Reliability Panel AEMC

DRAFT REPORT

Annual Market Performance Review

4 November 2010

Submissions due 1 December 2010. Reference: REL0042
Report

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About the AEMC

The Council of Australian Governments, through its Ministerial Council on Energy (MCE), established the Australian Energy Market Commission (AEMC) in July 2005 to be the rule maker for national energy markets. The AEMC is currently responsible for rules and providing advice to the MCE on matters relevant to the national energy markets. We are an independent, national body. Our key responsibilities are to consider rule change proposals, conduct energy market reviews and provide policy advice to the Ministerial Council as requested, or on AEMC initiative.

About the AEMC Reliability 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 the safety, security and reliability 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 (NEL).

Executive Summary

This Annual Market Performance Review Draft Report reviews the performance of the National Electricity Market in terms of reliability, security and safety over the 2009-10 fiscal year. It examines the events and activities that have either positively or adversely affected the supply of electricity to consumers and assesses the performance of these aspects. The report has been prepared and published in accordance with the Panel's obligations under clause 8.8.3 of the National Electricity Rules (the Rules) and in accordance with the Terms of Reference issued by the AEMC.

A reliable national electricity system is critically important for all Australians. Consumers, energy supply and transmission and distribution organisations, and governments all have a direct interest in security and reliability. This report presents the Reliability Panel (Panel) of the Australian Energy Market Commission (AEMC) Review of the performance of the interconnected national electricity system over the 2009-10 fiscal year in terms of safety, reliability and security. The Panel includes stakeholders involved in electricity generation, transmission, distribution and retailing, as well as consumer representatives and the Australian Energy Market Operator (AEMO).

The Panel reviews performance of the power system with regard to two main criteria: the availability of adequate bulk supply to meet consumer demand ("reliability"), and the technical security of the power system itself ("security"). Under the Rules, the Panel is responsible for determining the standards for reliability and security against which the national electricity system's performance is to be assessed.

The current Reliability Standard is that there should be sufficient generation and bulk transmission capacity so that, over the long-term using a moving average of the actual observed levels of annual unserved energy (USE) for the most recent ten financial years, no more than 0.002% of the annual energy of consumers in any region is at risk of not being supplied.

Some matters that affect continuity of supply, such as the impact of transmission or distribution network failures, lie outside the scope of the Reliability Standard and the responsibility of the Reliability Panel. Also, where USE is the result of a controlled response to prevent power system collapse due to multiple unanticipated disruptions, rather than as the result of insufficient generation or bulk transmission capacity being made available, this is formally classified as a security issue and is not considered part of the Reliability Standard. Such security issues are addressed separately in this report.

Reliability

- There was no USE due to reliability events in 2009-10.
- Since the market started in December 1998, the averages for USE due to shortfalls in available capacity indicate that all regions remain within the Reliability Standard.

- During 2009-10, an additional 1 559 MW of generating capacity (both scheduled and non-scheduled) was registered to be brought into service in the future.
- National peak demand in both summer and winter was lower than the previous year. This was reflected in regional peak demand for all regions, which decreased by between 1.1 and 5.7 percent, except Queensland. Queensland peak demand increased by 2.1 percent compared with 2008-09.
- In general, the accuracy of reserve projections and demand forecasts was similar, or slightly improved compared with 2008-09.
- During 2009-10, AEMO did not exercise the Reliability and Emergency Reserve Trader (RERT), but did issue two directions for reliability.

Security

- Four major incidents involving multiple contingency events are discussed in this report. The Panel notes that AEMO has taken the appropriate actions to maintain the reliability and security of the power system during the 2009-10 fiscal year.
- Three of these incidents resulted in disruption to customer load. The Panel notes that a number of other incidents during 2009-10 also resulted in some minor localised interruptions.
- Several frequency deviations occurred over the year. In one instance on the mainland, frequency was not restored to the normal frequency operating band sufficiently quickly and the frequency operating standards were breached.
- Voltage was generally maintained within advised limits.
- System damping times for significant events were generally within requirements.

Safety

The Panel considers that AEMO appears to adhere to its National Electricity Law (NEL) and Rules obligations with regards to safety in the National Electricity Market (NEM).

Transmission and distribution networks

The Panel has also included an overview of the reliability performance of transmission and distribution networks in chapter 6 in order to provide context for the bulk supply Reliability Standard.

Stakeholder consultation

In accordance with the requirements under clause 8.8.3 (f) of the Rules, a public meeting will be held at the AEMC offices on Thursday, 18 November 2010. The purpose of this presentation is to inform interested parties of the draft report and the Panel's process to undertake the review.

The Panel invites initial comments from interested parties in response to this Draft Report by close of business on Wednesday, 1 December 2010. Submissions may be sent electronically or by mail in accordance with the following requirements.

Lodging a submission electronically

Submissions must be lodged online through the AEMC's homepage using the link entitled "online lodgement". The submission must cite the project reference code "REL0042". The submission must be on letterhead (if submitted on behalf of an organisation), signed and dated. The submission must be in PDF format, and must also be forwarded to the Panel via ordinary mail.

Upon receipt of the electronic version of the submission either via email or online lodgement, the Panel will issue a confirmation email. If this confirmation email is not received within 3 business days, it is the submitter's responsibility to ensure successful delivery of the submission has occurred.

Lodging a submission by mail

The submission must be on letterhead (if an organisation), signed and dated by the respondent. The submission should be sent by mail to:

The Reliability Panel
Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

or by fax: (02) 8296 7899.

Reliability Panel Members

Chairman

Neville Henderson, Commissioner, Australian Energy Market Commission

Other AEMC Reliability Panel Members

Gavin Dufty, Manager Policy and Research, St Vincent de Paul Society, Victoria

Hugh Gleeson, Chief Executive Officer, United Energy

Mark Grenning, Chief Advisor Energy, Rio Tinto

Gordon Jardine, Chief Executive, Powerlink

Tim O'Grady, Head of Public Policy, Origin Energy

Stephen Orr, Commercial Director, International Power Australia

David Swift, Executive General Manager, Australian Energy Market Operator

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1 Introduction

A reliable and secure supply of electricity is key to Australian households and businesses. Consumers understand reliability and security in terms of the continuity and quality of delivered electricity, which is reliant upon all parts of the electricity supply chain including generation, high voltage transmission, and local network distribution.

1.1 What is this report about?

Specifically, this report addresses:

- "safety" which, for the purposes of this report, refers to a number of areas of the NEL in different contexts. Safety usually relates to public safety or electrical safety in a technical sense;

- "reliability" which relates to availability of sufficient bulk electricity generation and transmission capability; and

- "security" which relates to operation of the power system within its technical limits.

Some of a customer's interruption to supply occurs in local transmission or distribution networks. These are presently regulated in each State and Territory and the local authority publicises standards of performance for these networks. This report provides a brief overview of information on this segment of electricity supply in Chapter 6.

This Report contains information which was relevant from the period 1 July 2009 to 30 June 2010.

1.2 How to use this report

- The **Executive summary** provides a brief outline of the purpose and scope of this performance review and a summary of the Panel's main findings.

- The **Year in review** outlines the main events that affected the national electricity system's performance in 2009-10 and the Panel's analysis and recommendations.

- The **Performance assessment** chapters provide the comprehensive statistical data on the system's reliability and security performance over the year and an in-depth discussion of the mechanisms used to measure that performance.

- The **Network performance** section provides an overview of the arrangements for managing the reliability of the NEM distribution and transmission networks.

- The **Glossary** provides explanations of key terms and concepts for those that may not be familiar with the subject matter.

1.3 Background

1.3.1 National Electricity Market

The NEM is the market through which wholesale electricity is traded in the eastern and southern states of Australia. The scope of the NEM is defined by the interconnected transmission network that runs from Queensland to South Australia, and across to Tasmania. The market operates across a number of regions; these are Queensland, New South Wales, Victoria, South Australia and Tasmania. The NEM commenced operation in 1998 and since that time, it has undergone a series of reforms to establish the current market arrangements.

1.3.2 The Regulatory framework

In 2003, the Ministerial Council on Energy (MCE) agreed to establish a new regulatory framework for Australia's energy market, including a package of reforms regarding governance, institutional arrangements, economic regulation, electricity transmission, user participation, and gas market development.

Under this regulatory framework, the national electricity objective was developed, which is specified in section 7 of the NEL and is as follows:

> "The objective of this Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to-
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system."

To help achieve this objective, the Rules were drafted to replace the previous National Electricity Code; the Australian Energy Market Commission (AEMC) was set up to manage market development and rule-making; and the Australian Energy Regulator (AER) was established to monitor compliance with the Rules. On 1 July 2005, the Rules came into effect and the AEMC and the AER came into operation.

1.3.3 Australian Energy Market Commission

The responsibilities of the AEMC are to:

- administer and publish the Rules;
- undertake the Rule-making process under the NEL;
- make determinations on proposed Rules;
- undertake reviews on its own initiative or as directed by the MCE; and

- provide policy advice to the MCE in relation to the NEM.

1.3.4 The Reliability Panel

The Panel was established by the AEMC under section 38 of the NEL. It includes electricity industry and consumer representatives, and is chaired by a Commissioner of the AEMC. Its responsibilities are specified under clause 8.8.1(a) of the Rules. Some of these responsibilities are:

- reviewing and determining the power system security and reliability standards;
- determining and maintaining guidelines governing the exercise of the AEMO's power to issue power system directions;
- determining and maintaining guidelines and policies governing the exercise of AEMO's power to contract for the provision of reserves;
- monitoring, reviewing and reporting on the performance of the market in terms of power system security and reliability;
- determining the system restart standard on the advice of AEMO;
- monitoring and reviewing the system standards, as well as access, performance and plant standards for connecting to the network, in terms of their effects on power system security;
- developing and publishing principles and guidelines that determine how AEMO should maintain power system security while taking into account the costs and benefits to the extent practicable; and
- determining guidelines that identify or provide for the identification of operating incidents and other incidents that are of significance for the purposes of the definition of "Reviewable operating incident".

Until 30 June, 2005 the Panel was under the auspices of the National Electricity Code Administrator (NECA). On 1 July, 2005 the Panel was transferred to the AEMC. A list of the current Panel Members is contained in the introductory part of this report.

2 Year in review - reliability and security

This section of the report discusses and makes recommendations concerning the most significant incidents and issues that affected the performance of the national electricity system in 2009-10. Included in the analysis is a discussion on the Panel's key learnings.

This section reviews the performance of the power system in the context of the following broad areas:

- scope of the performance review: reliability and security;
- the major power system incidents; and
- other security issues.

Since 2005-06, maximum summer demand on the NEM has grown by 2 977 MW or 9.5 percent with an annual average growth rate of approximately 2.4 percent (almost three times the rate of growth of energy over the same period). Over this time, projected summer aggregate scheduled and semi-scheduled generation capacity has risen by 3 540 MW, or 8.7 percent, with additional increases from smaller unscheduled plant.[1]

In respect of new capacity and changes to existing capacity in 2009-10, the Panel notes that a total of 1 559 MW of new plant (including both scheduled/semi-scheduled and non-scheduled plant) has been registered with AEMO to be brought into service in the future.

2.1 Scope of the performance review: reliability and security

The "health" of the power system is often discussed in terms of supply reliability and power system security.

Reliability is generally associated with the notion of measuring the continuity of electricity supply to customers. This can be affected by factors such as the availability of adequate generating plant capacity to meet demand, the incidents of unexpected contingency events on generation and transmission equipment, the availability of adequate transmission capability to convey the electricity to distribution networks and the performance of the distribution network down to end users of electricity.

The Panel’s current standard for reliability (Reliability Standard) is that there should be sufficient generation and bulk transmission capacity so that the maximum permissible USE, that is, the maximum allowable level of electricity at risk of not being supplied to customers, is 0.002% of the annual energy consumption for the associated region or regions per financial year. Compliance with the Reliability Standard should be measured over the long-term using a moving average of the actual observed levels of

1 Scheduled generating plant participates in the central dispatch process operated by AEMO, while non-scheduled generating plant is not subject to central dispatch. AEMO, Electricity Statement of Opportunities, 2010.

annual USE for the most recent ten financial years. This Reliability Standard applies until 30 June 2012. A new Reliability Standard will apply from 1 July 2012. [2]

For the purpose of measuring reliability, "bulk transmission" capacity in effect equates to interconnector capability.[3] Consequently, only constraints in the transmission network that affect interconnector capability are considered when assessing the availability of reserves in a region.[4] The Reliability Standard does not take into account USE that is caused by outages of local transmission or distribution elements that do no 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 standard. The Panel, however, summarises the transmission and distribution network reliability in the NEM in chapter 6 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.

2.2 Overall power system performance

Table 2.1 below shows the latest available data on the performance of the generation, distribution and transmission sectors as experienced by consumers in each region.

2 In April 2010, the Reliability Panel completed the Reliability Standard and Reliability Settings Review. As part of this Review, the Panel determined that from 1 July 2012, performance of the NEM should be considered against the Reliability Standard with the objective of providing continuous improvement to the processes that monitor and maintain reliability, rather than the current practice of measuring compliance against a ten year moving average. More information can be found at www.aemc.gov.au/Market-Reviews/Completed/Review-of-the-Reliability-Standard-and-Settings.html.

3 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.

4 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.

Table 2.1 Unsupplied system minutes in the NEM

	Region	System minutes unsupplied	
		Target	Actual
Generation[5]	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
Transmission[6]	QLD	n/a	n/a
	NSW	n/a	0.42
	VIC	n/a	7.46
	SA	n/a	0.99[7]
	TAS	n/a	1.83
Distribution[8]	QLD	318.33	344.20
	NSW	302.00	177.83
	ACT	91	25.8
	VIC[9]	124.75	94.27
	SA[10]	226.14	217.86
	TAS	420	258

5 For generation, system minutes unsupplied is calculated using the reliability standard and is equivalent to the number of minutes of lost load at average demand.

6 For transmission, system minutes unsupplied is calculated as the amount of energy (MWh) not supplied to customers divided by maximum demand (MW) (multiplied by 60 to convert to system minutes). The latest available transmission data is for 2008-09. Source: Energy Supply Association of Australia, 2010, Electricity Gas Australia, p.26.

7 Based on the 2008 calendar year.

8 For distribution, system minutes unsupplied is calculated using the unplanned SAIDI figures and is averaged across feeders and networks. SAIDI is the sum of the duration of each sustained customer interruption, divided by the total number of customers.

9 Based on 2008 calendar year The Panel expects the 2009 data will be available for the Final Report.

10 These figures are based on the 2008-09 data. The Panel expects the 2009-10 data will be available for the Final Report.

2.3 Major power system incidents

This section describes and provides commentary on the four major power system incidents that occurred during the 2009-10 financial year that resulted in the involuntary shedding of customer load for both reliability and system security events. These incidents are:

- Multiple generator disconnection and under frequency load shedding, 2 July 2009;
- Bushfires in the New South Wales region, 28 November 2009;
- Simultaneous trip of Aurora Energy Tamar Valley units, 30 September 2009;
- Trip of Keilor terminal station 220 kV busbar, 8 October 2009.

AEMO has investigated all four incidents and in each case has published a report on its findings in accordance with clause 4.8.15 of the Rules.[11]

2.3.1 Multiple generator disconnection and under frequency load shedding, 2 July 2009

A transformer failure occurred in the Hunter Valley which resulted in eight generating units being disconnected, with a total generation loss of 3 205 MW and the interruption of 1 131 MW of load.

Box 2.1: Excerpt from AEMO's Power System Incident Report[12]

On 2 July 2009 the failure of a current transformer in the Bayswater Power Station 330 kV switchyard in the Hunter Valley resulted in the multiple disconnection of transmission lines and generating units and under-frequency load shedding.

Following the initial fault, there were three subsequent faults in the Bayswater switchyard caused by the fireball from the original failure being blown across adjacent bays.

A total of eight generating units disconnected within approximately 6 minutes from the time of the incident, with a total generation loss of 3 205 MW. The loss of generation automatically resulted in automatic under-frequency load shedding across the interconnected system. A total of 1 131 MW of load was interrupted. All load was reconnected within 61 minutes.

11 AEMO, Operating Incident Reports, www.aemo.com.au/reports/nemreports.html#ops.

12 AEMO, Power System Incident Report - Multiple Generator Disconnection and under frequency load shedding event - 02 July 2009, Volume 1, www.aemo.com.au/reports/0232-00016.pdf.

Comments

A major proportion of the load shedding in this event was due to the operation of under-frequency load shedding. The Panel notes that the operation of the under-frequency load shedding was predominantly as expected, although the system frequency did not return to the normal frequency band for over 11 minutes, which is outside the 10 minutes required by the frequency operating standard. Also, load shedding was not shared equally between the regions as the minimum frequency was approximately equal to the relay setting of 49.0 Hz. The Panel notes AEMO's recommendation to investigate suitable options to address the risk of power system frequency not recovering within the required time to the normal operation frequency band following a multiple contingency event where the frequency does not fall below 49.0 Hz. The Panel agrees with AEMO that load was promptly restored.

The Panel notes that during the event, the main lines supplying power to the greater Sydney area were lost. If one of the remaining two lines had tripped, the other would have been severely overloaded. The system was therefore insecure from a thermal overload point of view, for 28 minutes. The Panel also notes that the emergency voltage rating was marginally exceeded for a short period of time for four substations. The Panel agrees that reasonable actions were taken by AEMO to maintain power system security.

The Panel notes AEMO's recommendations for AEMO to assess the risk posed by similar current transformers in the rest of the power system and to assess the likely impact of the event occurring for a range of system conditions. The Panel considers that these are appropriate steps to help prevent or manage any similar future incidents.

2.3.2 Bushfires in the New South Wales region, 28 November 2009

Extreme weather conditions in New South Wales led to a number of bushfires around Newcastle and subsequent tripping of three major transmission lines.

Box 2.2: Excerpt from AEMO's Power System Incident Report[13]

On 28 November 2009, severe weather conditions caused bushfires and subsequent tripping of 3 major transmission lines in the New South Wales region. As a result, 243 MW of load supplied from the Argenton/Merewether sub-transmission substations was interrupted. The Hydro Aluminium Potlines 1 and 2 were also disconnected, with a combined load of 212 MW. The Tomago Aluminium Company potlines were subsequently manually shutdown following voltage depression that occurred at the time of the trip, disconnecting approximately 840 MW of load.

Interruption to Argenton/Merewether substations lasted for 22 minutes.

13 AEMO, Power System Incident Report - Bushfires in the New South Wales region - 28 November 2009, http://www.aemo.com.au/reports/0232-0048.html.

Comments

The Panel notes that the power system remained in a secure operating state during this event and that protection systems operated correctly to disconnect the three transmission lines that were affected by the bushfires. The Panel is satisfied that equipment and load was returned to service as soon as practicable once the fire had passed through the area.

The Panel notes the recommendation by the AEMC in the Final Report for the Review of the Effectiveness of NEM Security and Reliability Arrangements in light of Extreme Weather Events that AEMO review the current arrangements for technical performance in the NEM with the objectives of identifying priority areas for improving the power system security. The AEMC considers such a review could include whether any special protection schemes should be developed to manage the impacts of low probability, high impact contingencies, where appropriate.

2.3.3 Simultaneous trip of Aurora Energy Tamar Valley units, 30 September 2009

On 30 September 2009 the Aurora Energy Tamar Valley closed cycle gas turbine (CCGT) and open cycle gas turbine (OCGT) tripped, resulting in a loss of 261 MW of generation in Tasmania and 56 MW of load.

Box 2.3: Excerpt from AEMO's Power System Incident Report[14]

On 30 September 2009 at 08:52 hrs, Aurora Energy Tamar Valley CCGT and OCGT tripped as a result of a failure in the controller of the gas supplies which resulted in a loss of pressure. This led to a loss of 261 MW of generation in Tasmania. Subsequently, Bell Bay Three generating units were brought online by 09:13 hrs but tripped out of service at 09:15 hrs. The Bell Bay Three units were fed from a separate gas supply which was controlled by the same controller and consequently there was a loss of pressure in that supply as well.

Comments

The Panel notes that while this incident resulted in the loss of generation and load, there were no violations of power system security. The frequency in Tasmania remained inside the frequency operating standard. Furthermore, the Panel notes that the loss of each of the generating units was due to the same cause, and that AEMO understands suitable measures are in place to prevent the outage occurring again.

14 AEMO, Power System Incident Report - Simultaneous trip of AETV CCGT and OCGT units - 30/09/2009, http://www.aemo.com.au/reports/0232-0035.html.

2.3.4 Trip of Keilor terminal station 220 kV busbar, 8 October 2009

The trip of the Keilor terminal station no.1 busbar and B1 transformer at a time when a planned outage was progressing resulted in the trip of the B4 transformer and approximately 242 MW of load being interrupted.

Box 2.4: Excerpt from AEMO's Power System Incident Report[15]

On the 8th October 2009, the No.3 220 kV busbar at Keilor Terminal Station (KTS) was out of service for planned work requiring the B3 220/66 kV transformer to be taken out of service. This left the Keilor 66 kV load supplied through the remaining three 220/66 kV transformers.

At 15:00 hrs, the No.1 220 kV busbar at KTS tripped which also tripped the B1 220/66 kV transformer, reducing the number of transformers connected to the KTS 66 kV busbars from three to two. During subsequent switching the loading on one of the remaining transformers increased to the point where its overload protection operated. This resulted in tripping of the transformer and loss of 242 MW of load.

Comments

The Panel notes that there were no power system security violations during this event. The power system frequency remained within the normal operating frequency band. The Panel considers that the recommendation that SP Ausnet rely on automated overload protection and explore all possible means to restore load in the shortest time possible, is appropriate.

2.4 Other security issues

A number of other security issues occurred during the year as follows.

2.4.1 Other events

In total, there were 58 contingency events reported by AEMO for the 2009-10 financial year. Of these events, 34 were classified by AEMO as multiple contingency events.

These contingency events were made up of:

- 11 transmission related reviewable operating incidents (excluding bus trips);
- 11 generation related reviewable operating incidents;
- 6 combined transmission/generation reviewable operating incidents

15 AEMO, Power System Incident Report - Trip of the No.1 Keilor terminal station 220 kV busbar on 08 October 2009, http://www.aemo.com.au/reports/0232-0039.html.

- 23 bus related reviewable operating incidents (including those combined with generation or load loss) and
- 7 power system security related reviewable operating incidents.

Some of the events resulted in customer load interruptions in order to maintain power system security. There were no interruptions due to power system reliability issues.

2.4.2 Directions

AEMO issued seven directions throughout the 2009-10 financial year to manage local power system security issues. Further discussion on the directions issued by AEMO is covered in section 4.5 of this report. Of the directions during the 2009-10 financial year, one was in New South Wales, four were in Queensland, one was in South Australia and one was in Tasmania. Table 2.2 sets out the number of directions issued by AEMO.

Table 2.2 Directions issued by AEMO

Year	Number of directions
2009-10	7
2008-09	12
2007-08	6
2006-07	10
2005-06	60
2004-05	41
2003-04	10

2.4.3 Frequency deviations

During the 2009-10 fiscal year, the frequency on the mainland NEM deviated from the normal operating band on 10 occasions. The frequencies remained outside the normal band for more than five minutes on all of these occasions. There was one occasion when the frequency was outside the normal operating band for more than 10 minutes. This was the longest deviation outside of the normal operating band and lasted 664 seconds due to the disconnection of multiple generators following the failure of a current transformer in the Bayswater Power Station (see section 2.3).

2.5 Lessons from reliability and security events

2.5.1 Reliability results

Since market start in December 1998, the long-term moving average of the actual observed levels of annual USE for the most recent ten financial years due to supply shortages are as follows:

- New South Wales, 0%;
- Queensland, 0%;
- Victoria, 0.0004%;
- South Australia, 0.00032%; and
- Tasmania, 0%.

The values of USE given above exclude USE associated with power system security incidents that result from:

- multiple or non-credible contingencies;
- planned outages of intra-regional transmission or distribution network elements; or
- industrial action or 'acts of God' at existing generating or inter-regional transmission facilities.

Table 2.3 shows the performance of the NEM against the Reliability Standard for the past ten years.

In May 2007, in accordance with a Panel recommendation to the MCE, the National Electricity Market Management Company (NEMMCO)[16] published a report on the impact of the current drought on system reliability for the second quarter of 2007 to the first quarter of 2009.[17] From this time NEMMCO, and subsequently AEMO, has published an updated drought report each quarter. In June 2008, the Commission introduced a new Rules requirement for AEMO to produce the Energy Adequacy Assessment Projection (EAAP). The EAAP provides the market with projections of the impact of generation input constraints on energy availability. AEMO published the first EAAP on 31 March 2010. The EAAP replaced and extended the existing Drought Reports.[18]

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16 In 2009, NEMMCO was replaced by AEMO.

17 AEMO, Drought reports, www.aemo.com.au/corporate/drought.html.

18 More information is available at www.aemc.gov.au/Electricity/Rule-changes/Completed/NEM-Reliability-Settings-Information-Safety-Net-and-Directions.html.

The latest EAAP was published in September 2010, covering the study period from 1 October 2010 to 30 September 2012. The report advised that under the short-term average rainfall scenario, the Reliability Standard is not expected to be exceeded in any region of the NEM. However, under the low rainfall scenario, the Reliability Standard of 0.002% USE is expected to be exceeded during the 20011-12 summer in Victoria and South Australia.

Table 2.3 Regional USE for the past 10 years

Year	Queensland	New South Wales	Victoria	South Australia	Tasmania[19]
2009-2010	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
2008-2009	0.0000%	0.0000%	**0.0040%**	**0.0032%**	0.0000%
2007-2008	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
2006-2007	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
2005-2006	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
2004-2005	0.0000%	**0.00005%**	0.0000%	0.0000%	0.0000%
2003-2004	0.0000%	0.0000%	0.0000%	0.0000%	
2002-2003	0.0000%	0.0000%	0.0000%	0.0000%	
2001-2002	0.0000%	0.0000%	0.0000%	0.0000%	
2000-2001	0.0000%	0.0000%	0.0000%	0.0000%	
Average	**0.0000%**	**0.0000%**	**0.0004%**	**0.00032%**	**0.0000%**

2.5.2 Security results

While none of the incidents this year resulted in USE due to insufficient supply, the Panel notes that there has been some USE due to power system security issues.

System security events, including non-credible contingency events, can have a serious impact on the supply of electricity to consumers. From a consumer's perspective the impact of security events are not clearly distinguishable from that of reliability events, especially as they occur at the bulk supply level.

Non-credible contingency events can indicate unexpected operation of plant at times when the power system is most stressed. When the power system is experiencing a credible contingency event, it is important that power system plant respond in accordance with defined performance standards to minimise the potential for cascading (i.e. non-credible contingency) events. The alternative of operating the

19 There is no data reported for the first five years as Tasmania joined the NEM in May 2005.

power system to cater for non-credible contingency events without having to shed customer load would result in conservative operating limits, particularly for interconnectors. This could also result in high electricity prices for end use consumers and potentially reduced reliability.

2.6 Related Reliability Panel reviews

2.6.1 Review of the Reliability Standard and Reliability Settings

Under clause 3.9.3A of the Rules, the Panel is required to undertake a biennial review of the Reliability Standard and Reliability Settings.[20] The review focuses on the longer term issues of:

- the form and level of the existing Reliability Standard, and whether these are still appropriate for current market arrangements, given that more than 0.002% of annual (but not 10 year) USE was observed during the high temperature incidents in Victoria and South Australia on 29 and 30 January 2009; and
- the recommended market price cap (MPC), cumulative price threshold (CPT) and market floor price necessary to achieve the Reliability Standard.

The Panel published the Final Report for the review on 30 April 2010. With regard to the Reliability Standard, the Panel determined to:

- retain the USE form of the reliability standard;
- leave the level of the standard at 0.002% USE per annum for each region, and therefore for the NEM as a whole;
- retain the current scope of the reliability standard in terms of excluding system security events, industrial action and 'acts of God';
- retain the current operational approach of targeting to achieve an expectation of no greater than 0.002% USE each year and in each region, and in the NEM as a whole; and
- consider performance against the standard each year with the objective of providing continuous improvement to the processes that monitor and maintain reliability in the NEM, rather than the current practice of measuring compliance with the Reliability Standard over a ten year moving average.

These changes to the Reliability Standard come into effect on 1 July 2012.

20 Further information is available at http://www.aemc.gov.au/Market-Reviews/Completed/Review-of-the-Reliability-Standard-and-Settings.html.

With regard to the Reliability Settings, the Panel recommended that:

- starting on 1 July 2012, the value of the MPC is increased annually in real terms from $12 500/MWh according to the change in the Stage 2 (intermediate) Producer Price Index (PPI).

- starting on 1 July 2012, the value of the CPT is increased from $187 500/MWh annually according to the same index that is applied to the MPC.

- the Panel maintains an annual review process to determine whether higher increases in the MPC or CPT are necessary, and whether there are any significant changes that occurred to the economics and mechanism for delivering the Reliability Standard.

- the MPC and CPT continue to be indexed according to this process as long as appropriate, given the Panel annual review process.

- the market floor price is maintained at -$1 000/MWh.

The Panel also noted that it was concerned that increases in the MPC may reach a tipping point beyond which the benefits of increasing the MPC and CPT do not offset the costs in terms of market risks. The Panel considered the AEMC would be best placed to undertake a review of both the mechanism for delivery of the capacity to ensure reliability, and the impact of the risk allocation framework in the NEM on achievement of reliability in the long term.

2.6.2 Review of the Operational Arrangements for the Reliability Standards

On 3 March 2009 the AEMC approved terms of reference requesting the Panel to undertake a review relating to Operationalisation of the Reliability Standards, in accordance with section 38 of the NEL and clause 8.8.3 of the Rules.[21] The Panel was requested to review the operationalisation of the Reliability Standard including:

- the methodology and process used by AEMO for calculating the MRLs, especially where the MRLs apply across more than one jurisdiction;

- the MRLs and associated arrangements and standards to be used in the short-term reserve assessment of reliability;

- the current "Guidelines for management of electricity supply shortfall events" (sometimes referred to as 'share the pain' guidelines) that were issued by the Panel in September 1998;

- the need for and possible design of a short-term version of the reliability and emergency reserve trader (RERT) that could be used in a critical emergency;

21 For more information see http://www.aemc.gov.au/Market-Reviews/Completed/Review-of-Operationalisation-of-the-Reliability-Standards.html.

- whether the wording of the standard as published by the Panel in the Comprehensive Reliability Review could be clarified to give better guidance to AEMO as to how to operationalise the standard; and
- whether the Rules should be amended to clarify the requirement for market participants to inform AEMO, via dispatch bids or offers, of their actual capability under the prevailing or forecast temperature conditions.

The Final Report was published on 21 December 2009. The Panel made a number of recommendations on the methodology used by AEMO to calculate the MRLs, including that AEMO consider an extreme weather and 90 percent probability of exceedance (POE)[22] maximum demand scenario and consider developing joint regional reserve requirements. The Panel also made changes in order to clarify the Guidelines for the Management of Electricity Supply Shortfall Events and the Reliability Standard. In addition, the Panel submitted a Rule change proposal to the AEMC to extend the operation of the RERT so that it could be used in short notice situations. The AEMC published its final Rule determination on 15 October 2009 and determined to make the Rule.[23]

2.7 Related AEMC reviews

2.7.1 Review of the Effectiveness of NEM Security and Reliability Arrangements in light of Extreme Weather Events

The AEMC recently completed the Review of the Effectiveness of NEM Security and Reliability Arrangements in light of Extreme Weather Events.[24] The MCE requested that the AEMC:

- examine the current arrangements for maintaining the security and reliability of supply to end users of electricity and provide a risk assessment of the capability of those arrangements to maintain adequate, secure and reliable supplies;
- provide advice on the effectiveness of, and options for, cost-effective improvements to current security and reliability arrangements; and
- if appropriate, identify any cost-effective changes to the market frameworks that may be available to mitigate the frequency and severity of threats to the security and reliability of the power system.

22 The probability of exceedance is the likelihood that a forecast electricity maximum demand figure will be exceeded. For electricity, a forecast 10 percent POE maximum demand figure will, on average, be expected to be exceeded only 1 year in every 10.

23 For more information see http://www.aemc.gov.au/Electricity/Rule-changes/Completed/Improved-RERT-Flexibility-and-Short-notice-Reserve-Contracts.html.

24 Further information is available at http://www.aemc.gov.au/Market-Reviews/Completed/Review-of-the-Effectiveness-of-NEM-Security-and-Reliability-Arrangements-in-light-of-Extreme-Weather-Events.html.

The Final Report concluded that there were a number of key areas where improvements can be made to existing electricity market frameworks and mechanisms to enable the NEM to respond more effectively to future extreme weather events. The report proposed a number of changes which sought to ensure that consumer expectations for reliability are achieved and delivered as efficiently as possible. The key areas for improvement included technical performance and power system security, the reliability standard and the governance arrangements and processes for determining the Reliability Standard and Reliability settings. The MCE is currently reviewing these recommendations.

2.7.2 Transmission Frameworks Review

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 is 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 AEMC recently published an Issues Paper which discusses the key issues for the review.[25]

2.8 Australian climate 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 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

25 Further information is available at http://www.aemc.gov.au/Market-Reviews/Open/Transmission-Frameworks-Review.html.

or trees falling on distribution lines.[26] Below is a summary of the climate for the 2009-10 fiscal year by each season:[27]

- **Winter**

  In 2009, the winter was particularly mild for most of Australia. Mean temperatures were particularly warm, and were very close to the record. There was little rain over most of the continent and it was particularly dry in the north and east.

- **Spring**

  Spring was also very warm and dry, with rainfall below normal and maximum and minimum temperatures above normal for most of the country. There was little tropical activity in the north. In the southern inland there was a major rain event in November.

- **Summer**

  The 2009-10 summer was particularly wet for most of the country, particularly the east. Summer was also warmer than normal, particularly in Western Australia and the southeast.

- **Autumn**

  The 2010 autumn was generally warm and wet across Australia. Temperatures were mostly above normal, particularly at night. In early March, there was significant flooding in southern Queensland and northern New South Wales. There were also severe hailstorms in Melbourne and Perth.

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26 More information on the impact of extreme weather on electricity supply can be found in the AEMC Review of the Effectiveness of NEM Security and Reliability Arrangements in light of Extreme Weather Events 1st Interim Report, http://www.aemc.gov.au/Media/docs/1st%20Interim%20Report-07b5d46e-0aad-4880-a82f-71416e680dda-0.PDF.

27 Australian Bureau of Meteorology, Australian seasonal climate summary archive, http://www.bom.gov.au/climate/current/season/aus/archive.

3 Reliability performance assessment against the power system security and reliability standards

This part of the report contains comprehensive statistical data on the power systems reliability performance over the 2009-10 fiscal year as well as discussion on the mechanisms used to measure that performance.

The Panel acknowledges the AER and AEMO for their assistance in the preparation of the data in this section.

3.1 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 3.1. The operation of each element of the model is explained and analysed in detail in this section.

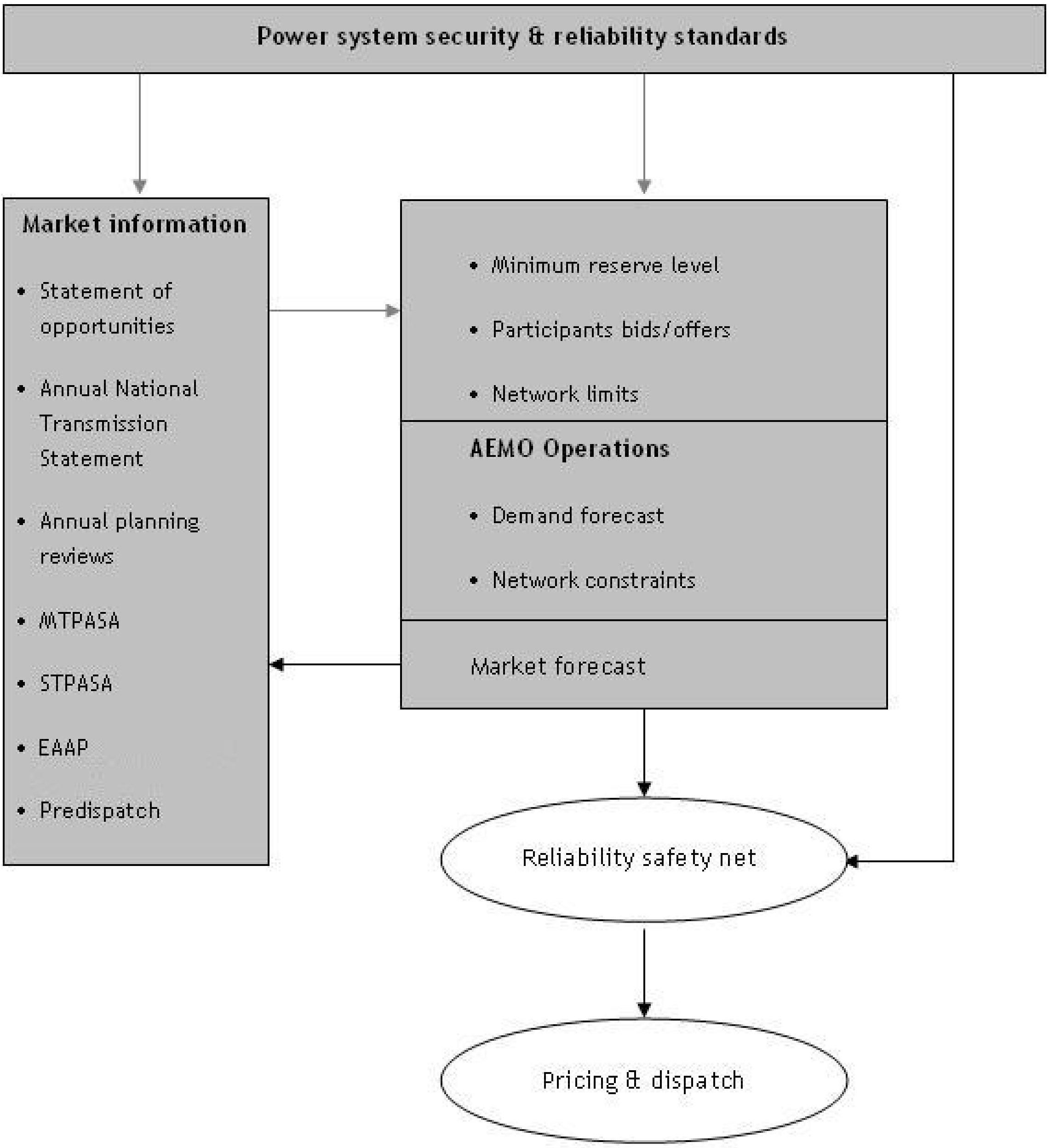
The national market aligns incentives for decisions by market participants about plant operation with overall reliability outcomes. There is an extensive suite of information published by AEMO to support those decisions.

Market information provides data and projections with increasing levels of detail closer to the time of dispatch. The annual Electricity Statement of Opportunities (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 3.1 Reliability Panel Model



3.2 Reliability Standard

The Reliability Standard of 0.002% 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 customers 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 customers. However, from a customer point of view, reliability is also impacted by the performance of the distribution and local transmission networks. Chapter 6 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.

3.2.1 Performance assessment

No USE occurred during 2009-10 as a result of a reliability incident and therefore, the reliability standard was met in all regions.

3.3 Minimum reserve levels

The Reliability Standard of 0.002% USE is a statistical risk of not meeting consumer demand over time. To meet the Standard operationally, AEMO calculates minimum reserve levels (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 3.4) 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%). The MRLs are derived by comparing the minimum generation requirement with a demand condition which has all regions at their maximum 10 percent POE demand and taking into account reserve available across interconnectors.

In June 2010, AEMO completed a review of the MRLs. These new MRL values will become operational in the summer of 2010-11. As part of the recalculation process, 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.

Table 3.1 Revised minimum reserve levels

	Queensland*	New South Wales	Victoria& South Australia	South Australia*	Tasmania
2005-06	610 MW	-290 MW	530 MW	265 MW	144 MW
2006-07	480 MW	-1 490 MW	615 MW	-50 MW	144 MW
2007-08	560 MW	-1 430 MW	615 MW	-50 MW	144 MW
2008-09	560 MW	-1 430 MW	615 MW	-50 MW	144 MW
2009-10	560 MW	-1 430 MW	615 MW	-50 MW	144 MW
2010-11	829 MW	-1 548 MW	552 MW	-131 MW	144 MW

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

The industry will benefit from further refinement of the MRLs for different applications and time horizons. These different time horizons could, for example, include forecasts of reserves one week ahead in addition to the ten year projections of system adequacy in AEMO's annual ESOO. In particular, refinement could focus on how the minimum reserve level criterion can best be applied in the short-term to avoid the risk of unnecessary intervention or load shedding.

In the Comprehensive Reliability Review, the Panel recommended that a task force review the methodology and process for calculating MRLs.[28] The Comprehensive Reliability Review also recommended that AEMO conduct a review of the level of short-term reserves that should be used in the short-term PASA.[29] The Panel understands that AEMO has recently reviewed the possibility of applying short-term MRLs and is considering the practicality of such an approach.

The AEMC is currently considering a Rule change proposal from AEMO which seeks to amend the Rules to remove AEMO's obligation to prepare and publish "for each region" the reserve requirements used in the medium-term PASA. AEMO considers the proposed Rule would allow it to use reserve requirements that apply across multiple regions so that medium-term PASA can more optimally share medium term capacity

28 AEMC Reliability Panel 2007, Comprehensive Reliability Review, Final Report, December 2007, Sydney, p.81.

29 Ibid, p.88.

reserves between those regions in accordance with the Reliability Standard. The AEMC published the Draft Report on 9 September 2010 and agreed in principle with AEMO's proposal.[30]

3.3.1 Performance assessment

The forecasts reflect the outcomes of the supply-demand balance from short-term and pre-dispatch PASA at the time of calculation. Under these circumstances, AEMO advises the market of its forecasts and seeks a market response to mitigate the low reserve conditions. In South Australia the market response for additional capacity was generally received from the intermediate generation plants.

The Panel notes that there is still no distinction made between short and medium-term MRLs in PASA and the pre-dispatch schedule, even though there is greater certainty about demand in the short-term. However, MRLs are currently set such that the Reliability Standard would be met in each region over the longer term. While this is appropriate for such a longer term measure, the Panel recognises that adjusting the Reliability Standard to apply to a shorter time frame may be difficult and therefore, there may be difficulty determining the MRLs for the short-term. Demand forecasting for different applications and time frames is further discussed in Section 3.4 below.

3.4 Reserve projections and demand forecasts

Market information is provided in a number of formats and time frames ranging from the annual ESOO which contains projected information for the next ten years, to the detailed five minute and thirty minute price and demand pre-dispatch schedule. Market information also includes Annual Planning Reviews, the National Transmission Statement (to be replaced by the National Transmission Network Development Plan (NTNDP) from 2010)[31], 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 inaccurate forecasts can contribute to less efficient market actions. Accurate forecasting is in part dependent on the quality of weather forecasts and knowledge of participant demand management activities.

3.4.1 Market information

Each year AEMO publishes an ESOO for the following ten years.[32] This is complemented by Annual Planning Reviews that are prepared by each transmission

30 For more information see http://www.aemc.gov.au/Electricity/Rule-changes/Open/Amendments-to-PASA-related-Rules.html.

31 Under clause 5.6A.2, AEMO must no later than 31 December each year publish the NTNDP for the following year.

32 In August 2010, AEMO indicated that it would begin to provide the supply-demand outlook in two documents. One is the Power System Adequacy report which presents operational information and

network service provider (TNSP). The Annual Planning Review focuses on networks and includes forecasts of transfer capacities, potential constraints and possible intra-regional augmentations.

In December 2009, AEMO published an interim National Transmission Statement (NTS). The NTS provides an integrated overview of the current state and potential future development of major national transmission flow paths and was introduced as a result of the recommendations of the AEMC in the Final Report of the National Transmission Planning Arrangements.[33] The NTS is a transitional document that will be replaced by the NTNDP and will be published for the first time in 2010. The NTNDP will outline the long-term efficient development of the power system, including future and current capability of the national transmission network and development options. AEMO has recently undertaken stakeholder consultation on the scope and purpose of the NTNDP, as well as the proposed methodologies.[34]

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.

Performance assessment

Table 3.2 compares the forecast demand, for medium growth and 10 percent, 50 percent and 90 percent POE, with the actual maximum demand. The forecast demand values shown are from the 2010 ESOO.

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the supply-demand outlook for the summers of the next two years and assesses potential operational issues for this period. The other is the ESOO which would present the investment outlook for the NEM supply capacity for years 3 to 10 of the 10 year outlook.

33 On 20 February 2009, the Commission received a Rule change proposal from the MCE. The Rule change proposal resulted from the MCE's response to the Commission's Final Report on the National Transmission Planning Arrangements in June 2008. More information is available at http://www.aemc.gov.au/Electricity/Rule-changes/Completed/National-Transmission-Statement.html.

34 More information is available at http://www.aemo.com.au/planning/ntndp.html.

It can be observed that for Queensland, New South Wales and Tasmania, the maximum demand was generally below the 90 percent POE level. The exception to this is summer 2009-10 where maximum demand New South Wales was between the 90 percent and 50 percent POE levels. In Victoria and South Australia, maximum demand was between the 90 percent POE and 50 percent POE levels for both winter 2009 and winter 2010 and between the 50 percent and 10 percent POE levels for summer 2009-10.

Table 3.2 2010 ESOO maximum demand comparison (MW)

Region	QLD	NSW	VIC	SA	TAS
Winter 2009					
2009 SOO peak forecast (10% POE)	8 726	14 703	8 328	2 730	1 886
(50% POE)	8 606	14 313	8 190	2 580	1 863
(90% POE)	8 434	13 963	8 084	2 460	1 843
Actual maximum demand	7 774	13 091	8 178	2 460	1 753
Summer 2009-10					
2009 SOO peak forecast (10% POE)	10 074	15 375	10 346	3 500	1 442
(50% POE)	9 582	14 445	9 790	3 230	1 417
(90% POE)	9 283	13 545	9 244	2 990	1 402
Actual maximum demand	9 070	14 051	10 118	3 341	1 390
Winter 2010					
2010 ESOO peak forecast (10% POE)	8 729	14 655	8 347	2 660	1 932
(50% POE)	8 612	14 236	8 179	2 540	1 908
(90% POE)	8 444	13 877	8 057	2 430	1 889
Actual maximum demand[35]	7 396	13 302	8 169	2 523	1 786

The methodology that is used in determining load forecasts was augmented with some of the recommendations from a report by KEMA commissioned in 2005 by NEMMCO.[36]

In the 2009-10 fiscal year, the national summer peak reached 33 741 MW in January 2010. The national winter peak demand reached 32 105 MW in June 2010. This is down from 34 843 MW the previous summer and 34 363 MW the previous winter. Maximum demands that occurred in the 2009-10 fiscal year were as follows:

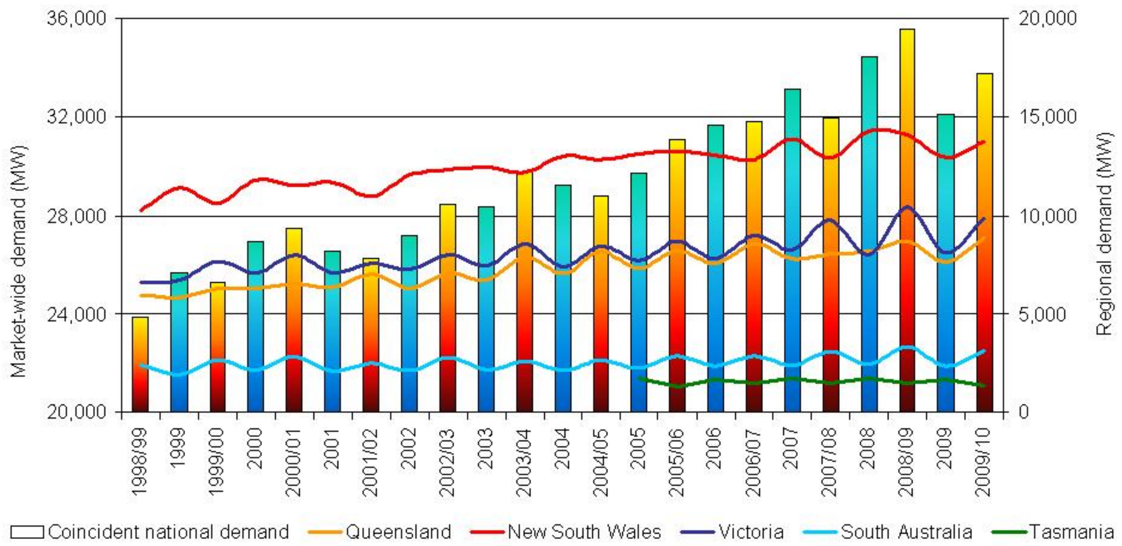
35 These numbers have not yet been finalised by AEMO.

36 KEMA, June 2005, Review of the Process for Preparing the SOO Load Forecasts.

- 8 890 MW in Queensland in January 2010;
- 13 766 MW in New South Wales in January 2010;
- 9 893 MW in Victoria in January 2010;
- 3 279 MW in South Australia in January 2010; and
- 1 669 MW in Tasmania in July 2009.

Figure 3.2 shows the relationship between the regional peak demand and the coincident national peak, since market start. This figure shows that national peak demand does not necessarily coincide with the regional peak. Increased coincidence in regional peak demands would have resulted in an increase national peak.

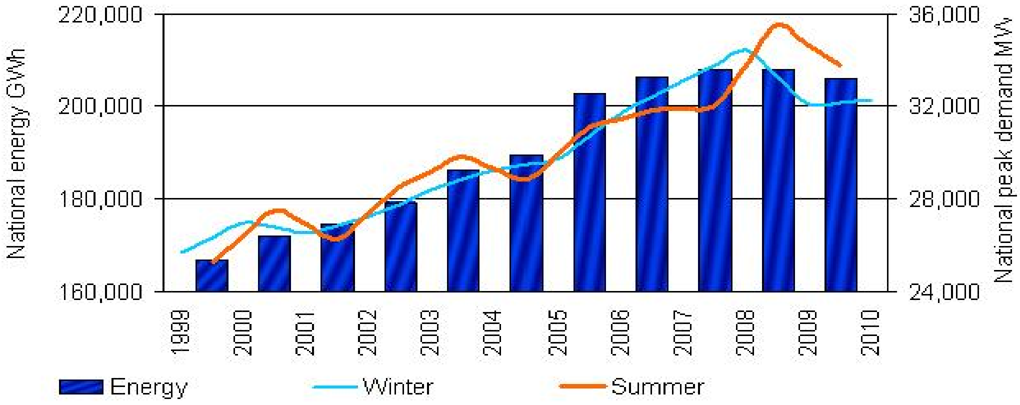
Figure 3.2 Combined peak demand and demand for each region



Source: AER

Figure 3.3 shows the annual average growth in total demand in comparison with the national peak summer and winter demand. It can be seen that energy demand has grown significantly since market start, but that this growth has slowed in recent years. The Panel notes that greater investment in generation and/or interconnector capacities may be required to meet future demand growth – especially during the summer peak – while also maintaining the reliability of the power system. There should be sufficient generating capacity available to maintain levels of USE within the 0.002% Reliability Standard.

Figure 3.3 National energy and maximum demand requirements



Source: AER

3.4.2 Energy Adequacy Assessment Projection

On 26 June 2008, the AEMC made a Rule that introduced the EAAP as an information mechanism.[37] The EAAP is a quarterly information mechanism which will provide the market with projections of the impact of generation input constraints on energy availability.

Both the AEMC and the Panel consider that the EAAP will function as an additional source of information for the market regarding when and where energy constraints may impact on energy availability. It is anticipated to also lead to an improved market response to projected shortfalls in reserve.

As required under clause 3.7C(d) of the Rules, AEMO published the first EAAP on 31 March 2010.

3.4.3 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 percent 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
- as the basis for any intervention decisions by AEMO, for example invoking the RERT.

37 National Electricity Amendment (NEM Reliability Settings: Information Safety Net and Directions) Rule 2008 No.6.

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.

Table 3.3 depicts the frequency of outages submitted by TNSPs to AEMO during the 2009-10 fiscal year.

Table 3.3 Transmission outages submitted to AEMO

Region	QLD	NSW	VIC	SA	TAS	MurrayLink	Terranora	Total
Total outages[38]	1025	1575	1286	688	255	47	87	4963
Outages scheduled with less than 4 days notice	28%	25%	27%	25%	23%	68%	20%	26%
Forced outages[39]	3%	3%	3%	3%	5%	13%	0%	3%

In some circumstances, outages scheduled at short notice improve overall reliability and market efficiency by taking advantage of the most recent market information; 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 percent POE forecast with a daily resolution. This forecast uses the summer and winter weekday 10 percent POE demand forecasts consistent with the most recent ESOO and sculpts the remainder of the year by estimating seasonal and weekend fluctuations.

38 Only primary plant outages (affecting load carrying capability) are included.

39 These are outages not previously notified to AEMO, including failures and amendments by TNSPs in response to unforeseen extreme conditions.

Performance assessment

As sufficient reserve levels were generally maintained in the power system, medium-term PASA accuracy is generally satisfactory for its primary function of checking reliability at peak times well in advance of operation.

In May 2005, medium-term PASA was enhanced to share reserve deficits across regions more equitably. This means that where a reserve shortfall exists, medium-term PASA reports this in each of the affected regions and attempts to share the reserve shortfall in proportion to the demand in the regions. This functionality was used in the 2009-10 fiscal year.[40]

Medium-term PASA now has the ability to produce two sets of results: one where there are no network outages modelled and another where network outages are modelled. In November 2005, the release of the Market Management System (MMS) further improved medium-term PASA by including an assessment of network outages based on 50 percent POE demand forecasts, while reliability was assessed against 10 percent POE demand forecasts.

AEMO in consultation with the medium-term PASA Users Reference Group, continually reviews the medium-term PASA process to:

- identify and develop options to address aspects of the medium-term PASA process that need improvement; and
- ensure that documentation is thorough and adequate for user needs.

Table 3.4 summarises the percentage of days when actual demand was greater than medium-term PASA forecast demand, as well as the average amount by which actual demand exceeded forecast demand for those days. The Panel notes that overall, the medium-term PASA forecasts for Queensland, Victoria, South Australia and Tasmania improved compared with the 2008-09 forecasts.

40 The current Rules require inputs and outputs of the medium-term PASA process to be prepared and published for each separate NEM region. In response to recommendations by the Reliability Panel in the Review of Operational Arrangements for the Reliability Standard, AEMO is seeking to amend the Rules to allow reserves to be shared across the NEM regions in the medium-term PASA process. More information is available at http://www.aemc.gov.au/Electricity/Rule-changes/Open/Amendments-to-PASA-related-Rules.html

Table 3.4 Medium-term PASA demand forecasts comparison

	QLD	NSW	VIC	SA	TAS
Proportion of weekdays where demand greater than 10 percent POE forecast	0.0%	2.3%	2.3%	5.0%	1.1%
Weekdays demand deviation	0%	2%	4%	9%	2%
Weekend days where demand greater than 10% POE forecast	0.0%	2.9%	1.0%	5.8%	10.6%

Source: AER

3.4.4 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.[41]

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.

Performance assessment

Over time, enhancements have been made to improve consistency between the medium-term PASA and short-term PASA systems, most notably in the management of constraints and in the optimisation of the medium-term PASA. The short-term PASA and medium-term PASA use a similar common linear programme solver. This functionality in the PASA processes was used throughout the 2009-10 fiscal year.

Table 3.5 shows the average short-term PASA demand forecast accuracy for two, four and six days ahead. The Panel notes that overall the accuracy of the short-term PASA demand forecast was similar to that of last year. Most regions showed deviation of between 0 and 1 percent compared with the previous financial year. However South Australia showed deviations of up to 2.4 percent.

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

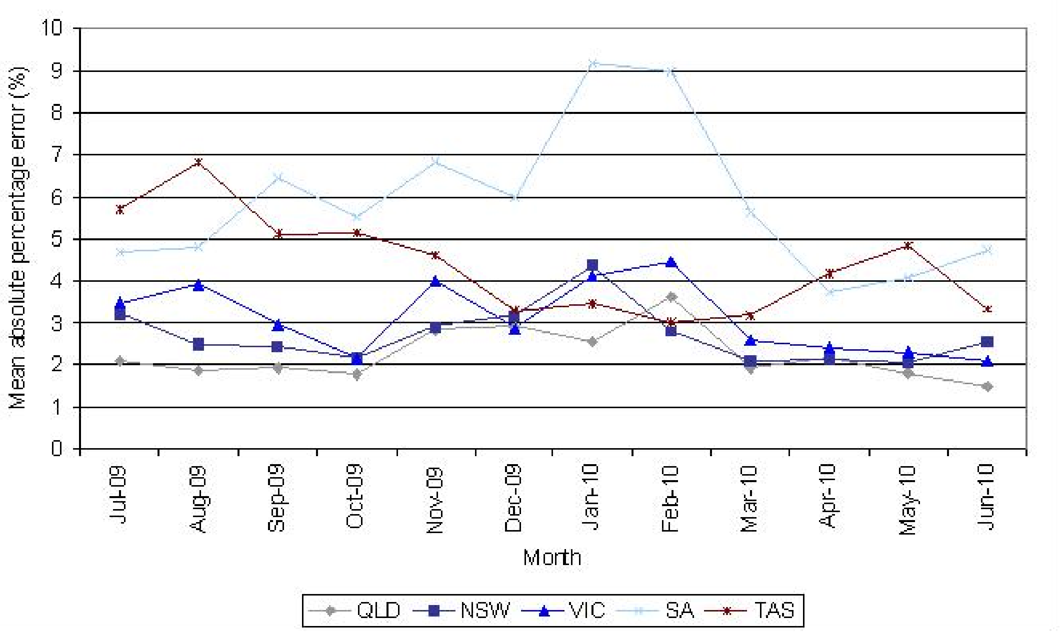
Table 3.5 Accuracy of short-term PASA demand forecasts

Short-term PASA demand forecast absolute percentage deviation	QLD	NSW	VIC	SA	TAS
2 days ahead	2.2%	2.7%	3.1%	5.9%	4.4%
4 days ahead	2.6%	3.2%	3.7%	6.9%	4.8%
6 days ahead	2.9%	3.6%	4.4%	8.0%	5.3%

Source: AER

The short-term PASA demand forecasts as shown in Figure 3.4, were consistently reliable for the 2009-10 fiscal year, typically around 2 to 4.5 percent in each region. This was especially the case in the Queensland, New South Wales and Victoria regions. The Panel also notes that the demand forecasting errors in South Australia and Tasmania were consistently high for many months.

Figure 3.4 Mean absolute percentage error (2 day ahead - ST PASA)



Source: AER

3.4.5 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 also 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.

Performance assessment

Analysis of pre-dispatch information generally shows that when supply is tight, forecast prices are initially high until participants rebid to increase their availability. This is consistent with an appropriate market response. The forecast of high prices provides an incentive for additional capacity to be presented to the market.

Accuracy of the demand forecasts by AEMO used in pre-dispatch is an important determinant of the accuracy of the pre-dispatch overall.

Table 3.6, which was provided by the AER, summarises the number of trading intervals affected by significant variations between pre-dispatch and actual prices during the 2009-10 fiscal year, as well as the most probable reasons for the variations.

The table illustrates that while there are a large number of trading intervals that are affected by significant variations between pre-dispatch and actual prices, the proportion of trading intervals that are affected is generally less than 10 percent. The exception to this is Tasmania, where nearly a quarter of the trading intervals are affected by variations. Generally, these variations are due to changing conditions such as regional demand or generator availability, and the impact of these variations is calculated in successive pre-dispatch runs.

The Panel considers that pre-dispatch has been working satisfactorily as an indicator of reliability and security. Its utility to the market however, will always be affected by the accuracy of demand forecasts. The Panel notes that load forecasting is a continuing challenge. A related problem is forecasting the output of increasing quantities of intermittent generation such as wind farms.

Table 3.6 Trading intervals affected by price variation

Reason for price variation	Number of trading intervals affected by variations									
	QLD		NSW		VIC		SA		TAS	
Demand	886	51%	770	49%	768	44%	897	44%	695	16%
Availability	546	31%	511	32%	743	42%	849	41%	3558	84%
Combination (e.g. of changes in plant availability, demand, rebidding activities)	297	17%	265	17%	252	14%	297	15%	0	0%
Other (e.g. network outages)	7	0%	30	2%	0	0%	3	0%	0	0%
Total trading intervals affected	1397	8%	1280	7%	1461	8%	1675	10%	4099	23%

Source: AER

Note: The number of trading intervals affected for each of the reasons above (in rows 2 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.

Table 3.7 shows the average pre-dispatch demand forecast deviation twelve hours ahead. The Panel notes that the accuracy of the pre-dispatch demand forecast in 2009-10 is very similar to that of 2008-09, with only minor deviations of up to 0.4 percent for each jurisdiction.

Table 3.7 Accuracy of pre-dispatch demand forecasts

Pre-dispatch demand forecast absolute percentage deviation	QLD	NSW	VIC	SA	TAS
12 hours ahead	1.8%	2.2%	2.6%	4.6%	3.7%

Source: AER

AEMO currently uses time varying scaling factors for New South Wales, Victoria and Queensland. This enables the 10 percent POE and the 50 percent POE forecasts to converge as the time to dispatch gets closer. This allows AEMO to reduce the level of reserve shortfall for periods closer to dispatch time frames.

3.4.6 Demand forecast assessment

Figure 3.5 to Figure 3.9 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 percent 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.

For example, in Queensland, the maximum deviation between forecast and actual demand in the top tenth percentile, ranges from 741 MW lower than forecast to 690 MW higher than forecast.

These forecast errors are large compared to those in lower demand levels. For example, the maximum deviation between forecast and actual demand in the bottom tenth percentile, ranges from 389 MW lower than forecast to 289 MW higher than forecast.

The deviation between forecast and actual demand appears to follow a similar trend within the other NEM regions.

The Panel notes that the four hour ahead demand forecasts:

- appear to be consistently biased towards under estimation for high demand periods;
- appear to have maximum under estimates that could be difficult to cover on notice shorter than four hours; however
- the average deviation for all regions is less than 2 percent.

Figure 3.5 Queensland demand forecast deviation four hours ahead

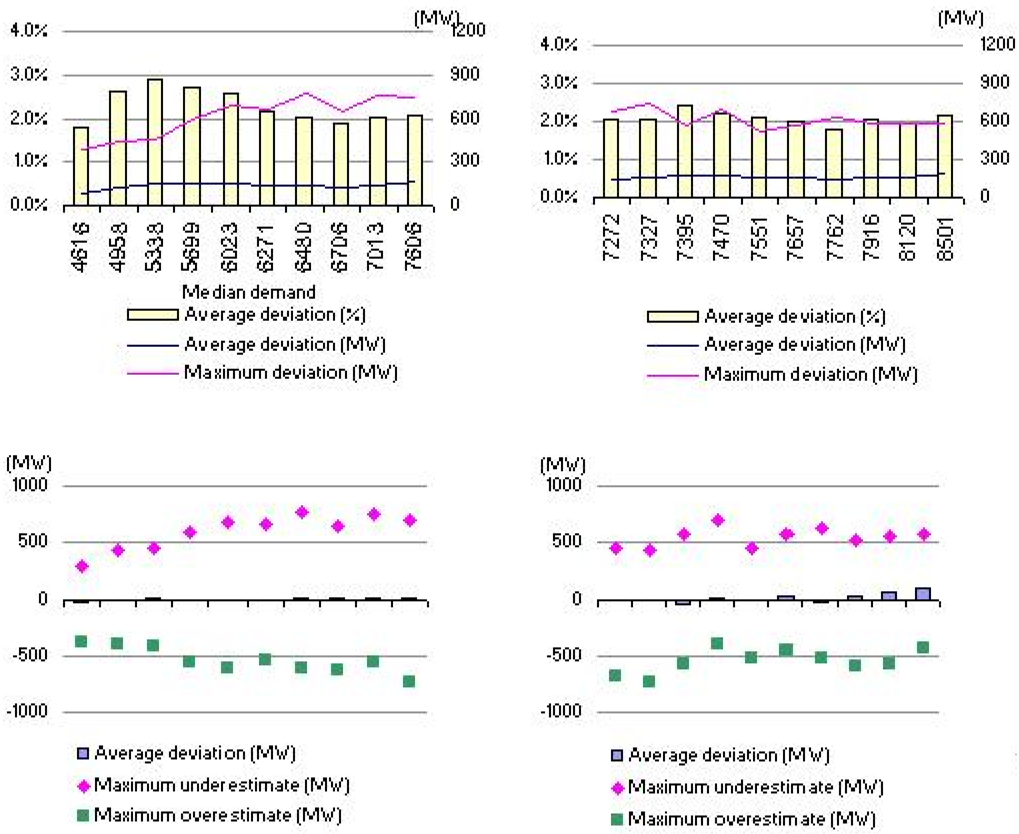


Figure 3.6 New South Wales demand forecast deviation four hours ahead

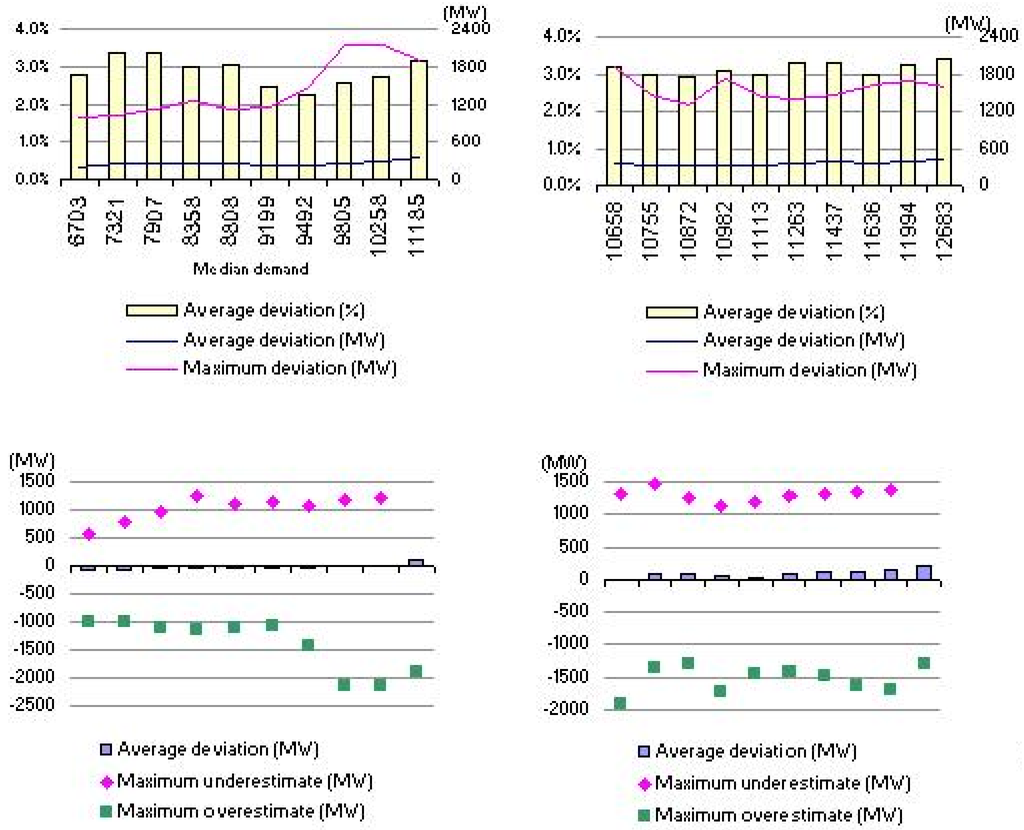


Figure 3.7 Victoria demand forecast deviation four hours ahead

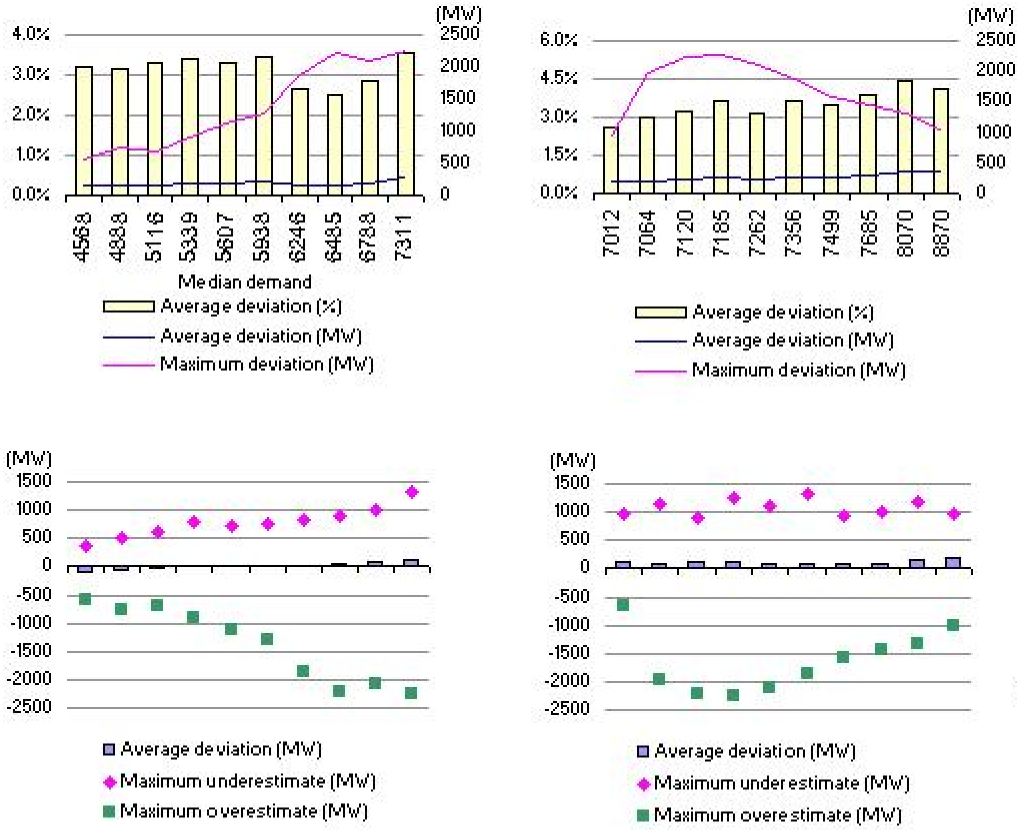


Figure 3.8 South Australia demand forecast deviation four hours ahead

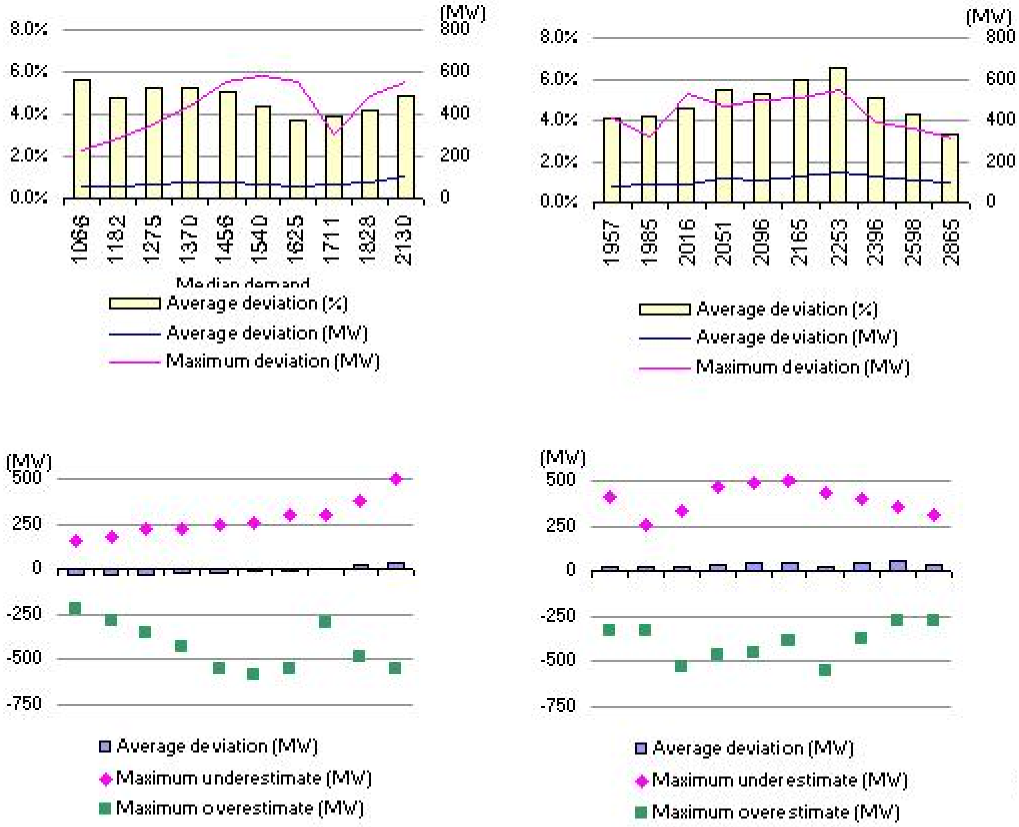
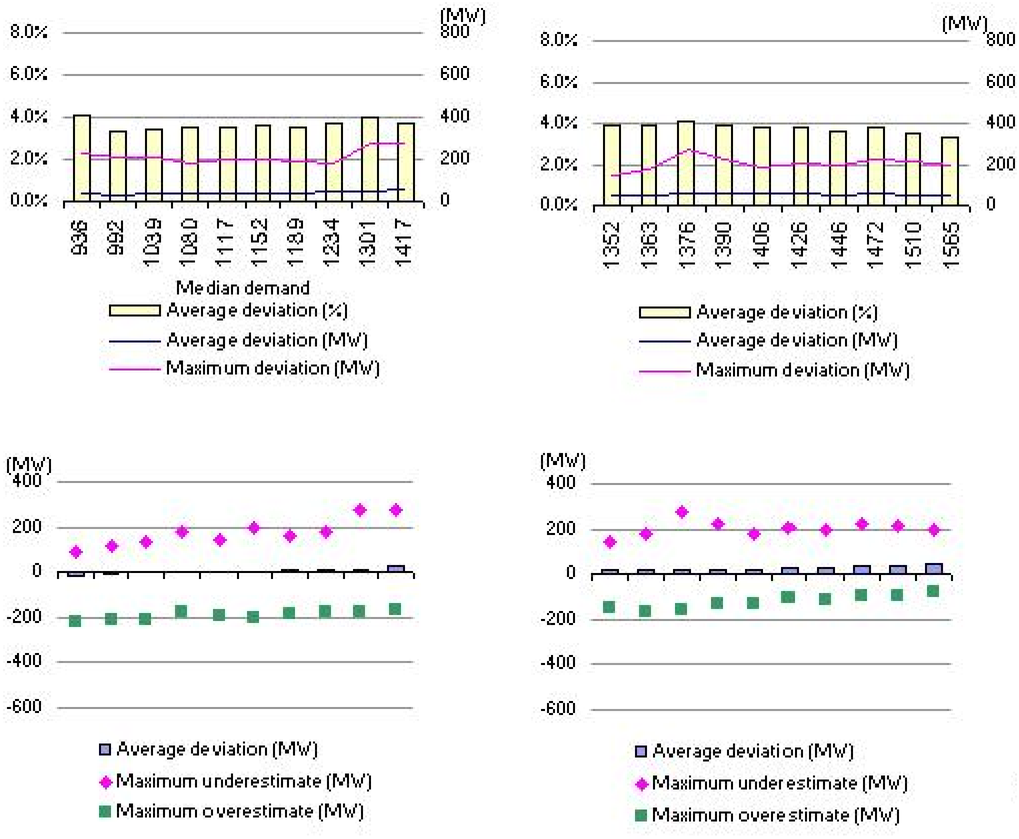


Figure 3.9 Tasmania demand forecast deviation four hours ahead



3.4.7 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.

Performance assessment

There were 5 517 market notices issued by AEMO during the 2009-10 fiscal year. These notices are summarised by type in Table 3.8.

Table 3.8 Market notices

Type of notice	Number of notices
Administered Price Cap	7
General notice	106
Inter-regional transfer	872

Type of notice	Number of notices
Market intervention	27
Market systems	140
Manual priced dispatch Interval	14
NEM systems	3
Non-conformance	2 664
Power system events	20
Price adjustment	16
Process review	1
Reclassify contingency	953
Reserve notice	585
Settlements residue	109

Source: AER

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.

3.4.8 Wind forecast

To improve the assessment of the demand forecasts, the Panel considers it may be necessary in the future to report separately on the accuracies of the underlying demand forecasts and wind generation forecasts as the penetration of wind generation increases.

Phase 1 of the Australian Wind Energy Forecasting System (AWEFS) was implemented internally in NEMMCO on 12 September 2008. NEM market participants currently receive wind generation forecasts as part of the updated MMS release implemented from November 2008. Phase 2 of the AWEFS was implemented in June 2010. The Panel considers that, where appropriate, it would assess the performance of the AWEFS in future reports.

3.4.9 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. While there is no distinction between the types of directions, there are different impacts on market pricing. For the purpose of this report, the Panel makes the following distinction:

- Reliability directions are those that affect a whole region and therefore require intervention or "what-if" pricing (i.e. spot prices are determined as if the direction had not occurred).
- Directions for local security issues, which do not affect pricing, are covered under the topic of Security (section 4.5 of this report).

Performance assessment

During the 2009-10 fiscal year, the Panel notes that AEMO did not exercise the RERT.

During the 2009-10 fiscal year AEMO issued two directions for reliability. On 20 November 2009, high temperatures in New South Wales resulted in AEMO declaring an LOR2 condition for the region. In order to improve generation reserves available for dispatch, AEMO directed one participant to bid its generating unit available and to follow dispatch targets. On the same morning, AEMO directed another participant by withdrawing permission to proceed with planned maintenance, in order to maintain interconnector transfer capability.

4 System security performance against the power system security and reliability standards

This section analyses the arrangements for security and assesses the performance of the NEM against the power system security standards for the 2009-10 fiscal year.

The power system security standards for the technical operation of the power system are set by a combination of the Rules and determinations by the Panel. With few exceptions, these standards require that no consumer load should be involuntarily interrupted in order to manage power system security following a single credible contingency, for example, the unplanned shutdown of a single generating unit. The simultaneous unplanned shutdown of more than one unit is not regarded as credible under normal conditions (see Glossary).

The Panel acknowledges the AER and AEMO for their assistance in the preparation of the data in this section.

4.1 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.

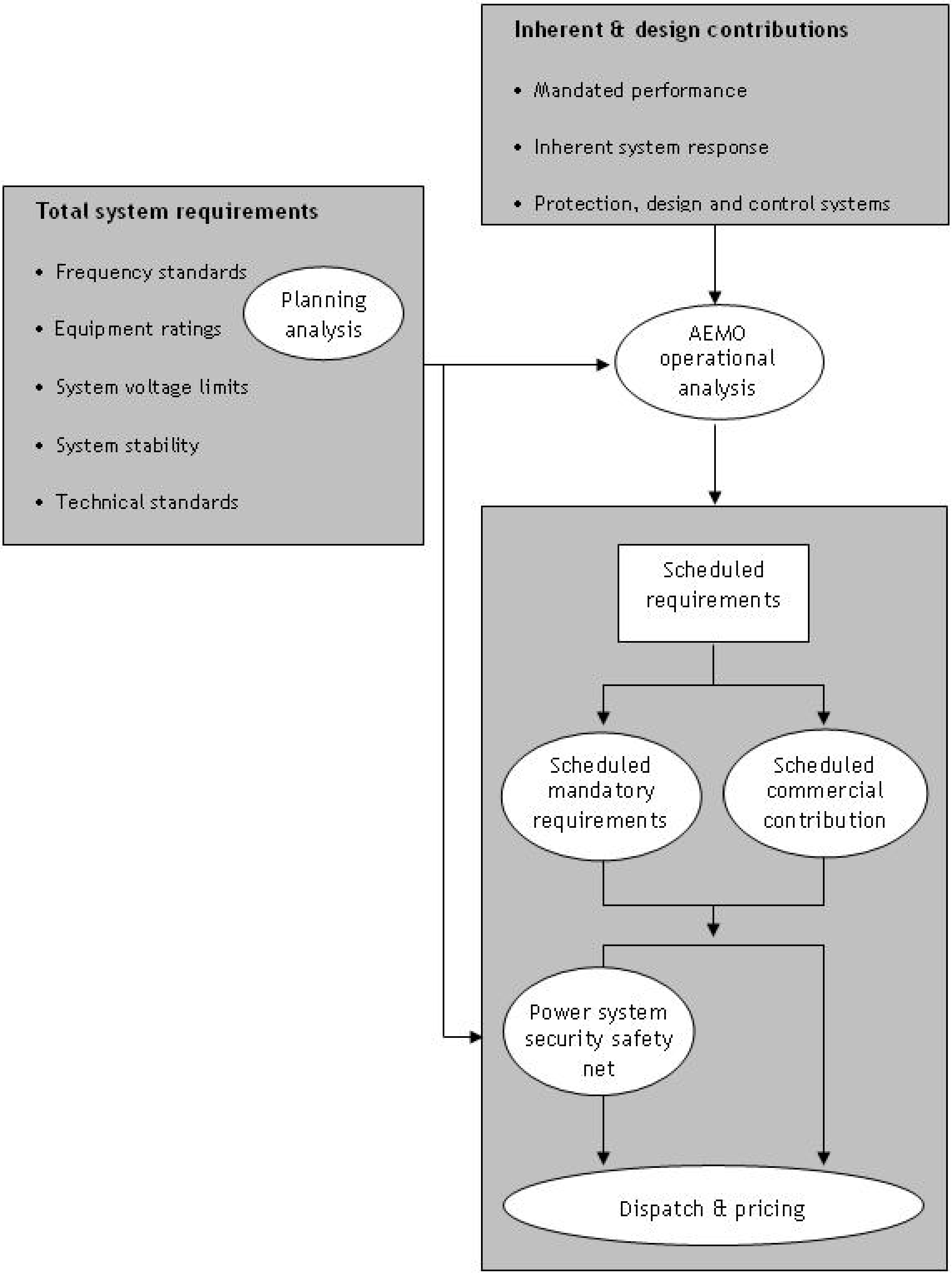
AEMO determines the total technical requirements for all services needed to meet the different aspects of security from: the Panel's power system security and reliability standards; market Rules obligations; knowledge of equipment performance; design characteristics; and modelling of the dynamic behaviour 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 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 4.1 illustrates the overall arrangements for security. The operation of each element is explained and analysed in this section.

Figure 4.1 Security model



4.2 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.

4.2.1 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.

4.2.2 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 programmes. These programmes 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 programme 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.[42]

A plant's performance standard once set, does not vary unless an upgrade is required, which would need a variation in the connection agreement.

Changes to performances standards

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

- Review into the enforcement of and compliance with technical standards;[43]
- Technical Standards for Wind and Other Generator Connections Rule change;[44]
- Resolution of Existing Generator Performance Standards Rule change;[45]
- Performance Standard Compliance of Generators Rule change;[46]and
- Reliability Panel Technical Standards Review.[47]

In addition, as a result of the making of AEMC 2008, National Electricity Amendment (Performance Standard Compliance of Generators) Rule 2008 No. 10, 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.

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42 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.

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

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

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

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

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

4.2.3 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 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 percent 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 4.1.

Table 4.1 NEM mainland frequency operating standards (except "islands")

Condition	Containment	Stabilisation	Recovery
Accumulated time error	5 seconds	n/a	n/a
No contingency event or load event	49.75 to 50.25 Hz[48] 49.85 to 50.15 Hz 99% of the time[49]	49.85 to 50.15 Hz within 5 minutes	
Generation or load event	49.5 to 50.5 Hz	49.85 to 50.15 Hz within 5 minutes	
Network event	49 to 51 Hz	49.5 to 50.5 Hz within 1 minute	49.85 to 50.15 Hz within 5 minutes
Separation event	49 to 51 Hz	49.5 to 50.5 Hz within 2 minutes	49.85 to 50.15 Hz within 10 minutes
Multiple contingency event	47 to 52 Hz	49.5 to 50.5 Hz within 2 minutes	49.85 to 50.15 Hz within 10 minutes

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

49 This is known as the normal operating frequency band.

The frequency operating standards that apply on the NEM mainland to any part of the power system that is islanded are shown in Table 4.2.

Table 4.2 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 4.3 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 4.3 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 use of this provision	48 to 52 Hz (Queensland and South Australia) 48.5 to 52 Hz (New South Wales and Victoria)	49.0 to 51.0 Hz within 2 minutes	49.5 to 50.5 Hz within 10 minutes
Multiple contingency event or separation event	47 to 52 Hz	49.0 to 51.0 Hz within 2 minutes	49.5 to 50.5 Hz within 10 minutes

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.

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 customers 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.[50] 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 4.4.

Table 4.4 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,[51] which can be implemented for any generating system with a capacity that is greater than 144 MW by the automatic tripping of load.

The frequency operating standards that apply in Tasmania to any part of the power system that is islanded are outlined in Table 4.5.

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

51 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.

Table 4.5 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	
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,[52] which can be implemented for any generating system with a capacity that is greater than 144 MW by the automatic tripping of load.

Performance assessment

The power system frequency was generally maintained within the limits set by the Panel. There were some instances, however, where the frequency did not meet the requirements of the frequency operating standards.

NEM mainland

Table 4.6 shows the number of times the frequency moved outside the normal operating band during the 2009-10 fiscal year for the NEM mainland.

The frequency moved outside the normal operating band 10 times during the 2009-10 fiscal year. This is less than the 2008-09 fiscal year, where the frequency moved outside the normal operating band 20 times.

Table 4.6 Frequency events on the mainland 2009-10

Number of events	Total	Low frequency	High frequency
outside normal operating frequency band	10	10	0
outside normal operating frequency excursion band	1	1	0
Events where duration exceeds 300 seconds[53]	10	10	0

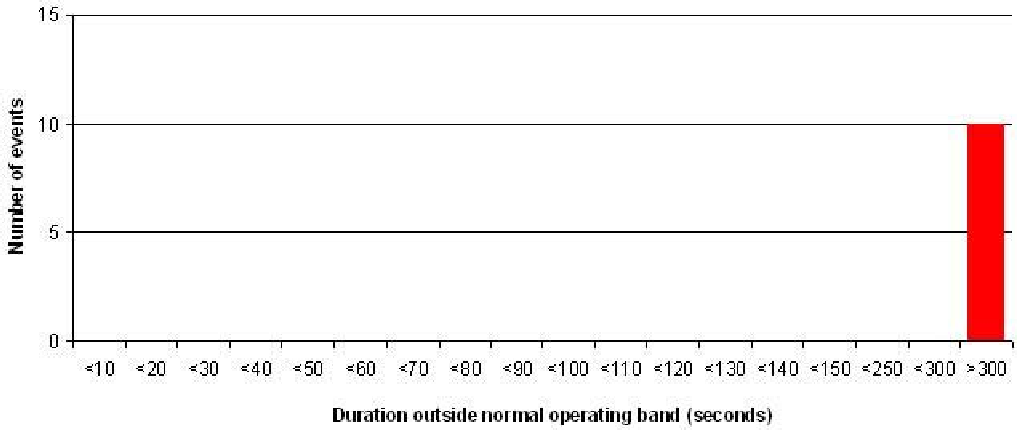
Source: AER

52 Ibid.

53 The frequency operating standards required recovery to the normal band within 300 seconds for generators, load and network events.

Figure 4.2 shows that the duration of all the frequency excursion events in the 2009-10 fiscal year were longer than five minutes. While 2009-10 had fewer events, like 2008-09, all of these events were longer than 5 minutes.

Figure 4.2 Duration of frequency events on the NEM mainland



Source: AER

A minimum frequency of 49.00 Hz for a duration of 664 seconds occurred on the NEM mainland on 2 July 2009, following the disconnection of multiple generators following the failure of a current transformer in the Bayswater Power Station. On no occasion did the frequency on the NEM mainland exceed the upper limit of the normal operating frequency band in 2009-10.

In 2001, the Panel introduced a probabilistic frequency standard. In response to that standard, the requirement for regulation frequency control ancillary services (FCAS)[54] (raise and lower), in the mainland, which is used to manage minor fluctuations in frequency, has been progressively reduced by NEMMCO since June 2003.

In June 2006, sculpted FCAS requirements were introduced.[55]

On 17 December 2007 changes to the regulating FCAS requirements for the NEM mainland were implemented. These changes use FCAS constraint equations in dispatch to determine the amounts of regulation FCAS (raise and lower) based on the time error.[56] The principle is that the FCAS dispatch constraints will set regulation to the current levels of 130 (for raise)/120 (for lower) if the time error remains inside +/- 1.5s. After that the constraints will add 60 MW of regulation per 1s deviation from that with an upper limit of 250 MW.

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54 Note that FCAS is not a Rules defined term. Under the Rules, these services are termed Market Ancillary Services.

55 NEMMCO Communication, 16 June 2006.

56 NEMMCO Communication, 7 December 2007.

Changes in the raise and lower regulation FCAS requirements for the NEM mainland are illustrated in Table 4.7.

Table 4.7 Reductions to raise and lower regulation FCAS requirement (Mainland)

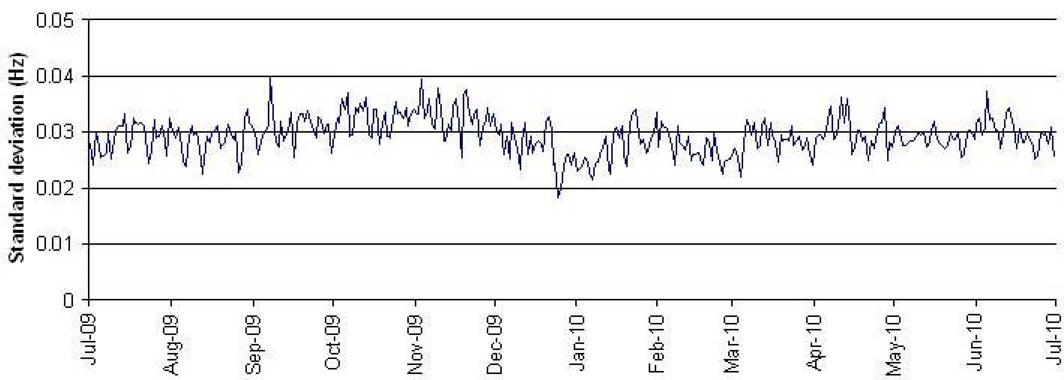
Month	Enabled regulation FCAS (MW)	
Pre July 2003	250	
July 2003	220	
October 2003	200	
March 2004	180	
May 2004	160	
July 2004	150	
April 2005	140	
August 2005	130	
June 2006	Time sculpted (raise)	120 (lower)
December 2007	130 (raise) - may be adjusted for time error	120 (lower) may be adjusted for time error

Source: AER

Figure 4.3 shows the distribution of the measured frequency on the NEM mainland for each day in the 2009-10 fiscal year.

AEMO develops FCAS constraint equations in dispatch to determine the required amounts of regulation FCAS (raise and lower) based on the accumulated time error. AEMO is working towards co-optimising regulation and the related contingency services.

Figure 4.3 Daily standard deviation of frequency on the NEM mainland



Source: AER

Tasmania

Table 4.8 shows the number of times the frequency moved outside the normal frequency operating band during the 2009-10 fiscal year for Tasmania.

Table 4.8 Frequency events in Tasmania 2009-10

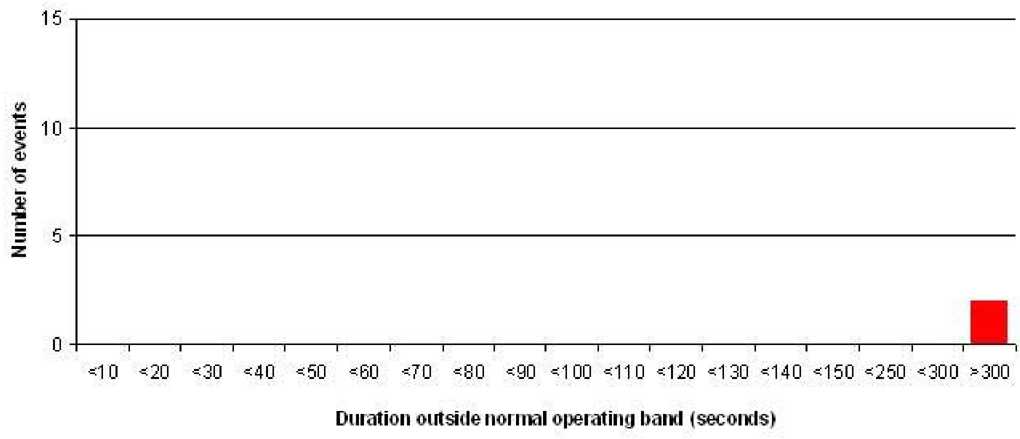
Number of events	Total	Low frequency	High frequency
outside normal operating frequency band	2	2	0
outside normal operating frequency excursion band	2	2	0
Events where duration exceeds 300 seconds	2	2	0

Source: AER

There were two occasions where the frequency moved outside the normal frequency operating band. This is slightly lower than the 2008-09 fiscal year where there were five such occurrences.

The duration of both of these frequency events was longer than that stated in the frequency operating standards. These events each exceeded 300 seconds as shown in Figure 4.4.

Figure 4.4 Duration of frequency events in Tasmania

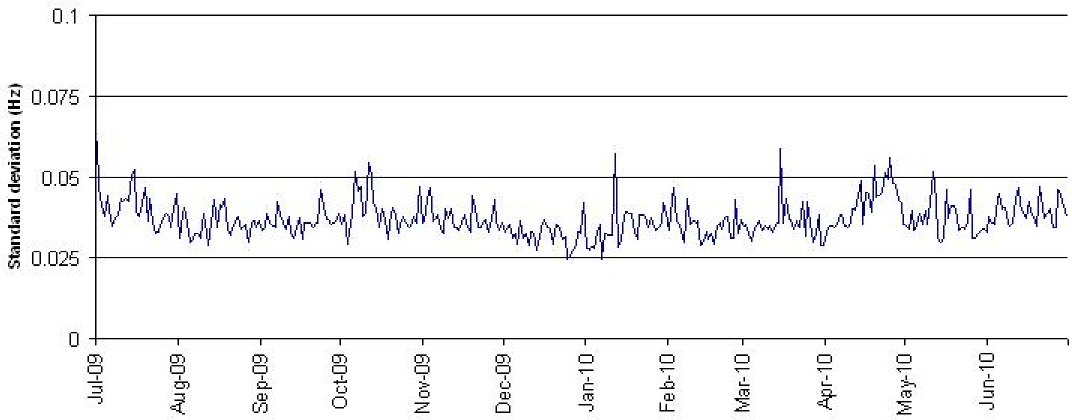


Source: AER

A minimum frequency of 48.9 Hz occurred in Tasmania on 31 December 2009 following the trip of the John Butters generating unit. This low frequency excursion event lasted for 356s. On no occasion did the frequency in Tasmania exceed the upper limit of the normal operating frequency band in 2009-10.

Figure 4.5 shows the distribution of the measured frequency for each day in the 2009-10 fiscal year for Tasmania.

Figure 4.5 Daily standard deviation of frequency in Tasmania



Source: AER

4.2.4 Equipment ratings

Asset owners provide a statement about the envelope within which AEMO may operate individual items of plant and equipment. AEMO then allows for the occurrence of any single credible contingency event before the ratings are reached.

Performance assessment

There were no known incidents 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 monitoring systems.

4.2.5 System voltage limits

This is the standard agreed between AEMO and the TNSPs for the envelope within which the transmission network voltage is maintained. AEMO has systems to monitor the performance of voltage levels against the limits advised by the 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.

Performance assessment

AEMO advised that it was generally able to maintain voltages within advised limits throughout the 2009-10 fiscal year. However, on 9 October 2009, control actions by local Kogan Creek power station staff resulted in the power system in the vicinity of Braemar 275kV substation deviating from the satisfactory operating state for six minutes.

4.2.6 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 State estimator, power flow and contingency analysis software. In recent years, AEMO has introduced a number of additional tools.

The first consists of monitoring equipment that detects oscillatory disturbances on the power system that could lead to a security threat. 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.

The second key security analysis tool is the online Dynamic Security Assessment (DSA) tool. The DSA uses 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 tool uses 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 compliments AEMO's oscillatory stability monitoring capability and enhances observability of power system disturbances in operational time frames and for post contingency analysis.

Performance assessment

AEMO's reviews of significant events 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 were a number of occasions 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 the constraint equations 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 identified and fed back to the relevant TNSP.

4.3 AEMO planning analysis

AEMO is required to determine total operational requirements for frequency, voltage and stability management and operation within equipment ratings and standards under the Rules. Constraint equations used in the market systems and AEMO's operating procedures are derived in this process.

4.3.1 Performance assessment

The quality of AEMO's analysis is difficult to measure directly. An indirect measure of performance is provided by the overall technical performance of the power system compared with operating standards. Analysis in other sections of this report of the technical performance of the power system – for example, frequency, system stability, and loading against equipment ratings – suggests that AEMO is generally performing this function satisfactorily.

4.4 Inherent system aspects to address system security

A portion of the total requirements for security is derived from the inherent response of consumer demand to variation in frequency and the fundamental physical characteristics of power system equipment. The inertia of the physical mass of generators determines how susceptible the power system is to disturbances. This inherent response is taken into account when determining the requirements for services scheduled by AEMO. The components of the inherent system response and design contributions include mandated performance, system response and the performance of protection and control systems. The components are described and analysed below.

The Panel will closely watch the effects of the introduction of alternative technologies, such as wind generation, over the coming years.

4.4.1 Mandated performance

In many cases satisfactory performance of the power system relies on both the correct operation of individual items of participant equipment and on the coordination of their operating characteristics. The Rules require the actual response to be measured by participants and reported to AEMO. AEMO also compares the actual system and participant response to power system events with the requirements of the Rules.

4.4.2 Inherent system response

The inherent system response is the automatic response of plant and equipment to disturbances over which there is no direct operational control. Examples include the change in demand placed on the system by consumer load when power system frequency or voltage varies from normal, and the rate at which large generating units can change speed or alter output. Although it is not a large contributor to the overall security response, inherent response reduces the need for response from other sources such as ancillary services.

Inherent load relief[57] is determined by AEMO based on analysis of system performance during frequency disturbances. This value is then taken into account when determining the requirements for FCAS scheduled by AEMO.[58]

4.4.3 Performance of protection and control systems

Protection and control systems are the automatic fast acting systems, such as the facilities to isolate power system faults, and emergency control systems installed to enhance network transfer capability and safeguard the power system in the event of multiple contingency events. The provision of generator protection and control systems is documented through the registration process and connection agreements. Under the Rules, the performance is recorded by the plant operator and provided to AEMO following system disturbances.

Performance assessment

AEMO has investigated and reported on power system events, including the four major events detailed in section 2.3. Generally, these investigations found there were no significant issues with the protection systems.

4.4.4 AEMO operational analysis

The inherent and design contributions are analysed by AEMO and compared with the total requirements to determine the requirements for scheduled contributions to ensure

57 Load relief occurs when frequency dependent loads vary in a manner that favours frequency recovery, as the amount of generator response that is required to recover the frequency is reduced.

58 An estimate of the load relief factor is taken as 1.5 percent per 1 percent of frequency change, that is, for every 0.5 Hz, the load relief is 1.5 percent of the demand.

secure operation. The additional requirements are in the form of scheduled mandatory and commercial contributions and of necessary intervention. This analysis is performed close to dispatch.

This analysis can have a significant impact on commercial and system security outcomes. For example, AEMO's online monitoring tools may identify the need to reduce interconnector transfer capability in order to maintain security. On these occasions, the power system conditions at the time are 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 the constraint equations used to manage those limits. AEMO therefore refers these situations to the relevant TNSP for further action and potential updating of limit advice.

4.4.5 Scheduling

Scheduled services are added to the inherent and design contributions to ensure the total control capability meets the overall requirement. Scheduled services include mandatory requirements and commercially acquired services. Examples of scheduled mandatory requirements include generating unit reactive power output in accordance with the performance standards, governor performance and capacitor bank switching for voltage control.

4.4.6 Scheduled commercial contribution

These are the commercially sourced ancillary services required to balance the total requirement. Examples include generating unit reactive power output beyond the performance standards, and frequency control ancillary services. AEMO's scheduling process is reviewed in the market auditor's reports.[59]

4.5 Power system directions

Power system directions are the power system security safety net mechanisms available to AEMO to issue directions to maintain the power system in a secure operating state. For the purposes of this report, reliability directions are those that affect a whole region and therefore require intervention or 'what if' pricing. A direction for a local security issue does not affect pricing.

AEMO issued seven directions during the 2009-10 fiscal year to manage local security issues, these are discussed below. Table 4.9 shows a comparison with past financial years.

59 Market audit reports are available to registered market participants.

Table 4.9 Number of directions issued by AEMO

	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

On 4 October 2009, AEMO reclassified the loss of transmission lines from Ross to Strathmore in Queensland as a credible contingency. According to AEMO, when the generator was constrained on, it rebid its units unavailable. AEMO then issued a direction to the Registered Participant to synchronise and follow dispatch targets in order to maintain the lines within secure limits and avoid load shedding.

On 20 November 2009, high temperatures in New South Wales resulted in AEMO declaring LOR2 conditions for the region. AEMO directed a Registered Participant, whose units were currently unavailable, to bid its units available and follow dispatch targets in order to improve generation reserves.

On 27 November 2009, contingency analysis indicated the loss of the Robertson to Para and Robertson to Tungkillo lines would overload the Bungama to Brinkworth line in South Australia. A constraint was applied to resolve the violation, however, no effective solution could be found. To resolve the violation, AEMO issued two directions to a Registered Participant to reduce generation on two generating units.

On 28 November 2009, high temperatures in Queensland resulted in two generating units in northern Queensland reducing their outputs and going off line. The reduction in energy caused a constraint equation to violate. AEMO issued a series of related directions to a number of generating units in northern Queensland to either generate or increase output to maintain power system security.

On 31 December 2009, AEMO reclassified the loss of the Farrell to Sheffield and Chapel Street to Gordon lines in Tasmania as non-credible contingent events due to lightning storms. This reclassification caused a reduction of Raise 6 second FCAS and constraints to violate. Constraints were progressively applied to reduce the inter-regional transfer limit and AEMO directed a Registered Participant in Tasmania to make Raise 6 second FCAS available from one of its generators.

On 17 January 2010, increasing temperatures placed the power system in far north Queensland in an insecure state. To restore secure operation AEMO issued a direction to a Registered Participant with available generating plant to provide additional output.

On 21 March 2010, AEMO declared the simultaneous trip of 275 kV feeders 879 and 880 in Queensland as a credible contingency event due to the presence of a tropical cyclone. Following this, constraint limits flowing from central to north Queensland began to violate. AEMO issued a direction to a Registered Participant to start up one of their available generating units, synchronise and follow dispatch targets so the north Queensland power system could be restored to a secure system.

5 Safety

The Panel is required in accordance with section 38 of the NEL to monitor, review and report on, in accordance with the Rules, the safety of the national electricity system. Safety is referred to in a number of areas of the NEL and the Rules, usually in relation to public safety or electrical safety in a technical sense.

5.1 Electrical safety in a technical sense

As regulation is the responsibility of jurisdictional regulators there is no national safety regulator for electricity. There are explicit transmission and distribution system safety duties that refer to the safe transmission or distribution of electricity, and the safe operation of a transmission or distribution system. These duties are obligations on regulated network service providers under the relevant Acts of the associated participating jurisdictions (section 2D(a) of the NEL).

There are various references in the National Electricity Objective (section 7 of the NEL), the AEMC's Rule making powers (section 34 of the NEL), Reliability Panel's functions (section 38 of the NEL) and disclosure of information by AEMO (section 54G of the 2009 amendment to the NEL) that refer to "safety, reliability and security" of supply of electricity and the national electricity system. AEMO considers these to be references to Part 8 of the NEL, which describes the arrangements for the "safety and security of the National Electricity System". These cover the AEMO load shedding procedures, jurisdictional load shedding guidelines and sensitive loads. In this context, safety is referring to "public safety" rather than electrical safety.

The Rules generally refer to safety in a technical sense. For example, the purpose of the system standards in schedule 5.1a is for the safe and reliable operation of equipment and facilities, and the definition of power system security refers to the "safe scheduling, operation and control of the power system". AEMO considers operation of the power system according to the general principles for maintaining power system security (clause 4.2.6) to be "safe" for the purposes of the Rules.

5.2 Public safety

Part 8 of the NEL also outlines AEMO's powers of direction to maintain power system security for reasons of public safety (section 116 of the NEL). A person must not, without reasonable excuse, obstruct or fail to comply with a direction issued by AEMO (section 118 of the NEL). AEMO would expect the directed party to consider safety of personnel or equipment as reasonable excuses in deciding whether to obstruct or comply with a direction issued by AEMO.

5.3 Performance assessment

The Panel considers that AEMO appears to adhere to its NEL and Rules obligations in respect of safety in the national electricity market

6 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 customers 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.

6.1 Transmission network performance

This section includes an overview of the jurisdictional arrangements for managing the reliability performance of the NEM transmission networks.

6.1.1 Queensland

The mandated reliability obligations and standards are contained in Schedule 5.1 of the Rules, the Queensland Electricity Act, the 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 Country 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 (N-1 conditions) unless otherwise agreed with affected participants. This is based on satisfying the following obligations:

- to ensure as far as technically and economically practicable that the transmission grid is operated with enough capacity (and if necessary, augmented or extended to provide enough capacity) to provide network services to persons authorised to connect to the grid or take electricity from the grid (Electricity Act 1994, S34(2));

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

- the Connection Agreements between Powerlink and ENERGEX, Ergon Energy and Country 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. N-1. Following the EDSD report in 2004, ENERGEX and Ergon are required to plan their subtransmission networks (which interact with the Powerlink transmission network) to the N-1 criterion.

6.1.2 New South Wales

TransGrid is obliged to meet the requirements of Schedule 5.1 of the Rules. TransGrid's planning obligations are also interlinked with the distribution licence obligations imposed on all DNSPs in NSW. These licence obligations are generally N-1 in most urban and rural areas with a higher standard of N-2 in CBD areas.

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 New South Wales Electricity Supply (Safety and Management) Regulation 2008 . This includes lodging and then complying with a Network Management Plan with the NSW Department of Water and Energy. TransGrid issued an updated Network Management Plan in February 2009. The plan is required to be reviewed every two years.

Under this plan, TransGrid's planning and development of its transmission network is required to be on an "N-1" basis, except under conditions such as radial supplies, inner metropolitan areas, and the CBD. Transmission network developments servicing inner metropolitan and CBD areas are planned on a modified "N-2" basis or, when required, to accommodate AEMO's operating practices.

6.1.3 Victoria

AEMO is responsible for planning the Victorian electricity declared shared network in accordance with its obligations under the Rules.

AEMO publishes a Victorian Annual Planning Report (VAPR), which provides forecasts for energy demand and supply, and identifies future transmission development needs for the declared shared network.

AEMO assesses new augmentations under the Regulatory Investment Test for Transmission (RIT-T) as specified by the AER. In accordance with the RIT-T requirements, AEMO identifies the benefits of various transmission investment options using a probabilistic planning process that calculates, amongst other things, reduction in unserved energy, reduction in generation fuel costs, transmission loss reductions, and capital plant deferrals. These benefits are then balanced against the cost of investments, and AEMO generally proceeds with the option with the highest net economic benefit out of a range of options.

AEMO calculates the benefits of reductions in expected unserved energy by application of a value of customer reliability (VCR). The VCR as at 2010 is set at $ 60 178 per MWh. AEMO also considers a sector specific VCR where the transmission constraint affects only a reasonably distinguishable subset of the load.

6.1.4 South Australia

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 ESCOSA.[60] The ETC sets specific reliability standards (N, N-1, N-2 etc) for each transmission exit point.

ESCOSA concluded a review of the specific reliability standards under clause 2.2.2 of the ETC in 2006. The associated changes to the ETC took effect from 1 July 2008 to align with the AER's current price determination for ElectraNet.[61] As part of the review, ESCOSA sought to clarify network reliability standards for the Adelaide CBD, which is supplied jointly by ElectraNet and ETSA Utilities, and ElectraNet will be required to install a new transmission connection point to the CBD by the end of 2011. This will ensure that future CBD demand growth can be met with a greater level of reliability. ElectraNet has developed a proposed solution to meet this requirement which satisfies the requirements of the Regulatory Test[62], and is proceeding to complete this augmentation within the required time frame.

ESCOSA has commenced its next 5-year review of the specific reliability standards under clause 2.2.2 of the ETC and will consult on any proposed changes to the ETC during 2011.

6.1.5 Tasmania

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, ESI (Network Performance Requirements) Regulations 2007, 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 ESI (Network Performance Requirements) Regulations 2007 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.

The AER's STPIS sets and administers reliability based service standards targets which involve an annual financial incentive (bonus/penalty) incorporated in Transend's

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60 ESCOSA, 2008, Electricity Transmission Code, http://www.escosa.sa.gov.au/webdata/resources/files/060906-R-ElecTransCodeET05.pdf.

61 ESCOSA, 2006, Review Of The Reliability Standards Specified In Clause 2.2.2 Of The Electricity Transmission Code Final Decision, http://www.escosa.sa.gov.au/webdata/resources/files/060906-R-ReviewReliabilityElectricityTransmissionCodeFinalDec.pdf.

62 ElectraNet Pty Ltd, 10 July 2009, Proposed New Large Network Asset, Adelaide Central Region, South Australia: Final Report, http://www.aemo.com.au/consultations/0179-0009.html.

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.

6.2 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)[63] has adopted four indicators of distribution network reliability that are widely used in Australia and overseas.[64] 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).[65] While all jurisdictions report on SAIDI and SAIFI, Distribution Network Service Providers (DNSP) performance data may not be directly 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.

6.2.1 Queensland

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

Queensland Electricity Industry Code requires that the Queensland Competition Authority 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,[66] the Queensland Competition Authority set the current MSS and GSL, which apply from 1 July 2010.

In October 2009, the Queensland Competition Authority also completed a review which resulted in changes to the Queensland Electricity Industry Code provisions

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

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

65 See the Glossary for further information.

66 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, www.qca.org.au/electricity/service-quality/RevMinServStandLev.php.

covering the lodgement and assessment of GSL claim procedures.[67] Both decisions can be accessed from the Authority's website.[68]

Distributors report quarterly to the Authority on their performance relative their MSS. The Authority also monitors their GSL performance.

Table 6.1 provides a summary of the performance of the Queensland DNSPs including target and actual performance for each DNSP.

Table 6.1 Performance of the Queensland DNSPs for the 2009-10 Year

DNSP	Feeder	SAIDI (minutes)		SAIFI	
		Target	Actual	Target	Actual
Energex	**CBD**	20	1.19	0.33	0.08
	urban	110	88.48	1.32	1.20
	short-rural	220	215.73	2.50	2.41
Ergon	**urban**	150	221.74	2.00	2.25
	short-rural	430	542.89	4.00	4.58
	long-rural	980	995.19	7.50	7.19

SAIDI and SAIFI performance data for 2008-09 and 2009-10 were based on data provided by DNSPs under the QEIC. This data excludes outages caused by generators and transmission networks.

Table 6.1 shows that Energex met its SAIDI and SAIFI targets for all feeder categories during 2009-10. Conversely, Ergon Energy failed to meet 5 out of its 6 MSS targets (the exception being long-rural SAIFI) for the second consecutive year. This was despite improvement across all feeder categories (except urban SAIDI) in comparison to the previous year. Ergon Energy indicated that its reliability performance for 2009-10 was adversely impacted by the same two operational factors that affected its performance in 2008-09, namely the increase in planned outages and planned outage durations as a result of the suspension of live line work practices (from February 2009) and operation restrictions being placed on air break switches in 2008 due to increasing air break switch failures.

Ergon Energy also cited a number of other factors contributing to its failure to achieve its MSS targets in 2009-10, including stricter national clearance standards, tropical cyclone Ului remediation works and the reinstatement of bans on substation air break switches due to an operational failure in March 2010. More detailed performance

67 Queensland Competition Authority, October 2009, Final Decision: Proposed amendments to the Electricity Industry Code regarding customer claims for GSL payments, www.qca.org.au/files/E-ServQual-QCA-GSLClaimPro-FinalDec-1009.PDF.

68 The Queensland Competition Authority website is available at http://www.qca.org.au.

information is available from network performance reports available on the Authority's website.

Up until the March quarter 2010, the Authority also monitored service quality performance under the its Service Quality Reporting Guidelines established in its previous role as distribution regulator. Monitoring by the Authority ceased from 1 July 2010, when responsibility transferred to the AER.

6.2.2 New South Wales

The Electricity Supply Act 1995 covers the licensing framework for the New South Wales DNSPs. The network performance standards are implemented licence conditions imposed by the Minister.

From August 2005, the network performance standards for the New South Wales DNSPs have been set by the Minister for Energy through Ministerially imposed licence conditions. These licence conditions were amended on 1 December 2007 and are published on the Independent Pricing and Regulatory Tribunal's (IPART)[69] website (conditions 14-19).[70]

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

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

Table 6.2 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 2002 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.

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

70 The Minister For Energy and Utilities, 2005, Design, Reliability and Performance Licence Conditions Imposed On Distribution Network Service Providers, http://www.ipart.nsw.gov.au.

The network performance standards are enforced under the Electricity Supply Act 1995, Schedule 2, Clauses 8 and 8A. Under 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 6.2 Performance of the New South Wales DNSPs for the 2009-10 year

DNSP	Feeder	SAIDI (minutes)		SAIFI	
		Target	Actual	Target	Actual
Country Energy	Urban	128	69	1.84	1.04
	Short rural	308	204	3.06	2.19
	Long rural	710	384	4.60	2.88
	All	n/a	196	n/a	1.99
Energy Australia	CBD	48	38.1	0.31	0.11
	Urban	82	66.7	1.22	0.95
	Short rural	320	179.1	3.40	2.05
	Long rural	740	443.6	6.50	3.52
	All	n/a	79.0	n/a	1.05
Integral Energy	Urban	82	59	1.22	0.8
	Short rural	300	157	2.80	1.7
	Long rural	n/a	1331	n/a	8.3
	All	n/a	79.4	n/a	1.0
NSW	CBD	n/a	38.1	n/a	0.11
	Urban	n/a	64.6	n/a	0.91
	Short rural	n/a	188.1	n/a	2.05
	Long rural	n/a	387.1	n/a	2.90
	All	n/a	107.4	n/a	1.26

Table 6.2 shows that Country Energy, Energy Australia and Integral Energy each met its SAIDI and SAIFI targets for all feeder categories during 2009-10.

6.2.3 Australian Capital Territory

The Utilities Act (2000) 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[71] and in the Consumer Protection Code,[72] which also has minimum service standards.

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.

Table 6.3 shows a summary of the performance of the Australian Capital Territory DNSP for 2009-10. More detailed performance information is available from network performance reports available on the ICRC website.

Compared with the DNSP performance last year, performance against the SAIDI, SAIFI and CAIDI has improved for the urban feeders and the network as a whole for almost all categories. However, performance of the rural short feeder category against the SAIDI and SAIFI has decreased.

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71 ICRC, 2000, Electricity Distribution (Supply Standards) Code, http://www.icrc.act.gov.au/__data/assets/pdf_file/0016/16630/electricitydistributionsupplystandardscodecw.pdf.

72 ICRC, 2007, Consumer Protection Code, http://www.icrc.act.gov.au/__data/assets/pdf_file/0011/47909/Consumer_Protection_Code.pdf.

Table 6.3 Performance of the Australian Capital Territory DNSP 2009-10

Feeder		SAIDI (minutes)		SAIFI		CAIDI	
		Target	Actual	Target	Actual	Target	Actual
Urban	Overall	n/a	79.7	n/a	0.88	n/a	90.2
	Distribution network - planned	n/a	50.9	n/a	0.24	n/a	215.6
	Distribution network - unplanned	n/a	28.9	n/a	0.65	n/a	60
	Normalised distribution network - unplanned	n/a	25.5	n/a	0.61	n/a	60.0
Rural short	Overall	n/a	71.4	n/a	0.981	n/a	72.8
	Distribution network - planned	n/a	45.3	n/a	0.197	n/a	229.7
	Distribution network - unplanned	n/a	26.1	n/a	0.783	n/a	60
	Normalised distribution network - unplanned	n/a	26.4	n/a	0.783	n/a	33.4
Network	Overall	91.0	80.4	1.2	0.9	74.6	89.6
	Distribution network - planned	n/a	51.3	n/a	0.24	n/a	216.1
	Distribution network - unplanned	n/a	29.1	n/a	0.66	n/a	44.1
	Normalised distribution network - unplanned	n/a	25.8	n/a	0.62	n/a	41.6

6.2.4 Victoria

The Electricity Industry Act 2000 and the Essential Services Commission Act 2001 cover the network performance requirements for the Victorian DNSPs. From 1 January

2009, responsibility for the compliance monitoring and enforcement of the DNSPs' distribution licence conditions was transferred from the Essential Services Commission of Victoria (ESC) to the AER.[73]

The ESC sets performance targets for unplanned SAIFI, unplanned SAIDI and MAIFI for the 2006-10 regulatory period for calculation of the financial incentive for improving supply reliability. Financial rewards and penalties apply to DNSPs depending on how their performance compares to their respective performance targets, in accordance with the S-factor scheme.[74] DNSPs are also required to make GSL payments to the worst served customers if there have been excessive sustained supply outages and momentary interruptions.[75]

The performance indicators for the Victorian DNSPs are reported to the AER for the calendar year. The distribution licence requires independent audits of these indicators on a rotating basis. All DNSPs were last audited in mid-2009. The AER publishes annual comparative performance reports for the distributors.[76]

Extended heatwave and extremely high temperatures in late January and early February 2009 seriously impacted the level of supply reliability in Victoria. Temperatures in Melbourne exceeded 43°C for three days in a row from 28 to 30 January 2009. About one week later, on 7 February 2009 (black Saturday), temperatures in Melbourne reached a record 46.6°C.

The heatwave resulted in higher power usage, coupled with transmission and distribution network faults and outages, including the unavailability of the Bass Link connection to Tasmania. A series of load shedding events were initiated during these periods in order to keep the electricity system running. This contributed to a significant deterioration in supply reliability measures.

Table 6.4 shows a summary of the performance of the Victorian DNSPs for 2008. This includes target and actual performance values for each DNSP in Victoria. More detailed performance information is available from network performance reports available on the AER's website. The Panel anticipates that the 2009 data will be available for the Final Report.

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

74 Details of the S-factor scheme are available from the Electricity Distribution Price Review 2006-10 documents, available from the ESC's website at http://www.esc.vic.gov.au/public/Energy/Regulation+and+Compliance/Decisions+and+Determinations/Electricity+Distribution+Price+Review+2006-10.

75 Details of the guaranteed service level payments are contained in clause 6 of the Electricity Distribution Code (EDC), available at http://www.esc.vic.gov.au/public/Energy/Regulation+and+Compliance/Codes+and+Guidelines/.

76 Prior to January 2009, performance reports for the Victorian distributors were published by the ESC.

Table 6.4 Performance of the Victorian DNSPs for 2008

		SAIDI (minutes)				SAIFI			
		Unplanned		Planned		Unplanned		Planned	
DNSP	Feeder	Target	Actual	Target	Actual	Target	Actual	Target	Actual
Jemena	**Urban**	73	111.42	6	9.22	1.27	0.03	1.18	0.04
	Short rural	113	173.42	14	25.57	2.25	0.08	2.78	0.09
CitiPower	**CBD**	14	10.37	6	2.79	0.25	0.02	0.16	0.02
	Urban	35	51.70	10	4.64	0.80	0.03	0.61	0.02
Powercor	**Urban**	98	93.38	16	14.79	1.63	0.09	1.40	0.07
	Short rural	118	107.89	35	28.57	1.80	0.15	1.46	0.13
	Long rural	297	214.96	70	28.90	3.30	0.25	2.14	0.21
SP AusNet	**Urban**	109	205.95	16	39.35	1.82	0.09	1.38	0.14
	Short rural	185	365.37	35	74.61	2.73	0.15	2.63	0.34
	Long rural	300	344.35	70	89.97	4.28	0.30	3.65	0.46
United Energy	**Urban**	59	262.94	16	16.33	1.06	0.10	1.27	0.05
	Short rural	96	464.60	35	25.17	2.03	0.15	2.01	0.09

Notes:

1. Performance figures are based on National Reporting Framework format and include both Planned and Unplanned interruptions.
2. An electricity Distribution Business Comparative performance report is available from the AER's website at www.aer.gov.au.

The enforcement of the network performance standards is through adjustment to the DNSP's revenue, based on the unplanned SAIDI, SAIFI and MAIFI values, performance of the distribution call centres, and through payments to customers where the GSL requirements are not met.

Table 6.5 shows the performance data for the Victorian DNSPs with the impact of a number of extreme events excluded from the service performance data.

Table 6.5 Performance of the Victorian DNSPs for 2008 - impact of excluded events[77] removed

		SAIDI (minutes)				SAIFI			
		Unplanned		Planned		Unplanned		Planned	
DNSP	**Feeder**	**Target**	**Actual**	**Target**	**Actual**	**Target**	**Actual**	**Target**	**Actual**
Jemena	**Urban**	73	61.88	6	9.22	1.27	0.89	0.03	0.04
	Short rural	113	97.75	14	25.57	2.25	1.44	0.08	0.09
CitiPower	**CBD**	14	10.35	6	2.79	0.25	0.16	0.02	0.02
	Urban	35	23.88	10	4.64	0.80	0.41	0.03	0.02
Powercor	**Urban**	98	79.91	16	14.79	1.63	1.28	0.09	0.07
	Short rural	118	97.08	35	28.57	1.80	1.33	0.15	0.13
	Long rural	297	194.88	70	28.90	3.30	1.97	0.25	0.21
SP AusNet	**Urban**	109	73.59	16	39.35	1.82	0.99	0.09	0.14
	Short rural	185	146.13	35	74.61	2.73	2.19	0.15	0.34
	Long rural	300	199.62	70	89.97	4.28	3.31	0.30	0.46
United Energy	**Urban**	59	61.39	16	16.33	1.06	0.92	0.10	0.05
	Short rural	96	84.8	35	25.17	2.03	1.56	0.15	0.09

77 Excluded events are "upstream events", such as transmission outages and load shedding events, and "major event days" exceeding the relevant daily unplanned SAIFI thresholds set by the ESC for the 2006-10 regulatory period.

6.2.5 South Australia

The DNSP supply restoration and reliability standards are established by the Essential Services Commission of South Australia (ESCOSA) through the Electricity Distribution Code and the Electricity Distribution Price Determination 2005-2010 (EDPD).

The reliability and performance standards established by ESCOSA for the DNSP, ETSA Utilities, comprise three main elements:

- Average Standards

  Average service standards for network reliability performance measured by frequency and duration of supply interruptions experienced by customers. Standards are based on the DNSP performance averaged across all customers connected to the network within each of seven defined regions, expressed in terms of the performance over a 12 month period. The standards to be met for the 2005-2010 period were determined on the basis of historical reliability performance in the period 2000-2004. Customer service standards (e.g. telephone responsiveness) are based on historical performance levels and cover state-wide performance. Average standards underpin the distribution prices permitted to be charged by the DNSP and are specified in the Electricity Distribution Code.

- Incentives to improve reliability to poorly served customers

  Service Incentive (SI) Scheme provided for in the EDPD provides a financial incentive (increased revenue) for the DNSP to improve reliability service to the worst served consumers comprising approximately 15 percent of the customer base. A penalty applies if performance worsens beyond established benchmarks. The SI scheme also includes telephone responsiveness, although this is focussed on all customers not solely on poorly served customers.

  The key difference between the SI scheme established for the DNSP in South Australia and those established in some other jurisdictions is that the SI scheme focuses on driving reliability performance improvements for poorly served customers, rather than for all customers.

  From 1 July 2010, the AER will be responsible for administering ETSA Utilities' entitlements under its newly established Service Target Performance Incentive Scheme (STPIS).

- GSL scheme

  Both the average standards and the SI scheme involve an assessment of DNSP performance as experienced by a group of customers (e.g. performance averaged across customers in the defined regions, or the worst served 15 percent of customers). The third major component of the service standard framework for the DNSP is a GSL scheme, which involves payments for poor service by the DNSP to individual customers.

> The Electricity Distribution Code establishes GSLs, within Part B of the Electricity Distribution Code (the standard connection and supply contract between ETSA Utilities and its customers) in relation to a number of timeliness matters (e.g. timeliness of appointments; connections; and street light repair). It also requires the DNSP to make specified payments if the frequency of interruptions or the duration of any single interruption exceeds the thresholds set out in the Code. Following a review, from 1 July 2010 payments range from, $90 for a single outage which is 12-15 hours duration $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.

DNSP reliability performance is reported to ESCOSA on a quarterly basis pursuant to Electricity Guideline 1. The DNSP 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 2008-09 fiscal year is illustrated in Table 25. The Panel anticipates that the data for the 2009-10 fiscal year will be available for the Final Report.

Table 6.6 Performance of the South Australian DNSP for 2008-09

Region	SAIDI (minutes)		SAIFI		CAIDI	
	Target	Actual	Target	Actual	Implied Standard	Actual
Adelaide Business Area	25	23	0.3	0.19	80	123
Major Metropolitan Areas	115	118	1.4	1.26	82	94
Central	240	225	2.1	1.84	115	122
Eastern Hills/Fleurieu Peninsular	350	326	3.3	3.11	105	105
Upper North and Eyre Peninsular	370	375	2.5	2.49	150	150
South East	330	226	2.7	1.86	120	121
Kangaroo Island	450	232	n/a	2.95	n/a	79
Total network	165	161	1.7	1.53	97	105

6.2.6 Tasmania

The Tasmanian Economic Regulator sets network performance requirements through the Tasmanian Electricity Code (TEC), price determinations and regulations.

On 1 January 2008, the 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 form part of the price/service package reflected in the Regulator's 2007 price determination and 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.[78]

The new 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.[79]

For 2009-10, the Tasmanian DNSP has continued to report against the former supply reliability standards for the purposes of year-on-year comparison.

Table 6.7 Performance of the Tasmanian DNSP 1 July 2009 to 30 June 2010 (against the former supply reliability standards)[80]

Feeder	SAIDI (minutes)	SAIFI	CAIDI
CBD	57	0.54	105.6
Urban	257	1.31	196.2
Rural	768	3.58	214.5
Network	211	1.75	120.6

Table 6.7 shows a summary of the performance of the Tasmanian DNSP against the former supply reliability standards. Similarly, Table 6.8 shows the performance of the Tasmanian DNSP against the network performance standards in the amended TEC.

78 Office of the Tasmanian Economic Regulator, 2005, Tasmanian Electricity Code, http://www.economicregulator.tas.gov.au.

79 Office of the Tasmanian Economic Regulator, 2007, Guideline - Guaranteed Service Level (GSL) Scheme, http://www.economicregulator.tas.gov.au.

80 System performance is for the distribution system only, and excludes outages caused by generators and transmission networks.

Table 6.8 Performance of the Tasmanian DNSP 1 July 2009 to 30 June 2010 (against the amended TEC)

Community category	SAIDI (minutes)		SAIFI	
	TEC (12 month category limit)	Performance	TEC (12 month category limit)	Performance
Critical infrastructure	30	21	0.20	0.19
High density commercial	60	80	1.00	0.76
Urban and regional centres	120	209	2.00	1.38
Higher density rural	480	798	4.00	3.69
Lower density rural	600	992	6.00	4.16

All categories performed within the TEC frequency standards for the 2009-10 reporting period. All categories, with the exception of Critical Infrastructure, exceeded their TEC duration standards during the 2009-10 reporting period. The Urban, High Density and Low Density Rural categories were all significantly impacted by storms in August and September of 2009. The High Density Commercial category was significantly impacted by two large unplanned outages during the year.

The following Table 6.9 shows the performance indices for each individual community in the Tasmanian region.

Table 6.9 Individual community performance indices (1 July 2009 to 30 June 2010)

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
	TEC Community limit	No. of non-complying communities	TEC Community limit (mins)	No. of non-complying communities		
Critical infrastructure	0.2	0/1	30	0/1	0/1	0/1
High density commercial	2.0	1/8	120	1/8	2/8	0/8
Urban and regional centres	4.0	0/32	240	11/32	11/32	0/32
Higher density rural	6.0	2/33	600	11/33	12/33	1/33
Lower density rural	8.0	1/27	720	10/27	10/27	1/27
Total		4/101		33/101	35/101	2/101

7 Glossary

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.

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).
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. **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.
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.
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)	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 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.
operating state	The operating state of the power system is defined as satisfactory, secure or reliable, as described below. **satisfactory operating state** The power system is in a satisfactory operating state when: • it is operating within its technical limits (i.e. frequency, voltage, current etc. are within the relevant standards and ratings) and • the severity of any potential fault is within the capability of circuit breakers to disconnect the faulted circuit or equipment. **secure operating state** The power system is in a secure operating state when: • it is in a satisfactory operating state and • it will return to a satisfactory operating

	state following a single credible contingency event. **reliable operating state** The power system is in a reliable operating state when: • AEMO has not disconnected, and does not expect to disconnect, any points of load connection under clause 4.8.9 (NER) • no load shedding is occurring or expected to occur anywhere on the power system under clause 4.8.9 (NER), and • in AEMO's reasonable opinion the levels of short term and medium term capacity reserves available to the power system are at least equal to the required levels determined in accordance with the power system security and reliability standards.
participant	An entity that participates in the National Electricity Market.
plant capability	The maximum MW output which an item of electrical equipment is capable of achieving for a given period.
power system reliability	The measure of the power system's ability to supply adequate power to satisfy demand, allowing for unplanned losses of generation capacity.
power system security	The safe scheduling, operation and control of the power system on a continuous basis.
Probability of Exceedance (POE)	POE relates to the weather/temperature dependence of the maximum demand in a region. A detailed description is given in the AEMO ESOO.
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 demand + demand-side participation.
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).
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.
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)	The PASA in respect of the period from two days after the current trading day to the end of the seventh day after the current trading day inclusive in respect of each trading interval in that period.
spot market	Wholesale trading in electricity is conducted as a spot market. The spot market allows instantaneous matching of supply against demand. The spot market trades from an electricity pool, and is effectively a set of rules and procedures (not a physical location) managed by AEMO (in conjunction with market participants and regulatory agencies) that are set out in the Rules.

spot price	The price for electricity in a trading interval at a regional reference node or a connection point.
supply-demand balance	A calculation of the reserve margin for a given set of demand conditions, which is used to minimise reserve deficits by making use of available interconnector capabilities.
technical envelope	The power system’s technical boundary limits for achieving and maintaining a secure operating state for a given demand and power system scenario.
transmission network 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.

Abbreviations

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AWEFS	Australian Wind Energy Forecasting System
CAIDI	Customer Average Interruption Duration Index
CCGT	closed cycle gas turbine
CPT	cumulative price threshold
DC	direct current
DNSP	Distribution Network Service Providers
DSA	Dynamic Security Assessment
EAAP	Energy Adequacy Assessment Projection
EDC	Electricity Distribution Code
EDPD	Electricity Distribution Price Determination
ESC	Essential Services Commission of Victoria
ESCOSA	Essential Services Commission of South Australia
ESOO	Electricity Statement of Opportunities
ETC	Electricity Transmission Code
FCAS	frequency control ancillary services
GSL	Guaranteed Service Level
HSM	high speed monitoring system
ICRC	Independent Competition and Regulatory Commission
IPART	Independent Pricing and Regulatory Tribunal
MAIFI	Momentary Average Interruption Frequency Index

MCE	Ministerial Council on Energy
MMS	Market Management System
MPC	market price cap
MRL	minimum reserve level
MSS	Minimum Service Standards
NECA	National Electricity Code Administrator
NEL	National Electricity Law
NEM	National Electricity Market
NEMMCO	National Electricity Market Management Company
NTNDP	National Transmission Network Development Plan
NTS	National Transmission Statement
OCGT	open cycle gas turbine
Panel	Reliability Panel
PASA	projected assessment of system adequacy
POE	probability of exceedance
PPI	Producer Price Index
RERT	Reliability and Emergency Reserve Trader
RIT-T	Regulatory Investment Test for Transmission
Rules	National Electricity Rules
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCONRRR	Steering Committee on National Regulatory Reporting Requirements
STPIS	Service Target Performance Incentive Scheme
TEC	Tasmanian Electricity Code

TNSP	transmission network service provider
USE	unserved energy
VAPR	Victorian Annual Planning Report
VCR	value of customer reliability