices for customers.

The SCER requested that the AEMC:

- Confirm or modify the design of the optimal firm access (OFA) model;
- Engage with industry participants and governments to build an understanding of the model and potential impacts; and
- Recommend whether to implement the optimal firm access model and if so, how it could be implemented.

In December 2014, the AEMC published a note acknowledging the problems and concerns of stakeholders raised about the need of the OFA and asked stakeholders to provide feedback if the OFA was still a problem as identified in the Transmission Frameworks Review. Submissions closed 30 January 2015, with ten submissions received from stakeholders.

On 12 March 2015, the AEMC published its draft report on the OFA review. The draft report comprised two volumes:[86]

- Volume 1 – impact assessment and recommendation – sets out the AEMC's assessment of whether optional firm access would contribute to the NEO, and the AEMC's draft recommendation on whether optional firm access should be implemented.
- Volume 2 – optional firm access model – provides an overview of the optional firm access model that has been designed and developed during this review.

Submissions closed on 30 April 2015.

85 For further information see the optional firm access, design and testing project page, project code EPR0039 on the AEMC's website.

86 ibid.

7.1.4 Review of governance arrangements

The Council of Australian Governments (COAG) committed in April 2007 to undertake a review of energy market governance arrangements five years after their commencement. These arrangements include a review of the national regulator, rule maker and market development body and market and system operator overseen by a ministerial council now known as the COAG Energy Council.[87]

The review is intended to examine the broad energy market institutional structure created by COAG as well as the legislative framework that establishes and assigns functions to institutions. The Review will provide advice to the Energy Council on potential areas of improvement to the institutions and their oversight by the Energy Council.

To provide input to the review, the COAG Energy Council in accordance with the terms of reference established an expert Review Panel in December 2014. The expert Review Panel consists of Dr Michael Vertigan AC as Chair, Professor George Yarrow and Mr Euan Morton.

An issues paper for this review was published in April 2015. The issues paper has been prepared to assist individuals and organisations to prepare submissions. It outlines:

- the scope of the review;
- background and context on the Australian energy markets, its institutions and reform processes;
- questions on which the expert Review Panel is seeking comment and information; and
- the consultation and submission process.

The review is expected to be completed by September 2015.

7.2 Rule changes made by the AEMC

7.2.1 Improving demand side participation provided to AEMO by registered participants

AEMO contended that the NER did not provide for a process by which it can obtain information specifically on demand side participation from registered participants. AEMO noted that it had conducted voluntary surveys of registered participants in the past, but the quality of the information received from survey respondents was limited.

87 For further information on the review of governance arrangements see: www.scer.gov.au/workstreams/energy-market-reform/review-of-governance-arrangements.

AEMO considered that more accurate demand side participation information would improve the quality of its load forecasts, from short term forecasts such as five minute pre-dispatch (looking out one hour ahead), to long term forecasts such as the ten year forecasts in the National Electricity Forecasting Report.

The final rule made by the AEMC in March 2015 consisted of the following requirements:[88]

- registered participants are required to provide to AEMO with information on demand side participation, in accordance with new guidelines;
- AEMO must develop these guidelines in consultation with registered participants and other interested stakeholders, providing these parties with an opportunity to engage with AEMO on the appropriate specification of the guidelines;
- AEMO is required to have regard to registered participants' costs of compliance with the guidelines compared to the likely benefits of the use of that information by AEMO for the purpose of its load forecasts under the NER;
- AEMO must take the information on demand side participation received into account when developing and using load forecasts under the NER; and
- AEMO to publish details, no less than annually, on the extent to which demand side participation information has informed the development or use of its load forecasts.

The rule also articulates the scope of required information that AEMO may specify in the guidelines.

AEMO is required to develop and publish the guidelines related to gathering demand side participation information no later than the end of September 2016.

7.2.2 System restart ancillary services

System restart ancillary services (SRAS, or restart services) allow electricity supply to be restored following a large-scale blackout of the entire power system. These blackouts can have significant economic and social impacts, so it is important there are enough restart services available to quickly restore power supply.

The Panel is responsible for determining the level of restart services that must be procured, including the speed of restoration and how much supply is restored following a major blackout. AEMO then buys restart services on behalf of consumers to meet the requirements established by the Panel.

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88 AEMC, *Improving demand side participation provided to AEMO by registered participants*, Rule determination, 26 March 2015, pp.i-iii.

The costs of providing restart services are recovered from consumers and generators. It is therefore important that an efficient price is charged for these services.

The AEMC made a final rule in April 2015 that focussed on improving the frameworks for restart services in the NEM. The changes were intended to promote greater competition in the market for system restart services and to improve the governance arrangements to make these services more cost reflective.

The new rules provided the following changes to the system restart services framework:[89]

- clarification of the objective that the Panel must have regard to when determining how quickly the power system should be restarted following a major black out;
- clarification of the objective of AEMO in procuring restart services to meet the requirements of the Panel at the lowest cost possible;
- clarification of the purpose of the restart services such that enough services are procured so that each part of the power system can be restored independently; and
- requiring AEMO to report annually on whether it has procured sufficient services to meet the requirements established by the Panel and the processes it has followed to procure those services.

7.3 Pricing event reports

AEMO publishes Pricing Event Reports which report on significant price events.[90] These reports highlight unusual pricing outcomes in the NEM and the factors that contributed to these outcomes. The pricing events provide a short description of the event and are targeted to be published within four business days of the event.

The reports explain:

- the factors contributing to the abnormal pricing outcomes;
- whether outcomes were consistent with dispatch offers and power system conditions; and
- the performance of pre-dispatch in forecasting the abnormal outcomes.

Effective from 25 January 2015, the reports are produced when the: maximum daily spot price (trading interval price) in any region is more than $2,000/MWh*, or the

89 AEMC, *System restart ancillary services*, Rule determination, 2 April 2015, pp.i-vi.

90 For further information see the pricing events report section under the electricity resources part of AEMO's website.

minimum daily spot price for any region is less than -$100/MWh.[91]Similarly, a report may be produced where the maximum daily sum of frequency control ancillary services half hourly averaged prices exceeds $3,000/MWh in Tasmania, or $150/MWh for all other NEM regions.

The pricing event reports demonstrate the interaction between power system operations, generator performance and the market. For instance the price event report for Tuesday 17 June 2014 reported[92]

> "The rebid of capacity during the morning peak demand period resulted in a high 5-minute dispatch price for DI 0700 hrs, when generation priced at the market price cap had to be dispatched from various generators to meet the Queensland demand. Generation capacity offered below $236/MWh was available from Mt Stuart unit 2 and Oakey unit 2, but these units are all fast start units and require at least one dispatch interval to synchronise before it can receive dispatch targets.
>
> The target transfer to Queensland on the QNI interconnector could not be increased as higher imports were limited by the New South Wales stability constraint N^^Q_NIL_B1. The constraint prevents NSW voltage collapse for the tripping of the Kogan Creek PS. Target flow north on the Terranora interconnector was not possible due to outage of all 3 Directlink cables."

This report demonstrates the following:

- The importance of the load forecasting in the ST PASA and pre dispatch timeframe.
- Capability of generators to respond at short notice potentially resulting in a period of unsupplied energy.
- Network limits impacting/managing power system security.

AEMO does not produce a summary of the Market Event Reports. The Panel sees value in such a report which would provide the market with a greater transparency of the interaction between market performance and power system performance.

7.4 Market prices

The AEMC is responsible for calculating the Market Price Cap (MPC) and the cumulative price threshold (CPT) each year to apply from 1 July each year. The AEMC

91 AEMO may publish a brief report if the maximum daily spot price in any region is between $500/MWh and $2,000/MWh.

92 This report may be found on AEMO's website at: http://www.aemo.com.au/Electricity/Resources/Reports-and-Documents/Pricing-Event-Reports/June-2014 (viewed 1 May 2015).

must publish these values by 28 February each year. For the 2013-14 financial year the values for MPC and CPT are shown in Table 7.1.[93]

Table 7.1 2013-14 market price cap and cumulative price threshold values

	1 July 2012 to 30 June 2013	1 July 2013 to 30 June 2014
MPC	$12,900/MWh	$13,100/MWh
CPT	$193,000	$197,100

The Panel considers that identifying periods in the AMPR report where the market achieved the CPT or the MPC was reached would add value and provide additional insight into the performance of the NEM. These periods would normally occur during periods of binding network constraints, generation shortfall or unexpected power system conditions. In general this would occur during periods of power system stress. Publication of these periods would assist the market understand if these periods were increasing. The Panel recommends including this additional information in future AMPR reports.

93 AEMC, *Schedule of reliability settings*, 28 February 2013.

Abbreviations

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMPR	annual market performance review
AWEFS	Australian Wind Energy Forecasting System
CAIDI	Customer Average Interruption Duration Index
CBD	central business district
CCGT	combined cycle gas turbine
CPT	Cumulative Price Threshold
DC	direct current
DFS	Demand Forecasting System
DNSP	distribution network service provider
DSA	Dynamic Security Assessment
EAAP	Energy Adequacy Assessment Projection
ESC	Essential Services Commission of Victoria
ESCOSA	Essential Services Commission of South Australia
ESOO	Electricity Statement of Opportunities
ESV	Energy Safe Victoria
ETC	Electricity Transmission Code
FCAS	Frequency Control Ancillary Services
FCSPS	Frequency Control System Protection Scheme
FOS	Frequency Operating Standard
GSL	Guaranteed Service Level

HSM	High-speed Monitoring System
ICRC	Independent Competition and Regulatory Commission
IPART	Independent Pricing and Regulatory Tribunal
LNG	liquefied natural gas
LRC	Low Reserve Condition
LRET	Large-scale Renewable Energy Target
LRPP	Last Resort Planning Power
MAIFI	Momentary Average Interruption Frequency Index
MCE	Ministerial Council on Energy
MFP	Market Floor Price
MPC	Market Price Cap
MRL	minimum reserve level
MSS	Minimum Service Standards
MT PASA	Medium Term Projected Assessment of System Adequacy
NECF	National Energy Customer Framework
NEFR	National Electricity Forecasting Report
NEL	National Electricity Law
NEM	national electricity market
NEMMCO	National Electricity Market Management Company Limited
NEO	national electricity objective
NER	National Electricity Rules
NMAE	normalised mean absolute error
NSCAS	Network Support and Control Ancillary Services

NTNDP	National Transmission Network Development Plan
OFA	Optional Firm Access
OFGS	over-frequency generator shedding
Panel	Reliability Panel
PBST	Powerline Bushfire Safety Taskforce
PGG	Private Generators Group
PLC	Programmable Logic Controller
POE	probability of exceedance
PSA	Power System Adequacy
PV	photovoltaic
QCA	Queensland Competition Authority
QEIC	Queensland Electricity Industry Code
RERT	Reliability and Emergency Reserve Trader
RIT-D	regulatory investment test for distribution
RIT-T	regulatory investment test for transmission
rules	See NER
SAER	South Australian Electricity Report
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SASDO	South Australian Supply and Demand Outlook
SCER	Standing Council on Energy and Resources
SCONRRR	Steering Committee on National Regulatory Reporting Requirements
SRAS	System Restart Ancillary Services
ST PASA	Short Term Projected Assessment of System Adequacy

STPIS	service target parameter incentive scheme
TEC	Tasmanian Electricity Code
TNSP	transmission network service provider
TVGCS	TVPS Generator Contingency Scheme
TVPS	Tamar Valley Power Station
UFLS	Under-Frequency Load Shedding
USE	unserved energy
VAPR	Victorian Annual Planning Report
VCR	value of customer reliability
VSAT	Voltage Security Assessment Tool
WST	Workplace Standards Tasmania

A Weather summary 2013-14

A.1 Weather Summary

This section provides a review of the weather across the NEM regions for the 2013-14 financial year 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 plant 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 the 2013-14 financial year by each season.[94]

A.2 Winter 2013

Average temperatures were well above average in most areas and slightly above average in Tasmania during July and August 2013.

Rainfall was below average for Queensland and much of southeast Australia, including South Australia and Tasmania.

A.3 Spring 2013

Spring 2013 was the warmest spring on record for Australia, although maximum temperatures for Tasmania, southwest Victoria and adjacent southeast South Australia were near average.

New South Wales and South Australia recorded below average, and Tasmania recorded above-average, spring rainfall.

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

A.4 Summer 2013-14

Summer as a whole was warmer than average for Australia as a whole, especially due to relatively high temperatures in South Australia, Tasmania, Victoria and southern New South Wales.

One of the most significant multi-day heatwaves on record affected southeast Australia over the period from 13 to 18 January 2014. The major area affected by the heatwave consisted of Victoria, Tasmania (particularly the western half), southern New South Wales away from the coast, and the southern half of South Australia. Over most parts of this region, it ranked alongside the heatwaves of January-February 2009, January 1939 and (from the limited information available) January 1908 as one of the most significant multi-day heatwaves on record. While peak temperatures mostly fell short of those observed in 2009 and 1939, extreme heat persisted for a longer period than it did in those heatwaves over some areas, particularly near-coastal regions of Victoria and South Australia (including Melbourne and Adelaide).

Numerous records were broken for extended periods of heat. Most notably, state-average data reveal that Victoria had its hottest four-day period on record, for both maximum and daily mean temperature. In both cases these surpassed records set in 2009, while for three-day periods the 2014 heatwave ranked second behind that of 2009. These two heatwaves, both of which have occurred in the last five years, stand ahead of any others recorded on a statewide basis. The heatwave was more notable for persistent heat than for individual extreme hot days, but some locations still had their hottest day on record, particularly in the southeast of South Australia, and around and to the west of the Snowy Mountains in New South Wales.

Rainfall in summer 2013-14 was above average in parts of South Australia and below average for Tasmania, Victoria and eastern New South Wales and Queensland.

A.5 Autumn 2014

Autumn 2014 was warmer than average for Australia.

Above average rainfall was experienced in much of New South Wales, northern Victoria, South Australia. Below average rainfall was experienced in inland and western Queensland.

A.6 Notable hot periods during 2013-14

Sydney's warmest days were Monday 23 December 2013 and Thursday 2 January 2014 with maxima 36 degrees and above. These dates were during low electricity demand periods.

Melbourne, from Tuesday 14 January to Friday 17 January 2014, experienced maximum temperatures each day above 40 degrees. It was also notably hot in South Australia at the same time. The weekend (a low electricity demand time) of 8 and 9

February 2014 in Melbourne also exceeded 40 degrees. Tuesday 28 January 2014 was another notably hot day in Melbourne, with the temperature ranging from a minimum of 24.5 to a maximum of 42.0, resulting in a mean daily temperature of 33.3 degrees.

Brisbane's hottest weather was in early January 2014, a low electricity demand period, with maxima above 40 degrees on Friday 3 and Saturday 4. Tuesday and Wednesday 21 and 22 January 2014 and Thursday 20 February 2014 also brought high mean daily temperatures in excess of 30 degrees.

Adelaide experienced maxima above 40 degrees for several days in early January and February 2014. The most significant were Tuesday 14 January to Friday 17 January 2014 (correlating with the hot period in Melbourne) and Wednesday 12 February 2014. The highest mean daily temperature occurred on Thursday 16 January 2014 when the minimum was 29.6 and the maximum was 41.7 degrees.

A.7 Notable cold periods during 2013-14

Sydney's coldest days were Tuesday 9 July 2013 (when temperatures ranged between 8.7 to 13.6 degrees) and Thursday 8 August 2013 (when temperatures ranged between 9.3 to 13.1 degrees).

Melbourne's coldest days were Tuesday 9 July 2013 (when temperatures ranged from 3.1 to 14.5 degrees) and Thursday 25 July 2013 (when temperatures ranged from 4.1 to 12.4 degrees - similar temperatures on the preceding Sunday).

Brisbane's coldest day was on Wednesday 21 August, with a temperature range of 1.4 to 21.6 degrees.

Adelaide's coldest days were Monday 8, and Tuesday 9 July 2013, with temperatures ranging from 4.4 to 14.4 and 3.2 to 15.6 degrees, respectively.

Hobart's coldest days included Tuesday 9 July 2013 (1.2 to 10.6 degrees) and Wednesday 11, to Friday 13 September 2013 (4.4 to 10.1, 1.9 to 11.7 and 0.6 to 10.6 degrees, respectively). In addition, Friday 3 January 2014 and Monday 6, to Thursday 9 January 2014 had exceptionally cold mornings for summer, although these days were in the otherwise low electricity demand period.

B Reliability Panel guidelines

The Panel and the AEMC are responsible for developing and publishing power system standards and guidelines to assist AEMO in performing its power system security and reliability functions.[95] This appendix provides further explanation of these standards and guidelines, which include:

- Power system security and reliability standards;
- System restart standards;
- Performance standards;
- Plant standards;
- Principles and guidelines for maintaining power system security;
- Guidelines for intervention by AEMO for reliability and policies;
- Reliability and Emergency Reserve Trader (RERT) guidelines;
- System operating incidents guidelines;
- AEMO report to the Reliability Panel on the accuracy of demand forecasts; and
- Template for Generator Compliance Programs.

B.1 Power system security and reliability standards

The Reliability Panel determines the power system security and reliability standards, including:

- Standards for the power system operating frequency;
- Standard for the reliability of generation and bulk supply;
- Reliability standards (and its associated determination);[96]
- Frequency operating standards (mainland);[97]and
- Frequency operating standards (Tasmania).[98]

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95 Further information on the electricity guidelines and standards can be found on the AEMC's website at www.aemc.gov.au.

96 AEMC Reliability Panel, *NEM Reliability Standard – Generation and bulk supply*, Electricity guidelines and standards, July 2012.

97 AEMC Reliability Panel, *Application of Frequency Operating Standards During Periods of Supply Scarcity*, Final determination, 15 April 2009.

B.2 System restart standard

The Panel also determines the system restart standard for the acquisition of system restart ancillary services.[99]

In relation to these services, AEMO also publish a number of guidelines. These include guidelines for primary restart services and secondary restart services, and guidelines for AEMO in determining electrical sub-networks.

On 12 April 2012, the Panel determined the system restart standard that would apply from 1 August 2013. Prior to that time, an interim standard prepared by AEMO applied.

B.3 Performance standards

The Panel also publishes a report on the implementation of automatic access and minimum access standards as they relate to performance standards. On 30 April 2009, the Panel published the final report for its Technical Standards Review on the adequacy and content of the technical standards.[100] Performance standards are the technical standards which apply to generators, loads and market network service providers (MNSP) and are set out in Chapter 5 of the NER. Generators, market customers and MNSP's are required to negotiate their performance standards with their connecting network service provider and AEMO

B.4 Principles and guidelines for maintaining power system security

The Panel is also required to develop and publish principles and guidelines that determine how AEMO should maintain power system security. These principles must take into account the costs and benefits to the extent practicable.[101]

B.5 Guidelines for intervention by AEMO for reliability and policies

The Panel is required to determine guidelines governing AEMO's exercise of power to issue directions in connection with maintaining or re-establishing the power system in a reliable operating state.

If there is a major supply shortfall in the NEM, AEMO must implement any necessary involuntary load shedding in an equitable manner, in accordance with the guidelines established by the Panel as part of the power system security and reliability standards.

98 AEMC Reliability Panel, *Tasmanian Frequency Operating Standard Review*, Final Report, 18 December 2008.

99 AEMC Reliability Panel, *System Restart Standard*, Electricity guidelines and standards, 1 August 2003.

100 AEMC Reliability Panel, *Reliability Panel Technical Standards Review*, Final Report, 30 April 2009.

101 AEMC Reliability Panel, *Guidelines for management of electricity supply shortfall events*, Electricity guidelines and standards, 1 December 2009.

B.6 Reliability and Emergency Reserve Trader Guidelines

The Panel is also required to develop, publish and amend from time to time guidelines that assist AEMO when it operates the Reliability and Emergency Reserve Trader.

B.7 System operating incidents guidelines

The Panel is also required to determine guidelines identifying or providing for the identification of operating incidents and other incidents that are of significance.[102]

B.8 AEMO report to the Reliability Panel on the accuracy of electricity demand forecasts

The NER require AEMO to prepare and provide a report to the Panel in November of each year on the accuracy of AEMO's demand forecasts, as published in AEMO's most recent ESOO, and any improvements made by AEMO or other related parties to the forecasting process that will apply to the next ESOO. The Panel is subsequently required to publish this report.

Since 2012, AEMO has published its demand forecasts in the National Electricity Forecasting Report (NEFR). As a result, it is the NEFR which is the subject of AEMO's report on the accuracy of its demand forecasts.

The Panel recognises that demand forecasts play an essential role in the market where they may be used by stakeholders when making key operational and investment decisions. It is important that robust and reliable forecasting is available to facilitate these business requirements. Demand forecasts are also important to end-use consumers to provide transparency and improve awareness of energy use and other market issues.

B.9 Template for Generator Compliance Programs

The Panel determines and publishes the template for generator compliance programs. The Panel published the first template in July 2009 and a revised template was published in June 2012.[103] The AER undertakes an audit of generators compliance with the template and publishes the results of these audits. The results of the audits can be found in the AER's quarterly compliance reports.[104]

102 AEMC Reliability Panel, *Guidelines for identifying reviewable operating incidents*, Electricity guidelines and standards, 1 April 2013.

103 AEMC Reliability Panel 2009, *Template for Generator Compliance Programs*, 31 July 2009.

104 Further information can be found under compliance reporting part of the wholesale markets section on the AER's website at: www.aer.gov.au.

C Reliability assessment

This appendix provides details of the criteria used to determine 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 (10+ years) that are published annually, through to the detailed five- and thirty- minute pre-dispatch price and demand projections.

This market information is published across a range of tailored reports, including the ESOO, NEFR, APRs, NTNDP, medium-term PASA, short-term PASA and market notices. The following sections describe these reports in more detail.

C.2 Planning information

Each year, AEMO publishes the National Electricity Forecasting Report (NEFR). This provides AEMO's independent electricity consumption and maximum demand forecasts for the five NEM regions. The report presents 20-year forecasts at annual resolution, and across high, medium, and low growth scenarios.

AEMO uses the NEFR forecasts as an input into its electricity planning publications, including the Electricity Statement of Opportunities (ESOO).

The ESOO, published annually, highlights the changing electricity generation mix, and assesses the adequacy of supply to meet demand over a 10-year outlook period. The ESOO also highlights NEM-wide generation and demand-side investment opportunities by analysing factors that influence these types of investment.

While the ESOO and NEFR focus on supply and demand respectively, annual planning reports (APRs) are produced by each transmission business to focus on network capabilities. In particular, the APRs focus on transfer capacities, potential constraints, and possible intra-regional augmentations in the short- to medium-term.

Longer-term network planning is the focus of AEMO's annual National Transmission Network Development Plan (NTNDP), which presents an independent strategic plan for the NEM transmission network over a 20-year period.

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. AEMO undertakes annual consultation with stakeholders to establish the scope of the NTNDP, identify material issues for investigation, and seek feedback on the proposed methodology.

These documents together provide a narrative on the state of the market, and its potential evolution over the short and long-term. This information can assist both existing and intending participants when identifying opportunities in the market.

C.3 Energy Adequacy Assessment Projection (EAAP)

The EAAP is a quarterly information mechanism that provides the market with projections of the impact of generation input constraints on energy availability.[105]

The Panel consider that the EAAP functions as an additional source of information for the market regarding when and where energy constraints may impact on energy availability. The Panel completed a review of the EAAP in February 2013.

C.4 Medium-term Projected Assessment of System Adequacy

Medium-term PASA assesses the adequacy of supply to meet demand at the time of anticipated daily maximum demand, based on a 10% probability of exceedance (POE) for each day over the next two years.[106]

Medium-term PASA information is provided:

- To assist participants in planning for maintenance, production planning and load management activities over the medium term (over a two year period); and
- As the basis for any intervention decisions by AEMO, for example, invoking the Reliability and Emergency Reserve Trader (RERT).

Demand forecasts are prepared by AEMO. Generation and demand-side daily availability estimates are submitted by participants under clause 3.7.2(d) of the NER. In addition, planned network outages are submitted to AEMO by network service providers under clause 3.7.2(e) of the NER.

The ability to forecast network capability and in particular interconnector capability is important for the reliable and efficient operation of the market. Every month, AEMO and the TNSPs publish planned network outage information for the following 13 months. AEMO also determines and publishes an assessment of the projected impact of network outages on intra- and inter-regional power transfer capabilities, and provides constraint equation information and plain English descriptions of the impact for all transmission businesses.

Interconnector capability can be a function of the pattern of generation, availability of reactive support and certain network services.

In some circumstances, outages are scheduled at short notice by taking advantage of the most recent market information without compromising supply reliability; however, short notice outages can also increase uncertainty for market participants and for the management of reliability and power system security. Other outages have little effect on reliability.

105 The reporting requirement was introduced following a Rule change request resulting from a Rule proposal from the Panel.

106 Probability of exceedance refers to the likelihood that a MD projection will be met or exceeded.

The medium-term PASA demand forecast is a 10% POE forecast with a daily resolution. This forecast has historically used the summer and winter weekday 10% POE demand forecasts consistent with the most recent NEFR and sculpts the remainder of the year by estimating seasonal and weekend fluctuations.

C.5 Short-term Projected Assessment of System Adequacy

Short-term PASA assesses the adequacy of supply to meet demand for each half-hour of the following seven days.[107]

Demand forecasts are prepared by AEMO. Generation and demand side availabilities are submitted by participants in accordance with clause 3.7.3(e) of the NER. Transmission outage programs are supplied by TNSPs under clause 3.7.3(g) of the NER. This information is to assist participants in optimising short-term physical and commercial planning for maintenance, production planning and load management activities.

PASA in the pre-dispatch timeframe (PD PASA) is also published. Using some outputs from the pre-dispatch run as an input to PD PASA achieves a closer alignment with pre-dispatch results.

C.6 Pre-dispatch

C.6.1 Demand forecast assessment

Figures 11 to Figure 15 depict the demand forecast four-hours-ahead for the summer 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. The first 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 forecast demand deviations are plotted

The second graph shows the top 10 per cent of actual demand in one percentage groupings.

The third graph examines raw deviations in tenth percentile groupings and plots the average raw deviation and the maximum demand forecast deviation for each grouped sample. Similarly, the fourth 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.

107 For further information the section regarding ST PASA on AEMO's website.

The graphs for each region show that forecasting is generally less reliable towards the top end.

Figure C.1 Queensland demand forecast deviation four hours ahead

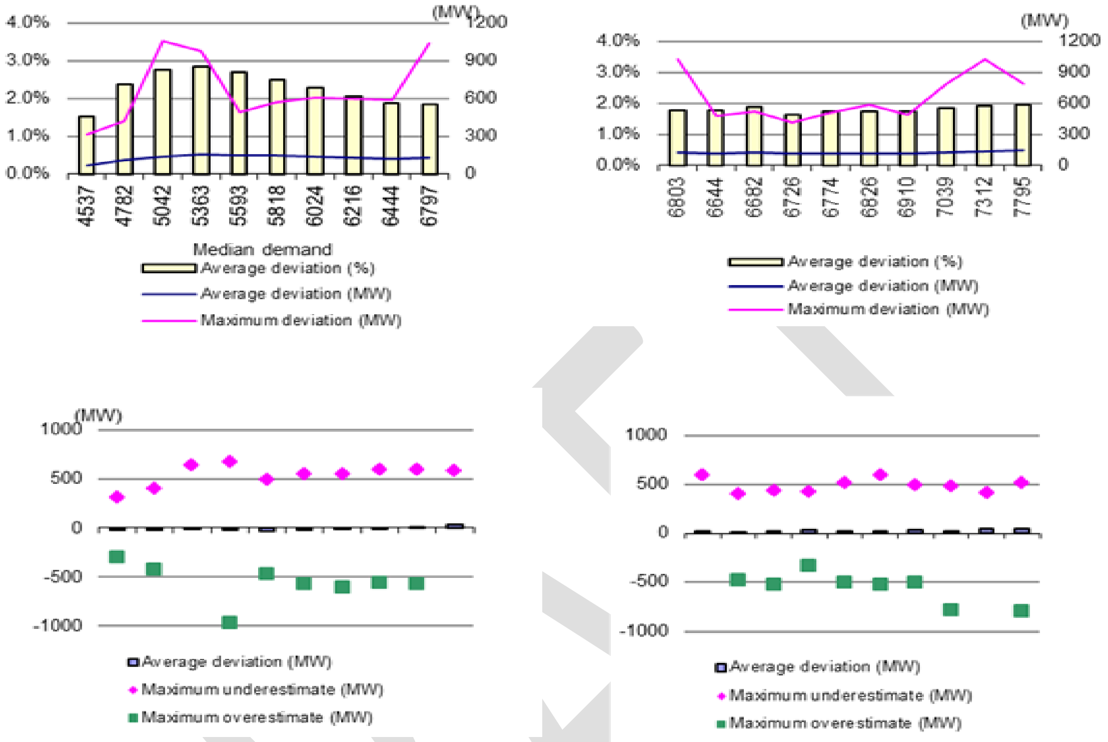


Figure C.2 New South Wales demand forecast deviation four hours ahead

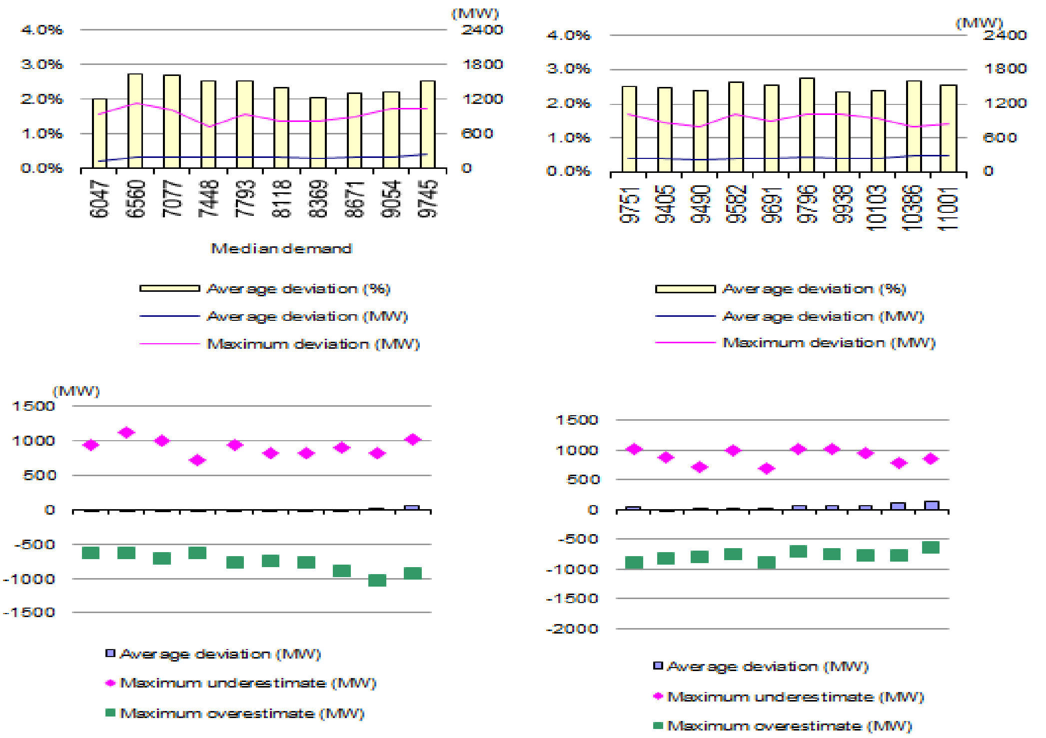


Figure C.3 Victoria demand forecast deviation four hours ahead

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

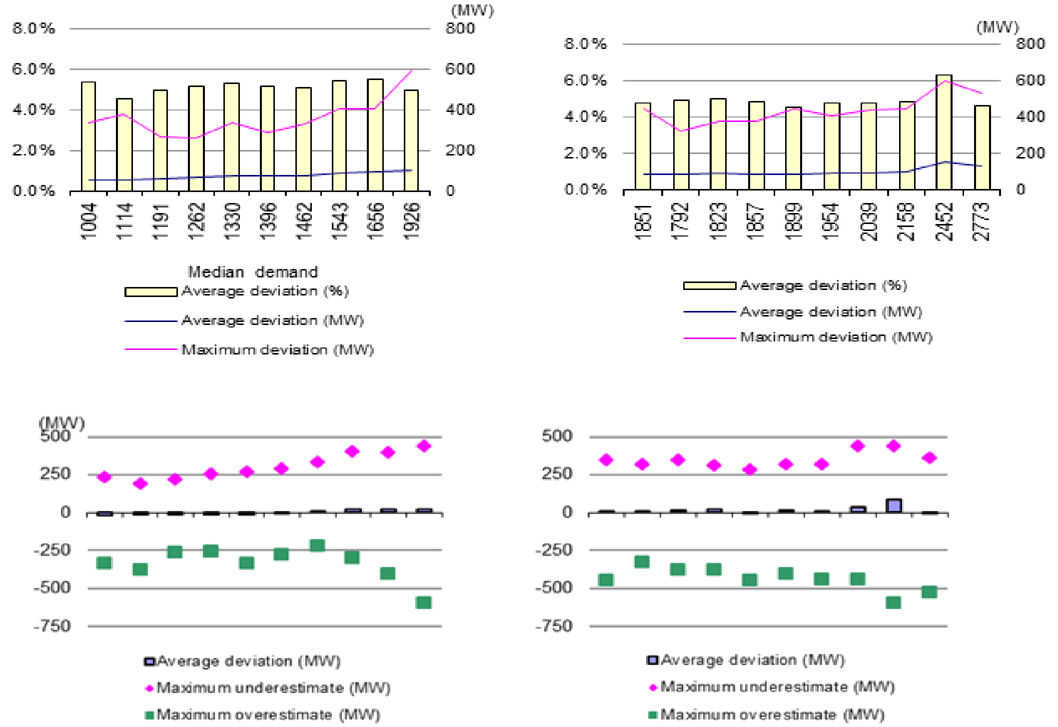
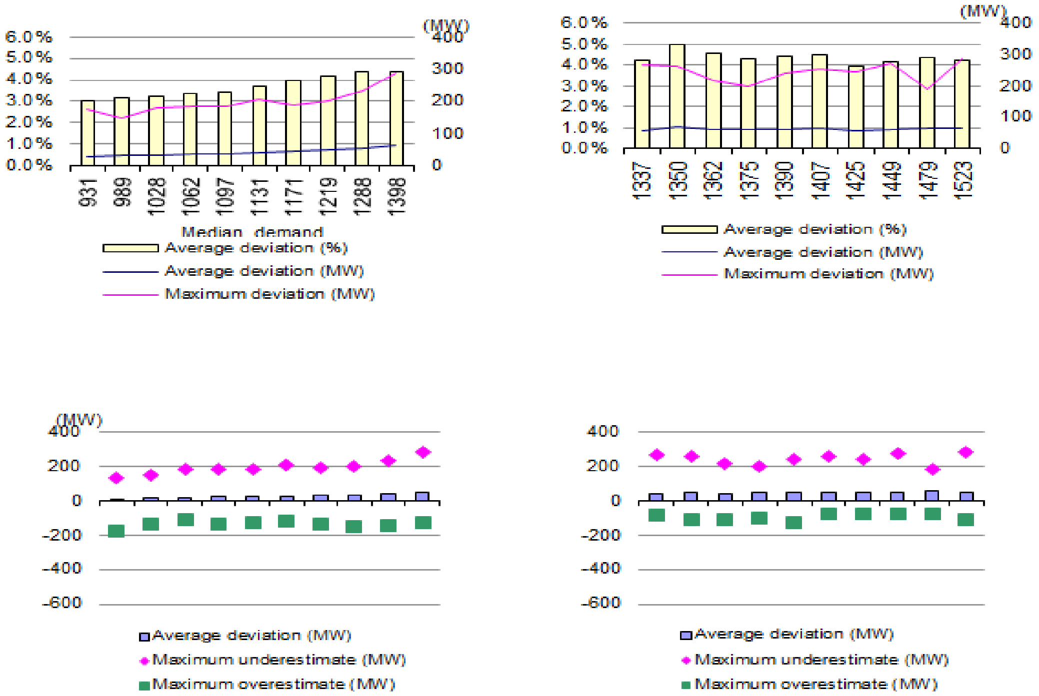


Figure C.5 Tasmania demand forecast deviation four hours ahead



C.6.2 Minimum reserve level

AEMO calculates minimum reserve levels (MRL) to meet the Reliability Standard operationally, where AEMO's objective is to maintain reserve levels above the MRLs. 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. Table 14 provides a history of the values of the MRL over the previous ten years.

Table C.1 Revised minimum reserve levels (note 1)

	Queensland (note 2)	New South Wales	Victoria and South Australia	Victoria	South Australia (note 2)	Tasmania
2005-06	610 MW	-290 MW	530 MW		265 MW	144 MW
2006-07	480 MW	-1490 MW	615 MW		-50 MW	144 MW
2007-08	560 MW	-1430 MW	615 MW		-50 MW	144 MW
2008-09	560 MW	-1430 MW	615 MW		-50 MW	144 MW
2009-10	560 MW	-1430 MW	615 MW		-50 MW	144 MW

	Queensland (note 2)	New South Wales	Victoria and South Australia	Victoria	South Australia (note 2)	Tasmania
2010-11	829 MW	-1548 MW		653 MW (note 3)	-131 MW	144 MW
2011-12	913 MW	-1564 MW		297 MW	-168 MW	144 MW
2012-13	913 MW	-1564 MW		297 MW	-168 MW	144 MW
2013-14 (note 4)	913 MW	-1564 MW		(note 5)	(note 5)	144 MW

Note 1: 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.

Note 2: This is a local requirement and must be met by generation within the region assuming 0 MW supporting flow from neighbouring regions.

Note 3: For Victoria only. In previous years, a single point was used on the reserve sharing curve to determine reserve sharing for Victoria and South Australia. This process is described in the 2010 ESOO, Chapter 6, Section 6.3.1.

Note 4: This year's data was sourced from AEMO's reserve notice MT PASA publication (22 October 2013), available at: www.aemo.com.au/AEMO%20Home/Market%20Notices/0043489.

Note 5: While AEMO specified static MRLs for the Queensland, New South Wales and Tasmanian regions, AEMO specified optimum shared MRLs between Victoria and South Australia regions.

There are six constraints on the amount of reserves required for Victoria and South Australia:

- Victorian Reserve ≥ 205.00;
- 5.88 x Victorian Reserve + South Australian Reserve ≥ 1237.88;
- 1.33 x Victorian Reserve + South Australian Reserve ≥ 228.00;
- 0.43 x Victorian Reserve + South Australian Reserve ≥ -40.53;
- 0.23 x Victorian Reserve + South Australian Reserve ≥ -147.55;
- South Australian Reserve ≥ -368.00.

Reserve levels are forecast and monitored by AEMO through a number of tools discussed in the following section. These tools allow AEMO and the market to understand any potential for reserve levels being below the MRL threshold and allow the management of reliability in the NEM.

As the market operator, AEMO takes the reliability standard as determined by the Panel 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 (MRL) for each region. Details of the MRL's for each region are included in this appendix. By convention, MRL's are expressed relative to a region's 10% probability of exceedance (POE) maximum demand, including any demand-side participation (DSP).

MRLs 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.

The Medium-Term Projected Assessment of System Adequacy (MT PASA) applies the MRL's to assess the supply adequacy for a two-year (daily) outlook. This assessment includes the scheduled maintenance pattern of generating units and transmission assets. MT PASA is published weekly and is intended to provide information to the market about times when there is a high likelihood of low reserves. Under these conditions, AEMO may need to intervene through the Reliability and Emergency Reserve Trader (RERT) process. As the MT PASA is published on a weekly basis there is no assessment undertaken of the accuracy of the output.

In the longer term, the supply-demand outlook applies the MRLs in the 10-year (yearly) outlook published in the Electricity Statement of Opportunities. The supply-demand outlook is intended to provide market participants and other interested parties with information about the timing and magnitude of additional investment required to maintain the Reliability Standard. Details of the supply adequacy are included in Section 8.2.1 ESOO.

D Network performance

While the Panel is responsible for dealing with reliability and security matters in the wholesale bulk electricity market and the transmission network, the ultimate level of reliability and security which consumers receive is also impacted by the performance of the local transmission and distribution network. Although the Panel is not involved with local supply matters, this section includes an overview of the jurisdictional arrangements for managing the reliability performance of the NEM transmission and distribution networks.

D.1 Transmission Network Performance

D.1.1 Queensland

The mandated reliability obligations and standards are contained in Schedule 5.1 of the NER, the Queensland Electricity Act, Powerlink's Transmission Authority, and in connection agreements with the distribution networks. In addition, the AER sets and administers reliability-based service standard targets which involve an annual financial incentive (bonus/penalty).[108]

Consistent with the NER, the Transmission Authority requirements and connection agreements with Energex, Ergon Energy and Essential Energy, Powerlink plans future network augmentation so that the reliability and power quality standards of Schedule 5.1 of the NER can be met during the worst single credible fault or contingency (N–1 conditions) unless otherwise agreed with affected participants. This is based on satisfying the following obligations:

- 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 (Electricity Act 1994, S34(2)).

- The transmission entity must plan and develop its transmission grid in accordance with good electricity industry practice such that … the power transfer available through the power system will be adequate to supply the forecast peak demand during the most critical single network element outage (Transmission Authority No T01/98, S6.2(c)).

- The Connection Agreements between Powerlink and Energex, Ergon Energy and Essential Energy include obligations regarding the reliability of supply as required under Schedule 5.1.2 of the NER. Capacity is required to be provided such that forecast peak demand can be supplied with the most critical element out of service, i.e. N–1. Following the EDSD report in 2004, Energex and Ergon are required to plan their subtransmission networks (which interact with the Powerlink transmission network) to the N–1 criterion.

D.1.2 New South Wales

TransGrid is obliged to meet the requirements of Schedule 5.1 of the NER, as well as, requirements imposed by connection agreements, environmental legislation and other statutory instruments. During 2013-14, TransGrid was also obliged to meet the statutory obligations contained in the New South Wales Electricity Supply (Safety and Management) Regulation 2008 (the 2008 Regulation). This included lodging a Network Management Plan with the Department of Trade and Investment and complying with it. TransGrid issued an updated Network Management Plan in February 2013.

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

The transmission design reliability standard for New South wales represents a legal obligation TransGrid must meet.

In general terms the standard requires TransGrid to plan and develop its transmission network on an "N–1" basis or, when required, to accommodate AEMO's operating practices, except under conditions such as radial supplies, inner metropolitan areas, and the CBD. Transmission network developments servicing the inner metropolitan and CBD areas must be planned on a modified "N–2" basis. Furthermore, this standard interlinks TransGrid's planning obligations with the distribution licence obligations imposed on all distribution network service providers in New South Wales. The specific requirements are set out in TransGrid's network management plan.[109]

The 2008 Regulations underpinning the standard were replaced with the Electricity Supply (Safety and Network Management) Regulation 2014. These new regulations no longer require the publication of a network management plan.

D.1.3 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 publishes a Victorian Annual Planning Report (VAPR), which identifies existing and emerging electricity transmission network limitations and future transmission development needs for the declared shared network.

AEMO assesses new augmentations under the Regulatory Investment Test for Transmission (RIT-T) as specified in the NER in accordance with the RIT-T requirements.

108 This section has been completed with the assistance of Powerlink.

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

AEMO identifies the benefits of various network and non-network investment options. These benefits may, amongst other things, result from reduction in expected unserved energy, 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, and 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. AEMO calculates the benefits of reductions in expected unserved energy by applying a value of customer reliability (VCR). AEMO also considers a sector-specific VCR where the transmission constraint affects only a reasonably distinguishable subset of the load.

D.1.4 South Australia

In addition to the reliability performance obligations set out in Schedule 5.1 of the NER, ElectraNet is also subject to the Electricity Transmission Code (ETC) administered by the Essential Services Commission of South Australia (ESCOSA).[110] The ETC 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. ElectraNet also participates in the Service Targets Performance Incentive Scheme (STPIS) administered by the AER, which applies an annual financial incentive (bonus/penalty) based on performance against reliability-based service standards targets and the market impact of transmission congestion.[111]

ESCOSA has commenced a review of the specific reliability standards set out in clause 2 of the ETC. This review is scheduled to finish in late 2015 in order to be reflected in ElectraNet's revenue proposal for the 2018-2023 regulatory control period.

D.1.5 Tasmania

In addition to the network performance requirements located in Schedule 5.1 of the NER, TasNetworks is obliged to meet the requirements of its transmission licence, Electricity Supply Industry (Network Performance Requirements) Regulations 2007 (Tas), termed the Tasmanian regulations, and the terms of its connection agreements.[112] The connection agreements between TasNetworks and its customers include obligations regarding the reliability of supply as required under Chapter 5 of the NER.

The objective of the Tasmanian regulations is to specify the minimum network performance requirements that a planned power system of a transmission business 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

110 This section has been completed with the assistance of ElectraNet.

111 ESCOSA, *Electricity Transmission Code – TC/07 (version 2)*, 1 July 2013.

112 This section has been completed with the assistance of TasNetworks.

includes discussion of any forecast supply shortfalls against the Tasmanian regulations, and proposed remedial actions.

The Tasmanian Department of Infrastructure, Energy and Resources undertook a review of the requirements of the Tasmanian regulations, and amended them in 13 November 2013. The changes to the Regulations relate to:

- The minimum network performance requirements in respect of electricity transmission services.
- The process for exemptions in respect of such requirements.
- Provisions in respect of ministerial approval of certain augmentation in respect of such services.

The AER's Service Target Performance Incentive Scheme (STPIS) sets and administers reliability based service standards targets which involve an annual financial incentive (bonus/penalty) incorporated in TasNetworks' transmission revenue determination. The STPIS covers all prescribed transmission services except where transmission customers have agreed to varying levels of connection services under their connection agreements.

D.2 Distribution Network Performance

All jurisdictions have their own monitoring and reporting frameworks for reliability of distribution networks. In addition, the Steering Committee on National Regulatory Reporting Requirements[113] has adopted four indicators of distribution network reliability that are widely used in Australia and overseas.[114] These are the system average interruption frequency index (SAIFI), system average interruption duration index (SAIDI) and customer average interruption duration index (CAIDI) and momentary average interruption frequency index (MAIFI).[115]

While all jurisdictions report on SAIDI and SAIFI, the approach of distribution businesses in relation to inclusions and exclusions differs. To that end, in some cases the data reported by each jurisdiction is subject to qualification. Stakeholders should refer to the respective jurisdictional publications for a detailed understanding of these variations.

113 SCONRRR is a working group established by the Utility Regulators Forum

114 Utility Regulators Forum , *National regulatory reporting for electricity distribution retailing businesses, discussion paper*, 2012.

115 See the Glossary for further information.

D.2.1 Queensland

The Queensland Electricity Act 1994 and the Electricity Regulation 2006 define the arrangements for the Queensland distribution businesses.[116] Performance standards for Queensland distribution businesses were introduced in September 2007.

The Queensland Electricity Industry Code requires that the Queensland Competition Authority (QCA) 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.[117]

Although the minimum service standard requires a gradual improvement in performance each year, the minimum service targets applying to Energex were held constant at the 2011-2012 level for its current regulatory control period.[118] This reflects the differences in the minimum services targets for Energex and Ergon Energy, with the targets for Energex being more stringent.

The distribution businesses report quarterly to the QCA on their performance relative to their targets. The QCA also monitors the performance of their guaranteed service levels.

Table D.1 Performance of the Queensland distribution businesses for 2013-2014

DNSP	Feeder	SAIDI (minutes)		SAIFI (interruptions)	
		Target	Actual	Target	Actual
Energex	CBD	15	3.56	0.15	0.058
	Urban	102	74.864	1.22	0.804
	Short-rural	216	173.392	2.42	1.556
Ergon	Urban	146	118.4872	1.92	1.3939
	Short-rural	406	291.908	3.8	2.767
	Long-rural	916	798.4215	7.1	6.118

Table D.1 provides a summary of the performance of the Queensland distribution businesses including target and actual performance. It shows that Energex met its

116 This section was prepared with the assistance of the Queensland Competition Authority.

117 Queensland Competition Authority, April 2009, Final Decision on the Review of Minimum Service Standards and Guaranteed Service Levels to Apply in Queensland from 1 July 2010.

118 This was to reflect the 2011 recommendations of the Electricity Network Capital Program Review. See: Electricity Network Capital Program Review 2011, Detailed report of the independent panel, released on 8 December 2011.

SAIDI and SAIFI targets for all feeder categories during 2013-2014. Ergon Energy met five out of its six minimum service level targets (the exception being long-rural SAIDI).

Ergon Energy's performance in 2013-2014 was consistent with its performance in 2011-2012 where it also met five out of its six minimum service level targets.

Notwithstanding, Ergon Energy's underlying SAIDI performance during 2012-13 represented an improvement on its 2011-12 performance for all feeder types. This is Ergon Energy's third consecutive year of improvement in urban and short rural SAIDI performance. SAIFI performance also improved, with the exception of urban feeders, where performance was slightly worse than in 2011-12.

Ergon Energy's 2012-13 performance was adversely impacted by the extended aftermath of tropical cyclone Oswald and extensive flooding in its southern and central supply regions. While the impact of the most severe weather days was excluded in accordance with the exclusion criteria in the Code, Ergon Energy noted that there were a number of heavy storms and bushfire events during 2012-13 that had a significant impact on the network, but which did not meet the criteria for a major event day exclusion.

D.2.2 New South Wales

The Electricity Supply Act 1995 requires the New South Wales distribution businesses to be licenced.[119] Network performance standards for the New South Wales distribution businesses 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 (conditions (14-19).[120]

The performance of the New South Wales distribution businesses 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.

Table D.2 shows a summary of the performance of the New South Wales distribution businesses including an overall target for each distribution business and the actual performance by feeder classification. More detailed performance information is

119 This section was prepared with the assistance of the NSW Department of Trade and Investment, Regional Infrastructure and Services.

120 IPART is the independent body that oversees regulation of the water, gas, electricity and public transport industries in New South Wales.

available from network performance reports available on each of the distribution businesses websites.

The distribution businesses 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 D.2 Performance of the New South Wales distribution businesses for 2013-2014

DNSP	Feeder	SAIDI (minutes)		SAIFI	
		Target	Actual	Target	Actual
Essential Energy (previously known as Country Energy)	Urban	125	63	1.8	0.78
	Short rural	300	180	3.0	1.83
	Long rural	700	357	4.5	2.70
	All	n/a	181	n/a	1.73
Ausgrid (previously known as EnergyAustralia)	CBD	45	7.3	0.3	0.01
	Urban	80	64.5	1.2	0.74
	Short rural	300	156.3	3.2	1.45
	Long rural	700	440.2	6.0	3.09
	All	n/a	76.5	n/a	0.82
Endeavour Energy (previously known as Integral Energy)	Urban	80	63	1.2	0.8
	Short rural	300	173	2.80	1.7
	Long rural	n/a	989	n/a	3.4
	All	n/a	83	n/a	1.0
New South Wales	CBD	n/a	7.3	n/a	0.04
	Urban	n/a	63.5	n/a	0.77
	Short rural	n/a	169.8	n/a	1.66
	Long rural	n/a	595.4	n/a	3.06
	All	n/a	113.5	n/a	1.18

The network performance standards are enforced under Schedule 2, clauses 8 and 8A of the Electricity Supply Act 1995. Under these clauses, the Minister can impose fines or cancel a distribution licence if the holder of the licence has knowingly contravened the requirements of the Act or the regulations, the conditions of the licence, or an endorsement attached to the licence.

Table D.2 shows that Ausgrid, Essential Energy and Endeavour Energy each met all SAIDI and SAIFI targets for all feeder categories during 2013-2014.

D.2.3 Australian Capital Territory

The Utilities Act (2000) underpins all codes and performance and compliance requirements for distribution businesses operating in the Australian Capital Territory (the ACT).[121]

The Independent Competition and Regulatory Commission (ICRC) sets the performance standards for distribution businesses operating in the ACT.[122]These standards are available in the Electricity Distribution Supply Standards Code and in the Consumer Protection Code, which also has minimum service standards.[123]

Distribution businesses and other licensed utilities must report annually to the ICRC on their performance and compliance with their licence obligations. The ICRC publishes the results in its compliance and performance reports. The ICRC stated in its most recent compliance and performance report (2011/12) that it believes there is a strong case for collecting a smaller set of data from distribution businesses in the future.

Table D.3 shows a summary of the performance of ActewAGL Distribution for 2013-14. More detailed performance information is available from network performance reports available on the ICRC website.

Table D.3 Performance of the Australian Capital Territory distribution business 2013-14

Feeder		SAIDI (minutes)		SAIFI		CAIDI	
Urban	Overall	Target	Actual	Target	Actual	Target	Actual
	Distribution network – planned	n/a	65.19	n/a	0.65	n/a	99.98
	Distribution network – unplanned	n/a	25.09	n/a	0.48	n/a	52.82
	Normalised distribution network - unplanned	n/a	23.45	n/a	0.46	n/a	50.98

121 This section was completed with the assistance of ActewAGL.

122 ICRC, Electricity Distribution (Supply Standards) Determination Code 2013, 22 August 2013.

123 ICRC, Utilities (Consumer Protection Code) Determination 2012, 28 June 2012.

Feeder		SAIDI (minutes)		SAIFI		CAIDI	
Rural short	Overall	n/a	89.45	n/a	0.97	n/a	92.22
	Distribution network - planned	n/a	33.24	n/a	0.16	n/a	213.08
	Distribution network - unplanned	n/a	56.21	n/a	0.81	n/a	69.14
	Normalised distribution network - unplanned	n/a	54.23	n/a	0.81	n/a	67.03
Network	Overall	91.0	67.84	1.2	0.69	74.6	98.89
	Distribution network - planned	n/a	39.35	n/a	0.17	n/a	226.54
	Distribution network - unplanned	n/a	28.49	n/a	0.51	n/a	55.64
	Normalised distribution network - unplanned	n/a	26.81	n/a	0.50	n/a	53.84

D.2.4 Victoria

The Electricity Industry Act 2000 and the Essential Services Commission Act 2001 contain the network performance requirements for the Victorian distribution businesses.[124] The Essential Services Commission of Victoria (ESC) was responsible for setting performance targets for unplanned SAIFI, unplanned SAIDI and MAIFI for calculation of the financial incentive for improving supply reliability.[125]

From 1 January 2009, responsibility for the compliance monitoring and enforcement of the distribution businesses' distribution licence conditions was transferred from the ESC to the Australian Energy Regulator (AER).

As part of its 2010 distribution determination the AER set revenue and service targets for the Victorian distribution businesses for the 2011–15 regulatory period.[126] The service targets are applied through the AERs service target performance incentive scheme (STPIS). The STPIS provides incentives for distribution businesses to maintain

124 This section was completed with the assistance of the AER. Where applicable, the latest available information has been used.

125 The ESC is still responsible for regulatory framework rule making regarding a distribution business's licence conditions in Victoria.

126 Information about the AER's 2011–15 distribution determination is available from the AER's website.

and improve their service performance. The STPIS includes both a reliability component (including SAIDI, SAIFI and MAIFI parameters) and a customer service component based on a telephone answering parameter.

The STPIS also includes a guaranteed service level (GSL) component which sets threshold levels of service for distribution businesses to achieve, and requires direct payments to customers who experience service worse than the predetermined level. However, the GSL component of the STPIS only applies where the jurisdictional GSL arrangements no longer apply. The jurisdictional GSL arrangements continue to apply in Victoria.

Under the STPIS the AER annually reviews the service performance outcomes and determines the resulting financial penalty or reward based on a distribution businesses performance against the targets established at the time of the distribution determination.

The average Victorian customer experienced 264.9 total minutes-off-supply in 2013 (planned + unplanned). This was an increase of 29 per cent over the 205 minutes without supply experienced by the average Victorian customer in 2012. After normalising the data, that is removing the impact of excluded events and outages occurring on major event days, the average Victorian customer experienced 224.6 minutes without supply in 2013 (an increase of 29 per cent over the 174.7 total normalised minutes without supply in 2012).

The average Victorian customer experienced 139.5 unplanned minutes without supply in 2013. This was an increase of 9 per cent over the 127.7 unplanned minutes-off-supply in 2012. After normalising the data the average Victorian customer experienced 99.2 unplanned minutes without supply in 2013 (an increase of 2 per cent over the 97.6 unplanned normalised minutes without supply in 2012).

Three of the five Victorian distribution businesses reduced their average unplanned normalised minutes without supply in 2013. United Energy achieved the greatest reduction with 9 per cent fewer unplanned normalised minutes without supply than in 2012.

Table D.4 shows the normalised 2013 reliability outcomes for the Victorian distribution businesses.

Table D.4 Performance of the Victorian distribution businesses 2013-14

DNSP	Feeder	SAIDI (minutes)				SAIFI			
		Unplanned (normalised)		Planned		Unplanned (normalised)		Planned	
		Target	Actual	Target	Actual	Target	Actual	Target	Actual
Jemena	Urban	68.498	57.514	n/a	21.789	1.127	1.057	n/a	0.077
	Short rural	153.150	114.395	n/a	66.872	2.588	2.424	n/a	0.273
CitiPower	CBD	11.27	8.009	n/a	8.797	0.186	0.174	n/a	0.041
	Urban	22.36	31.057	n/a	19.069	0.45	0.443	n/a	0.062
Powercor	Urban	82.467	96.968	n/a	28.554	1.263	1.111	n/a	0.125
	Short rural	114.807	96.616	n/a	51.739	1.565	1.124	n/a	0.217
	Long rural	233.759	251.735	n/a	92.216	2.54	2.287	n/a	0.409
AusNet Services	Urban	101.803	86.162	n/a	194.271	1.448	1.377	n/a	0.726
	Short rural	208.542	165.105	n/a	668.242	2.632	2.233	n/a	2.445
	Long rural	256.578	178.565	n/a	207.967	3.378	2.454	n/a	0.713
United Energy	Urban	55.085	66.613	n/a	47.695	0.899	0.934	n/a	0.141
	Short rural	99.151	170.530	n/a	84.809	1.742	2.014	n/a	0.278

D.2.5 South Australia

The AER is responsible for making price determinations and setting the service incentive scheme element of SA Power Networks service standard framework.[127] The distribution determination for SA Power Networks for the 2010-2015 regulatory period was made by the AER in May 2010.

The Essential Services Commission of South Australia (ESCOSA) still retains a central role in the regulatory process and continues to be responsible for setting elements of the service standard framework for the current regulatory period. For example, the average service standards and the guaranteed service level scheme. ESCOSA also remains responsible for setting the South Australian jurisdictional service standards applying to SA Power Networks.

ESCOSA 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 2010-2015 regulatory control period, these are 179 minutes per annum for duration interruptions and 1.68 interruptions per annum for frequency interruptions.

The Code also establishes guaranteed service level payments in relation to the distribution businesses timeliness. This includes, timeliness of appointments; connections; and street light repair. 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 current 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, assessed 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.

127 This section was completed with the assistance of ESCOSA.

The performance of the South Australian distribution business for the 2013-2014 fiscal year is illustrated in Table D.5.

Table D.5 Performance of the South Australian distribution business for 2013-14

Region	SAIDI (minutes)		SAIFI	
	Target	Actual	Target	Actual
Adelaide Business Area	25	9	0.25	0.12
Major Metropolitan Areas	130	265	1.45	1.72
Central	260	242	1.8	1.59
Eastern Hills/Fleurieu Peninsular	295	425	2.8	2.90
Upper North and Eyre Peninsular	425	390	2.3	1.69
South East	295	428	2.5	2.45
Kangaroo Island	450	385	n/a	n/a
Total network	179	287	1.68	1.83

D.2.6 Tasmania

The network performance requirements for electricity distribution in Tasmania are prescribed in the Tasmanian Electricity Code (TEC).[128]

On 1 January 2008, the Office of the Tasmanian Energy 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 Aurora Energy. These are designed to align the reliability standards more closely to the needs of the communities served by the network. Further details on the standards are contained in Chapter 8 of the TEC.[129]

128 This section was completed with the assistance of the Office of The Tasmanian Energy Regulator.

129 Office of the Tasmanian Economic Regulator, 2013, Tasmanian Electricity Code, available at: www.economicregulator.tas.gov.au

The distribution network supply reliability standards have two parts:[130]

- 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.

The following Table D.6 shows the performance of the Tasmanian distribution business against the network performance standards in the TEC that applied in 2013-2014.

Table D.6 Performance of the Tasmanian distribution business 2013-2014

Community category	SAIDI (minutes)		SAIFI	
	TEC (12 month category limit)	Performance	TEC (12 month category limit)	Performance
Critical infrastructure	30	16	0.20	0.21
High density commercial	60	43	1.00	0.47
Urban and regional centres	120	164	2.00	0.85
Higher density rural	480	521	4.00	2.18
Lower density rural	600	740	6.00	3.11

In 2013-2014, only the high density commercial community category achieved both the frequency and duration standards set by the TEC.

The critical infrastructure community category also met the duration standards with the remaining three community categories (urban and regional centres, higher density rural and lower density rural) not meeting the duration standards.

All community categories with the exception of critical infrastructure met the TEC frequency standards.

130 Office of the Tasmanian Economic Regulator, 2012, Guideline - Guaranteed Service Level (GSL) Scheme, available at: www.economicregulator.tas.gov.au.

E System security performance

This appendix provides detailed background information on system security management and measuring power system security performance. For a discussion of the Panel's assessment of performance in the 2013-14 financial year, please refer to Chapter 5.

E.1 Security management

Maintaining the security of the power system is one of AEMO's key objectives. The power system is deemed secure when all equipment is operating within safe loading levels and will not become insecure 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.

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.
- Design characteristics and modelling of the dynamic behaviour of the power system.

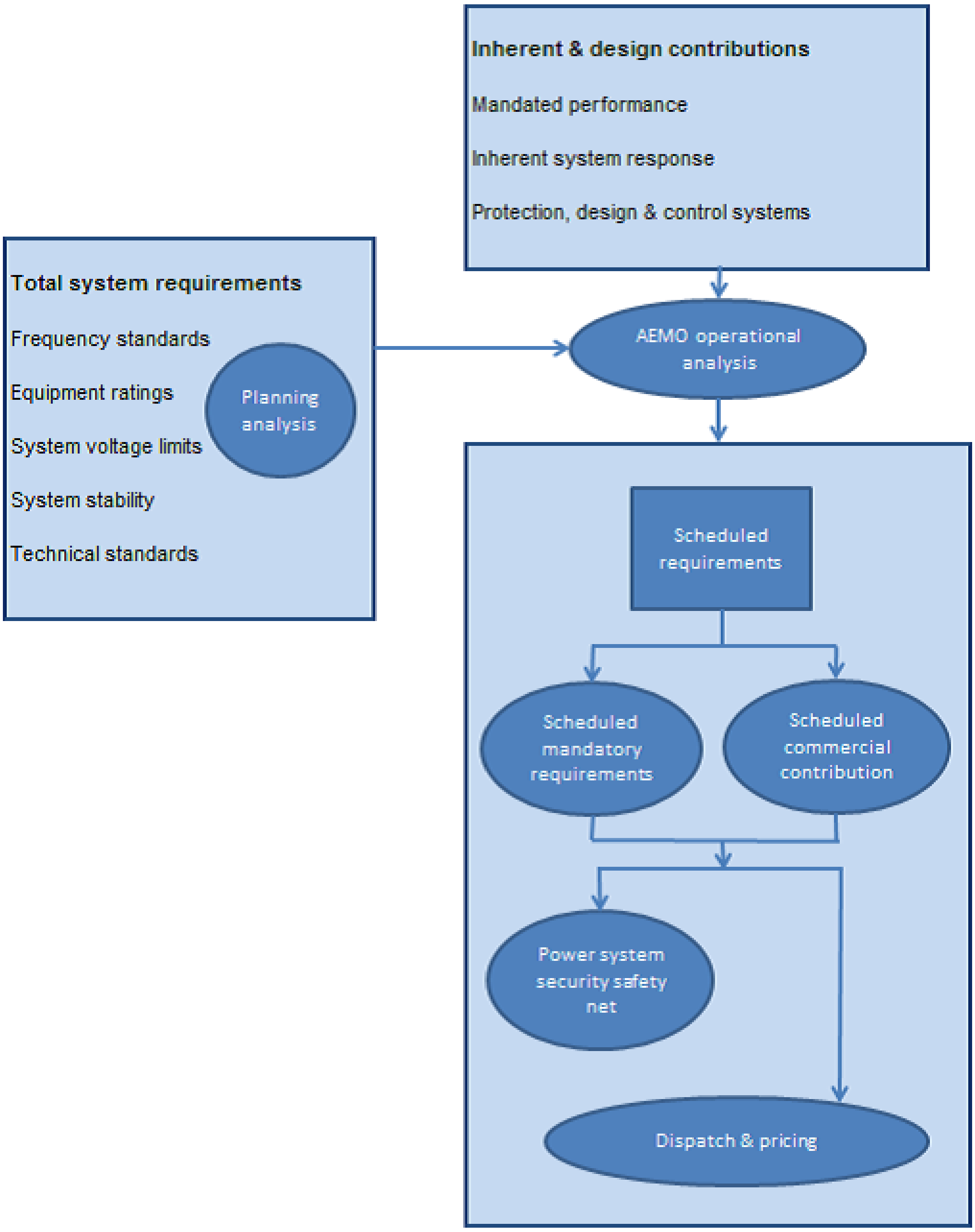
This allows AEMO to determine the safe operating limits of the power system and associated ancillary service requirements.

Some of the requirements are inherent in the sensitivity of demand and generating plant to frequency. For example, the inertia of synchronous generating plant. Others rely on the correct operation of network protection and control schemes. The rest are procured as part of the scheduling process from commercial ancillary services, the mandatory capability of generators and, as a last resort, load shedding arrangements. If necessary, AEMO may direct participants to provide services.

There is some scope for scheduled sources to make good on any deficiencies from inherent and designed sources. It is not always feasible, however, to pre-test or measure every possible contribution without the test itself threatening security. Consequently, there is heavy reliance on measurements from the occasional system disturbance.

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

Figure E.1 Security model



E.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.

E.3 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.
- Plant standards set out the technology specific standards that, if met by particular facilities, would ensure compliance with the access standards.

The 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.

E.4 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 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.[131]

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.

E.5 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.[132]
- Technical standards for wind and other generator connections rule change.[133]
- Resolution of existing generator performance standards rule change.[134]
- Performance standard compliance of generators rule change.[135]
- Reliability Panel technical standards review.[136]

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.[137]

The Panel is currently undertaking a further review of the template for generator compliance, which is due to be completed in June 2015.

131 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 (NEMMCO) (now AEMO).

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

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

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

135 AEMC, *National Electricity Amendment (Performance Standard Compliance of Generators) Rule 2008 No. 10*, 23 October 2008, Sydney.

136 AEMC Reliability Panel, *Reliability Panel Technical Standards Review*, Final Report, 30 April 2009, Sydney.

137 The Panel's final report is available on the AEMC website under the project reference: "REL0047".

E.6 Frequency operating standards

Control of power system frequency is crucial to security. To this end, the Panel determines 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.

E.6.1 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 E.1 to E.3.

Table E.1 NEM mainland frequency operating standards (except "islands")

	Containment	Stabilisation	Recovery
Accumulated time error	5 seconds	n/a	n/a
No contingency event or load event	49.75 to 50.25 Hz[100] 49.85 to 50.15 Hz 99% of the time[101]	49.85 to 50.15 Hz within 5 minutes	
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

Table E.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

Table E.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	n/a	
Generation event, load event or network event	48 to 52 Hz (Queensland and South Australia) 48.5 to 52 Hz (New South Wales and Victoria)	49.0 to 51.0 Hz within 2 minutes	49.5 to 50.5 Hz within 10 minutes
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

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.[138] 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 E.4 and E.5.

138 AEMC, *Review of Frequency Operating Standards for Tasmania*, Final Report, 18 December 2008, Sydney.

Table E.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 99% of the time	49.85 to 50.15 Hz within 5 minutes	
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	47.0 to 55.0 Hz	48.0 to 52.0 Hz within 2 minutes	49.85 to 50.15 Hz within 10 minutes
Multiple contingency event[139]	47.0 to 55.0 Hz	48.0 to 52.0 Hz within 2 minutes	49.85 to 50.15 Hz within 10 minutes

Table E.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

E.7 System stability

Transferring large amounts of electricity between generators and consumers over a wide area presents technical challenges to 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

139 AEMO may, in accordance with clause 4.8.9 of the rules, direct a Generator to exceed 144 MW contingency limit if AEMO reasonably believes this would be necessary in order to maintain a reliable operating state.

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 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.

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 (DSA) tool monitors transient instability on the power system and the Voltage Security Assessment Tool (VSAT) monitors voltage instability. Both the DSA and VSAT 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 DSA and VSAT 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 (HSM). The HSM complements AEMO's oscillatory stability monitoring capability and enhances observability of power system disturbances in operational timeframes and for post-contingency analysis.

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 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.

F Safety framework

As noted in Chapter 6, network service providers 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 .

F.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 intent of the plan is to identify priority areas for improvement in electrical safety, and strategies to reduce electrical incidents and subsequent fatalities, serious injury and property damage in these priority areas. The Electrical Safety Plan for Queensland 2009–2014 was published in 2008 and sets out strategies designed to achieve the Board's goal of eliminating all preventable electrical deaths in Queensland by 2014.

F.2 New South Wales

In New South Wales, the Independent Pricing and Regulatory Tribunal (IPART) is the jurisdictional regulator for network technical and safety licensing. The NSW Department of Trade & Investment is responsible for monitoring of network performance and safety as part of licensing regime and network management regime under the Electricity Supply Act 1995 (NSW) and the Electricity Supply (Safety and Network Management) Regulation 2008 (NSW).

The NSW Fair Trading monitors the safety of customer electrical installations under the Electricity (Consumer Safety) Act 2004 (NSW) and Electricity (Consumer Safety) Regulation 2006 (NSW). It also authorises accredited service providers under the Electricity Supply Act 1995 (NSW) and Electricity Supply (General) Regulation 2001 (NSW). WorkCover 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 Trade & Investment oversees electricity transmission and distribution system operators so they provide an adequate, reliable and safe supply of electricity of appropriate quality in NSW. Under the provisions of the Electricity Supply Act 1995 (NSW), the Department requires that each network operator produce an annual report covering the major issues concerning the operation of their networks, including safety issues in the areas of public safety, network employee safety, customer installation safety, bushfire risk management and public electrical safety awareness campaigns. These reports are available on the websites of NSW distribution and transmission network service providers.

F.3 Australian Capital Territory

The Australian Capital Territory Planning and Land Authority (ACTPLA) 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 ACTPLA 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 [111].

F.4 Victoria

Electricity safety in Victoria is regulated by Energy Safe Victoria (ESV). The role of ESV 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. ESV 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 ESV audits to test compliance of their safety systems.

In June 2013, the ESV released its report on the 2012 Safety Performance Report on Victorian Electricity Distribution and Transmission Businesses. The report focuses on key safety indicators reported by the businesses, ongoing critical safety programs, the progression of directions placed on the distribution businesses to meet the recommendations of the 2009 Victorian Bushfires Royal Commission and the Powerline Bushfire Safety Taskforce (PBST), and the operation of the Electricity Safety Management Schemes. ESV also reports on audits undertaken, including those to assess the readiness of the distribution businesses for the bushfire season.

F.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.

The activities undertaken by the electrical infrastructure, electrical installations and electrical appliances sections of the regulator are discussed in detail in its annual report on electricity. 112

F.6 Tasmania

Until 1 June 2010, several safety functions were vested with the Tasmanian Economic Regulator under the Electricity Industry Safety and Administration Act 1997 (Tas) (EISA Act) and the Electricity Supply Industry Act 1995 (Tas). The EISA Act:

- 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 (WST) via an amendment to the EISA Act in 2009.

G Examples of AEMC recommendations for reviewable operating incidents 2013-14

Table G.1 AEMO recommendations for reviewable operating incidents 2013-14 Participant responsible

	AEMO recommendation
AEMO	• Ensure reclassifications of on-credible contingencies occur in the appropriate time. • Revise its procedures to explicitly require it to document its risk assessment results as part of the record of decisions made in the bushfire contingency reclassification process. • Review and amend its processes to ensure the timely re-classification of non-credible contingencies, cancellation of re-classified non-credible contingencies, and the issuing of associated Market Notices. • Include a requirement in the power system security guidelines that a market notice must be issued within two hours of a non-credible contingency occurring.
Generator	• Undertake a number of actions to address a hardware fault. • Undertake work to recalibrate all plant associated with an under-frequency load shedding scheme. • Complete protection and circuit breaker testing. • Remove undocumented bridges and replace a communications switch in their communications network. • Review plant alarms to provide increased auxiliary fuel igniter system reliability. • Review protection schemes and protection settings on the plant transformers. • Review the under voltage control system logic for a generating unit auxiliary plant.
Participant responsible	• AEMO recommendation and implement any required modification to ensure compliance with generator performance standards. • Conduct ongoing monitoring of the inlet pressures and system temperatures with further tuning as required.
TNSP	• Make necessary protection configuration/setting changes to a tripping scheme. • Complete a circuit breaker damper overhaul program. • Investigate the operation of a over frequency generation shedding scheme.

	AEMO recommendation
	• Review the information available to control room staff in relation to synchronising capabilities of circuit breakers. • Review the communication requirements for on-site observers. • Review the capability of the frequency recorders. • Resolve time stamping issues with the relevant protection relays on transmission lines. • Resolve the incorrect protection relay indications on transmission lines. • Investigate and report on the adequacy of the earthing and lightning protection arrangement. • Complete protection and circuit breaker testing.
Other parties	• Implement a permanent solution to the residual magnetism issue on the current transformer that supplies the circuit breaker failure protection. • Implement modifications to the control for the auxiliary supply change-over at a converter station to avoid future maloperation of the scheme maloperation of the scheme.

H Generator plant availability

H.1 Committed Generator Details

In the 2014 ESOO, AEMO reported a further reduction of 225 MW in available generation is expected over the next two years and an additional 224 MW is expected to be retired in 2016.[140] These changes were incorporated into the supply-demand outlook for the next 10 years published in the 2014 ESOO.

Since the publication of the 2014 ESOO further reductions in available generation have been announced. Reported reductions totalling 332 MW included the withdrawal of 143 MW of coal fired generation at Redbank Power Station in New South Wales and 189 MW of coal fired generation at Morwell/EnergyBrix Power Station in August 2014.[141]

H.2 Committed Generation Projects

As at December 2014, there were 10 committed, but yet to be commissioned generation projects in the NEM totalling 648.5 MW in capacity.[142] Current investment interest is focussed on renewable and peaking generation, with publicly announced proposals involving over 1,150 MW of solar generation, 14,500 MW of wind generation and 6,300 MW of gas generation.[143]

Wilga Park Power Station (gas) has 6 MW of additional capacity committed in NSW commissioned in September 2014. In addition, 566.7 MW of wind generation was commissioned in the last quarter of 2014.[144]

Additionally the committed capacity includes 275 MW of large-scale solar generation comprising:

Power station	Capacity (MW)	Fuel source	Commissioning date
Kogan Creek – Queensland	44	Solar Thermal	July 2015
Broken Hill – New South Wales	53	Solar	August 2015
Nyngan – New South	102	Solar	July 2015

140 AEMO, *Electricity statement of opportunities – for the National Electricity Market*, August 2014, p12.

141 Advice from AEMO.

142 Sourced and compiled from the generation information section of AEMO's website.

143 AEMO, *Electricity statement of opportunities – for the National Electricity Market*, August 2014, p11.

144 The commissioned generating plant included: Gullen Range wind farm in New South Wales, Mount Mercer wind farm in Victoria and the Snowtown stage 2 wind farm in South Australia.

Power station	Capacity (MW)	Fuel source	Commissioning date
Wales			
Royalla – New South Wales	20	Solar	February 2015
Moree – New South Wales	56	Solar	February 2016
Total committed	**275**		

Wind generating capacity of 373.45 MW, comprising:

Power station	Capacity (MW)	Commissioning date
Stage 1 Boco Rock Wind Farm 11 – New South Wales	113	March 2015
Taralga Wind Farm – New South Wales	106.7	May 2015
Portland Stage 4 Cape Nelson North and Cape Sir William Grant Wind Farm - Victoria	47.15	May 2015
Bald Hills Phase 1 Wind Farm – Victoria	106.6	May 2015
Total Committed	**373.45**	

One wave energy project in South Australia with a capacity of 1 MW:

Power station	Capacity (MW)	Commissioning date
Port Macdonnell wave energy project – South Australia	1	To be advised.
Total committed	**1**	

I Demand forecasts

I.1 National Electricity Forecasting Report

I.1.1 Electricity Consumption

AEMO reports operational consumption and maximum demand forecasts in the National Electricity Forecasting Report (NEFR).[145] This report provides AEMO's independent electricity forecasts for the five NEM regions. The 2014 NEFR was published in June 2014, and presents annual forecasts to 2033-34 across high, medium, and low consumption scenarios. AEMO uses the NEFR forecasts as an input into its electricity planning publications, including the Electricity Statement of Opportunities.

I.1.2 Regional Maximum Demand

Maximum demand (MD) grew in most NEM regions between 2006-07 and 2010-11, but has been consistently lower in subsequent years. For example, operational summer MD in New South Wales in 2013-14 is around 2,717 MW (18 per cent) lower than the 2010-11 peak. Victorian summer MD steadily decreased between 2008-09 and 2011-12 (reflecting a 1402 MW reduction), but has increased in 2012-13 (a 600 MW increase) and 2013-14 (an increase of 539 MW).

The 2014 NEFR MD forecast shows a slower rate of growth for most NEM regions compared to the 2013 NEFR forecast. Tasmanian winter MD is projected to grow faster than previously forecast in the short-term due to the changed behaviour of large industrial loads.

Only Queensland and New South Wales are expected to reach their historical record MD within the long-term period to 2034. Queensland reaches its historical record in 2015-16 due to increasing consumption by liquefied natural gas (LNG) projects, and New South Wales in 2022-23 due to a slower uptake in rooftop photovoltaic (PV) installations than other regions.

The slower MD growth trajectory across most NEM regions is due to an overall rise in rooftop PV installations, increased energy efficiency projections as a result of government building standards, and changes in industrial plant operations.

In all regions except Queensland, MD is growing faster than annual energy, leading to peakier consumption profiles. MDs typically occur in the afternoon or early evening, and the contribution of rooftop PV is shifting these peaks to later in the day – this effect is particularly strong in South Australia where the MD is forecast to shift from approximately 5:30 pm in summer 2014-15 to 6:30 pm by summer 2023-24.

145 AEMO, *2014 National Electricity Forecasting Report – for the National Electricity Market*, June 2014.

I.1.3 NEM-Wide Operational Consumption

From 2009-10 to 2013-14, annual operational consumption declined by 13,613 GWh (an annual average decline of 1.8%) to reach 181,248 GWh. This is 5,355 GWh (2.9 per cent) lower than the 2013 NEFR forecast for 2013-14. The historical decline was driven by reductions in industrial load (such as the closure of the Kurri Kurri aluminium smelter in New South Wales), consumer response to electricity price increases, and growth in rooftop PV and energy efficiency.

The 2014 NEFR forecasts that the recent historical decline will continue in 2014-15, resulting in a reduction of 5,556 GWh (3 per cent) compared with 2013-14, and a reduction of 16,691 GWh (9 per cent) compared with the 2013 NEFR forecast for 2014-15.

Beyond 2014-15, there is some short-term growth driven by the ramp-up of electricity consumption from LNG projects in Queensland. Following the ramp-up phase, electricity consumption in the NEM plateaus.

Over the 10-year outlook period, the NEM operational consumption forecast indicates average annual growth of 0.3 per cent from 2013-14 to 2023-24. As with MD, these trends are linked to:

- population growth;
- energy efficiency initiatives;
- increased rooftop PV installations;
- consumer response to rising electricity prices;
- the closure of some large industrial customers; and
- the ramp-up of consumption from Queensland LNG projects.

AEMO has reported that the 2014 electricity forecasting process implemented a number of improvements to the 2013 methodology. These include increasing the number of large industrial customers interviewed, applying more granular rooftop PV datasets, and placing greater emphasis on recent historical trends in the residential and commercial sectors.

The validity and accuracy of the models was independently reviewed by external consultants, and AEMO assessed the performance of its models in the 2014 Forecast Accuracy Report.[146] AEMO proposes further improvements for the 2015 NEFR, as published in AEMO's 2015 NEFR Action Plan.[147]

146 AEMO, *2014 National Electricity Forecasting Report Update for the National Electricity Market*, December 2014.

147 AEMO, *Action plan – For the 2015 National Electricity Forecasting Report*, November 2014.

J AMPR data sources

AMPR requirements – data sources

Requirement	Evidence	Data/Information Request	Source Organisation
Reliability of the power system	Review of performance of NEM based on network, generation and power system information published in AMPR	Generator Performance Demand Forecast Network Performance USE Statistics Power System Incidents ESOO MT PASA ST PASA PSA Predispatch	AEMO AEMO Queensland - Powerlink NSW – TransGrid Victoria AEMO South Australia – ElectraNet Tasmania – TasNetworks AEMO AEMO AEMO AEMO AEMO AEMO AEMO
Power system security and reliability standards	Schedule of Reliability Settings USE[148] Review of Power System Performance	Market Price Cap (MPC) and Cumulative Price Threshold (CPT) statistics System security performance assessment AEMO performance – Power System Security Guidelines[149] Power System	Not requested Not requested Not requested AEMO

148 AEMC Reliability Panel, *Reliability Standard and Reliability Settings Review 2014*, Final Report, 16 July 2014.

149 AEMO, *Power system security guidelines – document reference SO_OP_3715*, 20 March 2015.

Requirement	Evidence	Data/Information Request	Source Organisation
		Incidents Observed USE	
System restart standard	System Restart Standard	No evidence was provided if this service was procured. Performance may be measured on AEMO reporting on services that were tested and how they performed during the year	Not Requested
Guidelines referred to in clause 8.8.1(a)(3)	Reliability Panel Review of the Guidelines for Identifying Reviewable Operating Incidents	AEMO Operating Incidents[150] AEMO Statistics of Operating Incidents[151]	Not Requested Not Requested
Policies and guidelines referred to in clause 8.8.1(a)(4)	Reliability Panel – Reliability and Emergency Reserve Trader (RERT) Guidelines 128	AEMO Guidelines are maintained in accordance with Guidelines[152]	Not Requested
Guidelines referred to in clause 8.8.1(a)(9) in accordance with this clause 8.8.3	Reliability Panel – Guidelines for Identifying Reviewable Operating Incidents	AEMO Guidelines are maintained in accordance with Guidelines List of Operating Incidents in accordance with guidelines AEMO Statistics of Operating Incidents[153]	Not Requested Not Requested Not Requested

150 www.aemo.com.au/Electricity/Resources/Reports-and-Documents/Power-System-Operating-Incident-Reports

151 AEMO, *Statistics of operating incidents*, Final report, 31 March 2014.

152 AEMC Reliability Panel, *Reliability and emergency reserve trader (RERT) guidelines*, 16 June 2010.

153 AEMO, *Statistics of operating incidents*, Final report, 31 March 2014.

K AEMO's assessment of forecasting accuracy

AEMO provided the 2014 Forecast Accuracy Report to the Panel in November 2014.

K.1 Energy Forecasts

AEMO's residential and commercial energy forecasting model for each NEM region is assessed using 'back assessment' and 'backcasting'.

Back assessment compares one-year-ahead forecasts from previous years with actual outcomes. Performance is measured for each year as percentage deviation of the forecast from the actual.

Backcasting compares the in-sample forecast performances of the current and previous models over a 10-year period. For the current model, the entire forecast period coincides with the sample data used to estimate the model. This shows the goodness of fit between each model and actual residential and commercial energy consumption. It also enables a comparison of performance between the current and previous models.

The previous model was also re-run using actual input data for the latest year (which was previously a forecast year and therefore out-of-sample). The difference in performance of the previous model using forecast and actual input data reveals the relative contribution of model error and errors in forecasting input variables towards the total variation between the previous year's forecast and most recent actual outcome.

AEMO also discusses other contributions to inaccuracy in the overall energy forecast, including major industrial loads, distributed PV generation, energy efficiency, transmission losses and generator auxiliary loads.

The Panel notes that AEMO does not test the current model using out-of sample forecasting. Such testing should be undertaken by restricting the sample used to estimate the model and then producing a forecast for the excluded historical period using the restricted model.

K.2 Maximum Demand Forecasts

AEMO's summer maximum demand forecasting model for each mainland NEM and the winter maximum demand forecasting model for Tasmania is assessed using different methods to those used for the energy forecasting model.

Back assessment, comparing one-year-ahead forecasts from previous years with actual outcomes, is not strictly undertaken for maximum demand. Forecast maxima are for the levels of demand that are expected to be achieved with varying degrees of likelihood; whereas actual maxima are subject to the vagaries of the weather, amongst other uncertainties. Therefore making direct comparisons between the two is fraught with difficulty.

AEMO's alternative assessment for the maximum demand forecast compares the in-sample forecast with the actual frequency distribution. In an infinite sample, actual maximum demands would be evenly distributed above and below the estimated 50th percentile of maximum demand for each season. The available sample of less than 15 seasons may be insufficient to draw absolute conclusions but nevertheless provides a firm indication of the acceptability of alternative forecasts.

AEMO undertakes an assessment using the current and previous maximum demand models, actual maximum demands and forecast maximum demand distributions and presents

- a visual analysis of actual and forecast 10th, 50th and 90th percentile maximum demands;
- a count of the number of actuals exceeding the above percentiles; and
- an objective statistical analysis showing the probability of actual outcomes being distributed with the forecast frequency.

In this manner, AEMO is able to compare the performance of the current with the previous model.

A variant of backcasting using the previous maximum demand forecasting model is undertaken by comparing the previous forecast demand distribution (developed with forecast input data for the most recent season) with the current estimated demand distribution (developed using actual data for the most recent season). This assessment is undertaken for both native and operational demand to show contributions to changes in the forecast from small non-scheduled generation assumptions.

Other contributions to maximum demand forecast inaccuracy include contributions from major industrial loads, distributed PV generation, energy efficiency, transmission losses and generator auxiliary loads.

The Panel notes that the above procedure does not test the point accuracy of the underlying maximum demand forecasting model.

K.3 Changes to Forecasting Methodology

Enhancements to AEMO's forecasting models made in 2014 included:

- a change from native energy and demand to operational energy and demand as the basis for analysis;
- increased customer segmentation by identifying additional industrial customers whose demand is identified by survey, rather than by being included in modelling of the residual 'residential and commercial sector';
- the use of input data from multiple weather stations in each region, rather than just one;

- use of a composite income variable, standardised across regions;
- incorporation of intercept correction to account for a declining trend in demand growth since 2008;
- implemented structural break analysis into the maximum demand modelling process to test significant changes in load factors and residual distributions (none were found significant);
- incorporation of an automated adjustment process in the maximum demand models to better account for extreme observations; and
- the use of a separate model to forecast distributed PV generation on a half-hourly resolution.

AEMO links the findings of the 2014 Forecast Accuracy Report forward to the 2015 NEFR Action Plan. However the Panel notes there is no explicit backward link made in the report between the 2014 model enhancements and the previous 2014 NEFR Action Plan.

L Glossary

In addition to the list of abbreviations provided from page 60 of this report, the following definitions are provided to assist the reader and should not be relied upon as the legal definition of the term. Formal definitions of some of these terms can be found in the rules. Some of these definitions have been sourced with permission from AEMO's Electricity Statement of Opportunities

Team	Explanation
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 A contingency event whose occurrence is considered “reasonably possible” in the circumstances. For example: the unexpected disconnection or unplanned reduction in capacity of one operating generating unit; or the unexpected disconnection of one major item of transmission plant. non-credible contingency event 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

Team	Explanation
	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.

Team	Explanation
Ministerial Council on Energy (MCE)	The MCE is the national policy and governance body for the Australian energy market, including for electricity and gas, as outlined in the COAG Australian Energy Market Agreement of 30 June 2004.
National Electricity Code	The National Electricity Code was replaced by the National Electricity Rules on 1 July 2005.
National Electricity Market (NEM)	The NEM is a wholesale exchange for the supply of electricity to retailers and consumers. It commenced on 13 December 1998, and now includes Queensland, New South Wales, Australian Capital Territory, Victoria, South Australia, and Tasmania.
National Electricity Law (NEL)	The NEL is contained in a Schedule to the National Electricity (South Australia) Act 1996. The NEL is applied as law in each participating jurisdiction of the NEM by the application statutes.
National Electricity Rules (NER 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	A person who 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

Team	Explanation
	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: (a) AEMO has not disconnected, and does not expect to disconnect, any points of load connection under clause 4.8.9 of the rules; (b) no load shedding is occurring or expected to occur anywhere on the power system under clause 4.8.9 of the rules; and (c) 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

Team	Explanation
	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 (a) excursions outside the normal operating frequency band but within normal operating frequency excursion band (b) 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); (c) 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); (d) 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); (e) 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

Team	Explanation
	equipment; and (f) 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): 1. the power system is in a satisfactory operating state; and 2. 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.

Team	Explanation
Transmission network service provider (TNSP)	A person who 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