REVIEW OF RELIABILITY AND SECURITY IN THE ABSENCE OF THE RERT

A report to the Department Transport, Energy and Infrastructure South Australia

7 July 2011

FINAL

Intelligent Energy Systems

Executive Summary

Purpose of the Review

This report by Intelligent Energy Systems (IES) explores the issues and evidence of whether the existing framework as defined by the NEM Rules and their implementation is likely to be sufficient to provide an acceptable level of reliability in the future. The purpose of this review pertains to the AEMC recommendation that the Reliability and Emergency Reserve Trader (RERT) should expire on 30 June 2013 and that the requirement for the review of the RERT mechanism be removed from the rules.

Main IES Finding

The IES modelling and analysis found that the current MPC was sufficient for new generation capacity to be economic on the spot market within the NEM reliability standard, but that the required spot price signals were highly variable and not guaranteed in any one year. This result reflected the oligopoly nature of the NEM and the uncertainties associated with spot price outcomes. As such, supporting mechanisms may be required to supplement the reliability and security setting moving forward if reliability is to be ensured.

The distribution of USE when the market is at the 0.002% reliability standard has load shedding expected in most years when the level of maximum demand is at or greater than that expected. This suggests that the 0.002% standard of reliability may not be fully appreciated, in that when operating at the reliability standard AEMO may be required to act each year to avoid load shedding.

The modelling indicated the potential for significant differences between the NEM regions which needs to be more fully understood.

The presence of intra-regional constraints has a significant impact on the assessed level of reliability. This indicates that the impact of intra-regional constraints on reliability needs to be understood and that possibly the reliability standard should include the impact of intra-regional transmission constraints.

IES Approach

The main recommendations of the AEMC reports were that the Market Price Cap (MPC) needed to be increased and that the reliability and security setting are sufficient to have generation economic on the spot market at reliability levels within the established NEM 0.002% standard. These were also the conclusions of the modelling undertaken by ROAM on which the AEMC recommendations were based.

IES reviewed the ROAM modelling reports and concluded that there was a substantive issue of approach. The ROAM modelling assumed that new peaking plant would face the same economics as the “last peaking” operating in a perfectly competitive market. This would have it last on in the merit order, operate only to avoid load shedding, and receive a price near the MPC when operating. As such the MPC required for such plant to be economic is a maximum.

In undertaking their analysis, ROAM did not appear to properly account for the full distribution of load and wind generation. An analysis of the MPC needed for a "last peaker" to be economic in South Australia showed a required MPC of near $40,000/MWh. The fact that the ROAM modelling resulted in a required MPC less than half this value for South Australia is considered to reflect an approach that contained biasing of the load distribution and that was highly deterministic.

IES considered that an assessment of the MPC required to have sufficient new generation enter on spot market economics required that the full distribution of load and wind generation be considered and that the dynamics of the NEM (in terms of observed generator behaviour – bidding and new entry) be properly considered. IES undertook market simulation modelling that accounted for these issues (to account properly for wind diversity was outside the scope of this study).

IES Review and Analysis

Reliability and the Standard

The review begins by identifying the components that reliability (as defined by the AEMC) covers in the supply chain. Reliability is primarily defined in terms of Unserved Energy (USE) that results from generator outages and interconnector capacity reductions. All other demand interruptions are considered security related which are principally related to intra-regional transmission events.

The required level of reliability is defined by the reliability standard, which states that no more than 0.002% of demand should be unserved due to generator and interconnector capacity reductions / outages. This is equivalent to about 4 GWh per year which roughly corresponds to about 300,000 homes across the NEM being interrupted for about 5 hours each year. Security is managed through technical and operating standards.

Factors that Determine Reliability Outcomes

This report next considers the factors that influence reliability outcomes. These can broadly be classified in terms (1) the technical capability of the power system compared to demand and (2) market behaviour in terms of how this technical capability is utilised by the market. In the past the key uncertainties have been associated with non-intermittent generator plant availability and demand level. Forecasting uncertainty has also been an important issue as this influences decisions from unit commitment on the day, organising and proceeding with planned outages, to new capacity investment. This uncertainty is not likely to decrease in the future.

The increasing level of intermittent wind generation has added another uncertainty, and with the levels foreseen to be developed this may become one if not the key uncertainty in the market, particularly in South Australia.

The AEMC Reports on Reliability and Security

The AEMC papers reviewed for this study were “Reliability Standard and Reliability Setting Review” dated 30 April 2010 and “Review of the Effectiveness of the NEM Security and Reliability Arrangements in light of Extreme Weather Events” dated 31 May 2010).

Key Issues and Recommendations

The key issues and recommendations of these reports are summarized below.

“Reliability Standard and Reliability Setting Review” dated 30 April 2010.

In this report the AEMC considered the form and level of the Reliability Standard, monitoring and compliance with this standard, and the reliability setting required to ensure the standard is met. The report also presented a number of views on these matters expressed in submissions to the AEMC.

The effect of changing the Reliability Standard was assessed through modelling work undertaken by ROAM Consulting (ROAM), which provided analysis and recommendations on the values of the reliability settings to apply from 1 July 2012 such that the Reliability Standard is met. The AEMC paper relied on the modelling in concluding that the reliability framework and setting would be sufficient to provide for sufficient investment in new generation.

The difficulties in monitoring reliability were noted with recommendations that this be done on an annual basis.

“Review of the Effectiveness of the NEM Security and Reliability Arrangements in light of Extreme Weather Events” dated 31 May 2010)

This report considered the issues of the existing processes for determining the Reliability Standard and Reliability Settings, capacity mechanisms (the need to depart from the NEM’s energy-only market design), how reliability is forecast and whether the reliability setting determined in the Reliability Setting report are adequate in the light of possible extreme weather. The later issue was addressed by having ROAM extend their previous modelling to include 1 in 20 year extreme weather and demand events.

The report concluded that there is no evidence that the current arrangements are not working well although some improvements were identified. These were to have an explicit requirement that the level of reliability valued by consumers be included in the Rules and to support AEMO working with industry to make incremental improvements to forecasting methods on an ongoing basis.

The recommendations appeared to be based on the modelling result that including extreme demand events does not change the relationship between

MPC and reliability. The reason cited was that high demands provided increased revenues that would support the level of additional peaking plant required.

The ROAM Modelling

The reliance given to and conclusions drawn from the ROAM modelling in the AEMC reports meant that the robustness of that modelling is a (if not the) key issue to this review.

The purpose of the ROAM modelling was to assess the level of MPC required for new entrant Open Cycle Gas Turbines (OCGTs) to be (marginally) profitable in each region and to provide advice on the impact of any change in the financial risks faced by market participants. To do this the approach assumed that the marginal peaking plant runs only when required to reduce USE and receives a spot price close to the MPC when it generates (thus assuming it bids near the MPC). The modelling assumed that all available generators were made available at such times.

IES considers that the ROAM modelling failed in two key areas, transparency and approach. IES had a number of clarifying questions in relation to the modelling undertaken and these were described in a note that was sent to ROAM and then the AEMC for comment. These questions were not satisfactorily addressed. In relation to approach, the ROAM modelling (1) did not properly address load and wind generation uncertainty and (2) did not attempt to include the dynamics of the spot market which translates the reliability and security setting into new generator entry and dispatch offer prices which in turn result in the outturn spot prices which serve as the required new-entrant price signals.

IES Modelling

IES undertook its own modelling for the purpose of verifying the modelling undertaken by ROAM and for investigation of factors not considered in the AEMC and ROAM reports. This incorporated the impact of load and wind generation uncertainty and the dynamics of the spot market in terms of generator entry and generator bidding. This analysis and modelling showed the following:

- That the MPC v USE relationship presented by ROAM can be closely reproduced through simple spreadsheet analysis, reflecting that this relationship largely represents the assumed pattern of load (net of the assumed wind generation) and the number of hours the marginal OCGT plant is required to operate at a price near the MPC to be economic.
- There is evidence to suggest that a full incorporation of load and wind uncertainty would result in a significantly higher estimated value for the MPC required for extreme peaking plant to be economic;
- The dynamics of actual capacity investment observable in the market to date do not match the approach used in the ROAM modelling. This is especially true for OCGT plant;

- The current MPC is sufficient to provide for new OCGT plant to be economic prior to the expected level of USE increasing above 0.002%.reliability;
- The spot price outcomes and new entry economics show considerable variability on an annual basis due to uncertainties in demand and other stochastic factors;
- Including the AEMO constraint equations in the modelling results in a near doubling of the expect level of USE. Given that these equations understate the constraints that would actually be expected and that they combine both intra-regional and inter-regional issues, the matter of transmission needs to be more fully understood.

Table of Contents

List of Figures

List of Tables

1 Glossary of Terms

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
CCGT	Combined Cycle Gas Turbine
CPT	Cumulative Price Threshold
CRA	CRA International
CRR	Comprehensive Reliability Review (2007)
DPI	Victorian Department of Primary Industries
DTEI	Department of Transport, Energy and Infrastructure
ESOO	Electricity Statement of Opportunities (prepared by AEMO, was NEMMCO SOO)
FCAS	Frequency Control Ancillary Service
FOR	Forced Outage Rate
GSOO	Gas Statement of Opportunities
GWh	Gigawatt hour
IES	Intelligent Energy Systems
LGC	Large scale Generation Certificate
LOLP	Loss of Load Probability
LRMC	Long run marginal cost
LRET	Large Scale Renewable Energy Target
MCE	Ministerial Council on Energy
MD	Maximum Demand (MW)
MPC	Market Price Cap
MRET	Mandatory Renewable Energy Target
MRL	Minimum Reserve Level
MT	Medium term
MW	Megawatts
MWh	Megawatt hours
NEM	National Energy Market
NER	National Electricity Rules
NTS	National Transmission Statement (previously ANTS)
OCGT	Open Cycle Gas Turbine
PASA	Projected Assessment of System Adequacy
PoE	Probability of Exceedence (%)
REC	Renewable Energy Certificate
ROAM	ROAM Consulting
RSSR	Reliability Standard and Settings Review
SA	South Australia
SRMC	Short Run Marginal Cost
ST	Short Term
USE	Unserved Energy
VCE	Value of Customer Reliability
VoLL	Value of Lost Load
WACC	Weighted Average Cost of Capital

2 Introduction

2.1 Background

Power shortages and interruptions to power supplies have high costs to consumers and are politically undesirable. Consequently there is a strong incentive for national and state governments to ensure that power systems are developed and operated to provide a reliable and secure electricity supply.

The Reliability and Emergency Reserve Trader (RERT) mechanism was developed to provide a safety net should circumstances arise in relation to the reliability of power supply. The Final Report "Review of the Reliability and Emergency Reserve Trader" dated 21 April 2011 by the Reliability Panel recommends that the Reliability and Emergency Reserve Trader (RERT) should expire on 30 June 2013 and that the requirement for the review of the RERT mechanism be removed from the rules.

The recommendations by the Reliability Panel were based on a number of factors including its recent review of the reliability and security setting in the NEM. The two relevant reports by the AEMC are:

- "Reliability Standard and Reliability Setting Review" dated 30 April 2010 (referred to as the "AEMC Reliability report")
- "Review of the Effectiveness of the NEM Security and Reliability Arrangements in light of Extreme Weather Events" dated 31 May 2010 (referred to as the "AEMC Reliability in the light of Extreme Weather report")

The South Australian Department for Transport, Energy and Infrastructure (DTEI) has concerns that the reasons giving rise to the recommendations contained in the above mentioned reports have not been adequately demonstrated, and as a result, DTEI has concerns that the market mechanisms currently in place may not be adequate to insure continued reliability of supply and security of the NEM power system, in the absence of the RERT.

The particular market mechanisms that are the subject of this report are the "Reliability and Security Settings" that refer to the Market Price Cap (MCP), Cumulative Price Threshold, and Market Floor Price.

To assist DTEI in this matter, DTEI commissioned Intelligent Energy Systems (IES) to undertake a review of reliability of supply and security of the power system in the National Electricity Market (NEM) in the absence of the RERT mechanism. The scope of the study excluded matters such as market structure, governance arrangements and the operation of the RERT.

2.2 Approach and Outline of this Report

This study is concerned with reviewing the evidence that supports the view that the existing framework defined by the NEM Rules is sufficient to result in an acceptable level of reliability in the absence of the RERT from July 2013.

To address this question IES reviewed the abovementioned AEMC reports on reliability and security and undertook modelling to investigate a number of identified issues that may influence reliability in the future.

This report is concerned with reliability. Security is addressed through technical management such as security constraints.

The work undertaken by IES is presented in this report as follows:

- The definition of reliability and security and the index that expresses the NEM reliability standard are first reviewed. Following this the issues critical to reliability are identified and categorised into technical and market behavioural;
- To support the analysis a review of actual market outcomes is presented. This is in terms of new entry generators, generator bidding behaviour, and the January 2009 reliability and security event;
- The two relevant AEMC reports are reviewed and the key points identified, together with IES commentary on the analysis and conclusions drawn. The modelling undertaken by ROAM is then critically reviewed and issues identified;
- To support the review of ROAM's and IES modelling the physical uncertainties that influence reliability and NEM market dynamics are reviewed. The first of these is discussed in the context of "extreme peaking" plant economics. This includes a statistical analysis of the potential variability of demand and wind generation in the future that will impact reliability in South Australia. The second matter is addressed in the context of generator entry decisions and how generators price energy (ie bid) in the market;
- Simulation modelling undertaken by IES is described and the results presented. The purpose of this modelling was to explore spot price market signals as new generation is required to support reliability;
- The report concludes with a number of observations and conclusions drawn from the review.

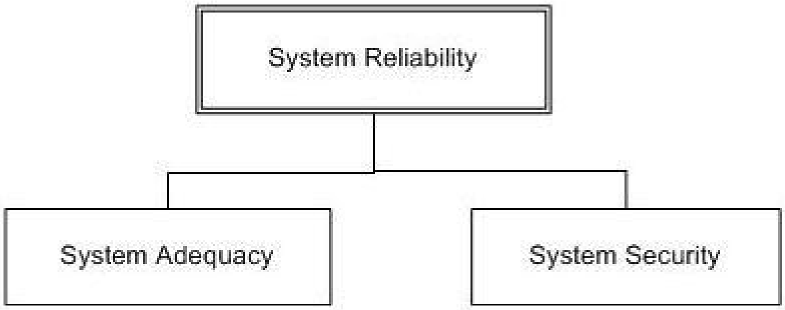
3 Reliability

3.1 General Definition of Reliability

Power system reliability can be defined as the degree to which the performance of the elements in a bulk system results in electricity being delivered to customers within accepted standards and in the amount desired. The degree of reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply.[1]

Power system reliability is based on two aspects of the power system, these being power system adequacy and power system security (Figure 3-1). Adequacy relates to the existence of sufficient generation, transmission and distribution facilities to satisfy the consumer load demand. Security relates to the ability of the system to respond to disturbances arising within that system such as the failure of a generating unit or the loss of a transmission line.

Figure 3-1 Power System Reliability, Adequacy and Security



Much of power system planning is focussed on power system adequacy:

- Is there an adequate amount of generation?
- Is the transmission system adequate?
- Is the distribution system adequate?

The National Electricity Rules (NER) define reliability as ‘the probability of a system, device, plant or equipment performing its function adequately for the period of time intended, under the operating conditions encountered’. The concept of reliability is turned into an operational standard in the NEM via the reliability standard set by the Reliability Panel.

[1] Electric Power Research Institute, Dynamics of Interconnected Power Systems, A Tutorial for System Dispatchers and Plant Operators, prepared by Power Technologies, Inc., Schenectady, N.Y., for the Electric Power Research Institute, Palo Alto, Calif., May 1989.

3.2 AEMC Definition of Reliability and Security

The use of the terms “reliability” and “security” throughout this report is consistent with AEMC definitions.

The AEMC defines reliability and security in Section 2.3.1 of their report “Review of the Effectiveness of the NEM Security and Reliability Arrangements in light of Extreme Weather Events” dated 31 May 2010). This is as follows:

> Reliability events are characterized as those supply interruptions caused by a lack of capacity due to power system equipment reaching operating limits. A reliability event occurs when all reserve capacity is exhausted. The likelihood of reliability events can generally be predicted ahead of real-time as demand and generation availability forecasts reveal supply deficits. As such, reliability events can be planned for and consumer load shedding can be managed (and is often shared) across the NEM. Examples of a reliability event would include a supply interruption caused by insufficient generation or network capacity to meet consumer load. An efficient approach to reducing the incidence of reliability events would generally involve investment in additional capacity.
>
> Security events are characterized as those supply interruptions caused by the rapid disconnection of power system equipment from service due to either equipment failure or the activation of protection systems. Security events occur when reserve capacity may still be available in the system, but that reserve capacity cannot be accessed. Security events can generally not be predicted ahead of real-time as equipment failure is sudden and unexpected. As such, load shedding is generally indiscriminate, and is most often location specific or triggered automatically under the NEM's under frequency load shedding arrangements. Examples of a security event include the simultaneous tripping of more than one generating unit due to a system disturbance, or the tripping of several transmission lines due to a bushfire. An efficient approach to reducing the incidence of security events would generally involve improving the performance or management of power system equipment or, in some circumstances, capital expenditure to provide redundancy.

Scope of Reliability

Noting the above, the AEMC limit the application of the reliability standard to generation and interconnection in the supply chain. Section 3.1 of the AEMC report “Reliability Standard and Reliability Setting Review” dated 30 April 2010 defines the scope of reliability as follows:

> For the purposes of assessing the Reliability Standard, the bulk electricity supply is taken to mean the total generation and demand side capacity within a region, together with the support available from other regions via interconnectors, that can contribute to meeting consumer demand within the region. The Reliability Standard excludes distribution and those transmission components that do not impact on inter-regional transfer capability. Distribution networks are subject to performance standards that are set and monitored by jurisdictional bodies.

Thus, reliability refers to customer load shedding that is due to inadequate generation including reductions in interconnector capacity that prevents spare generation in one region being used to support demand in another.

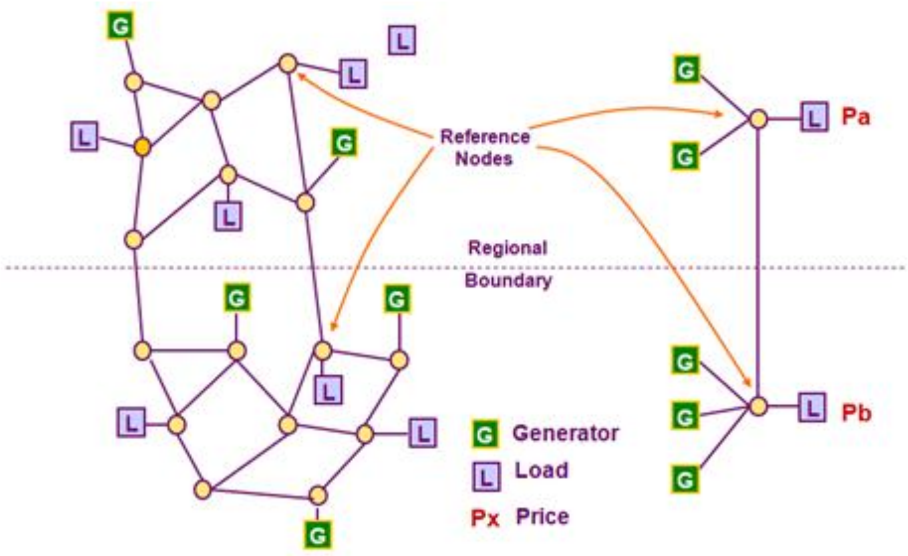
A rationale for this definition (although not stated in AEMC reports) is that market price signals basically exclude intra-regional transmission and intra-regional transmission development is managed through individual jurisdictional requirements.

3.3 Notional Interconnectors

The concept of confining the reliability standard to include inter-regional transmission but exclude intra-regional transmission is an important issue that needs to be understood.

Interconnectors in the NEM are referred to as "notional" interconnectors to emphasise that they are not composed of identifiable assets. Figure 3-2 illustrates by way of example the (1) real network spanning two regions (shown on the left) and (2) how this is represented in the NEM regional model which has a single notional "interconnecting" transmission line joining the two regional nodes (shown on the right). The "regional model" used in the NEM provides for inter-regional losses to be modeled and inter-regional surpluses to be accrued.

Figure 3-2 Notional Interconnectors



Transmission constraints used in the AEMO dispatch engine are written in the general form:

$$a_1 \, gen_1 + a_2 \, gen_2 + \ldots \, a_n \, flow_1 + a_{n+1} \, flow_2 \ldots \; < \text{constant}$$

where gen_n is the generation level from generator "n , $flow_j$ is the flow on interconnector "j", and the constant term is a function of metered system conditions (such as demand, generator outputs, line flows etc).

There are many constraints that contain both generation and flow terms.[2] Constraints that contain inter-regional flow terms are considered associated with inter-regional flow limits. However these constraints could be associated with transmission elements located deep in the meshed network. Inter-regional transmission constraints can be modeled and intra-regional constraints excluded by selecting only those constraints that have inter-regional flows terms.

3.4 The Reliability Standard

The reliability standard in the NEM is that the level of unserved energy (USE) per annum over the long term should be below 0.002% of total customer demand.[3] The way this standard is interpreted in the NEM is that it is a standard with respect to generation and inter-regional transmission adequacy. That is no more than 0.002% of demand should be unmet due to generator and interconnector capacity inadequacies or outages. All other bulk supply demand interruptions are considered security related which principally covers supply interruptions due to intra-regional transmission limitations.

For the year 2010, 0.002% of annual demand corresponds to about 4 GWh or about 300,000 houses without power for 5 hours each year.

There has been debate over what is meant by the long term. The usual form for this index is in terms of the expected unserved energy (EUSE) which is the mathematical expectation (or average) of the distribution of unserved energy for each year. This would mean that USE should average no more than 0.002% per annum over a number of years.

There are other reliability statistics that could have been used such as the loss of load probability (LOLP). These statistics are generally closely related and a standard developed using one statistic can be made to be approximately equivalent to another standard using an alternative statistic. The current reliability standard says nothing in relation to the probability of not shedding load each year though a 0.002% expected unserved energy is likely to correspond to some value for the loss of load probability.

Prior to the NEM, Victoria's reliability standard was to have an 85% probability of not shedding load in any one year. NSW adopted a LOLP of 7 hours per year. The current reliability standard says nothing in relation to the probability of not shedding load each year.

[2] These are the so called Option 4 constraints.
[3] This is discussed in Section 5.1 of the AEMC Reliability in the light of Extreme Weather report.

3.5 Factors that Influence Reliability

The factors that influence reliability in the context here are many and complex. However these can be categorized as those relating to the technical capability of the generation and interconnecting transmission relative to demand and those related to how the market responds and brings forth existing and new capacity. These are considered in turn below.

3.5.1 Technical Capability

Technical capability of the power system refers to its ability to supply demand assuming that the power system is operated to the maximum of its capability. This is usually the assumption in reliability models which assume for example, that all generation plant is planned to be on during periods of potential high demand.

The factors that influence technical capability are those that relate to the ability of the generation system to provide capacity when required, the capacity and reliability of the transmission system, and the level and nature of high demands. Factors impacting these three aspects are described below.

Regional Generation

- The total level of installed generation capacity;
- The makeup of the generation system in terms of generator types and the firmness of capacity associated with each power station and technology type such as thermal, hydro and wind generation. This can entail flexibility in planned outages and also but to a lesser degree in forced outages;
- The response times of plant to respond to forecast power system conditions;
- Limitation such as water or fuel limitations;
- The distribution and correlation of intermittent generation (particularly wind energy) both within and between regions, and the correlation of intermittent generation to demand both within and between regions;
- The reduction in generation capability under high ambient temperatures.

Transmission

- The firmness of transmission within each region that provides for generation capacity to be used to supply regional load when required;
- The capacity of interconnecting transmission that provides for power transfers between regions.

Demand

- The nature and level of high regional demands. Key issues with high demands are their potential level and likelihood, how long high demand periods can last for, the potential number of high demand days that can occur, and the time of year;

- The correlation of high demands between regions;
- The reliability and accuracy of load projections the next day and in the longer term. This impacts decisions of plant commitment for the next day and the lead times to develop new plant. This is often termed load forecast uncertainty.

3.5.2 Market Behaviour

Market behaviour relates to the way in which the market responds to price signals in the short, medium and long term through bidding for dispatch, unit commitment, outage planning and capital investment.

The information systems developed and administered by AEMO are designed to assist in this task. This includes the GSOO and ESOO, MT PASA, ST PASA, pre-dispatch and the associated spot price sensitivities. In the longer term price signals are provided through spot price trends and the forward curve.

Through this information decisions are made regarding generation capacity. This entails investment decisions usually made 3 to 5 years from when the plant first enters the market, outage planning months to a year ahead, and unit commitment decisions which may require actions the day before.

Transmission operation is largely independent of price signals although AEMO and transmission bodies operate to coordinate transmission capability with generation. Load forecasts are a key input and output to AEMO information provision, which are subject to uncertainty due to weather uncertainty in the short term and economic uncertainty in the longer term. Table 3-1 presents the timeline of factors that influence reliability outcomes.

Table 3-1 Timeline of Market Behaviour

	Generation	Interconnection	Load
Real time	Bidding for dispatch Unforeseen outages and availability	Unforeseen outages	Actual demand
Days ahead	Committing units to service	Proceeding with planned outages	Weather / demand forecasts
Months ahead	Planning and committing to plant outages	Planning and committing to plant outages	Uncertain demands
Years ahead	Investment in new plant	RIT-T and the planning process	Long term economic and demand forecasts

The translation of market information and price signals to decisions from the short term to the long term are influenced by the commercial drivers of the relevant players (investors and market participants). In the short term, influencing factors include portfolio structure (generation and retail) and contract position, while in the long term factors include projected spot and contract prices, price history, economic outlook, development costs and policy / regulatory outlook / certainty.

3.5.3 South Australia

While this report has been developed on the basis of a NEM-wide assessment, we do note that each state / region has particular characteristics and this is particularly the case for South Australia. Here we note the following in relation to South Australia:

- Highly temperature sensitive demand with a small number of "base" thermal units making reliability sensitive to one to two unit outages;
- A very significant and growing level of wind generation. This is and will continue to influence new entry peaking economics and will increasingly make reliability critical on wind correlation between wind farms and to demand; and
- The dominance of a single "gen-tailer" (AGL) in South Australia influences market behaviour in the short term, contract liquidity, and new entry investment. For example, the commitment strategy of Torrens Island Power Station is influenced by wind generation projections and negative spot prices (and its subsequent ability to respond to events).

3.6 Review of 2009 Reliability and Security Events

The reliability and security events of 29 and 30 January 2009 in South Australia and Victoria are reviewed in Appendix 3. Presented are a chronology of the events on these days and graphs of generation, demand (net of load shedding), ancillary services used, prices etc. The purpose of this review is to understand how the market and AEMO (then NEMMCO) respond to such events, and whether the issues that were instrumental in this event will still be present in the future.

The key observation from these two days is that transmission outages were an important part of the reasons for load shedding. It is also noted that security was maintained at all times through operating reserves being maintained in regions not experiencing load shedding. This was the reason why FCAS prices were low while energy prices were high in South Australia and Victoria.

4 Review of Recent AEMC Reports

IES reviewed the two most recent AEMC reports that related to the adequacy of the reliability and security setting to provide for reliable supply in the NEM. These were:

- “Reliability Standard and Reliability Setting Review” dated 30 April 2010; and
- “Review of the Effectiveness of the NEM Security and Reliability Arrangements in light of Extreme Weather Events” dated 31 May 2010).

The intention is to summarise the key points relevant to this study from these reports and to provide commentary on the issues identified. A detailed discussion of the ROAM modelling is presented in the next chapter.

4.1 AEMC Reliability Standard and Reliability Setting Report

This section reviews the AEMC Final Report Reliability Standard and Reliability Setting Review dated 30 April 2010.

To ensure precise meanings are not lost this is done by first reproducing key paragraphs in that report followed by IES commentary on key aspects germane to this study. Bolding in reproduced sections has been ***added*** to emphasise key points and which are also commented on later.

4.1.1 Summary of Key Points

The Reliability Standard and Settings

Key paragraphs are:

> “The Reliability Standard is a measure of the expected amount of energy at risk of not being delivered to consumers due to a lack of available capacity. **Currently under the Reliability Standard, the level of expected unserved energy (USE) should not exceed 0.002% of the annual energy consumption per region.”**
>
> “The level of the MPC, the market floor price and the CPT are the key price envelopes within which the wholesale spot market seeks to balance supply and demand and deliver capacity to meet the Reliability Standard with the aim of avoiding unmanageable risks for market participants.”
>
> “Within the existing energy only market design framework, the mechanisms that can be adjusted to provide investment signals are limited to the MPC, the CPT and the market floor price.”
>
> “In its CRR (Comprehensive Reliability Review), the Panel noted that there was general support for retaining the USE form of the Reliability Standard from stakeholders. The reasons given where that it:
>
> - reflects the economic impact on typical consumers;
> - is relatively easy to measure;

- applies equally to each of the NEM regions; and
- has been used since the NEM commenced."

"Therefore, the Panel considers that the Reliability Standard that applies to the operation of the competitive wholesale market should only consider unserved energy that can be managed by adjusting the Reliability Settings. That is, the level of investment in new capacity in the NEM, and hence the resulting reliability, is regulated through the process of setting the MPC and the CPT."

"**Similarly, the Panel also considers that increasing the MPC and CPT is not the appropriate mechanism to manage the unserved energy caused by system security events such as multiple contingencies**. The Panel considers that such incidents are better managed through operating procedures, technical compliance programs and the economic regulation of the networks."

"Operationally, the Reliability Standard is currently targeted to be achieved in each financial year, for each region and for the NEM as a whole. **That is, AEMO aims to have sufficient reserves in advance of a given period, usually the summer, so that the expected USE will be within the 0.002% USE standard.** The actual USE that results will depend on the system conditions that end up occurring."

Compliance

Key paragraphs are:

"The NGF considered that targeting 0.002% USE each year while monitoring the performance over ten years is inconsistent. Similarly, Origin Energy considered that it is confusing that the Reliability Standard is specified as an annual amount of electricity at risk, but compliance is measured over the long-term (ie ten years)."

"Macquarie Generation stated that compliance with the Reliability Standard over the previous ten year period should act as a guide, rather than a hard target, to avoid adjusting the Reliability Settings to influence investment to correct for events that took place up to ten years earlier."

"Prior to the completion of the CRR, the Reliability Standard was expressed as a target of 0.002% USE defined as being "over the long term". The Panel was concerned that this timeframe was unclear and proposed that the definition could be more explicit, for example "over 10 years". To this end, the Panel amended the Reliability Standard such that:

"Compliance with this Reliability Standard for Generation and BulkTransmission should be measured over the long-term using a moving average of the actual observed levels of annual USE for the most recent 10 financial years."

"**The characteristics of the underlying distribution of possible USE outcomes for a given year can be estimated using Monte Carlo simulations.** The accuracy of the estimate of this distribution depends on the quality of the Monte Carlo simulations and associated assumptions."

"It is not possible to measure compliance with the Reliability Standard in a meaningful manner, because of the random nature of USE outcome for a given year."

"Considering the USE as a moving average over the past ten financial years has the effect of smoothing out some of the statistical variation from year to year. However, this approach has a number of problems, including:

- more than ten years of data would be required to give a statistically meaningful estimate of compliance with the Reliability Standard;
- the underlying distribution of possible USE outcomes varies from year to year, as demonstrated by AEMO's need to re-assess the MRLs every few years. Therefore, it is not statistically meaningful to use the moving average as a measure of compliance; and
- a ten year delay in measuring compliance is not satisfactory if its purpose is to promote continuous improvement of the processes for meeting the Reliability Standard."

"The Panel does not believe that measuring the effectiveness of the Reliability Standard would be meaningful."

"The Panel considers that it is much more appropriate to review the reliability of the NEM each year, in particular following periods where there has been one or more incidents that have resulted in USE."

ROAM Consulting Modelling

The key paragraphs are:

"The AEMC, on behalf of the Panel, engaged ROAM Consulting (ROAM) to undertake the modelling work to assist the Panel to assess the Reliability Settings. **The aim of the modelling is to assist in forming a recommendation as to the levels of the MPC and the CPT to apply in the NEM.** These values would take effect from 1 July 2012 and apply for the 2012/13 and 2013/14 financial years. ROAM was also requested to provide the Panel with advice on the impact of any change on the financial risks faced by market participants".

"The approach used by ROAM to determine the Reliability Settings, in particular the MPC, has been to:

- adjust the level of generator capacity using advanced and/or announced projects so that there is sufficient capacity to achieve the Reliability Standard in each region in each year of the modelling period from 2012 to 2020; then
- **adjust the level of the MPC so that a new entrant open cycle gas turbine (OCGT) is marginally profitable**, that is, would recover sufficient expected income to cover its annualised capital and fixed operating costs, plus a return on its investment."

"Previous modelling for determining the level of the MPC and CPT was undertaken by Charles Rivers Associates International (CRA) as part of the 2007 CRR. At that time, the decision was made to increase the MPC from $10,000 to $12,500/MWh and the CPT from $150,000 to $187,500 effective from 1 July 2010."

"Given this review of the Reliability Settings was undertaken by a different consultancy, ROAM undertook benchmarking studies to ensure continuity of the results. ROAM used the same input data as CRA when performing the modelling work for the benchmarking study."

"**The ROAM modelling assumes that the new entry OCGTs derive all their income from the spot market**. Therefore, a new entry OCGT is regarded as profitable when its expected spot market income exceeds its annualised capital and fixed operating costs, plus a return on its investment."

"**However, ROAM and the Panel considered the approach of considering spot market revenues was consistent with previous assessments of the required MPC and a valid proxy for the entry of the new entry extreme peaking plant.** The Panel considered this view was reasonable because the value of contracts is derived from the outcomes expected in the spot market. The Panel also considered that the approach is also both quantifiable and traceable."

The report then briefly described the key assumptions (these are further discussed in the detailed review of the ROAM modelling later in this report):

- Load traces – 10% and 50% POE traces;
- Transmission network – 2009 NTS that incorporate all intra and inter-regional constraints;
- Generators – based on 2009 ESOO;
- Fuel and capital costs – 2009 ACIL Tasman report to AEMO;
- Intermittent generation – installed to meet the 20% renewable target by 2020. Wind generation patterns used existing wind traces;
- Generator bidding – developed using a bid analyser process;
- New OCGTs bid in at a price near the MPC. Assumed forced outage rate (FOR) of 3%.

The conclusions of the modelling were stated as follows:

"The modelling in the ROAM report indicates that from 1 July 2012 it may be necessary to consider raising:

- the MPC from $12,500/MWh effective from 1 July 2010 to approximately $16,000/MWh; and
- the CPT from $187,500/MWh effective from 1 July 2010 to approximately $240,000/MWh.

"The ROAM modelling considered the level of MPC required for new entrant OCGTs to be marginally profitable in each region. **The ROAM modelling shows different values of MPC would be required for each region because of the unique characteristics of the regions,** including the load shape, the mix of generation and the degree of inter-regional interconnection. However, under the current design a single MPC value applies in all regions of the NEM."

"ROAM calculated an MPC value that is the average of the individual regional values, weighted with the regional annual energy consumption. **This approach will be expected to deliver sufficient investment across the NEM as a whole but may be expected to deliver insufficient investment in the regions that appear to require a higher MPC value.** However, the reliability of these regions will tend to be supported by the investment in the other regions."

Stakeholder Views and Issues

Noted views were:

"In their submissions on the Issues Paper, the NGF and Origin Energy supported regular reviews of the Reliability Settings due to the changes in climate change policies."

"The majority of submissions on the Draft Report did not support an increase in the level of the MPC."

Panels Views and Issues

Noted views and issues were:

"ROAMs modelling for the Panel assumed that investment in the extreme peaking generator will occur if the forecast spot market prices are sufficient. The Panel notes that these participants do not consider that the forecast spot market price provides sufficient revenue certainty and therefore do not consider it to be the key driver for investment."

"The Panel notes the possibility that an increased MPC may mean that the spot market prices become more volatile".

"**In recent years there has mainly been investment in peaking generating capacity in all regions of the NEM**. The Panel notes that AEMO 2009 ESOO shows that there is sufficient generation capacity to meet the Reliability Standard up to 2011/12 in South Australia, 2012/13 in Victoria, 2013/14 in Queensland and 2013/14 in New South Wales".

"The Panel notes that the prudential requirements required by market customers will be likely to increase as a result of increase in the level of the MPC. This is an additional burden for market customers and may, in the extreme, become a barrier to entry into the market."

"**A significant increase in the MPC may reduce the opportunities to exercise transient market power in a competitive market.** That is, in the short-term, the possibility of higher prices may increase the level of contracting in the energy market, thus reducing the incentive to exercise transient market power. In the long-term the potential of higher prices is likely to encourage increased generator and demand side investments, thus increasing competition at times of high spot prices."

"The Panel considers that a substantial increase to the level of the MPC may make more demand side options economically viable. If this is the case, the price would be capped below the higher MPC when the demand side options are dispatched, thus the MPC may not need to be increased by as much as the increase indicated by the ROAM analysis."

"A significant increase in the MPC will also increase risks to generators trading in the NEM. In particular, generators may be less willing to contract their capacity as they would be exposed to increased risks at times of high prices should their physical generation not be available due to plant failure, network congestion or network outages."

Panel's Recommendations

The recommendations of the panel are fully reproduced below.

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

However, in making this recommendation, the Panel notes that the current set of Reliability Settings is required to achieve multiple objectives. These are:

- Meeting the Reliability Standard;
- Managing the financial risk of market participants; and
- Meeting customer's value of reliability.

The Panel considers that the ability of the current set of Reliability Settings to achieve each of these objectives is limited. The Panel recommends that the AEMC perform a comprehensive 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.

In particular, **the Panel is 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.** In particular, the Panel cites increasing prudential risk, increasing price volatility risk to consumers and increasing outage and congestion risk, where some generating capacity may not be able to be dispatched due to limitations on the transfer capability of the network at various times. This risk can be difficult for generators and retailers to manage."

4.1.2 IES Comments

The key points of the AEMC report noted above relate to:

- The confidence that can be afforded the analysis and modelling undertaken;
- The assumed impact of a higher MPC on the market; and
- Noted differences in outcomes between the NEM regions.

These are discussed below.

Modelling

The recommendations contained in the report relied on the results and assumed rigor of the ROAM modelling. This was read to be:

- The concept of "extreme peaking" plant (as defined) was considered a valid approach to assessing how the market brings forth new capacity;
- The modelling incorporated generator bidding behaviour that was consistent with observed behaviour, and that spot price outcomes reflected such behaviour;
- Changes to the MPC were reflected in the spot market which new peaking plant responded to;
- That the underlying distribution of possible USE outcomes for a given year can be estimated using Monte Carlo simulations.

None of these were demonstrated or are likely to be true in the ROAM modelling. In particular:

- Plant that behaves as defined by "extreme peaking" plant is not observed in the NEM. Consequently, the price signals associated with these plant will not correspond to that required by actual plant as observed;
- Neither the AEMC nor the ROAM report illustrated the bidding dynamics used or the resulting spot price patterns. This is basic to any modelling that relies on spot prices driving new entry generation. Here we note that we would expect combined cycle and OCGT plant to both be entering the market;
- It was not stated how changes to MPC would influence the bidding behaviour of generators in the market. The ROAM report only indicated that peaking OCGT plant received the assumed MPC when being required to generate to avoid load shedding;
- The level of uncertainty associated with potential regional load variations, regional wind variations, correlations of demand between regions, correlations of wind within and between regions, potential planned outage

programs and the pattern of forced outages is very large. To gain a proper assessment of the distribution of USE using simulation modelling would be a very extensive study and the required study breadth was not reported in the ROAM modelling.

MPC Impact on the Market

The AEMC noted two potential impacts (1) that an increase 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, and (2) a significant increase in the MPC may reduce the opportunities to exercise transient market power in a competitive market due to increased contract levels.

There was no analysis provided to explore either of these potential impacts.

Regional Differences

The AEMC noted that the ROAM modelling had shown differences between the regions and that some regions needed a higher MPC to ensure the economics of required new entry. This important matter was not properly investigated. In our view this was a serious oversight as the differences between regional requirements may be substantial.

We also note that by calculating the required MPC as a weighted average diminishes the requirements of the smaller States, particularly South Australia. Arguably, to comply with the requirement of the market rules, the MPC should be set at the maximum of that required by each region.

4.2 AEMC Reliability in the light of Extreme Weather Report

This section reviews the AEMC Final Report “Review of the Effectiveness of the NEM Security and Reliability Arrangements in light of Extreme Weather Events” dated 31 May 2010. This is done by summarising the key discussion points and recommendations. To ensure precise meanings are not lost key paragraphs in that report are reproduced. This is followed by IES observations and comments.

4.2.1 Summary of Key Points

Chapter 2: Context

- Explained what is extreme weather, how heat waves can impact power supply and how Australia’s climate is forecast to change in the future;
- Categorises supply interruption – generation / transmission / distribution and reliability / security;
- Reviewed the performance of the NEM which shows that reliability only accounts for 12% of supply interruptions due to generation and transmission.

Chapter 3: Technical performance and power system security

- Reviews issues of technical standards;

- Recommended AEMO commence a review on managing technical performance.

Chapter 4: Whole of power system reliability

- Describes the interactions between investment in generation and transmission which use MPC and Value of Customer Reliability (VCR) respectively in valuing unserved energy;
- With respect to whether increasing MPC would result in higher levels of reliability the report states:

> "The main implication of the analysis above is that setting the MPC for the energy market at a level that is lower than the value that consumers place upon reliability would be expected to reduce the level of reliability."
>
> "We conclude that efficient investment in reliability across the supply chain can be achieved by investing to the level of VCR for those consumers most affected by the investment. With respect to generation investment, the level of VCR for residential consumers should be used because this class of consumer places the lowest value on reliability and are usually shed first during a reliability event. **At present the VCR level for residential consumers (in Victoria) is estimated to be $13,250/MWh, which aligns reasonably closely with the current MPC."**

Chapter 5: The Reliability Standard

- Reviews the reliability standard in terms of the index used (USE), what it means, and the 0.002% level;
- Reviews regional USE statistics over the period 1999/00 to 2008/09 which shows that all regions have had an average USE level substantially less than 0.002%, but that South Australia and Victoria had USE above the 0.002% level in 2008/09;
- The scope of the standard does not include intra-regional transmission;
- There has been no request from stakeholders, including those of consumer representative groups, for a change to the standard's level;
- The report reviewed the issues on monitoring and described the regime to commence 1 July 2012:
  - The Reliability Standard was originally expressed as a target of 0.002% USE that was defined as being 'over the long term'. However, the Reliability Panel considered that this timeframe was unclear and changed the definition of the Reliability Standard to measure USE as a 10-year moving average,
  - Given it is difficult to meaningfully measure the performance of the power system against the Reliability Standard over any timeframe, the Reliability Panel amended the Reliability Standard to take effect from 1 July 2012, such that the performance of the NEM will be measured

against the Reliability Standard each year. This means that instead of measuring compliance with the Reliability Standard over a 10-year moving average, the objective of the revised Reliability Standard is to provide continuous improvement to the processes that monitor and maintain reliability in the NEM.

Chapter 6: The Market Price Cap and other Reliability Settings: ROAM Modelling

This is a key chapter of the report for this study as it related to the confidence that the reliability and security setting will have to investment in new generation.

As background to this chapter, the AEMC report noted that the current NEM framework for reliability in the generation sector places significant emphasis on prices in the spot market as the primary signal for investment.

The AEMC explains that they engaged ROAM to undertake modelling to examine the price-reliability trade-offs of a phased increase in the MPC. The report says:

> "Our engagement of ROAM was concurrent with the Reliability Panel's engagement of ROAM to undertake the market modelling for their biennial review of the Reliability Standard. This concurrent engagement has allowed us to use the same model (and assumptions) as those used to inform the Reliability Panel's recommendation on the MPC to apply in the NEM from 2012. This provides a sound basis for comparison."

> "**The modelling undertaken by ROAM emulates the operation of the NEM**. It bases dispatch decisions on generator bidding patterns (including renewable energy generators), models of planned generator outages and inter-regional transmission capabilities and constraints. However, the sole driver on investment decisions is profitability delivered through the wholesale market. The modelling does not consider other factors that influence investment such as non-wholesale market revenue, or NEM participation costs and risks."

> "For the Extreme Weather Events Review, ROAM modelled two separate demand scenarios: a 'normal demand' scenario, and an 'extreme demand' scenario."

Modelling results were shown for:

- The MPC versus USE for the Normal Demand Scenario for 4 levels of MPC over the period 2012/13 to 2018/19;
- The additional generator capacity that would be delivered and associated costs by increasing MPC from the base case of $16,000 to $40,000 and $55,000.

From these results the report notes:

> "Thus, for an additional $90m a year, additional generating capacity could be installed that would roughly halve the USE expectation under the Reliability Standard to 0.001%. However, this result needs to be interpreted with care as it does not consider the other impacts of raising the MPC as described in Section 6.2.4."

The report then discussed the costs and other implications of a higher MPC. There were no issues identified not discussed in the other AEMC report.

The chapter then considered the MPC requirements under a scenario of (increased) extreme weather. The report describes additional modelling undertaken by ROAM and the results of that modelling. The report says:

> "This modelling is an extension of the modelling to determine the reliability that would be delivered by higher levels of MPC as presented in Section 6.2. But, whereas the modelling for Section 6.2 used demand forecasts consistent with historical demand growth (the 'normal demand' scenario), the modelling for this section used higher demand forecasts to represent the demand that would be likely during extreme temperature events (the 'extreme demand' scenario)."
>
> "**The modelling shows that there is little difference in observed USE between the normal demand (Figure 6.1) and the extreme demand scenarios** (Figure 6.2), for a given level of MPC. For both scenarios, an MPC of $16 000 is sufficient to incentivise enough investment in generation to satisfy the Reliability Standard (0.002% USE). This is despite there being a much higher level of demand to be satisfied under the extreme demand scenario."
>
> "**The reason for this is that under the extreme demand scenario there is more opportunity for generation to earn high returns from elevated spot prices**. If the incidence of extreme demand and the associated high prices were to double relative to the historical experience, then generators would have twice the opportunity to earn high returns from the spot market to recover their costs. Hence the level of the MPC does not need to be as high for these generators to be profitable."

The conclusions of this work include the following

> "If demand were to increase due to an increase in the incidence of extreme weather (such as more extreme heatwaves), additional investment in generator capacity (or demand-side participation) would be required to satisfy that demand. However, the MPC would not necessarily need to rise to deliver that additional generator capacity. **The level of the MPC is dependant on the shape of the demand profile.**"

Chapter 6: The Market Price Cap and other Reliability Settings: Jurisdictional Expectations

The chapter concludes by considering the differences in jurisdictional expectations. The issues noted here are:

- That raising the MPC in one region relative to another would likely deliver additional investment in that region. While this would deliver higher reliability it would also increase the costs to consumers in that region;
- Such an arrangement (that allows a different MPC in each region) would be a fundamental change to the market design, in particular requiring preference be given to the region with the higher MPC in times of supply shortage;

- This would have implications to how load shedding was shared between regions and also would also create market settlement shortfalls for the AEMO.

Submissions on this matter generally opposed to the introduction of different MPCs across regions. There were a number reasons given, including maintaining a common national electricity market, avoiding market distortion and that such an arrangement would be inefficient and ineffective.

However the Victorian Department of Primary Industries (DPI) took a different view, stating that there are fundamentally different incentives in the NEM between those regions where generation and transmission differences are privately owned relative to those regions where generation and transmission businesses are government owned. It stated that ‘regions with private ownership are reliant on appropriate market signals to facilitate investment to meet community expectations. DPI also responded to arguments raised against differing MPCs stating that the materiality of this issue had not been specified and that changes to prudential requirements is already expected with the possible introduction of a Carbon Pollution Reduction Scheme.

In considering issues that include economic efficiency in investment and operations, reliability and price, regulatory complexity, the AEMC concluded that an arrangement allowing the level of the MPC to vary between regions should not be pursued further.

Chapters 7 to 9

Chapters 7 to 9 discussed in turn:

- Governance arrangements for determining the Reliability Standard and Reliability Settings;
- Processes for determining the Reliability Standard and Reliability Settings;
- Alternative mechanisms to deliver reliability in the NEM.

While these chapters deal with issues outside the scope of this study the conclusions contained in these chapters are presented below for completeness.

The AEMC recommendation proposed that the existing governance arrangements are amended to reflect that:

- The AEMC make all reliability parameter decisions (that is, to review and, if need be, amend the Reliability Standard and Reliability Settings);
- AEMO make all reliability operational decisions (including to initiate the RERT and to review and, if need be, amend the MRLs); and
- High-level policy guidance is included in the Rules, which the AEMC would need to have regard to when reviewing and, if need be, amending the Reliability Standard and Reliability Settings.

The AEMC recommended amending the existing processes for determining the Reliability Standard and Reliability Settings, specifically that:

- An explicit requirement for the Reliability Standard and Reliability Settings to reflect the level of reliability valued by consumers be included in the Rules;
- the MPC and VCR would be checked against each other to assess whether the reliability parameters are consistent with the value that consumers place on reliability;
- The Reliability Standard and Reliability Settings would be reviewed, and amended where necessary, by the AEMC every 5 years;
- The Reliability Standard and Reliability Settings would be specified and given effect in a schedule referred to in the Rules;
- AEMO would use the same VCR for its transmission planning activities as is used for determining the reliability parameters; and
- The methodology and assumptions that would be applied to determine the Reliability Standard and the Reliability Settings, MRLs and the VCR would be subject to public consultation and would be established before the process for determining these parameters commences.

The AEMC considered that implementation of alternative mechanisms is not needed at this stage as there is no evidence to suggest that reliability in the NEM has not been achieved with the application of the current Reliability Standard and Reliability Settings. The AEMC also considered that the performance of the NEM's energy only design should be monitored to determine if the market design remains resilient and sustainable over time, particularly if extreme weather events do become more frequent in the future.

4.2.2 IES Comments

The main messages from this report relevant to this study are the following:

- That greater consideration be given to the management of the technical performance of the power system. This matter addresses security issues;
- That the effectiveness of the reliability setting in ensuring the reliability standard is satisfied is not impacted to any significant degree by the infrequent extreme weather and demand events;
- That the shape of the load curve is the prime driver to the relationship between MPC and USE in the NEM.

In IES' view, the conclusions of the last two dot points reflect the modelling approach used, and could be challenged if the simplifying assumptions of the ROAM modelling were replaced by more realistic modelling.

5 Review of ROAM Modelling

As previously noted, the outcomes of the modelling undertaken by ROAM were a key input into the conclusions developed AEMC. The purpose of the modelling by ROAM was expressed in the AEMC report as follows:

> "The aim of the modelling is to assist in forming a recommendation as to the levels of the MPC and the CPT to apply in the NEM. These values would take effect from 1 July 2012 and apply for the 2012/13 and 2013/14 financial years. ROAM was also requested to provide the Panel with advice on the impact of any change on the financial risks faced by market participants".

In the work for the AEMC, ROAM produced two reports:

- "Reliability Standards and Setting Review" dated 21 April 2010
- "Levels of the MPC that are consistent with the value of customer reliability" dated 9 April 2010

The first of these formed an appendix to the AEMC report "Reliability Standard and Reliability Setting Review" dated 30 April 2010, while the second formed an appendix in the AEMC report "Review of the Effectiveness of the NEM Security and Reliability Arrangements in light of Extreme Weather Events" dated 31 May 2010.

The "Reliability Standards and Setting Review" report is the more substantive of the reports as it presents more detail on the methodology used. The "Levels of MPC that are consistent with the value of customer reliability" report presents additional modelling that incorporates extreme weather demands. It also explains a change in methodology used (Average versus Iteration method).

This chapter reviews the modelling undertaken by ROAM for the AEMC. Our first comment on the ROAM reports is that they lacked transparency in that there were a number of key issues not explained. In an attempt to address this issue IES sent a letter to ROAM on the issues requiring clarification and also talked to the AEMC. However there was no formal reply on the matters raised. Consequently, ***the review presented here is based on the reading of the listed ROAM reports above***.

5.1 What ROAM Did

This section presents a review of the objectives, modelling approach and results that ROAM presented in their reports (for the two AEMC reports) reviewed in this study. This is first done for the modelling associated with the reliability setting report followed by that for the extreme weather report.

5.1.1 Reliability Standards and Setting Review

Terms of Reference

While no explicit Terms of Reference were noted in the ROAM report, the purpose of the ROAM report was described as:

> "detailed analysis and discussion of the reliability settings which would be required from 1st July 2012 to meet the Reliability Standard. The ROAM modelling has not addressed other policy variables."

In Section 4.3.1 of the AEMC report on Reliability setting, the purpose of the modelling was described as:

- Developing the relationship between MPC (and CPT) and reliability; and
- Noting any change in financial risks associated with changing MPC.

Methodology

The overall methodology used by ROAM was outlined in their report "Reliability Standards and Setting Review". Taken from this report their approach is understood to be as follows.

ROAM first benchmarked their model to the previous modelling undertaken for the AEMC for the CRR by CRA:

- This was done by using the same assumptions and comparing USE results. The USE average over all simulations was close to that of CRA;
- The MPC that would make the marginal generator just profitable was determined.

  Note: It was not clear whether the ROAM modelling had (1) the marginal generator just profitable in each simulation or (2) profitable on average over all the simulations performed.

ROAM then performed the reliability modelling. This was done as follows:

- All input assumptions were developed and inputted into the model. These included:
  - Demands;
  - Generator planned outages and forced outage parameters;
  - Transmission limits (2009 NTS constraints developed by AEMO);
  - Wind generation patterns (traces) for the wind farms modelled;
  - Hydro water limitations;
  - Generator bidding assumptions (developed using a bid analyser);
- The model was run for "simulation sets" that used 10% and 50% POE loads respectively;
- Generation plant was installed until the USE averaged 0.002% across all the simulations – each individual simulation had a different level of USE. For

each year this gave 100 individual simulations which had the same level of generation installed but with differences due to variations in the POE demand levels and generator forced outage patterns;

- Each individual simulation required a different MPC to make the marginal generator just profitable;
- Over 7 years there were 700 individual simulations (in the final runs).

ROAM then plotted the relationship of USE and MPC calculated for each of the 700 individual simulations. The simulation which had USE at near 0.002% provided the MPC required for the marginal plant to be economic.

This is what ROAM refers to as the "Iteration" method.

Note: The ROAM report indicates that 100 simulations were performed in the final runs for each year. However it was not clear how many simulations were done for the 10% PoE demand and how many for the 50% PoE demand cases.

Modelling Outputs

The modelling results shown in their report were:

- The MPC versus USE relationship (excluding the raw data points);
- The annual USE over the period 2010/11 to 2019/20 for each region at various MPC levels;
- The pattern of USE across the simulations;
- The sensitivity of USE to the level of installed capacity.

5.1.2 Levels of the MPC that are consistent with the value of customer reliability

Terms of Reference

For their assessment of the impact of extreme weather the AEMC requested ROAM to undertake additional modelling that incorporated extreme weather demands (not included in the Reliability Standards and Setting Review).

The Terms of Reference from the AEMC report specified that the modelling was to model extreme weather events as follows:

- Use the 10% PoE and 50% PoE maximum demand (MD) forecasts but apply a higher probability to the 10% PoE MD (say 1 in 5 years);
- Model a lower PoE MD (say 5%) as well as the 10% PoE and 50% PoE MDs; and
- Model a lower PoE MD (say 5%) and assume a higher probability.

The terms of reference further stated:

- The best approach is probably to model 5%, 10%, 50% and 90% PoE MDs, but to double the associated probabilities for the 5% and 10% PoE MDs;

- In order to model extreme weather events, ROAM has redistributed the weightings for 5% PoE,10% PoE and 50% PoE such that the 5% PoE and 10% PoE demands have probabilities twice that calculated using the ROAM methodology, at the expense of the 50% PoE demand weighting.

Methodology

The methodology used was assumed to be the same as in the Reliability Standards and Settings work, except for one change. This was that ROAM used (what they term) the "Averaging" method instead of the "Iteration" method. These methods are understood to be as follows:

- The Iteration method has the data points of the USE v MPC curve based on each individual simulation – peaking plant being profit neutral in each simulation, while
- The Average method has the data points of the USE v MPC curve based on peaking plant being profit neutral on average across all simulations.

Modelling Outputs

The modelling results shown were:

- The annual USE over the period 2012/13 to 2018/19 for the NEM as a whole for various MPC levels;
- The MPC versus USE relationship over the period 2012/13 to 2018/19;
- Differences in generation capacity between various MPC levels;
- The effect of generator forced outage rates on required MPC;
- The effect of capital cost on required MPC;
- The pattern of USE across simulations;
- The sensitivity of USE to the level of installed capacity.

5.2 Clarification of ROAM Modelling

The report was not clear on a number of important issues which are listed below. These are categorised under the heading statistical variations, renewable generation, market behaviour, and results.

Statistical variation

Statistical variation in loads and wind generation is an important issue for reliability. So is the pattern of planned outages relative to the demand trace. The report does not describe how these issues were treated. In particular:

- How many wind traces were used to represent wind generation across the NEM and were the same wind traces used for each simulation? Was the level of wind at time of maximum demand designed to provide the assessed capacity support as specified by AEMO as reliable, and if not what was the level used in the simulations?

- Was the same load trace used for all the 10% PoE simulations and the 50% PoE simulations?
- Was the same generator planned outage pattern used in all the simulations and was all generation planned to be in service at the time of MD?

Renewable Generation

IES studies have indicated that the current outlook for the LRET is that the 20% target by 2020 may be difficult to satisfy. This is due to the likely level of carbon price, the status of technologies such as geothermal and the level of the shortfall penalty. The ROAM modelling assumed that the 20% target would be satisfied by 2020 but no description was provided on the economics and geographical distribution of renewable energy plant. Particular issues are:

- The economics of the renewable generation projects that entered the market to satisfy the LRET target; and
- The profile of regional development of renewable technology by type, and the level of wind development in South Australia.

Market Behaviour

Market behaviour refers to the manner generator units are committed to service, how they bid for dispatch, and in the longer term decisions to develop new plant (and retire existing plant).

The basis of the ROAM modelling was the entry of “extreme peaking” OCGT plant that only operates to avoid load shedding and receives a price near the MPC when it generates. In this regard we note that the economics of peaking plant as observed in the NEM includes revenues from periods outside times it is required for reliability.

The modelling states that realistic bidding was used. This raises the following questions:

- Did only OCGT plant enter in the simulations?
- How did the peaking plant bid in the simulations and was this different for “extreme peaking” and “shoulder” peaking plant?
- Did peaking plant have a fixed unit size?
- Were most of the generators in the market bids adjusted each year in response to factors such as load (and contract level) growth?
- Were interconnectors assumed to be 100% reliable?

Results

In modelling work of this sort it is normal practice to provide all the key outcomes such as spot prices, total capacity development by time, type and location. This is essential for understanding the modelling and for transparency. This was not evident in the ROAM reports. In particular:

- What did the price duration curve look like each year?
- How much capacity entered and how did this compare to the current AEMO reserve margin criteria?
- The results presented in Figure 7.4 and 7.5 are important to the conclusions in the Reliability Standards and Setting report. To understand the accuracy of this curve, the 700 points need to be provided.

5.3 Key Finding of the ROAM Modelling

The key findings of the ROAM modelling were as follows:

- For the years 2012-2013 and 2013-2014 an MPC of approximately $16,000/MWh is necessary to ensure sufficient incentive exists for the recovery of an investors required rate of return for an extreme peaking gas turbine while meeting the Reliability Standard of 0.002% USE;
- A CPT of $240,000 be adopted for 2012-13 and 2013-14, retaining the same multiplier as previously;
- Increasing capital costs of peaking capacity, increasing peakiness of load, the decreasing value of money and the increasing penetration of intermittent generators all contribute to the need for a higher MPC than that determined in the 2007 Comprehensive Reliability Review;
- Different values of MPC would be required for each region because of the unique characteristics of the regions, including the load shape, the mix of generation and the degree of inter-regional interconnection.

5.4 Issues with the ROAM Modelling

Given the importance placed on the ROAM modelling in the AEMC review process, it was critical that the scope and any limitations of the modelling be properly understood. The lack of transparency in the modelling was a major shortcoming not only of the modelling but of the AEMC process.

IES considers that the ROAM modelling failed to address two key issues. These are the uncertainties of load and wind generation (as they influence reliability), and the dynamics of the market which translate the reliability and security setting into actual spot price outcomes (and associated new-entrant price signals). In relation to these matters the following are noted.

Demand / supply uncertainties

- There was limited discussion on the approach used to model the key stochastic factors of extreme loads, wind generation and planned outage patterns. It appears that these were modelled using historical traces that provided a variation within simulations but had identical patterns in all the simulations undertaken.[4]

- The demands used did not include the 90% PoE demand scenario. Also in the extreme weather modelling the probabilities of the 10% and 5% PoE demands were doubled. The resulting load distribution assumed was changed to have a higher mean and lower variance than historically observed. The consequences of this were that the full demand scenario distribution was not modelled and there was a bias towards additional revenues, especially for peaking plant. The risk of this is that investment in OCGT plant will be overstated and resulting USE understated. Appendix 4 presents a discussion of this matter.

Market dynamics

- The modelling did not include any discussion or attempt to model market entry dynamics as observed. As previously discussed the concept of extreme peaking plant was used (that received near the MPC when generating).
- The manner other generators behaved was not described. From the description it appeared that generators used fixed bids that did not respond to market conditions;
- Average spot prices were shown in the ROAM presentation to stakeholders but there were no results on the pattern of spot prices fundamental to peaking plant economics.

[4] The approach of using the same traces in every simulation meant that the profile of UE to MPC simply reflected (1) the profile of the assumed load pattern net of the assumed wind generation pattern at the time the marginal plant was required and (2) the number of hours the marginal OCGT plant was required to be economic at a price near the MPC.

6 Economics of “Extreme Peaking” Plant

The ROAM modelling summarised and reviewed in the previous chapter used the concept of “extreme peaking” plant. This refers to OCGT plant that operates last in the merit order stack (and thus to avoid load shedding) and receives (close to) the MPC when operating.

While IES considered such plant to be hypothetical as there are no plants in the NEM that operate in this manner, this chapter reviews the issues associated with the economics of such hypothetical extreme peaking plant. This is undertaken to identify the key factors impacting the economics of extreme peaking plant as defined, and to assist in the interpretation of the MPC – USE characteristic developed by ROAM through their simulation modelling.

To do this, the chapter presents a description of new OCGT plant economics and associated power system reliability under (1) the above assumptions of extreme peaking plant operation and (2) accounting for wind and load uncertainty.

The analysis is based on a single region market. This assumption is considered reasonable since at times of load shedding in one region it is likely that interconnecting transmission would be constrained, making that region marginal on its own extreme peaking plant. However it is appreciated that this may not always be the case (particularly between South Australia and Victoria). Of course in the limit of no transmission constraints the NEM would move to a single region market with a slightly flatter demand curve (than for the individual regions).

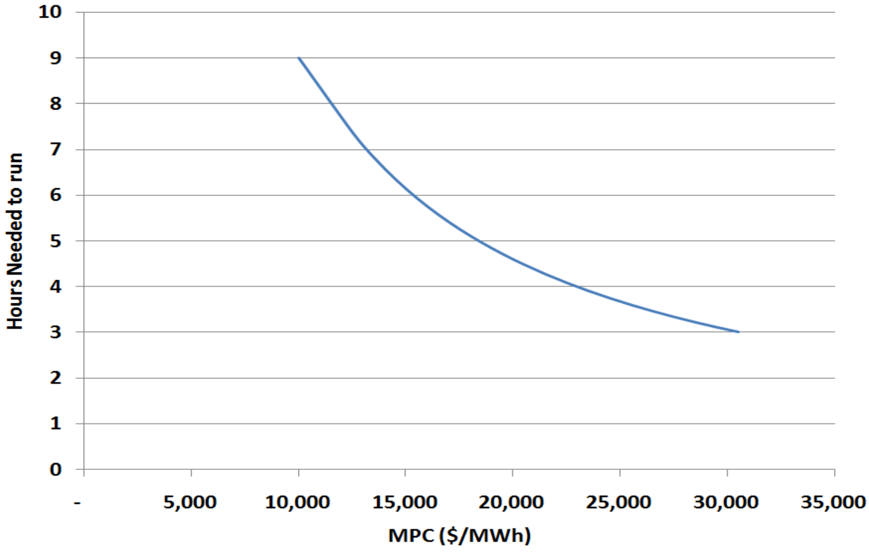
6.1 No Load or Wind Generation Uncertainty

OCGT Plant Economics

Let us first consider the costs and economics of new OCGT plant. The ROAM modelling used the assumption that the capital cost for an OCGT in 2010/11 is $918/kW and that the required annual returns are to be calculated over a 30 year life at a real post tax WACC of 6.81%. This corresponds to an annualised capital cost of about $90/kW/year or about $10/MWh (when allowing for forced outages).

From this we can calculate the number of hours such a plant would need to operate at various MPC levels to be profit neutral on the assumption it receives the MPC for all those hours. This relationship is shown below. As shown, for extreme peaking plant as defined, a change to the MPC translates to an inverse change in the number of running hours required.

Figure 6-1 No Hours of OCGT Operation versus MPC



Assumptions

Let us assume the market consists of thermal generators only (ie no wind generation) and that new thermal generators (CCGT and OCGT) can be installed in 1 MW sizes (to overcome any lumpiness issues). To keep things simple let us also assume that:

- There are no planned or forced outages of generators;
- New OCGT plant can be started and stopped very quickly;
- The MPC is $12,500/MWh;
- New OCGT behaves as an "extreme peaking" plant – it bids near the MPC and thus receives this price when it operates.

From Figure 6-1 at an assumed MPC of $12,500 a new OCGT plant needs to operate for 7 hours to be economic.

For the purposes of considering the economics of a new OCGT generator we need only consider the load duration curve. As a new OCGT plant will not be developed until it operates for 7 hours per year we can quickly assesses the level of USE that will correspond to this OCGT plant just being economic. Under the assumptions above the shape of the load curve totally dictates the relationship of the level of USE associated with the OCGT just being economic. This is illustrated in Figure 6-2.

From this we can determine the relationship between MPC and USE. The higher the level of MPC, the lower the number of hours the extreme peaking plant needs to operate (receiving MPC for these hours) to be just economic.

The relationship of MPC to USE for each of the NEM regions based on the above assumptions of OCGT costs and the 2008/09 load curve is shown in Figure 6-3.

Figure 6-2 Level of USE when OCGT Plant Just Economic

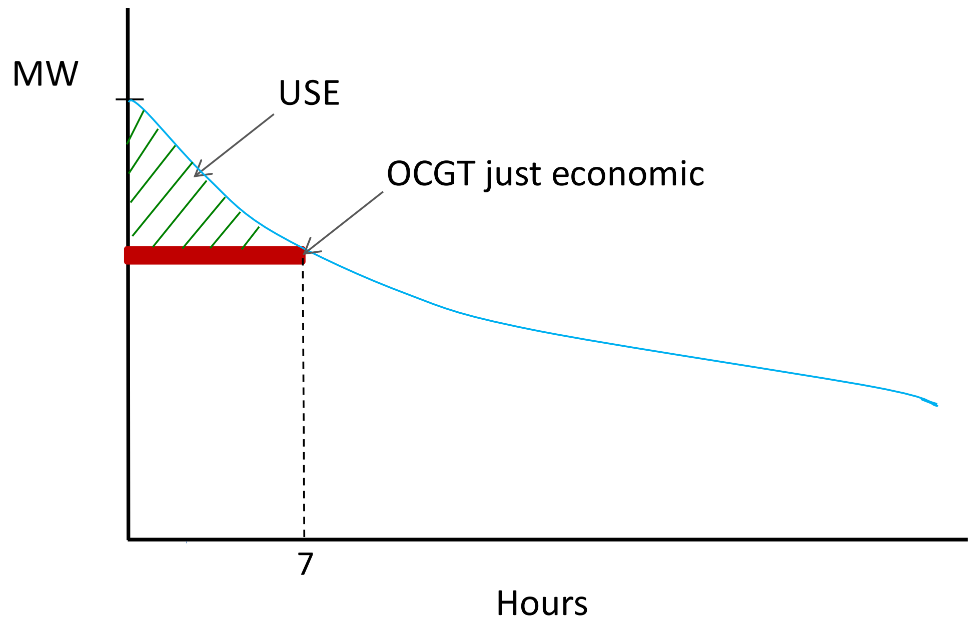
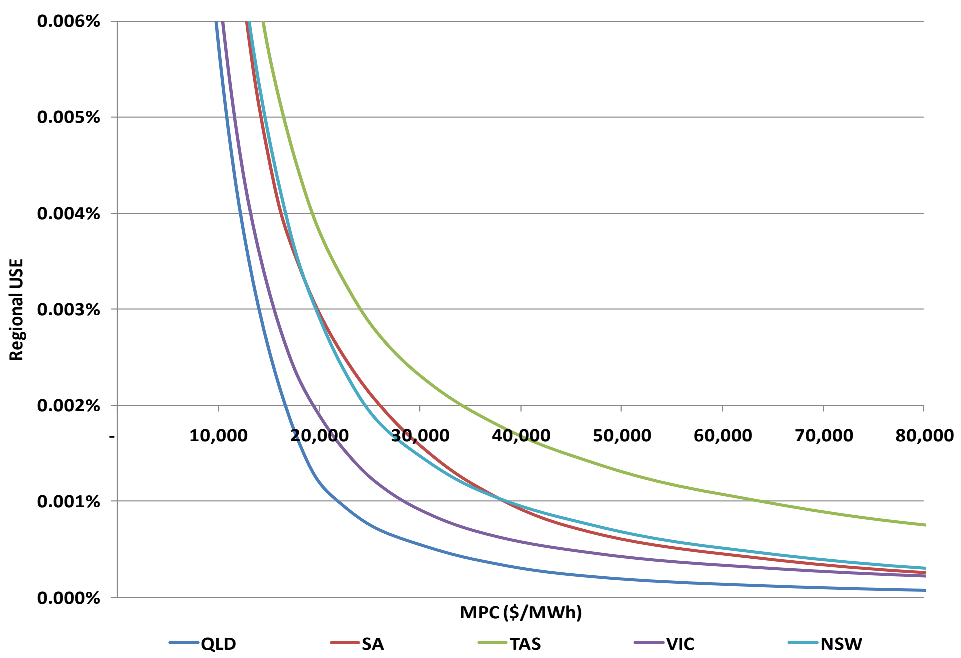


Figure 6-3 MPC v USE Relationship – 2008/09 Load Shape



The figure shows that to achieve an USE of 0.002% Tasmania needs the highest MPC and Queensland the lowest MPC for the extreme peaking plant to be economic.

6.2 Load Uncertainty

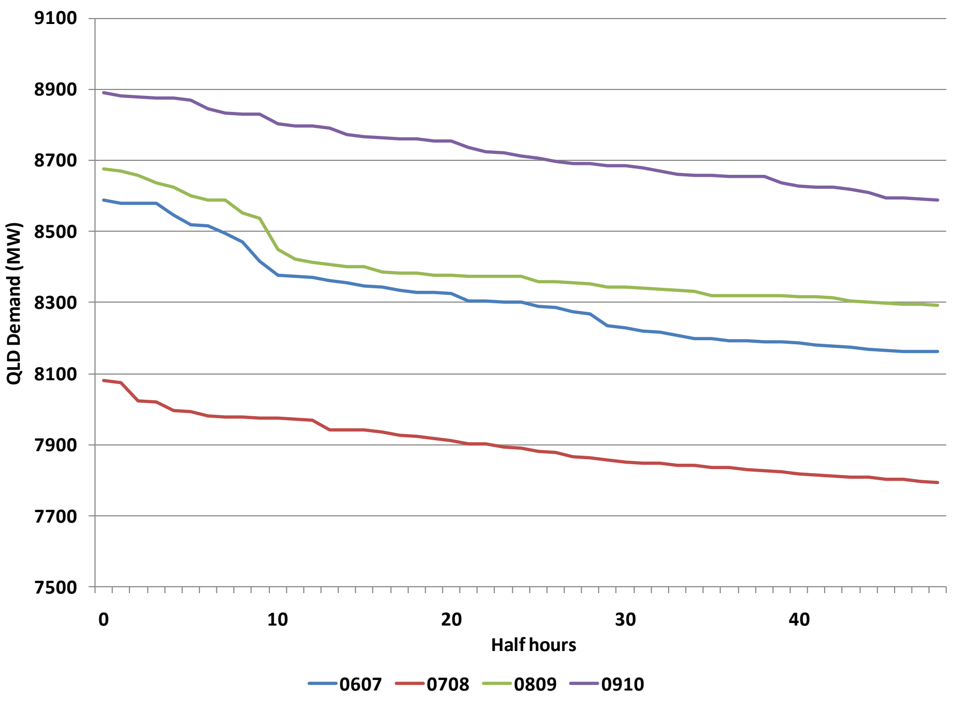
Loads Shape

Let us now assume that the load shape is uncertain and can change. For a given level of installed generation the level of USE will be different for each possible load shape. The expected level of USE would be that average over all possible load shapes accounting for their probability.

To illustrate how the pattern of load can change, the top 50 half hour periods (when extreme peaking plant would operate) of the load duration curve for Queensland over the past 4 years is shown in Figure 6-4 below. What is quite noticeable is the degree to which both the shape of these curves and the actual maximum demands change from year to year. This illustrates the variation that can occur from year to year that substantially changes the economics of extreme peaking generators and consequently the MPC – USE relationship.

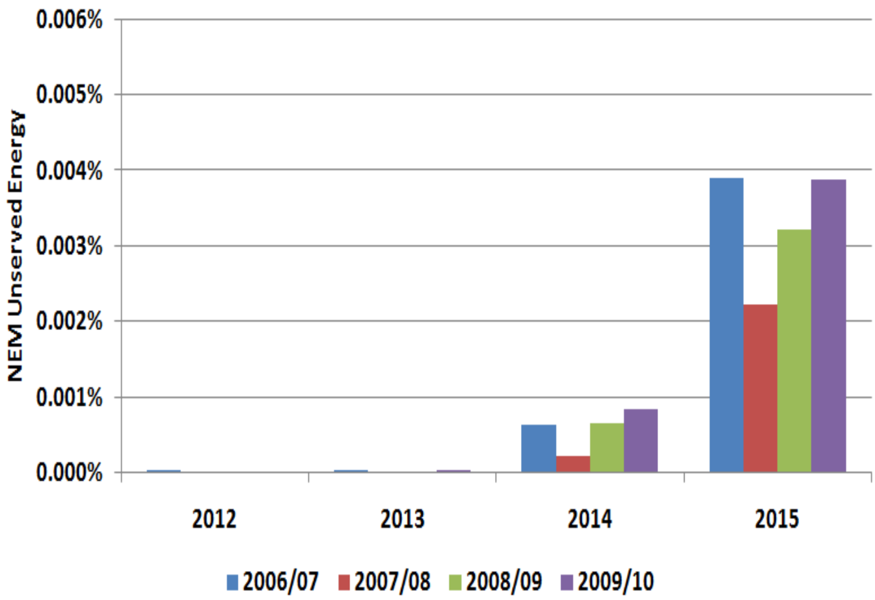
What can also be said is that the manner previous years load curves are scaled to align with defined maximum demand levels can have a significant impact on results. For example, a year of moderate demands (with no demand spikes) has a fairly flat load duration curve and if simply scaled would have a significant number of hours near the defined maximum demand level.

Figure 6-4 Historic Queensland Load Duration Curves (top 25 hours)



To illustrate the sensitivity of reliability to load shape (assuming the maximum demand level was the same) IES undertook market simulation modelling of the next four year using four different load traces based on the load shapes recorded over the period 2006/07 to 2009/10. The modelled USE when using each of the load shapes is shown in Figure 6-5. The results show a potentially significant sensitivity. Here we also note that a more significant sensitivity is likely to be the level of maximum demand.

Figure 6-5 Reliability Sensitivity to Different Load Patterns



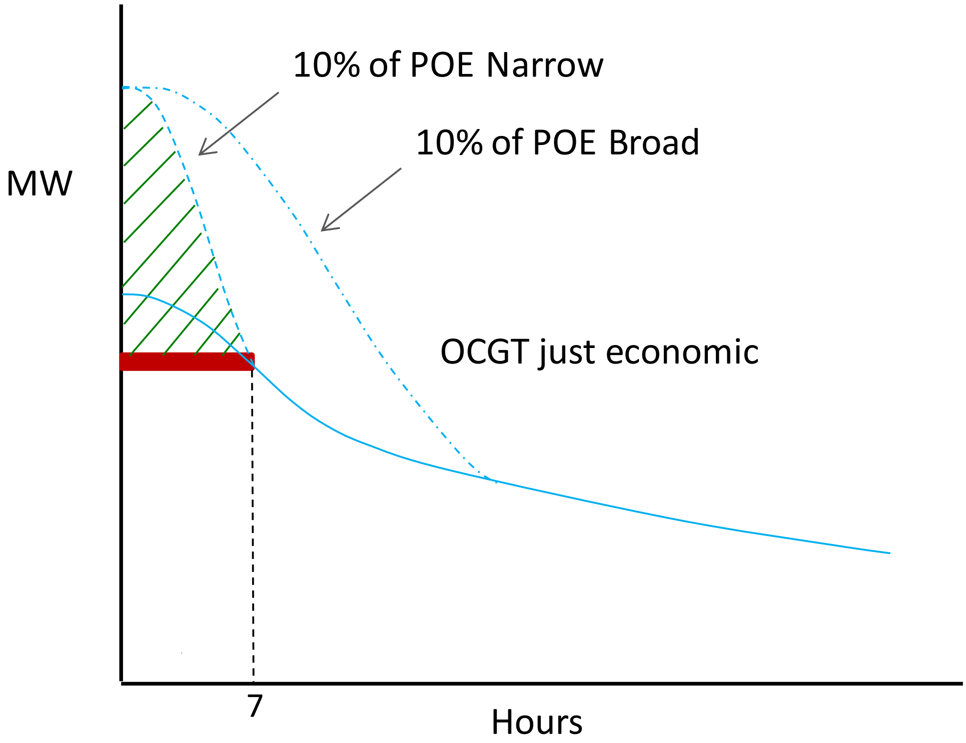
Inclusion of Extreme Loads

We now consider the economics of extreme peaking plant and the MPC-USE relationship when infrequent years of extreme demands are included. These are demands that may occur one year in ten due to extreme weather conditions.

If additional peaking capacity is to be economic such that on average the USE is within the 0.002% level, then such plant has to be economic on average over the probability weighted normal years and the 10% PoE demand years. This weighting should include with appropriate probabilities the 90% PoE, 50% PoE and the 10% PoE years.

As important as the level of maximum demand is the number of hours of high demand, as this directly corresponds to the hours of operation of extreme peaking plant. Based on the number of high demand days (and hours) relative to expected conditions (50% PoE demand and average number of high demand days) Figure 6-6 below shows two types of 10% PoE load patterns, what we have termed 10% PoE Narrow and 10% PoE Broad.

Figure 6-6 Extreme Peaking Plant Operation and 50% and 10% PoE Demands



We note the following:

- 10% PoE Narrow – has the same number of high demand days (as the 50% PoE case) with these days having higher demands. Such a demand shape does not have extreme peaking plant running more hours meaning that no additional extreme peaking plant would be economic. The result would be higher USE.
- 10% PoE Broad – has an increased number of high demand days (and more hours of high demand). Such demand would have extreme peaking plant operating for more hours, making additional plant economic. The amount of additional plant would depend on the load curve shape.

This illustrates that care is required in any modelling undertaken to ensure the correct load distributions are used. In particular, that the correct average number of high demand hours is achieved over time. This requires that the 90%, 50% and 10% PoE demand years are recognized and that the number of high demand days in each of these year types is correctly represented.

6.3 Inclusion of Wind Generation

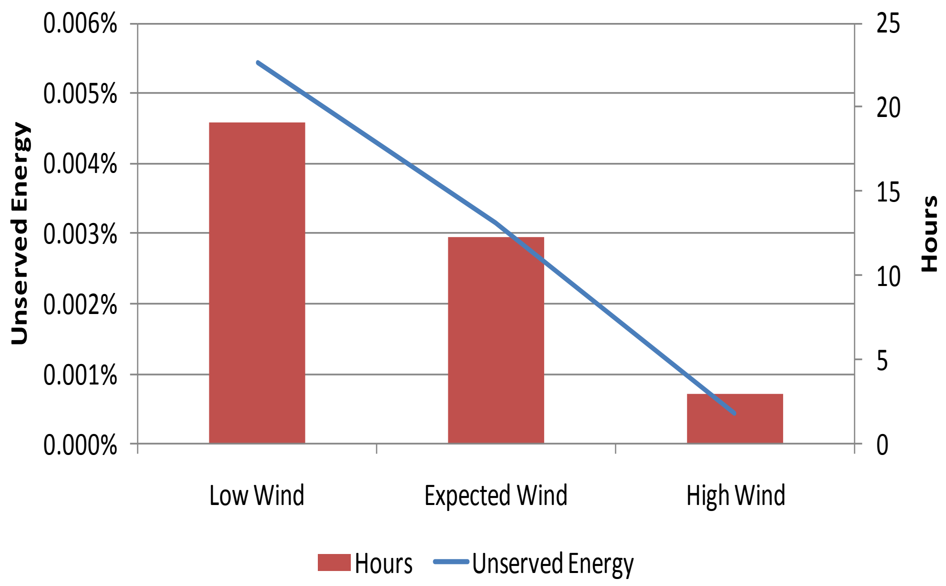
Let us now include wind in the mix of generation. Let us assume that the level and pattern of wind is known and that we are adding OCGT plant when economic (as before). Once again we need the marginal OCGT to operate for at least 7 hours. If the pattern of wind generation is known with certainty, particularly at the time of high demands, then the OCGT plant will again operate for 7 hours but the level of USE will be based on the load shape net of the wind generation.

Let us now assume that based on the above, the pattern of wind generation can change (but that the load shape and installed generators stays the same). Let us assume we have 100 possible patterns of wind generation. For each wind pattern the level of USE will also change. The expected level of USE would be the average over all possible wind traces accounting for their probability. The more wind generation there is the greater the level of wind generation uncertainty. Furthermore the economics of the new OCGT plant will change for each scenario of wind generation. In the actual market the economics of an OCGT plant would consider its positions over all wind traces and any entry decision would be based on the expected revenues (possibly leaving out some of the very high revenue scenarios).

Here we note that the uncertainty of wind generation may have the same impact as variations in peak demand levels, in that with enough wind generation developed, wind generation variation may be greater than the difference between 50% and 10% PoE demand levels.

To investigate the sensitivity of reliability to wind generation uncertainty, IES undertook market simulation modelling using a number of different potential wind traces. From this modelling three wind traces were selected that were labeled Low, Expected and High. For these wind traces the hours and USE and level of USE for South Australia are shown in the figure below. The results show a significant sensitivity of SA USE to the assumed pattern of wind generation.

Figure 6-7 SA Reliability Sensitivity to Wind Pattern Assumed



6.4 Including Load and Wind Generation Uncertainty

Let us now assume both load and wind generation uncertainty. This of course leads to a greater variation in possible outcomes. If we had 100 wind scenarios and 100 possible load scenarios then we would have 10,000 possible outcomes (assuming load and wind generation to be independent of each other). Each of these would have a different level of USE and different economics for the marginal extreme peaking OCGT plant.

The time it takes to undertake market simulations means that undertaking 100,000 market simulations is not possible in a reasonable time frame (and is outside the scope of this report).

To gain an appreciation of the impact load and wind variability can have on reliability and the required MPC, IES undertook a statistical approach to assessing South Australian reliability and the MPC required for extreme peaking plant to be economic.

This involved analysing and developing distributions for South Australian demand and wind generation and their correlations. Using these distributions the MPC required for the marginal peaking plant to be economic was determined (when paid the MPC for its generation).

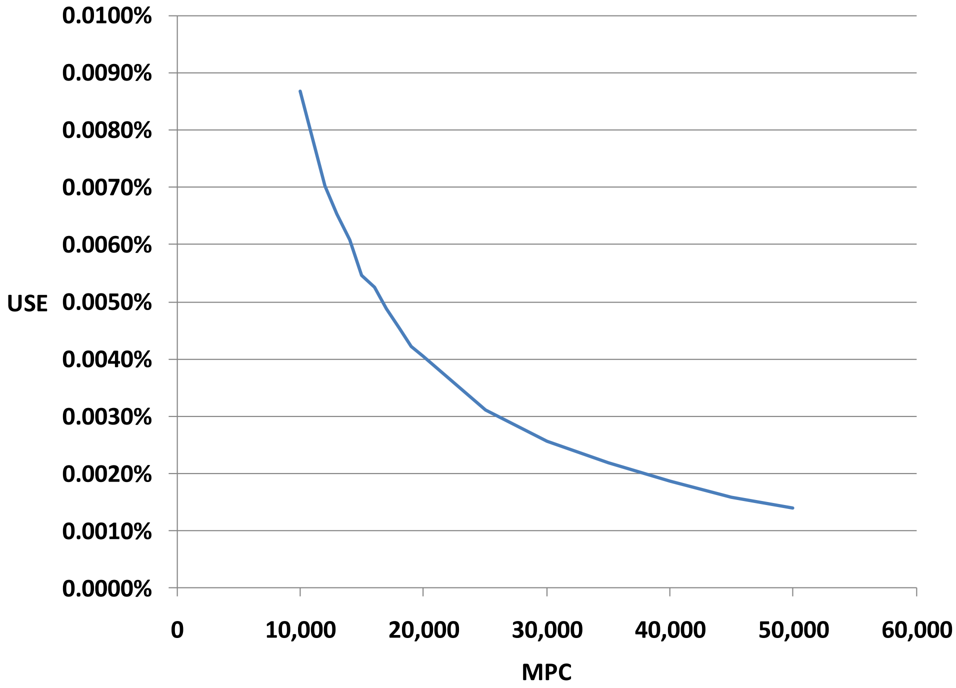
The approach used was as follows:

- The distribution of net demand was calculated by working out the probability distribution of the South Australia demand less wind generation. This was done by a convolution of the two distributions;
- The demand was then found which had a probability of exceedence equal to the breakeven capacity factor;
- Then the expected amount of load not been served was calculated.

The details of this approach are presented in Appendix 5. The result of this analysis is shown in the Figure 6-8 below.

What is interesting is that this analysis suggests that a MPC of around $40,000/MWh is required to achieve 0.002% expected USE in South Australia. What this is saying is that when the full distribution including load and wind generation uncertainty is considered, the MPC is substantially higher than when assessed through a more deterministic approach.

Figure 6-8 SA MPC – USE Relationship when including Wind and Load Uncertainty



6.5 MPC – USE Relationship Developed by ROAM

The simplifying assumptions used in Section 7.1 of the ROAM report are understood to form the basis of the modelling undertaken by ROAM. In particular:

- The marginal OCGT plant bids near the MPC and receives a price very near the MPC when it operates;
- No variation in load shape each year (ie the same load traces used for all simulations);
- No variation in the pattern of wind each year (ie the same wind traces used for all simulations);

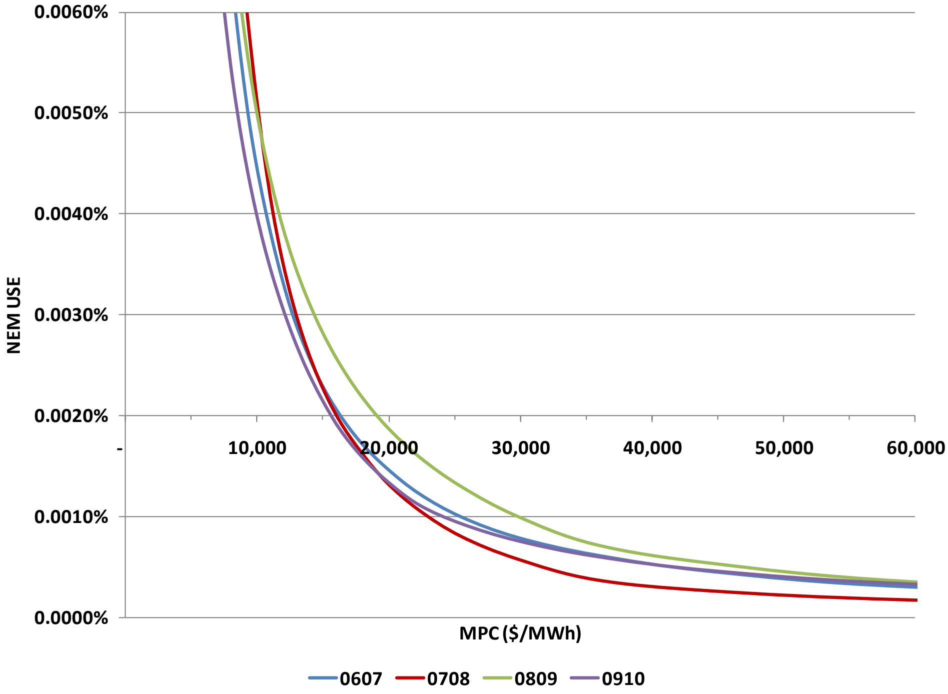
The main differences in the ROAM modelling were that generator forced and planned outages were included, and that the NEM regions together with transmission constraints were represented.

We can reproduce Figure 7.3 in the ROAM Reliability Standards and Setting report in the same manner this was done in Section 7.1 of this report. Since we do not know what wind traces ROAM used in their modelling this has been done for the NEM based on having OCGT plant run for the required number of hours using the shape of the load duration curve only.

The results of this are shown in Figure 6-9 for the NEM as a whole with the load shape based on four historical load traces (2006/07 to 2009/10). We note that the ROAM modelling used to 2008/09 load shape. What is interesting is that the relationship shown is very similar to that presented in the ROAM report.

It would therefore appear that the relationship developed by ROAM accounts vert little for load and wind uncertainty and excludes any consideration of market behaviour and the normal dynamics associated with OCGT plant economics.

Figure 6-9 USE v MPC Relationship in the NEM



7 NEM Market Dynamics

The basis of NEM market simulation modelling is to replicate actual market operations to the extent possible. It is understood that this was also the intended basis for the ROAM modelling which as described by the AEMC “emulates the operation of the NEM”. There are two key aspects to this, (1) the physics of the power system and (2) the dynamics of the market.

The first of these was addressed in the previous chapter which illustrated the key uncertainties of load and wind and the influence these can have on generation reliability. The chapter concluded that the ROAM modelling did not appear to incorporate the impacts of such uncertainty.

This chapter addresses the second issue of the dynamics of the NEM. Here we also note that by assuming all new OCGT would operate as extreme peaking plant the ROAM modelling did not attempt to include any consideration of NEM market dynamics.

It is usual for market modelling to be compared to actual market operation in order to ascertain the degree to which the model emulates the market. While it is not possible for any model to emulate the NEM in total detail, it is important to understand how the model aligns on key issues. These include bidding, the pattern of generator operation, spot price outcomes, and investment.

Given the importance of new generator investment and how generators operate at times of very high demands, this chapter presents a review of:

- Generator behaviour at times of high demand and high spot prices. This includes an assessment of the impact an increase in the MPC may have had to actual price outcomes in the NEM;
- Investments that have occurred in the NEM since 2000 and the relationship of such investments to spot prices and generator economics.

This discussion forms the basis for modelling undertaken by IES (and presented in the following chapter) that is designed to reproduce the essential elements of actual market operation.

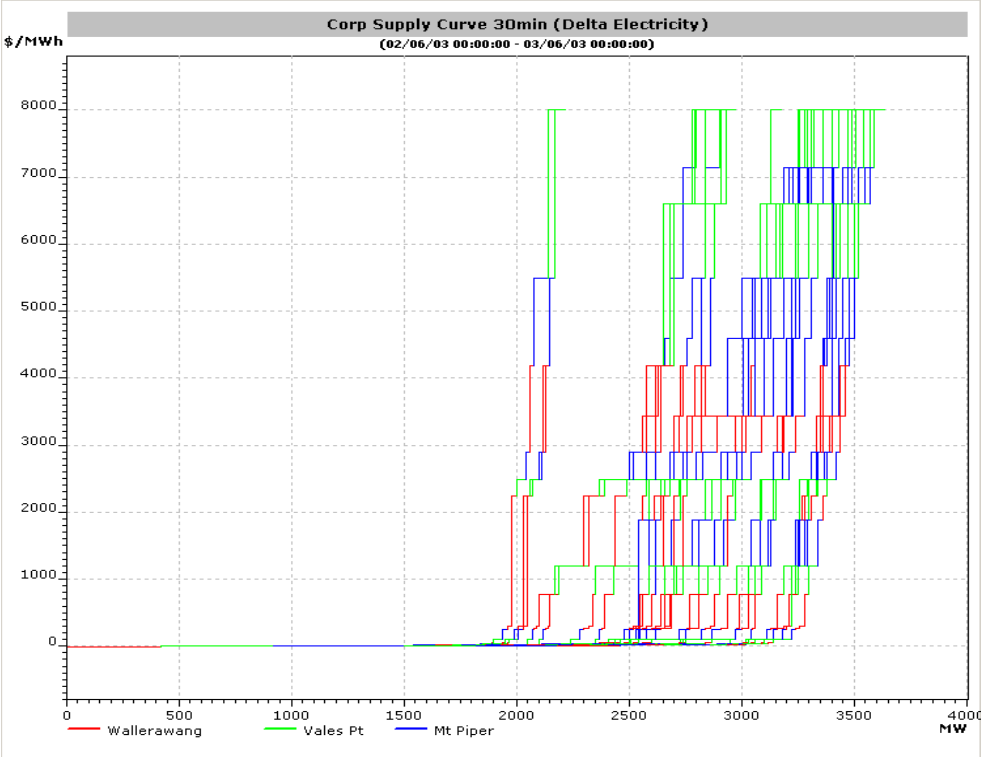
7.1 Generator Behaviour

7.1.1 Normal Conditions

In energy only spot electricity markets such as the NEM, generators are incentivised to bid near their SRMC to their swap contract quantity and to bid higher prices for generation above this level. The result of such bidding is that spot prices can be at levels approaching the MPC when there is still surplus capacity in the market.

Such behaviour is illustrated in the figure below, which shows the 48 hour hourly NSW supply curves for a typical day in NSW. What is noticeable is the amount of capacity that is offered into the market at prices greater than $1,000/MWh.

Figure 7-1 Typical Regional Supply Curve



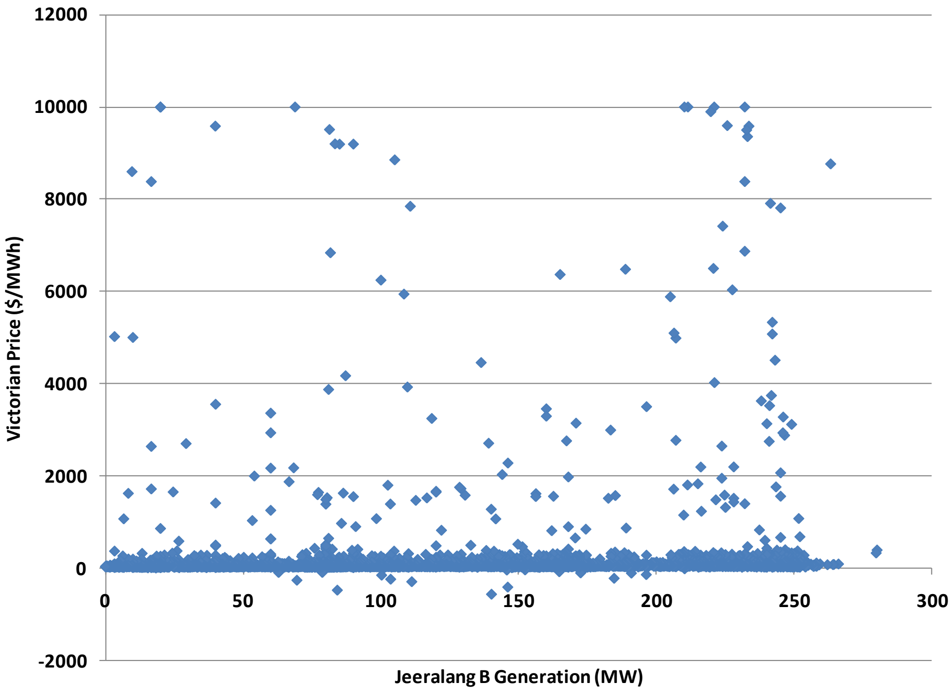
7.1.2 High Spot Price Periods

The behaviour of generators is observed to change during periods of high prices. Observations of generator bidding at times of high demand and high spot prices shows that the large portfolios (particularly in NSW) have a tendency to withdraw capacity through pricing at times of high prices, providing for open cycle plant to operate at higher levels than it would otherwise do. This behaviour reflects the marginal value high pricing provides to the large generator companies both in terms of immediate spot revenues and also the impact on the forward curve. During such periods an open cycle plant that bids high prices during most hours so as to not operate will typically reduces its bid to zero or below in order to ensure operation.

An example of this bidding dynamic is presented in Appendix 2, which shows for a day that contained periods of very high demands and high spot prices, how a base load generator and a peaking generator actually behaved.

In general in the NEM, OCGT plant operates when spot prices are over some threshold value, which is typically not very high. To illustrate this, the Figure 7-2 below shows for the period 2006 – 2011 the level of Jeeralang B operation versus spot price outcomes. This shows Jeeralang operating when spot prices are above about $70/MWh, and that during such periods the level of Jeeralang operation is not highly correlated to spot prices.

Figure 7-2 Jeeralang B Generation versus Spot Price: 2006-2011



Appendix 8 shows similar figures for the following OCGT plant: Mt Stuart in Queensland, Hallett in SA, and Hunter Valley in NSW.

We note that at times of load shedding when prices are at the MPC all available plant attempts to maximise its output.

7.2 Impact of an increase in the MPC

As part of the IES modelling presented in this report, the influence of an increase in the MPC to $20,000 is considered. To support the approach used, this section investigates the potential impact a higher MPC would have had to actual spot price outcomes (on the assumption the generators in the market remained unchanged).

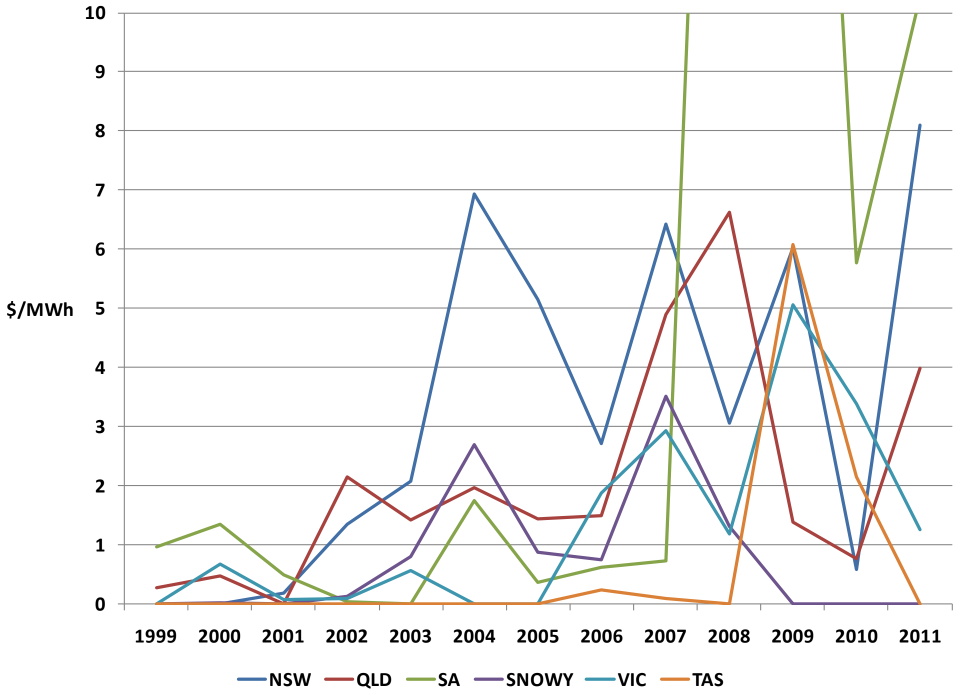
This was done by hypothesising that an increase in the MPC to $20,000 would have generators change their bids as follows:

- No change in price bands less than $4,000/MWh;
- For price bands over $4,000/MWh, a linear change in prices such that prices at $12,500 (when this was the MPC) move to $20,000 and prices at $4,000

are unchanged. Based on this assumption, spot prices would increase as described above as the marginal price band would scale as do the offer prices.

The figure below shows the results of the analysis. This is shown for each region (including Snowy when it existed) over the period 1999 to 2011.

Figure 7-3 Historical Assessment of the Increase in Spot Price due to increasing the MPC to $20,000/MWh



The results show an increase that trends larger over time reflecting a tightening of the demand/supply balance, but that is quite uncertain. The average increase over the period is in the order of about $3/MWh.

7.3 Historical New Entry in the NEM

Spot price theory essentially has it that new entrant generation enters the market when the revenues from spot electricity sales is sufficient to cover marginal plus annualised capital costs (in other words provide for a sufficient return on capital). In practice the market is more complex with entry decisions being based on factors that include the forward curve and secured contracts, spot prices and the business need.

The relationship between spot prices and return on capital for new entrants that have entered the market can be understood through a review of spot price outcomes and the cost structure of generators that have entered the NEM. A very convenient way to view this is a comparison of spot price premiums and the annualised capital costs of new plant.

Appendix 1 describes the concept of spot price premiums and how these are used to assess the spot market economics of new generators. Having done this the appendix presents a review over the period 2000 to 2011 for each region of the NEM (excluding Tasmania) of spot price outcomes and the spot market economics of new generators that entered the NEM (excluding renewable generation). This review illustrates that:

- The pattern of new entry is complex and does not closely align with spot price signals. The reasons for this are understood to be associated with differences in private and government generator development, market projections at the time, portfolio strategies, contract values at the time etc;
- By and large new entry has been economic on the spot market;
- The plant that has shown the greatest departure from spot price economics are the high operating cost OCGT plant;
- This shows that the dynamics of capacity investment (especially for peaking plant) are quite different to that assumed by the ROAM modelling.

8 IES Market Modelling

IES undertook market simulation modelling to investigate the issues and ability of the current spot prices signals (as influenced by the reliability and security settings), to provide sufficient capacity to ensure that the 0.002% USE target is satisfied. The study period of the modelling was 2011 to 2018 (calendar years).

The modelling was intended to address the physical and market dynamics issues noted in the previous chapters, with the objective of identifying the operation of the reliability and security settings in terms of the strength and variation in the spot price signals.

8.1 Description of the Modelling Undertaken

Assumptions

The modelling used the most recent assumptions from AEMO statement of opportunity documents and a 5% carbon trajectory. The actual values are not important to this study.

Intra-regional Constraints

The modelling incorporated the 2009 NTS transmission constraints developed by AEMO that had inter-regional flow terms only. Intra-regional constraints were excluded consistent with the AEMC definition of reliability. The sensitivity of simulation modelling results to the incorporation of the full NTS constraints is presented in Appendix 6.

As a general comment, given that intra-regional constraints do impact the ability of generators to supply load, the full incorporation of both inter-regional and intra-regional constraints should be the preferred approach. We note that ROAM included the full NTS 2009 constraint set.

Bidding and New Entrant Plant

The modelling had generator bids dynamically developed during the simulation in the manner observed in the NEM, and new generators entering the market based on adequate revenues from the spot market. Under this approach the main generator types that enter and the price signals required were as follows:

- CCGT – expected to be the main source of new base load plant. The economics of this plant can be estimated by comparing the LRMC of such plant (capital + fuel + carbon + fixed and variable costs) to the average spot price;
- OCGT – expected to enter to support capacity needs resulting from increasing growth in maximum demands, increasingly levels of intermittent generation and possibly closures of existing plant. OCGT plant has substantially higher operating costs than CCGT plant and generally operates at capacity factors between 0 and 10%. The economics of this type of plant

can be estimated by comparing its annualized capital cost (estimated at about $10/MWh) to spot price premiums at a strike price of $100 to $300 (OCGT plant typically operate when spot prices are above $100 to $300);

- Wind / Renewables – over the next 7 years or so wind generators are expected to be the main source of new entrant renewable generation. The economics of this are based on the regional spot price and the Large scale Generation Certificate (LGC) price. Significant developments of other large renewable generators are only likely with additional funding.

Approach and Cases Modelled

The following modelling was undertaken. Firstly the NEM was simulated as described above for the study period with no new generators entering. The modelling used 50% POE maximum demand levels.

This modelling was designed to investigate the manner spot price signals increase as the reserve margin decreases and the expected level of USE increases. The modelling incorporated 25 simulations from which the minimum, maximum and medium annual values of average spot price, spot price premium at a $300 strike price and USE were recorded for each NEM region.

Then the NEM was then simulated as before but with new entry generators entering when economic. The modelling was undertaken using 50% PoE maximum demand levels and also using 10% PoE maximum demand levels.

Plant was considered to be economic based on the expected level of profitability over all simulations. This modelling was designed to investigate the amount of new entrant generation that would enter the market and the variation in spot prices that resulted. The modelling incorporated 25 simulations from which the same results as above were recorded together with the new generators that entered.

8.2 Price Signals with No New Generator Entry

The figures below show the results of the modelling undertaken assuming no new generators enter the market excluding renewable generation that enters with assistance from the LRET. There is one graph per NEM region (excluding Tasmania). As no new entry generators are allowed to enter we see prices rise each year and the level of USE also rises. For reference the dotted line shown is $10/MWh - when the $300 spot price premium is above this level an OCGT plant is expected to be economic.

The key observations from the results are as follows:

- There is a slight “knee” in the price and USE curves at about the time USE is near the 0.002% level;
- For NSW and Queensland, OCGT plant becomes economic based on the minimum annual $300 premiums post 2014. This roughly corresponds to when the expected USE is near the 0.002% level;

- South Australia and Victoria are quite similar with the maximum USE not exceeding 0.002% until 2016. The lower price signals and USE reflects the low level of demand growth over the study period;
- There is significant variation in the minimum and maximum time when OCGT becomes economic and USE levels each year.

Figure 8-1 NSW 50 PoE No New Entry

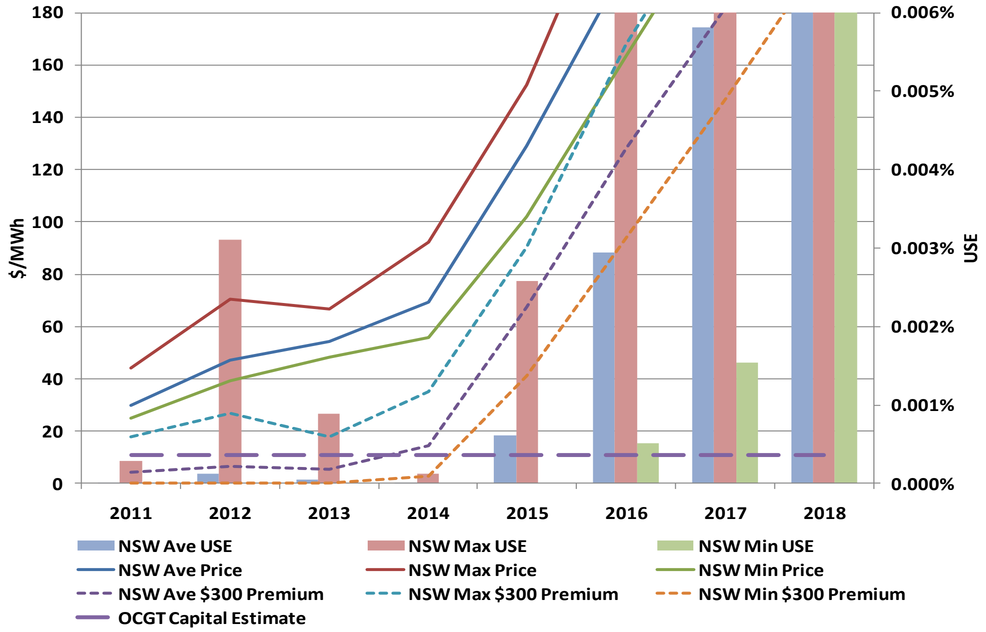


Figure 8-2 QLD 50 PoE No New Entry

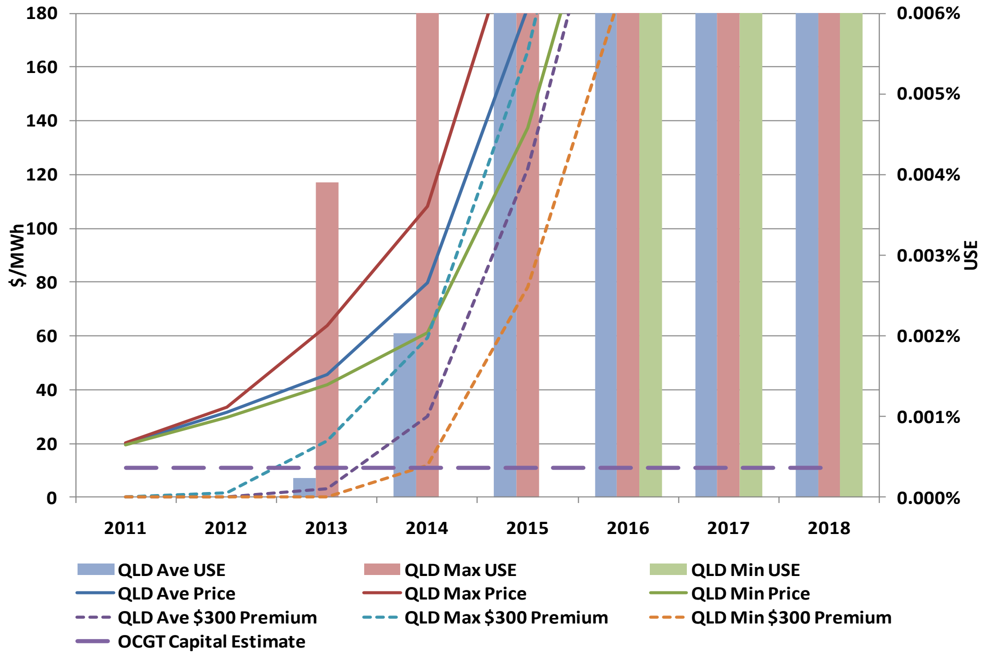


Figure 8-3 SA 50 PoE No New Entry

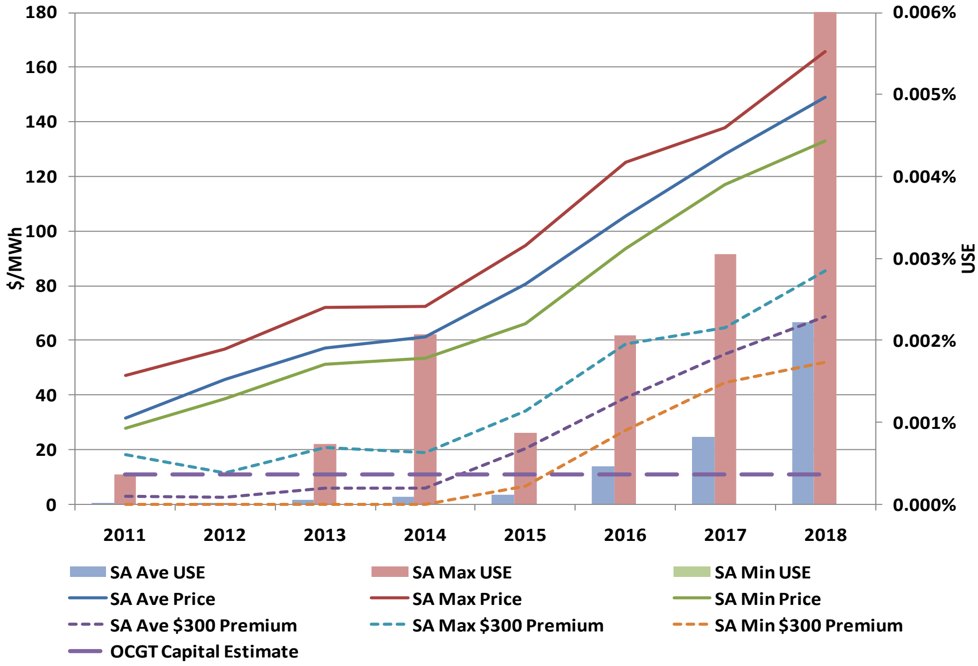
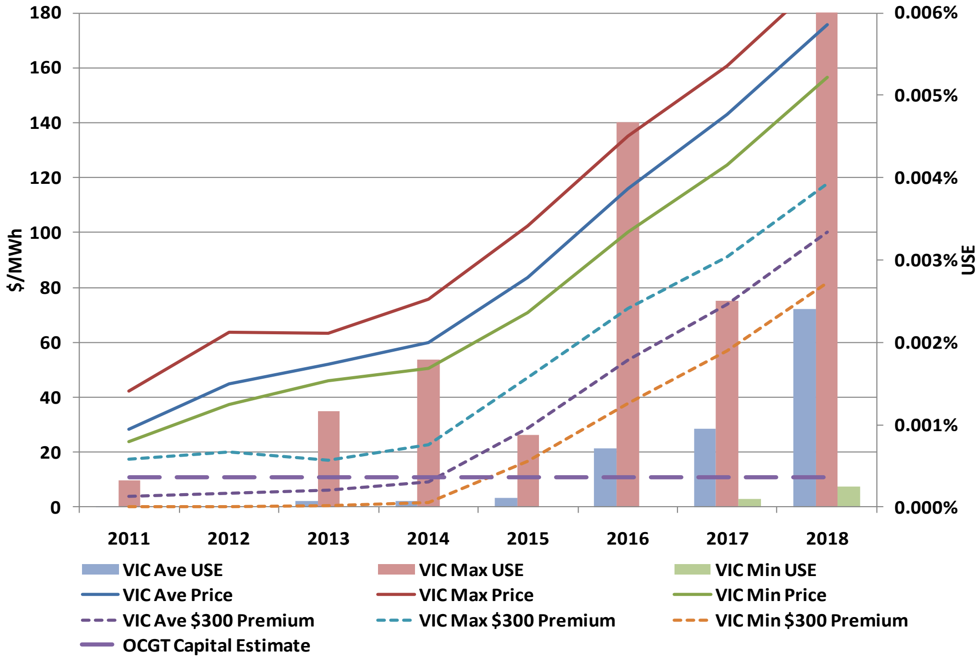


Figure 8-4 VIC 50 PoE No New Entry



This analysis shows that the current MPC is sufficient for OCGT entry to occur prior to when the expected USE reaches the reliability limit of 0.002%.

8.3 Price Signals and USE when New Generators Respond

The figures below show the results of the modelling undertaken assuming new generators respond to price signals and enter the market when economic. Three series of modelling runs were done on this basis, the first used 50% PoE demand, the second used 10% PoE demands and the third used 90% PoE demands. New generators entered when economic on the weighted average economics on the three demand cases. The figures over the next 4 pages show the results for the 50% PoE demand and 10% PoE demand cases in turn, with one region shown per figure.

The key observations from the results are as follows:

- The entry of new generators results in annual spot price premiums levelling off over the study period. As spot price premiums are a measure of capacity costs, they are not influenced by carbon costs;
- The "ups and downs" in the spot price patterns ($300 spot price premiums and average spot prices) reflect the impacts of lumpy generator investment;
- For the 50% PoE demand cases:
  - the medium $300 premium tracks around $10/MWh, this being the economic cost of OCGT plant
  - the minimum $300 premium is always below the $10/MWh entry level of OCGT plant
  - there is a spread of about $20/MWh in premium values each year;
- The 10% PoE demand cases have considerably higher $300 premium results and levels of USE. The minimum $300 premium has new entry OCGT plant economic and the medium level of USE under this demand scenario is often above the 0.002% level. This should be expected as this is a one year in 10 outcome and new entry plant has entered to be economic based on being economic when considering the weighted average of the 90%, 50% and 10% PoE cases;
- The increase in the level of average spot prices reflects the increase in carbon emission costs and gas costs over the study period;.
- There is potential for significant differences between the NEM regions which needs to be more fully understood.

These results indicate that the current MPC allows sufficient OCGT entry to meet the 0.002% reliability criteria in all regions on average. Note however that some of the 25 simulations carried out resulted in levels of USE greater than the reliability criteria for all regions by NSW. When the 10%PoE load forecast was used, the MPC was no longer sufficient to maintain the 0.002% reliability level in South Australia and Victoria on an average basis.

From this, it can be seen that the results display considerable variability on an annual basis due to uncertainties in demand and other stochastic factors. Thus load uncertainty is a critical parameter and the full distribution should be considered in any detailed modelling study regarding spot price outcomes, new entry economics and USE.

Figure 8-5 NSW 50 PoE Projections

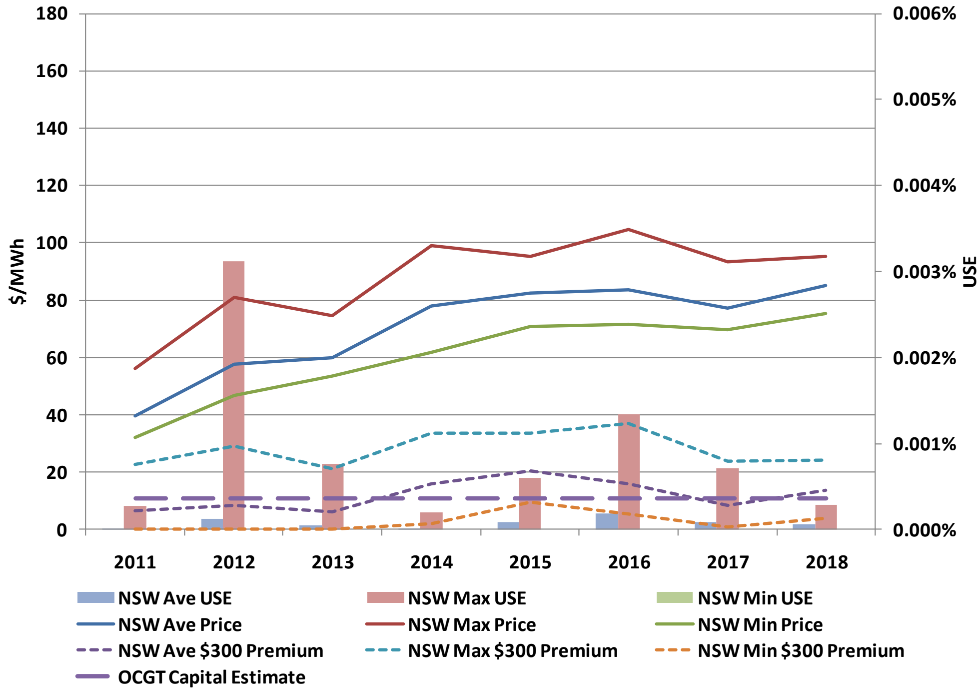


Figure 8-6 QLD 50 PoE Projections

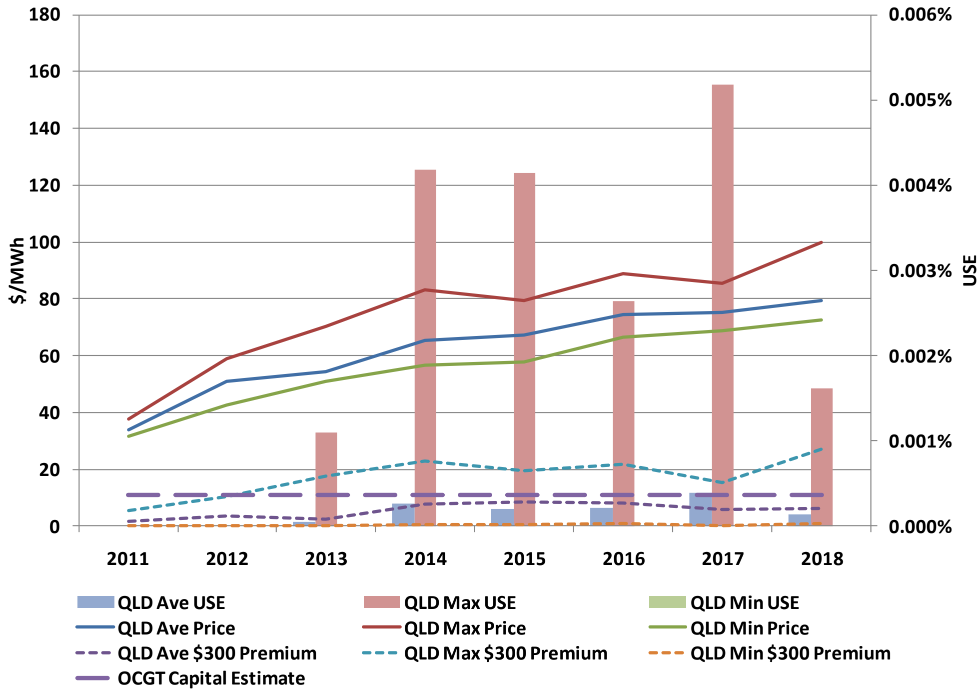


Figure 8-7 SA 50 PoE Projections

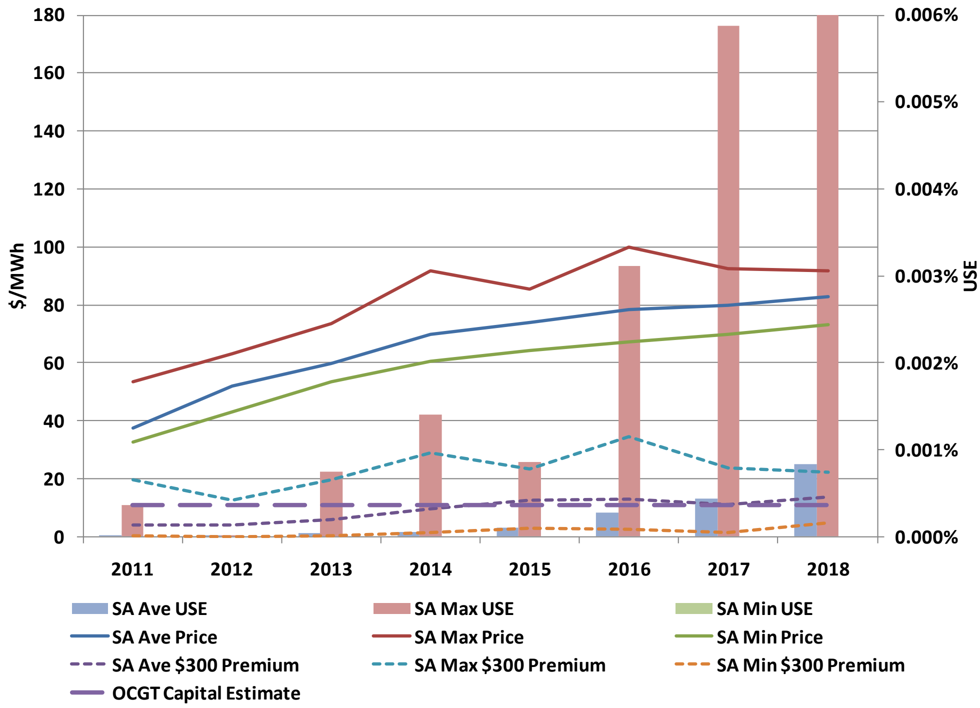


Figure 8-8 VIC 50 PoE Projections

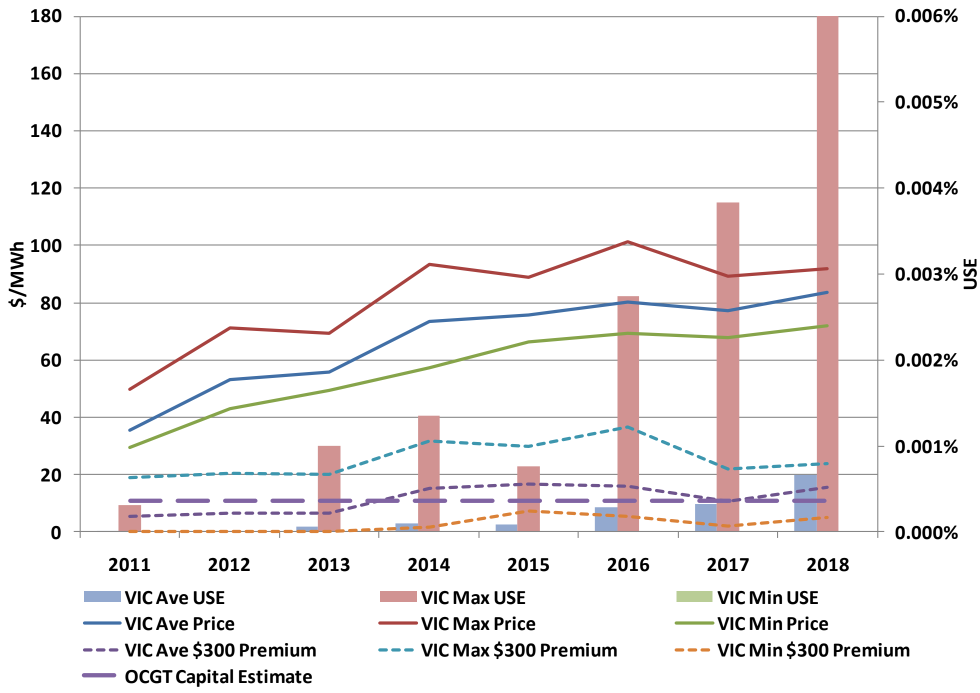


Figure 8-9 NSW 10 PoE Projections

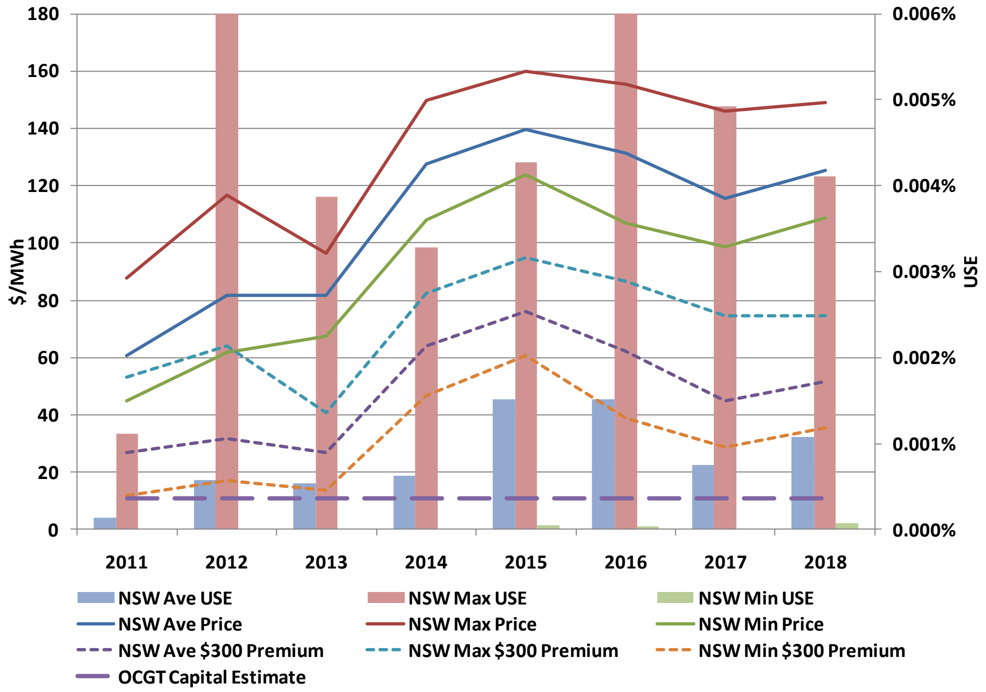


Figure 8-10 QLD 10 PoE Projections

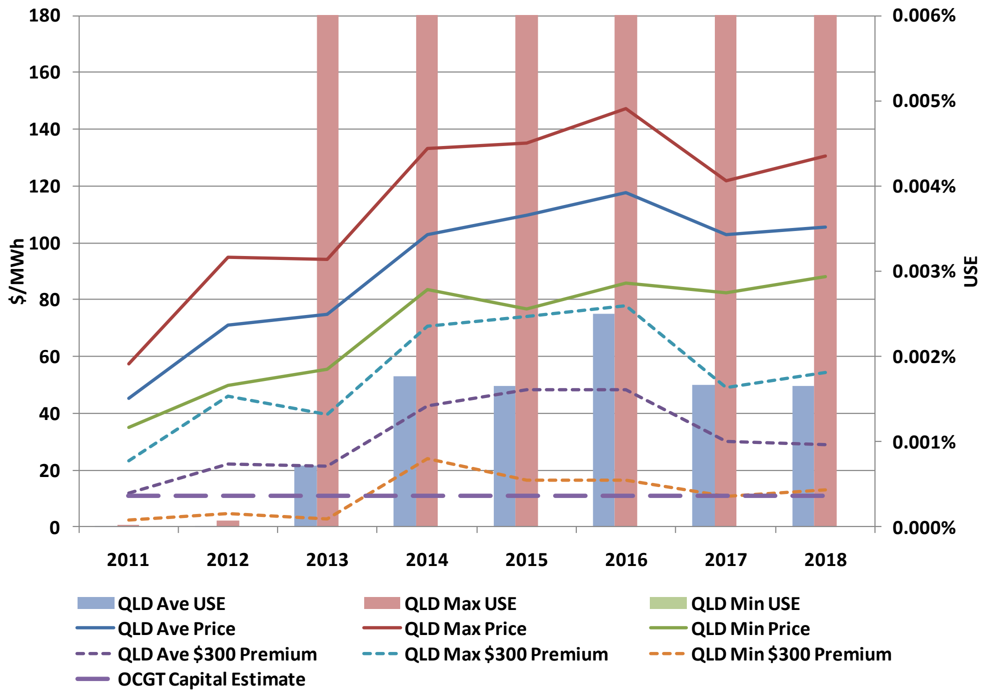


Figure 8-11 SA 10 PoE Projections

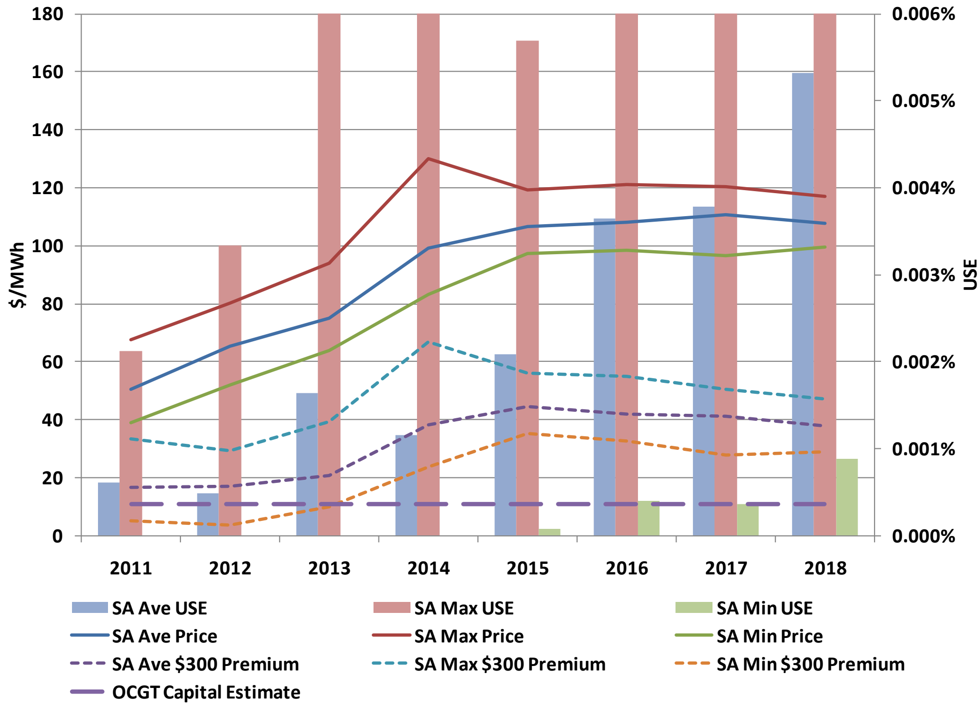
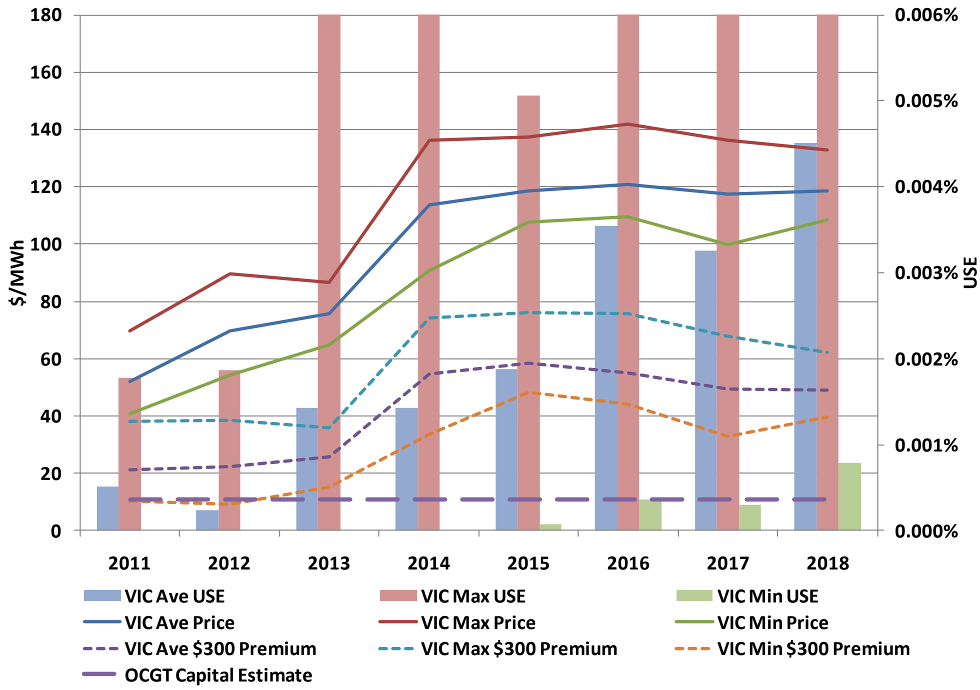


Figure 8-12 VIC 10 PoE Projections



8.4 Distribution of USE

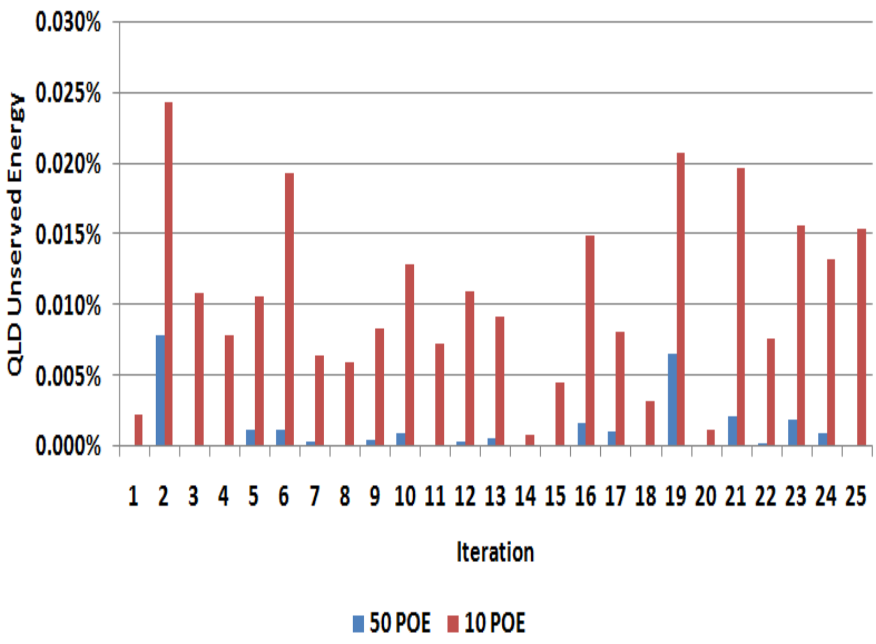
The results above illustrate the variation in price and USE outcomes possible in any one year, influenced by the level of demand and other uncertainties such as the pattern of generator outages and wind patterns.

The ROAM modelling showed that when the reliability level was near 0.002% standard, there was USE in most of their simulations. This would correspond to a Loss of Load Probability (LoLP) approaching 1 (ie USE expected in every year with a demand level at or above the 50% PoE level).

The IES simulation modelling found a similar result for the 50% and 10% PoE demand cases. To illustrate this, Figure 8-13 shows the level of unserved energy measured as a % of demand for 25 simulations using the 10% demand level and 25 simulations using the 50% PoE demand level. The results show that every 10% PoE demand simulation has USE and about two thirds of the 50% PoE demand levels have USE (but less than that in the 10% PoE demand cases). Runs of 100 simulations showed similar results.

This result was quite surprising as it means that if the modelling is to be believed, at the NEM reliability standard, unserved energy would be expected in years that have a maximum demand level at or above that expected. This could mean likely intervention by AEMO and use of the RERT was it to be available.

Figure 8-13 USE Distribution Across Simulations



8.5 Changing the MPC

The modelling presented in the previous sections illustrated the manner spot prices signal new generation and the uncertainty that is associated with spot price outcomes / associated signals and USE. That modelling was based on a MPC of $12,500.

This section presents the results of market simulation modelling designed to investigate the impact of increasing the MPC on spot price outcomes when incorporating the manner generators formulate offers in the market.

To do this, the 50% PoE demand case with new generators entering when economic was repeated with the MPC increased to $20,000. The manner generators formulated their bids was undertaken as previously described in Figure 7-1 and as observed in the market. This was generators bidding near SRMC to their swap contract volumes, near the strike price of cap contracts, and at high prices resulting in an offer curve that reaches the MPC.

The results of the modelling are shown in the figures below. These show for each region in turn, the annual average spot and annual $300 spot price premiums when the MPC is increased to $20,000 and for comparison purposes the previous model run results that had the MPC at $12,500. The increase in average spot prices and $300 premiums is quite significant. If this increase were maintained, additional generation plant would enter that would reduce the premium to the original level.

Figure 8-14 NSW comparison

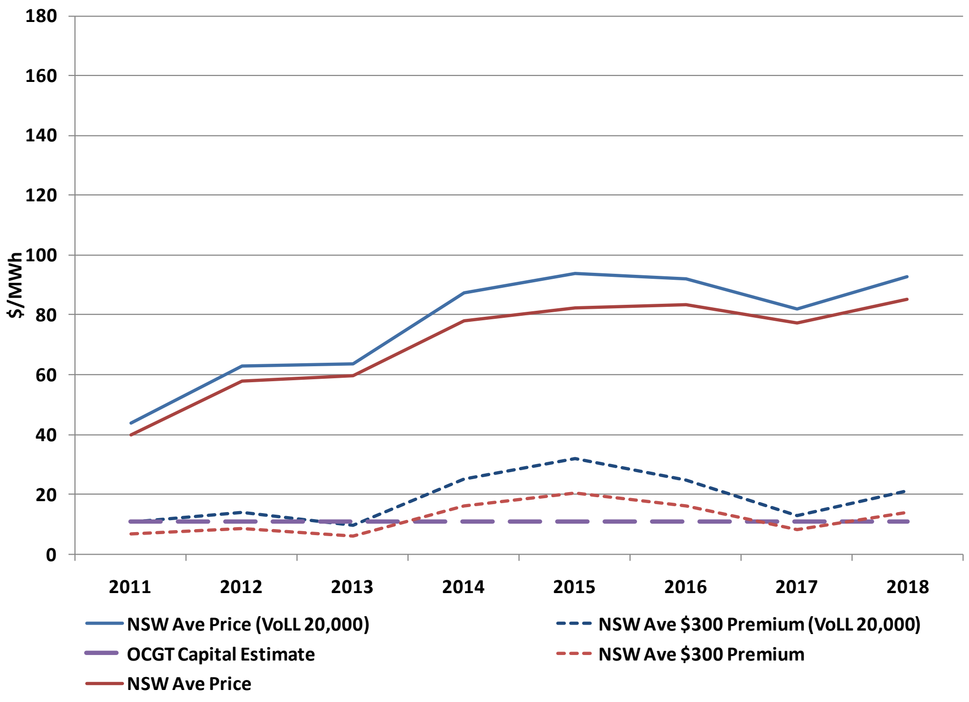


Figure 8-15 QLD Comparison

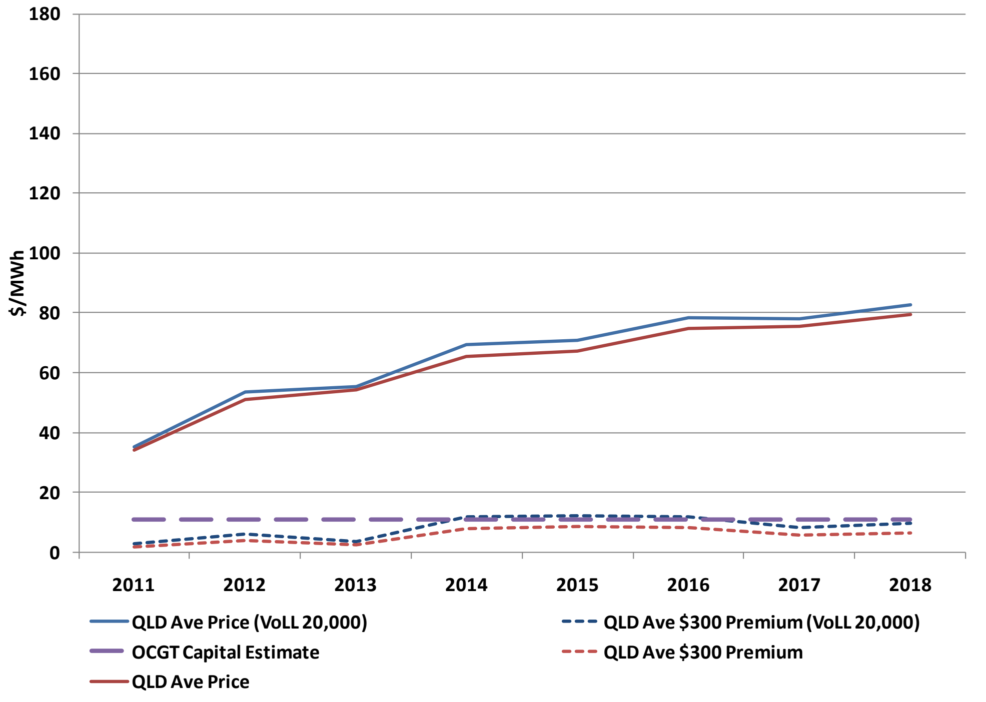


Figure 8-16 SA Comparison

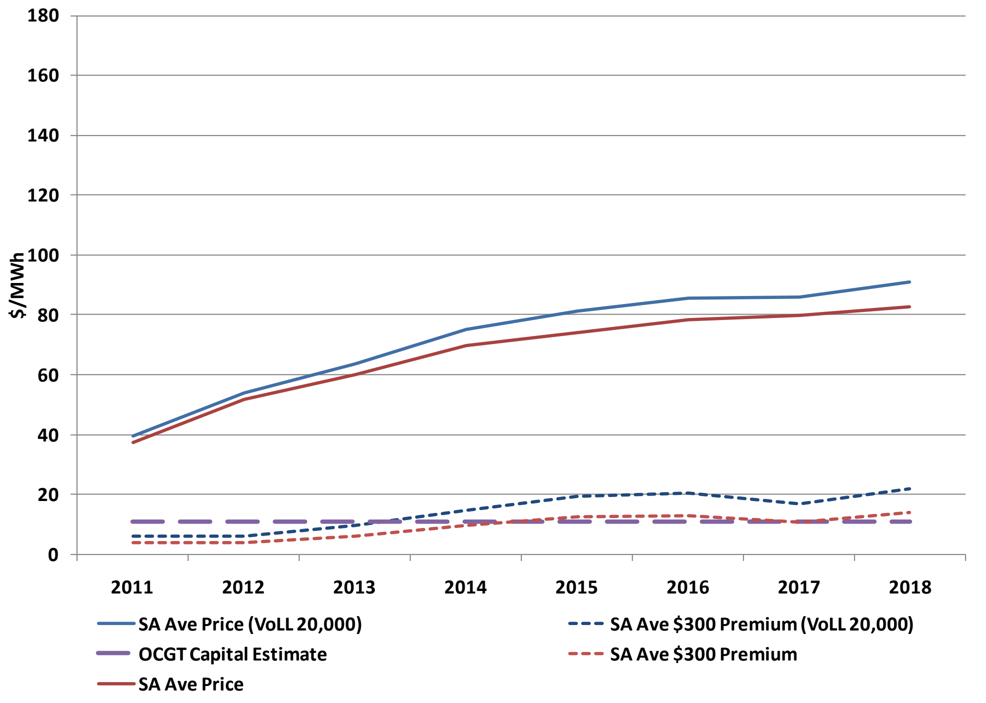
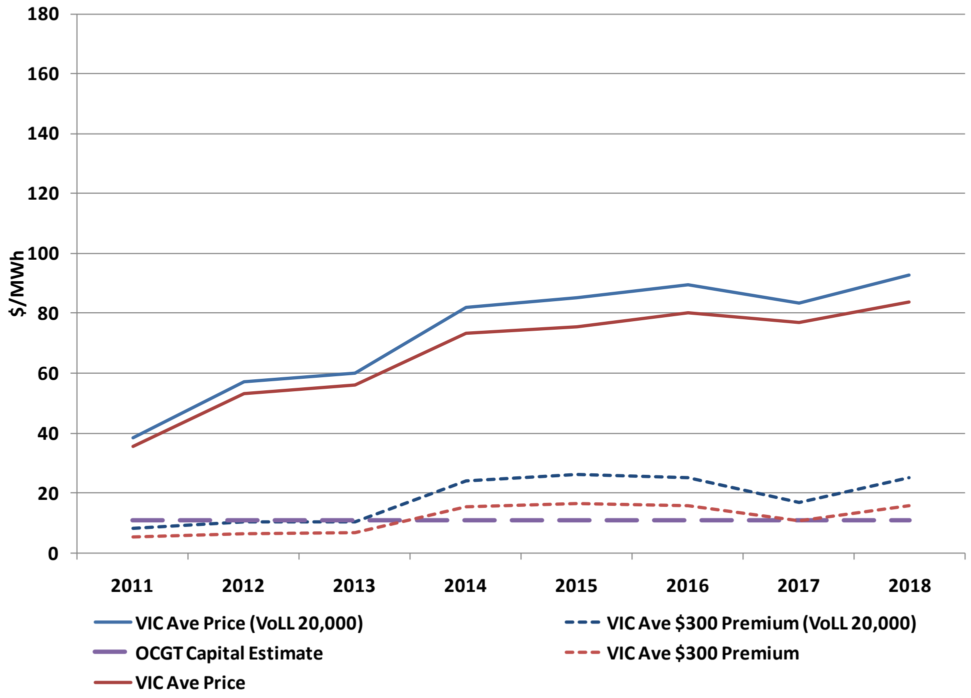


Figure 8-17 VIC Comparison



Note however that irrespective of any increase in MPC, the vagaries of spot price signals as explored in Section **Error! Reference source not found.** means that the reliability and security setting may not provide for new generation to be economic when required.

9 Summary and Conclusions

The key issues and conclusions from the review of the AEMC reports, ROAM reports and IES modelling were as follows.

9.1 Summary

AEMC Reports

- No considered interpretation of the ROAM modelling was presented;
- The differences in reliability between the states was recognised but not properly investigated.

ROAM Modelling

- The lack of transparency in the ROAM reports meant that a proper interpretations of the results was not possible;
- The ROAM simulation modelling did not appear to have addressed:
  - A number of key physical issues impacting reliability, and
  - the market mechanisms that translate the reliability and security setting to spot price signals;

  These issues were evident in the observation that the MPC v USE relationship developed by ROAM can be closely reproduced through simple spreadsheet analysis;
- USE would be expected in years where the level of maximum demand is at or above that expected.

IES Modelling

- An analysis of South Australia indicated that a substantially higher MPC would be required for extreme peaking plant economics when accounting for the full distribution and load and wind generation;
- IES simulation modelling indicated that:
  - the current MPC is sufficient for new entry generation to be economic on expected market outcomes prior to USE exceeding the NEM reliability standard
  - the spot price signals show considerable annual variation
  - increasing the MPC would strengthen spot price signals and should result in additional generation entry
  - USE would be expected in years where the level of maximum demand is at or above that expected.

Other Observations

- The distribution of USE when the market is at the 0.002% reliability standard suggests that AEMO would take action each year to avoid load shedding;

- Including the AEMO constraint equations in the modelling has a significant impact on the results:
  - given that these equations understate the constraints that would actually be expected and that they combine both intra-regional and inter-regional issues, the matter of transmission needs to be more fully understood
  - the reliability standard should include the impact of intra-regional transmission constraints impacting the ability of generators to supply demand;
- The 0.002% standard of reliability may not be fully appreciated. In particular how this translates to LOLP.

9.2 Conclusions

The main conclusions for the review and modelling are as follows:

- The ROAM modelling was not suitable to draw the conclusions made by the AEMC. In particular:
  - that an increase in MPC was required, and
  - that the reliability and security setting were sufficient on their own for new generation to be economic at the required reliability level;
- Modelling that incorporates observed market dynamics illustrates that an increase in the MPC may not be required, but that irrespective of any increase, the vagaries of spot price signals means that the reliability and security setting may not provide for new generation to be economic when required.

10 Appendix 1 – Review of New Entry Generation in the NEM

This appendix reviews the new generator plant that has entered the NEM since its commencement. The purpose is to show the relationship between spot prices and generator entry, the relevance of which relates to the approach used in spot price market modelling to assess the economics and entry of new generator capacity. As generation under the RET also entails revenues from the sale of LGC's such generation is noted but not discussed.

A convenient method of showing the economics of generators from spot price revenues uses the concept of spot price premium. Over a period such as a year, the spot price premium at defined strike price is the contribution to the average spot price over that period due to spot prices above the strike price. The equation for this is as follow:

$$\frac{\sum_{Spot\ price\ \geq Strike\ Price}(\boldsymbol{Spot\ price} - \ \boldsymbol{Strike\ Price})}{\sum \boldsymbol{Dispatch\ Periods}}$$

This is identical to the value of a cap contract during that period at that strike price (as the payouts occur when spot prices are greater than the strike price). Of note is that the spot price premium at a strike price of $0 is the average spot price in that year.

This method can be used to determine whether a generator in the NEM would be profitable from spot prices alone. This is done by constructing spot price premium curves at a strike price equal to the generator's SRMC. The equation for this is as follows:

$$\frac{\sum_{Spot\ price\ \geq SRMC}(\boldsymbol{Spot\ price} - \ \boldsymbol{SRMC})}{\sum \boldsymbol{Dispatch\ periods}}$$

The spot price premium at the SRMC of the generator equals the return on capital the generator would receive if it operated when spot prices are greater than its SRMC. Clearly this may not be the case but is a reasonable assumption for the purposes of this analysis.

A major advantage to using premium curves in this manner is that no assumptions need to be made in regard to the capacity of the plant or the capacity factor of operation.

Using this approach, the figures below show over the period 2000 to 2011, the spot price premiums at strike prices equal to the Short Run Marginal Cost (SRMC) of the common generation types, these being coal, combined cycle gas, open cycle gas and wind. Also shown on the graphs are the entry times of new entrants and their assessed annualised capital cost. The colouring of these has new entrant matching the colour of the spot price premium of the matching

SRMC. New entrants are economic on the spot each year if their annualised capital cost is less than the corresponding spot price premium.

The figures below show for NSW, Queensland, South Australia and Victoria, spot price premiums, new entrant timings and annualized capital costs over the period.

Figure 10-1 NEM New Entry – New South Wales

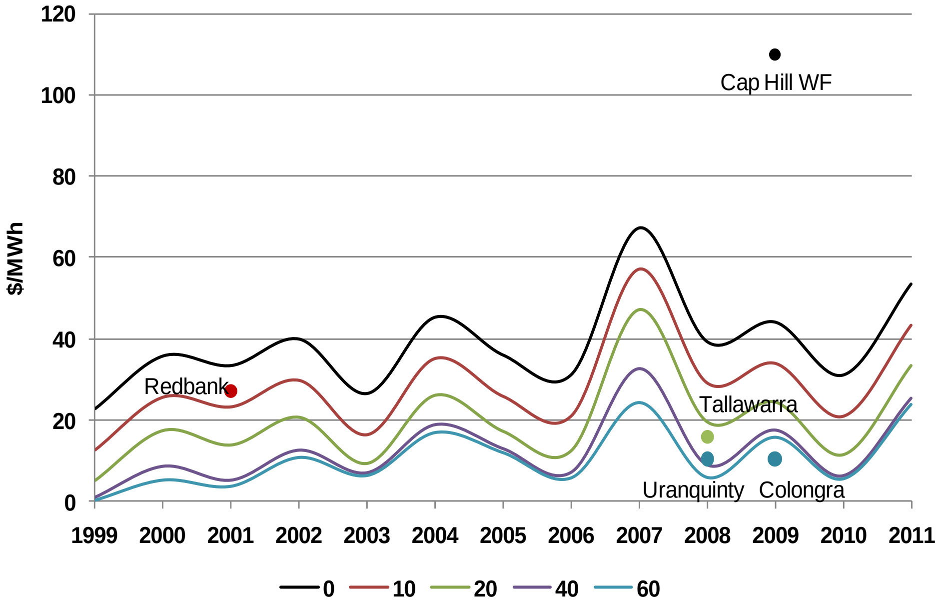


Figure 10-2 NEM New Entry – Queensland

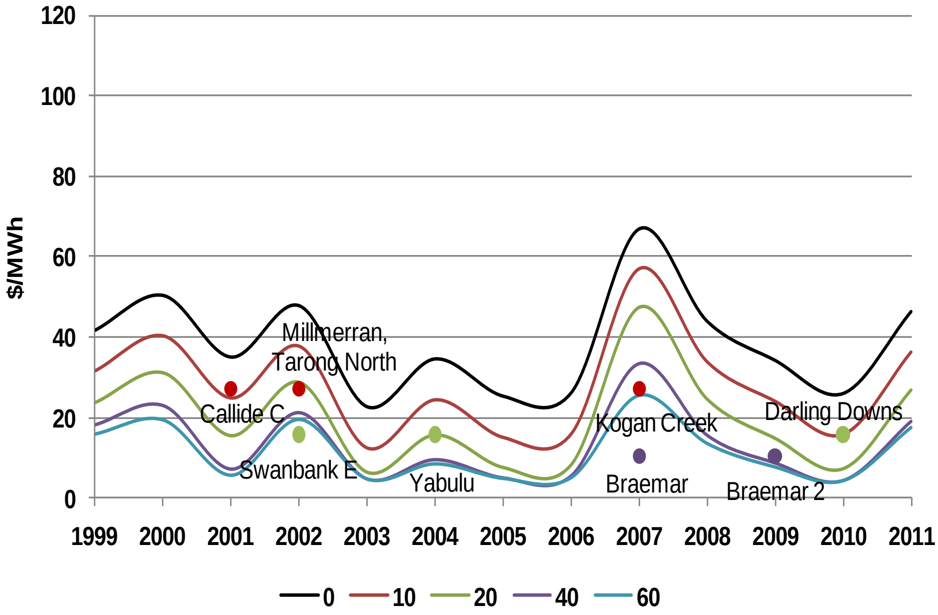


Figure 10-3 NEM New Entry – South Australia

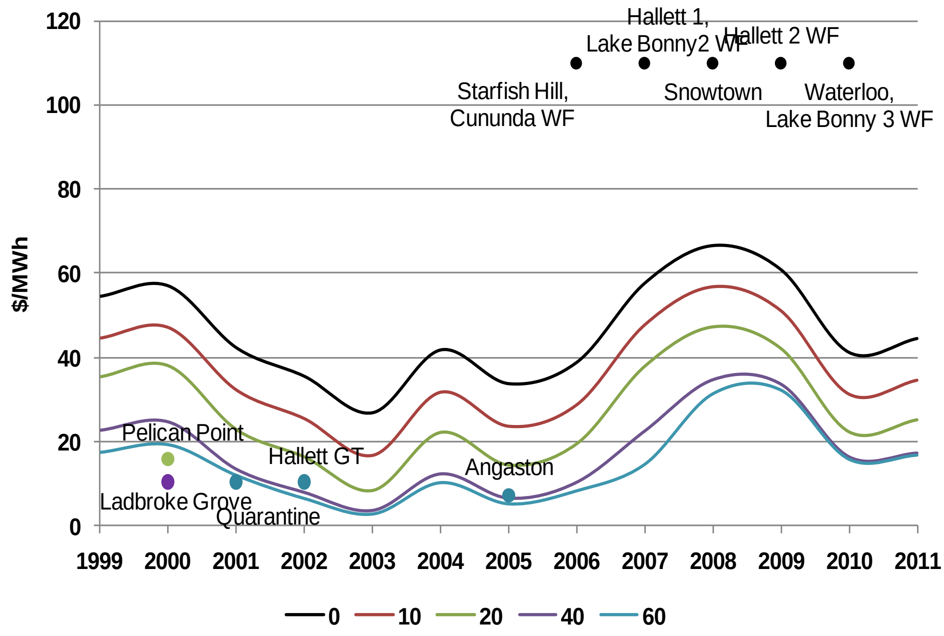
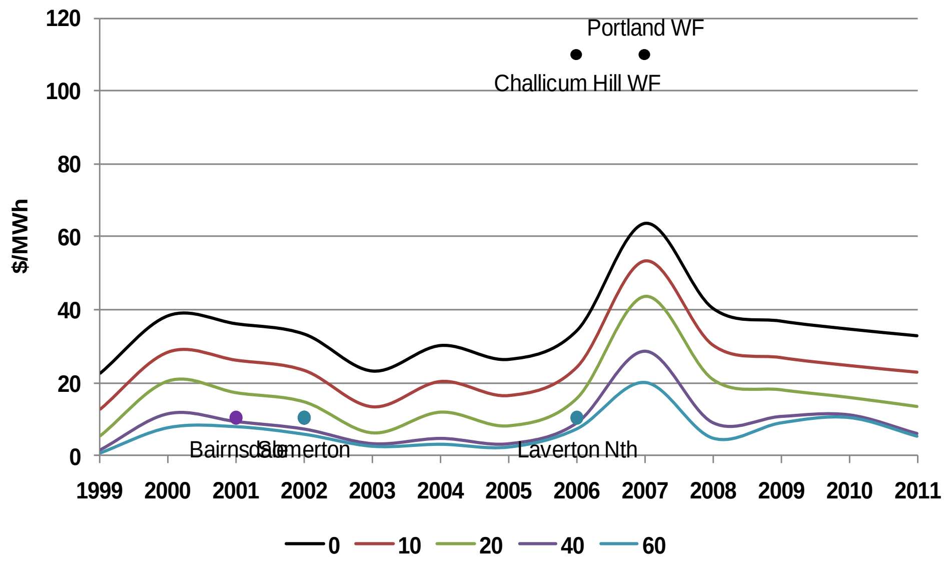


Figure 10-4 NEM New Entry – Victoria



The pattern of spot prices reflects issues such as the demand / supply balance, extreme and mild weather conditions leading to high and moderate prices particularly in summer, the drought in 2007, and the general level of competition in the market.

11 Appendix 2 – Examples of Generator Bidding Behaviour at times of High Prices

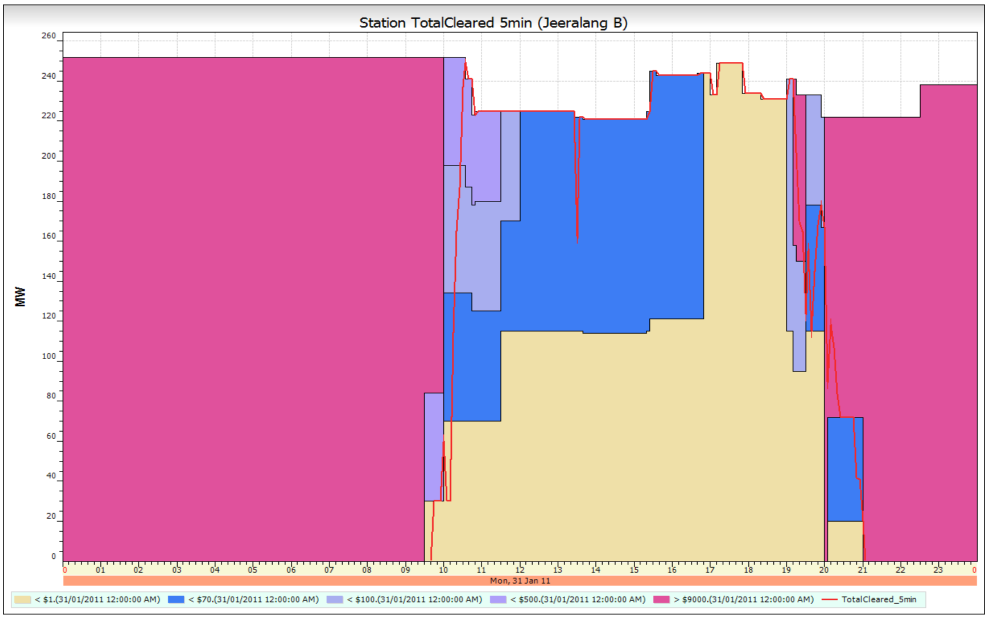
OCGTs in the NEM generally run as a peaking generation in that they mainly generate during high demand / price periods. This is due to their high fuel cost compared to other NEM generators. OCGT plant usually has capacity factors between 0 to 10%. Most OCGT's run on gas but some use liquid fuel. Peaking OCGT's dispatch weighted price varies and is usually observed to be between $50-$5,000/MWh.

An example that illustrates commonly observed behaviour of how generators bid at times of high prices is shown below. This is for the day of 31 January 2011 when spot prices were high in Victoria and SA.

The figure below shows the bids for Jeeralang B on that day. Outside of the high price period its bid price is high so not to generate (pink is quantity above $9,000/MWh).

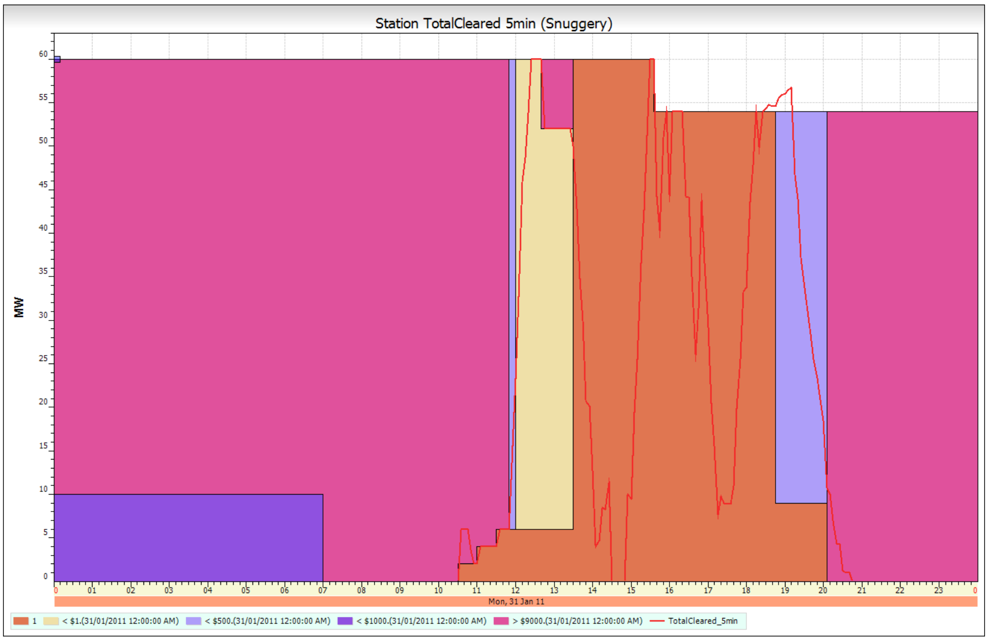
During the middle of the day when the spot price became high it offers quantities at $0/MWh and others between $50-$500/MWh. It generated to its maximum offered capacity as prices were high during this period.

Figure 11-1 Jeeralang B Bids on a Day its Generates



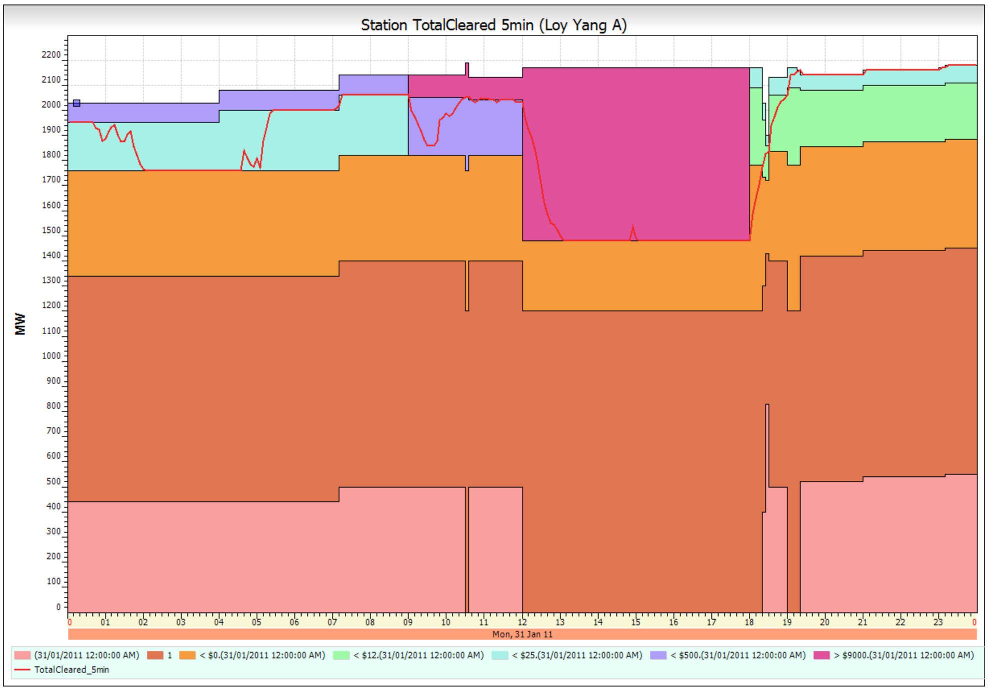
A similar chart is shown below for Snuggery.

Figure 11-2 Snuggery Bids



During the period of high prices Loy Yang A increased the prices in of some of its bid quantities in order to support a high spot price.

Figure 11-3 Loy Yang A Bids



12 Appendix 3 – Review of 2009 Reliability and Security Events

This appendix presents a review of the reliability and security events that occurred on 29 and 30 January 2009. Presented are:

- Chronology of events;
- The Short Term PASA project for SA for the days 20 January and 30 January 2009;
- The actual Victorian and SA demand and level of generation capacity in Victoria and South Australia reserved for security reasons (FCAS).

12.1 Chronology

Figure 12-1 Chronology 29 January 2009

Time	Region	Event Description
8:05-9:05	VIC	Victorian prices reach and remain at VoLL $10,000/MWh
8:35	SA	Available reserve capacity in South Australia drops below 50 MW
8:49	VIC	Victoria load shedding 500MW *"NEMMCO considers that the occurrence of a credible contingency event is likely to require involuntary load shedding in Victoria region, for the following period08:30 hr Thursday 29 January The current LOR2 reserve shortfall is 500 MW"*
9:03	VIC	HWTS transformer has returned to service
9:28	VIC	Cancellation of load shedding in Victoria
12:45-13:20	VIC	Victorian prices reach and remain at VoLL $10,000/MWh
12:46	VIC	Load shedding *"Customer load has been instructed to be interrupted in order to Maintain security of the power system in Victoria region, for the following period 1240 hr estimated to continue until 1630"*
13:45	VIC	Available reserve capacity in Victoria drops below 50 MW
13:45-14:30	SA	South Australia prices reach and remain at VoLL $10,000/MWh
13:54	SA	Load shedding *"Customer load has been instructed to be interrupted in order to maintain security of the power system in South Australia region, for the following period, from 1350 hr estimated to continue until 1630"*
14:05	VIC	Available reserve capacity in Victoria drops below 0 MW
14:15-14:40	TAS/VIC	Limits & flow on Basslink set to 0 MW NEMMCO Market Notice states Basslink tripped at 14:03hrs, returned to service at 14:55
14:15-15:55	VIC	Victorian prices reach and remain at VoLL $10,000/MWh
15:05-21:05	SA	South Australia reaches cumulative price limit and starts administered price period
15:20	VIC/SA	Cancellation of Lack of Reserve for Victoria & South Australia
17:00	VIC	Victoria reaches cumulative price limit and starts administered price period

Figure 12-2 Chronology 30 January 2009

Time	Region	Event Description
12:31	VIC	NEMMCO is aware of two fires. East Rowville Terminal Station to Cranbourne Terminal Station No 1 and 2 220kV lines Hazelwood Terminal
12:37	VIC	Load shedding *"NEMMCO advises Customer load has been instructed to be interrupted in order to maintain security of the power system in Victoria region, for the following period, 12:25 hr until 16:30"*
12:45	VIC	Available reserve capacity in Victoria drops below 50 MW
12:50-14:55	TAS/VIC	Basslink flow goes to 0MW – Line limits reported as(±125MW) Basslink transfer reduced to 0MW due to a protective block at 12:41hrs Basslink has returned to service at 14:55
12:55	VIC	Available reserve capacity in Victoria drops below 0 MW
12:56	SA	Load shedding *"NEMMCO advises Customer load has been instructed to be interrupted in order to maintain security of the power system in SA region, for the following period from 12:52 hr until 16:30"*
15:43	SA	Cancellation of Lack of Reserve/Load Shedding
16:15	VIC	Cancellation of Lack of Reserve/Load Shedding
17:16	SA	The South Morang Keilor 500kV #2 line tripped. Load shedding is initiated in Victoria west of Keilor
17:34	SA	The South Morang Sydenham 500kV #2 line tripped
18:10	VIC/SA	Victoria to South Australia interconnector constrained at – 300 MW (Flow from VIC into SA)
23:14	SA	The Power System Security Directions in the Victorian Region ceased at 23:10 The South Morang Sydenham #2 500kV line

The events illustrated the following:

- Transmission outages were an important part of the reasons for load shedding;
- Security is maintained at all times. Operating reserves were maintained in other regions thus not impacting the level of load shed.

Figure 12-3 ST PASA Projection for SA – 29 and 30 January 2009

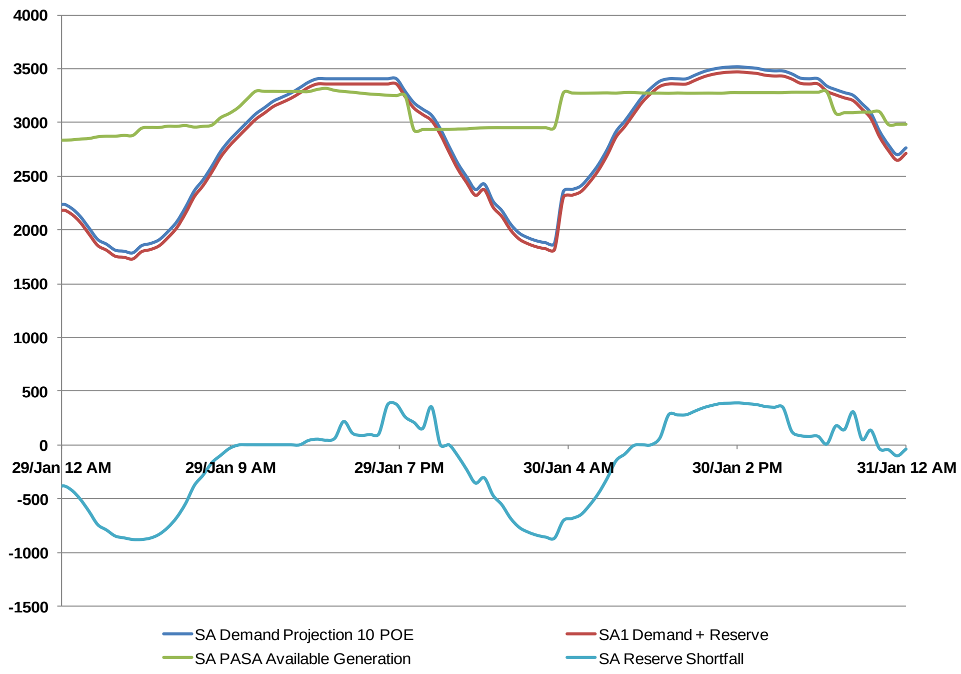
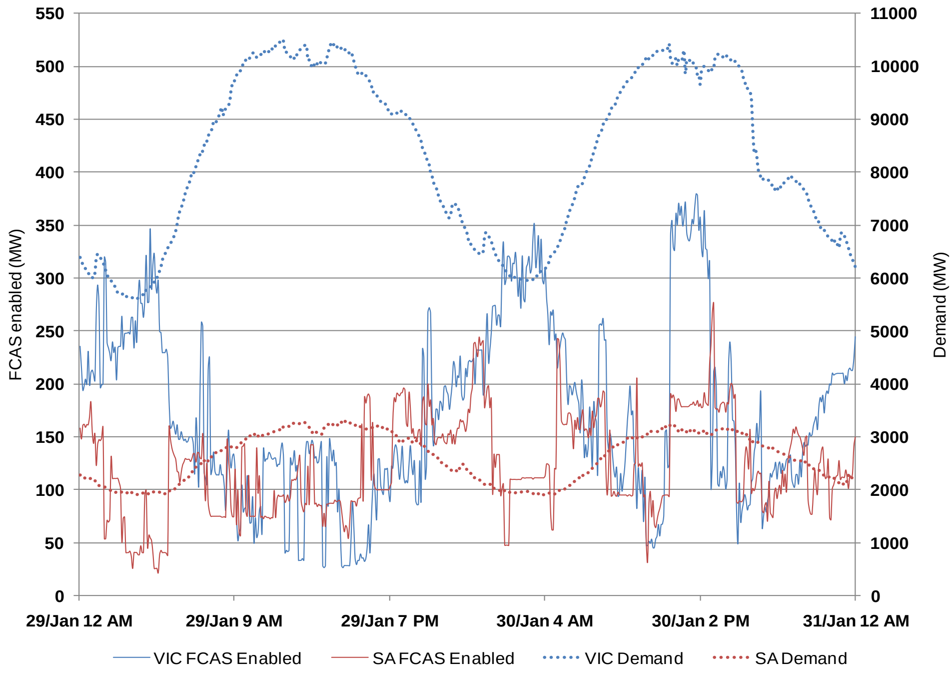


Figure 12-4 SA and Vic Demand, and FCAS Enabled



13 Appendix 4 – Weighting POE Demands

For a number of NEM simulation studies selected demand traces are used. These are often based on using peak demand forecasts based on the 10%, 50% and 90% probabilities of exceedence. These traces are usually weighted in the ratios of 30%, 40% and 30% respectively. The origin of these probability weights is based on choosing values and probabilities from a normal distribution such the weighted values have the same mean and variance as the original distribution, see Table 13-1.

In this table we have assumed that the original distribution was a normal distribution with a mean of zero and a variance of 1. If we use the three probability of exceedence points we get a sample of values (-1.28, 0, 1.28) and if we use the weights (30%, 40% and 30%) we end up with a distribution whose mean is zero and variance is 0.99. These statistics are approximately the same as those of the original distribution.

Table 13-1 POE Demand Weightings

Probability of exceedence	Normal Value	Probability	Mean	Variance
90%	-1.282	0.3	-0.38	0.49
50%	0.000	0.4	0.00	0.00
10%	1.282	0.3	0.38	0.49
			0.00	**0.99**

Now, some reliability modelling does not always use the 90% probability of exceedence peak demand forecasts and only uses the 50% and 10% and weights these by 70% and 30% respectively. Essentially this modelling has replaced the 90% probability of exceedence demand information with the 50% probability of exceedence demand information. When this is done the mean and variance of this distribution are no longer correct. In the case of the normal distribution above the sample mean is 0.38 and the variance is 0.34, an increase in the mean and a very substantial drop in the variance.

When this is done there is a lack of sampling of years when peak demands are low and hence faulty inferences can be made. For example, the economics of OCGT plant could be overstated and expected USE understated.

14 Appendix 5 – South Australian Reliability Accounting for Uncertainty

This appendix develops a statistical model of South Australian generation adequacy accounting for the uncertainty in demand and wind generation. The appendix concludes with the development of a MPC – USE relationship.

14.1 Generation Adequacy and Power System Reliability

When investigating whether there is adequate generation in a region the question is whether there is sufficient generation to meet the demand with a high probability or small expected loss of load. These requirements can be expressed mathematically as whether there is sufficient generation capacity, C such that:

Prob(Generation(C) > Demand) > A

Loss of Load Probability (LOLP) = 1-A

or

Expected Value [Demand – Generation | Generation(C) < Demand] < B

Where	Generation(C)	is available generation considering outages (a random variable)
	Demand	is half hourly demand (a random variable)
	A	is the desired probability that all demand is met
	B	is the maximum expected unserved energy

Where there is wind generation or other intermittent generation it is worthwhile separating the scheduled and controlled generation from the intermittent generation as these two different sources will have different characteristics.

Thus when a single region is looked at and intra-regional transmission constraints are ignored these probabilistic calculations can be determined with information about the distributions of demand, thermal or other fully controllable generation and wind or other intermittent generation. All the calculations of reliability or unserved energy essentially revolve around determining the distribution of generation reserve:

Generation reserve = thermal generation + wind generation – demand.

The expected value of generation reserve is:

E[Generation reserve] = E[thermal generation] + E[wind generation] – E[demand]

The variance is:

Var[Generation reserve] = Var[thermal gen] + Var[wind gen] + Var[demand]
+ 2 x Cov[thermal,wind] - 2 x Cov[thermal,demand]
- 2 x Cov[wind,demand]

Now generator forced outages are likely to be uncorrelated with either wind or demand, given that a generator is already running. However generator forced outages for some peaking plant may occur when starting up and thus be indirectly correlated with higher demands. If the outage rates for these units include failure rates for starting up then, to a first approximation thermal generator outages could be assumed to be uncorrelated with wind generation and demand. In the case of wind and demand there may be some correlations. Thus the equation for the variance can be reduced to:

V[Generation reserve] = V[thermal generation] + V[wind generation] + V[demand]
- 2 x Cov[wind,demand]

Thus if wind is positively correlated with demand it reduces the generation reserve variance. If it is negatively correlated it increases the variance.

Now if each of the random variables was normally distributed then the probabilistic calculations for generation reliability, loss of load probability and expected unserved energy could be calculated readily using properties of the normal variable.

14.2 Thermal Generation Distribution

To illustrate the shape of the thermal generation distribution IES used appropriate summer capacity ratings and forced outage rates (Table 14-1). IES calculated the distribution of available generation by essentially calculating every combination of possible outages, the probability of each of these combinations occurring and the total available capacity. In order to speed up the algorithm which did this we rounded each unit's capacity to the nearest 5MW. The results are presented in Figure 14-1.

What is interesting to note about the distribution of available generation capacity (blue line) is that the distribution is quite ragged. This is due to the relatively small number of larger unit sizes. The red line is the available capacity smoothed with a moving average.

Figure 14-2 shows the smoothed distribution and the distribution of a fitted normal variable. From this figure it is evident that the distribution is slightly negatively skewed. Unfortunately the lack of fit of the normal distribution at low available capacities means that the normal approximation is not very good for reliability studies.

Figure 14-1 Distribution of Available Thermal Generation in SA

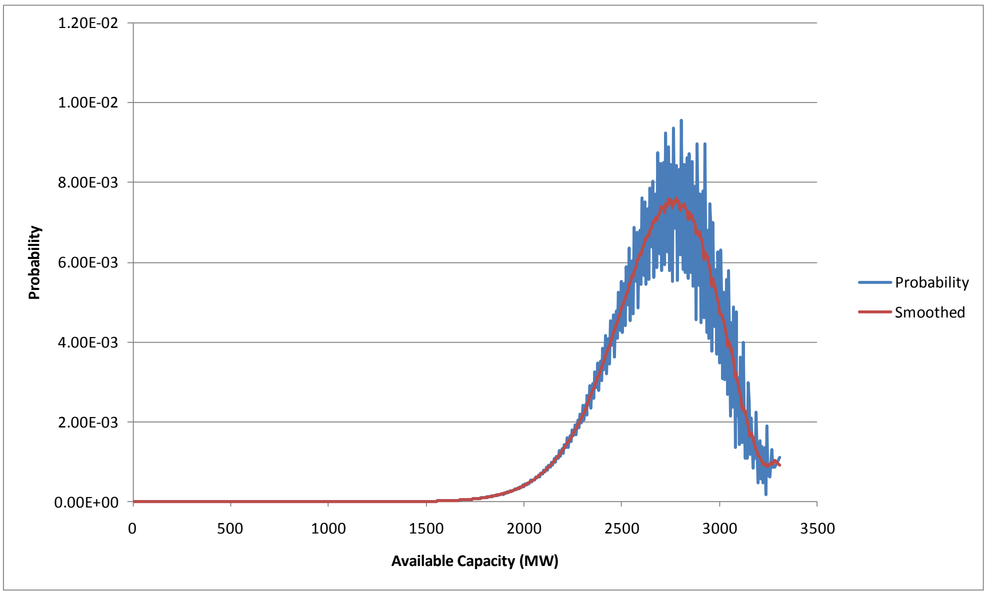


Figure 14-2 Distribution of Availability and Fitted Normal Distribution

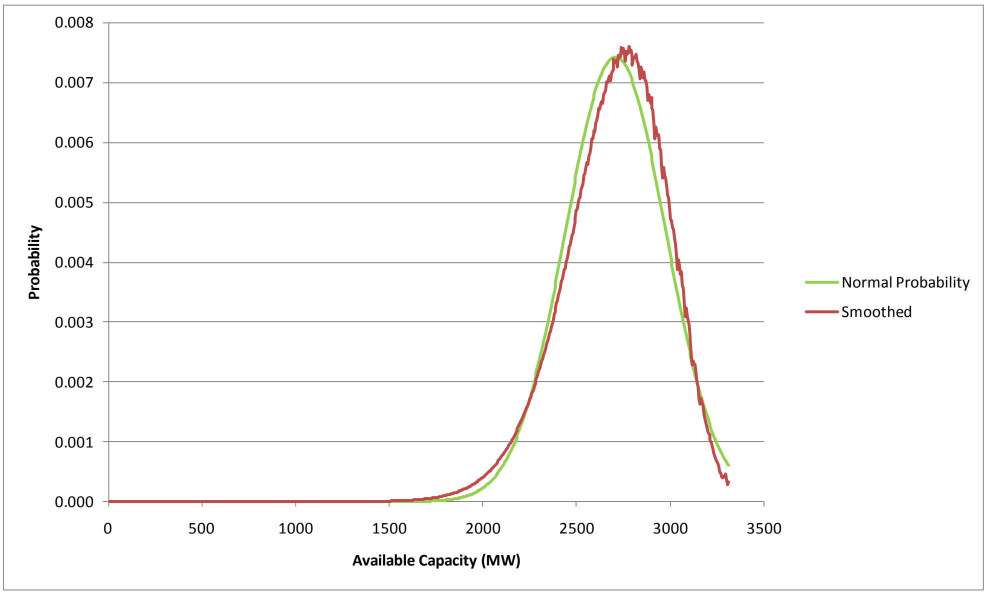


Table 14-1 SA Generation Capacities and Forced Outage Rates

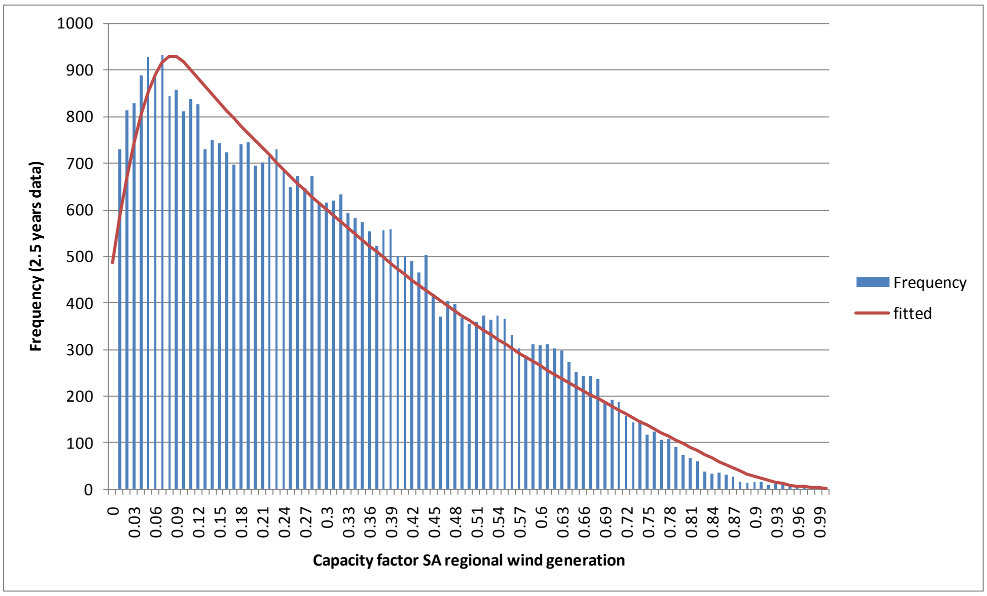
Plant	Summer Capacity (MW)	Winter Capacity (MW)	Effective FOR (%)
Angaston 1	24	24	27.88%
Angaston 2	25	25	27.88%
Dry Creek 1	39	49	27.88%
Dry Creek 2	38	49	27.88%
Dry Creek 3	38	49	27.88%
Hallett	151	188	27.88%
Ladbroke Grove 1	35	43	27.88%
Ladbroke Grove 2	35	43	27.88%
Mintaro	67	89	27.88%
Northern 1	271	273	4.36%
Northern 2	271	273	4.36%
Osborne	175	192	4.63%
Pelican Point	448	474	4.63%
Playford	200	220	4.36%
Port Lincoln	63	75	27.88%
Quarantine 5	95	127	27.88%
Snuggery 1	51	66	27.88%
Torrens Is A1	120	126	27.88%
Torrens Is A2	120	126	27.88%
Torrens Is A3	120	126	27.88%
Torrens Is A4	120	126	27.88%
Torrens Is B1	200	205	27.88%
Torrens Is B2	200	205	27.88%
Torrens Is B3	200	205	27.88%
Torrens Is B4	200	205	27.88%

14.3 Wind Generation Distribution

Figure 14-3 presents of the frequency distribution of total wind generation output for South Australia. It is based on approximately 2½ half years of half hourly data. The frequency distribution is in terms of capacity factor rather than MWs to account for new wind farms that commenced operation during the period.

What is striking about the distribution is that the wind distribution is very skewed with a high frequency of low generation (capacity factors) and a low frequency of high generation (capacity factors). The red line is a smooth curve fitted to the data.

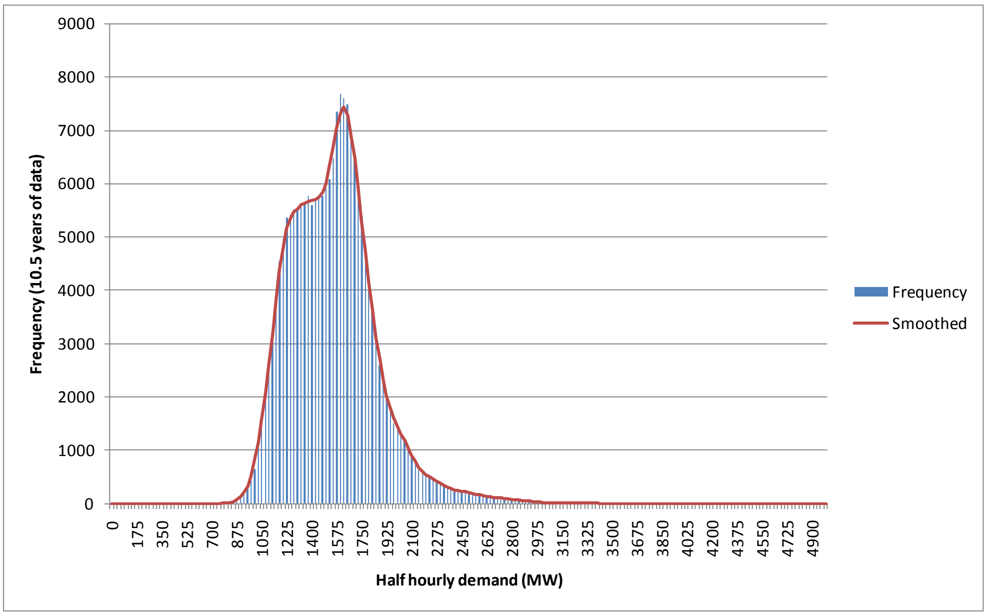
Figure 14-3 Frequency Distribution of SA Wind Generation Output in terms of Capacity Factor



14.4 Demand Distribution

Figure 14-4 presents the frequency distribution of SA half hourly demands. It is based on approximately 10½ half years of half hourly demand data, starting from the beginning of 2000, which were adjusted for growth over time. The adjustments were done by fitting a linear regression over time to the half hourly demand data and then scaling up or down each half to an underlying energy consumption for the beginning of 2011. This was done by multiplying each half hourly demand by the ratio of the fitted value for the linear trend for 12 am 1/1/2011 to the fitted value for the half hour in question. This process aimed to approximately adjust all of the demand data to 1/1/2011 demands.

Figure 14-4 Frequency Distribution for Half Hourly SA Demand Data for 10½ years



Not surprisingly, the distribution of demands has a long tail and appears to be a mixture of two or more distributions. This is probably due to time of day factors and seasonal factors in influencing demands.

14.5 Correlation of Wind and Demand

IES analysed one year of half hourly wind farm data and regional loads. To do this IES had to adjust the regional demands and add back into the demand figures the non scheduled wind generation. The reported regional demands are demands net of any embedded or non-scheduled generation. The correlations of the regional demands and the aggregate regional wind generations are presented in Table 14-2. What is interesting to note is that the correlations of the aggregate wind generation with the regional demands are low and not material. To a first approximation these correlations between regional demands and loads could be assumed to be zero. The consequence of this is that the variance of the generation reserve can be approximated as:

Var[Generation reserve] = Var[thermal gen] + Var[wind gen] + Var[demand]

Table 14-2 Correlations of Regional Demands and Regional Wind Generation

	NSW	QLD	SA	TAS	VIC	NSW wind	SA wind	TAS wind	VIC wind
NSW	1.00								
QLD	0.83	1.00							
SA	0.81	0.67	1.00						
TAS	0.72	0.54	0.58	1.00					
VIC	0.89	0.75	0.85	0.78	1.00				
NSW wind	**0.08**	0.11	0.05	0.10	0.07	1.00			
SA wind	-0.16	-0.08	**-0.07**	-0.15	-0.16	0.34	1.00		
TAS wind	-0.06	0.04	-0.06	**-0.04**	-0.04	0.31	0.24	1.00	
VIC wind	-0.08	-0.05	-0.06	0.00	**-0.05**	0.44	0.64	0.47	1.00

Even though the correlations between regional demands and the aggregate regional wind generation are low, the correlations between wind farms can be high. Table 14-3 presents the correlations between SA wind farms' generation, regional demand and the aggregate wind generation. All of the wind farms are quite highly correlated with the aggregate wind farm generation, which suggests that they are all, to some extent, influenced by similar underlying weather patterns with local variations.

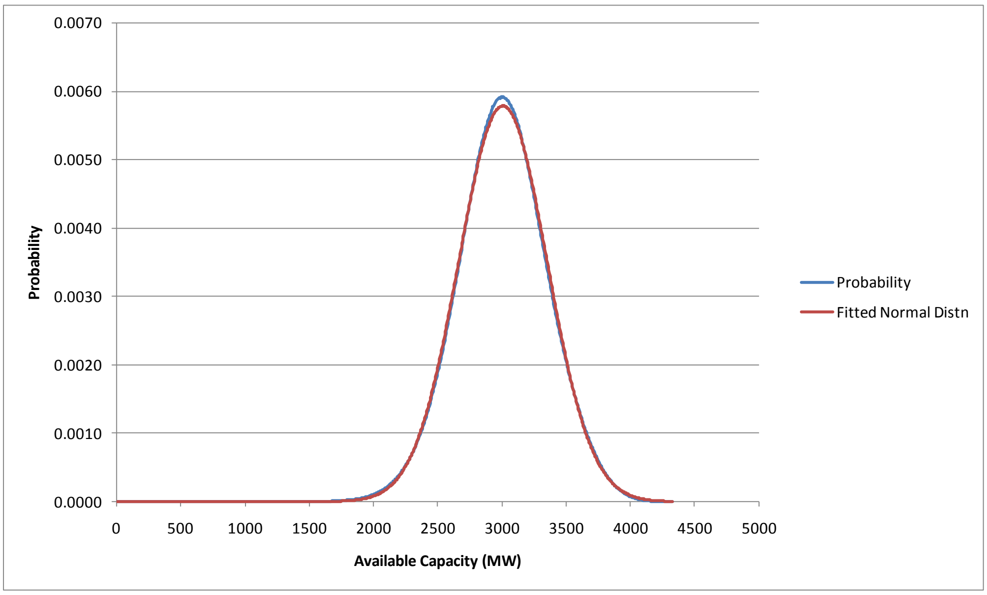
Table 14-3 Correlations Between Wind Farms and Demand in South Australia

	SA	*SA wind*	*Cathedral Rocks*	*Clements Gap*	*Canunda*	*Hallett 1*	*Hallett 2*	*Lake Bonney 1*	*Lake Bonney 2*	*Lake Bonney 3*	*Mt Millar*	*North Brown Hill*	*Snowtown*	*Starfish Hill*	*Waterloo*	*Wattle Point*
SA	1.00															
SA wind	-0.07	1.00														
Cathedral Rocks	-0.06	0.64	1.00													
Clements Gap	-0.09	0.75	0.48	1.00												
Canunda	0.00	0.69	0.42	0.33	1.00											
Hallett 1	-0.05	0.82	0.52	0.64	0.46	1.00										
Hallett 2	-0.05	0.83	0.51	0.65	0.50	0.91	1.00									
Lake Bonney 1	0.02	0.70	0.40	0.33	0.93	0.46	0.48	1.00								
Lake Bonney 2	-0.01	0.69	0.37	0.31	0.85	0.43	0.45	0.88	1.00							
Lake Bonney 3	-0.03	0.63	0.33	0.28	0.85	0.40	0.42	0.83	0.88	1.00						
Mt Millar	-0.01	0.70	0.53	0.56	0.40	0.56	0.56	0.39	0.35	0.32	1.00					
North Brown Hill	-0.20	0.59	0.28	0.50	0.06	0.53	0.50	0.04	0.05	0.05	0.27	1.00				
Snowtown	-0.06	0.77	0.50	0.80	0.34	0.65	0.66	0.33	0.32	0.29	0.66	0.44	1.00			
Starfish Hill	-0.06	0.69	0.56	0.51	0.48	0.48	0.51	0.44	0.41	0.38	0.52	0.34	0.52	1.00		
Waterloo	-0.13	0.74	0.39	0.55	0.28	0.73	0.74	0.29	0.28	0.25	0.35	0.67	0.48	0.41	1.00	
Wattle Point	-0.03	0.73	0.50	0.54	0.49	0.49	0.53	0.48	0.42	0.37	0.64	0.30	0.59	0.74	0.34	1.00

14.6 Combined Wind and Thermal Generation

If we assume that there is 1020 MW of wind generation in South Australia and the output from this generation has the shape of the wind distribution presented in Figure 14-3, then this can be combined with the thermal generation distribution presented in Figure 14-1 to obtain a distribution of thermal and wind generation. This distribution is obtained by a convolution of the two distributions. The result is presented in Figure 14-5. What is interesting to note is that in this case the normal distribution is a very good approximation to the actual probability distribution, though this may not remain true for significant amounts of additional wind generation capacity over the 1,020 MW assumed. With this distribution the probability that any particular demand can be met in South Australia without any imports over the interconnector can be calculated. For instance a demand of 3,000 MW has only a 50% chance of being met if there are no imports into South Australia. A demand of about 2,000 MW would have a 99.98% chance of being met if there are no imports into South Australia.

Figure 14-5 Probability Distribution of Combined Thermal and Wind Generation



It gives some insight into the reliability situation doing the above calculations but to get a true picture of the reliability situation the distribution of demands needs to be included.

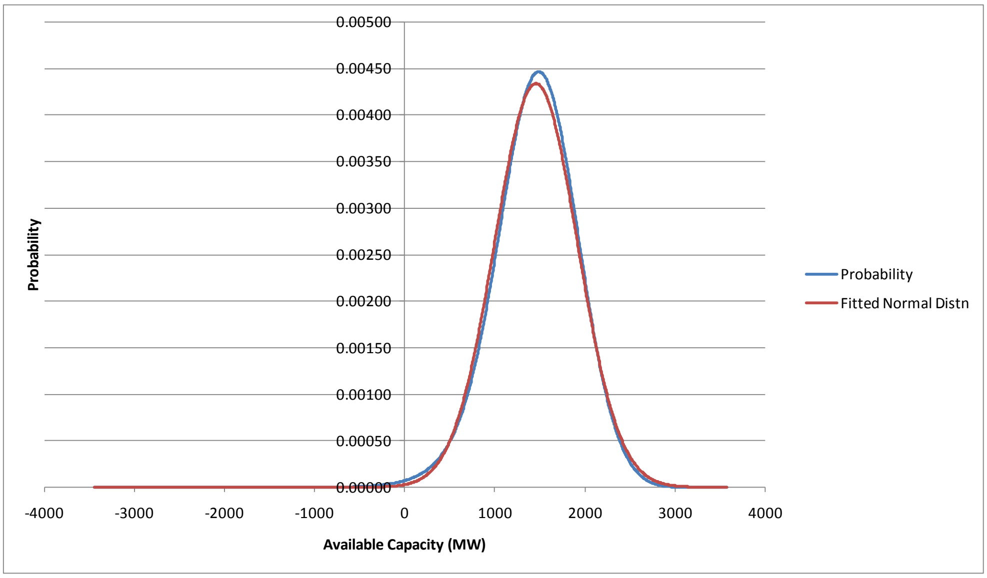
14.7 Distribution of Generation Reserves

In this section we define the generation reserve as being the amount of generation capacity available in excess to demand, that is:

generation reserve = thermal capacity + wind generation - demand

Using the same assumptions regarding the amount of wind capacity and the distributions of wind generation, available thermal generation capacity and South Australia demands this information can be combined to produce a probability distribution of reserve generation. This distribution is calculated using a convolution of all three distributions. The result is presented in Figure 14-6. What is interesting to note is that in this case the normal distribution is a not such a good approximation to the actual probability distribution for low generation reserve levels. This is probably due to the demand distribution having a long tail.

Figure 14-6 Probability Distribution of Generation Reserves



The probability of not meeting demand, having zero or negative amounts of generation reserve can be calculated from the cumulative distribution, see Figure 14-7 and Figure 14-8. Based on this analysis if there were no imports of power on the interconnector there would be about 0.33% probability of a loss of load. However, if 500 MW of imports were available at these times of low reserves then this would drop down to around 0.03% probability.

Figure 14-7 Cumulative Distribution of Reserves

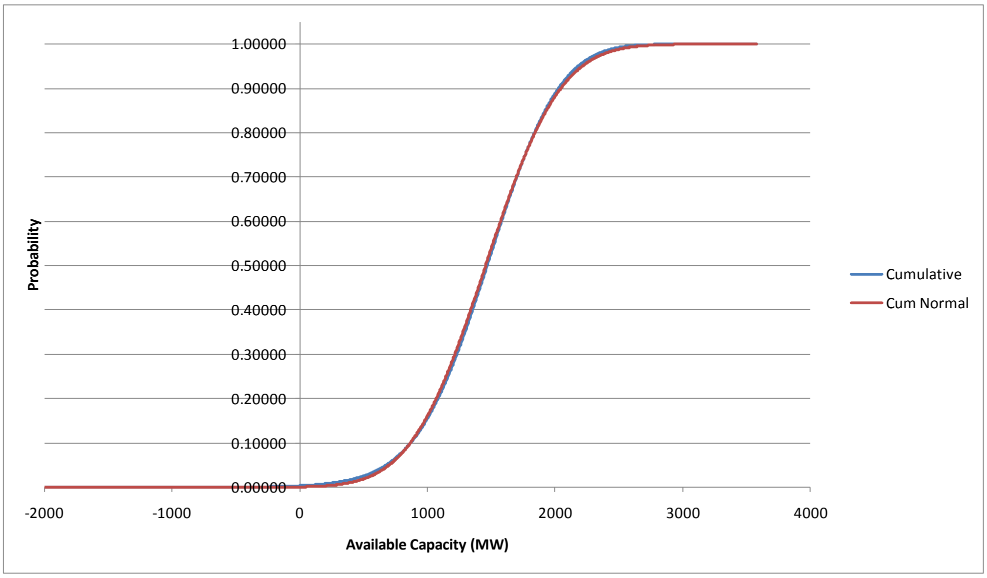
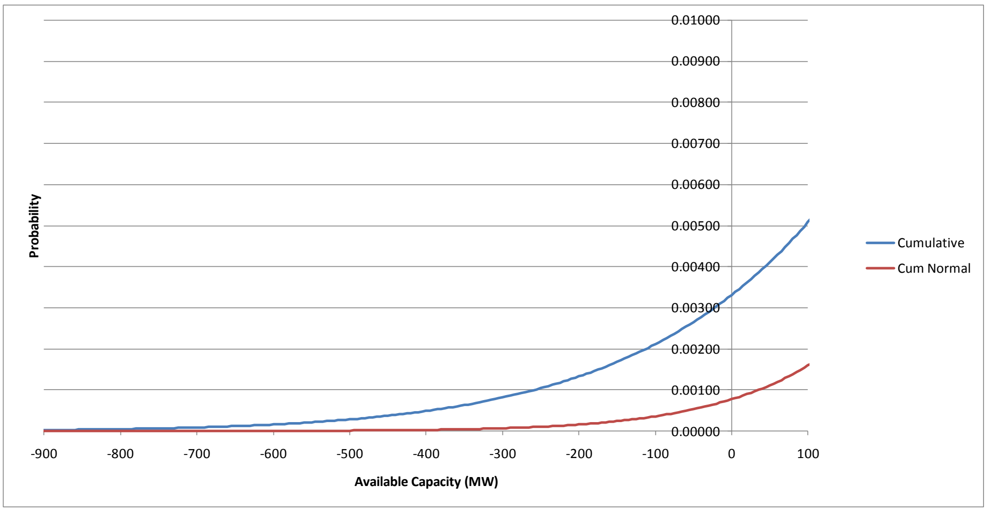


Figure 14-8 Cumulative Distribution of Reserves for Low Reserves



14.8 Conclusions Regarding Distributions

The analysis presented so far has shown what the distributions of available thermal generation capacity, wind generation and South Australia demand look like and how they can be combined to produce probabilistic information regarding demand and supply and reserves. Table 14-4 shows the means, variances and standard deviations for thermal generation, wind and demand and for reserves and for combined generation. From this table it is worth noting that the standard deviation of the available reserve distribution is almost twice that of the available thermal generation capacity. As well, even though the MWs of wind generation is quite a lot smaller than that for the thermal generation its standard deviation is almost as large. This information suggests that any modelling of reserves or reliability should pay just as much attention to modelling the variability of demands and wind generation as it does to modelling thermal generation plant.

Table 14-4 Statistics for Supply and Demand

	Mean	Variance	Standard Deviation
Thermal generation available capacity	2,707	72,044	268
Wind Generation	301	46,457	216
SA demand	1,550	92,612	304
Thermal + Wind	3,008	118,501	344
Thermal + Wind - Demand	1,458	211,113	459

14.9 Unserved Energy versus Market Price Cap

One way of looking at the market price cap is to look at how many hours a peaking plant would have to operate to breakeven. That is, what capacity factor would allow the plant to breakeven if it was paid the market price cap? The breakeven hours of operation are presented in Table 14-5. This table also presents the expected unserved energy.

The breakeven hours of operation were calculated for a gas turbine generator with an assumed capital cost of $920/kW, a life of 30 years, a real post tax discount rate of 6.81%, a forced outage rate of 5% and a variable cost of $150/MWh. The capital cost gives a fixed cost $8.84/MWh and $9.31/MWh when forced outages are considered. The breakeven capacity factor, X, is determined as follows:

$$X = \text{fixed cost} / (\text{market price cap} - \text{variable cost})$$

The expected unserved energy was calculated using the following approach:

- Firstly the net demand was calculated by working out the probability distribution of the SA demand – wind generation, see Figure 14-9. This was done by a convolution of the two distribution;
- Next the demand was found which had a probability of exceedence equal to the breakeven capacity factor;
- Then the expected amount of load not been served was calculated.

What is interesting to note in this table is that it suggests that a market price cap of around $40,000 per MWh is required to achieve 0.002% expected unserved energy in South Australia.

Figure 14-9 Probability Distribution of Demand – Wind Generation

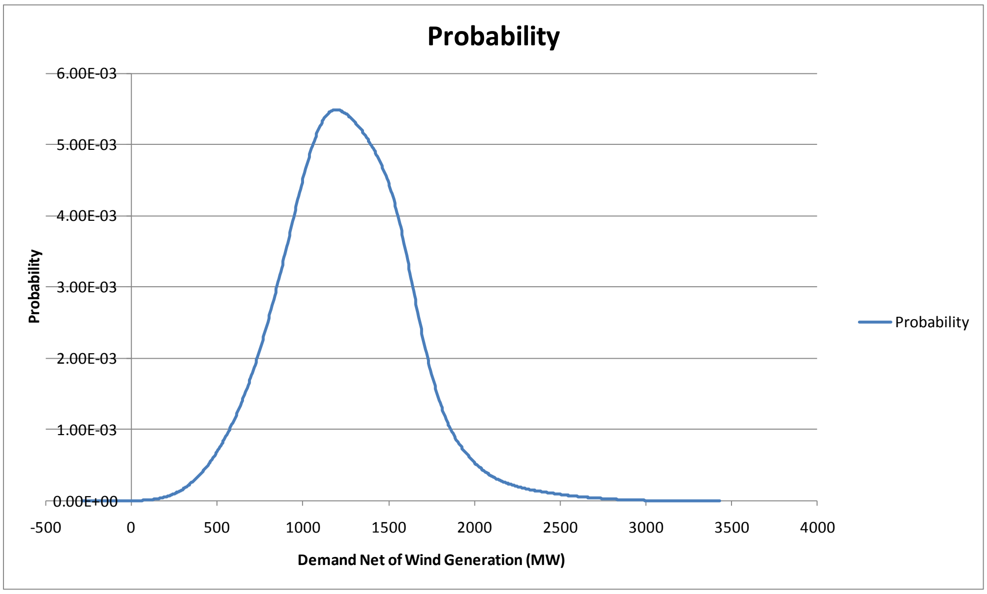


Figure 14-10 EUSE versus Market Price Cap

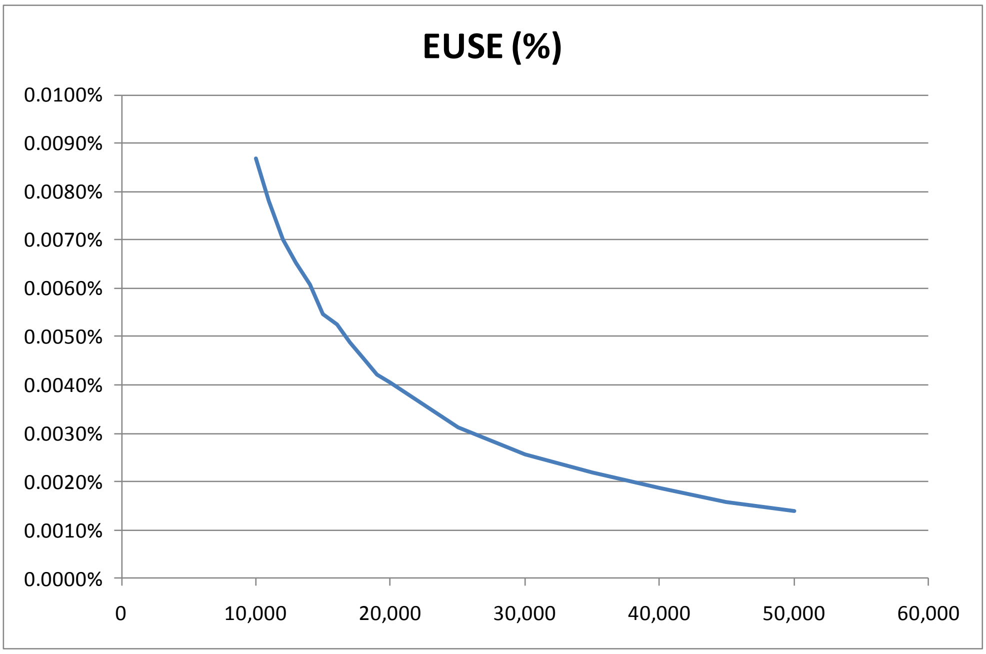


Table 14-5 Breakeven Hours of Operation and Expected Unserved Energy (EUSE)

Market Price Cap	Break even capacity factor	Hours to breakeven	Net demand (demand – wind)	EUSE (MW average)	EUSE (MWh per annum)	EUSE (%)
10,000	0.0945%	8.28	2770	0.135	1179	0.0087%
11,000	0.0858%	7.52	2785	0.121	1061	0.0078%
12,000	0.0786%	6.88	2800	0.109	953	0.0070%
13,000	0.0724%	6.35	2810	0.101	887	0.0065%
14,000	0.0672%	5.89	2820	0.094	825	0.0061%
15,000	0.0627%	5.49	2835	0.084	740	0.0055%
16,000	0.0587%	5.15	2840	0.081	714	0.0053%
17,000	0.0552%	4.84	2850	0.076	663	0.0049%
18,000	0.0522%	4.57	2860	0.070	616	0.0045%
19,000	0.0494%	4.33	2870	0.065	572	0.0042%
20,000	0.0469%	4.11	2875	0.063	551	0.0041%
25,000	0.0375%	3.28	2910	0.048	423	0.0031%
30,000	0.0312%	2.73	2935	0.040	349	0.0026%
35,000	0.0267%	2.34	2955	0.034	298	0.0022%
40,000	0.0234%	2.05	2975	0.029	253	0.0019%
45,000	0.0208%	1.82	2995	0.024	214	0.0016%
50,000	0.0187%	1.64	3010	0.022	189	0.0014%

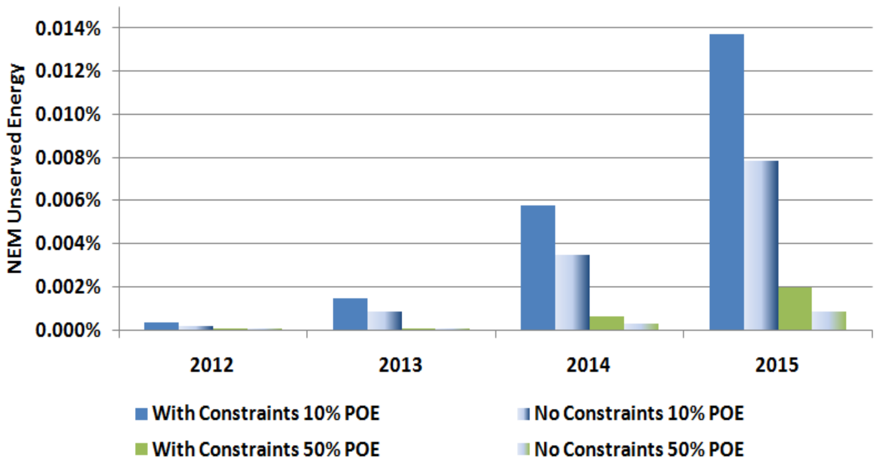
15 Appendix 6 – Intra-regional Constraints

This appendix illustrates the impact of incorporating intra-regional constraints in the modelling of NEM market outcomes, in particular USE.

To investigate this sensitivity, a sample year was modelled using (1) the 2009 NTS constraints and (2) using only the inter-regional transfers limits as reported by AEMO.

These cases were run over the period 2012 to 2015 under both the 50% and 10% PoE demands for those years. No new entry was assumed to enter the NEM. The results are shown in the figure below.

Figure 15-1 Sensitivity of Reliability to Inclusion of Intra-regional Constraints



The results show that inclusion of both intra-regional and inter-regional constraints as contained in the AEMO provided constraints have a significant impact on the modeled level of reliability.

This raises the question as to how reliability levels should be modeled given the AEMC definition of reliability that excludes intra-regional constraints. However in doing so it should be noted that a substantial level of the unreliability (USE) would not be responsive to changes in the market price signals. The difference is also a measure of risks being imposed on contracted generators,

16 Appendix 7 – IES Note sent to ROAM Consulting

The following note was sent to the AEMC and ROAM for clarification of modelling issues.

16.1 Introduction

IES is currently undertaking a review for the South Australian Department of Transport, Energy and Infrastructure on the issues associated with the reliability and security setting in the NEM. This has been the subject of several recent reports by the AEMC ("Reliability Standard and Reliability Setting Review" dated 30 April 2010 and "Review of the Effectiveness of the NEM Security and Reliability Arrangements in light of Extreme Weather Events" dated 31 May 2010)

IES has reviewed the ROAM report Reliability Setting and Settings Review" dated 21 April and has a number of questions. These are presented below.

We may also have some questions at a later time on the report by ROAM "Levels of the MPC that are consistent with the value of customer reliability" dated 9 April 2010.

16.2 Clarification of Methodology

The methodology used by ROAM is understood to be as follows:

- ROAM model benchmarked to CRA modelling.
  - This was done by using the same assumptions and comparing USE results. The USE average over all simulations was close to that of CRA.
  - The MPC that would make the marginal generator just profitable was determined.

QUESTION: Was this done by looking at the individual simulation that had USE at near 0.002% or on average over all simulations?

- ROAM then did the reliability modelling as follows:
  - Input all assumptions
  - Run simulation sets using 10% and 50% PoE loads
  - Install plant until the USE averages 0.002% across all the simulations. For each year this gives 100 individual simulations which have the same level of generation installed but there are variations in PoE demand and generator forced outage patterns
  - Each individual simulation had a different level of USE and a different MPC to make the marginal generator just profitable
  - Over 7 years there were 700 individual simulations (in the final runs);

- ROAM then plotted the relationship of USE and MPC calculated for each individual simulation. The simulation which had USE at near 0.002% provided the MPC required for the marginal plant to be economic.

QUESTION: Is this understanding as described above correct?

16.3 Number of Simulations Performed

The ROAM report indicates that 100 simulations were performed in the final runs for each year.

QUESTION: How many simulations were done for the 10% PoE demand and how many for the 50% PoE demand?

16.4 Wind, Load and Planned Outage Variability between Simulations

Statistical variation in loads and wind generation is an important issue to reliability. So is the pattern of planned outages relative to the demand trace. The report does not describe how these issues were treated.

QUESTIONS:

Wind Generation

- **Were the same wind traces used for each simulation (ie no variation between simulations)?**
- **Was this designed to provide the assessed capacity support as specified by AEMO as reliable at time of maximum demand?**
- **If not what was the level used in the simulations?**

Load Traces

- **Was the same load trace used for all the 10% PoE simulations?**
- **Was the same load trace used for all the 50% PoE simulations?**

Planned Generator Outages

- **Was the same generator planned outage pattern used in all the simulations**
- **Was all generation planned to be in service at the time of MD?**

16.5 Transmission Limits used in the Modelling

The definition of Reliability in the NEM as defined by the AEMC is the level of unserved energy due to insufficient generation and interconnector capability. It specifically excludes intra-regional transmission which is includes in security.

QUESTIONS:

- **Why did ROAM include the NTNDP constraint equations related ti intra-regional constraints in the modelling?**

- **Would this result in changes to the regional MPC required – some lower and some higher – has intraregional constraints not been used?**

The ROAM report "Reliability Standard and Setting Review" dated 21 April 2010 describes the manner transmission constraints were modelled. The report states in several places that a 6 region model was used and noted that the Snowy region was abolished (benchmarking and study runs). Thus they included the Snowy region in the model. Section A.5) shown below described the interconnector constraints used.

Network model

The NEM existed as a six-region network, consisting of Queensland, New South Wales, Victoria, South Australia and Tasmania. Tasmania is connected electrically to the mainland through the Basslink transmission link. The sixth region consisted of the Snowy Mountains Hydro Scheme generators and straddled the Victorian and New South Wales border.
ROAM has modelled the transmission network according to the thermal limitations of the inter-regional interconnectors. The following table shows the transmission capacity between regions in this model.

Table A.2 – 2007 Transmission Thermal Limits

Interconnector	Region A	Region B	Maximum Transfer Capacity A → B (MW)	Maximum Transfer Capacity B → A (MW)
QNI	NSW	QLD	589	1078
Terranora	NSW	QLD	105	234
SNO_NSW	SNO	NSW	3559	1150
VIC_SNO	VIC	SNO	1313	1842
Heywood	VIC	SA	460	300
Murraylink	VIC	SA	220	214
Basslink	TAS	VIC	600	480

The ROAM report also states that the 2009 NTS equations were used – see below.

Transmission

The transmission model has been applied as per the 2009 NTS constraints 'workbook' provided by AEMO. This incorporates all intra- and inter-regional transmission constraints.
The Prophet function "region reserve based on flows" is not available in the 2-4-C model. That function is used only to select between the constraint sets V>>V_NIL_1A and V>>V_NIL_1D. As such the V>>V_NIL_1D constraint set will be applied always, which assumes that run-back schemes are enabled allowing for a higher import into the Victorian region.

However the 2009 NTS equations were written on the basis of having 5 NEM regions (ie Snowy not included).

QUESTION: Is our understanding correct of what you have said and is there an issue here?

16.6 Interconnection reliability

We assume that the modelling assumed that interconnectors are 100% reliable.

QUESTION: Given the historical relationship between interconnector capability and reliability is this assumption overly optimistic?

16.7 Bidding and the Pattern of Spot Prices

The economics of peaking plant includes revenues from periods outside times it is required for reliability. The modelling states that realistic bidding was used.

QUESTIONS:

- ***How did the peaking plant bid in the simulations and was this different for "extreme peaking" and "shoulder" peaking plant?***
- ***Did peaking plant have a fixed unit size?***
- ***Were most of the generators in the market bids adjusted each year in response to factors such as load growth?***
- ***What did the price duration curve look like each year?***

16.8 Maintaining Reserves at all Times.

The NEM is operated with sufficient generating reserves at all times. Load would be shed to maintain these reserves.

We expect that the requirement to maintain reserves was not included in the modelling.

QUESTION: Is the above correct?

16.9 Meeting the LRET Target

The current outlook is that the LRET target may be difficult to met. This is due to the likely level of carbon price, the status of technologies such as geothermal and the level of the shortfall penalty.

QUESTIONS

- ***Was much of the renewable generation that entered the market to satisfy the LRET target non economic?***
- ***What was the regional development of renewable technology by type (in particular the level of wind development in South Australia)?***

16.10 Results

The results presented in Figure 7.4 and 7.5are important to the conclusions. However there is not "feel" as to the spread of points and how well the curve matches the pattern of results.

QUESTION: Could a graph that has the 700 points also plotted by provided?

17 Appendix 8 – OCGT Generation v Spot Price

Figure 17-1 Jeeralang B Generation versus Spot Price: 2006-2011

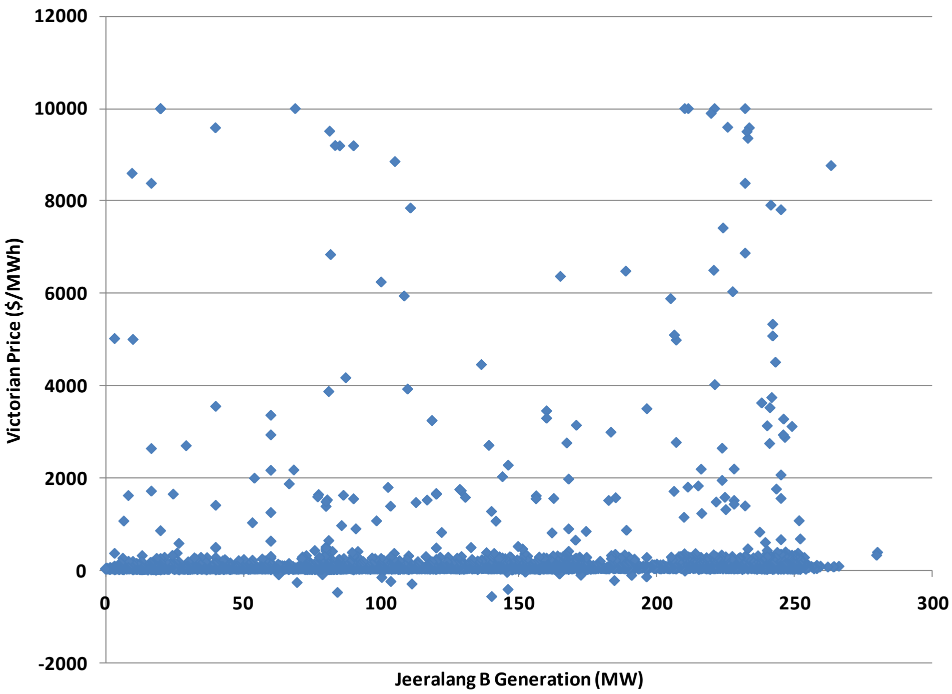


Figure 17-2 Hallett Generation versus Spot Price: 2006-2011

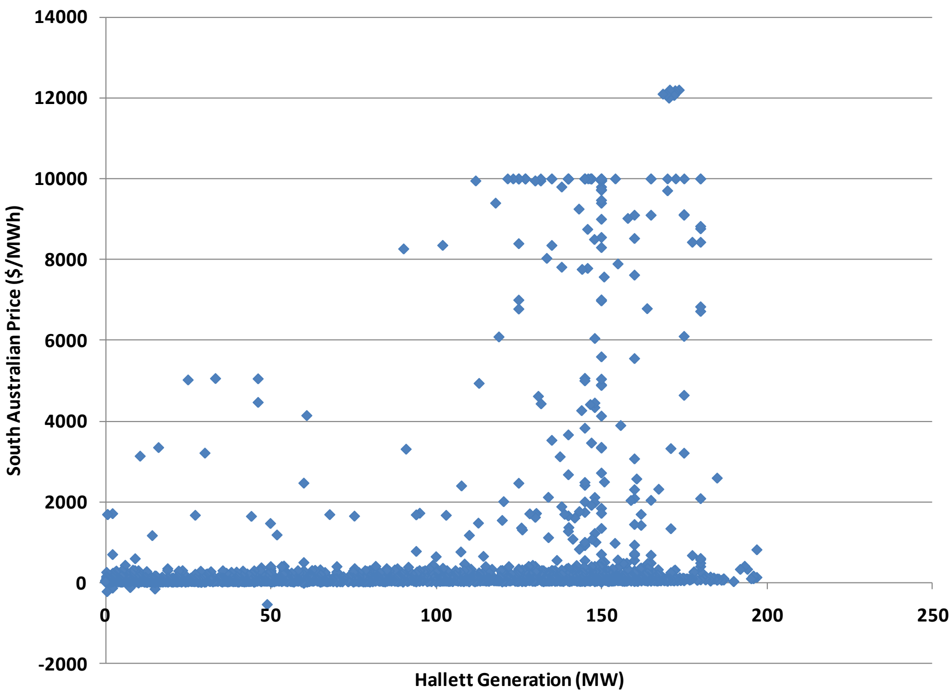


Figure 17-3 Mt Stuart Generation versus Spot Price: 2006-2011

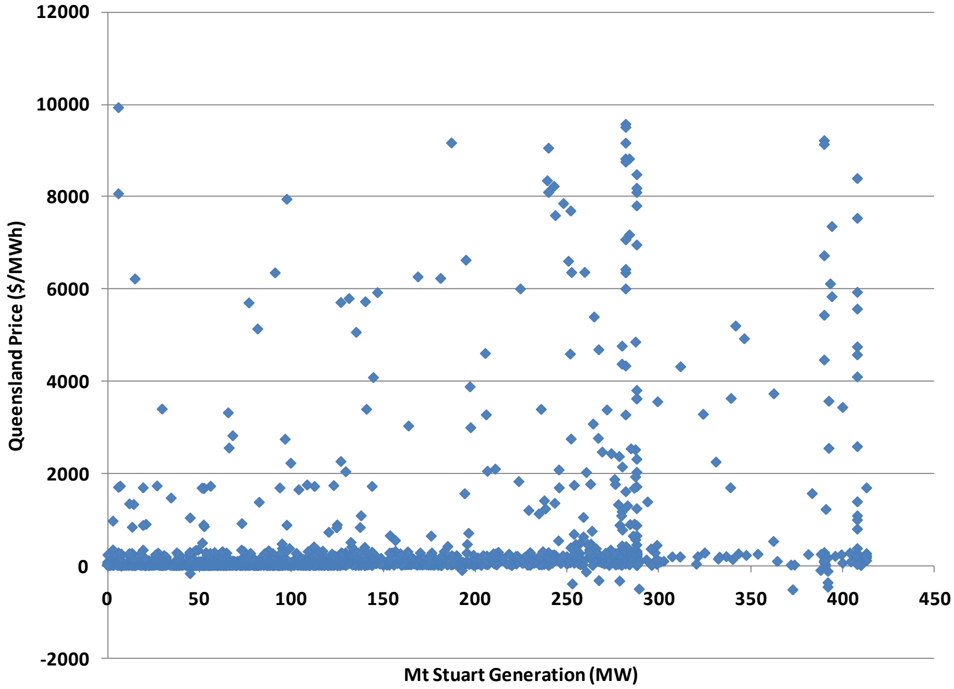


Figure 17-4 Hunter Valley Generation versus Spot Price: 2006-2011