Reliability Panel
AEMC

REVIEW

Reliability Panel AEMC

DRAFT REPORT

Annual Market Performance Review 2013

20 December 2013

Submissions due 14 February 2014
Reference: REL0052

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Reference: REL0052

Citation

AEMC Reliability Panel 2013, Annual Market Performance Review, Report, 20 December 2013, Sydney

About the AEMC

The Council of Australian Governments (COAG), through its then Ministerial Council on Energy (MCE), established the Australian Energy Market Commission (AEMC) in July 2005. In June 2011, COAG established the Standing Council on Energy and Resources (SCER) to replace the MCE. The AEMC has two main functions. We make and amend the national electricity, gas and energy retail rules, and we conduct independent reviews of the energy markets for the SCER.

About the AEMC Reliability Panel (Panel)

The Panel is a specialist body within 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 2012-13 financial year.

The NEM regions generally experienced temperatures that were warmer than normal over spring and summer, with a number of heat waves and below average rainfall, and average temperatures in winter and autumn. 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 last 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 that have been 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 seek comments on this draft report from stakeholders, including comments concerning the information and format of the report.

The preparation of this draft report could not have been completed without the assistance of the Australian Energy Regulatory, the Australian Energy Market Operator, transmission and distribution network service providers, and the State regulatory agencies in providing relevant data and information. I acknowledge their efforts and thank them for their assistance to date. The Panel also commends the staff of the AEMC for their efforts in compiling the information presented in this report and drafting 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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Contents

1 Introduction

This report has been prepared under the Reliability Panel's annual market performance review (AMPR). The review is a requirement of the National Electricity Rules (rules), where the Panel must carry out an annual review of the performance of the national electricity market (NEM) in terms of reliability and security of the power system.[1]

1.1 Purpose and scope

The purpose of this report is to set out the review's findings for the 2012-13 financial year. In conducting this review, the Panel considered publicly available information as well as information obtained directly from relevant stakeholders and market participants. The Panel's findings include observations and commentary on various aspects of the power system performance and this report also consolidates key market information relating to the reliability, security and safety of the NEM.

The scope of this review is to consider the reliability, security and safety of the NEM in terms of the performance against the standards and guidelines determined by the Panel under the rules. That is, the performance to be reviewed under the rules more directly relates to the bulk wholesale electricity systems rather than the local transmission or distribution networks.[2] However, where the information is available, the Panel has also included relevant performance results at the local level to provide a comprehensive overview of power system performance.[3]

Information on performance at a local level has been provided to the Panel by network service providers, jurisdictional bodies and the Australian Energy Regulator (AER). The information sets out the performance of the local networks in the context of impacts on consumer experiences and is discussed in section 3.3 and appendix D.

1.2 Issues for consultation and making submissions

As required by the rules, the Panel has been conducting this annual review since 2006.[4]The Panel would like to ensure that this report provides useful information and is continuously improved to meet the needs of stakeholders. To this end, the Panel invites comments on the content and format of the draft report. Some matters for consideration include:

- What are the most useful aspects of this report?
- How can the readability of the report be improved?

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1 Clause 8.8.3(b) of the rules.

2 These concepts are explored further in chapter 2 of this report.

3 Details of network performance are set out in detail in appendix D and, discussed throughout other relevant sections of this report.

4 Reports of prior annual reviews are available on the AEMC website: www.aemc.gov.au/Market-Reviews/Completed.html.

- Are there any other areas that can be included in the report?

The Panel invites comments from interested parties in response to this draft report by 14 February 2014. All submissions will be published on the AEMC Reliability Panel website.

Electronic submissions must be lodged online through the AEMC's website www.aemc.gov.au using the link entitled "lodge a submission" and reference code "REL0052". The submission must be on letterhead (if submitted on behalf of an organisation), signed and dated.

Upon receipt of the electronic submission, the AEMC website will issue a confirmation email. If this confirmation email is not received within three business days, it is the submitter's responsibility to ensure the submission has been delivered successfully.

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

The Reliability Panel
Australian Energy Market Commission
PO Box A2449
SYDNEY SOUTH NSW 1235

1.3 Structure of this report

The remainder of this report is set out as follows:

- **chapter 2 - Key concepts and relevant standards and guidelines:** provides an explanation of the key concepts used throughout the report;
- **chapter 3 - Year in review:** provides an overview of the power system performance in the 2012-13 financial year against the key market performance indicators;
- **chapter 4 - Power system incidents:** provides an analysis of the power system incidents that occurred in 2012-13;
- **chapter 5 - Reliability performance assessment:** builds upon relevant aspects of chapter 2 and provides a more detailed analysis of the performance of the power system from a reliability perspective;
- **chapter 6 - Security performance assessment:** builds upon relevant aspects of chapter 2 and provides a more detailed analysis of the performance of the power system from a security perspective;
- **chapter 7 - Safety performance assessment:** builds upon the relevant aspects of chapter 2 and provides a more detailed analysis of the performance of the power system from a safety perspective; and

- **appendices:** a number of appendices provide background information on various aspects of power system management and performance. A separate appendix (appendix D) also provides details of the performance of the transmission and distribution networks provided by network service providers and jurisdictional bodies.

1.4 Obligations under the rules

This review is carried out under clause 8.8.3(b) of the rules. The specific requirement of the rules and the relevant sections of this report that address each requirement is outlined as follows:

- review of the market in terms of reliability of the power system (chapters 3 and 5);
- review of the market in terms of the power system security and reliability standards (chapters 5 and 6; specific issues are noted and discussed in chapter 4);
- review of the guidelines governing the exercise of AEMO's power of directions (chapter 6); and
- review of the guidelines governing reviewable operating incidents (chapter 4).

The Panel is also required to review the policies and guidelines governing AEMO's power to enter into contracts for the provisions of reserves. The Panel notes that AEMO has not exercised this power, which is discussed briefly in chapter 5 of this report.

2 Key concepts and relevant standards and guidelines

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

2.1 Reliability

Reliability is generally associated with ensuring there is enough capacity to generate and transport electricity to meet all consumer demand.[5]

Reliability is measured in terms of unserved energy (USE) which refers to an amount of energy that is required by customers (or demanded) but cannot be supplied.[6] From 1 July 2012, a new Reliability Standard applies that is expressed in terms of the maximum expected unserved energy (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. 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.[7] 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. The reliability of the NEM should be reviewed each year to examine any incidents that have resulted in USE.

For the purpose of measuring reliability, "bulk transmission" capacity in effect equates to interconnector capability.[8] Consequently, only constraints in the transmission network that affect interconnector capability are considered when assessing the availability of reserves in a region.[9] The Reliability Standard does not take into account USE that is caused by outages of local transmission or distribution elements that do not significantly impact the ability to transfer power into the region where the USE occurred. Such events are outside the scope of the Panel's responsibility, and failures of that type have not been catered for in setting the Reliability Standard. The performance

5 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.

6 "Unserved energy" is a defined term under the rules.

7 AEMC Reliability Panel 2010, *Reliability Standard and Reliability Settings Review*, Final Report, 20 April 2010, Sydney.

8 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.

9 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.

of local transmission and distribution networks is monitored by the relevant jurisdiction. 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.[10]

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 the Australian Energy Market Operator (AEMO) and network operators in accordance with applicable technical standards.[11]

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 unstable 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;
- knowledge of equipment performance; and
- design characteristics; and modelling of the dynamic behaviour of the power system.

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

Some of the requirements are inherent in the frequency sensitivity of demand and generator plant, for example, the inertia of generator rotors. 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

10 Power system incidents are discussed in chapter 4.

11 Technical standards are explained in section 2.4.

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 any deficiencies from inherent 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 of system disturbance when they occur.

2.3 Safety under the NEL

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.[12] The Panel has included an overview of some of the jurisdictional safety provisions in chapter 7 of this report.

The Panel's safety considerations in the NEM are closely linked to the security of the power system and operating assets and equipment within their technical limits. For example, if a transmission line was overloaded, the lines could sag below minimum ground clearances. This would present a danger to people or vehicles near the transmission lines. 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.[13]

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.[14]

2.4 Relevant standards and guidelines

In addition to the Reliability Standard discussed above, 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 supplied. The system standards

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

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

14 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".

establish the target performance of the power system overall and are the frequency operating standards (as discussed further in appendix C). These standards are tightly linked with access standards.

- **Access standards** specify the quantified performance levels that plant (consumer, network or generator) must have in order to connect to the power system. Access standards 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 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.

- **Plant standards** set out the technology specific standards that if met by particular facilities would ensure 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. 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 the plant does not continue to meet its registered performance standards and compliance program obligations.[15]

15 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 Year in review

This chapter provides an overview of a number of key market performance indicators for the 2012-13 financial year. It also provides a summary of key learnings based on the Panel's consideration of relevant issues and events from 2012-13.

3.1 Key lessons

From the Panel's review of power system performance of the NEM in 2012-13, the Panel makes the following key observations:

- **Reliability** - there was no USE due to reliability events and, as such, the USE for all regions was within the Reliability Standard. AEMO was not required to issue any directions for reliability and it was not required to exercise the Reliability and Emergency Reserve Trader (RERT) mechanism.

- **Security** - the Panel notes there were 49 power system operating incidents that AEMO was required to report on in 2012-13. Some of these incidents resulted in disruptions to customer load, though generally the past financial year has been relatively uneventful compared to other years when more extreme weather events impacted security. There were also some incidents where frequency was outside the frequency operating standards on the mainland and in Tasmania. The number of frequency events in Tasmania in the 2011-12 financial year was quite high compared to previous years, but this number has reduced by 76 per cent to 12 for this financial year.

- **Safety** - the Panel is not aware of any incidents where AEMO has not achieved its obligations with respect to safety in the NEM.

Other considerations of the overall market outcomes are discussed in this chapter. Specific reliability, security and safety considerations are discussed in subsequent chapters.

3.2 Overall market conditions

As discussed in chapter 2, reliability of the NEM considers whether there is sufficient capacity to meet demand. As an assessment of the overall market conditions, the Panel has considered the general trends in capacity and demand growth.

A total of 522.7 MW of new large-scale generation was added to the NEM in 2012-13, including new registrations and increases in capacity of existing plant.[16] Of this new capacity, 462.7 MW is located in Victoria and 60 MW in New South Wales. New wind developments account for 439.5 MW, and are all located in Victoria[17]

16 The new capacity includes scheduled/semi-scheduled and non-scheduled plant.

17 AEMO, 2013 Electricity Statement of Opportunities, August 2013, pp. 4-5.

A total of 870 MW of Queensland coal-fired generation was placed in either seasonal dry storage or decommissioned in 2012-13. This comprised of Tarong Power Station Units 2 and 4 (700 MW), and Collinsville Power Station (170 MW). This is in addition to the South Australian availability changes of Playford B Power Station and Northern Power Station advised in 2011-12 where 240MW and 530MW respectively were assumed to be unavailable from 1April 2013 to 30 September 2014.

AEMO was also advised of small changes to the expected availabilities of generation capacity across the NEM, yielding a net reduction of 88.3 MW. This is composed of capacity increases to four generating units (101.7 MW), and capacity decreases to four units (190 MW). These changes have been incorporated into AEMO's supply-demand outlook for the next 10 years.[18]

As at August 2013, there have been eight newly committed generation projects in the NEM totalling 1,000 MW in capacity, comprising mostly wind (95%) and solar (5%) technologies.[19] The 1,000 MW of new capacity consists of:[20]

- 165.5 MW Gullen Range Wind Farm in New South Wales;
- 131.2 MW Mt Mercer Wind Farm in Victoria;
- 270 MW Snowtown Stage 2 in South Australia;
- 168 MW Musselroe Wind Farm in Tasmania;
- 113 MW Stage 1 of Boco Rock Wind Farm in New South Wales;
- 106.7 MW Taralga Wind Farm in New South Wales;
- 44 MW Kogan Creek solar generation in Queensland; and
- 1.5 MW Mildura demonstration plant solar generation in Victoria.

Current investment interest is focused on renewable and peaking generation, with publicly announced proposals of almost 13,500 MW of wind generation and almost 11,000 MW of gas-fired generation.[21]

In its National Electricity Forecasting Report (NEFR), AEMO has published detailed and independent demand forecasts out to 2022-23.[22] The forecasts show a lower growth trajectory for maximum demand for most NEM states compared to the 2012 forecast, except for Queensland, where the current maximum demand forecast reflects an increase on the 2012 forecast.

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18 Ibid, p. 6.

19 Ibid, pp. 4-5.

20 Ibid, p. 5.

21 Ibid.

22 AEMO, 2013 National Electricity Forecasting Report, June 2013.

The slower rate of growth in maximum demand in 2012-13 continues a trend which emerged in 2011-12.[23] Across the NEM, the current maximum demand forecast shows a combined 728 MW reduction for 2013-14 under a medium economic growth scenario.

The slower growth trajectory for maximum demand across most NEM regions is due to a rise in rooftop photovoltaic (PV) installations, increased energy efficiency projections as a result of building standards, and changes in industrial operations. Such changes include the revised timing of LNG and new mining projects, reduced operation at Victoria's Wonthaggi desalination plant and the deferral of the Olympic Dam mine expansion in South Australia.

In terms of annual energy, between 2011-12 and 2012-13, there was an overall decline of 1.6% across the NEM. This reduction was driven by the closure of the Kurri Kurri aluminium smelter closure in New South Wales, increased rooftop PV installations, energy efficiency initiatives and rising electricity prices.

In the 2013 forecast, NEM actual annual energy for 2012-13 was estimated to be 1.1% lower than was forecast in 2012. Forecast electricity use for 2013-14 is also reduced, showing a 2.4% reduction for 2013-14 compared to the 2012 forecast.[24]

Over the 10-year outlook period, the NEM annual energy forecast indicates average annual growth of 1.3% from 2013-14 to 2022-23, due to Queensland LNG projects coming online and population growth in most NEM regions.[25]

The validity and accuracy of the models used in AEMO's 2013 demand forecasts have been independently reviewed by external consultants. The 2013 modelling also implemented short-term (one-to-five year) modelling outcomes, which are expected to provide a more accurate and robust demand forecast over the 10-year outlook period.

AEMO reports annual demand forecasts in a dedicated publication, the National Electricity Forecasting Report (NEFR). AEMO's publication, the Electricity Statement of Opportunities (ESOO), uses these demand forecasts as an input when assessing long-term electricity supply adequacy.[26]

3.3 Overall power system performance

Reliability of the energy market is measured by comparing the component of any energy not supplied to consumers as a result of insufficient generation or bulk transmission capability against the Reliability Standard. This excludes energy not supplied due to management of security and performance of local transmission or distribution networks, and therefore only part of the overall measure of continuity of

23 A key exception is Queensland where the current maximum demand forecast reflects an increase of 3.2% average annual growth to 2022-23 compared to the 2012 forecast of 2.2% due to population growth and three large LNG projects coming online.

24 AEMO, 2013 National Electricity Forecasting Report, June 2013, p. x.

25 Ibid, p. ix.

26 These publications are discussed in further detail in appendix B of this report.

supply to consumers. However, from a consumer point of view, reliability is also impacted by the performance of distribution and local transmission networks, where measures for reliability are different.

The Panel has considered the overall power system performance in terms of the impact on end-use consumers. Consumer impact has been measured in terms of the length of time of where energy has not been supplied to consumers – or the "unsupplied system minutes". Unsupplied system minutes could arise from interruptions in generation, transmission networks and distribution networks and, due to the different reliability standards that apply, unsupplied system minutes need to be interpreted differently for each of these sectors.

The remainder of this section below provides a summary and explanation of the performance of the generation, distribution and transmission sectors in each region. The data does not include each region's "excluded events" or "major event days". These events are outlier events or events that are beyond the reasonable control of the participant as determined by each jurisdiction. The participants are permitted by the jurisdictions to exclude these events from their performance assessments.[27] Due to the different ways in which system outages are measured, the information in the tables below are not additive.

3.3.1 Generation performance

The performance of generation as experienced by consumers in each region has been calculated with reference to the Reliability Standard. The reliability standard, as explained in detail in section 2.1, is 0.002 per cent of USE. To convert this standard to system minutes, the total amount of time in a year has been multiplied by 0.002 per cent. There were no USE for 2012-13.

Table 3.1 Generation performance for 2012-13[28]

Region (generation)	System minutes unsupplied	
	Standard (minutes)	Actual
QLD	10.51	0.00
NSW	10.51	0.00
VIC	10.51	0.00
SA	10.51	0.00
TAS	10.51	0.00

27 For example, performance during extreme weather events may be excluded in some regions.

28 There are some exceptions to this time period as noted below.

3.3.2 Transmission network performance

The performance of transmission networks, and the reliability standards that must be met, fall within the responsibility of the jurisdictions. System minutes unsupplied in the transmission network are calculated as the amount of energy (MWh) not supplied to consumers, divided by the maximum demand (MW), and then multiplied by 60 to convert to minutes. That is, system minutes unsupplied for the transmission network is a total of all the outages that have occurred in a year in each jurisdiction.

Table 3.2 shows the performance of the transmission network as experienced by consumers in each region. The information has been supplied by transmission network service providers.

Table 3.2 Transmission networks unsupplied system minutes for 2012-13[29]

Region (transmission)	Calculated value in minutes (amount of energy not supplied, divided by maximum demand, multiplied by 60)
QLD	0.34
NSW	1.1
VIC	0.00
SA	5.8
TAS	0.49

3.3.3 Distribution network performance

The performance of distribution networks, and the reliability standards that must be met, also fall within the responsibility of the jurisdictions. For distribution networks, reliability standards are measured in terms of system average interruption duration index (SAIDI) and the system average interruption frequency index (SAIFI).

SAIDI measures the average duration of network outages. It 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 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 across different feeder and network businesses for each region, as set out in Table 3.3. The Panel understands different exclusion methodologies, variances in customer numbers by feeder, and different geographic conditions apply and that these averages are to represent a summary only.

29 Information supplied by TNSPs.

The underlying information are outlined in Appendix D. It is noted that the required performance levels for distribution reliability varies between jurisdictions and also between networks. Variations can be due to differences in distribution network characteristics and feeder types.

Table 3.3 Distribution network unsupplied system minutes for distribution for 2012-13[30]

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)
QLD	276.39
NSW	200.22
ACT	90.9
VIC	102.98
SA	355.01
TAS	202.8

3.4 Reliability and security

As discussed in chapter 2, the reliability of the power system is measured in terms of the Reliability Standard. To consider the performance of the NEM in the 2012-13 financial year against the Reliability Standard, the Panel has considered the USE experienced in each region. The Panel notes that the Reliability Standard has been met in 2012-13 as the USE was below 0.002 per cent in each region for the financial year . The USE for the last ten financial years are shown below.

The table below shows the performance of the NEM against the Reliability Standard for the past ten years.

Table 3.4 Regional USE for the past 10 years

Year	Queensland	New South Wales	Victoria	South Australia	Tasmania[31]
2012-13	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
2011-12	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%

30 Underlying data supplied by jurisdictional bodies or DNSPs and provided in Appendix D; averages calculated by AEMC Reliability Panel staff.

31 Tasmania joined the NEM in May 2005.

Year	Queensland	New South Wales	Victoria	South Australia	Tasmania[31]
2010-11	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
2009-10	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
2008-09	0.0000%	0.0000%	**0.0040%**	**0.0032%**	0.0000%
2007-08	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
2006-07	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
2005-06	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
2004-05	0.0000%	**0.00005%**	0.0000%	0.0000%	0.0000%
2003-04	0.0000%	0.0000%	0.0000%	0.0000%	

Specific power system incidents, and detailed reliability and security performance assessments are discussed in the following chapters.

3.5 Related Reliability Panel, AEMC and AEMO work

In 2012-13, the Reliability Panel, AEMC and AEMO completed a number of projects that related to the management of power system performance. A summary of the projects that were completed in the 2012-13 financial year is provided below. Additional information on these projects and the projects that were still underway as at 30 June 2013 is available on the AEMC and AEMO websites.[32]

3.5.1 Review of reliability outcomes and standards

SCER directed the AEMC to undertake a review of distribution reliability outcomes and standards in August 2011. The review had two separate workstreams, working to separate, but overlapping, timetables:

- a review of the distribution reliability outcomes in NSW; and
- a review of the frameworks across the NEM for expressing, delivering and reporting on distribution reliability outcomes.

Distribution framework - NSW workstream (completed by AEMC in August 2012)

With respect to the NSW workstream, its objective was to provide advice on the costs and benefits of alternatives for the future level of distribution reliability in NSW. The level of distribution reliability which was provided affects the reliability of customers' electricity supply, as well as the level of investment distribution businesses need to undertake and the prices paid by customers for distribution services.

32 See: www.aemc.gov.au and www.aemo.com.au.

On 31 August 2012, the AEMC published its final report on the NSW workstream. The final report sets out advice on the trade offs between distribution investment and reliability performance for the future level of reliability that could be provided by electricity distribution networks in NSW. The analysis suggests there are benefits to NSW consumers from reducing the level of distribution reliability in NSW. This is because the cost savings from reducing reliability are larger than the costs to customers of poorer reliability performance, compared to the continuation of the current requirements for distribution reliability. In other words, a relatively small reduction in reliability can lead to a large reduction in the investment required by electricity distribution networks. The report also provides information for the NSW Government should it decide changes should be made to the level of distribution reliability that is being provided in NSW.

Distribution framework - national workstream (see below on review of the national framework for reliability)

In relation to the national workstream, its objective was to analyse the different approaches to setting distribution reliability outcomes across the NEM. The AEMC would then consider if there was merit in developing a nationally consistent framework for expressing, delivering, and reporting on distribution reliability outcomes.

On 28 November 2012, the AEMC published a draft report for public consultation on whether there was merit in a national framework for distribution reliability outcomes. The draft report set out high level features of a framework which could deliver more efficient and effective reliability outcomes across the NEM. Under this framework, jurisdictions would retain responsibility for determining the level of reliability that should be provided by distribution businesses. However, reliability targets across the NEM would be set, delivered, and reported on under a national framework.

3.5.2 Review of the national framework for reliability (completed by AEMC in September 2013 for distribution and in November for transmission)

The AEMC received a request from SCER to undertake a review to develop national frameworks and methodologies for electricity transmission and distribution reliability across the NEM in February 2013. This review had two workstreams:

- a review to develop a national framework and methodology for transmission reliability in the NEM (transmission workstream); and
- a review to develop a national framework and methodology for distribution reliability in the NEM (distribution workstream).[33]

33 This review continued from the review of the frameworks across the NEM for expressing, delivering and reporting on distribution reliability outcomes.

These two workstreams were undertaken in parallel and where possible the AEMC sought to ensure that there was consistency between the frameworks which were developed for transmission and distribution networks.

This review formed part of a package of energy market reforms agreed to by the Council of Australian Governments and SCER in late 2012 to develop nationally consistent frameworks for transmission and distribution reliability and to allow jurisdictions to transfer the responsibility for applying these frameworks to the AER.

This review built on previous work undertaken by the AEMC under the:

- review of transmission reliability standards, which was finalised in November 2010 and was responded to by SCER in November 2011;
- the New South Wales workstream of the Review of distribution reliability standards and outcomes, which was finalised in August 2012; and
- the national workstream of the Review of distribution reliability standards and outcomes, which was further progressed through the distribution workstream of this review.

On 27 September 2013, the AEMC published its final report on its review of the national framework for distribution reliability. On 1 November 2013, the AEMC published its final report on the review of the national framework for transmission reliability. For each of the workstreams, the AEMC recommended a framework which promotes greater efficiency, transparency, and community consultation in how reliability levels are set and provided across the NEM.

3.5.3 Distribution network planning and expansion framework rule change (completed by AEMC in October 2012)

The MCE submitted a rule change request to the AEMC in relation to the introduction of a national framework for electricity distribution network planning and expansion In September 2011. The rule change stemmed from the AEMC's review of national framework for electricity distribution network planning and expansion in 2009. That review set out the AEMC's recommendations and supporting reasoning in respect of the establishment of a national framework, including: an annual planning and reporting process; a demand side engagement strategy; and a regulatory investment test for distribution.

On 11 October 2012, the AEMC published a final rule determination and final rule. The final rule is largely reflective of, and consistent with, the rule proposed by the Ministerial Council on Energy (MCE). However, the final rule incorporates several policy modifications and a number of drafting amendments to improve and clarify the application and operation of the new national framework.

The final rule consists of an annual planning and reporting process, and a distribution project assessment process. The key components of the final rule are as follows:

- a distribution annual planning review;
- a distribution annual planning report;
- demand side engagement obligations on distribution businesses;
- joint planning arrangements;
- the regulatory investment test for distribution (RIT-D); and
- a dispute resolution process for the RIT-D.

The final rule also makes several consequential amendments to the existing RIT-T rules as well as changes to the structure of Chapter 5 of the rules.

3.5.4 Review of the guidelines for identifying reviewable operating incidents (completed by Panel in December 2012)

The Panel conducted a review of the guidelines for identifying reviewable operating incidents following a request from AEMO to amend the guidelines in January 2012.

The rules set out criteria to determine which operating incidents are "reviewable". Reviewable operating incidents are generally incidents that occur in the power system that could have a significant effect on the operation of the power system in terms of system security.

AEMO applies guidelines to determine when a power system incident is considered a reviewable operating incident. These guidelines provide additional clarity and certainty on the review requirements. AEMO is required to review these incidents and report its findings.

On 20 December 2012, the Panel published the final report and the final revised guidelines. Consistent with the requirements under the rules, the final guidelines focus on reviewing incidents that could have a significant impact on the operation of the power system. To this end, the final guidelines introduce the concept of "critical transmission elements". Incidents that impact critical transmission elements will need to be reviewed by AEMO. The revised guidelines came into effect on 1 April 2013. This provided time for AEMO to consult with stakeholders on the definition of critical transmission elements.

3.5.5 Energy Adequacy Assessment Projection review (completed by Panel in February 2013)

The Panel undertook a review of the Energy Adequacy Assessment Projection (EAAP) provisions after receiving terms of reference from the AEMC to commence the work in July 2012.

The EAAP is an information mechanism that provides analysis on the impact of energy constraints in the NEM. The EAAP examines a two year outlook of the ability of generation in the NEM to meet demand in the presence of generator energy constraints. The EAAP operates in a similar manner to the capacity projection assessments of the MT PASA; however, the EAAP considers energy instead of capacity constraints.

AEMO publishes the EAAP on a three-monthly basis. AEMO is also required to establish a set of guidelines to assist with the administration of the EAAP. These guidelines were developed and published by AEMO in 2009.

On 21 February 2013, the Panel published its final report for this review. The Panel considered that the EAAP provided benefits to the market and to stakeholders while imposing minimal ongoing costs. The Panel found the existing EAAP arrangements were operating well and, as such, no changes to the EAAP arrangements were recommended (other than a minor change to update a cross-reference).

3.5.6 Transmission frameworks review (completed by AEMC in April 2013)

On 20 April 2010, the MCE directed the AEMC to conduct a review of the arrangements for the provision and utilisation of electricity transmission services in the NEM, with a view to ensuring that the incentives for generation and network investment and operating decisions are effectively aligned to deliver efficient overall outcomes. The AEMC was to review the role of transmission in providing services to the competitive sectors of the NEM, through considering the following key areas together in a holistic manner:

- transmission investment;
- network operation;
- network charging, access and connection; and
- management of network congestion.

The review stemmed from the AEMC's previous review of energy market frameworks in light of climate change policies. In the final report for that review, the AEMC recommended that further work be undertaken in relation to the efficient provision and utilisation of the transmission network. This reflected the AEMC's finding that climate change policies will fundamentally change the utilisation of transmission networks over time, both between and within regions of the NEM, and that this would place stress on existing market frameworks.

On 11 April 2013, the AEMC published the final report. The AEMC recommended both short term reforms to facilitate more efficient connections between generators and transmission networks, and further development of a longer term access model for generators, termed Optional Firm Access (OFA).

The OFA model would provide generators with the ability to “insure” against the risk of congestion (when more generators wish to use transmission than can be accommodated). It would change the way generators access the market during times of congestion and the way transmission investment decisions are made. The model enables better trade-offs to be made between the cost of transmission and the cost of generation. These trade-offs become more significant the greater the change from established fuel sources and transmission flowpaths. The AEMC recommended that the model be progressed to a detailed design and testing stage, in order to insure against the possibility of a future that brings significant changes from current patterns of demand and generation.

The cost, complexity and time delays associated with connecting new generation to the market are a concern which the AEMC considered could be addressed in the shorter term. Transmission businesses could be encouraged to make efficient trade-offs between the specification of connections and their cost. Ambiguity in the current rules also contributes to the problem. The recommendations will increase competition in and transparency of the construction process for assets required for generator connection(s) to the shared transmission network. However, the AEMC also considered that there is a need to balance increased competition with the maintenance of clear accountability for outcomes on the shared network.

3.5.7 System Restart Ancillary Services review (to be completed by AEMO in late 2013)

AEMO is currently conducting a review on its procedure and processes for procuring the system restart ancillary services (SRAS) for the NEM. The review is examining whether AEMO's method for assessing and procuring SRAS appropriately meets the requirements under the rules. AEMO's objective is to ensure the SRAS arrangements deliver value to energy consumers through an appropriate price and service balance.

AEMO has publicly consulted upon an issues and options paper, and a draft report for the review. In the issues and options paper, AEMO considered that SRAS costs have increased significantly in the last few tender processes, and raised the issue of whether the SRAS objective is being met by AEMO's method for assessing and procuring SRAS and whether it continues to be appropriate.[34]

In the draft report, AEMO recommended changes to the SRAS arrangements, including:

- to reduce the quantity of SRAS procured to meet the System Restart Standard by a combination of the following measures:
  - procuring SRAS on the basis of a regional, rather than NEM-wide, black system condition, while still meeting the System Restart Standard;
  - re-defining the electrical sub-networks, reducing their number from 10 to seven;

34 The SRAS objective is to minimise the expected economic costs to the market in the long term and in the short term of a major supply disruption, taking into account the cost of supplying SRAS.

- procuring one SRAS in each electrical sub-network except Tasmania, where two would be required to provide sufficient diversity and contingency. On the mainland, supply from adjacent regions can be used to support SRAS sourced within a region, providing sufficient diversity and contingency to meet the requirements of the System Restart Standard; and
- creating one SRAS definition to replace the current definitions of primary and secondary restart services;

- developing proposed rule changes to identify and manage non-competitive outcomes in the SRAS tender process, along similar lines to those in effect under clauses 3.11.5 (h)-(I) of the NER for the Network Support and Control Ancillary Services (NSCAS) tender process;
- to improve cost-reflective recovery for SRAS with respect to the benefits of a service, by allowing the costs of SRAS to be recovered on a regional basis; and
- to monitor and review the effectiveness of the current procurement process in relation to the SRAS objective in the NER by reviewing outcomes from the next tender process, after the implementation of SRAS quantity reductions, against comparable international benchmarks.

The Panel notes that AEMO's final report will not be published until after this Panel's draft report. If the AEMO's final report reflects the recommended changes proposed in its draft report, the Panel notes that these changes are a matter for the rule change process under the NEL.

However, the Panel also notes that the rules require the Panel to determine the System Restart Standard, which sets out the requirements that are to be met by AEMO in acquiring sufficient SRAS for the NEM.[35] Should AEMO identify any aspects of the System Restart Standard that it considers should be amended, it can raise this with the Panel or the AEMC. The AEMC and the Panel would then consider whether a review should be conducted to amend the standard. Any review of the standard would be carried out by the Panel in accordance with the provisions under the rules, which include the requirement to consult with stakeholders.

35 On 12 April 2012, the Panel reviewed the System Restart Standard and made a final determination that would apply for the acquisition of SRAS by AEMO, which commenced operation from 1 August 2013. Prior to this, an interim standard was in place since November 2006 which was determined by AEMO. The standard determined by the Panel largely retains key aspects of the interim standard with some minor amendments. The minor amendments were for clarification purposes and did not have any material impacts.

3.5.8 Reliability standard and settings review (to be completed by Panel in April 2014)

The Panel is currently reviewing the reliability standard of bulk transmission and supply, and the reliability settings.[36] This review is considering whether the existing reliability standard and settings remain appropriate under the current market conditions. The Panel will assess the appropriate standard and settings that should apply from 1 July 2016. The Panel is required to complete a review of the reliability standard and settings by 30 April 2014.

The Panel will review the reliability standard, which is currently set at 0.002 per cent unserved energy, and the reliability settings, which are the market price cap (MPC), the cumulative price threshold (CPT), and the market floor price. Consideration of the method with which the MPC and CPT are indexed is also included in the review.

In undertaking the review, the Panel is required to follow the rules consultation procedures. The Panel will have regard to the NEO, the potential impact of any proposed change on market participants and consumers, as well as the potential impacts on the market including the spot market, contracts market and investment signals. The Panel may take into account any other relevant matters.

36 Under the rules, the Panel is required to carry out a review of the reliability standard and reliability settings once every four years.

4 Power system incidents

This chapter discusses the power system incidents in 2012-13 identified under the System Operating Incident Guidelines (and relevant frequency standards where applicable).[37] Where any incidents have impacted reliability and security, this has been noted.

4.1 System operating incident guidelines

As the market operator, AEMO is responsible for reviewing system operating incidents of significance that occur in the NEM power system. In accordance with requirements under the rules, the Panel established guidelines to set out when an operating incident should be reviewed. The power system operating incidents that should be reviewed by AEMO include the following:

- an incident defined as a multiple contingency event;
- a black system condition;
- an incident where the frequency is outside the operational frequency tolerance band (currently set by the Panel at 49 to 51 Hz on the mainland and 47.5 to 52 Hz in Tasmania);
- an incident where the power system is insecure for more than 30 minutes;
- an incident where there is load shedding due to a clause 4.8.9 instruction;[38] or
- other incidents determined by the Panel and described in the Panel's guidelines.

4.2 Contingency events

In the 2012-13 financial year, there were 49 contingency events that were reviewable under the operating incident guidelines.[39] AEMO has published a report for each event. Of the 49 contingency events, AEMO classified 37 of these as multiple contingency events. The Panel notes that the numbers of events were marginally higher than the previous financial year which experienced 40 reviewable contingency events (with 27 of these being classified as multiple contingencies). The categorisation and number of contingency events are set out in Table 4.1.

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37 The guidelines for identifying reviewable operating incidents can be found on the AEMC Reliability Panel website: www.aemc.gov.au/Panels-and-Committees/Reliability-Panel/Guidelines-and-standards.html.

38 Clause 4.8.9 of the rules sets out AEMO's powers to issue directions to Registered Participants.

39 There was a change to the guidelines for reviewable events on 1 April 2013. See section 3.5.

Table 4.1 Reviewable operating incidents 2012-13

Event description	Number of incidents[40]
Transmission related incidents (excluding busbar trips)[41]	29
Generation related incidents	5
Combined transmission/generation incidents	8
Busbar related reviewable incidents	12
Power system security related	0

Some of the events resulted in customer load interruptions. There were 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 incident recurrence. Examples include recommending AEMO revise its processes to ensure timely re-classification of non-credible contingencies, recommending a generator to undertake work to recalibrate all plant associated with an under-frequency load shedding scheme, and recommending a TNSP to investigate and report on the adequacy of the earthing and lightning protection arrangement. Further examples are listed in appendix E.

As a result of AEMO's review of incidents that occurred in 2012-13, 43 actions were recommended for completion within a specific time frame. As at 13 September 2013, 33 recommended actions had been completed, 0 were overdue for completion, and 10 were to be completed.[42] The Panel notes that AEMO reports on the progress of recommended actions on a quarterly basis.

4.3 Major incidents

Based on the Panel's review of the power system incident reports published by AEMO, the Panel has considered the following more significant events in detail. The Panel has considered these incidents as being more significant as they:

40 Some events are included in more than one category.

41 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'.

42 Recommendations arising from power system operating incident reports, available at: www.aemo.com.au/Electricity/Resources/Reports-and-Documents/Progress-on-Operating-Incident-Recommendations.

- resulted in material levels of load shedding and therefore would have more directly impacted consumers' experiences; and/or

- involved multiple generation/network elements and therefore may indicate issues requiring more serious attention.

Relevant details from AEMO's operating incident reports are summarised and discussed as follows. AEMO's full reports for each of the 46 operating incidents in 2012-13 can be accessed from AEMO's website.[43]

4.3.1 Lightning strikes in Tasmania and Pacific Aluminium Potline Load Reductions (21 March 2013)

Type of event

This event was a credible contingency event relating to three simultaneous trips of transmission lines due to lightning that occurred in March 2013 in Tasmania. This resulted in a total interruption of 439 MW of customer load.

Summary of event details

There was significant lightning activity across Tasmania at the time of the incident. The lightning strike resulted in simultaneous losses of:

- Farrell-Reece No.1 and No.2 220 kV transmission lines;

- Farrell-Sheffield No.1 and No.2 220 kV transmission lines; and

- George Town-Sheffield No.1 and No.2 220 kV transmission lines.

In response to the faults for each of these transmission lines, Pacific Aluminium reduced load at the potlines by 118 MW, 100 MW and 221 MW, respectively. Upon investigation of the load reductions of their potlines, Pacific Aluminium determined that the load reductions at the potlines were due to plant protection operation, and operation of emergency fail-safe shutdown systems as a result to loss of supply during the fault.

Subsequent to the investigation, Pacific Aluminium disabled the phase asymmetry relay function related to the plant protection, and replaced the batter banks supplying the emergency shutdown relays.

The Panel's comments and observations

The Panel notes AEMO reclassified the incident as a credible contingency due to lightning. AEMO cancelled this reclassification as it was satisfied that Pacific

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43 Available at: www.aemo.com.au/Electricity/Resources/Reports-and-Documents/Power-System-Operating-Incident-Reports.

Aluminium carried out the appropriate work to mitigate the risk of a similar incident occurring in the future.

The power system remained in a secure operating state throughout the incident. The Panel notes that the frequency operating standard for the Tasmania region was met.

While this event was caused from lightning and did not result in broader power system security issues, the event highlights the material impact that lightning activity can have on customers. This event was one example of lightning activity in the 2012-13 financial year which resulted in customer load shedding; however, it had the most significant impact on customers in terms of interruption to the load.

4.3.2 Simultaneous trips of Millmerran Power Station units 1 and 2 (9 March 2013)

Type of event

This event was a credible contingency event relating to simultaneous trips of two generating units that occurred in March 2013 in Queensland. This resulted in a total interruption of 823 MW of generation.

Summary of event details

The incident was caused by a hardware fault in the Programmable Logic Controller (PLC) of the Emergency Diesel Generator at Millmerran Power Station. Prior to the incident, Units 1 and 2 at Millmerran Power Station were generating 399 MW and 424 MW respectively to give a combined output of 823 MW.

At the time of the incident, the power supply to the PLC was found to have powered down and faulty. During investigation by Intergen of this fault, the PLC unexpectedly powered up on its own and tripped the supply to the station 6.6 kV common board. This resulted in the shutdown of all in-service and standby station air compressors, ultimately leading to the tripping of the two generating units 1 and 2. No reserve issues were identified in the Queensland Region as a result of the simultaneous trip.

The Panel's comments and observations

The Panel notes AEMO reclassified the incident as a credible contingency. This was because AEMO believed that there was still a risk where a single point of failure will result in the loss of supply to all the air compressors and eventually the loss of both Millmerran generating units. AEMO noted that it would review this reclassification once Intergen completed making changes to remove the single point of failure. AEMO also recommended that Intergen undertake a number of other actions to address the fault, and for Intergen to inform AEMO once they are completed. The power system remained in a secure operating state throughout the incident.

While the incident does not appear to reflect broader power system security issues, and no reserve issues were identified, the Panel has included the incident as an example of the magnitude of generation supply loss that can arise from equipment faults.

4.3.3 Trip of Georgetown B 220kV (27 November 2012)

Type of event

This event was a non-credible contingency event relating to trips of a transmission busbar and lines in November 2012 in Tasmania. The total interruption to generation was 202 MW and to customer load was 337 MW.

Summary of event details

The incident resulted from an incorrect protection operation that occurred during work on the protection scheme at George Town Substation. The George Town–Tamar Valley No 3 220 kV transmission line (202 MW) and the George Town–Comalco No 4 220 kV transmission line (106 MW) also tripped. This led to a number of subsequent events:

- disconnection of the Tamar Valley Power Station CCGT (TVPS) following trip of the George Town–Tamar Valley No 3 220 kV transmission line (202 MW);
- forming of an electrical island with the Tamar Valley Power Station Gas Turbine (GT1) supplying the Tamar Valley Power Station’s auxiliary equipment (4 MW);
- the Tamar Valley Power Station Generator Contingency Scheme (TVGCS) was triggered by the disconnection of the TVPS, leading to the tripping of:
  - the selected Temco load block (74 MW); and
  - the selected Nyrstar load block (28 MW);
- the further tripping of a Nyrstar load block (28 MW) due to oversensitive control/protection settings within their plant; and
- a potline tripped at Rio Tinto Aluminium Smelter following trip of the George Town–Comalco No 5 220 kV transmission line (101 MW).

The Panel's comments and observations

The Panel notes that the power system remained in a secure operating state throughout the incident. The Basslink frequency controller also maintained Tasmanian region frequency within the normal frequency operating band.

The Panel notes that Transend considered that this event is unlikely to reoccur because it was initiated by incorrect protection operation. Transend found that there was an incorrect labelling of a cable within the bus zone protection wiring which the test procedures had not identified, and took corrective actions. The control and protection settings of the Nyrstar equipment were also being reviewed by contractors. The TVGCS has been reconfigured, and Nyrstar load blocks have been excluded since 1 January 2013.

This incident has been included in this report due to the impact on customer load and the multiple parts of the network that were impacted.

4.3.4 Simultaneous trip of Eraring – Vales Point (No 24) 330kV line and No3 potline at Tomago (4 October 2012)

Type of event

This event was a credible contingency event relating to a simultaneous trip of a transmission line and potline in October 2012 in New South Wales. The total interruption to customer load was 300 MW.

Summary of event details

The trip of the Eraring – Vales Point 330 kV 24 transmission line was due to a fault associated with a bushfire close to the line. This triggered the protection to operate to trip the line.

Immediately following the line trip, Tomago potline 3 tripped. Upon further investigation by Tomago Aluminium, the cause of the potline trip was determined to be as a result of incorrect operation of the Tomago Under-Frequency Load Shedding (UFLS) scheme. The scheme trips a selected potline at a relay set-point of 49.0 Hz after a time delay of 150 ms. However, there was no evidence mainland frequency dropped as low as 49.0 Hz during the event, nor were there any other Mainland loads with similar UFLS settings which had tripped during the event. This suggested that the Tomago UFLS incorrectly operated.

The Panel's comments and observations

The Panel notes TransGrid returned Eraring – Vales Point 330 kV 24 line to service after considering the bushfire had subsided.

The Panel notes AEMO reclassified the incident as a credible contingency. AEMO would review this reclassification once the UFLS scheme owner, Macquarie Generation, carried out work to recalibrate all plant associated with the Tomago UFLS scheme, and provide test results from the calibration to Tomago Aluminium by the end of January 2013.

The Panel notes that the power system remained in a secure operating state throughout the incident, noting Eraring – Vales Point 330 kV 24 line protection operated within approximately 80 ms after the initial fault.

While this event was caused from a bushfire and did not result in broader power system security issues, the event highlights the material impact that bushfire activity can have on customers. This event was one example of bushfire activity in the 2012-13 financial year which resulted in customer load shedding.

4.3.5 Multiple contingency event in Tasmania due to Basslink trip (5 July 2012)

Type of event

This event was a non-credible contingency event relating to simultaneous trips of Basslink, six generating units and a potline in July 2012 in Tasmania. The total interruption to generation was 604 MW and to customer load was 121 MW.

Summary of event details

Basslink tripped at the Loy Yang converter station due to a faulty transformer temperature sensor at the Basslink Loy Yang converter station. Prior to the event Basslink was transferring 597 MW from Tasmania to Victoria. On the loss of Basslink, the Frequency Control System Protection Scheme (FCSPS) operated correctly to manage the frequency in the Tasmania region, leading to the tripping of six generating units in Tasmania with a total of 604 MW.

Simultaneously with the Basslink trip, there was an unexpected loss of 121 MW at one of the potlines at the Rio Tinto aluminium smelter in George Town, Tasmania. This was due to issues with Rio Tinto's local 240 V control supplies coupled with abnormal plant configuration within the Rio Tinto aluminium smelter at the time of the event.

The Panel's comments and observations

The Panel notes that following this event, Basslink Pty Ltd replaced the faulty temperature indicator and Basslink was returned to service on 5 July 2013.

The Panel notes Rio Tinto completed modifications on the 240 V distribution network at the George Town smelter to prevent a re-occurrence of this type of trip, and advised Transend who have advised AEMO. The modifications were implemented on 3 September 2012. Further, AEMO did not reclassify the incident as a credible contingency because it did not consider the potential for this type of event to reoccur.

The Panel notes that the power system remained in a secure operating state throughout the incident. The FCSPS operated correctly to maintain the power system security, and tripped the required level of generation in the Tasmania region to control frequency in that region. The frequency standards for both the Mainland and Tasmania were not exceeded during this event despite the unexpected loss of 121 MW of load at Rio Tinto.

Although the power system remained in a secure operating state throughout the incident, the Panel notes the following observations by AEMO:

- if the same event had occurred while Rio Tinto remained in the abnormal operating condition, there was the potential risk that the power system may have been in an insecure state. The FCSPS would have operated to cover the loss of Basslink and Tasmanian sourced FCAS would be required to cover the loss of the Potline; and

- if the contingency lower FCAS dispatched in the Tasmania region was less than that required to cover the loss of a single potline, the frequency in Tasmania may not have met the Tasmanian Frequency Operating standards (FOS).

This incident has been included in this report due to the impact on customer load, generation and the impact on multiple parts of the network that can arise from an equipment fault and abnormal plant configuration.

5 Reliability performance assessment

This chapter sets out the Panel's assessment and discussion of the power system reliability performance and the mechanisms to measure reliability performance. Additional background information is set out in Appendix B.

5.1 Minimum reserve levels

AEMO calculates minimum reserve levels (MRLs) 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 5.1 Revised minimum reserve levels (note 1)

	Queensland (note 2)	**New South Wales**	**Victoria & 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
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	There are 6 constraints on the amount of reserves required for Victoria and South Australia (note 5)	(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 5.1. 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 6 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.

5.2 Reserve projections and demand forecasts

Market information on reserve projections and demand forecasts are published by AEMO in various forms. In this section, the Panel considers these forecasts for the 2012-13 financial year. Background information providing detailed explanations of each type of market information is outlined in section B.4.

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

5.2.1 Electricity Statement of Opportunities

AEMO publishes the Electricity Statement of Opportunities (ESOO) on an annual basis in August.

The 2013 ESOO provides an analysis of electricity supply and demand over a 10 year outlook period. It also 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 next 10 years.

Under a medium economic growth scenario, the 2013 outlook for 2013–14 to 2022–23 projects:

- reserve deficit of 159 MW in Queensland in 2019–20, bringing the LRC forward by one year compared to the 2012 ESOO;[44] and
- no reserve deficits in New South Wales, Victoria, South Australia, or Tasmania until after 2022–23, deferring the LRC by at least one year in those states compared to the 2012 ESOO.[45]

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 in 2013.

Under clause 3.13.3(u) of the rules, AEMO is required to provide to the Panel a report on the accuracy of the demand forecasts in the ESOO by 1 November each year. Details of AEMO's assessment are outlined in this report, which is published on the AEMC Reliability Panel website. AEMO continuously reviews and updates its methodologies.

In November 2013, AEMO published a 2013 ESOO Update due to recent changes in the electricity generation fleet and electricity consumption trends.[46] Since the publication of the 2013 ESOO:

- electricity consumption forecasts have been revised down by 1.3 per cent for 2013-14, given electricity consumption has trended lower than forecast, down by approximately 3.5 per cent compared to the 2013 NEFR forecasts. This is due to changes in large industrial loads, a warm winter-early spring period, and reduced commercial and residential load;
- status of generation fleets have changed with all newly committed, commissioned, or announced projects being renewable in nature, consisting primarily of wind generation, with several solar projects, and a 1 MW wave energy project also committed;
- supply side has changed, which impact the adequacy results include only commitment of the Portland Stage 4 Wind Farm (47.2 MW) in Victoria, which further defers reserve deficits in Victoria; however, only projections for 2013-14 are impacted, while there is no direct impact on reserve deficit timings beyond that period.

44 The 2013 ESSO notes that this change is due to increased forecasts for large industrial demand and improved modelling resolution.

45 AEMO, 2013 Electricity Statement of Opportunities, 13 Aug 2013, pp. 2-3.

46 AEMO, 2013 Electricity Statement of Opportunities Update, November 2013.

5.2.2 National Electricity Forecasting Report

In 2013, AEMO published its second edition of the NEFR, which represents the second time AEMO has developed independent electricity demand forecasts on a consistent basis for the five NEM regions. The NEFR details electricity demand forecast information used as an input to the 2013 ESOO.

The findings of the 2013 NEFR include:

- forecast annual energy for 2013-14 is projected to be 2.4 per cent lower than estimated under the medium economic growth scenario in the 2012 NEFR;
- under the same medium economic growth scenario, the 10 year period (2013–14 to 2022–23) is now forecast to grow by 1.3 per cent, down from 1.7 per cent forecast in the 2012 NEFR;
- maximum demand forecasts across the NEM (with the exception of Queensland) sees a 728 MW reduction for 2013–14 under the medium economic growth scenario in the 2012 NEFR. However, there is still an anticipated maximum demand growth over the 10 year period, albeit at a lower trajectory compared to the 2012 forecast; and
- annual maximum demand under the 10% probability of exceedance (POE) forecast for the 10 year period is projected to grow by an average of 3.2 per cent in Queensland, 1.0 per cent in New South Wales, 0.0 per cent in South Australia, 0.9 per cent in Victoria and 0.1 per cent in Tasmania.

The Panel notes that the key demand forecast drivers over this period are the three large industrial liquefied natural gas (LNG) projects in Queensland, continued increases in rooftop PV, population growth in most NEM regions, and an easing in electricity price growth over the 10-year outlook period.

In November 2013, AEMO published a 2013 NEFR Update to provide updated data in relation to its annual electricity consumption forecasts for 2013-14. This revised forecast updates the 2013-14 period only and was developed using a medium economic growth scenario.[47] Since the publication of the 2013 ESOO:

- the NEM electricity forecasts for 2012-13 were revised by -1.3 per cent (-2,444 GWh):
  - 1,205 GWh of the revised forecast was attributed to changes in large industrial load; and
  - 1,239 GWh of the revised forecast was attributed to reduced residential and commercial electricity usage and warmer weather; and

47 AEMO, 2013 National Electricity Forecasting Report Update, November 2013.

- a first quarter NEM-wide variance of -4.7% (-466 GWh) in large industrial loads (including LNG), comprising of forecast reductions of:
  - 22 per cent in Queensland;
  - 17 per cent in New South Wales;
  - 16 per cent in South Australia;
  - 18 per cent in Victoria; and
  - 55 per cent in Tasmania.

The Panel notes that AEMO has not revised the maximum demand forecast for 2013-14, as its observed variances in the large industrial load maximum demand were not significant.

5.2.3 Power System Adequacy - two year outlook

On an annual basis for the last three years, AEMO has published the Power System Adequacy (PSA) in the lead up to summer. The PSA is a two year outlook to assess the electricity supply over the next two years, complementing the 10 year outlook provided by the ESOO.[48]

The 2013 PSA established the following key points:[49]

- The reserve capacity and energy adequacy assessment indicates that the power system will have sufficient supply capacity to meet the Reliability Panel's reserve requirements, and (as at the time of publication) AEMO is not expecting to invoke the 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 schemes (OFGS) 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. AEMO expects to implement the schemes in 2014.
- 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

48 Producing and publishing the PSA is not a rules requirement.

49 AEMO, Power System Adequacy, 13 August 2013, available at: www.aemo.com.au/Electricity/Resources/Reports-and-Documents/Power-System-Adequacy.

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.

5.2.4 National Transmission Network Development Plan

Under its role as the National Transmission Planner, AEMO publishes the National Transmission Network Development Plan (NTNDP) on an annual basis. The NTNDP outlines the long-term efficient development of the power system including future and current capability of the national transmission network and development options.

The latest available NTNDP was published in December 2012. The following information was included in the final report on the 2012 AMPR. This information has been reproduced for this draft report.

The 2012 NTNDP report found that overall, there have been changes in the energy environment including lower electricity demand and energy forecasts, and higher projected gas costs. The report shows less transmission investment is required compared to previous estimates, and there is clear opportunity to achieve integration and efficiency from this investment.

Due to the lower forecast demand growth, the previous estimate of $7 billion in the main transmission networks over 20 years has been revised to $4 billion in the 2012 NTNDP. For the same reason, estimated required generation investment of $65 billion over the next 20 years has been revised to $26 billion.[50]

In relation to transmission investment, other key findings from the 2012 NTNDP were:[51]

- Investment will be needed to replace old assets and augment transmission networks.
- There is generally sufficient capability in the main transmission network for new generation to connect at locations which allow for growth avoiding the need for significant new transmission investment.

The 2012 NTNDP also incorporates a suite of documents including a 2012 Network Support and Control Ancillary Service (NSCAS) assessment report. This report shows that the only gap for maintaining security is identified in New South Wales, requiring up to 800 MVAr for absorbing reactive power for the next five years.

The Panel notes that the NTNDP takes a least-cost approach to the development of the power system and reflects AEMO's best estimate of economic and policy outlooks.

50 AEMO, 2012 National Transmission Network Development Plan, 11 December 2012, p. iii, V.

51 Ibid.

The efficient integration of different energy sources and technologies will become increasingly important in the energy markets. The Panel understands that AEMO will continue to explore alternative scenarios and opportunities to support further market integration.

The Panel also notes that the AEMC completed in December 2012 its latest investigation into whether to exercise the last resort planning power (LRPP). The AEMC determined that all inter-regional flow paths were being adequately addressed and, as a result, it would not issue a direction to a Registered Participants under the LRPP in 2012.[52]

5.2.5 Energy Adequacy Assessment Projection

As required by the rules from March 2010, AEMO has published the Energy Adequacy Assessment Projection (EAAP) each quarter. The EAAP provides information of the impact of energy constraints 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. In addition to annual projections, USE projections for each region are also provided for each month in the forecast period.

EAAP consists of two reports, EAAP public report and private EAAP reports for each Generator who owns scheduled generating units or hydro power schemes. The most recent publicly available EAAP determined that the forecast unserved energy is below the Reliability Standard of 0.002 per cent for all regions for both years (1 October 2013 to 30 September 2015) in the three scenarios covered in the September 2013 EAAP.[53] This indicates that the availability of energy in these NEM regions meets the reliability standard for supply adequacy in both years.[54]

5.2.6 Medium-term Projected Assessment of System Adequacy

As required under the Rules, AEMO publishes the medium-term projected assessment of system adequacy (MT PASA) reports. These reports set out the aggregate supply

52 Under the Rules the AEMC has the LRPP, which is an oversight power that allows the AEMC to direct any registered participant in the NEM to apply the regulatory investment test for transmission (RIT-T) which the AEMC considers is likely to address any inter-regional transmission investment shortfall (clause 5.6.4 of the rules). AEMC, Investigation into the Exercise of the Last Resort Planning Power review, 11 December 2012.

53 AEMO, Energy Adequacy Assessment Projection Report Update, September 2013, available at: www.aemo.com.au/Electricity/Resources/Reports-and-Documents/EAAP.

54 Ibid.

and demand balance at the time of anticipated daily peak demand for each day over the next two years (based on a 10 per cent probability of exceedance).

Table 5.2 summarises the percentage of days when actual demand was greater than MT PASA forecast demand, as well as the average amount by which actual demand exceeded forecast demand for those days. The table shows that for weekdays, South Australia and New South Wales experienced demand on weekdays greater than the 10 per cent POE forecast. For weekend days, South Australia and Tasmania experienced demand greater than the 10 per cent POE forecast.

For example, in South Australia, the actual demand was greater than the 10 per cent POE forecast for 0.4 per cent of weekdays (around 1 weekday in total that year) and for 1.0 per cent of weekend days (around 1 weekend day that year). On average across the year, the actual weekday demand values for South Australia differed from the forecast value by 3 per cent, while the actual weekend demand values differed from the forecast value by 32 per cent.

The Panel notes that overall, the accuracy of the MT PASA forecasts across the NEM for 2012-13 has not substantially changed on average from 2011-12. However, the Panel notes the following noticeable changes in 2012-13 from 2011-12:

- With respect to the average proportion of weekdays where the demand was greater than the 10 per cent POE forecast, the forecast error:
  - reduced in Victoria from 0.3 per cent in 2011-12 to 0 per cent in 2012-13; and
  - increased in South Australia from 0 per cent in 2011-12 to 3 per cent in 2012-13.
- With respect to the average proportion of weekends where the demand was greater than the 10 per cent POE forecast, the forecast error:
  - reduced in Tasmania from 2.6 per cent in 2011-12 to 1 per cent in 2012-13; and
  - remained highest in South Australia compared to the other regions increasing from 9.7 per cent in 2011-12 to 32 per cent in 2012-13.

It is noted that South Australia has not performed as well compared to other regions in the MT PASA demand forecasts for 2012-13. AEMO has advised the Panel that reviews are being undertaken to consider ways in which it can improve its forecasting processes. AEMO will update the Panel on its progress and any relevant information will be considered in the Panel's final report

Table 5.2 Medium-term PASA demand forecasts comparison 2012-13

	QLD	NSW	VIC	SA	TAS
Proportion of weekdays where demand greater than 10 per cent POE forecast	0.0%	0.4%	0.0%	0.4%	0.0%
Proportion of weekend days where demand greater than 10 per cent POE forecast	0%	0%	0%	1.0%	3.8%
Average demand deviation from forecast for weekdays	0%	0%	0%	3%	0%
Average demand deviation from forecast for weekend days	0%	0%	0%	32%	1%

Source: AER

5.2.7 Short-term Projected Assessment of System Adequacy

In addition to MT PASA reports, AEMO also publishes short-term projected assessment of system adequacy (ST PASA) reports. As 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.

Table 5.3 shows the average short-term PASA demand forecast accuracy for two, four and six days ahead. For example, the table shows for South Australia that on average, the 12 hours ahead forecasts were within 4.3 per cent of the actual demand outcomes.

The Panel notes that overall the accuracy of the ST PASA demand forecasts has marginally improved from 2012-13 for all regions:

- on average across the four forecast categories, Tasmania marginally improved in accuracy, e.g. for 2 days ahead ST PASA, demand forecast accuracy improved from 4.5 per cent in 2011-12 to 3.7 per cent in 2012-13;

- with the exception of 12 hours ahead forecast category, South Australia, Victoria and Queensland marginally improved, e.g. for 2 days ahead ST PASA in South Australia, demand forecast accuracy improved from 5.1 per cent in 2011-12 to 4.9 per cent in 2012-13;

- New South Wales and South Australia remained the same in accuracy as the previous financial year in relation to the 4 days ahead and 12 hours ahead, respectively; and
- for the 12 hours ahead forecast category, the accuracy marginally declined in Queensland, New South Wales and Victoria.

Table 5.3 Accuracy of short-term PASA demand forecasts 2012-13

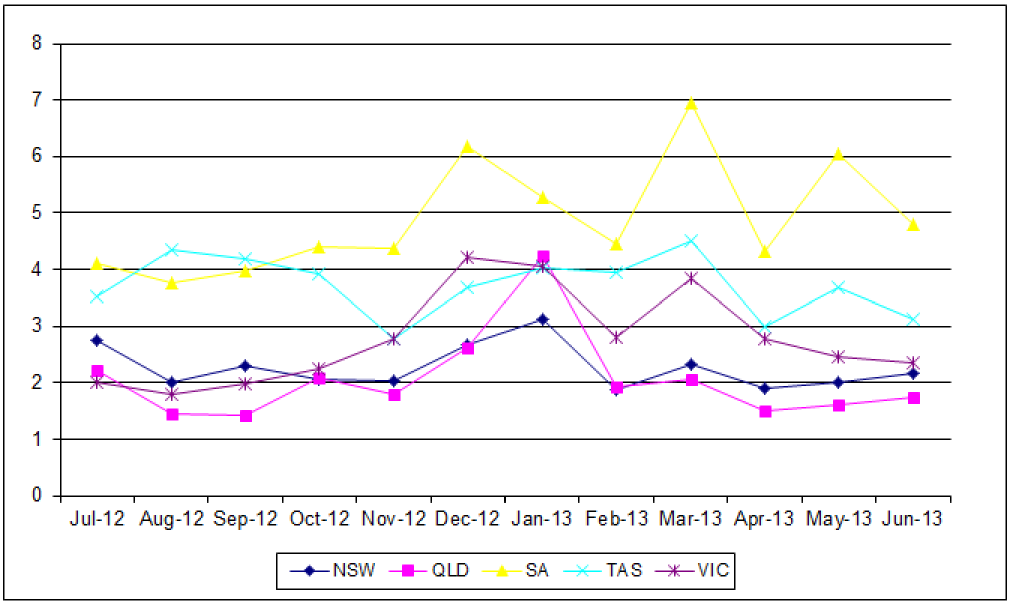
Short-term PASA demand forecast absolute percentage deviation	QLD	NSW	VIC	SA	TAS
12 hours ahead	1.9%	2.1%	2.7%	4.3%	3.1%
2 days ahead	2.1%	2.3%	2.8%	4.9%	3.7%
4 days ahead	2.3%	2.5%	3.0%	5.8%	4.3%
6 days ahead	2.5%	2.7%	3.6%	7.2%	5.0%

Source: AER

The Panel has also examined the accuracy of ST PASA based on the mean absolute percentage error (2 days ahead). The Panel observes that demand forecasts, as shown in Figure 5.1, were relatively consistent for New South Wales, Queensland and Victoria where the mean error was around two to four per cent for the duration of the year. With the exception of Tasmania, the mean errors were higher for all regions over the summer months and early autumn, most notably for South Australia where the errors peaked at 6.94 per cent in March 2013. The mean error for Tasmania was highest in August and March 2013. The results are demonstrated in the following figure.

There is a notable variation in South Australia compared to the other regions in terms of the mean error for 2 day ahead ST PASA. As noted above, AEMO is reviewing its forecasting process and will advise the Panel of its progress.

Figure 5.1 Mean absolute percentage error (2 day ahead - ST PASA)



Source: AER

5.2.8 Pre-dispatch

Pre-dispatch provides an aggregate supply and demand balance comparison for each half-hour of the next day. The information is provided to relevant participants to assist with their operations management, and the data is available publicly the following day. The Panel notes that 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.

The Panel notes that 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 constraints and approximation of some terms in those equations. The quality of the forecasts is important but obtaining better forecasts will only address one issue in improving the alignment between dispatch and pre-dispatch.

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 twenty-two 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 sub-regional demand forecasts up to eight days ahead, compared to the previous method of deriving sub-regional forecasts by scaling NEM regional forecasts. This has improved the accuracy of constraint equations in pre-dispatch and ST PASA.

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

The Panel has considered the number of trading intervals affected by statistically significant variations between pre-dispatch and actual prices during the 2012-13 financial year, as well as the most probable reasons for the variations. The data that the Panel has considered is set out in Table 5.4. For example, the table shows that for Queensland, a total of 2474 trading intervals in 2012-13 were affected by significant price variations which represents 14 per cent of trading intervals in total. Of these 14 per cent, 51 per cent of the price variations were due to variances in the demand values and 27 per cent were due to changes in plant availability.

The Panel notes that overall, the number of trading intervals affected by statistically significant variations between pre-dispatch and actual prices during the 2012-13 financial year has increased on average from 2011-12. The Panel notes noticeable changes in 2012-13 from 2011-12:

- With respect to the number of total trading intervals affected by price variation and price variations due to variances in the demand values, Queensland and South Australia showed substantial increases, while Tasmania showed substantial reductions in these areas;
- With respect to plant availability, the numbers increased in Queensland and South Australia, while numbers in New South Wales, Victoria and Tasmania reduced, with Tasmania showing a substantial reduction;
- With respect to a combination of reasons for price variations, the numbers have broadly increased across the regions, with Queensland and South Australia showing the largest increases; and
- With respect to network related price variations, these numbers have broadly reduced across the regions, although this slightly increased in New South Wales.

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, as demonstrated by an increase in price variations due to variances in demand values from the previous AMPR. As previously observed, the Panel notes that load forecasting is a continuing challenge.

There was an increase in the number of trading intervals that were affected by differences in forecast and actual prices in Queensland and South Australia. Significant price fluctuations were experienced in the second half of the financial year and were due to:

- in Queensland: congestion in central Queensland which led to rebidding of generation capacity; and storm and flooding events in the Brisbane area; and

- in South Australia: between April and June 2013, a reduction in available generation, low wind generation and a reduction in inter-regional trading capacity with Victoria.

Table 5.4 Trading intervals affected by price variation

Reason for price variation	Number of trading intervals affected by variations									
	QLD		NSW		VIC		SA		TAS	
Demand	1590	51%	543	62%	735	57%	1777	55%	390	20%
Availability	836	27%	186	21%	314	24%	903	28%	1520	79%
Combination (e.g. of changes in plant availability, demand, rebidding activities)	665	21%	141	16%	236	18%	530	16%	1	0%
Network (e.g. network outages)	57	2%	6	1%	5	0%	22	1%	14	1%
Total trading intervals affected	2474	14%	748	4%	1075	6%	2589	15%	1873	11%

Source: AER

Note: The number of trading intervals affected for each of the reasons above (in rows 1 to 4) do not necessarily equal the total number of trading intervals affected (row 5). A number of forecasts are published for each trading interval, multiple variations, sometimes with different reasons can occur in the one trading interval.

The table illustrates that while there are a large number of trading intervals that are affected by significant variations between forecast and actual prices, the proportion of trading intervals is less than 15 per cent in all regions:[55]

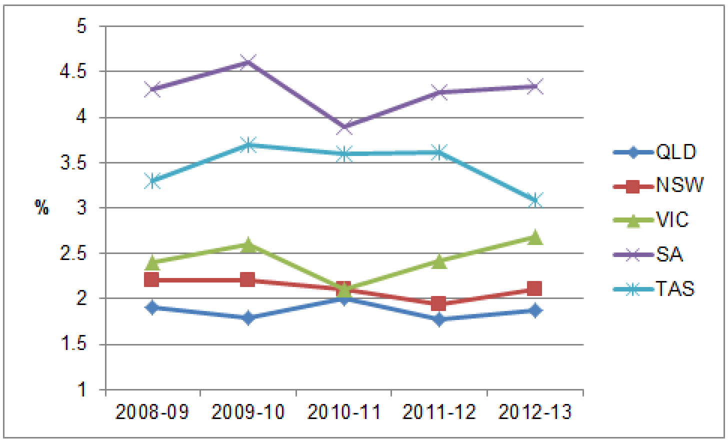
- for New South Wales and Victoria, the total number of trading intervals affected this year is relatively consistent with last year;
- the proportion of intervals affected in:
  - Queensland is greater than the last financial year with 14 per cent and 6 per cent last year; and
  - South Australia is greater than the last financial year with 15 per cent this year and 8 per cent last year; and

55 In 2011-12, the total trading intervals affected (percentage wise) were: Queensland 6 per cent, New South Wales 4 per cent, Victoria 6 per cent, South Australia 8 per cent and Tasmania 24 per cent.

- the proportion of intervals affected in Tasmania is less than the last financial year, with 11 per cent this year and 24 per cent last year.

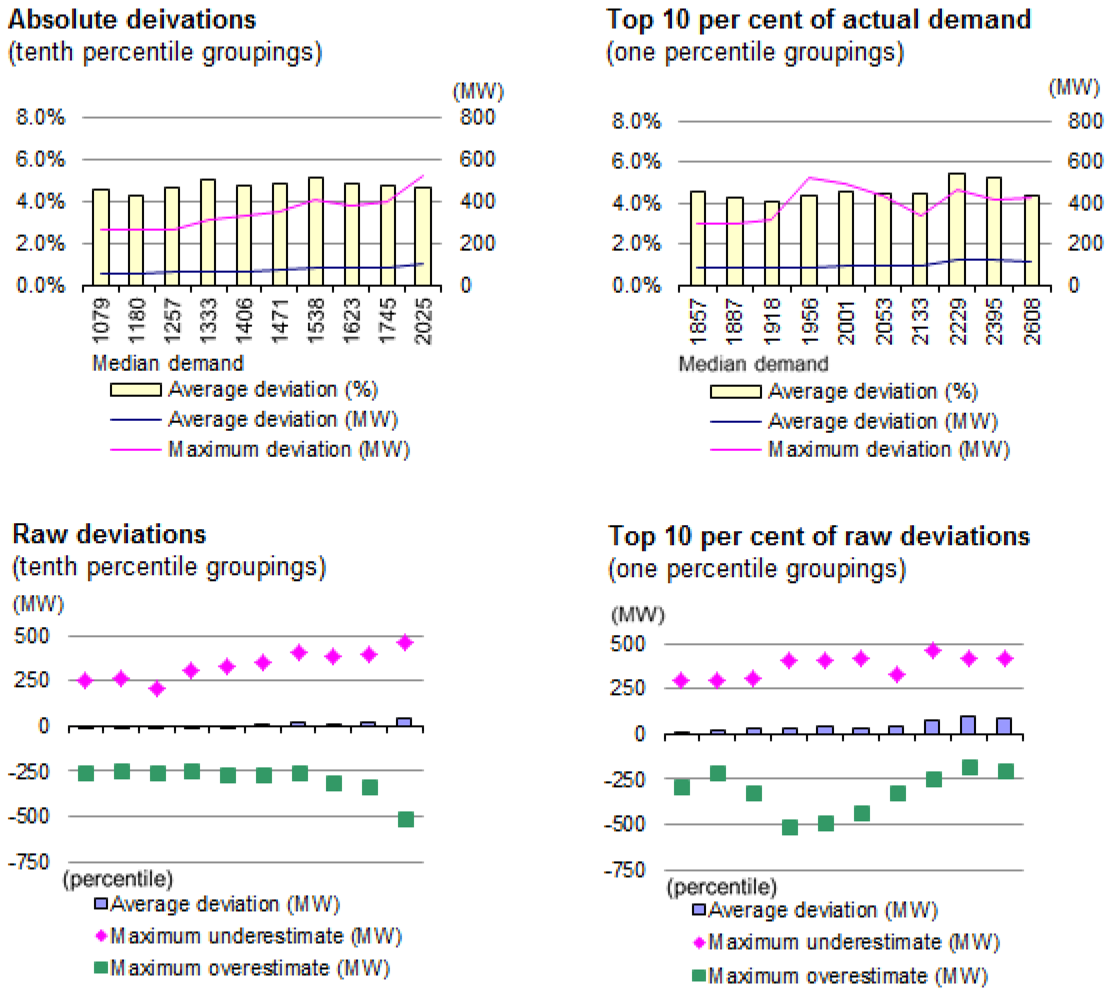
The Panel has also considered the accuracy of the pre-dispatch demand forecasts (12 hours ahead basis). Figure 5.2 below shows accuracy further improved in 2012-13 for Tasmania. Accuracy marginally declined for the other regions.

Figure 5.2 Accuracy of pre-dispatch demand forecasts (12 hours ahead) (absolute percentage deviation - actual demand compared to 12 hours ahead forecast)



As the accuracy of demand forecasts play a crucial role in the pre-dispatch process, the Panel has also assessed the performance of the four hour ahead demand forecasts for the summer period. The Panel has considered all regions, with South Australia shown in the figure below as an example. Other regions are outlined in further detail in section B.4.6.

Figure 5.3 South Australia demand forecast deviation four hours ahead



Source: AER

The graphs show the deviation (actual demand minus forecast demand) for the four hour ahead forecasts (a detailed description is contained in appendix B). The outcomes above for South Australia show that the maximum deviation between forecast and actual demand in 2012-13 ranged from 470 MW lower than forecast to 520 MW higher than forecast. On average, the deviations were between 4.1 and 5.4 per cent for the top tenth percentile of demand.

The magnitude and pattern of deviation differs for each NEM region. Generally speaking, the Panel notes that the four hour ahead demand forecasts:

- appear to be biased towards under estimation of high demand periods;
- appear to have maximum under estimates that could be difficult to cover on notice shorter than four hours; and
- the average deviation for all regions (at the top tenth percentile) is below 4 per cent, with the exception of South Australia.

There is a difference in average deviation in South Australia compared to the other regions. AEMO is actively investigating and improving its forecasting processes. The Panel will liaise with AEMO to better understand the underlying causes and consider any updated information and analysis in its final report.

5.2.9 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 Commonwealth Department of Resources, Energy and Tourism involving a '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 the NEM forecasting process. The Panel recognises that wind generation capacity in the NEM is expected to continue to grow under Australia's Large-scale 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 5.4.

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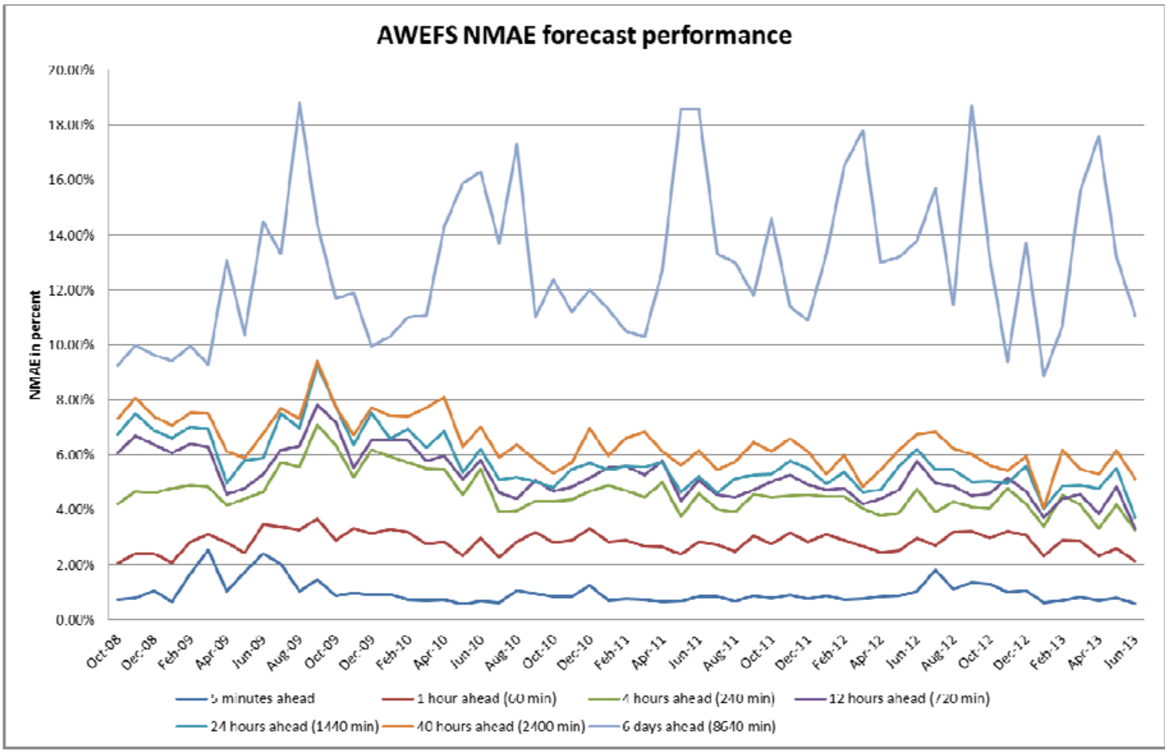
56 Further background on the AWEFS is available at: www.aemo.com.au/Electricity/Market-Operations/Dispatch/AWEFS.

Figure 5.4 Accuracy of AWEFS (normalised mean absolute error)



Source: AEMO

The Panel notes that:

- as could be expected, the accuracy of the forecasting improves as the forward looking timeframe shortens;
- the percentage error for the 6-day ahead forecast was the lowest during the summer months for 2012-13, which was a significant improvement from the 2011-12 where it had highest percentage of inaccuracy;
- the highest NMAE values correspond to situations when forecasting is difficult, i.e. periods with very high or very low wind speeds; and
- with the exception of the 6-day ahead forecast, the accuracy of the forecasting, particularly in the 12 to 40 hour bands have continued to improve since its introduction. The Panel will continue to review performance annually.

5.3 Reliability safety net

AEMO has the power to issue directions as a last resort measure, or to contract for the provision of reserves to maintain power system security and reliability. AEMO's powers of direction are set out in clause 4.8.9 of the rules. The terms "secure operating state", "satisfactory operating state" and "reliable operating state" are defined under the rules and set out in the glossary of this report.

AEMO may 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. Where a direction affects a whole region, intervention or 'what if' pricing would be required (where spot prices are determined as if the direction had not occurred).

As noted in section 3.1, the Panel notes that AEMO did not exercise the RERT mechanism in 2012-13.

The Panel also notes that AEMO did not issue any directions for reliability in 2012-13.

6 System security performance assessment

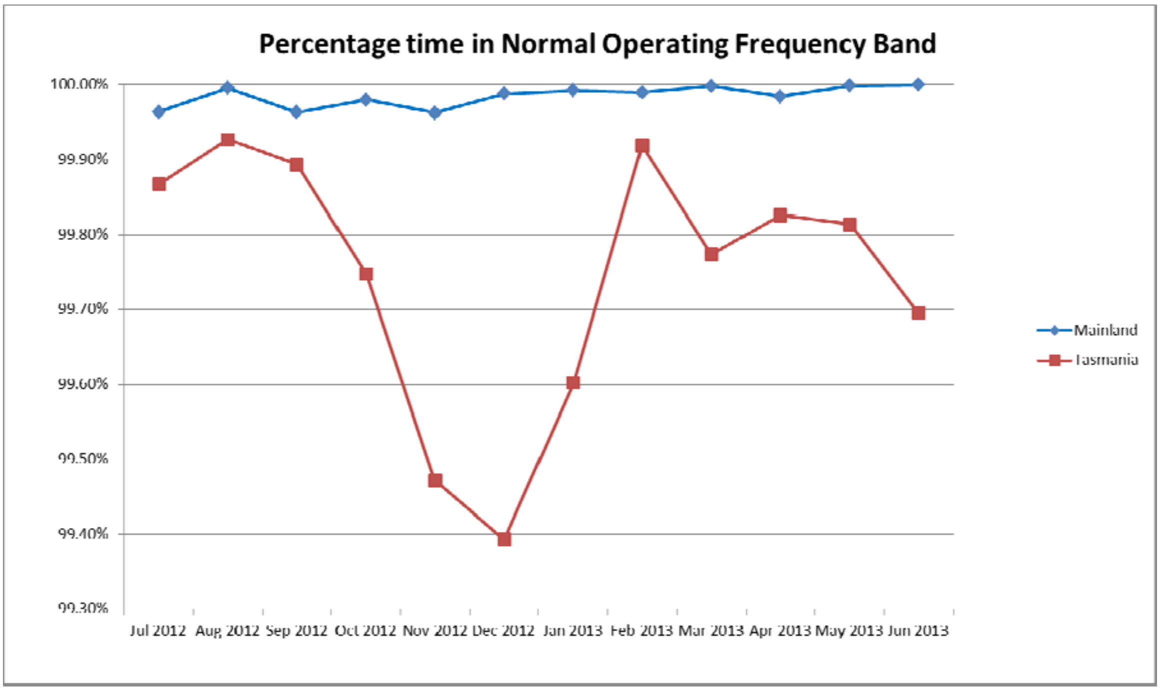
This chapter sets out the Panel's assessment of the performance of the system from a security perspective. The Panel has considered the performance with respect to the relevant technical standards. Additional background information is set out in appendix C.

6.1 Frequency

The control of power system frequency is a crucial element of managing power system security. The Panel has considered the number of times in the past financial year where events resulted in the frequency operating standards not being met. That is, the events where the frequency departed from the normal operating frequency band and did not return within the time prescribed in the frequency operating standards. The mainland and Tasmanian frequency operating standards are detailed in appendix C.

During 2012-13, both the mainland and Tasmania frequencies remained within the normal operating frequency band more than 99 per cent of the time. The percentage of time where frequency remained within the normal operating frequency band during 2012-13 is shown in Figure 6.1.

Figure 6.1 Percentage time frequency remained within normal operating frequency band



Source: AEMO

The amount of time the frequency remained within the normal operating frequency band is consistent with the frequency operating standards.

Mainland NEM

There were two frequency events on the mainland in the 2012-13 financial year that were non-compliant with the frequency operating standards. The Panel notes that this is four fewer than in 2011-12.

The Panel notes that the two frequency events were low frequency excursions, and for these events the frequency was outside the normal operating frequency band for more than 300 seconds. The two events were caused by:

- a 744 MW generating unit trip at Kogan Creek power station in Queensland on 26 September 2012, resulting in a frequency excursion that lasted 452 seconds (~7.5 minutes). This was classified as a generation event under the mainland frequency operating standard.[57] The event was assessed as non-compliant as the duration of the frequency excursion was not was not within the limit of 5 minutes under the frequency operating standards.

- six generating units operating below their dispatch targets on 2 July 2012, resulting in a frequency excursion that lasted 584 seconds (~9.7 minutes). This was classified as a no contingency or load event under the mainland frequency operating standard.[58] The event was assessed as non-compliant as the duration of the frequency excursion was not within the limit of 5 minutes under the frequency operating standards.

The Panel notes that the Kogan Creek power station in Queensland also tripped in 2011-12 relation to a low frequency incident. It previously tripped on 18 October 2011 for the financial year 2011-12. At that time, the frequency excursion lasted 438 seconds (~7.3 minutes).

On no occasion did a high frequency excursion of the NEM mainland not meet the requirements of the mainland frequency operating standards in 2012-13.

Tasmania

There were 13 events in Tasmania in the 2012-13 financial year that were non-compliant with the Tasmanian frequency operating standards. Of these events, 10 were low frequency excursions and three were high frequency excursions.

Only one of these events resulted in the frequency being outside the normal operating frequency band for more than 300 seconds. This event:

- occurred on 3 November 2012 for 1220 seconds (~20.3 minutes). The frequency reached as low as 49.70 Hz. AEMO advised that the incident occurred during a period of low Tasmanian demand when Basslink was not transmitting power, and the delivery of regulation frequency control ancillary services (FCAS) was

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57 Appendix C sets out the requirements under the mainland frequency operating standards. Refer to Table C.1.

58 Appendix C sets out the requirements under the mainland frequency operating standards. Refer to Table C.1.

not suitable to control the frequency within the normal operating frequency band;

- was classified as a no contingency or load event under the Tasmanian frequency operating standard. The event was assessed as non-compliant as the duration and magnitude of the frequency excursion was not within the limit of the frequency operating standards.

The number of events in 2012-13 is materially lower than in the previous year, where there were 50 events in 2011-12. As outlined in the 2012 AMPR, the events for 2011-12 were thought to have related to Basslink transitioning through the 'no-go zone' for market-related reasons.[59] Since that time, AEMO has undertaken further investigation into these events and advised that:

- a number of events in January 2012 and February 2012 occurred at times where Basslink was importing power to Tasmania at its maximum limit and was therefore unable to assist in controlling low frequency excursions; and

- a number of events related to instances where Basslink did not follow its dispatch targets, causing frequency disturbances.[60]

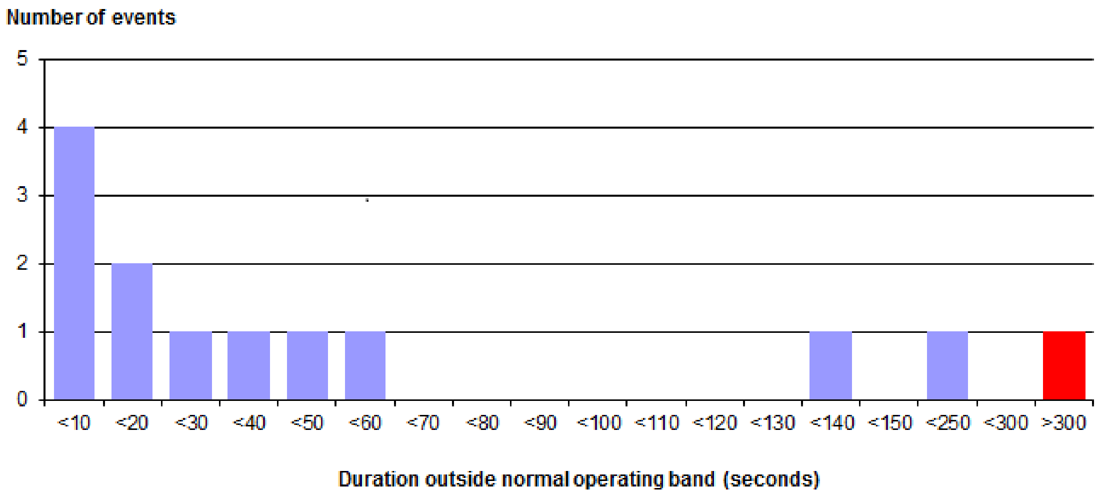
The Panel notes that these events illustrate the challenge of controlling the Tasmanian frequency when Basslink is not available for frequency control. AEMO has since developed tools to better monitor the delivery of regulation FCAS, which will assist in the investigation of similar events that occur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

The duration of the non-compliant frequency events in Tasmania in 2012-13 are shown in Figure 6.2.

59 Basslink is to be unable to operate with a flow between -50 MW and +50 MW. It can only operate in one direction at a time and it takes time to switch the flow of energy (direction). Therefore, when changing the flow of energy Basslink must be taken from the minimum level (50MW) to 0MW. This takes a couple of minutes before the changed direction of energy flow can operate at 50MW.

60 Non-compliance with dispatch target incidents are recorded and monitored by AEMO operational staff when they occur. Further investigations are then conducted by AEMO where appropriate and necessary. The Panel will further liaise with AEMO about whether there is any additional information on these incidents that should be discussed in the final report.

Figure 6.2 Frequency excursion duration - Tasmania



Source: AER, AEMO

6.2 Voltage limits

In addition to maintaining the frequency of the power system, the voltage of the power system is also important for the security of the power system. AEMO and transmission network service providers (TNSPs) agree on the technical envelope within which the transmission network voltage is maintained. AEMO's systems monitor the voltage performance levels against the limits advised by TNSPs. The Panel notes that an adequate supply of suitably located responsive reactive power to reduce voltage instability is vital in maintaining power system stability.

The Panel understands that AEMO was generally able to maintain voltages within advised limits throughout the 2012-13 financial year.

6.3 Interconnector performance

The Panel is not aware of any incidents in the 2012-13 financial year where an interconnector was above its secure line rating limit.

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.

Potential overloads are reported through AEMO's online management system.

6.4 System stability

In addition to managing frequency and voltage levels to maintain system security, AEMO has a number of real time monitoring tools which help it meet its security obligations including power flow and contingency analysis software. This includes monitoring equipment that detects oscillatory disturbances that could lead to a security threat and the online Dynamic Security Assessment (DSA) tool. The DSA uses real time data from AEMO's energy management system to simulate the behaviour of the power system for a variety of critical network, load and generator faults.

The Panel notes that AEMO uses these real-time monitoring tools to actively manage and operate the power system. These tools provide AEMO with the ability to respond to issues as they arise and provide critical information on the performance of the system against technical limits.

6.5 Other factors

The Panel notes that various other factors, such as the correct operation of individual pieces of equipment and the correct performance of protection and control systems, affect the security performance of the system. These are considered further in section C.2. The Panel notes that AEMO investigates and reports on power system events as further discussed in chapter 4.

6.6 Power system directions by AEMO

AEMO is able to issue power system directions to registered participants to direct that they take certain action to maintain the power system in a secure operating state.

The Panel notes that AEMO issued two power system directions in the 2012-13 financial year. In particular, both were in Tasmania on 11 April 2013, where AEMO issued a direction to Basslink to turn off the Basslink frequency controller after advice that Basslink could not transfer FCAS due to an inter-site communications failure. The direction was cancelled that day after communications were restored. The direction was necessary to maintain power system security. [61]

Table 6.1 sets out the directions issued in the previous financial years.

Table 6.1 Number of security directions issued by AEMO

Financial year	QLD	NSW	VIC	SA	TAS	Total
2012-13	0	0	0	0	2	2
2011-12	0	0	0	0	0	0
2010-11	0	0	0	0	0	0

61 Available at: aemo.com.au/Electricity/Resources/Reports-and-Documents/Reports-on-Directions/NEM-Event-Direction-to-Basslink-11-April-2013.

Financial year	QLD	NSW	VIC	SA	TAS	Total
2009-10	4	1	0	1	1	7
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

Source: AER

7 Safety assessment

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 considerations primarily relate to the bulk transmission system of the NEM. The Panel's assessment of the safety of the NEM is therefore limited to considerations of links to the security of the power system and maintaining the system within relevant standards and technical limits. For the 2012-13 financial year, 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 AEMO only issued two power system security directions in 2012-13 (see section 6.6), the Panel notes that there were no safety issues related to these directions from AEMO.

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[62].

7.1 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;

62 Unless stated otherwise, the information below has been drawn directly from the websites of the relevant jurisdictional entities.

- 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.[63]

7.2 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.

7.3 Queensland

In Queensland, the Electrical Safety Office is 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

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63 ACT Planning and Land Authority Annual Report 2010-11, p.7, available at: www.actpla.act.gov.au/__data/assets/pdf_file/0015/25431/1131-ACTPLA_-Annual_report-2011-TaggedWeb.pdf.

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.

7.4 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.[64]

64 Available at: www.sa.gov.au/government/entity/959/About+us+-+Office+of+the+Technical+Regulator/What+we+do/Annual+reports#Electricity.

7.5 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.

7.6 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.

A 2012-13 weather summary

The weather can have 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 produce at rated production levels. In addition, hot weather and bushfires can also adversely affect transmission and distribution network capability.

Long periods of drought can 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, such as lightning strikes to transmission lines or trees falling on distribution lines.

Below is a summary of the climate for the 2012-13 financial year by each season:[65]

- **Winter 2012**
  - Temperature (maximum): Most of Australia experienced close to normal maximum temperatures at 0.42 °C above normal, except for Western Australia where large parts were in the top 10 per cent of records with an anomaly of +0.95 °C (its eighth warmest winter daytime temperatures on record).
  - Temperature (minimum): For much of the country, it was below normal night time temperatures due to below average rainfall, with the third lowest mean winter minimum temperature on record at an anomaly of -0.91 °C. However, Tasmania was the only state with above normal winter minimum temperatures.
  - Rainfall: Most of the country in the western half of Australian and parts of the southeast had below average rainfall, such as Western Australia with its seventh driest winter to fall in the top 10 recorded in history. The remaining parts of the country were average to above average, including broad areas of Queensland, parts of the Northern Territory, the far northeast of SA, most of southern Victoria, areas around Adelaide in South Australia, and the southern coast of Western Australia.
- **Spring 2012**:
  - Temperature (maximum): Spring was warmer than normal across Australia, with above normal daytime temperatures at 1.73 °C above normal - the second warmest spring maximum temperature recorded for 65

65 Information in this appendix has been obtained from the Australian Bureau of Meteorology, Australian seasonal climate summary archive, www.bom.gov.au/climate/current/season/aus/archive.

per cent of the country in the top 10 per cent of records. The Northern Territory and South Australia had the warmest spring maximum temperatures on record, Western Australia and Tasmania experienced their second warmest spring, New South Wales its fifth, and Queensland its sixth.

- Temperature (minimum): Minimum temperatures were also warmer than normal across Australia at 0.40 °C above normal, including: Western Australia with its third warmest night time temperatures on record at an anomaly of +1.00 °C; and exceptional heat was experienced across central and southeastern Australia with a number of places in Victoria and South Australia breaking their existing State records. On the other hand, Queensland experienced its coolest overnight temperatures in 18 years.

- Rainfall: Rainfall was mostly below average across Australia, except for Western Australia. South Australia and Victoria had the top ten of historical records, with South having its third-driest spring on record, and Victoria its tenth driest. Western Australia experienced above-average spring rainfall and eastern Australia, South Australia and parts of the Northern Territory had below normal rainfall. However, most of Western Australia and isolated parts of the Northern Territory and Queensland recorded above normal rainfall.

- **Summer 2012-13**:

  - Temperature (maximum): Summer had the warmest maximum and mean temperatures on record for Australia, with the mainland recording in the top 10 records (except for part of the east coast and Western Australia recording near average due to above average rainfall) at 1.44°C above average. Notably, a large area of the inland of the eastern States and smaller parts of the far north, centre, and southern Western Australia recorded maxima 2 to 3 °C above average. Australia experienced warmer than average temperatures since Spring 2012 combined with a number of heatwaves recorded over the period. This has led to daytime records for maximum temperature throughout Spring 2012 and Summer 2012-2013. January 2013 was the hottest month recorded ever in Australia, as a result of the exceptionally long and widespread heatwave in late December 2012 and the first half of January 2013. The extent of the heat across Australia has been unprecedented, given that extreme heat is usually confined to a smaller geographic area for a shorter length of time rather than has been the case for this summer.

  - Temperature (minimum): Minimum temperatures were the sixth warmest in the last 103 years at 0.79 °C above average across most of Australia, from +0.48 °C in Tasmania to +1.31 °C in New South Wales, with Western Australia in the top 5 records.

— Rainfall: Most of Australia experienced rainfall below average. However, part of the east coast and most of Western Australia recorded above average rainfall. The remainder of Western Australia and the central Northern Territory recorded near average rainfall. Ex-cyclone Oswald also largely contributed to high totals for the January rainfall along the eastern coast.

- **Autumn 2013**:

    — Temperature (maximum): Autumn had average maximum temperatures across Australia, which was the eighth warmest record at an anomaly of +1.03 °C. Above average maximum temperatures in the highest 10 % of records were experienced across most of the country with Tasmania, most of Victoria, southwestern New South Wales, southeastern Western Australia, South Australia, western Queensland and southern parts of the Northern Territory. Above average maximum temperatures were the highest on record for parts of the southern coast of both the mainland and Tasmania. Heatwaves were also present in this season, particularly early March for southeast South Australia, Tasmania and southern Victoria.

    — Temperature (minimum): Minimum temperatures were 0.89 °C above average for most of Australia (the tenth warmest autumn in 104 years of record), but near average for most of New South Wales and southeastern half of Queensland.

    — Rainfall: Rainfalls were below average for southeastern Australia and northwestern Queensland. On the other hand, most of the remainder of Australia for the Top End and most of Western Australia and central Australia received above average falls.

B Reliability performance - detailed background information

This appendix provides detailed background information on reliability management and measuring power system reliability performance. For a discussion of the Panel's assessment of performance in the 2012-13 financial year, please refer to chapter 5.

B.1 Reliability management

The overall arrangement for ensuring the Reliability Standard is met, including the safety mechanism arrangements if the market mechanisms fail, is illustrated in the reliability model in Figure B.1. The operation of each element of the model is explained and analysed in detail in this section.

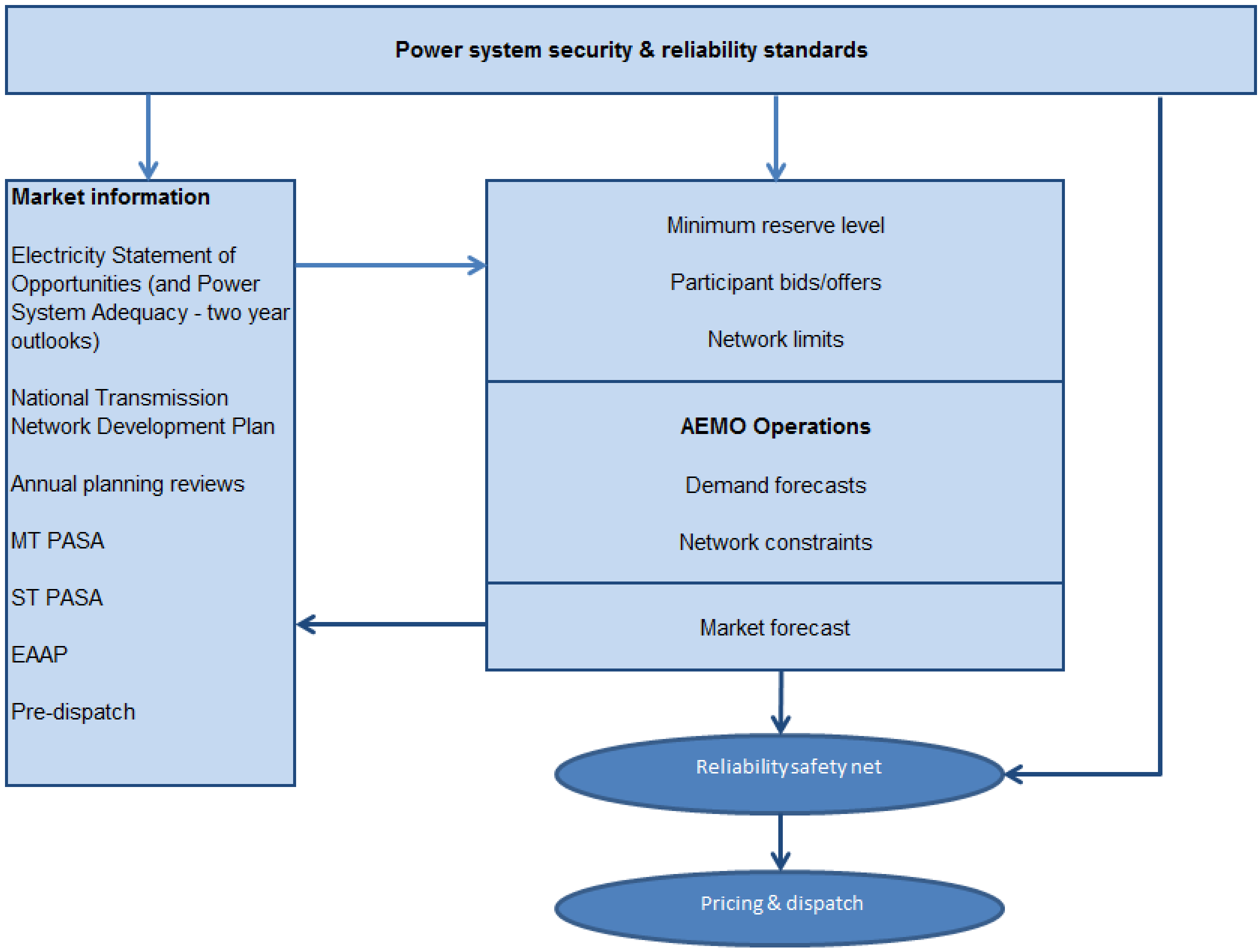
The national market aligns incentives for decisions by market participants about plant operation with overall reliability outcomes. There is an extensive suite of information published by AEMO to support those decisions.

Market information provides data and projections with increasing levels of detail closer to the time of dispatch. The annual ESOO provides information for ten years ahead. The shortest time period, called the pre-dispatch schedule, provides five minute projections of dispatch, consumer demand and market price.

Market information is derived from technical data and advice of the commercial intentions for plant operation provided to AEMO by participants. AEMO develops forecasts of demand and aggregates participant information to produce overall forecasts for publication. Participants are encouraged to adjust their intentions and are obliged to provide revised data to AEMO. The final data is used by AEMO to operate the power system and facilitate the operation of the market.

In addition, the reliability safety net allows AEMO to monitor the level of reserve in each region and may intervene if these reserves fall below the margins necessary to meet the Reliability Standard determined by the Panel.

Figure B.1 Reliability Model



B.2 Reliability Standard

The Reliability Standard of 0.002 per cent USE is designed to measure whether there is sufficient available capacity to meet demand. It is the basis for AEMO's calculation of minimum reserve levels (MRLs) for market information purposes, and if necessary intervention through reserve contracting under the RERT, or its directions powers. Reliability within a market region depends on the reserve within that region and other regions and on the capability of interconnectors.

Reliability of the energy market is measured by comparing the component of any energy not supplied to consumers as a result of insufficient generation or bulk transmission capability against the Reliability Standard. This excludes energy not supplied due to management of security and performance of local transmission or distribution networks, and is therefore only part of the overall measure of continuity of supply to consumers. However, from a consumer point of view, reliability is also impacted by the performance of the distribution and local transmission networks. Appendix D provides a summary of the performance of these networks in order to provide context for the Reliability Standard.

Reliability is driven by the adequacy of investment and level of generating and transmission plant presented to AEMO for dispatch in the market. The market design relies on commercial signals in the market price to create incentives for market participants to bring capacity online. The Reliability Standard sets the threshold at which AEMO may intervene in the operation of the market to ensure sufficient available capacity. Security, however, is the product of the technical performance characteristics of plant and equipment connected to the power system and how it is operated by AEMO and network service providers.

B.3 Minimum reserve levels

The Reliability Standard of 0.002 per cent USE is a statistical risk of not meeting consumer demand over time. To meet the Standard operationally, AEMO calculates MRLs for each region and combination of regions. 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.

MRLs provide AEMO with an operational trigger for intervention to maintain supply reliability. AEMO may intervene using reserve contracting or its power for directions if the reserves delivered by the market are below the designated MRL. The medium-term and short-term projected assessment of system adequacy (PASA), pre-dispatch schedule and market notices (see section B.4) alert the market to the potentiality of reserve levels being below the MRL threshold. This information and the responses by participants are central aspects of the management of reliability in the NEM.

The methodology used by AEMO to determine the MRLs is probabilistic. The calculation process first requires determining a minimum level of generation capacity that will deliver the Reliability Standard in all regions (i.e. expected USE = 0.002 per cent). The MRLs are derived by comparing the minimum generation requirement with a demand condition which has all regions at their maximum 10 per cent POE demand and taking into account reserves available across interconnectors.

In 2010 AEMO identified some changes to the methodology used to determine the MRLs. The recalculated MRLs use a historic level of demand diversity across regions, rather than an artificially low level of demand diversity. In addition, AEMO calculated the relationships that relate to reserve sharing between regions.

B.4 Reserve projections and demand forecasts

AEMO provides market information in a number of formats and timeframes, ranging from the annual ESOO which contains projected information for the next ten years, to the detailed 5-minute and 30-minute price and demand pre-dispatch schedule. Market information also includes Annual Planning Reviews, the NTNDP, the PSA - two year outlook, medium-term PASA, short-term PASA and market notices. Each is described and analysed below.

AEMO's forecasts of demand are crucial to all processes and can contribute to efficient market outcomes. Accurate near real-time forecasting is in part dependent on the quality of weather forecasts, and participant demand management activities. The accuracy of longer term forecasting, such as presented in the NEFR, is reliant on the quality of a range of modelling and scenario inputs, including economic conditions, population growth, electricity prices, penetration of localised supply sources (such as rooftop PV), participant load expectations and government policy settings (such as energy efficiency standards).

B.4.1 Market information

AEMO publishes a demand forecast report, the National Electricity Forecast Report (NEFR). In the past, AEMO has published demand forecasts via a series of AEMO planning publications, namely the Electricity Statement of Opportunities (ESOO), the Victorian Annual Planning Report (VAPR), and the South Australian Supply and Demand Outlook (SASDO) – now known as the South Australian Electricity Report (SAER). However, since 2012, the NEFR has been the key AEMO publication presenting electricity demand forecasts for the NEM.

Each year, AEMO publishes an ESOO that combines generation availability, network capability, and AEMO's latest electricity demand forecasts, to assess supply adequacy over the next 10 years.

While summarising the investment environment for each NEM region, including the supply-demand outlook and current generation investment interest, the ESOO highlights generation and demand-side investment opportunities from a system reliability perspective.

These reports are complemented by Annual Planning Reports that are prepared by each TNSP. The Annual Planning Reports focus on networks and include forecasts of transfer capacities, potential constraints and possible intra-regional augmentations.

In addition, AEMO publishes the PSA on an annual basis, which assesses the electricity supply outlook over the next two years. The PSA is not a rule requirement but has been published on an annual basis by AEMO since 2010. The PSA examines specific scenarios and projections of system outcomes. The 2013 PSA examined the expected scenario and its power system impacts.

The expected scenario represents power system outcomes AEMO considers the most likely in the next two years.[66]

In December 2010, AEMO published its inaugural National Transmission Network Development Plan (NTNDP), which is an independent strategic plan for the NEM transmission network. AEMO revised the 25-year plan in 2012 in line with updated conditions, particularly as described in the 2012 NEFR. In preparing the plan, AEMO explores a wide range of scenarios to determine the impact of certain drivers on the

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66 AEMO, Power System Adequacy, 13 Aug 2013, p. iv.

transmission network - the most prominent drivers being demand growth, carbon price and renewable energy policies. In developing the NTNDP each year, AEMO undertakes extensive consultation with stakeholders to consider the scope and purpose of the report and to seek feedback on proposed methodologies.

These documents provide technical and market data, in addition to useful information about market opportunities, for both existing registered and intending market participants. The information includes:

- forecasts of energy use, peak demands, generator capabilities and other means of meeting electrical energy requirements, and ancillary service requirements necessary for the secure operation of the power system;
- forecasts of inter and intra-regional transmission network capabilities and a summary of network augmentation projects that will affect these capabilities (the inter-regional transfer capabilities reflect the network's ability to exchange energy between regions within the NEM);
- AEMO's assessment of the adequacy of supply, referred to as the supply/demand balance; and
- a brief summary of significant initiatives and projects expected to influence market development over the coming years.

B.4.2 Energy Adequacy Assessment Projection (EAAP)

The EAAP is a quarterly information mechanism which provides the market with projections of the impact of generation input constraints on energy availability.[67]

Both the AEMC and 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.

B.4.3 Medium-term Projected Assessment of System Adequacy

Medium-term PASA is a comparison of the aggregate supply and demand balance at the time of anticipated daily peak demand, based on a 10 per cent POE for each day over the next two years.

Medium-term PASA information is provided:

- to assist participants in planning for maintenance, production planning and load management activities over the medium term; and

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67 The reporting requirement was introduced following a rule change request resulting from a rule proposal from the Panel. Available at: www.aemo.com.au/Electricity/Resources/Reports-and-Documents/EAAP.

- as the basis for any intervention decisions by AEMO, for example invoking the 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 rules. In addition, planned network outages are submitted to AEMO by network service providers under clause 3.7.2(e) of the rules.

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 limit equation information and plain English descriptions of the impact for all TNSPs.

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 the 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.

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

B.4.4 Short-term Projected Assessment of System Adequacy

Short-term PASA is an aggregate supply and demand balance comparison for each half-hour of the following seven days.[68]

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 rules. Transmission outage programs are supplied by TNSPs under clause 3.7.3(g) of the rules. 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) has been improved to have a closer alignment with pre-dispatch results. This has been achieved by using some outputs from the pre-dispatch run as inputs to PD PASA.

68 For further information see: www.aemo.com.au/data/stpasa.shtml.

B.4.5 Pre-dispatch

Pre-dispatch is an aggregate supply and demand balance comparison for each half-hour of the next day. It contains forecasts of market price and its sensitivity to changes in demand. Forecasts of individual scheduled generators and scheduled loads are presented to relevant participants, but not to other parties until the following day.

Demand forecasts are prepared by AEMO. Generation and demand-side availabilities are submitted by participants. The effects of transmission outages scheduled by TNSPs are incorporated. Forecasts of reserves in each region are also published. Scheduled outages should not breach the power system security and reliability standards.

Pre-dispatch information is used to assist participants in optimising very short-term physical and commercial planning for maintenance, production planning and load management activities in conjunction with the other information mechanisms available.

There is also a five minute pre-dispatch process designed to enhance information on demand and supply for the subsequent hour. This is particularly significant for the operation of fast start generators.

B.4.6 Demand forecast assessment

Figure B.2 to Figure B.6 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.

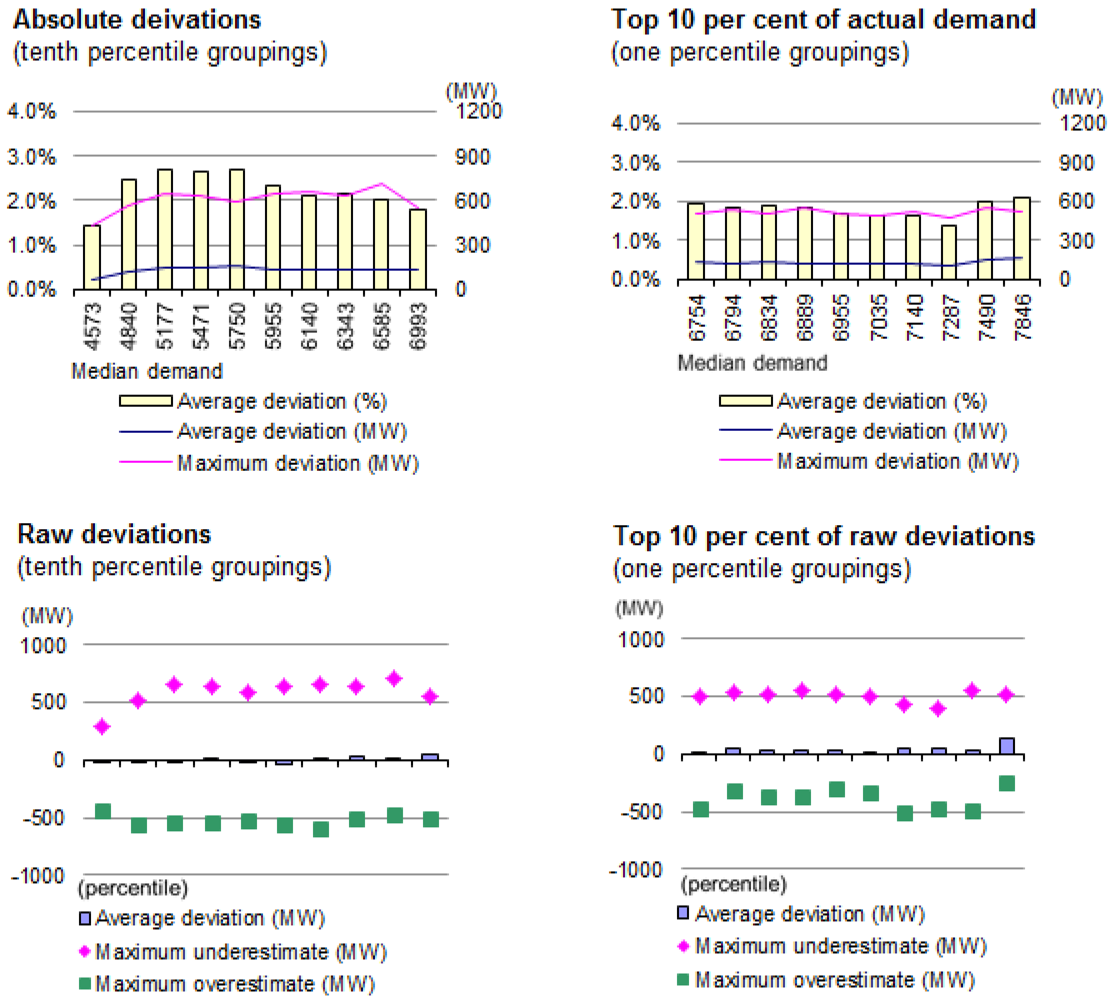
For each region there are four graphs. The first graph examines the absolute deviations for equal sized samples of demand. Demand is grouped into samples of tenth percentile, with the median values of each grouped sample shown on the horizontal axis of the graph. For each group of demand samples, the 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.

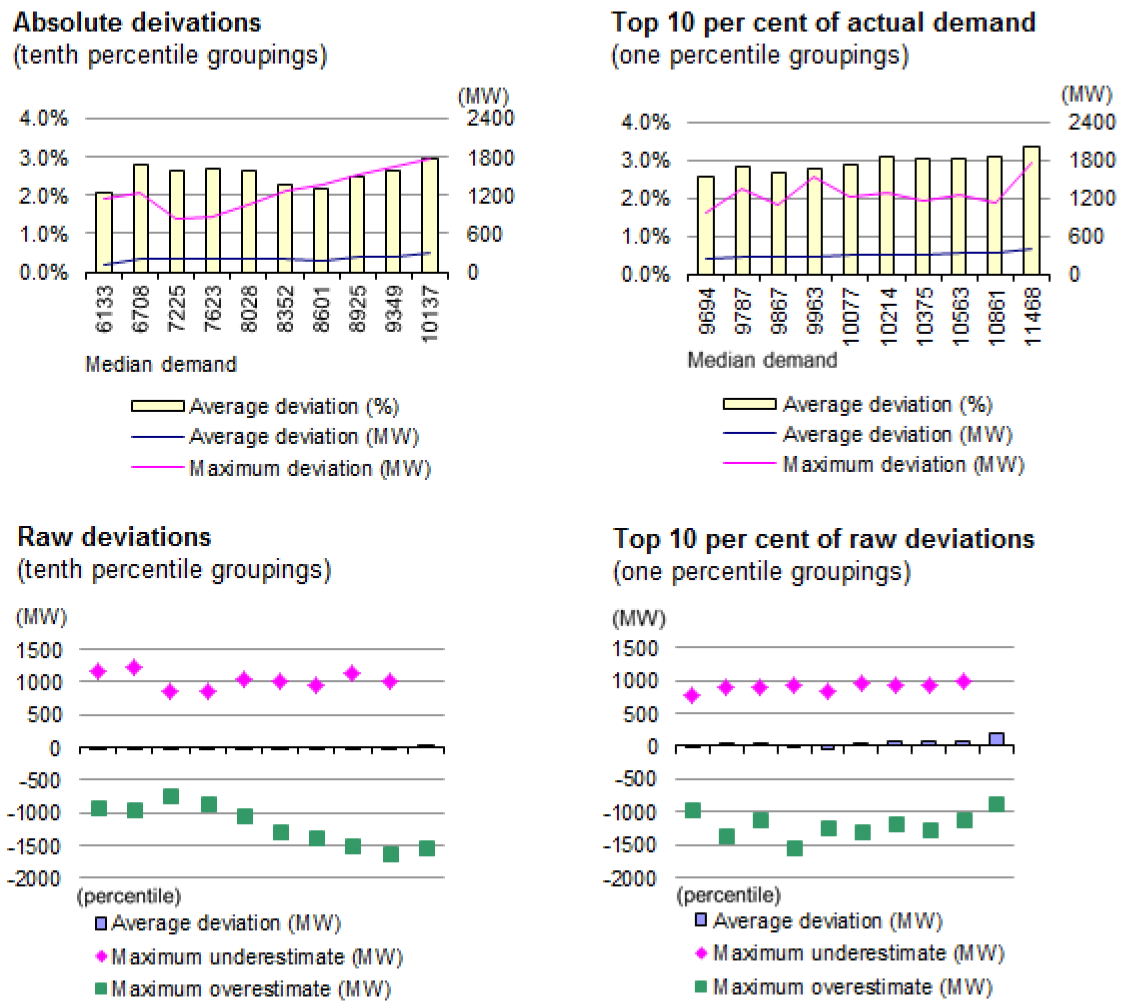
The graphs for each region show that forecasting is generally less reliable towards the top end of demand.

Figure B.2 Queensland demand forecast deviation four hours ahead



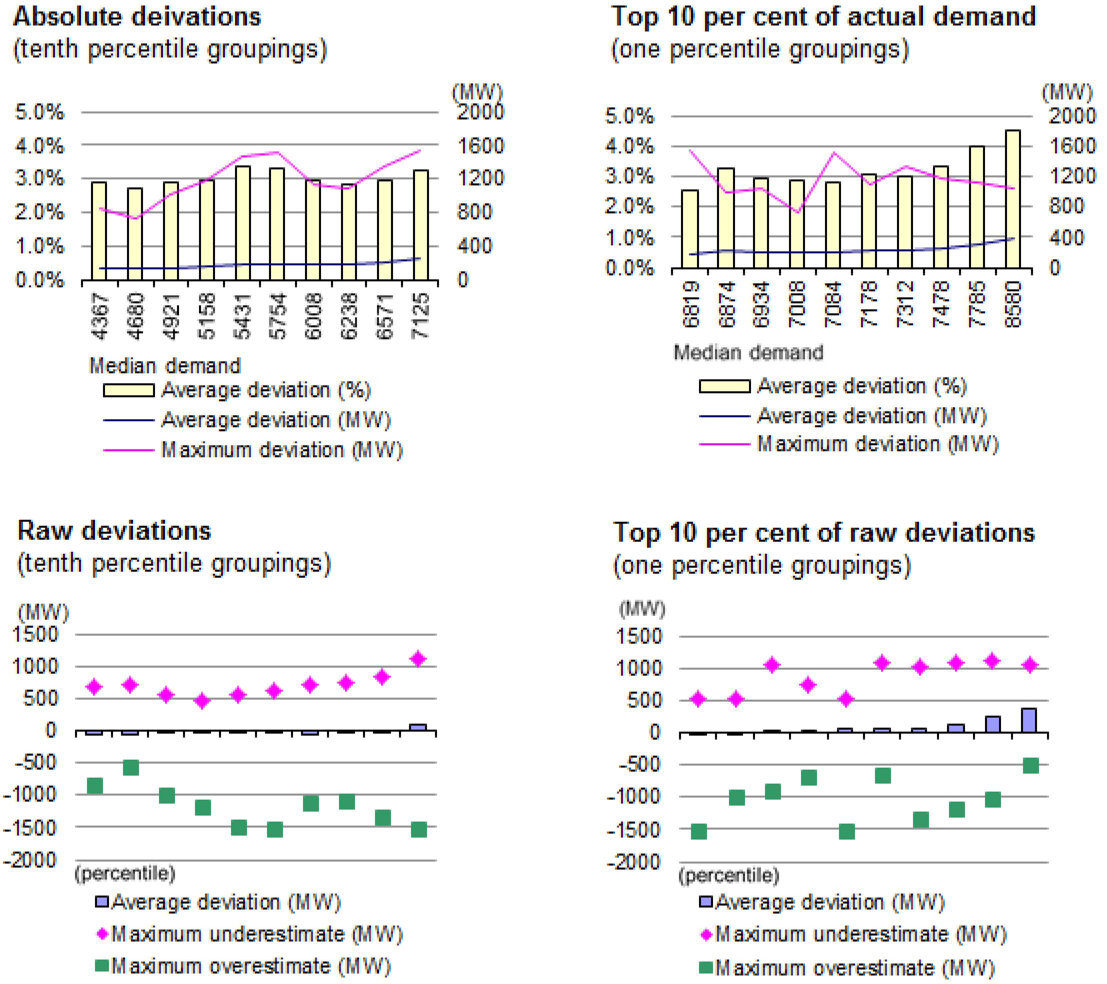
Source: AER

Figure B.3 NSW demand forecast deviation four hours ahead



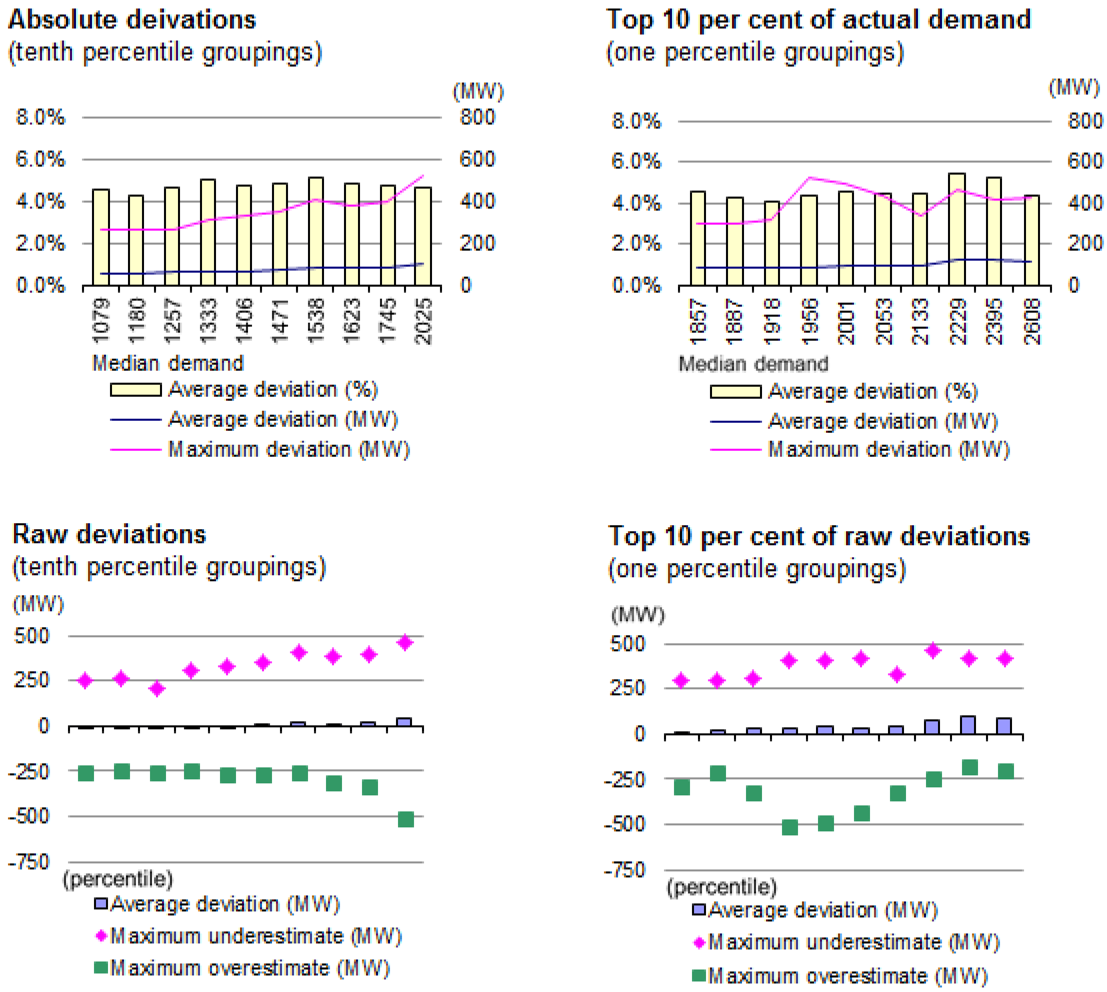
Source: AER

Figure B.4 Victorian demand forecast deviation four hours ahead



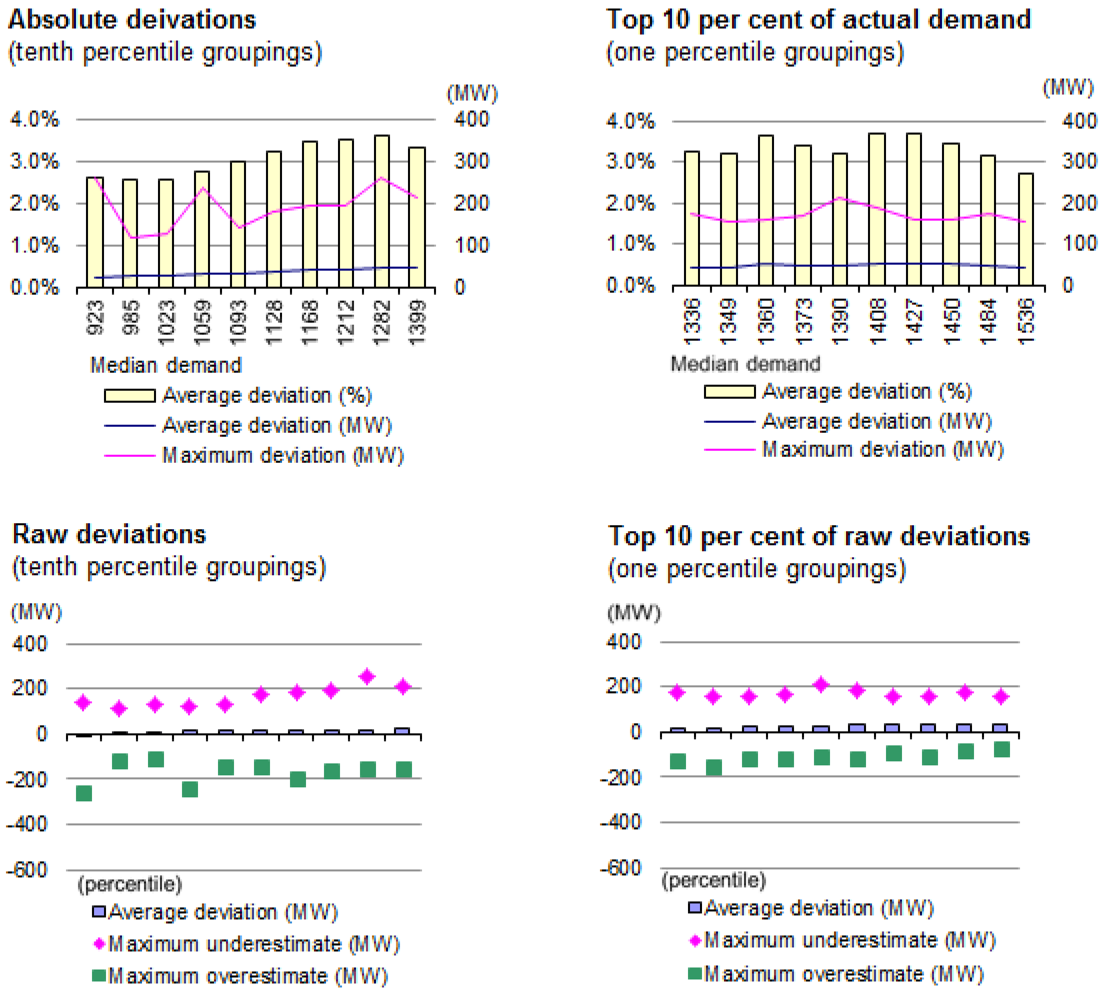
Source: AER

Figure B.5 South Australia demand forecast deviation four hours ahead



Source: AER

Figure B.6 Tasmanian demand forecast deviation four hours ahead



Source: AER

B.4.7 Market notices

Market notices are ad hoc notifications of events that impact on 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.

There were 3,654 market notices issued by AEMO during the 2012-13 financial year. These notices are summarised by type in Table B.1.

Table B.1 Market notices

Type of notice	Number of notices
Administered Price Cap	0

Type of notice	Number of notices
Constraints	2
General notice	167
Inter-regional transfer	347
Market intervention	4
Market systems	144
Manual priced dispatch Interval	0
NEM systems	0
Non-conformance	849
Power system events	77
Price adjustment	4
Prices subject to review	310
Prices unchanged	304
Process review	0
Reclassify contingency	785
Reserve notice	496
Settlements residue	165
Total	3,654

Source: AEMO

Overall, market notices are considered to be an effective method of communicating with market participants and the wider public. The quality of the notices, and/or their timeliness has not been considered by the Panel in its assessment.

C System security performance - detailed background information

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 2012-13 financial year, please refer to chapter 6.

C.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 unstable 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; knowledge of equipment performance; and
- design characteristics; and modelling of the dynamic behaviour of the power system.

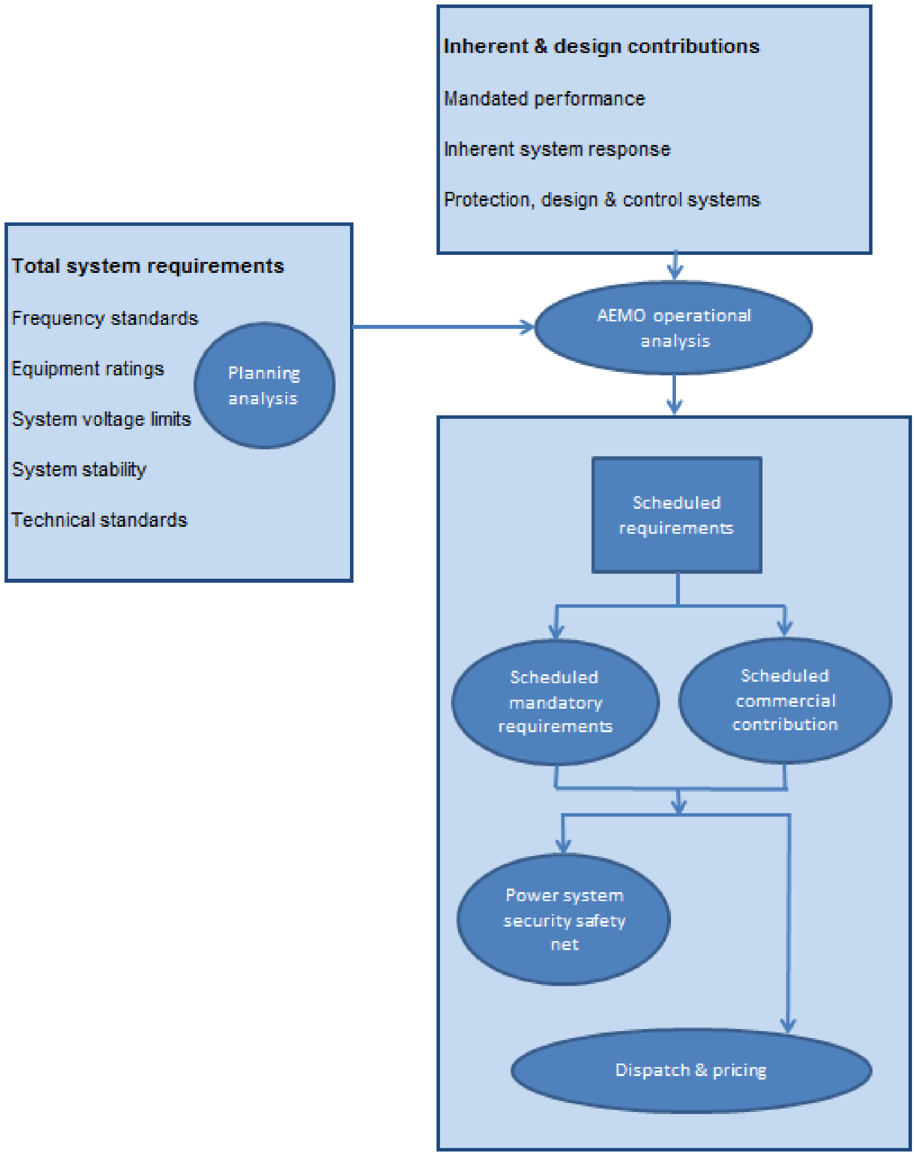
This allows AEMO to determine the safe operating limits of the power system and associated ancillary service requirements.

Some of the requirements are inherent in the frequency sensitivity of demand and generator plant, for example, the inertia of generator rotors. 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 C.1 illustrates the overall arrangements for security. The operation of each element is explained and analysed in this section.

Figure C.1 Security model



C.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.

C.2.1 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.

C.2.2 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.[69]

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.

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69 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 NEMMCO.

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;[70]
- Technical standards for wind and other generator connections rule change;[71]
- Resolution of existing generator performance standards rule change;[72]
- Performance standard compliance of generators rule change;[73]and
- Reliability Panel technical standards review.[74]

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.[75]

C.2.3 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

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70 AEMC 2006, Review of enforcement of and compliance with technical standards, Report, 1 September 2006, Sydney, available at: www.aemc.gov.au/Market-Reviews/Completed/Review-into-the-enforcement-of-and-compliance-with-technical-standards.html.

71 AEMC 2007, National Electricity Amendment (Technical Standards for Wind and other Generator Connections) Rule 2007, Rule Determination, 8 March 2007, Sydney, available at: www.aemc.gov.au/Electricity/Rule-changes/Completed/Technical-Standards-for-Wind-Generation-and-Other-Generator-Connections.html.

72 AEMC 2006, National Electricity Amendment (Resolution of existing generator performance standards) Rule 2006 No. 21, Rule Determination, 7 December 2006, Sydney, available at: www.aemc.gov.au/Electricity/Rule-changes/Completed/Resolution-of-existing-generator-performance-standards.html.

73 AEMC 2008, National Electricity Amendment (Performance Standard Compliance of Generators) Rule 2008 No. 10, 23 October 2008, Sydney, available at: www.aemc.gov.au/Electricity/Rule-changes/Completed/Performance-Standard-Compliance-of-Generators.html.

74 AEMC Reliability Panel, Reliability Panel Technical Standards Review, Final Report, 30 April 2009, Sydney, available at: www.aemc.gov.au/Market-Reviews/Completed/Reliability-Panel-Technical-Standards-Review.html.

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

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.

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 Table C.1.

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

<table>
<tr><th>Condition</th><th>Containment</th><th>Stabilisation</th><th>Recovery</th></tr>
<tr><td>Accumulated time error</td><td>5 seconds</td><td>n/a</td><td>n/a</td></tr>
<tr><td>No contingency event or load event</td><td>49.75 to 50.25 Hz[76]
49.85 to 50.15 Hz 99% of the time[77]</td><td colspan="2">49.85 to 50.15 Hz within 5 minutes</td></tr>
<tr><td>Generation event or load event</td><td>49.5 to 50.5 Hz</td><td colspan="2">49.85 to 50.15 Hz within 5 minutes</td></tr>
<tr><td>Network event</td><td>49 to 51 Hz</td><td>49.5 to 50.5 Hz within 1 minute</td><td>49.85 to 50.15 Hz within 5 minutes</td></tr>
<tr><td>Separation event</td><td>49 to 51 Hz</td><td>49.5 to 50.5 Hz within 2 minutes</td><td>49.85 to 50.15 Hz within 10 minutes</td></tr>
<tr><td>Multiple contingency event</td><td>47 to 52 Hz</td><td>49.5 to 50.5 Hz within 2 minutes</td><td>49.85 to 50.15 Hz within 10 minutes</td></tr>
</table>

The frequency operating standards that apply on the NEM mainland to any part of the power system that is islanded are shown in Table C.2.

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76 This is known as the normal operating frequency excursion band.

77 This is known as the normal operating frequency band.

Table C.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

On 16 April 2009, the Panel published its final determination for the review of the mainland frequency operating standards during periods of supply scarcity. In its final determination, the Panel amended the frequency operating standards for the NEM mainland that apply in an islanded region during periods of load restoration. Table C.3 outlines the minimum allowable frequency for a single generator contingency event during load restoration, following an islanding event. That is:

- 48.0 Hz for the Queensland and South Australia regions;
- 48.5 Hz for the New South Wales and Victoria regions; and
- in cases where an island incorporates more than one region, the critical frequency to be adopted is the maximum value of the critical frequencies for these regions.

Table C.3 NEM mainland frequency operating standards during supply scarcity

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 Refer to notes below for specific requirements to be satisfied prior to	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

Condition	Containment	Stabilisation	Recovery
use of this provision			
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

The mainland frequency operating standards during supply scarcity apply if:

1. a situation of supply scarcity is current;

2. in cases where an island incorporates more than one region, then the critical frequency to be adopted is the maximum value of the critical frequencies for these regions (e.g. for an island comprised of the regions of Victoria and South Australia the critical frequency would be 48.5 Hz);

3. the power system has undergone a contingency event, the frequency has reached the recovery frequency band and AEMO considers the power system is sufficiently secure to begin load restoration;

4. the estimated amount of load available for under-frequency load shedding within the power system or the island is more than the amount required to ensure that any subsequent frequency excursions would not go below the proposed Containment and Stabilisation bands as a result of a subsequent generation event, load event, network event or a separation event during load restoration; or

5. the amount of generation reserve available for frequency regulation is consistent with AEMO's current practice.

Tasmanian frequency operating standards

Although Tasmania is a part of the NEM, the Tasmanian power system is not synchronised with that of the NEM mainland. This is due to the Basslink interconnector between the two systems being an asynchronous direct current (DC) connection.

The frequency operating standards adopted in Tasmania allow for wider variations than the NEM mainland equivalents. This is due to the State's small size, predominately hydro-electric generation mix and the relatively large contingencies that can occur there. Importantly, Tasmanian consumers have not experienced any significant problems as a result of the wider range of frequencies.

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.[78] 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 Table C.4.

Table C.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	47.0 to 55.0 Hz	48.0 to 52.0 Hz within 2 minutes	49.85 to 50.15 Hz within 10 minutes

The size of the largest single generator event is limited to 144 MW, which can be implemented for any generating system with a capacity that is greater than 144 MW by the automatic tripping of load.[79]

The frequency operating standards that apply in Tasmania to any part of the power system that is islanded are outlined in Table C.5.

Table C.5 Amended Tasmanian 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	

78 AEMC 2008, Review of Frequency Operating Standards for Tasmania , Final Report, 18 December 2008, Sydney, Appendix A, available at: www.aemc.gov.au/Market-Reviews/Completed/Review-of-Frequency-Operating-Standards-for-Tasmania.html.

79 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.

Condition	Containment	Stabilisation	Recovery
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

The size of the largest single generator event is limited to 144 MW, which can be implemented for any generating system with a capacity that is greater than 144 MW by the automatic tripping of load.[80]

C.2.4 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 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

80 Ibid.

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.

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[81]

The mandated reliability obligations and standards are contained in Schedule 5.1 of the rules, the *Electricity Act 1994* (Qld), Powerlink's transmission authority, and in connection agreements with the distribution networks. In addition, the AER sets and administers reliability-based service standards targets which involve an annual financial incentive (bonus/penalty).

Consistent with the rules, its Transmission Authority requirements and connection agreements with Energex, Ergon Energy and Essential Energy, Powerlink plans future network augmentations so that the reliability and power quality standards of Schedule 5.1 of the rules can be met during the worst single credible fault or contingency (–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* (Qld), section 34(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, section 6.2©)); and

- 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 rules. Capacity is required to be provided such that forecast peak demand can be supplied with the most critical element out of service, i.e. –1. Following the EDSD report in 2004, Energex and Ergon are

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

required to plan their subtransmission networks (which interact with the Powerlink transmission network) to the –1 criterion.

D.1.2 New South Wales[82]

TransGrid is obliged to meet the requirements of Schedule 5.1 of the rules. In addition to meeting requirements imposed by the rules, connection agreements, environmental legislation and other statutory instruments, TransGrid must meet the statutory obligations contained in the *Electricity Supply (Safety and Management) Regulation 2008* (NSW). This includes lodging and then complying with a Network Management Plan with the Department of Trade and Investment (DT&I). TransGrid issued an updated Network Management Plan in February 2013. The plan is required to be reviewed every two years.

In accordance with a direction on behalf of the NSW Government issued by the NSW Director General of Industry and Investment on 23 December 2010, TransGrid's current Network Management Plan sets out TransGrid's network planning approach to ensure the Government's Transmission Design Reliability Standard for NSW – December 2010 are fully implemented. The legal authority for the Reliability Design Standard for NSW arises from the operation of *Electricity Supply (Safety and Network Management Plan) Regulation 2008* (NSW). Accordingly, the Transmission Design Reliability Standard for NSW – December 2010 represents legal obligations that must be met by TransGrid.

In general terms, this Standard requires TransGrid to plan and develop its transmission network on a "–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 are planned on a modified "–2" basis. Furthermore, this Standard interlinks TransGrid's planning obligations with the distribution licence obligations imposed on all distribution network service providers in NSW. The specific requirements are set out in TransGrid's Network Management Plan.[83]

D.1.3 Victoria[84]

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

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.

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82 This section has been completed with the assistance of TransGrid.

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

84 This section has been completed with the assistance of AEMO.

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, 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[85]

In addition to the reliability performance obligations set out in Schedule 5.1 of the rules, ElectraNet is also subject to the Electricity Transmission Code (ETC) administered by the Essential Services Commission of South Australia (ESCOSA)[86]. The ETC sets specific reliability standards which are determined economically and expressed on a deterministic basis (N, –1, –2 etc) for each transmission exit point. ElectraNet also participates in the Service Targets Performance Incentive Scheme 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.

ESCOSA concluded a review of the specific reliability standards under clause 2.2.2 of the ETC in 2011, supported by advice from AEMO, with subsequent minor amendments in 2013. The associated changes to the ETC took effect from 1 July 2013 to align with the AER's current revenue determination for ElectraNet.[87]

These changes confirmed the adoption of 10% probability of exceedance demand forecasts by ElectraNet, resulting in significant reliability investment deferral, together with minor changes to the reliability standards at a small number of connection points.

D.1.5 Tasmania[88]

In addition to the network performance requirements located in Schedule 5.1 of the rules, Transend is obliged to meet the requirements of its transmission licence,

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

86 ESCOSA, 2013, Electricity Transmission Code, available at: www.escosa.sa.gov.au/library/130701-ElectricityTransmissionCode-TC07_2.pdf.

87 ESCOSA, 2012, Review of the Reliability Standards Specified in Clause 2.2.2 of the Electricity Transmission Code, available at: www.escosa.sa.gov.au/projects/165/review-of-the-electricity-transmission-code.aspx.

88 This section has been completed with the assistance of Transend.

Electricity Supply Industry (Network Performance Requirements) Regulations 2007 (Tas), and the terms of its connection agreements. The connection agreements between Transend and its customers include obligations regarding the reliability of supply as required under chapter 5 of the rules.

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

The Tasmanian Department of Energy, Industry and Resources has undertaken a review of the requirements of the ESI (Network Performance Requirements) Regulations 2007, and at the time of writing, it is in the process of updating the Regulations. The changes to the Regulations are expected to account for changes in the regulatory environment since 2007 (most notably the introduction of the RIT-T); some clarification in wording and definitions; and, significantly, a process whereby Transend will be exempt from meeting the performance requirements of the Regulations, at a particular connection point, if all the transmission customers at that connection point agree lower performance requirements are acceptable. The performance requirements will remain unchanged.

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 Transend's 2009–2014 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, and in addition, the Steering Committee on National Regulatory Reporting Requirements (SCONRRR)[89] has adopted four indicators of distribution network reliability that are widely used in Australia and overseas.[90] 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).[91] While all jurisdictions report on SAIDI and SAIFI, DNSP performance data may not be directly

89 SCONRRR is a working group established by the Utility Regulators Forum.

90 Utility Regulators Forum, 2002, National regulatory reporting for electricity distribution retailing businesses, discussion paper.

91 See the Glossary for further information.

comparable between jurisdictions due to minor jurisdictional differences in approach, such as variation in inclusions and exclusions. 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.

D.2.1 Queensland[92]

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

The Queensland Electricity Industry Code (QEIC) requires that the Queensland Competition Authority (QCA) review the Minimum Service Standards (MSS) and Guaranteed Service Level (GSL) requirements to apply at the beginning of each regulatory period. Following a review in early 2009, the Queensland Competition Authority set the current MSS and GSL arrangements, which applied from 1 July 2010.[93]

The MSS require gradual improvements in performance each year, although the MSS targets applying to Energex were recently flat-lined at the 2011-12 levels for the remainder of the current regulatory control period.[94] Reflecting the differences in their networks, the MSS targets for Energex are more stringent than those for Ergon Energy.

The DNSPs report quarterly to the QCA on their performance relative to their MSS targets. The QCA also monitors their GSL performance.

Table D.1 provides a summary of the performance of the Queensland DNSPs including target and actual performance for each DNSP.

Table D.1 Performance of the Queensland DNSPs for 2012-13

DNSP	Feeder	SAIDI (minutes)		SAIFI (interruptions)	
		Target	Actual	Target	Actual
Energex	**CBD**	15	1.41	0.15	0.00
	urban	102	71.92	1.22	0.79
	short-rural	216	156.94	2.42	1.53

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

93 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, available at: www.qca.org.au/electricity/service-quality/RevMinServStandLev.php.

94 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, available at: www.business.qld.gov.au.

DNSP	Feeder	SAIDI (minutes)		SAIFI (interruptions)	
		Target	Actual	Target	Actual
Ergon	**urban**	147	135.12	1.94	1.49
	short-rural	412	341.44	3.85	2.98
	long-rural	932	951.53	7.20	6.25

Note: SAIDI and SAIFI performance data for 2012-13 were based on data provided by DNSPs under the QEIC. This data excludes certain interruptions as permitted under section 2.4.3 of the QEIC.

Table D.1 shows that Energex met its SAIDI and SAIFI targets for all feeder categories during 2012-13. Ergon Energy met five out of its six MSS targets (the exception being long-rural SAIDI).

Ergon Energy's performance in 2012-13 was consistent with its performance in 2011-12 where it also met five out of its six MSS targets. Notwithstanding this, Ergon Energy's underlying SAIDI performance during 2012-13 represents an improvement on its 2011-12 performance, for all feeder types, and is the 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 aftermaths 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 QEIC, 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[95]

The *Electricity Supply Act 1995* (NSW) requires NSW DNSPs to be licenced. Network performance standards for the NSW DNSPs have been set by the Minister for Energy through licence conditions. These licence conditions were set in 2007 and are published on the Independent Pricing and Regulatory Tribunal's (IPART's) website (conditions 14-19).[96]

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

- periodic self-exception reporting;

95 This section was prepared with the assistance of the NSW Department of Water and Energy.

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

- 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 DNSPs including an overall target for each DNSP and the actual performance by feeder classification. More detailed performance information is available from network performance reports available on each of the DNSPs websites.

The DNSPs are required by the *Electricity Supply (Safety and Network Management) Regulation 2008* (NSW) 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.

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

Table D.2 Performance of the New South Wales DNSPs for 2012-13

DNSP	Feeder	SAIDI (minutes)		SAIFI	
		Target	Actual	Target	Actual
Essential Energy (previously known as Country Energy)	Urban	125	73	1.8	0.86
	Short rural	300	237	3.0	1.94
	Long rural	700	450	4.5	2.94
	All	n/a	232.6	n/a	1.85
Ausgrid (previously known as EnergyAustralia)	CBD	45	38.5	0.3	0.12
	Urban	80	57	1.2	0.65
	Short rural	300	148	3.2	1.42
	Long rural	700	533	6.0	2.56
	All	n/a	82.4	n/a	0.73
Endeavour Energy (previously known as	Urban	80	65.0	1.2	0.90
	Short rural	300	200.5	2.80	2.20
	Long rural	n/a	730.7	n/a	13.50

DNSP	Feeder	SAIDI (minutes)		SAIFI	
		Target	Actual	Target	Actual
Integral Energy)	All	n/a	87.9	n/a	1.12
NSW	CBD	n/a	38.5	n/a	0.12
	Urban	n/a	60.9	n/a	0.75
	Short rural	n/a	210.5	n/a	1.87
	Long rural	n/a	452.2	n/a	2.96
	All	n/a	114.2	n/a	1.11

Note: the data in this table is based on the NSW Reliability Licence conditions criteria and methodology that differs from that used by, and reported to, the AER by the businesses.

Table D.2 shows that Ausgrid, Essential Energy and Endeavour Energy each met all SAIDI and SAIFI targets for all feeder categories during 2012-13.

D.2.3 Australian Capital Territory[97]

The *Utilities Act (2000)* ACT underpins all codes and performance and compliance requirements for the Australian Capital Territory DNSP.

The Independent Competition and Regulatory Commission (ICRC) sets the performance standards for the Australian Capital Territory DNSP. These standards are available in the Electricity Distribution Supply Standards Code and in the Consumer Protection Code, which also has minimum service standards.[98]

The DNSP 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 has stated in its 2011-12 compliance and performance report that it believes there is a strong case for collecting a smaller set of data from DNSP's in the future.

Table D.3 shows a summary of the performance of the Australian Capital Territory DNSP for 2012-13. More detailed performance information is available from network performance reports available on the ICRC website.

In comparison with the DNSP performance for the previous year, SAIDI performance whilst improved in the planned interruptions category, decreased in the unplanned

97 This section was completed with the assistance of ActewAGL.

98 ICRC, 2000, Electricity Distribution (Supply Standards) Code, available at: www.icrc.act.gov.au/wp-content/uploads/2013/02/electricitydistributionsupplystandardscodecw.pdf; ICRC, 2012, Consumer Protection Code, available at: www.legislation.act.gov.au/di/2012-149/current/pdf/2012-149.pdf.

category affecting the overall rating. As with the SAIDI ratings, SAIFI performance showed a similar trend.

Table D.3 Performance of the Australian Capital Territory DNSP 2012-13

Feeder		SAIDI (minutes)		SAIFI		CAIDI	
		Target	Actual	Target	Actual	Target	Actual
Urban	Overall	n/a	90.7	n/a	0.90	n/a	99.0
	Distribution network - planned	n/a	42.4	n/a	0.20	n/a	238.8
	Distribution network - unplanned	n/a	48.3	n/a	0.74	n/a	65.4
	Normalised distribution network - unplanned	n/a	28.2	n/a	0.59	n/a	48.8
Rural short	Overall	n/a	96.3	n/a	0.86	n/a	111.5
	Distribution network - planned	n/a	69.2	n/a	0.26	n/a	267.4
	Distribution network - unplanned	n/a	27.0	n/a	0.60	n/a	44.7
	Normalised distribution network - unplanned	n/a	25.9	n/a	0.60	n/a	43.3
Network	Overall	91.0	90.9	1.2	0.92	74.6	99.2
	Distribution network - planned	n/a	43.1	n/a	0.18	n/a	239.9
	Distribution network - unplanned	n/a	47.8	n/a	0.74	n/a	64.9
	Normalised distribution network - unplanned	n/a	28.7	n/a	0.59	n/a	48.3

D.2.4 Victoria[99]

The following information relates to the 2012 calendar year.

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

From 1 January 2009, responsibility for the compliance monitoring and enforcement of the DNSPs' distribution licence conditions was transferred from the Essential Services Commission of Victoria (ESC) to the AER.[100]

As part of its 2010 distribution determination,[101] the AER set revenue and service targets for the Victorian DNSPs for the 2011–15 regulatory period. The service targets are applied through the AER's service target performance incentive scheme (STPIS).[102] The STPIS provides incentives for DNSPs to maintain 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 DNSPs 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 DNSPs performance against the targets established at the time of the distribution determination.

The average Victorian customer experienced 178.4 total minutes-off-supply in 2012. This was an increase over the 174.4 minutes experienced in 2011. However, after normalising the data (that is, removing the impact of excluded events and outages occurring on major event days) the average Victorian customer experienced 97.2 minutes-off-supply in 2012 (down from 100.8 minutes in 2011).

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99 This section was completed with the assistance of the AER. Latest available information has been used.

100 The ESC is still responsible for regulatory framework rule making regarding DNSPs' licence conditions in Victoria.

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

102 Available at: www.aer.gov.au/sites/default/files/Amended%20STPIS%20-%20November%202009.pdf.

Three of the five Victorian DNSPs reduced their average normalised minutes-off-supply in 2012. SP AusNet achieved the greatest reduction with 13 per cent fewer normalised minutes-off-supply than in 2011.

Table D.4 shows the normalised 2012 reliability outcomes for the Victorian DNSPs.

Table D.4 Performance of the Victorian DNSPs for 2012 - impact of excluded events removed

		SAIDI (minutes)				SAIFI			
		Unplanned		Planned		Unplanned		Planned	
DNSP	Feeder	Target	Actual	Target	Actual	Target	Actual	Target	Actual
Jemena	Urban	68.498	49.749	n/a	18.911	1.127	0.927	n/a	0.067
	Short rural	153.150	57.489	n/a	55.157	2.588	0.863	n/a	0.235
CitiPower	CBD	11.27	9.239	n/a	7.488	0.186	0.109	n/a	0.029
	Urban	22.36	33.481	n/a	14.541	0.45	0.547	n/a	0.049
Powercor	Urban	82.467	80.720	n/a	18.843	1.263	0.967	n/a	0.080
	Short rural	114.807	107.803	n/a	46.619	1.565	1.186	n/a	0.205
	Long rural	233.759	220.599	n/a	81.069	2.54	2.138	n/a	0.409
SP AusNet	Urban	101.803	61.862	n/a	139.856	1.448	0.919	n/a	0.485
	Short rural	208.542	162.883	n/a	222.444	2.632	1.960	n/a	0.858
	Long rural	256.578	207.813	n/a	332.184	3.378	2.492	n/a	1.195
United Energy	Urban	55.085	70.831	n/a	34.906	0.899	1.007	n/a	0.103
	Short rural	99.151	173.259	n/a	24.505	1.742	2.112	n/a	0.082

Note: excluded events are “upstream events”, such as transmission outages and load shedding events. An event is also excluded where daily unplanned SAIDI for the DNSP’s distribution network exceeds the major event day boundary as set out in appendix D of the STPIS.

D.2.5 South Australia[103]

The AER is responsible for making price determinations and setting the SI scheme element of SA Power Networks' Service Standard Framework. The AER made the distribution determination for SA Power Networks for the 2010-2015 regulatory period in May 2010.

ESCOSA retains a central role in the regulatory process, insofar as it continues to be responsible for setting elements of the Service Standard Framework to apply to SA Power Networks for the 2010-2015 regulatory period: the average service standards and the GSL scheme. In that context, the Commission remains responsible for setting the South Australian jurisdictional service standards to apply to SA Power Networks.

The Commission has established annual standards for frequency and duration interruptions for seven geographic regions within SA Power Networks' distribution network; these are specified by the Commission as best endeavours annual targets in the Electricity Distribution Code. The code was amended following the introduction of the NECF in SA in February 2013. SA Power Networks' service standards, set out in Chapter 1 of the revised code, make up the main body of the code with which SA Power Networks must comply.

While there are no annual targets specified for the entire network (state-wide), there are implied state-wide targets based on the customer-weighted averages of the implied regional targets; for the 2010-2015 regulatory period, these are 179 minutes per annum for duration interruptions and 1.68 interruptions per annum for frequency interruptions. The Commission is currently reviewing the Service Standard Framework to apply the SA Power Networks for SA Power Networks to determine the financial requirements in its submission to the AER for the upcoming regulatory reset.

The Electricity Distribution Code also establishes Guaranteed Service Level (GSL) payments in relation to aspects concerning timeliness (e.g. timeliness of appointments; connections; and street light repair). It also requires SA Power Networks to make specified payments if the frequency of interruptions or the duration of any single interruption exceeds the thresholds set out in the Code. Payments in the current regulatory 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 the Commission 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, for at least 2 consecutive years.

103 This section was completed with the assistance of ESCOSA.

Reliability performance is reported to ESCOSA on a quarterly basis pursuant to 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 pursuant to the requirements set out in Guideline 4. ESCOSA publishes the results in annual compliance and performance reports available from its website.

The performance of the South Australian DNSP for the 2012-13 fiscal year is illustrated in Table D.5.

Table D.5 Performance of the South Australian DNSP for 2012-13

Region	SAIDI (minutes)		SAIFI	
	Target	Actual	Target	Actual
Adelaide Business Area	25	12.8	0.25	0.169
Major Metropolitan Areas	130	143.6	1.45	1.450
Central	260	299.6	1.8	1.580
Eastern Hills/Fleurieu Peninsular	295	316.8	2.8	2.280
Upper North and Eyre Peninsular	425	474.5	2.3	1.640
South East	295	411.3	2.5	2.560
Kangaroo Island	450	686.5	n/a	n/a
Total network	179	201.4	1.68	1.570

D.2.6 Tasmania[104]

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

On 1 January 2008, the Office of the Tasmanian 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.[105]

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

105 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:

- 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 GSL supported by the TEC and relevant guidelines.[106]

The following table shows the performance of the Tasmanian DNSPs against the network performance standards in the TEC that applied in 2012-13.

Table D.6 Performance of the Tasmanian DNSP 2012-13

Community category	SAIDI (minutes)		SAIFI	
	Tasmanian Electricity Code (12 month category limit)	Performance	Tasmanian Electricity Code (12 month category limit)	Performance
Critical infrastructure	30	36	0.20	0.28
High density commercial	60	79	1.00	0.28
Urban and regional centres	120	90	2.00	0.90
Higher density rural	480	270	4.00	2.37
Lower density rural	600	539	6.00	3.51

In 2012-13, three of the five community categories achieved both the frequency and duration standards set by the TEC. Both the critical infrastructure and high density commercial categories failed to meet the duration standards whilst the critical infrastructure category also failed to meet the frequency standard. Critical infrastructure was impacted by eight planned outages in the area and three operator errors.

The following table shows the performance indices for each individual community in the Tasmanian region.

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

Table D.7 Individual community performance indices (2012-13)

Community category	Average number of interruptions		Average minutes off supply		Total no. of communities below the limit for either frequency of duration	Total no. of communities below the limit in both frequency and duration
	Tasmanian Electricity Code Community limit	No. of non-complying communities	Tasmanian Electricity Code Community limit (mins)	No. of non-complying communities		
Critical infrastructure	0.2	1/1	30	1/1	1/1	1/1
High density commercial	2.0	0/8	120	3/8	3/8	0/8
Urban and regional centres	4.0	2/32	240	5/32	5/32	2/32
Higher density rural	6.0	2/33	600	4/33	4/33	3/33
Lower density rural	8.0	½7	720	6/27	6/27	½7
Total		6/101		19/101	19/101	7/101

A total of 20 communities were classified as poor performing due to exceeding the TEC limits of frequency or duration over the 12 month period ending 30 June 2013. These communities represent 12 per cent of the connected load in the distribution network.

There were 19 communities classified as poor performing based on the duration measure. Of the 19, six communities were classified as poor performing as they experienced prolonged outages due to a 'major event day' in the period. The remaining communities were classified as poor performing due to a combination of unplanned and planned outages.

E Examples of AEMO recommendations for reviewable operating incidents 2012-13

Below are examples of recommendations made by AEMO for reviewable operating incidents for 2012-13.

Table E.1 AEMO recommendations for reviewable operating incidents 2012-13

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 test plant test procedure and alternator fire protection design • 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 • 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

F Glossary & Abbreviations

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 ESOO.

F.1

Term	Explanation
AEMC	Australian Energy Market Commission
AEMO	Australia Energy Market Operator
AER	Australian Energy Regulator
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'.
CAIDI	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).
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.

Term	Explanation
	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.
directions	These are instructions NEMMCO issues to participants under clause 4.8.9 of the rules to take action to maintain or re-establish the power system to a secure operating state, a satisfactory operating state, or a reliable operating state.
dispatch	The act of initiating or enabling all or part of the response specified in a dispatch bid, dispatch offer or market ancillary service offer in respect of a scheduled generating unit, a scheduled load, a scheduled network service, an ancillary service generating unit or an ancillary service load in accordance with clause 3.8 (NER), or a direction or operation of capacity the subject of a reserve contract as appropriate.
distribution network	The apparatus, equipment, plant and buildings (including the connection assets) used to convey and control the conveyance of electricity to consumers from the network and which is not a transmission network.
DNSP	distribution network service provider
ESOO	Electricity Statement of Opportunities
frequency control ancillary services	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.

Term	Explanation
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 NEMMCO. Load shedding will cause interruptions to some energy consumers' supplies.
low reserve condition	This is when reserves are below the minimum reserve level.
MAIFI	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 (medium-term PASA) (also see short-term 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	The minimum reserve margin calculated by AEMO to meet the Reliability Standard.
Ministerial Council on Energy (MCE)	The MCE is the national policy and governance body for the Australian energy market, including for electricity and gas, as outlined in the COAG Australian Energy Market Agreement of 30 June 2004.
National Electricity Code	The National Electricity Code was replaced by the National Electricity rules on 1 July

Term	Explanation
	2005.
National Electricity Market (NEM)	The National Electricity Market is a wholesale exchange for the supply of electricity to retailers and consumers. It commenced on 13 December 1998, and now includes Queensland, New South Wales, Australian Capital Territory, Victoria, South Australia, and Tasmania.
National Electricity Law (NEL)	The NEL is contained in a Schedule to the National Electricity (South Australia) Act 1996. The NEL is applied as law in each participating jurisdiction of the NEM by the application statutes.
National Electricity Rules (NER)	The National Electricity Rules 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.
NTNDP	National Transmission Network Development Plan

Term	Explanation
operating state	The operating state of the power system is defined as satisfactory, secure or reliable, as described below. **satisfactory operating state** The power system is in a satisfactory operating state when: • it is operating within its technical limits (i.e. frequency, voltage, current etc. are within the relevant standards and ratings) and • the severity of any potential fault is within the capability of circuit breakers to disconnect the faulted circuit or equipment. **secure operating state** The power system is in a secure operating state when: • it is in a satisfactory operating state and • it will return to a satisfactory operating state following a single credible contingency event. **reliable operating state** The power system is in a reliable operating state when: • AEMO has not disconnected, and does not expect to disconnect, any points of load connection under clause 4.8.9 (NER) • no load shedding is occurring or expected to occur anywhere on the power system under clause 4.8.9 (NER), and • in AEMO's reasonable opinion the levels of short term and medium term capacity reserves available to the power system are at least equal to the required levels determined in accordance with the power system security and reliability standards.
participant	An entity that participates in the National Electricity Market.
plant capability	The maximum MW output which an item of electrical equipment is capable of achieving for a given period.
power system reliability	The measure of the power system's ability to

Term	Explanation
	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.
PSA	Power System Adequacy
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 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% 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%.
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

Term	Explanation
	demand + demand-side participation.
Rules	National Electricity Rules (also see NER)
SAIDI	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).
SAIFI	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	Under clause 4.2.2 of the rules, the power system is defined as being in a satisfactory operating state when: (a) the frequency at all energised busbars of the power system is within the normal operating frequency band, except for brief 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 equipment; and

Term	Explanation
	(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 (short-term PASA) (also see medium-term 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.

Term	Explanation
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 service provider (TNSP)	A person who owns, operates and/or controls the high-voltage transmission assets that transport electricity between generators and distribution networks.
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.
unserved energy (USE)	The amount of energy that cannot be supplied because there are insufficient supplies (generation) to meet demand.