Final Report to

Energy Users Association of Australia

Estimation of the Economically Optimal Reliability Standard for the National Electricity Market

16 June 2006

M M A

McLennan Magasanik Associates Pty Ltd
242 Ferrars Street
South Melbourne Vic 3205

Tel: (03) 9699 3977
Fax: (03) 9690 9881
Email: mma@mmassociates.com.au
Website: www.mmassociates.com.au

Ref: J1253f1.0

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

EXECUTIVE SUMMARY

Purpose

McLennan Magasanik Associates (MMA) has conducted a detailed study of the relationships between regional installed capacity, expected unserved energy and expected unserved energy cost in the National Electricity Market (NEM). The purpose of the study was to seek to develop a methodology using market simulation that would validate an optimal reliability standard for the NEM as promulgated by the Reliability Panel. The study did not evaluate different types of reliability standards but focused on an economic validation of the current standard. The study was conducted for the Energy Users Association of Australia (EUAA).

Key Outcomes

The modelling work has demonstrated that the current reliability standard as a target level does not represent a least cost balance of customer value for reliability and the associated cost of reserve capacity. Furthermore, the Reserve Trader intervention regime at the 0.002% level has significant potential to discourage appropriate efficient demand side participation in the NEM and to result in unnecessary and too frequent market intervention. A margin of some 50 MW to 100 MW needs to be subtracted from the target reserve margin before intervention can be justified given the inherent uncertainty in the measurement of reliability levels.

Optimal reliability levels indicated based on MMA's estimation of the marginal value of customer reliability in accordance with load shedding arrangements as stated in general terms by Jurisdictional Co-ordinators should be about 0.001% in Queensland and 0.004% in southern regions. If a common standard is nevertheless preferred then 0.0016% would be more beneficial than 0.002%.

Based on the current market structure and bidding behaviour, market prices at the optimal level of reliability would exceed new entry costs by about 10% to 50%. This would ensure that better than optimal reliability would be achieved if competitive new entry processes were maintained.

There is a need to reveal, review and optimise the load shedding arrangements in each jurisdiction and then to confirm an optimal reliability standard for each region based on the committed and forecast supply/demand conditions.

The benefits of moving to a more efficient standard in the NEM could be up to $40 M pa in the long-term. In the next five years, benefits of about $9 M pa could be achieved by moving to an optimal standard. Prices are in June 2005 dollars.

Model Concept

Readers are warned that parts of the report are highly technical and document some analysis that did not produce useful or sensible results. The material was included to show what was found to be useful and to provide a guide for further refinement of the analysis.

The concept of the study was that it should be possible to use a market simulation to derive:

- The relationship between installed capacity and expected unserved energy in each state region of the NEM. This excluded Snowy because it supplies no external customer load and it excluded Tasmania because a detailed hydrological reliability model was not available to MMA.
- A set of outage events that could be costed from a customer perspective having regard to their frequency, duration and peak load shed. The costing of these events would provide a more rigorous basis for relating unserved energy volume and customer cost.

By considering the fixed cost of reserve capacity at a notional $100/kW/year it was possible to estimate the optimal reliability level for each state region in the NEM which minimises the reliability cost. The reliability cost is the sum of the unserved energy cost and the corresponding reserve capacity cost. The reserve capacity cost is calculated relative to an arbitrary fixed capacity value for each region to represent the marginal cost of additional reserve capacity. It may also represent the avoided cost of mothballing surplus capacity if applicable.

It was expected that MMA would be able to obtain information from the jurisdictions on the priority for load shedding in each region but was subsequently advised by the Jurisdictional Co-ordinators that the data was regarded as sensitive and confidential. As a result, MMA made it's own assessment of load shedding resources and approximate costs based upon a general description of the applicable policy in each jurisdiction provided by the Co-ordinators during a teleconference in October 2005.

Model Methodology

Several approaches were used to estimate the optimal reliability level both on a state region basis and across the whole NEM. The methods employed and their major results are summarised as follows:

1. A probabilistic model called Strategist was used to confirm early in the project that there was a case to suggest that the optimal reliability standard across the NEM might differ from 0.002%.

2. A Monte Carlo simulation of the NEM based upon the 2004 load forecasts was established using Plexos which is a sophisticated electricity market modelling software package developed by Drayton Analytics[1]. Seventeen different capacity states were simulated in the financial years from 2005/06 to 2009/10 to derive expected unserved energy and the chronological characteristics of unserved energy events.

3. For each load shedding event in the simulation, the energy shed, the duration of the shortage, the peak demand interrupted and the times to the previous and next interruption were captured. These parameters were used to assess potential outage costs.

4. Using the Monte Carlo results in terms only of expected unserved energy and using the standard parameters of $100/kW/year for reserve capacity and $30/kWh for marginal cost of unserved energy, the optimal reliability was assessed for the NEM as a whole and for individual regions for each year. The chosen value of the marginal cost of unserved energy at $30/kWh for this initial assessment was in accordance with the average value of customer reliability derived in previous surveys by Monash University and Charles River Associates[2].

    a. In this study the common reliability standard that minimised the reliability cost was 0.0016% over the five years and regions with annual variations between 0.0012% and 0.0019% as shown in Figure 1.1. The shaded value for 2009 indicates that this was based upon interpolation between 2008 and 2010 as a valid function of unserved energy versus capacity could not be obtained from the available data. The potential cost of the current standard relative to this model was only $3.5 M per year levelised over the five years at 7% real discount rate.

    b. The development of a specific reliability level for each region gave a higher level of 0.0028% on average with regional averages ranging between 0.0012% for Queensland and 0.0071% for South Australia. The annual average variations across the four regions were between 0.0022% and 0.0037% as shown in Figure 1.2. The reliability level is highest in Queensland because of the flatter load profile and lowest in South

[1] www.plexos.info

[2] The marginal cost of unserved energy should not be confused with the NEM concept of VoLL, the value of lost load. The former is quite variable according to what kind of customer is affected during a supply shortage and for how long. The latter is merely a price cap in the NEM to manage extreme supply/demand imbalance risks.

Australia where the annual load profile is the most peaky. This is as was expected, although the lower level of reliability in South Australia seemed exaggerated.

Figure 1.1 Estimate of a Common Standard for Expected Unserved Energy

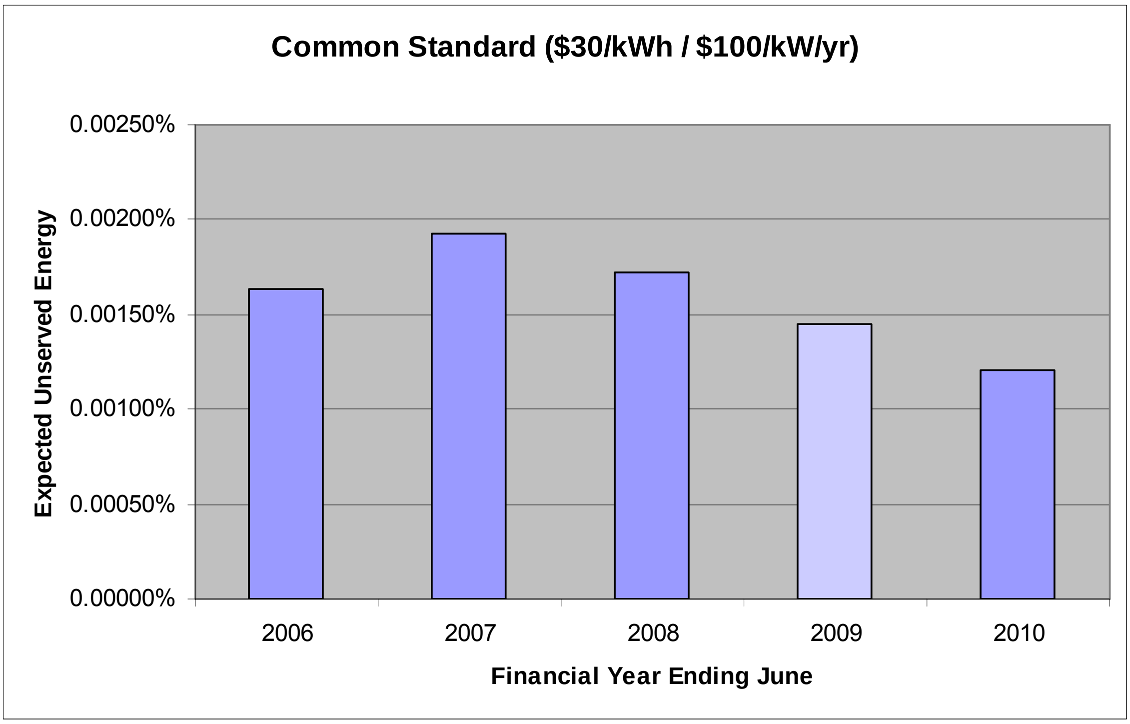
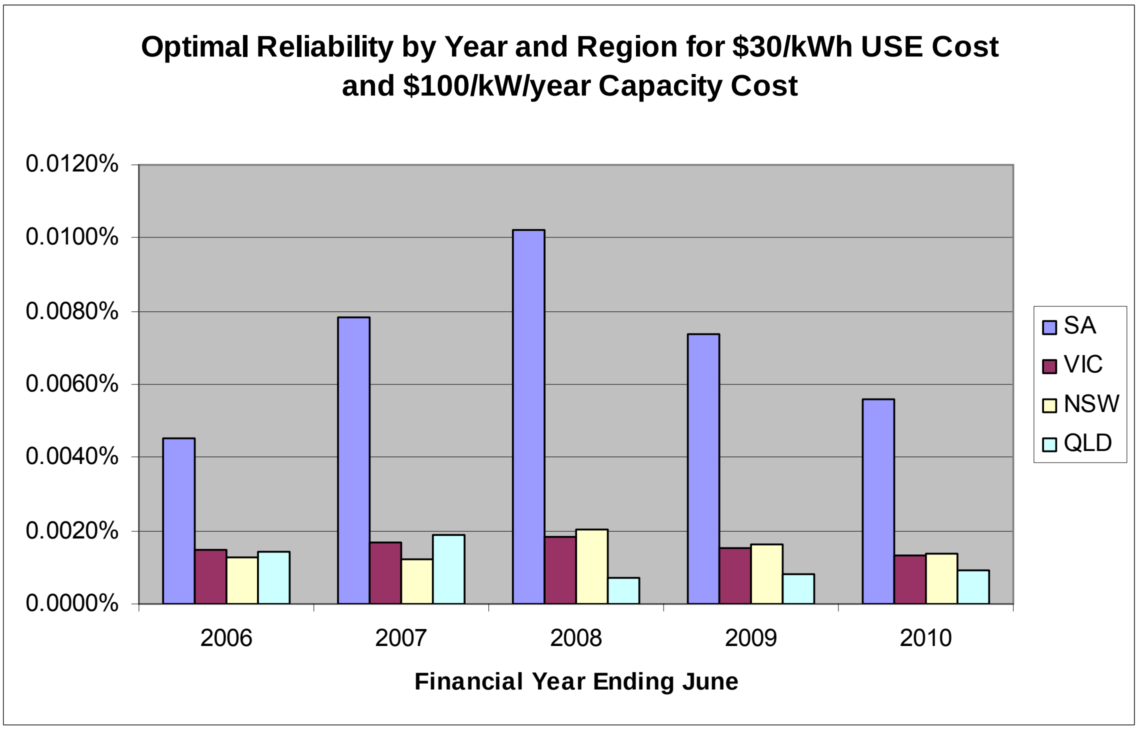


Figure 1.2 Estimate of an Optimal Standard for Expected Unserved Energy for each Region



c. The levelised benefit of adopting the regional model was nearly $33M per year on a levelised basis.

Load Shedding Cost Model

5. The results of the Monte Carlo simulations were also analysed to determine the costs of each load shedding event using an assumed sequence of load shedding priority according to the policy in each state region. Up to eight hours was regarded as load shedding. Events exceeding 8 hours duration or above 5% of the system peak demand in each region in magnitude were priced to represent the imposition of restrictions on the next day if applicable. The pricing of restrictions was relative to the load shedding energy that they replaced rather than the higher restricted volume which was not explicitly modelled. We modelled a priority sequence of load shedding as follows:

    a. Water pump load shedding in South Australia valued at $1/kWh

    b. Aluminium smelter shedding in Victoria and NSW with limits on the number of events per year, the energy per event, valued at $0.3/kWh based on the cost of replacement aluminium plus a risk margin

    c. General rotational load shedding in Queensland up to 1500 MW for up to 8 hours valued at $20/kWh[3].

    d. 2,900 MW of residential load shedding in the southern regions for up to 8 hours valued at $1/kWh

    e. 2,300 MW of small business load shedding in the southern regions for up to 8 hours valued at $50/kWh

    f. Large commercial load shedding in the southern regions for up to 8 hours valued at $100/kWh.

6. In the event that there are outages on sequential days of more than 5% of the system peak demand then restrictions are imposed and it is assumed that ten times more load is shed under restrictions than would occur with opportunistic load shedding as follows:

    a. We allow the balance of load shedding above 1,500 MW in Queensland to represent restrictions valued at $100/kWh of load shedding converted to restrictions.

[3] MMA modelled the current arrangements as described by the Queensland Jurisdictional Co-ordinator rather than more beneficial load shedding operations where the large industrial loads are given an economic incentive to participate.

b. In the southern states we have 4,000 MW of residential restrictions valued at $20/kWh of load shedding converted to restrictions.

c. The balance is business restrictions valued at $250/kWh of load shedding converted to restrictions.

7. Two approaches were attempted to relate the unserved energy cost to ether regional capacity or unserved energy. The first method, which was unsuccessful in providing meaningful results, developed the total expected unserved energy cost plus the reserve capacity cost as a function of the installed capacity in each of the regions without explicit reference to the unserved energy level.

8. The second method developed a quadratic regression of the expected unserved energy cost to the expected unserved energy in each region, added the reserve capacity cost to obtain the reliability cost and then found the unserved energy level which minimised the total reliability cost. This method worked better and was easier to understand.

9. Both methods showed that an economic basis could be developed for different reliability standards in each region and that the standards for the purpose of market intervention could be adjusted from year to year having regard to prevailing supply/demand conditions.

10. The second method provided more credible and stable results which are illustrated in Figure 1.3. The analysis produced an average optimal unserved energy level at 0.0037% with regional values varying between 0.0011% for Queensland and 0.0061% for Victoria. Annual averages ranged between 0.0027% and 0.0046%.

The Volatility of the Unserved Energy Cost

As part of the analysis of outage costs we examined the probability distribution of unserved energy costs on an annual basis as illustrated in Figure 1.4 for a particular set of capacity values covering expected unserved energy levels between 0.0007% and 0.0082% with an average over the years and regions of 0.0028%. The distributions are shown on a logarithmic scale to show the extreme asymmetry of the probability distribution of unserved energy cost. If the unserved energy is above the mean then it averages 5 to 20 times the mean. For a Normal Distribution the average above the mean is 39.9% of the standard deviation plus the mean value. Thus the unserved energy cost distribution is very skewed and difficult to sample accurately. It also means that basing the reliability standard on expected values does not recognise the possible consequences of rare but extreme events.

The asymmetry of the unserved energy cost distribution could be applied to assess a higher level of unserved energy cost that represents an extreme event that is to be avoided with substantial intent. For example, a thirty year time scale is about the

Figure 1.3 Optimal Reliability Levels Based Upon Minimum Total Expected Reliability Cost Versus Expected Unserved Energy

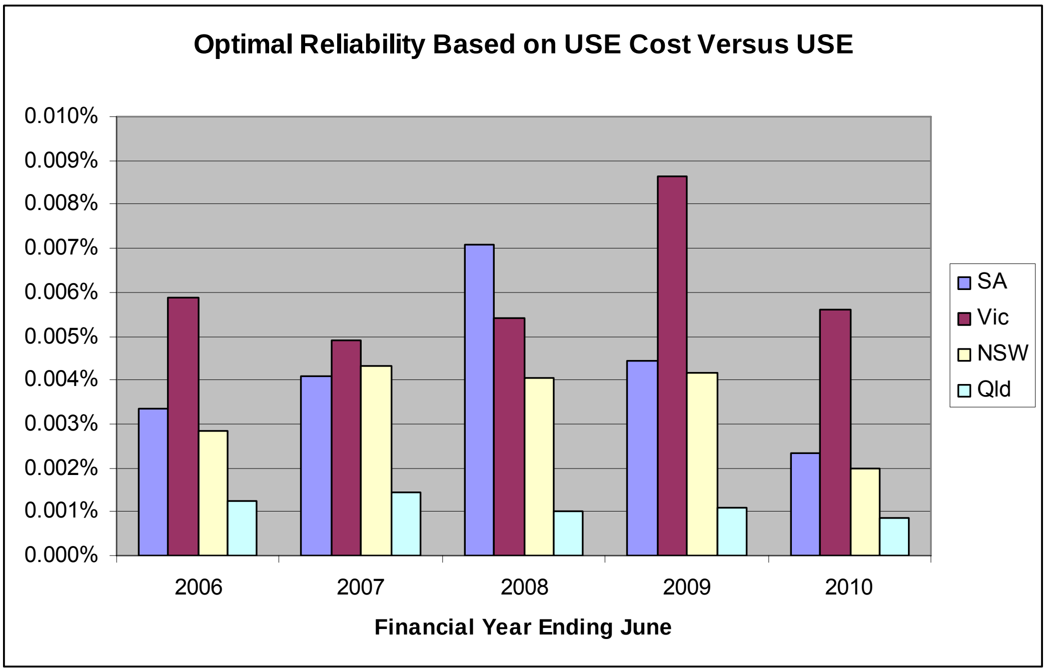
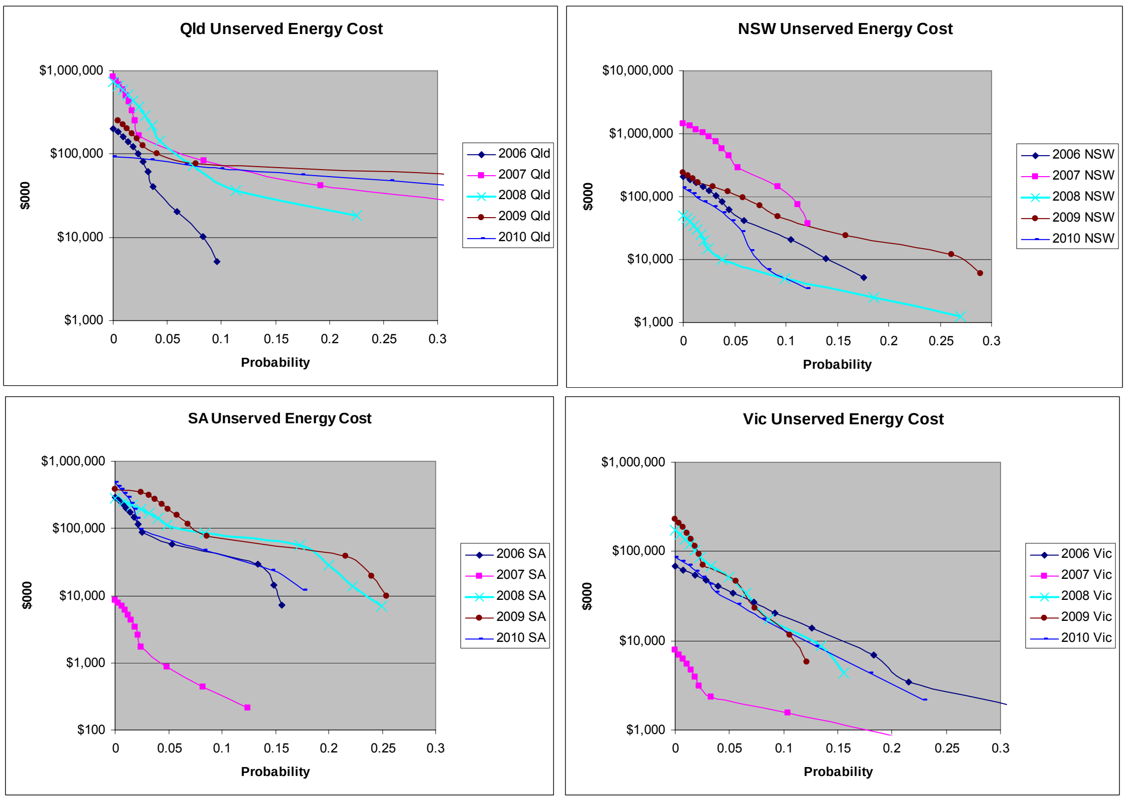


Figure 1.4 Unserved Energy Cost Distributions



frequency of major system shut-downs in mature interconnected electricity systems which occur even when there is adequate generating capacity. Such system shut-downs occur usually due to faults arising in and propagating through the transmission system due to secondary equipment failure and operator errors. A bulk system standard that matched this level of exposure on a 1 in 30 year basis may also be useful as an objective measure of extreme events that could be avoided purely from insufficient generation capacity.

The Cost of the Current Standard

The potential economic cost of continuing with the current standard has been estimated by comparing the estimated cost of maintaining the 0.002% common standard in each year with the cost of a more local and flexible standard based on these analyses. The costs have been estimated on an annual basis and levelised at 7% real discount for summary purposes. The annual levelised value of benefits for various models ranged from $3.5 M pa to $40 M pa.

Such benefits are assessed if the capacity in each region delivers the targeted reliability. The benefits would normally be expected to be lower if the unserved energy level were to be reduced and participants were delivering higher reserve capacity to meet their own risk management objectives as we have observed in recent years. In the case of the southern regions where there is surplus generating capacity relative to an economic level[4], the reliability standard could be relaxed and the savings could be more substantial. Detailed analysis of such benefits should be assessed for particular reliability standards that are to be adopted.

Optimal Reliability Levels

Table 1.1 provides an overall summary of the calculations of optimal unserved energy and the potential benefits of moving from the common 0.002% reliability standard. The last two entries summarise the potential benefits in mothballing currently committed capacity to match the current and optimal standard. These savings would only be passed on to customers if a dynamic demand side response was available at the times of peak demand and potential capacity shortages.

Based on the more robust models, economic benefits of up to $40 M per year could be achieved in the long term from moving to a separate reliability standard for each region and adjusting it each year to reflect prevailing market conditions and costs.

[4] The reference to a capacity surplus in the southern regions relates to the economic level of generating capacity. There is about 1000 MW of surplus capacity that should have been avoided in the first place. It has crowded out demand side response at much lower fixed cost that could deal better with the one in 10 year events.

Some of these benefits have already been achieved because market participants, for example in Queensland have delivered more capacity than required to meet the

Table 1.1 Summary of Optimal Reliability Analysis and Benefits of Change

Method	Capacity Cost $/kW/year	Unserved Energy Cost $/kWh	Average of the 5 Years and Regions	Range over the Years	Range over the Regions	Value compared with 0.002% $M/Year	Robustness and Credibility
Common Standard in all regions with Plexos	$100	$30	0.0016%	0.0012 – 0.0019%		Up to $11.6 in 2010 Up to $3.5 levelised over 5 years	**Good:** A good fit of the results provides a suitable common standard.
Standard optimised for each region	$100	$30	0.0028%	0.0022 – 0.0037%	0.0012 - 0.0071%	Up to $60.9 in 2008 Up to $32.7 levelised over 5 years	**Good Except for SA:** The reliability standard for SA averaging 0.0071% seems too high. The range 0.0012% to 0.0016% looks more reasonable.
Using unserved energy cost versus unserved energy	$100	Unserved Energy Cost Model	0.0037%	0.0027 – 0.0033%	0.0011 – 0.0061%	Up to $96 $40 levelised over 5 years	**Good:** Results reflect assumptions about interruption costs ore accurately than other methods.

Method	Capacity Cost $/kW/year	Unserved Energy Cost $/kWh	Average of the 5 Years and Regions	Range over the Years	Range over the Regions	Value compared with 0.002% $M/Year	Robustness and Credibility
Benefits of change from committed capacity through mothballing							
Moving from current committed capacity by mothballing to current standard using unserved energy cost versus unserved energy	$30 for moth-balling	Unserved Energy Cost Model	0.002%	0.002%	0.002%	Up to $97 $55 levelised over 5 years	Benefits would only be passed to customers with a dynamic demand side response to mitigate market power at the time of peak demand.
Moving from current committed capacity to optimal standard using unserved energy cost versus unserved energy	$30 for moth-balling	Unserved Energy Cost Model	0.001% Qld 0.004% elsewhere	0.001% Qld 0.004% elsewhere	0.001% Qld 0.004% elsewhere	Up to $107 $64 levelised over 5 years	Benefits would only be passed to customers with a dynamic demand side response to mitigate market power at the time of peak demand.

0.002% standard. However in the southern states it appears that generating capacity may be in excess of its economic opportunity with a corresponding displacement of demand side response to respond to infrequent supply shortages. Overall the NEM has delivered excess capacity with an annual cost of up to $63 M per annum relative to an optimal outcome based upon average conditions as best as we can evaluate them with readily available data.

Market Outcomes with Optimal Reliability as a Target

If the optimal standard were to be achieved in all NEM regions simultaneously with the current market structure then market modelling has shown that spot prices in all NEM regions would be about 20% to 30% above new entry costs. Therefore proving that a competitive new entry process for supply and demand side resources is maintained in the market, it can be expected that the NEM would deliver better than the optimal reliability standard without the need for market intervention.

Factors Affecting the Optimal Unserved Energy Cost

Other observations and study results of interest were as follows:

1. The optimal level of reliability as measured by the percentage of demand that is lost as unserved energy:

    a. Varies approximately as the marginal cost of unserved energy between $15/kWh and $60/kWh

    b. Varies approximately inversely as the cost of reserve plant between $50/kW/year and $150/kW/year

2. Such linear and inverse sensitivities of the standard could be used to readily adjust the standard to reflect short—term variations in marginal costs of capacity and unserved energy without requiring a full economic analysis each year.

3. The optimal level of reliability in each region of the National Electricity Market decreases as the load pattern becomes more high temperature weather sensitive on extreme days. The optimal level of reliability is highest for Queensland, then NSW, then Victoria, then South Australia with the lowest level if measured on a percent unserved energy criterion[1].

[1] Tasmania was not considered in this tudy because MMA using Plexos was unable to adequately represent unserved energy arising from hydrological uncertainty. This would require a detailed model of Hydro Tasmania's assets using confidential information.

4. The optimal level of reliability can be lower when there are low cost interruptible resources available such as smelter loads and water pumping. Demand side participation rules should be designed to ensure that the role of these resources is encouraged and maximised to reduce the need for reserve plant that is hardly ever used.

5. There is an apparent need to optimise the load shedding arrangements in each jurisdiction so that the demand side resources are efficiently applied to manage infrequent supply shortages and extreme peak demands.

6. There is a large effort required to capture and process sufficient statistical samples of unserved energy events so that the sampling error is reduced to an acceptable level. Extreme events are an important component of this cost analysis because when they occur they often make customers think that the reliability standards are inadequate.

Treatment of averages may be an inadequate way to characterise system reliability from a customer's perspective because when a serious event happens it has multiplier effects through the economy as restrictions are imposed to share the pain. This inevitably increases the total pain because restrictions are a very coarse method of balancing supply and demand on a real time basis.

Conclusions

Based upon the assumptions made and the results derived in this project we may conclude the following from the study results:

- The current 0.002% reliability standard is apparently inconsistent with the load shedding policies in each jurisdiction and the associated exposure to load shedding on an expected value basis.

- The reliability standard could be made more stringent in Queensland where load shedding risk is understood to be shared equitably. Based upon the model developed in this work a standard closer to 0.001 to 0.0012% would be more appropriate. The Queensland region in the NEM is already delivering much higher reliability than this economic level at additional costs to generators, customers, Government and Queensland tax payers.

- In Victoria and NSW where aluminium smelters may be available for addressing short-term capacity shortages and depending on the nature of contractual constraints and commercial arrangements, there is potential to relax the reliability standard in the range 0.003% to 0.004%. It would be necessary to confirm the commercial arrangements for smelter load shedding and the load shedding arrangements for residential and business customers and revising the analysis accordingly to confirm an appropriate value.

- In South Australia the reliability standard could also be relaxed to 0.004% on an expected value basis depending on the constraints on the interruption of water pumping load and the ability to use the Heywood interconnection and Murraylink to provide emergency supplies.

- If these standards were introduced and the capacity levels were commensurate with these standards in all NEM regions then there would be sufficient price incentive to maintain these standards or better them. This analysis confirms why the existing standard has been more than delivered in the NEM. There is evidence of sufficient market power to deliver reliable supply to meet the reliability standard.

- The potential savings in customer and generators costs would be up to $40 M per annum in the longer term if the reliability standard was defined on a regional and annual basis and tracked closely by new entrants.

- In the period to 2010, up to $55 M per annum could be saved by mothballing surplus capacity and stimulating demand side response to manage infrequent capacity shortages rather than bearing high maintenance costs for rarely used plant. A further $9 M per annum could be saved by implementing an economic reliability standard.

- The volatility of unserved energy costs on an annual basis is quite startling and suggests that this methodology should be further developed to provide an additional criterion that looks at the expected frequency of extreme events equivalent to 0.01% to 0.02% unserved energy. A 30 to 50 year time frame is the typical incidence of major network shut-downs caused by secondary equipment failure or operational errors with cascading outages. It may be desirable, even if not on a purely economic basis, to ensure that the bulk system reliability standard was also satisfied at a 1 in 10 or 1 in 30 year exposure commensurate with these more extreme events.

- Before new reliability standards can be defined, further work is needed to quantify the impact of load shedding policies and the costs of the resources applied so that the methodology developed here can be used to provide an economic justification for revised reliability standards. The commitment of Jurisdictional Co-ordinators (and Governments) to release this information will be needed before a robust and credible analysis can be provided. As mentioned above, MMA endeavoured to obtain such information from each of the Jurisdictional Coordinators but was unsuccessful in doing so. It is recommended therefore that EUAA continue with its efforts to have such information made more readily available.

The EUAA can promote a more efficient market by encouraging greater demand side participation and a supportive regulatory environment. Adjustment of reliability standards to economic levels must progress in step with increased demand side participation to ensure that the economic benefits of reduced reserve generating capacity are shared with customers and do not result in increased prices to customers and windfall gains to generators.

In view of the apparent inefficiency of the load shedding arrangements in Queensland, there is an opportunity for an enhanced economic role for the large industrial loads in Queensland to contribute through demand side participation in the load shedding arrangements if a more efficient reliability standard is to be adopted.

1 INTRODUCTION

1.1 RELIABILITY STANDARDS

The National Electricity Code requires the Reliability Panel (the Panel) to determine the power system security and reliability standards for the NEM. In June 1998, the Panel adopted the percentage of unserved energy (USE) within any NEM region as the most relevant measure for the national market. The level that has been set is 0.002% of firm energy required to be supplied to customers. This measure applies to the available supply of generation (or alternatives) in each region, and therefore includes consideration of inter-regional transmission capacity. The reliability standard specifically excludes the impacts of intra-regional transmission reliability and other factors that influence supply reliability (most notably the reliability of the distribution network and the impact of industrial relations disputes).

The reliability standard is modelled using statistical simulations of market operation with the objective of predicting the amount of unserved energy over a sufficient number of statistical simulations. These simulations assume that the failure of individual generating units and inter-regional transmission links are statistically independent. Thus the reliability standard is implicitly defined to exclude common mode failures which cause the simultaneous loss of generators and/or transmission links either due to control system failures that cause consequential plant trips or common mode failures. An example of this would be where a transmission line fault causes several generators to trip in rapid succession due to incorrect or inappropriate protection settings or multiple protection system or operational failures.

The reason that these failure types are not included in setting the criterion to determine the need for new generating capacity is that such events are more effectively mitigated by other measures such as quality control in protection, control systems and operational procedures to prevent cascade disconnection of plant and to enable rapid restoration when such events do occur. Whilst building additional generating capacity can mitigate these less frequent events to some degree and aid system recovery, this is not the most economic solution and would not be pursued by private investors seeking to achieve a market return on capital without some additional revenue to supplement earnings from the energy and ancillary services markets. The Reserve Trader role of NEMMCO could certainly ensure that additional capacity is built to cover such events but it would not be in the interests of energy users if these extra charges were passed on to them through regulated charges. It would be preferable that the control and protection systems were restored to proper performance efficient levels in accordance with good electricity industry practice using available technologies in an economic manner.

1.2 REVIEW OF STANDARD

The Reliability Panel's reliability standard, which is a major and fundamental issue within the market, has not been reviewed since before market start. The Panel is seeking to review the reliability standard and its application in the national electricity market. The review of the reliability standard will cover:

- the appropriateness of the unserved energy standard and its interpretation into minimum reserve levels;
- its application on a regional basis; and
- its application to short, medium and long term market operation.

The Panel required the preparation of an issues paper for consideration at its April 2005 meeting. However this process had been deferred to later in 2005 by Dr John Tamblyn the Chairman of the Australian Energy Market Commission (AEMC). Charles River Associates has been engaged to assist the Reliability Panel in the preparation of papers and the consultative process. No documents had been released by AEMC when the project analysis was finalised. Thus final version of the report was completed after the Reliability Panel's May 2006 Issues Paper had been released but this report does not specifically address the questions in the Issues Paper. However it does provide useful analysis to answer many of the questions raised.

1.3 EUAA VIEW

Any review of the reliability standard will have implications for end use customers. Specifically, changes to the reliability standard will have price/service trade-off implications for end users. For instance, raising the reliability standard would increase the level of reserve required thus raising network investment and/or generation investment at a cost to end users and base load generators. Alternatively, a lowering of the reliability standard would reduce the need for network and/or generation investment however at a cost of reducing reliable supply to end users. This will impact on the reliability of supply to users and the cost of supply. For users, there is a trade-off involved here and a need to ensure an optimal balance.

There is also some benefit of a more economic reliability standard for energy intensive users which can interrupt their consumption for relatively short periods at times of very high spot prices and supply shortages. This benefit arises because the capacity value of that interruption is much greater than the lost value of production. An overly reliable system with excess capacity prevents that value being delivered to energy users.

Hence, it is important for the Reliability Panel to set the optimum standard for end users. Indeed, the reliability standards set by the Panel should be about providing a reliable supply to end users at the minimum expected cost.

Accordingly, the EUAA is seeking to review the current reliability standard and its implications to end users as well as reviewing the end user implications of any draft recommendations contained in the Reliability Panel's Draft Report. Specifically, the EUAA is seeking to:

1. Assess whether the current 0.002% reliability standard is delivering reliable supply to end users compared to overseas benchmarks.

2. Assess whether the probabilistic approach to setting the standard is the most appropriate for end users.

3. Prepare a draft and final report in response to the AEMC Review/Report.

1.4 PURPOSE

The purpose of this report which was originally proposed by MMA is to provide an initial estimate of the optimal level of reliability for the major load serving regions of the NEM based upon:

- existing information on the cost of unserved energy,
- the relationship between unserved energy and installed generating capacity using open cycle gas turbines as the marginal new entry reserve capacity resource in each load supplying NEM region (Snowy and Tasmanian[2] regions were not considered), and
- the marginal cost of altering the installed capacity in a region.

MMA does not regard this as a definitive study because some of the important information required for the study was stated as unavailable by the Jurisdictional Co-ordinators. However the study makes some significant contributions to the debate about reliability standards by:

- proposing a methodology that can be enhanced in the future with further market research to confirm the key customer value parameters,
- modelling the reliability of the NEM using probabilistic and statistical simulations to measure the customer impacts of unreliability,
- quantifying the key reliability impacts on customers as best as can be done with existing public information,
- evaluating an economic optimum for the reliability standard in terms of expected unserved energy assuming such a measure is retained, and

[2] As discussed later, the relevant information to properly model reliability in Tasmania based on hydrological yield variability was not available to MMA. This would require a specialised study that only Hydro Tasmania could conduct effectively unless it released the relevant data on yield, storage and capacity levels.

- demonstrating the uncertainty in evaluating reliability measures and making a case for standards to reflect this uncertainty rather than being solely limited to consideration of average values.

There are some desirable objectives that have not been accomplished in this study but which MMA considers would be worthy of future analysis. We do not consider this study to be entirely definitive but rather sufficient to show that the current standard is uneconomic to the extent of up to $40M pa in additional costs to electricity market participants. Since the reserve capacity standard is more conservative than the current unserved energy standard, it is likely that some of these excess costs have been avoided under current practices. The analysis in this paper helps to explain why the market has in most times and places delivered more capacity than was needed to meet the reliability criterion. More analysis of the underlying uncertainties and the day to day implications of operating to a lower reserve capacity standard may yet justify the current reserve capacity standard.

The limitations of the present work were as follows:

- The focus is on reliability under a business as usual scenario with medium economic growth and with an outlook period of the next five years using known power generation technologies in current usage. Economic or supply shocks are not considered.
- We have not undertaken the requisite market research to validate the parameters to be used in the model due to the high cost of such research. Where possible published sources have been used. Otherwise, MMA has made judgements that are documented in the report.
- The jurisdictions have refused to release the necessary information for this study on the priorities for load shedding set by the respective state governments, presumably because of their political sensitivity. It was expected that this information could be made available for the study if necessary on a confidential basis but this has not eventuated. As a result only generally indicative conclusions have been drawn but these conclusions have identified the limitations of the current reliability standard.
- We have not fully considered all of the underlying uncertainties in quantifying the unserved energy such as:
  - Economic growth (only medium growth has been considered),
  - Generating plant performance (only typical forced outage rates have been modelled),
  - Uncertainty in timing of committed plant has not been considered (plants have been commissioned on time),

    - Evolution of transmission constraints over time and their influencing factors such as patterns of local demand growth (only existing transmission limits have been represented),
    - However, some weather uncertainty (only 90%, 50% and 10% POE weather patterns) has been considered.
- Also the uncertainty of the reliability measures both in terms of simulation measurement and the impact of forecast uncertainty are not considered in detail. We have continued to examine the current concept of expected unserved energy and not examined any risk based measure as has been proposed in previous MMA work on this matter[3].

[3] Recommendations from MMA's Final Report to the Reliability Panel enttled : Assessment of NEMMCO's 2001 Calculation of Reserve Margins" dated 10 September 2002.

2 ISSUES

2.1 THE RELIABILITY STANDARD

Since the Panel's June 1998 report the current standard for reliability has been clarified through the review processes to apply the long term average level of unserved energy (USE) within any region to determine a reserve margin standard for use by NEMMCO. The energy not served standard has been used by NEMMCO to derive a capacity reserve measure. This can be used in real time as the basis for intervention by NEMMCO as the Reserve Trader and is used to advise the market participants of the potential for inadequate reliability. The limitation of an energy measure is that it cannot be observed in real time as a basis for decisions because it is measured over a year.

Fortunately, the NEM has experienced excellent reliability at the level of the generation and inter-regional transmission system to which this standard applies and NEMMCO has not needed to intervene to ensure reserve capacity is provided except occasionally. This was necessary during 2005/06 summer in Victoria due to the profile of plant availability over the summer period and the delay to the Laverton North and Basslink projects. There have been a few load shedding events due to faults affecting Bayswater Power Station in NSW in August 2004 and Northern Power Station in South Australia in March 2005 but these were due to multiple contingencies that have been addressed as discussed above by enhancing control systems.

Participants have generally met their own reserve requirements through hedging arrangements or by building their own peaking capacity such as Valley Power, Somerton, Quarantine and Hallett Power Stations following the extreme demands of the 2000/01 summer. That period became a real test of whether high prices and tight reserve margins would stimulate new capacity and the NEM participants responded with quite short lead-times to build capacity that had already been in the planning pipeline awaiting the market opportunity to proceed. In some cases (AGL at Somerton and Hallett and Origin Energy at Quarantine) it was retailers protecting their own trading positions with self-insurance because they could not buy sufficient electricity caps in the market at an affordable price. In other cases it was generators enhancing their own ability to offer insurance or to self-insure their existing contract positions against plant failure (Edison Mission at Valley Power). International Power deferred plans to augment capacity at Snuggery and Mintaro after sufficient peaking capacity has been committed to meet the market's requirements.

This satisfactory situation provides an opportunity to review the Reliability Standard without being pressured by short-term objectives that reflect immediate priorities. It also means that the unserved energy standard has not really been tested with the benefit of practical experience in operating near the limit. Accordingly we have not been able to observe the real costs of operating at the current standard which limits our ability to critique its economic value. At this stage we can only:

- make projections based upon prior experience,
- adjust the Reliability Standard if it is deemed uneconomic with current information,
- await circumstances which allows us to test our theoretical cost and value models,
- monitor system reliability in the mean time, and
- update the analysis when new information makes it justifiable to do so.

2.2 MMA'S PREVIOUS WORK AND RECOMMENDATIONS

Dr Ross Gawler of MMA has been involved in assisting NECA to review NEMMCO's work on the 2001/02 review of the interpretation of the reliability standard. He has already commented on the risk management perspectives of using reliability standards and deriving applicable reserve margins as the basis for intervention in short, medium and long-term periods.

This work by Dr Gawler reviewed NEMMCO's analysis and recommended that[4]:

1. The Reliability Panel request NEMMCO to complete the analysis of reserve levels to meet the 0.002% USE criterion for the full range of load uncertainty to provide a basis for a preliminary economic review of appropriate intervention levels for capacity management in the NEM and possible relaxation of the traditional minimum reserve level as the basis for intervention. [This recommendation was founded on a view that the basis for intervention implied that the required reliability level would never be allowed to emerge in the market because the intervention level was set at the same or lower level than the reliability standard, particularly when applying the largest unit criterion.]

2. The Reliability Panel request NEMMCO to provide more information to the market so that the 0.002% reserve margin levels can be risk adjusted for the purposes of:

    - providing a warning when the market requires intervention having regard to the prevailing uncertainty of demand and supply conditions,
    - determining Reserve Trader volumes needed to restore acceptable reliability, and

[4] Recommendations from MMA's Final Report to the Reliability Panel enttled : Assessment of NEMMCO's 2001 Calculation of Reserve Margins" dated 10 September 2002. Further comments are provided in [square brackets].

- indicating the need for new capacity in the long-term as stated in the Statement of Opportunities.

This would require the recent NEMMCO work to be extended so that USE is defined in terms of a function of regional and zonal reserve margins and other factors that affect USE. From these functions and the uncertainty in USE estimation, appropriate reserve levels may be assessed for the various short and long-term applications.

For example, more work is needed by NEMMCO to provide a basis for the operational implementation of reserve margins having regard to the surplus capacity in NSW and Queensland and the extent to which this surplus can provide additional support to Victoria and South Australia to reduce minimum reserve margins below the sum of the largest units in the two states. [The intent of this recommendation was to develop an analytical basis for a more dynamic measure of suitable reserve margins equivalent to the target level of USE reliability so that the basis for intervention could be adjusted to reflect prevailing conditions and risks instead of defined by a set of studies that might be several years out of date.]

3. If the risk management approach in (2) is adopted, a further step which could be useful in the longer term would be for the Reliability Panel to add a criterion which says that there should be a XX% confidence that USE will not exceed 0.00YY% in any one year (where XX and YY are to be specified) based on uncertainties in:

   - the market operation (weather, generation and transmission failures),
   - the market context (underlying energy growth, supply mix), and
   - modelling uncertainty (level of approximation, statistical simulation, standard error of estimated parameters).

   This would provide a quantitative way of expressing a limitation on exposure to more extreme events having regard to the uncertainties in the reserve margin analysis. It may even be defined or calibrated to match the results of observed market behaviour of participants seeking to manage their own risk position by installing new plant or taking up demand side options. In this way changes in market investment behaviour having regard to prevailing market uncertainties would be usefully signalled and there would be a stronger relationship between reserve margins sought and underlying market uncertainty in the short, medium and long-term views.

In summary:

- The capacity to be installed in the NEM over the next several years in response to the risk management imperatives of market participants is expected to well exceed the Reliability Panel's minimum service criterion of 0.002% of unserved energy.

- NEMMCO's analysis is based on a largest unit reserve criterion that is shown to provide a higher standard of reliability than the Reliability Panel considers is required for the NEM.
- This simple approach is too conservative when inter-regional load diversity and reserve surpluses are available to support an adjacent region but this is not taken into account under this methodology[5].
- Thus this standard would result in additional costs to the market if it became a basis for intervention by NEMMCO. This is unlikely in the medium term as NEM participants in managing their own risk profile are exceeding the Reliability Panel's reliability standard. However, use of these same standards for short-term forecasts of low reserve conditions, failing to take into account known facts with regard to the actual system condition, may lead to unnecessary and potentially costly directions to market participants.
- If NEMMCO were to take a less conservative approach in future reviews, then more attention would need to be given by NEMMCO to quantifying the impact of market uncertainties in the analysis and defining how the uncertainty in the assessment affects how the reserve margin standard is to be applied in each application using risk management principles
- The Reliability Panel should endeavour to stimulate operational and regulatory mechanisms to ensure that reserve margins as they are assessed and applied reflect the prevailing level of uncertainty about the relevant market conditions.

2.3 PROGRESS SINCE MMA'S WORK AND NEMMCO'S REVIEW

There has been some progress by NEMMCO since that time. Although MMA has not had the opportunity to follow all of the consequential work, it is known that NEMMCO has devoted more effort to:

- Validating estimates of and tracking trends in the forced outage rates of thermal plant. The level of forced outages influences the relationship between reserve margin and energy not served with higher forced outage rates requiring higher reserve margins to achieve the same level of energy not served.
- Quantifying the impact of inter-regional load diversity and transmission constraints in the modelling of reliability and inter-regional capacity support and in specifying the minimum reserve margin consistent with the energy not served criterion.

[5] This has since been corrected by NEMMCO as discussed in section 2.3.

- Combining Victoria and South Australia as one zone for the purposes of defining reserve margin requirements because of the infrequency of constraints between these regions after development of Pelican Point and Murraylink and the return of Playford Power Station to service.

- Providing a supply/demand calculator as part of the Annual Statement of Opportunities so that estimates of required generation capacity can be made by participants.

The most recent work by NEMMCO has refined the allocation of reserve to the NEM regions in 2004/05 with:

- 530 MW required in Victoria/SA to match the largest unit principle.

- 610 MW required in Queensland because of the flatter peak load characteristic, the higher forced outage rates for base load plant and the export of power from Queensland to NSW on a regular basis.

- A net -290 MW required in NSW allowing for the remaining spare capacity in Queensland and support from the southern regions.

This most recent work has better represented the impact of load diversity and the optimal sharing of reserves across the NEM regions.

However there appears to have been no progress on the question of better quantifying the impact of market uncertainties and adjusting intervention and planning indicators to reflect risks, lead times and uncertainties related to varying time frames. Given the recent period of generally low prices in the NEM since 2000/01 and the lack of major commitments to new capacity except Laverton North and Kogan Creek, the need for reliability indicators and planning metrics for investors and Governments is expected to become more critical in the next few years.

2.4 RELIABILITY AND SECURITY

As indicated in the Terms of Reference there is some confusion between the application of reliability and security criteria in managing reserve margins in the NEM.

Reliability relates to how often and by how much supply to firm load might be disrupted due to inadequate generating capacity and interruptible load to maintain a continuous supply. An unreliable system has frequent disruptions to customers who otherwise require and expect continuous electricity service for their contracted demand requirements.

Security relates to the confidence that an electricity system would achieve a new stable operating condition after a disturbance. That might require some load shedding of interruptible load and some tripping of generation after an event to achieve a new stable state but continuous supply to other parties would not be threatened. To make an insecure system secure, sometimes it is necessary to commit emergency plant, rearrange network connections or reduce load to protect the system against a credible contingency.

It is possible for an unreliable system to be secure at all times and for a reliable system to be occasionally insecure depending on operating practices. An insecure system is usually unreliable because when disturbances occur there is generally a cascading of disconnection events that causes substantial loss of supply over a wide area. These concepts are related but different. All four combinations of unreliable/reliable and insecure/secure are possible in theory. An insecure system could be reliable if disturbances were extremely rare but this does not happen in practice for large scale electricity systems.

2.5 LESS THAN THE LARGEST UNIT

Based on the 2001/02 NEMMCO review and the more recent work in 2004, except for Queensland, the reserve capacity required to meet the reliability standard on an average basis for a typical set of planning assumptions related to loading patterns, fuel supply, plant reliability and interconnection performance can require LESS than the largest unit for meeting the 10% POE peak demand. This has been difficult for jurisdictions and market participants to accept for a number of reasons including:

- It is counter-intuitive for most people that a reliable large scale electricity system would have insufficient capacity to meet a peak demand (however defined[6]) with the largest generating unit out-of-service.
- It is difficult to understand how reserves may be shared across an interconnected power system when seasonal peaks are at different times of day, month or year. Taking reserve sharing into account avoids excessively conservative assessment of reliability and required system capacity to meet the reliability standard.
- A system carrying a peak demand in excess of operating capacity less the contribution of largest unit would be reliant on post-contingency under-frequency load shedding to maintain secure operation after loss of that unit. Therefore there is a perception of excessive reliance on sophisticated control measures to secure a system under such conditions and that any doubts by operators may cause them to shed load before any contingency to keep a satisfactory level of security. If such operator behaviour were not modelled in the reliability analysis then the reliability of the system may be over-stated in such circumstances.

[6] The definition of peak demand can vary according to averaging period and associated weather conditions. A peak can be defined as related to instantaneous, a four second sampling period as used for transmission system monitoring and control, a five minute average (the dispatch cycle), or a half-hour average as used the settlement period. The peak may be defined according to the associated weather conditions which are exceeded with 90%, 50% or 10% probability in a peak season (summer or winter),

- Traditional standards of generation reliability have related to reserve margins of up to 20% to 30% depending on generation technology and performance, system loading conditions and inter-regional support and such levels seem much greater than the NEMMCO standard. Commentators sometimes overlook that the NEMMCO standard refers to the 10% POE demand that is expected to be exceeded for about 15 minutes[7] once every ten years whereas larger reserve margins often relate to average peak conditions that may be exceeded for one half-hour once per year on average.

- Standards based on reserve margin cannot be compared between systems that have differing climate and generation resources and different development risks. Because of the complexity of this aspect of comparative system reliability, incorrect conclusions can be drawn by considering only reserve margins and not the nature of the underlying risk in terms of customer impacts and associated costs.

- This confusion is further compounded by assumptions that capacity must be provided in terms of generating capacity and that the role of demand side management for extreme demand conditions is not well understood or promoted. Of course setting conservative intervention levels also serves to undermine the role of demand side and encourage excess capacity disproportionate with the risks and economic costs.

MMA recognises that a more rigorous approach to capacity risk management and reliability would require a paradigm shift and a major re-education process that may be quite difficult and not offer substantial overall benefit given the difficulties in gaining stakeholder commitment. However there are some incremental improvements that could be made to better inform investors and Governments relating to:

- An economic justification for the reliability standard having regard to the cost of supply interruptions to customers and the cost of reserve capacity.

- The relative economic contribution of new generating capacity and demand side withdrawal to meet the reliability standard.

- The specification of a reliability standard that defines the exposure to and the potential customer cost of more extreme events rather than just specifying a long-term average that is in fact currently applied as an annual minimum rather than a long-term average.

2.6 RELIABILITY PANEL OBJECTIVES

The key objectives of the work proposed by the Reliability Panel involve:

[7] We say 15 minutes here as the peak refers to the average over half an hour and we would expect the load to exceed this level in about half of the settlement period on an instantaneous basis.

- A review as to whether the unserved energy standard for reliability is appropriate.
- Assessing the application of the standard on a regional basis.
- Assessing the appropriateness and impact of its application across various planning periods.

The manner in which NEMMCO determines the minimum reserve margin from the reliability standard is not an issue to be resolved in the Reliability Panel project. However, MMA considers that the feasibility of developing an effective operational practice that would deliver the reliability standard if there is market failure must be a criterion in the review process.

Given the applications of the reliability standard, the Reliability Panel project will involve considering how changes to the reliability standard will affect market participants and the market as a whole. The NECA Terms of Reference has identified the major impacts affecting:

- the assessment of risks and commitment to investment by market participants,
- the economic evaluation of regulated interconnector transmission investments to meet a regional reliability standard,
- the incidence of Reserve Trader activities of NEMMCO and the imposition of costs upon market participants, and
- the incidence and impact of reliability directions by NEMMCO.

2.7 ECONOMIC OBJECTIVES

The EUAA is clearly seeking to ensure that reliability standards are founded on an economic basis. This does not seem to be an explicit focus of the Reliability Panel review, although the questions in the Issues Paper do raise the appropriate basis for the standard in general terms. MMA considers that the standards should be defined on an economic basis and in particular take into account the potential economic impact of electricity shortages and restrictions when they are applied by Governments in response to imminent disruption to supply. To do this properly requires an understanding of not only the average level of energy not served but the incidence of major disruptions that might occur and be economically avoided by installing additional transmission and generation capacity. The objective of the study reported here is to start down the road of exploring these issues using available information and to make an initial assessment of where the optimal level of unserved energy might be for each of the load serving NEM regions as currently structured.

2.8 BASIS FOR QUANTITATIVE ANALYSIS

MMA used its Strategist and Plexos market simulation packages in the current project. These packages were used to assess such quantitative factors as:

- Confirm the level of energy not served in NEM regions for specific time periods up to the 2009/10 financial year.
- Confirm the probability distribution of the magnitude of energy not served per event and the time between incidences of power shortage.
- Confirm the relationship between capacity reserve margin and expected energy not served for a given supply/demand scenario.

For these statistics, and following discussion with NEMMCO, we examined the propensity of Governments to impose restrictions and relate that to the economic costs that have been reported in the past arising from such restrictions. This provides an initial basis for testing whether an average 0.002% is economically sustainable having regard to:

- The economic cost to customers of supply interruptions of varying magnitudes based on previous analysis by industry groups.
- The cost of energy not served as revealed by customer surveys (average $30,000/MWh over the whole market according to recent surveys by Monash University and Charles River Associates).
- The cost of holding reserve peaking plant, assumed to be a minimum of $100/kW/year.

3 METHODOLOGY

3.1 MINIMISING TOTAL SUPPLY COST

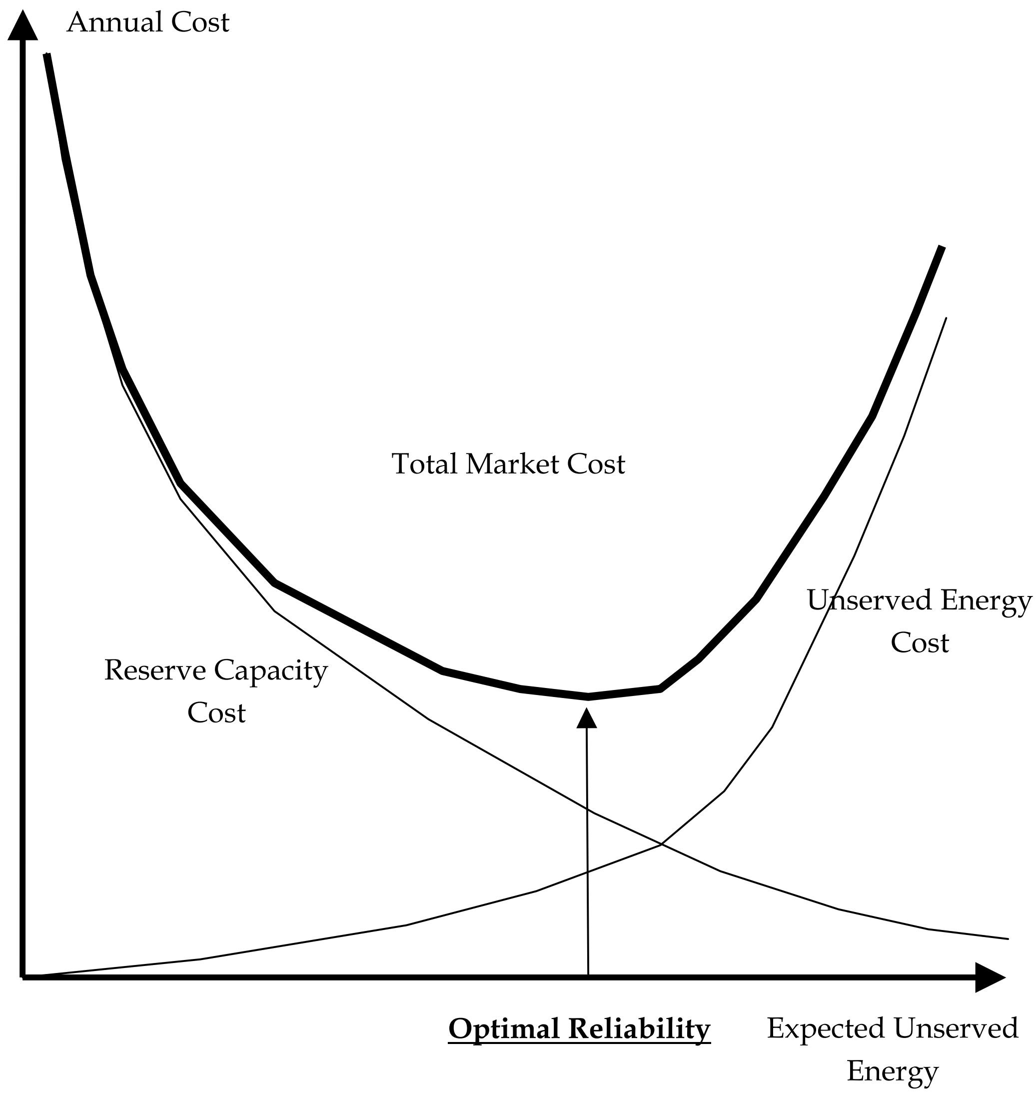
The overall methodology involved:

- Developing a concept of costing supply interruptions events to customers in each NEM region according to load shedding policies and demand side resources available and applied,
- Quantifying the elements of the concept from existing information and discussions with NEMMCO,
- Using market modelling to relate installed capacity to exposure to supply interruptions and developing functional description for optimisation purposes,
- Quantifying the magnitude and duration of interruptions and costing their impacts as a function of regional capacity and unserved energy,
- Adding the costs of reserve generating capacity or demand side participation when more economic, and
- Calculating the level of expected unserved energy that provides minimum total costs to participants across the NEM. We do not assume that all market costs are passed on to customers but rather quantify the supply chain costs from fuel and capital inputs through to customers costs of unreliability. The fuel cost savings during supply interruptions have been neglected for convenience because they are so much less than the customer impacts.

The concept representing the trade-off between capacity cost and supply interruption cost is illustrated in Figure 3.1. As you move toward zero expected unserved energy, the amount of required system capacity becomes extremely large[8]. This occurs because generating resources are not perfectly reliable and therefore system costs tend to infinity as more and more capacity is added to gain a small improvement in reducing unserved energy. Thus the capacity curve progressively becomes more vertical and approaches the cost axis in the chart. At zero unserved energy, the customers' costs of unserved energy are also zero and they rise approximately linearly with unserved energy at first. As the amount of unserved energy increases, higher and higher value services would be interrupted within the practicalities of managing supply shortages on a contingency basis and therefore the cost of interruptions progressively rises more rapidly as the total expected volume increases. Eventually the interruptions would become so severe that Government would introduce restrictions on consumption and a

[8] Tends to infinity in mathematical terms

Figure 3.1 Concept for Optimal Reliability Standard



much greater amount of energy would be unserved. If we consider the horizontal axis as the amount of unserved energy that would occur without restrictions applied (as modelled in a standard market simulation) but apply the costs of imposed restrictions for severe events, then the exposure to these events increases as the expected unserved energy increases and the costs to customers increases exponentially. The required amount of reserve capacity reduces and therefore the generation costs decline as the amount of unserved energy increases. Evidently there must be a point at which the total cost of generation and unserved energy is at a minimum and this represents the idealised optimal reliability level that would minimise the service costs and maximise the benefits to market participants over a long period of time. The structure of customer interruption costs is discussed further in section 3.4 below.

3.2 COMMERCIAL VIABILITY OF RELIABILITY STANDARD

An important question is whether the optimal level of reliability could ever be realised without market intervention. This is a complex question to consider because it depends on the commercial processes that drive the timely commitment of new capacity. It was beyond the scope of this project for the EUAA. However, we have examined the market simulations to assess whether there is evidence that an optimal standard could be sustainable with the current level of Value of Lost Load (VoLL). The concept is illustrated in Figure 3.2. At zero unserved energy, infinite capacity would be required and very likely, a high level of competition so if this state could exist we would expect market prices to approach marginal cost as reserve capacity increases and unserved energy reduces. In practice there may remain some market power and any price above marginal cost would reflect imperfect competition as illustrated by the "premium available for partial competition" in Figure 3.2. This concept could apply to time weighted prices relative to base load capacity, peak period prices relative to the costs of intermediate capacity and prices in the tail of the price duration curve relative to peaking capacity.

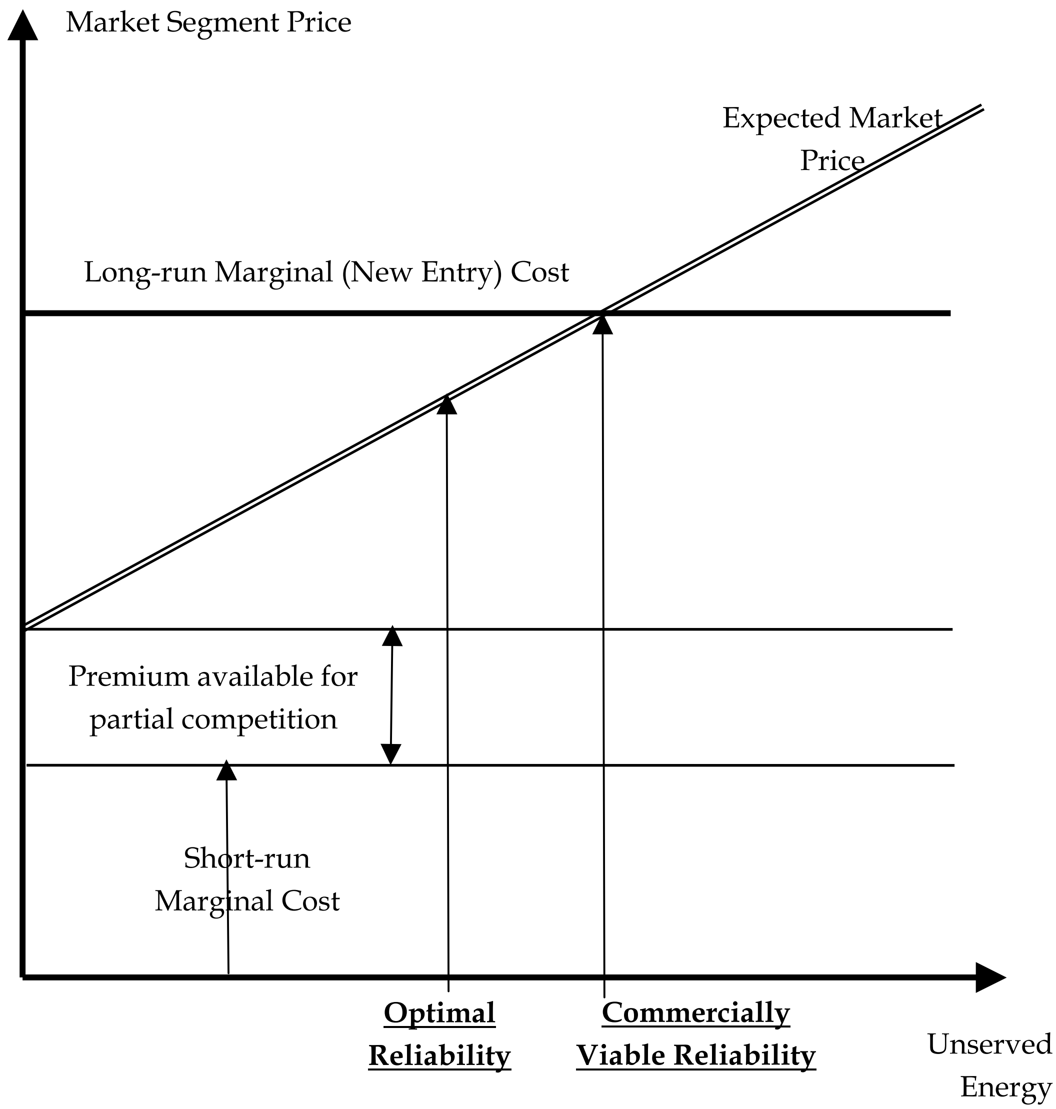
It is expected that the market price would be approximately linear with unserved energy because of the contribution at the Value of Lost Load price being proportional to the duration of load shedding.

The NEM market simulation was conducted for the five financial years from 2005/06 to 2009/10 for a medium economic growth scenario with three peak demand levels (90%, 50%, 10% POE). The relationship between expected unserved energy and reserve margin was assessed including the incidence of disruption events and the probability that restrictions would be implemented based on an analysis of those statistics. Over the range of about 0.001% to 0.004% (and 0.008% in some cases) we examined the potential economic costs of disruption and reserve plant costs to see where the optimal lies for each region separately and for the NEM as a whole if the same standard were used throughout.

A separate set of runs using a market gaming strategy were conducted to obtain the corresponding estimate of market prices associated with each reliability level[9]. NEM prices were extracted to ensure that new entry prices are still sustainable under each of the reserve margin levels. If prices remain consistently lower than new entry prices, this would indicate that NEMMCO would need to be regularly intervening as the Reserve Trader to ensure the required reserve margin levels are met. The results showed that the proposed reliability standards would be very likely to be delivered through market prices because of the level of market power in the NEM.

[9] The reason a second set of runs were done to assess prices was that the simulations to assess reliability were very time consuming and short-run marginal cost bidding solution gave lower run times than if price gaming were included. Also, less simulations were needed to obtain price information so overall it was quicker to conduct separate simulations: the SRMC simulations to obtain reliability parameters and the gaming simulations for price.

Figure 3.2 Relationship between unserved energy and market prices



3.3 STAGES OF WORK

The stages of work in the project were:

- Research the historical cost of supply interruptions versus severity based on press releases and EUAA information.
- Research data from customer surveys on the value of energy not served in relation to the duration of interruption.
- Prepare an assumptions report as the basis for NEM simulations using Plexos.
- Set up NEM simulations with three levels of reserve in each region over the next five years for a projected expansion sequence in the market.

- Determine the reserve and interruption costs as a function of reserve capacity and assess an optimal outcome as a function of reserve plant costs and customer reliability costs.
- Identify a reliability standard that is economically sustainable.
- Prepare a draft and final report that identifies an indicative economic basis for a reliability standard and the need for further analysis. This report represents this stage of the project.

3.4 A MODEL OF USER INTERRUPTION COSTS

The assessment of the costs of unserved energy has previously been limited to typical or average levels either over the system as a whole at about $30/kWh load weighted average value, or by market segment ranging between $1/kWh for brief residential interruptions up to $100/kWh in large commercial buildings. Some industrial processes such as aluminium smelters have even lower interruption costs for short periods of disruption, at about $0.30/kWh.

The marginal cost of unserved energy should not be confused with the NEM concept of VoLL, the value of lost load. The former is quite variable according to what kind of customer is affected during a supply shortage and for how long. The latter is merely a price cap in the NEM to manage extreme supply/demand imbalance risks. Previous surveys had estimated an average cost of unserved energy on a load weighted basis across the market of about $30/kWh. Such a measure is relevant to risks that cause a total shut-down of the system where all customers are equally affected. This project has provided a guide to the level of the marginal unserved energy cost but there remain some substantial uncertainties in the analysis as discussed in section 3.5.

This project attempted to link the results of the system simulations to the characteristics of the patterns of interruption using the following principles:

- Costs of unserved energy relate to who is disconnected and for how long.
- Who is disconnected depends on how much load reduction is required and for how long.
- Interruptions progress from low value uses to high value uses in the order of:
    - Disconnect "interruptible" industrial load that must be restored within 1.5 hours and which is most often used to provide spinning reserve and to manage frequency transients and short-term capacity constraints in the electricity market,
    - Disconnect residential areas with rotational load shedding with 2 hour durations,

  - Interrupt mixed small commercial and residential areas for longer periods typical of suburban zone substation loads excluding high value services such as hospitals and commercial centres with office blocks,
  - Interrupt commercial and industrial areas for longer periods,
  - Apply residential restrictions over days to manage longer term capacity limitations,
  - Apply restrictions to small commercial customers over days to manage longer term capacity limitations,
  - Apply restrictions to larger industry over days to manage longer term capacity limitations,
  - Note that a MW level is defined at which the next level of interruptions is applied in 2005/06 and the levels increase according to the energy growth forecast[10].
- The priority for interruption was to be tailored to the policies applied in each jurisdiction which were discovered by MMA to be different in the course of the project.

The five parameters describing the characteristics of an event of unserved energy as obtained from the market simulations were[11]:

- The time since the end of the last supply interruption – if this is less than 40 hours and the load at risk represents more than 5% of the peak demand, we would deem the supply shortage to be of such importance that Government intervention is likely and restrictions would be applied over contiguous days with supply interruptions. Thus the first day after a day without supply interruptions is regarded as unplanned load shedding. Subsequent days are then priced as if they were restricted if load interrupted would be more than 5% of the annual peak demand. If interruptions are less than 5% they are priced as if they were continuing unplanned interruptions. This is illustrated in Figure 3.3. When the peak load shed exceeds 5% restrictions are declared and apply on consecutive days until load shedding no longer occurs in the simulation. On restricted days the load shed is priced at the restriction price rather than the load shedding price.
- The time to the next supply interruption – if there is one or more days delay until the next interruption then restrictions would cease on the assumption that any continuing capacity shortage would be managed by rotational load shedding rather

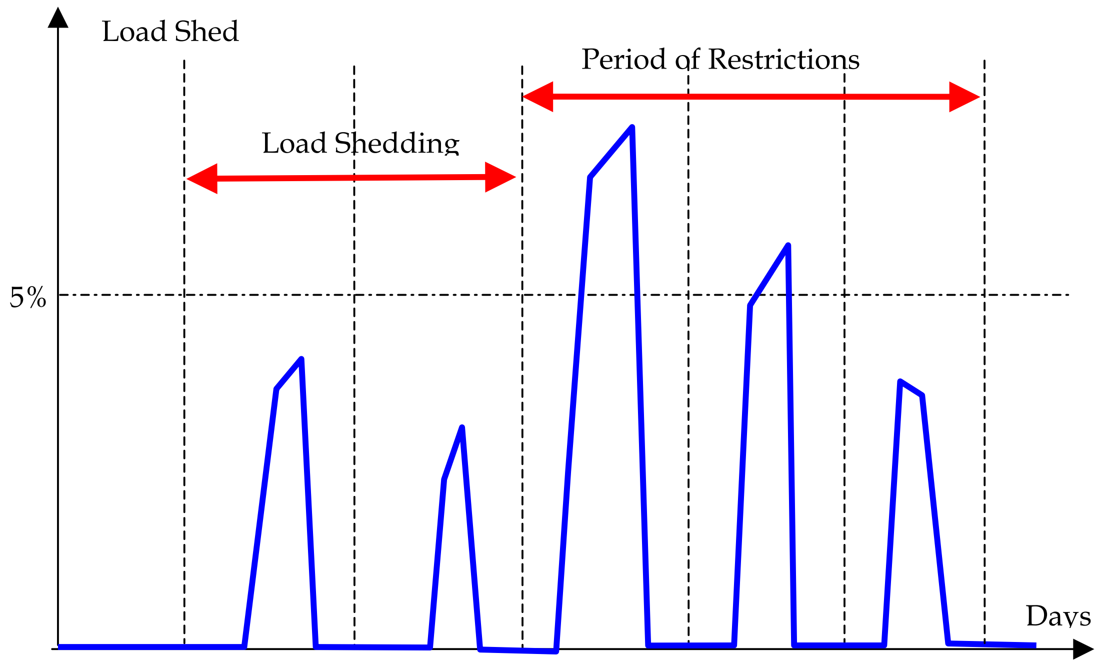
[10] The energy growth forecast is used in an atttempt to exclude the impact of large industrial loads which are not changing. A more detailed model would examine the growth in each market segment but that level of detail is not warranted as yet because the reliability value model is still being developed.

[11] It was intended that some of these parameters would be derived from actual load shedding policies but that was not possible because the jurisdictions refused to provide sufficient information. Therefore, we have developed a speculative view based on MMA's understanding of the electricity market.

than imposing limitations more widely. The cycle of analysis of unplanned outages and/or restrictions starts again.

- The duration of the outage in hours to the nearest half-hour as observed in the Plexos simulation. This parameter was used to schedule rotating smelter load interruptions over periods of up to 6 hours.

Figure 3.3 Concept for Designating Interruptions and Restrictions



- The maximum demand interrupted during the event – this determines which market sectors are deemed to be interrupted. This was determined half-hourly from the Plexos simulation. The load to be shed was assumed to be fixed and was varied for time of year and time of day and this level of complexity was not warranted by the quality of the input data.

- The unserved energy during the event assuming no additional restrictions were observed – these values are cumulated in each year to estimate expected unserved energy

At the simplest level we could ignore all the parameters except the cumulative unserved energy and apply the average cost of unserved energy at $30/kWh. Some examples using this principle including one that formed the basis for the justification of the project are discussed in Sections 4.1 and 4.4 below. This method is also applied to the Plexos simulation results to show the potential impact of using a simple approach as discussed in section 4.12 below. MMA argues than an economic reliability standard would be based on average marginal value of reliability having regard to the customers affected rather than a market average value. The market average value is appropriate for managing risks of system black where all customers are affected equally.

3.5 PARAMETERS FOR DESCRIBING LOAD SHEDDING AND RESTRICTIONS

Based upon MMA's participation in a teleconference of Jurisdictional Co-ordinators (JC) on 5th October 2005, the following understanding was gained as to load interruption policies in each of the states. The JC's agreed to provide a written summary of their policies but this was never received despite MMA following up the request with VENCorp several times. The analysis has been done in this manner to illustrate the complexity of analysing the costs of unserved energy and the potential significance of the key parameters.

The description of policies excludes the arrangements for contingency load shedding to deal with the requirements for frequency control following loss of a large generator. This is mostly achieved by shedding smelter load until reserve generation can be started to replace the lost capacity.

The following approach was adopted as described in the following sub-sections:

3.5.1 South Australia

3.5.1.1 Policy

In South Australia, there is some water pumping load which is bid out of the market as demand side management under high prices. If further load shedding is required, the next customers off are residential customers and small business. If supply interruptions are expected the next day as well, rationing would occur to stabilise the market on a planned basis rather than have unplanned load shedding.

3.5.1.2 Interpretation

The shedding of water pumping load was treated as available for up to 4 hours at a cost of $1/kWh. The estimated cost is low because it is generally possible to reschedule water pumping without major customer impacts. There are some risks with delayed pumping and so a nominal amount has been allowed. The volume was assumed to be about 100 MW. None of these parameters are accurately known to MMA. These are indicative estimates.

Above 4 hours and above 100 MW it is assumed that the interruption cost is based on residential customers up to 300 MW at $1/kWh and then 200 MW of small business customers at $50/kWh above in the steps shown in Table 3.1. The volumes are shown for 2005/06 and, except for water pumping, they are assumed to grow at the energy

Table 3.1 Indicative Unserved Energy Costs by Jurisdiction as Modelled

Stage	SA	Vic	NSW	Qld
1	Water pumping	Aluminium smelting	Aluminium smelting	Rotational shedding
Volume	100 MW	600 MW, 900 MWh per event 4500 MWh limit per year	800 MW, 1200 MWh per event 6000 MWh per year	1500 MW
Time	<= 4 hours	< =6 hours	< =6 hours	< =8 hours
Cost	$1/kWh	$0.3/kWh	$0.3/kWh	$20/kWh
2	Residential Shedding	Residential Shedding	Residential Shedding	
Volume	300 MW	1000 MW	1600 MW	
Time	<= 8 hours	<= 8 hours	<= 8 hours	
Cost	$1/kWh	$1/kWh	$1/kWh	
3	Small Business Shedding	Small Business Shedding	Small Business Shedding	
Volume	200 MW	800 MW	1300 MW	
Time	<= 8 hours	<= 8 hours	<= 8 hours	

Stage	SA	Vic	NSW	Qld
Cost	$50 /kWh	$50 /kWh	$50 /kWh	
4	Large Commercial Shedding	Large Commercial Shedding	Large Commercial Shedding	
Volume	600 MW	1200 MW	2000 MW	
Time	< = 8 hours	< = 8 hours	< = 8 hours	
Cost	$100/kWh	$100/kWh	$100/kWh	
5	Residential Restrictions	Residential Restrictions	Residential Restrictions	
Volume	500 MW	1500 MW	2000 MW	
Time	> 8 hours	> 8 hours	> 8 hours	
Cost	$20/kWh	$20/kWh	$20/kWh	
6	Business Restrictions	Business Restrictions	Business Restrictions	General Restrictions
Volume	The balance	The balance	The balance	The balance
Time	> 8 hours	> 8 hours	> 8 hours	> 8 hours
Cost	$250/kWh	$250/kWh	$250/kWh	$100/kWh

Notes to Table 3.1

1. Capacity levels are described for 2005/06 and are escalated at the respective State's energy growth rate per annum to 2009/10 (with the exception of the smelter loads which remain constant).

2. The Monash study undertaken by Kahn and Conlon in 1997 estimated the cost of residential load at around $0.74/kWh. CRA found that the value of unmet residential load at between $3.8/kWh and $21.1/kWh and explained the difference between its results and the Monash findings as the "result of the absolute versus unitised approaches to the way the costs were presented in the two studies". We are unable to fully understand this explanation as the full details of the studies are not available to be examined.

3. For the business sector, CRA estimated the value of lost load at $56.67/kWh while the Monash study estimated it at $76/kWh. These were also differences in the large industrial sector. Monash estimated the sector's VoLL at around $11/kWh and CRA at $18/kWh. A similar difference also occurred in the estimation of the value of unsupplied energy to the agricultural sector with Monash estimating a value of $96/kWh and CRA's estimate was around $55/kWh.

4. Restriction as are estimated as per kWh of load shedding replaced by restriction rather than per kWh of restricted load.

growth rate of the medium forecast published in the NEMMCO Statement of Opportunities 2005.

Above 600 MW or above 8 hours duration, restrictions would be imposed on residential customers and then commercial customers. The financial cost of restrictions to residential customers are likely to be higher than unplanned load shedding as some would seek to minimise the inconvenience by purchasing appliances such as backup batteries, torches, gas lights and barbeques. We assume that the cost is twice that of unplanned load shedding. The potential value is also increased due to the assumption that the load restricted would be ten times the load shed on an unplanned basis. Therefore the potential value is $20/kWh of avoided load shedding for residential customers.

The potential value of restrictions to commercial customers is assumed to be five times the standard value to represent the assumption that the load restricted would be ten times the load shed on an unplanned basis but at half the cost because these customers could prepare to minimise their losses. These estimates are indicative.

3.5.2 Victoria

3.5.2.1 Policy

Victoria has provision for limited interruption to aluminium smelter loads of up to 900 MW for 1.5 hours. After two hours the aluminium pots would freeze over at very high cost for recovery. We assume here that 600 MW of this capacity could be used to rotate for interruption periods of up to 6 hours. This gives us a range of 600 MW for 1.5 hours, 300 MW for three hours or 150 MW for 6 hours. There are restrictions on the number of interruptions over a period of time. These constraints could be modelled to make a more refined estimate but the information is not public and the effort is not warranted given the other uncertainties. We assume there is an annual limit of five times this amount, say 4,500 MWh of smelter shedding. No other information has been provided by VENCorp. MMA has assumed that priority shedding applies in the same way as assumed for South Australia and detailed in Table 3.1.

3.5.2.2 Interpretation

We assume a value of $0.3/kWh[1] as the cost of load shedding based on the replacement cost of aluminium plus a risk margin. The average energy value based on the price of

---

[1] Aluminium value is US $2,500/tonne = $A3300/tonne. Portland uses 580*8.76 GWh electricity to make 345,000 t per annum. Thus the average intensity is 580*8.76/345 = 14.73 MWh/t. So the marginal value is 3300/14.73= $224/MWh.

aluminium is about $224/MWh. It would be somewhat higher than this because some of the electricity is needed even if aluminium is not produced and there is a risk in interrupting the aluminium pots that they will not be able to be reconnected soon enough to avoid damage due to other plant failures.

The volumes and values have been adopted as shown in Table 3.1 to represent a hierarchy of sheddable resources to manage capacity constraints. We again assume that restriction result in ten times more load lost than for unplanned outages and that the value is half the cost of unplanned outages during restrictions.

3.5.3 NSW

3.5.3.1 Policy

The NSW representative indicated that NSW first switches off residential customers on 11kV feeders to reduce load. It is understood that smelter loads[2] could also be interrupted in NSW for short-term outages. MMA understands that the smelter load is about 1120 MW. We assume that there is 1200 MWh available for short-term load shedding based in 800 MW for 1.5 hours. We assume there is an annual limit of five times this amount, say 6,000 MWh of smelter shedding.

3.5.3.2 Interpretation

We have also assumed a similar profile to that in Victoria for residential and commercial load shedding with volumes about 60% higher than in Victoria as shown in Table 3.1.

3.5.4 Queensland

3.5.4.1 Policy

MMA modelled the current arrangements as described by the Queensland Jurisdictional Co-ordinator rather than more beneficial load shedding operations where the large industrial loads are given an economic incentive to participate. Manual rotational load shedding is used to manage capacity shortages on an equitable basis "in the public interest". Industrial loads seem to be protected from interruption even though some of them may have lower costs of unserved energy. The load shedding would be spread around all sectors of the economy excluding large industrials.

---

[2] Tomago uses more than 840 MW according to its web-site. The Kurri Kurri smelter produces 165,000 t aluminium per year which would require about 280 MW of load. Thus total smelter load is about 1120 MW.

3.5.4.2 Interpretation

MMA assumes this means that the value of load shedding in Queensland may be similar to the $30/kWh average value of unserved energy. However for the purpose of this study, we have split the cost into load shedding at $20/kWh and restrictions at $100/kWh for the purpose of showing some consistency with measures in the other states as we would not expect a great divergence in value of load shedding despite the fact of apparent different policies. This is an area of considerable uncertainty in defining the optimal reliability for Queensland.

3.5.5 Discussion of parameters

Based upon a review of the literature listed in Appendix A , we have assessed approximate value of unserved energy for each segment of the market considered as shown in Table 3.1. The analytical concept is that the unserved energy obtained from the simulations ought to be priced according to the severity of the incident and whether it leads to restrictions. The level of restrictions is assumed to be a multiple of the unserved energy that would be experienced if no restrictions were applied but the cost to commercial and industrial customers would be half the standard value because of notice given. Thus relative to unserved energy as assessed the price is five[3] times higher for restrictions.

3.6 COSTING OF SUPPLY INTERRUPTION EVENTS

Initially we considered that we would assess how many of each type of event would occur at a given level of unserved energy and then determine an equivalent function of number of events and costs and relate that to the expected unserved energy. This turned out to be impractical because of the volatility of random events and the inherent noise in the results of 17 different sets of simulations.

A simpler and more effective method was to go through the 30 simulations for each of the 17 scenarios and cost each half-hour of each event according to the formulation in Table 3.1 The expected unserved energy cost was then characterised as a function of the expected unserved energy or the regional capacity with a regression function in an attempt to filter out the sampling error.

Each interruption event was costed based on its key parameters:

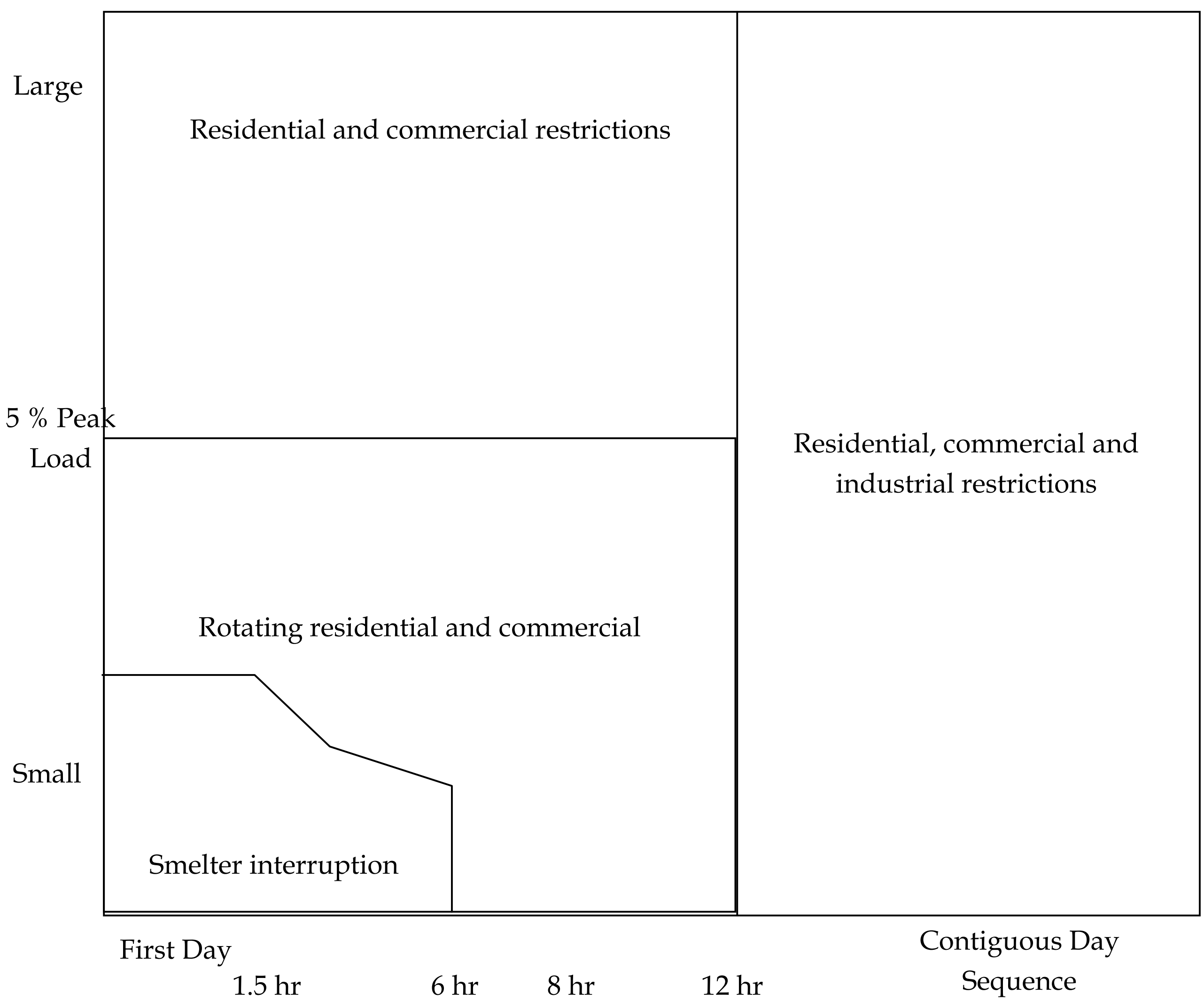
- Time since last interruption,

[3] 10 times the volume at half the value = 10/2 = 5 relative to unserved energy without notice.

- Size relative to 5% of peak demand, and
- Unserved energy for the event.

Figure 3.4 illustrates the typical volume and time dimension of the analysis in accordance with the principles of Table 3.1.

Figure 3.4 Time and Volume dimension of the analysis



The smelter interruption can represent rotating interruptions between 1.5 and 6 hours for the given total MWh block. The smelter interruption is limited on an annual basis for the more extreme situations. This gives some non-linearity to the cost of unserved energy function versus volume.

As magnitude and duration increase there is provision for implementation of restrictions that increase unserved energy supplied by a further factor of 5. Unserved energy events that extend beyond 8 hours and 5% of system demand are deemed of sufficient severity to warrant rationing to secure the stability of supplies and to share the pain of the shortage. A fully optimised load shedding policy would consider the threshold at which more broadly based restrictions would be preferred over load shedding as you go.

3.7 MARKET AND RELAIBILITY ANALYSIS PROCESS

The processes in the market analysis are illustrated in Figure 3.5. The figure shows how the market simulation data and the customer interruption data are related, compared and used.

The following steps were involved:

1. An initial trial and error method was used with 30 Plexos simulations to establish a capacity range for each NEM region such that the expected unserved energy would be in the approximate range of 0.001% to 0.004% to cover a binary order of magnitude higher and lower than the current 0.002%. This was the range in which we expected to find the optimal unserved energy based upon industry practice and the preliminary analysis discussed in Section 4.1 below.

2. Thirteen sets of regional capacity were formulated with three different values in each region in combination with a view to obtaining unserved energy in the target range. The capacity levels were intended to span the target range of unserved energy between 0.001% and 0.004%. The combinations are catalogued in Table 3.2. (0) represents a capacity level at which 0.002% is expected, (-) represents 0.004% and (+) represents the capacity level for 0.001% expected unserved energy. Subsequently, an additional 4 states were included with lower capacity values in SA and Victoria to obtain a wider range of unserved energy. Half of the capacity states in each state were aimed at being close to the standard level of unserved energy. Inter-regional support is represented in Plexos through the PASA/Preschedule algorithm. This LP algorithm optimises transmission line reserve sharing between regions, which allows it to project available capacity reserves for each region on a daily, weekly or monthly basis. The PASA algorithm also produces a maintenance schedule with the objective of maximising each region's minimum annual reserve level. Thus maintenance timing also takes into account interregional reserve sharing.

Figure 3.5 Analysis method for valuing reliability

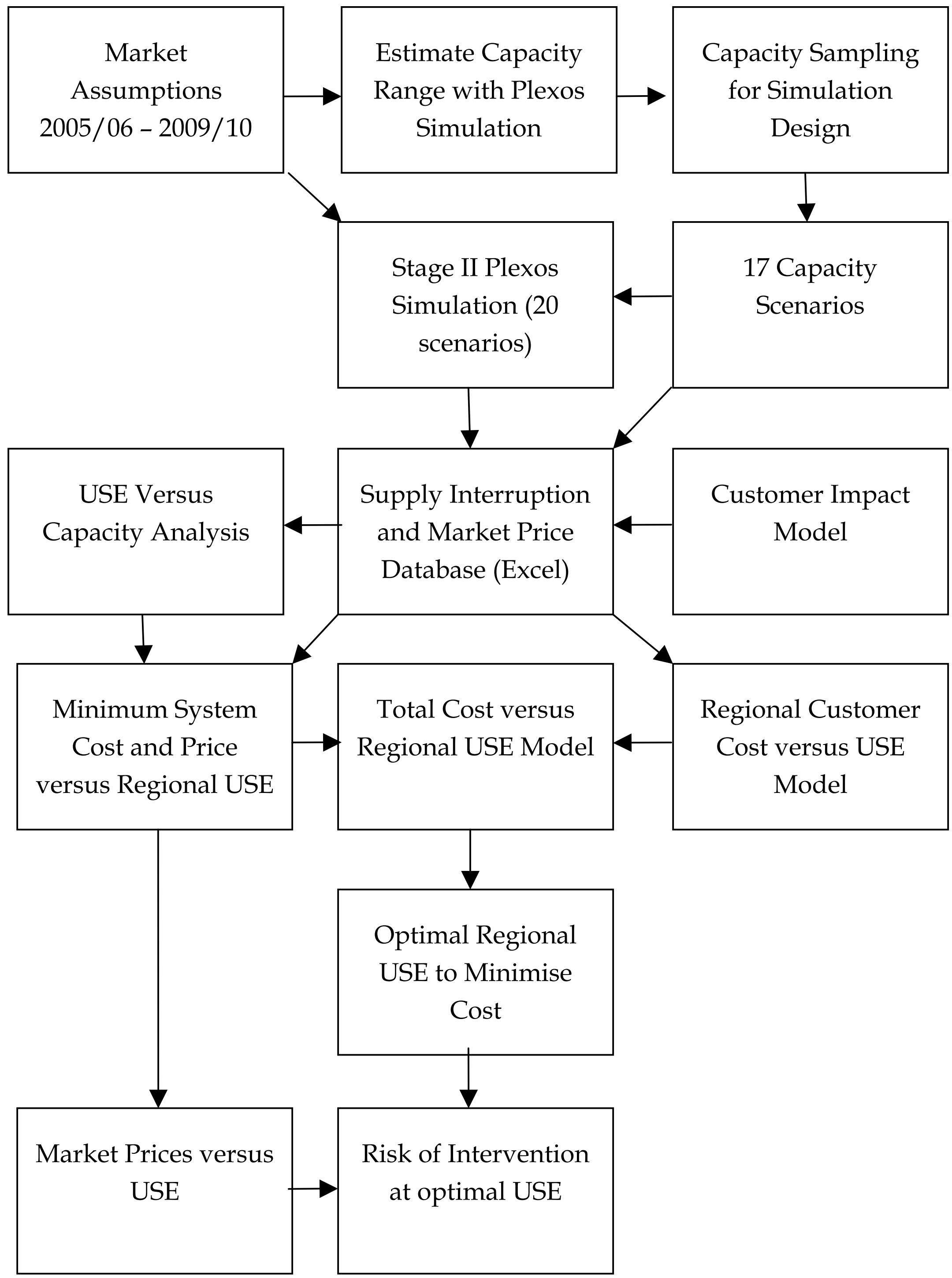


Table 3.2 Capacity states analysed

Capacity State	SA	Vic	NSW	Qld
1	0	0	0	0
2	+	-	0	0
3	+	0	-	0
4	+	0	0	-
5	-	+	0	0
6	0	+	-	0
7	0	+	0	-
8	-	0	+	0
9	0	-	+	0
10	0	0	+	-
11	-	0	0	+
12	0	-	0	+
13	0	0	-	+

Note: An additional 4 states were included with lower capacity values in SA and Victoria to obtain a wider range of unserved energy.

3. Simulations of these 17 cases were conducted with three levels of peak demand sampled at the 90%, 50% and 10% probability of exceedance (POE) level for the years 2005/06 to 2009/10 using Plexos. It was not practicable to randomly sample the load curves within the simulations. It was preferred to model each load pattern separately and to combine the analysis of the unserved energy events.

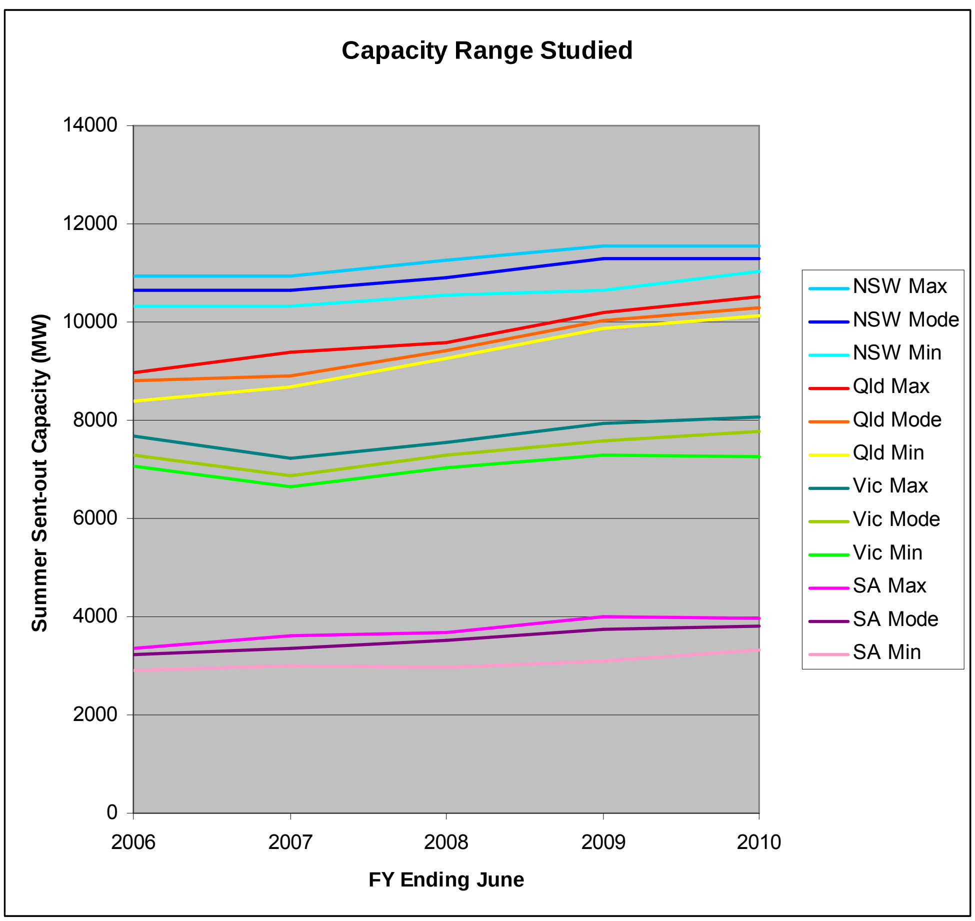
4. Unfortunately, it was found that the 90% POE load profile made a minimal contribution (less than 1%) of the total expected unserved energy only in South Australia. For Victoria and NSW its contribution was about 5% and 17% respectively, and for Queensland, which is the region with the flattest load, it contributed about 20%-25% to the expected unserved energy. The 90%POE load

trace must therefore be included in the present analysis. It was later found that the maintenance scheduling in Plexos was not optimal in the version used for the studies. Therefore we cannot be confident about the absolute capacity levels but the sensitivity of unserved energy to capacity should be reasonable.

5. The statistics of observed supply interruptions were collected into an Excel database as described in section 3.4.

6. The relationship between expected unserved energy and capacity in each region was assessed as an exponential function of a linear combination of the reserve capacity in each region relative to the 10% POE peak demand as forecast and modelled. These results demonstrated the need for some supplementary cases with lower capacity to obtain higher levels of unserved energy so that the regression versus capacity would produce better estimates of the capacity coefficients. The range of summer sent-out capacity studied in each region is shown in Figure 3.6. The total capacity data are tabulated for the 17 scenarios in Appendix C

Figure 3.6 Capacity Range Studied in each Financial Year for 17 Cases



7. For each simulation the volume and the cost of the unserved energy was evaluated. The cost was evaluated either using a standard average value of $30/kWh or using the model presented in Table 3.1 for comparison purposes.

8. The relationships between unserved energy in each region and installed capacity were determined as an exponential regression function with cost and unserved energy on a logarithmic scale. This provides an analytical relationship between a given level of capacity and unserved energy. This was intended to be used to model the trade-off between capacity and expected unserved energy and its uncertainty. In the course of the analysis it was assessed that some second-order terms would provide a more accurate function but this complicated the remainder of the analysis and resources were limited. Such extensions could be considered if the project is updated with more accurate load shedding cost data.

9. The relationship between the cost of unserved energy and the cost of reserve capacity defined from the installed capacity was derived from the 17 cases as a second order multi-variable polynomial regression function of the regional capacities. This is useful to allow us to determine the set of capacities that minimises the total cost of unreliability and reserve. Using the regression function in step 7 allows us to define the optimal reliability in each state region.

10. The change in capacity was costed at the annual fixed cost of open cycle gas turbines being $100/kW/year.

3.8 TREATMENT OF UNCERTAINTY

The main sources of uncertainty in this analysis were:

- The cost of reserve capacity which may vary according to the risks perceived by investors in bringing new reserve capacity into the market.

- Whether or not new capacity is actually required to meet the reliability criterion. For example, if in the short-term there is spare capacity then higher levels of reliability would be economically maintainable if the long-run marginal cost of recommissioning mothballed capacity were lower than the LRMC of new capacity. It would be expected that a market with capacity surplus would deliver a higher level of reliability without any regulatory intervention. The unserved energy level as the basis for intervention level could also be lower if the desire was to keep the market operating economically. However if the sole concern is reliability, then the intervention level could remain higher and need only to relate to the cost of new entry capacity.

- For a given level of unserved energy the actual cost of those interruptions given that they could occur in different ways. This was derived from examining the simulations and how the unserved energy cost randomly varied for the same or similar levels of unserved energy.

- The future market conditions that may give rise to other uncertainties which were not addressed in details as they were regarded as matters of lesser importance:

  - Different demand profiles that affect the relationship between unserved energy and reserve capacity.

  - Varying generator plant performance resulting in a different relationship between capacity levels and expected unserved energy

Table 3.3 shows how each of these uncertainties were addressed in the analysis with a view to ensuring that we do not present a more definitive assessment of optimal reliability than could be reasonable justified. The intention was to confirm a range within which the current standard might be expected to fall and perhaps to establish a better median value for each NEM region.

3.9 MARKET ASSUMPTIONS

All market modelling was conducted in December 2004 real dollars and has been reported here in June 2005 dollars.

The following summarises the market assumptions used in the study:

- The case was developed with medium economic growth only. High and low economic growth were not studied, although they should be if the reliability standard is to be used as the basis for market intervention that relates to investment activity with significant lead time as discussed in section 2.2 above.

- Only committed generators and interconnection developments as shown in Appendix B were included. All other capacity adjustments were effected by adding open cycle gas turbine plants of typical size or by removing plants as shown in Table 3.4.

- Generation parameters were as shown in Appendix B . This includes the assumed summer deratings on units, which have been taken from NEMMCO's 2004 Statement of Opportunities (SOO). The market analysis was completed before issue of the 2005 SOO.

Table 3.3 Treatment of Modelling Uncertainty

Uncertainty	Measure	Treatment	Comment	Policy Application
Whether or not new capacity is needed	If the required capacity level is below the committed capacity level then the marginal cost of capacity reverts to fixed operating costs of say $50/kW/year for an old coal fired plant which alters the slope of the capacity cost versus USE function	Considered as a potential variation in the marginal capacity cost between $50/kW/year and $100/kW/year. If capacity is in short supply, costs could increase to $150/kW/year for 1-2 years until supply is restored.	The lower cost includes some notional allowance for mothballing and recommissioning costs. This may flatten the capacity cost curve and lower the optimal USE level. Given that there is a capacity surplus the optimal level would be moved towards the actual level and the gap would be consistent with the potential value of intervention to keep marginal plant operating if economic.	The modelling suggests that the optimal reliability criterion is approximately proportional to the marginal cost of reserve capacity. This would enable an initial standard to be varied from year to year without detailed analysis. Base parameters could be updated every 3-5 years.

Uncertainty	Measure	Treatment	Comment	Policy Application
The cost of reserve capacity	Estimated from the cost of open cycle gas turbine plant at $100/kW/year .	Test the sensitivity of results to this cost by varying the input parameter. This was not examined for all studies due to limited resources.	The same capacity cost is assumed to be applicable in each region. Because of economies of scale, costs might be slightly higher in SA than in other regions because smaller GT units would be more economic.	The assessed cost of reserve capacity could be adapted to the prevailing supply/demand conditions in each regional market. The optimal unserved energy level is approximately inversely proportional to the reserve capacity cost. Variations in costs can be used to vary the standard from year to year to reflect the cost of the marginal capacity resource.
Peak load forecast uncertainty	Used historical profiles typical of 90%, 50% and 10% POE peak demands in each NEM region	Included in the market modelling for each specific capacity simulation to develop the sample of supply interruption events	Randomness of load shedding events reflects weather variation from year to year. Some of the Plexos studies showed higher levels of unserved energy for lower peak demand. This showed the influence of sampling error. There may have been some inaccuracy in the maintenance scheduling.	Weather uncertainty can be considered in deciding the type of reliability criterion: average or percentile level having regard to all uncertainties.

Uncertainty	Measure	Treatment	Comment	Policy Application
The events that make up the unserved energy	Derived from the Plexos simulations for a specific set of capacities.	Data are captured about the loss of supply events.	Each simulation gives a different set of events and a different cost of unserved energy. A statistical regression was used to relate cost to unserved energy and capacity.	Modelling uncertainty can be included in considering the uncertainty of the overall reliability measure.
Change in demand profiles over time	Formulate the demand forecast based on end-user usage profiles.	The historical system demand from each reference year was rescaled by Plexos to formulate the system shape for the future year.	There was no detailed analysis of change in system shape that might occur due to say increasing penetration of solar hot water services or microturbines for example.	Changing demand shape would be considered when market models are updated.
Generator plant performance	Forced outage probability and mean time to repair	Plexos uses uniform distribution of time to failure and either uniform or triangular distribution for time to repair. Fixed plant reliability parameters were used as per NEMMCO forecasts. Sensitivity to forced outages rates was not considered in this study.	Sensitivity to generator forced outage rate is a possible project extension. Higher forced outage rates would be expected to result in a higher optimal level of reliability because of the additional costs of providing reserve to meet a particular standard level with poorer generation plant performance.	Sensitivity to thermal plant performance can be included in the suite of Monte Carlo simulations.

This page was left blank by Word

Table 3.4 Adjustment of capacity to achieve reliability levels

	SA	Vic	NSW	Qld
Remove plant to lower reliability	Torrens Island A, Snuggery, Dry Creek and Mintaro	Energy Brix, Hazelwood and Jeeralang units	Munmorah and Liddell	Swanbank B, Callide A and Gladstone
Add gas turbines with capacity to increase reliability	130 MW	160 MW	200 MW	200 MW

- The plants removed were generally those that would be under-utilised in a surplus market due to higher operational costs or age of the plant. It was assumed that even old gas turbine plant would be maintained because the fixed costs of retaining them are usually quite low whereas steam plant requires more fixed costs per MW to maintain in operatable condition. Even when existing plant is removed the marginal cost of new capacity was still priced at gas turbine cost as this is the shadow value of capacity. Sensitivity to a lower cost which is reflective of the cost of mothballing existing plant and recommissioning later is also considered in some studies.
- Load profiles at 90%, 50% and 10% probability of exceedance were used to include the uncertainty due to weather variations. These cases were developed separately and combined in the ratios shown in Table 3.5 to represent the relationship between temperature variation and peak demand. A different combination is used for each region because the weather sensitivity of summer peak demand differs in each region. These ratios were developed by means of the application of the Miller and Rice[1] method for representation of continuous distributions by discrete distributions.
- Emission abatement was included in the modelling to ensure targeted levels of gas fired generation in Queensland and emission abatement in NSW. This affects production cost and market prices but not reliability.

[1] Miller A C and Rice T R, "Discrete Approximations of Probability Distributions", Management Science, Vol 29, No 3, March 1983.

Table 3.5 Combinations of peak demand cases to represent weather sensitivity of peak demand

Region	Probability of Exceedance		
	90%	50%	10%
NSW	26.4%	47%	26.6%
VIC	36.8%	37.8%	25.4%
QLD	23.1%	50.8%	26.1%
SA	27.0%	47.0%	26.0%

3.9.1 Demand

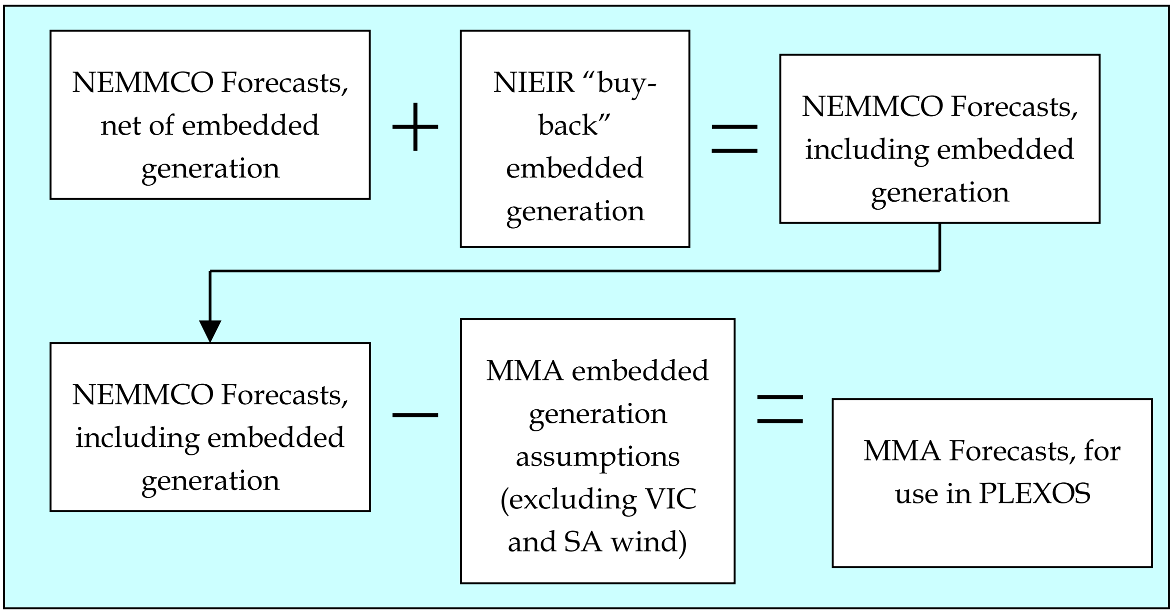
The growth trend for the demand forecast adopted by MMA is based on NEMMCO's 2004 SOO and applied to the 2002/03 actual half-hourly demand profiles[2]. We have used the 2002/03 load shape for all States as it reflects demand response to normal weather conditions and captures the coincidence in demand between States. NEMMCO's forecast was originally developed by the National Institute of Economic and Industry Research (NIEIR).

NEMMCO's forecasts already included a level of assumed embedded generation, as projected by NIEIR. However, MMA provides independent forecasts of the renewable energy projects, cogeneration, and other energy efficiency schemes that are likely to enter the market. Therefore, MMA adjusts the NEMMCO forecasts presented in the SOO to add back in the "buy-back" component of the embedded generation. MMA's Strategist model is then used in conjunction with a renewable energy model to explicitly project the renewable energy and DSM developments.

MMA's PLEXOS model does not explicitly model embedded generation, other than wind in Victoria and South Australia. Therefore, it is necessary to remove MMA assumptions on renewable generation and energy efficiency from the total energy and peak forecasts prior to modelling the scheduled dispatch in PLEXOS. The steps involved in converting the NEMMCO forecasts to MMA forecasts for PLEXOS are summarised in Figure 3.7. The resulting forecasts for sent-out energy and peak demand are shown in Figure 3.8. The peak demands illustrated are those with the 50% probability of exceedance (POE) in each region in each season.

[2] For Tasmania the 1999/2000 actual half-hourly demand profile was used as the 2002/03 profile was not available.

Figure 3.7 Steps involved in converting NEMMCO forecasts for use in PLEXOS



Note that these forecasts also include the following assumptions on future load:

- An expansion of the Sunmetal plant in North Queensland by 132 MW from January 2009
- We have not explicitly included the Aldoga smelter project as we consider the probability of this project commencing in the mid-term horizon is less than 10%.

3.9.2 Supply

3.9.2.1 Marginal costs

The marginal costs of thermal generators consist of the variable costs of fuel supply including fuel transport plus the variable component of operations and maintenance costs. The indicative variable costs for various thermal plants are shown in Table 3.6. We also include the net present value of changes in future capital expenditure that would be driven by fuel consumption for open cut mines that are owned by the generator. This applies to coal in Victoria and South Australia.

Figure 3.8 Medium Growth Forecasts Sent Out

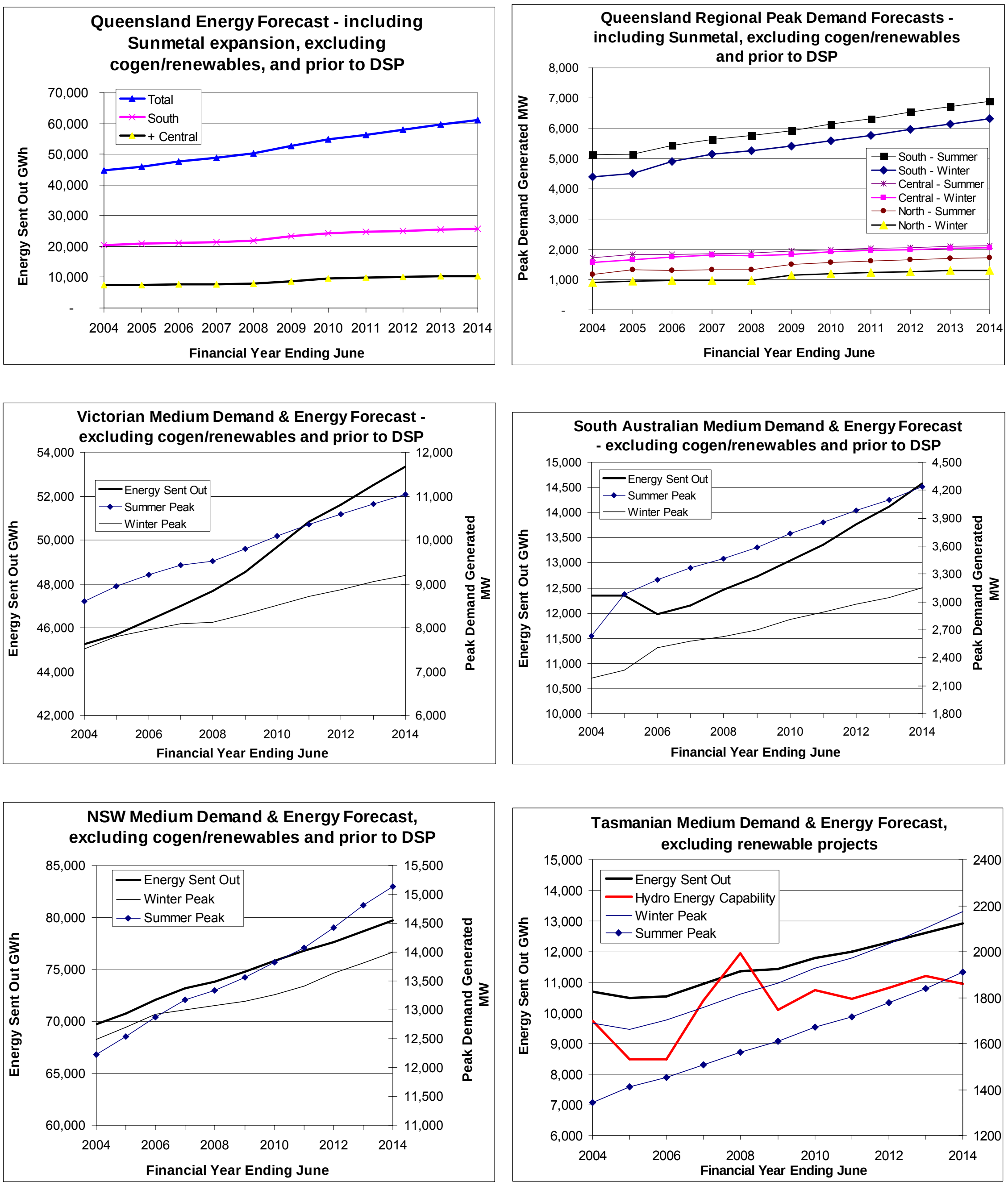


Table 3.6 Indicative Average Variable Costs for Thermal Plant ($December 2004)

Technology	Variable Cost $/MWh	Technology	Variable Cost $/MWh
Brown Coal – Victoria	$5 - $9	Brown Coal – SA	$10-$12
Gas – Victoria	$38 - $71	Black Coal – NSW	$13 - $19
Gas – SA	$20 - $170	Black Coal - Qld	$10 - $20
Oil – SA	$97-$200	Gas - Queensland	$21 - $57
Gas Peak – SA	$112-$155	Oil – Queensland	$170

3.9.2.2 Timing of new entry generation and transmission

Other assumptions that impact on system reliability are the commencement dates of committed new entry. MMA's assumptions are as follows:

- Basslink commencing operation in April/May 2006.
- The commissioning of Snowy Hydro's Laverton North open cycle gas fired power station in time for the 2005/06 summer.
- The commissioning of Kogan Creek as a base load generator in Queensland in September 2008.
- The commissioning of the 3 Wambo Braemar 150 MW OCGT gas turbines in July 2006.

3.9.3 Bidding behaviour

The associated market price for each reliability level was determined in a separate set of runs using PLEXOS's LRMC bidding algorithm. The following set of key assumptions form the basis on which these market prices were derived.

3.9.3.1 Market structure

We assume the current market structure continues under the following arrangements:

- Victorian generators are not aggregated.
- NSW generators remain under the current structure in public ownership.
- The ownership structure in Queensland remains as public ownership.
- The SA assets continue under the current portfolio groupings (Optima in the CLP portfolio and Synergen in the International Power portfolio with Pelican Point and Hazelwood Power).

This market arrangement provides the following features:

- NSW generators dominate the price making in Victoria and NSW due to their higher variable costs than the brown coal businesses and the coal fired surplus which leaves the Babcock & Brown/CLP Victorian gas fired business with little dispatch or market influence initially in Victoria.
- Victorian brown coal generators are assumed to maintain a price-taking role which is strengthened as demand grows in Victoria and the brown coal plants become fully loaded. Southern Hydro is also assumed to be a price taker in Victoria.

- Victorian brown coal generators may contribute to price making at times of very high peak demands when supply conditions permit.
- Competition in the NSW and Queensland markets increased significantly since the QNI capacity reached 1,050 MW.
- Since the commissioning of QNI and Millmerran, NSW generators also effectively set prices in Queensland.

In the event of a supply surplus resulting from PNG/Timor Sea gas projects, which would fill QNI for Queensland export, the NSW and Queensland prices would remain largely independent as long as Queensland prices stay at or below NSW prices.

This means that the following market dynamics are expected:

- Brown coal will bid marginal cost or shadow NSW bids to support off-peak prices in Victoria.
- All brown coal units will self-commit at all times but will attempt some price support in off-peak periods so as not to constrain the Victoria to NSW export limit.
- NSW generators with spare capacity (Macquarie Generation, Delta Electricity) will support NSW prices against competition from Victoria and Queensland by maintaining mothballing at Liddell and Munmorah and by strategic bidding to support NSW prices when these units return to service.
- Torrens Island and the peaking plants in South Australia will support SA prices by bidding strategically. International Power and CLP are also likely to use these units to assist in recovery of fixed costs for some of the Victorian plant.
- Queensland low cost black coal plants will bid marginal costs for most of their capacity. The higher cost coal plants such as Swanbank B and Gladstone will bid higher prices when necessary to support prices or to sell uncontracted energy.
- An extended period of mothballing in NSW will be necessary to support prices in NSW as well as Victoria and Queensland. Millmerran, Tarong North, Kogan Creek and Wambo Braemar are examples of projects that contribute to longer periods of mothballing in NSW by providing new capacity in Queensland.

4 MARKET ANALYSIS

4.1 PRELIMINARY ESTIMATE USING PROBABILISTIC SIMULATION

The basis for justification for this project was a preliminary estimate of the optimal level of unserved energy that was obtained based upon the following method:

1. The marginal cost of peaking capacity was assumed to be $100/kW/year,

2. The average cost of unserved energy was assumed to be $30,000/MWh based on earlier general research by Monash University and Charles River Associates,

3. The measure of unserved energy was determined from a probabilistic simulation of the NEM using the multi-area Strategist software package. MMA has been successfully using this package since 1993 to model the NEM for long-term price forecasting and investment analysis.

4. Eight different cases were prepared with varying levels of capacity in each NEM region as shown in Table 4.1. The installed capacity in each region includes firm import capacity in Strategist so a reference capacity level (C) was determined according to a specific level of unserved energy (y) by using a regression analysis using the function

   $$y = A\,e^{B(x - C)} \qquad \text{Equation (1)}$$

   Where:

   x is a capacity level

   C is the capacity level that provides a specific level of expected unserved energy

   A and B are constants

   Y is the expected unserved energy

5. Considering just the capacity level within each region, a set of regressions functions were obtained in the form of equation (1) above. These equations are shown in Figure 4.1 on page 63 for 0.002% as providing the reference capacity level where x – C is zero in the charts on the horizontal axis. There is no consideration of capacity in neighbouring regions to keep the analysis simple. However there is generally a good fit of expected unserved energy to capacity over the range of 0.0001% to 0.005% using the exponential function.

Table 4.1 Capacity states used to analyse expected unserved energy

Zone	Capacity Scenarios 1	(MW including import capacity) 2	3	4	5	6	7	8
Tas	2604	2430	2169	1995	1908	1908	1908	1908
SA	3740	3549	3247	3512	3684	3684	3684	3684
Vic	10962	10766	10439	10113	9615	9271	8926	8730
Snowy	5207	5207	5207	5207	5207	5207	5207	5207
NSW	14366	14170	13876	13586	13488	13488	13488	13488
QldSth	5268	5268	5268	5038	5038	5038	5038	5038
QldCen	6721	6721	6721	6721	6721	6721	6721	6721
QldNth	1888	1888	1888	1888	1888	1888	1888	1888
Tarong	5756	5756	5427	5427	5298	5098	5098	5098
Region	**Corresponding Unserved Energy (%)**							
Tas	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
SA	0.00096	0.00311	0.01455	0.00443	0.00232	0.00841	0.00743	0.00974
Vic	0.00000	0.00000	0.00000	0.00001	0.00013	0.00042	0.00122	0.00238
NSW	0.00010	0.00022	0.00077	0.00238	0.00426	0.00583	0.00683	0.00780
Qld	0.00067	0.00070	0.00094	0.00152	0.00199	0.00257	0.00320	0.00390

Note: capacity levels shown include import capacity into the region as modelled in Strategist

6. The regression equation was then used to cost additional capacity away from the zero level and the expected unserved energy was priced at $30/kWh. This provides a cost versus reliability level as shown in Figure 4.2 on page 63. The optimal reliability level is estimated to be 0.0026% by this method with a potential saving of $4.3 M per annum in reduced capacity costs less increased customer costs. There was evidently a case for further investigation to confirm this assessment using more accurate reliability models.

What we learned from this analysis was that we could readily estimate a functional relationship between expected unserved energy and capacity that could be used to relate capacity to reliability and to total market cost. What was not accurately modelled in this analysis was:

- The relationship between supply interruptions and customer costs; only an average value of $30/kWh was applied.
- The relationship between system production costs and reliability; it was assumed that system generation costs were independent of reliability whereas production costs would fall when energy is unserved although this is more than compensated for by increased customer costs.

Figure 4.1 Examples of unserved energy versus capacity from 0.002% reference level

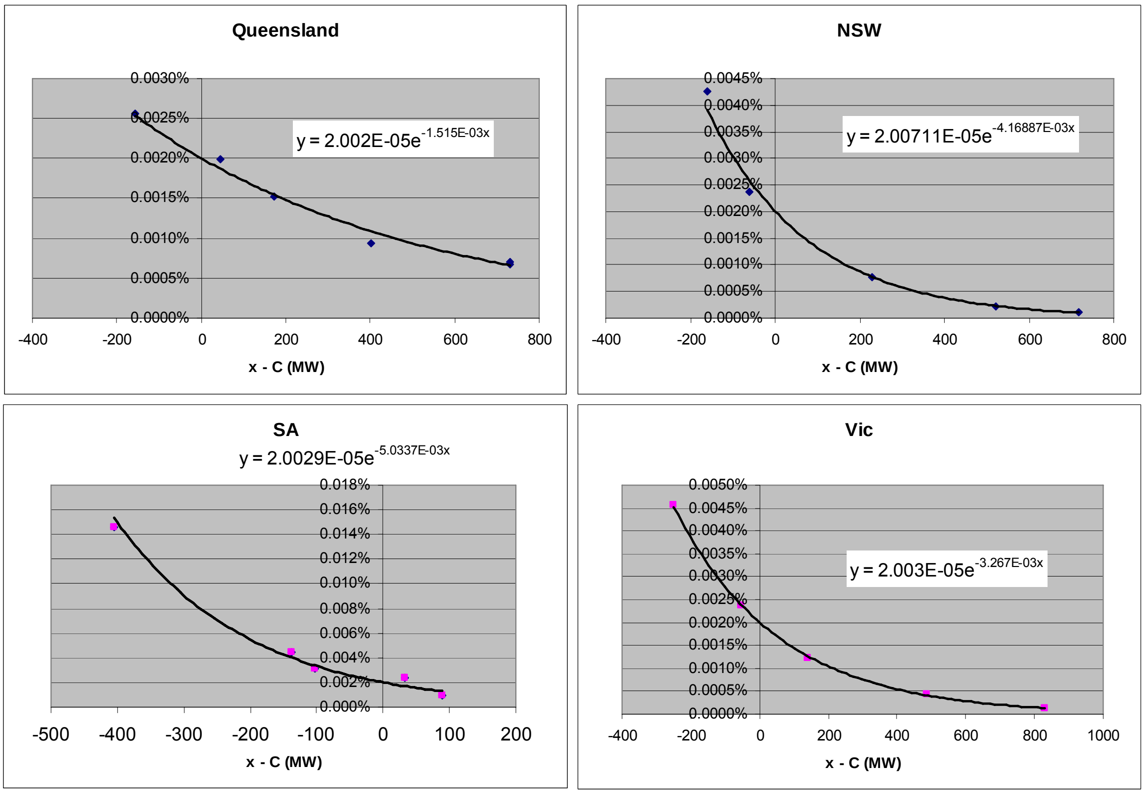
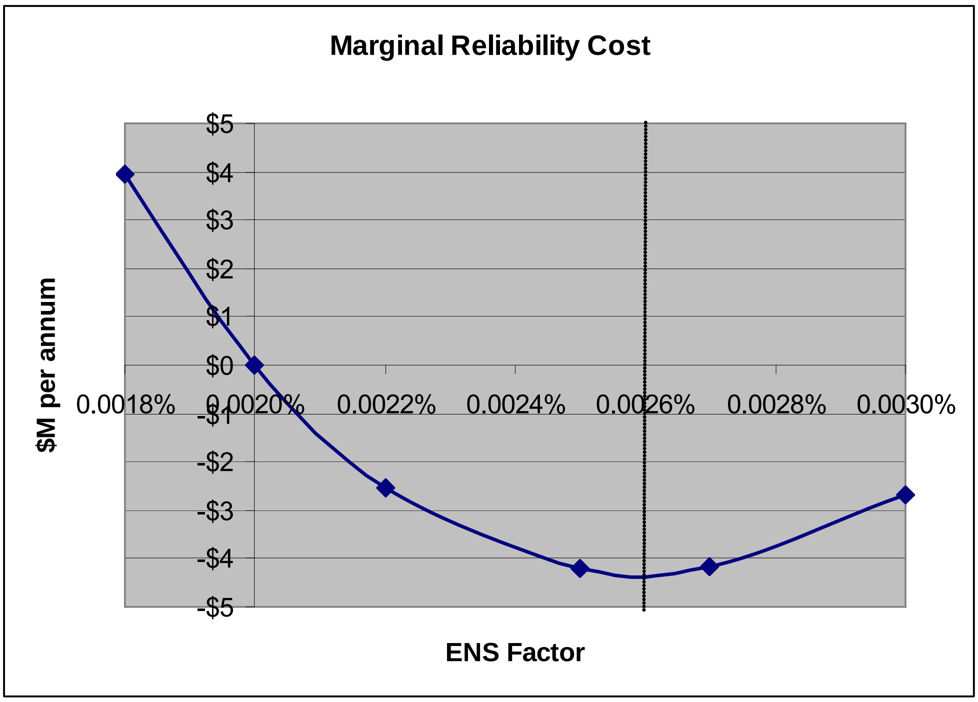


Figure 4.2 Indicative marginal cost of reliability standard based upon average cost of unserved energy



- The possibility of different reliability targets being optimal in each region. The same target level and associated capacity level was costed throughout the NEM.
- Tasmania was not considered as for average hydro yield there was no assessed unserved energy. This was a limitation of the Strategist model which does not represent hydro plant unreliability or hydro yield volatility and was not entirely realistic.

The purpose of this study was to employ a more sophisticated analysis of the customer cost and to determine if this level could be confirmed by the more detailed method and to provide a basis for further work on the optimal level of the reliability standard from a total market viewpoint. We have not attempted to calculate the optimal reliability for Tasmania as a more sophisticated hydrological model would be required and MMA did not have access to suitable data for this purpose that it was permitted to use.

4.2 PRELIMINARY CAPACITY ANALYSIS

The first stage of the project was to identify using the Plexos market simulation what capacity levels would produce expected unserved energy of between 0.001% and 0.004%. This was conducted for the 2006 and 2010 financial years by trial and error using 30 simulations (10 simulations for each load trace) with the results as shown in Table 4.2. During this phase of work, we also examined the relationship between regional capacity levels and assessed unserved energy using the following equation:

$$Y_j = f_j \left(\sum_{i=1 \text{ to } 4} A_{ij} C_{ij} \right) \qquad \text{Equation (2)}$$

Where: Y is the unserved energy

C_i is the capacity in region (i)

A_{ij} is a constant that relates the capacity in region (i) to the unserved energy in region (j)

f_j (x) is the non-linear exponential function $= e^{B_j x}$

Multi-variate regression was used to determine the A_{ij} 's and the B_j's by state by year. In most cases the R^2 coefficient was greater than 0.90 indicating an excellent fit. 3 out of the 20 cases had an R^2 coefficient of about 0.6; these were due to outliers arising from the relatively large standard errors of the mean USE estimates, and are evidence of a lack of convergence in the Monte Carlo statistics. The above result implies that the noise from the sampling error is small enough to ensure that a robust relationship can be derived between unserved energy and the regional capacities despite the presence of some outliers. We expected an even better relationship to result from the next phase of work, where a smaller range of unserved energy will be examined with more Monte

Table 4.2 Preliminary cases to establish the study range

Capacity Trial Level ▶		Trial Level 1	Trial Level 2	Trial Level 3	Trial Level 4	Trial Level 5	Trial Level 6	Trial Level 7
State ▼	Variable ▼	**2006**						
NSW	Capacity USE	9,820 0.0198%	10,333 0.0037%	10,545 0.0015%	10,746 0.0014%	10,845 0.0007%	11,058 0.0018%	
QLD	Capacity USE	8,397 0.0109%	8,522 0.0055%	8,677 0.0028%	8,737 0.0053%	8,802 0.0016%	8,948 0.0008%	
SA	Capacity USE	2,805 0.0108%	3,055 0.0057%	3,180 0.0021%	3,302 0.0022%	3,425 0.0007%		
VIC	Capacity USE	7,010 0.0043%	7,160 0.0038%	7,232 0.0033%	7,333 0.0028%	7,393 0.0017%	7,699 0.0006%	
		2007						
NSW	Capacity USE	10,234 0.0063%	10,333 0.0025%	10,435 0.0032%	10,633 0.0037%	10,746 0.0016%	10,947 0.0014%	
QLD	Capacity USE	8,690 0.0078%	8,847 0.0031%	8,970 0.0013%	9,057 0.0014%	9,250 0.0008%		
SA	Capacity USE	3,055 0.0052%	3,178 0.0032%	3,300 0.0025%	3,369 0.0032%	3,423 0.0014%	3,491 0.0020%	3,618 0.0008%
VIC	Capacity USE	6,637 0.0039%	6,716 0.0025%	6,838 0.0024%	6,910 0.0021%	6,960 0.0015%	7,070 0.0010%	7,170 0.0005%
		2008						
NSW	Capacity USE	10,333 0.0080%	10,545 0.0019%	10,746 0.0017%	10,845 0.0024%	10,947 0.0012%	11,145 0.0003%	
QLD	Capacity USE	8,935 0.0091%	9,092 0.0064%	9,127 0.0048%	9,215 0.0026%	9,337 0.0029%	9,407 0.0015%	9,617 0.0004%
SA	Capacity USE	3,180 0.0078%	3,302 0.0032%	3,425 0.0020%	3,493 0.0021%	3,547 0.0010%	3,747 0.0005%	
VIC	Capacity USE	6,828 0.0047%	7,130 0.0017%	7,214 0.0013%	7,333 0.0010%	7,393 0.0010%	7,490 0.0005%	7,731 0.0003%
		2009						
NSW	Capacity USE	10,746 0.0036%	10,845 0.0066%	10,947 0.0037%	11,058 0.0020%	11,145 0.0030%	11,259 0.0013%	11,358 0.0007%
QLD	Capacity USE	9,807 0.0037%	9,877 0.0023%	10,000 0.0012%	10,122 0.0013%	10,245 0.0008%	10,367 0.0002%	
SA	Capacity USE	3,430 0.0043%	3,552 0.0021%	3,625 0.0025%	3,679 0.0023%	3,806 0.0020%	3,933 0.0008%	
VIC	Capacity USE	7,086 0.0035%	7,368 0.0020%	7,678 0.0009%				
		2010						
NSW	Capacity USE	10,845 0.0071%	11,058 0.0034%	11,145 0.0026%	11,450 0.0007%			
QLD	Capacity USE	10,000 0.0038%	10,152 0.0053%	10,275 0.0019%	10,560 0.0004%			
SA	Capacity USE	3,430 0.0057%	3,679 0.0032%	3,806 0.0023%	4,016 0.0005%			
VIC	Capacity USE	7,360 0.0036%	7,540 0.0030%	7,688 0.0020%	7,768 0.0011%	7,970 0.0010%		

Carlo samples. However when variation of capacity is considered in all regions, a linear function did not perform as well as expected.

These trial and error runs also enabled us to choose the optimal proportion of 10%POE, 50%POE and 90% POE samples, which is the proportion that minimises the standard error for the average USE calculation across all 4 NEM regions (giving equal weight to each region). Based on this calculation, 15 samples were used for the 10% POE sensitivity, 9 samples for the 50% POE sensitivity and 6 samples for the 90% POE sensitivity.

This work demonstrated that combinations of the capacity levels shown in Table 4.3 could be used in each region over the five year period to achieve the desired objectives of the study. The capacity levels exclude any import levels and relate to the generators included in the model as tabulated in Appendix B . They correspond to the (0), (+) and (-) levels shown above in Table 3.2. The base capacity level was intended to approximate the current standard unserved energy of 0.002%. The minimum capacity was expected to produce about 0.004% and the maximum capacity to result in 0.001% unserved energy in each financial year shown for the medium growth forecast. For convenience the capacity levels relate to summer capacity so that a comparison with the reserve margin criterion is facilitated.

Table 4.3 Capacity level range for each region in the Plexos model

Financial Year ending June ►		2006	2007	2008	2009	2010
SA	Min	3054	3167	3373	3488	3611
	Base	3224	3369	3516	3744	3808
	Max	3367	3618	3669	4004	3966
Vic	Min	7060	6656	7046	7276	7465
	Base	7292	6860	7293	7587	7782
	Max	7497	7070	7533	7928	8075
NSW	Min	10333	10333	10534	10845	11035
	Base	10633	10633	10888	11299	11276
	Max	10947	10947	11225	11539	11539
Qld	Min	8642	8690	9257	9858	10125
	Base	8800	8907	9416	10048	10281
	Max	8957	9127	9571	10203	10438

Note: capacity refers to the generators shown in Appendix B

Subsequent analysis showed that four additional scenarios were needed to obtain a wider range of unserved energy as detailed in Appendix C. However the primary values used were as shown in Table 4.3

4.3 CALCULATING UNSERVED ENERGY

The next step was to examine the 17 capacity cases in more detail so as to define the relationship between regional capacity and unserved energy and thereby to estimate:

- the optimal capacity configuration to achieve a certain level of unserved energy,
- the relationship between unserved energy and the cost of reserve capacity, and
- the relationship between expected unserved energy, the types of supply interruption events and the types of customers affected.

The 17 cases were designed to provide the range of unserved energy between 0.001% and 0.004% in each region using the preliminary analysis described in section. The first 13 capacity levels were chosen using combinations of the form [0, 0, +, -] where 0 means the base level, + represents the maximum level and – means the minimum level. There are four regions and there are 4 * 3 ways of selecting these levels among the four regions: four ways to choose the + times 3 ways to choose the – with the remaining regions being in the zero capacity state. The additional four scenarios included some states with lower capacity to obtain higher levels of unserved energy.

For each of these capacity combinations in each year, 30 Monte Carlo simulations were run and the key statistics of unserved energy events were collected for each region in an Excel database.

Each case in each year corresponded to a particular average unserved energy level. A probabilistic method provided in the Plexos version 4.7 provided a good estimate of the expected unserved energy having regard to interconnection support. This is a more accurate value than could be obtained by multiple simulations because it has been shown by Drayton Analytics that it takes 1000 to 2000 simulations to obtain a convergent estimate of unserved energy because of the asymmetry of the distribution of annual unserved energy. It depends on few random and severe events and therefore the sampling distribution is highly skewed. This remains a potential problem with the work to date which would require further evaluation to be sure that a sufficient number of samples have been processed.

4.4 REGRESSION OF UNSERVED ENERGY VERSUS CAPACITY

The analysis of unserved energy versus capacity was not entirely satisfactory but assessed as good enough for our immediate purposes as follows:

- Some of the coefficients were positive which was not credible as increasing capacity in one region could not increase unserved energy in any other region in a real competitive power market. We think this may reflect sampling error and indicates more samples would give a better result. Where coefficients were positive, the corresponding variables were removed from the regression equation.
- Many of the coefficients although negative were not statistically significant and in that case the relevant state capacity was removed from the equation.

The resulting coefficients of the equation of the logarithm of the average unserved energy in MWh as a function of the capacity in each region are tabulated in Table 4.4.

Table 4.4 Regression Coefficients for Log of unserved energy versus capacity.

Financial			Capacity Coefficients				
Year	Region	R^2	SA	Vic	NSW	Qld	Constant
2006	SA	0.92	-0.00482	-0.00204	-0.00038	0	39.4
	Vic	0.80	-0.001	-0.00249	0	0	28.5
	NSW	0.56	0	0	-0.00313	-0.00117	50.7
	Qld	0.57	0	0	0	-0.00377	39.7
2007	SA	0.92	-0.00335	-0.00184	-0.00044	0	33.7
	Vic	0.91	0	-0.0021	-0.0005	0	26.9
	NSW	0.64	0	0	-0.00272	0	36.4
	Qld	0.54	0	0	0	-0.00361	39.5
2008	SA	0.51	-0.00259	0	0	0	14.4
	Vic	0.50	0	-0.00286	0	-0.00297	55.6
	NSW	0.58	0	-0.00077	-0.00216	-0.0016	51.7
	Qld	0.40	0	0	0	-0.00444	48.9
2009	SA	0.81	-0.00187	-0.00071	-0.00068	0	25.0
	Vic	0.56	0	-0.00119	-7.8E-05	0	16.8
	NSW	0.67	0	0	-0.00204	-0.00136	43.5
	Qld	0.57	0	0	0	-0.00443	51.3
2010	SA	0.87	-0.00371	-0.00197	0	0	34.2
	Vic	0.85	0	-0.00183	0	0	21.0
	NSW	0.58	0	-0.00107	-0.00318	-0.00241	76.3
	Qld	0.83	-0.00076	0	0	-0.00439	55.3

The accuracy of the regression fit as measured by the square errors was generally between 0.5 and 0.92. Higher levels would have been preferred and this can be achieved by including some second order terms but this adds complexity to the analysis which was not deemed essential at this stage. However, it should be considered if the work is to be adapted to setting an actual standard.

The zero terms apply where the regression coefficient including all variables was determined as positive or statistically insignificant from zero. The coefficients were removed if their value was less than about 1.4 times their standard error. This is equivalent to an 84% two-sided confidence interval. In some cases the coefficient was removed if it created non-credible effects when calculating optimal reliability levels. The following general observations were made and were consistent with expectations based upon previous modelling experience:

- The unserved energy in South Australia is not significantly affected by capacity in Queensland as would be expected. Sometimes Victoria and NSW coefficients were not significant.
- The unserved energy in Victoria is affected by capacity in NSW and South Australia in some years as would be expected.

- The unserved energy in NSW is affected by Victoria and Queensland in most years as would be expected.
- The unserved energy in Queensland is not significantly affected by capacity in the southern states .

The regression values for 2009 were quite different from the other years, due to a sampling range that was too limited for the required analysis. The parameters were therefore regarded as not credible[3]. The sensitivities of unserved energy to capacity were too low and this would have distorted some of the results. In some of the analyses we have used the average of the 2008 and 2010 parameters to attempt to provide a result for 2009 that makes sense and tracks the changes over time.

Two simple analyses were undertaken at this point before making complex analyses of event outage costs. The optimal level of reliability was assessed using the unserved energy versus regional capacity regression equation assuming a common cost for reserve capacity of $100/kW/year and $30/kWh for two approaches:

1. The optimal unserved energy ratio was assessed for the NEM as a whole assuming that all regions met the same standard simultaneously. In this case a set of capacities were determined that met the standard in each region and then the reliability standard to minimise the cost was assessed.

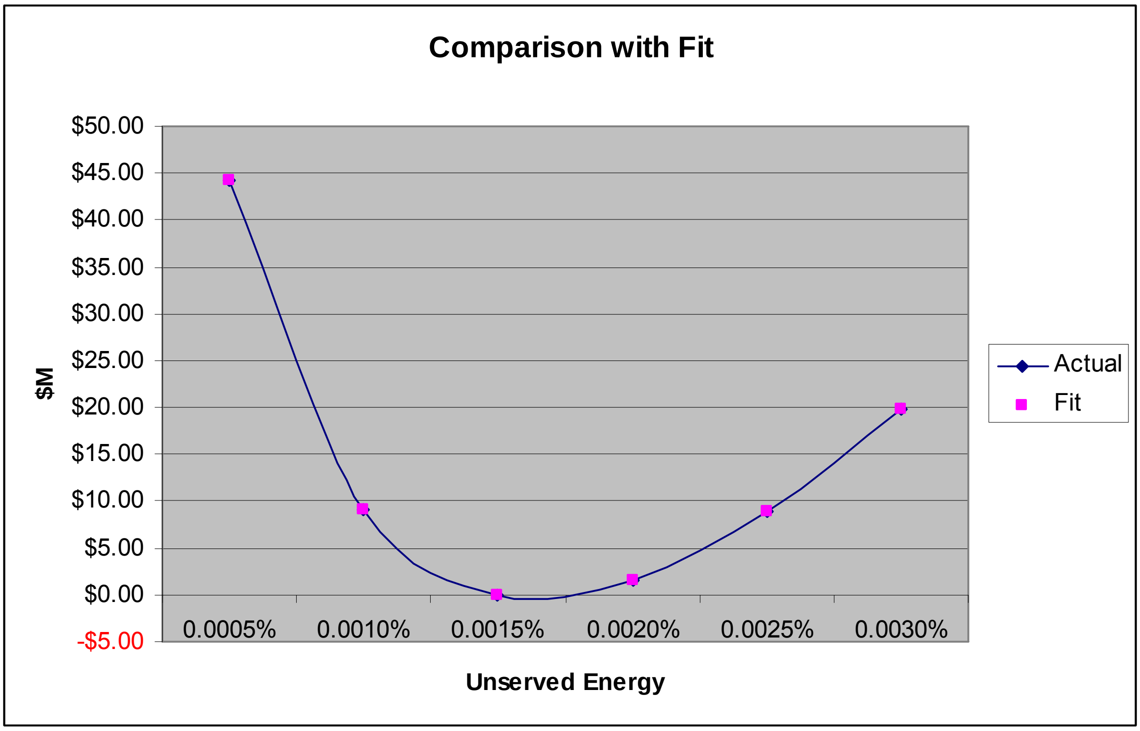
2. An optimal unserved energy level was assessed for each region separately. This involved minimising the total unserved energy and reserve capacity cost across the whole NEM by varying the regional capacity. The corresponding unserved energy was then calculated from the capacity using the regression of unserved energy versus capacity.

4.4.1 Estimate of a common reliability standard for constant values

The optimal level of unserved energy for the common charges for unserved energy and reserve capacity is shown in Figure 4.4. The relative cost functions are shown in Figure 4.3 offset to zero for the minimum value calculated. The cost functions were approximated as the sum of a quadratic function of unserved energy and the exponential of a quadratic function for the purposes of estimating the optimal value. An example of an actual curve and the fit is shown in Figure 4.3. Six parameters were used to fit the six points so there is every chance that the fit is good. The function is smooth so it provides a suitable basis for identifying the minimum point.

[3] Some analysis has shown that inclusion of second order terms for SA in 2009 could make the results slightly better but it would seem that additional samples would be needed to get more credible results.

Figure 4.3 Example of Fit of Reliability Cost to Unserved Energy Ratio



The optimal level of reliability found by this method is shown in Figure 4.4.

Figure 4.4 Estimate of a Common Standard for Expected Unserved Energy

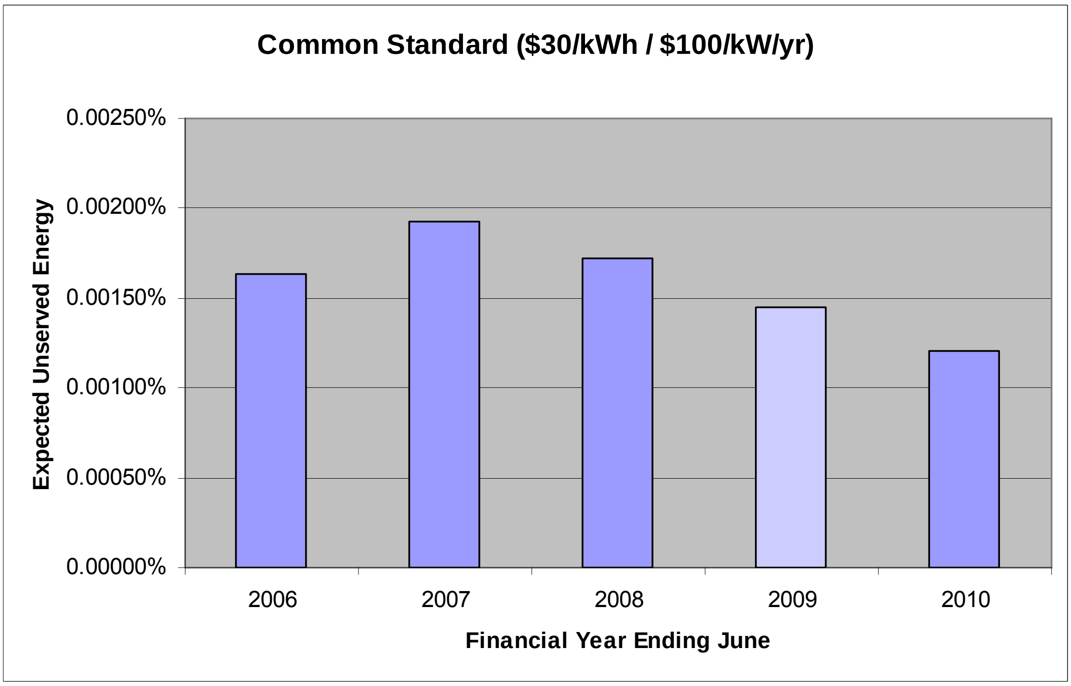
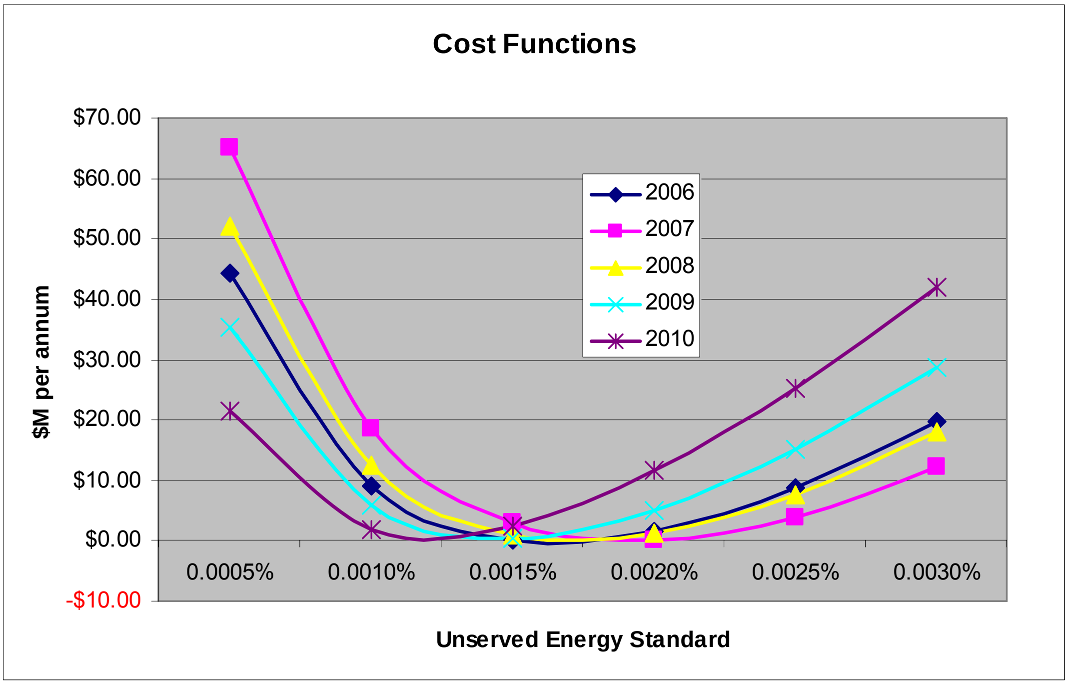


Figure 4.5 Cost Functions for Estimate of a Common Standard for Expected Unserved Energy



The average value over the years from 2006 to 2010 is 0.0016% with a range between 0.0012% and 0.0019%. Figure 4.5 shows a potential cost of up to $11.6M/annum in excess cost in 2010 if the reliability standard remains at the current value. The current level of 0.002% is correct for 2007. The value for 2009 in Figure 4.4 is shaded different to indicate that the estimate for that year is not robust. Overall it seems that based on these costs, the optimal reliability on an expected value basis would be between 0.0012% and 0.0020% This assumes that all regions meet this standard exactly and there is no spare capacity. The optimal unserved energy level would likely be lower and the actual reliability performance be higher if there were spare capacity in some regions because the marginal cost of reserve capacity would be correspondingly lower as discussed further in section 4.4.3. To assess this would require more detailed analysis than has been attempted here. However, this method would be suitable for deriving a common standard either in each year or across a group of years.

Contrary to the preliminary analysis presented in section 4.1, these more detailed results suggest that the optimal common standard should be lower than the current 0.002% level.

4.4.2 Reliability Standard Optimised for Each Region

The second phase of this stage of analysis was to find the optimal reliability for each region assuming they could be different. This calculation used the exponential / linear functions of capacity to assess unserved energy and to find the capacities in each region that minimised the total cost of reserve capacity and unserved energy. This analysis produced quite different results as shown in Figure 4.6 and summarised in Table 4.5.

The results conform to expectations in that the order of stringency in reliability standard is South Australia, Victoria, NSW and lastly Queensland which reflects the trend in the peakiness of demand over the year. South Australia would have a lower standard because of the high costs of maintaining reserves for very infrequent extreme peaks. At the other end of the scale, Queensland has a higher standard because its load curve in summer is much flatter and the cost of maintaining capacity reserve per unit of unserved energy saved is much lower.

However the very low reliability standard (high unserved energy) for South Australia would be a matter of concern as well as an opportunity. MMA does not consider that this value is robust on the analysis to date because it represents an extrapolation outside the range of the analysis and the result is well outside where the NEM has been operating. At most we would expect that a value of about 0.004% could be economic based on the range studied. MMA considers that further statistical analysis is warranted before a new standard could be set on an economic basis for South Australia. However we do expect that a lower reliability would be justified on an expected value basis and that more effort would be justified on securing economic demand side withdrawal to manage the risk of the extreme load shedding events.

Figure 4.6 Estimate of an Optimal Standard for Expected Unserved Energy for each Region

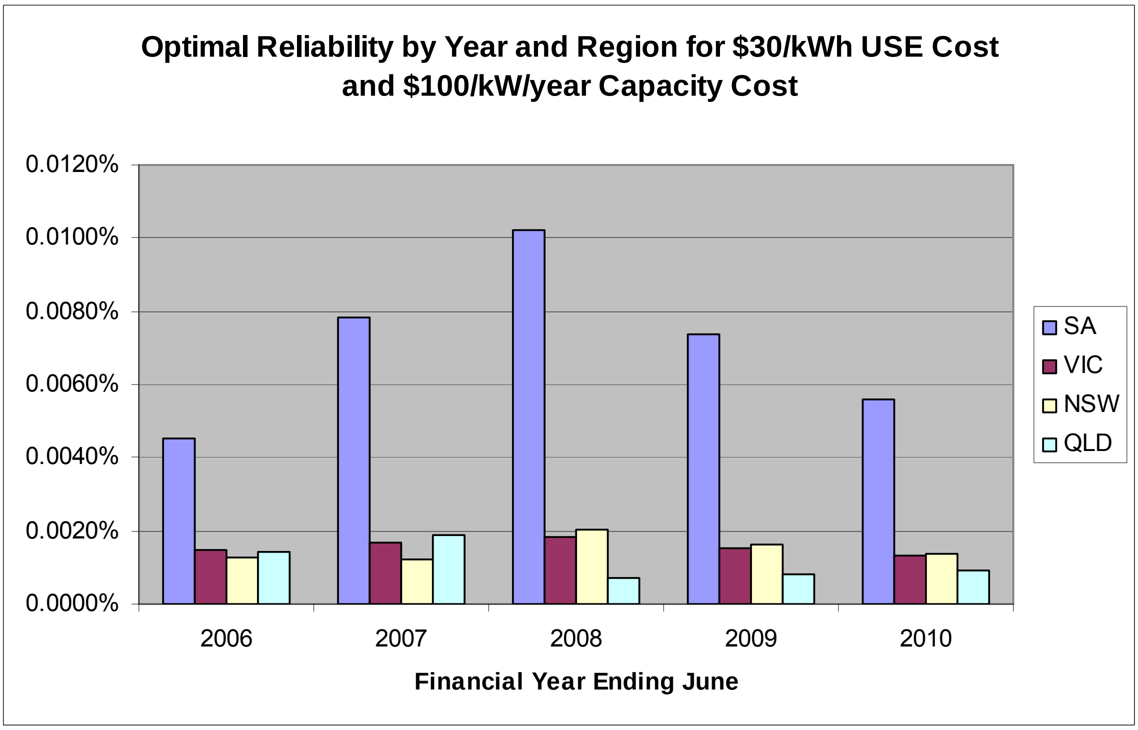


Table 4.5 Optimal Standard for Expected Unserved Energy for each Region

	2006	2007	2008	2009	2010	Average
SA	0.0045%	0.0078%	0.0102%	0.0074%	0.0056%	0.0071%*
VIC	0.0015%	0.0017%	0.0018%	0.0015%	0.0013%	0.0016%
NSW	0.0013%	0.0012%	0.0020%	0.0016%	0.0013%	0.0015%
QLD	0.0014%	0.0019%	0.0007%	0.0008%	0.0009%	0.0012%
Average	0.0022%	0.0032%	0.0037%	0.0028%	0.0023%	0.0028%

* Note that these values are outside the range of analysis and MMA considers that the results indicate that a value of 0.003% to 0.004% might be confirmed with further analysis.

4.4.3 Sensitivity to Input Parameters

The average cost of unserved energy could range between $10/kWh and $100/kWh when considering marginal impacts and for this reason we have studied what would happen to the assessed parameters above for unserved energy over this range as well as between $50/kW/year and $150/kWyear which represents the cost of capacity ranging between mothballing existing plants and a shortage of reserve plant in the market. To simplify the presentation we present the average values over the years 2006 to 2010 inclusive in Table 4.6. Generally, doubling the cost of unserved energy halves the optimal standard and doubling the cost of reserve capacity doubles the standard as may be observed in Table 4.6. This is reassuring and is as expected if the underlying relationships affecting the optimisation are sufficiently linear near the optimal solution.

Table 4.6 Common Reliability Standard versus Input Variables

	Unserved Energy Cost /kWh		
Capacity Cost $/kW/year	$15	$30	$60
$50	0.00159%	0.00080%	0.00040%
$100	0.00317%	0.00159%	0.00080%
$150	0.00476%	0.00239%	0.00126%

Whilst there is not a great deal of uncertainty about the cost of reserve capacity, there is a much greater uncertainty about the true costs of unserved energy on customers. This could be uncertain by -80% to +300% around the $30/kWh value depending on load shedding procedures and the particular customers affected. This would appear to be the key driver of an optimal reliability level and provides the incentive to examine load shedding costs more directly.

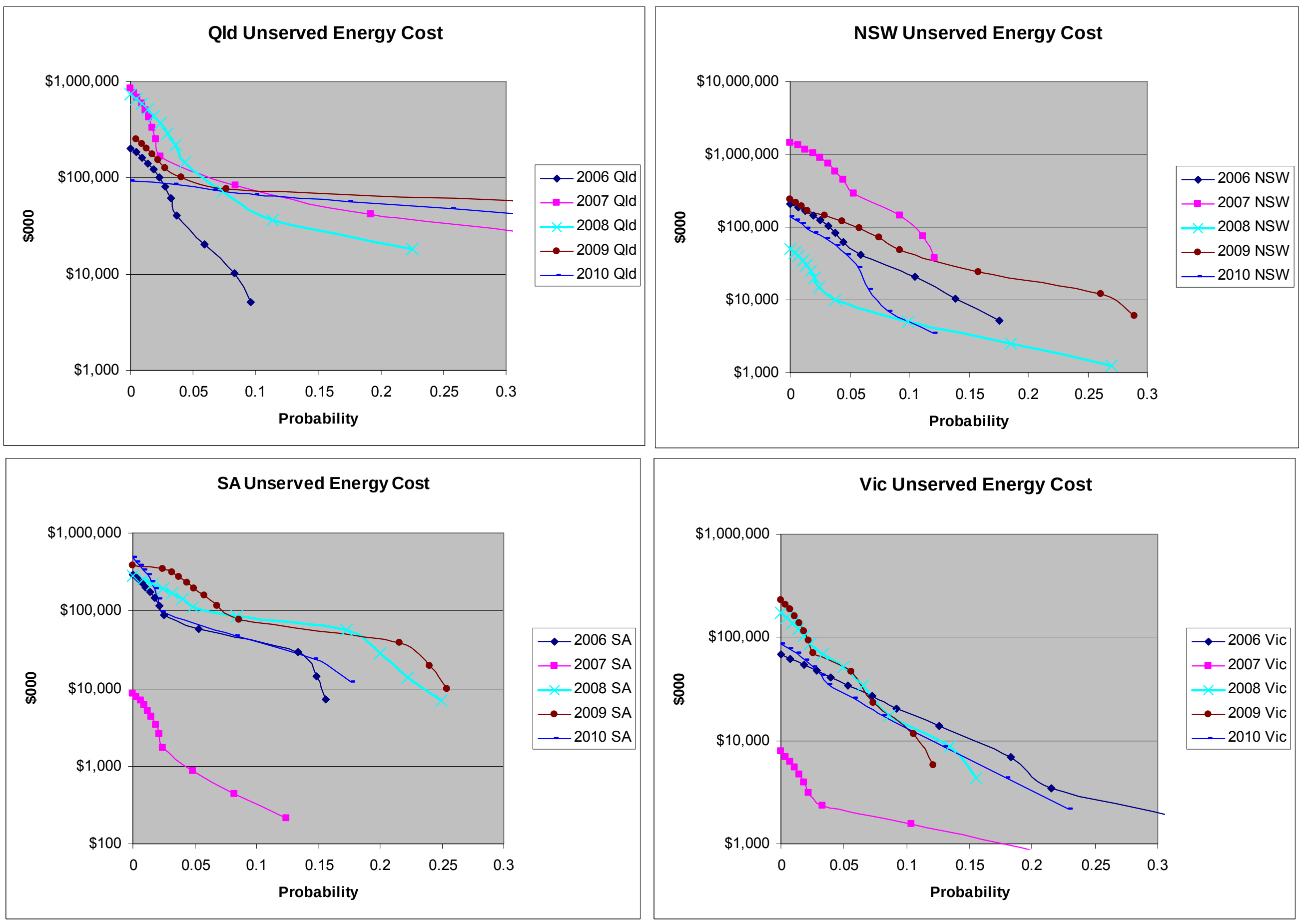
4.5 COSTING OF CAPACITY AND UNSERVED ENERGY

Using the unserved energy cost model for each region, we costed the events obtained from the simulations so that we could develop a summary of capacity states and the average of the unserved energy over the 30 simulations with appropriate weighting for the variation in peak demand. The unserved energy cost plus the reserve capacity cost over the whole NEM was formulated as the sum of a second order polynomial function and the exponential of a linear function so as to approximate the combination of regional capacity that would minimise the total cost over the NEM.

4.6 SUPPLY INTERRUPTION COST

An analysis of the unserved energy cost over the simulations and after weighting for the relative contribution of 10% POE, 50% POE and 90% POE peak demands demonstrated what we had suspected. The probability distribution of unserved energy cost is highly skewed which explains why it is difficult to capture enough random samples to characterise the average level. It is apparent why 30 samples just are not enough to obtain a robust result. Figure 4.7 shows an example of the unserved energy cost cumulative distribution curve for the four regions for one capacity

Figure 4.7 Unserved Energy Cost Distributions



state[4]. The corresponding unserved energy factors for the regions are shown in Table 4.7. The unserved energy factors range between 0.0004% for Qld in 2006 to 0.0082% in SA in 2008. They represent a practical range of outcomes and not the standard conditions. The standard value of 0.002% occurs approximately in Victoria in 2010, NSW in 2008, and Queensland in 2009. The likely economic value of 0.004% occurs in SA in 2010.

The unserved energy is plotted on a logarithmic scale in Figure 4.7 to so as to be able to show the very wide range in costs of unserved energy over the probability weighted samples. The unserved energy cost probability curves were derived from the equivalent curves for the 10% POE, 50% POE and 90% POE sample groups and then the curves were combined using the weightings of these peak demand outcomes. Essentially for each value of unserved energy cost the probability of its being exceeded for each peak load level are weighted by the probability of that peak load level to give the probability that it will be exceeded in the composite distribution.

Table 4.7 Unserved Energy Ratios for Scenario 17 (for Figure 4.7)

	SA	Vic	NSW	Qld
2006	0.0047%	0.0043%	0.0027%	0.0004%
2007	0.0007%	0.0015%	0.0057%	0.0031%
2008	0.0082%	0.0034%	0.0022%	0.0019%
2009	0.0079%	0.0034%	0.0048%	0.0021%
2010	0.004%	0.0024%	0.0017%	0.0028%

These distributions are highly skewed as demonstrated by the parameters shown in Table 4.8 for this capacity scenario. As compared to a Normal Distribution:

- The probability of the unserved energy cost being above the mean is typically about 10% to 20% instead of 50%,
- The probability of the unserved energy cost being above one standard deviation is typically between 4% and 10% instead of 16%,

[4] Capacity scenario number 17.

Table 4.8 Probability Distribution Characteristics of Unserved Energy Cost $000

	Mean	St Dev	Probability > Mean	Probability > Mean+ One Standard Deviation	Average if Above the Mean	Ratio of Mean
SA						
2006	$11,709	$37,320	15.1%	7.8%	$168,077	14.4
2007	$235	$1,108	12.1%	3.5%	$4,298	18.3
2008	$21,969	$40,183	21.0%	15.4%	$252,617	11.5
2009	$30,708	$65,497	22.6%	7.7%	$379,885	12.4
2010	$14,926	$60,577	16.9%	4.9%	$190,709	12.8
Vic						
2006	$7,511	$18,684	17.8%	7.6%	$72,380	9.6
2007	$517	$1,096	29.0%	9.9%	$3,021	5.8
2008	$7,482	$23,946	14.0%	6.9%	$131,764	17.6
2009	$8,112	$30,375	11.5%	6.2%	$159,728	19.7
2010	$5,330	$18,429	16.8%	6.4%	$67,689	12.7
NSW						
2006	$13,899	$43,658	12.8%	4.8%	$194,421	14.0
2007	$85,530	$337,709	10.8%	4.6%	$1,552,566	18.2
2008	$2,214	$6,622	20.3%	5.0%	$20,101	9.1
2009	$22,148	$56,554	17.5%	7.0%	$210,564	9.5
2010	$8,519	$31,558	7.9%	4.9%	$177,275	20.8
Qld						
2006	$9,263	$40,210	8.5%	3.5%	$205,689	22.2
2007	$42,476	$112,061	19.0%	3.3%	$275,527	6.5
2008	$35,533	$112,654	11.9%	4.3%	$575,989	16.2
2009	$26,032	$36,460	36.6%	6.0%	$74,933	2.9

	Mean	St Dev	Probability > Mean	Probability > Mean+ One Standard Deviation	Average if Above the Mean	Ratio of Mean
2010	$31,201	$29,112	39.3%	14.7%	$144,807	4.6

- If the unserved energy cost is above the mean, it is typically between 5 and 20 times the average value which is shown in Table 4.8 for this particular capacity scenario. Even when the expected unserved energy is around 0.002%, the factor above mean is typically between 5 and 13.

The interesting issue is that there is quite a low probability that the unserved energy cost will be above the average value but when it is above the average it is many times the average value. Due to the asymmetry of this distribution, the expected unserved energy is not a good measure of the impact on customers because most of the time there is no impact and when there is an impact it is huge!

It would be more realistic to have two criteria:

- One an average value criteria that represents an average economic outcome over a long period of time
- And the other an extreme value criterion related to a one in 20 or 30 year exposure that captures the impact of extremely unlikely but damaging events where high cost restrictions are imposed.

The study results indicate that a one in thirty year event (3.3% probability) would correspond to about 5 to 8 times the expected unserved energy cost. For a Normal Distribution the average above the mean is 39.9% of the standard deviation plus the mean value. The standard deviations of these distributions is about 2 to 4 times the mean which means that we would expect a ratio of about[5] 1.6 to 2.6 times the mean. Thus the expected unserved energy cost distribution is very skewed and difficult to sample accurately. It also means that basing the reliability standard on expected values does not recognise the possible consequences of rare but extreme events.

This extreme value ratio could be applied to assess a higher level of unserved energy cost that represents an extreme event that is to be avoided with substantia intent. This thirty year time scale is about the frequency of major system shut-downs in mature interconnected electricity systems which occur even when there is adequate generating capacity. Such system shut-downs occur usually due to faults arising in and

[5] Range is approxmately 1 + 2 *40% to 1 + 4 * 40% = 1.8 to 2.6 times.

propagating through the transmission system due to secondary equipment failure and operator errors.

However, we revert to the standard method and consider the average unserved energy as the key measure in terms of the installed capacity.

4.7 SUPPLY INTERRUPTION COST FUNCTIONS

We investigated two possible approaches to characterising the relationship between the reliability cost and the capacity installed in each region. The reliability cost is defined as the sum of the expected unserved energy cost and the reserve capacity cost relative to an arbitrary baseline equal to the average of the 17 capacity states modelled in each region.

The two methods were:

1. The first method which was not very successful was to obtain a quadratic regression function between the expected unserved energy cost plus the reserve capacity cost (described here as the "reliability cost") for each of the 17 capacity cases and the capacity levels in each region. The quadratic function was used to find the capacity values corresponding to minimum reliability cost.

2. The second method which was more useful was to relate the unserved energy to the unserved energy level within each region as a quadratic function and add the reserve capacity cost separately. Because the unserved energy is an exponential function of capacity it turns out that the solution equation for optimal reliability cost can be solved as an equation in unserved energy as shown in Appendix E without reference to particular capacity levels in particular regions.

In both methods the derivatives of the regression function were calculated and set to zero to find the capacity or unserved energy levels that gave minimum reliability cost. The corresponding expected unserved energy level was then obtained from the regression functions obtained in Section 4.4 above for Method 1. The unserved energy level is obtained directly from Method 2.

4.8 UNSERVED ENERGY COST VERSUS CAPACITY

The first method yielded some quadratic functions of the total unserved energy cost plus reserve capacity cost versus capacity level. This method also needed some constraints in the regression to obtain sensible results. For example the second order capacity terms were constrained to be greater than $500,000/GW^2 to avoid negative values and an inflexion point in the multi-variable quadratic polynomial function that did not represent a minimum cost. This value was chosen as being nominally small and positive having regard to typical positive values ranging from $542,000 to

$\$14,297,000/GW^2$ when the values of the coefficients were unconstrained. The capacity solution was also constrained to be within the range of capacities studied in the Plexos simulations to avoid extreme values. This did not always prevent unrealistic solutions as discussed below.

This second order equation of four variables was then solved for the set of capacity levels which gave the minimum total cost. The capacity levels were then used to estimate the expected unserved energy in each region as a proportion of the firm load. The results for the capacity levels are shown in Table 4.9. The corresponding reliability levels and their averages are shown in Table 4.10 and Figure 4.8.

Table 4.9 Optimal Capacity Levels Based Upon Minimum Total Expected Reliability Cost (MW)

Region	2006	2007	2008	2009	2010
SA	3035	3007	3439	3411	3692
Vic	7673	7123	7077	7806	7391
NSW	10333	10345	10734	10633	11035
Qld	8890	9308	9571	10203	10524

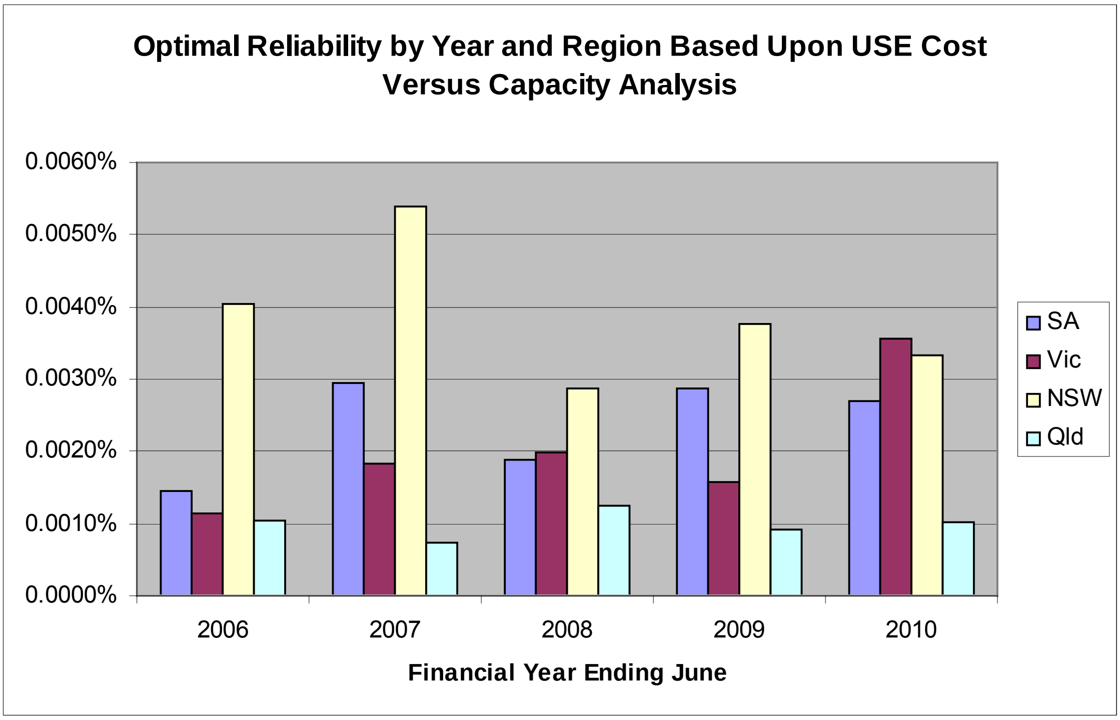
Table 4.10 Optimal Reliability Levels Based Upon Minimum Total Expected Reliability Cost Versus Regional Capacity

	2006	2007	2008	2009	2010	Average
SA	0.0014%	0.0029%	0.0019%	0.0029%	0.0027%	0.0024%
Vic	0.0012%	0.0018%	0.0020%	0.0016%	0.0036%	0.0020%
NSW	0.0041%	0.0054%	0.0029%	0.0038%	0.0033%	0.0039%
Qld	0.0010%	0.0007%	0.0012%	0.0009%	0.0010%	0.0010%
Average	0.0019%	0.0027%	0.0020%	0.0023%	0.0027%	0.0023%

The following observations of these results are made:

- The capacity solutions were not always stable because of the interaction between the regional capacities and the cost regression function. The results are subject to sampling error and there were insufficient capacity states to obtain a sensible result in any one year.

Figure 4.8 Optimal Reliability Levels Based Upon Minimum Total Expected Reliability Cost Versus Regional Capacity



- The reliability levels in Table 4.10 and Figure 4.8 vary quite considerably from year to year which also reflects the limited sample for each capacity scenario. However, using averaging over the years and regions to try to reduce the influence of this sampling error we do obtain an indication that about 0.002% is suitable as a NEM wide average as shown by the bottom right hand corner of Table 4.10.

- The reliability level obtained for SA is lower using this method of regression to capacity which is inconsistent with the results of the previous methods and inconsistent with the peaking nature of SA demand. This may be due to sampling error and an inadequate model of the interactions between the Victorian and SA regions.

- The reliability level for NSW seems to be over-estimated. This may be due to insufficient capacity states to separate out the state capacity effects as indicated by the need to constrain the coefficients in the regression equation to positive values.

- The reliability level in Victoria is higher than for Queensland as obtained previously. This is due to the allowable use of the smelters to manage short-term outages at low cost.

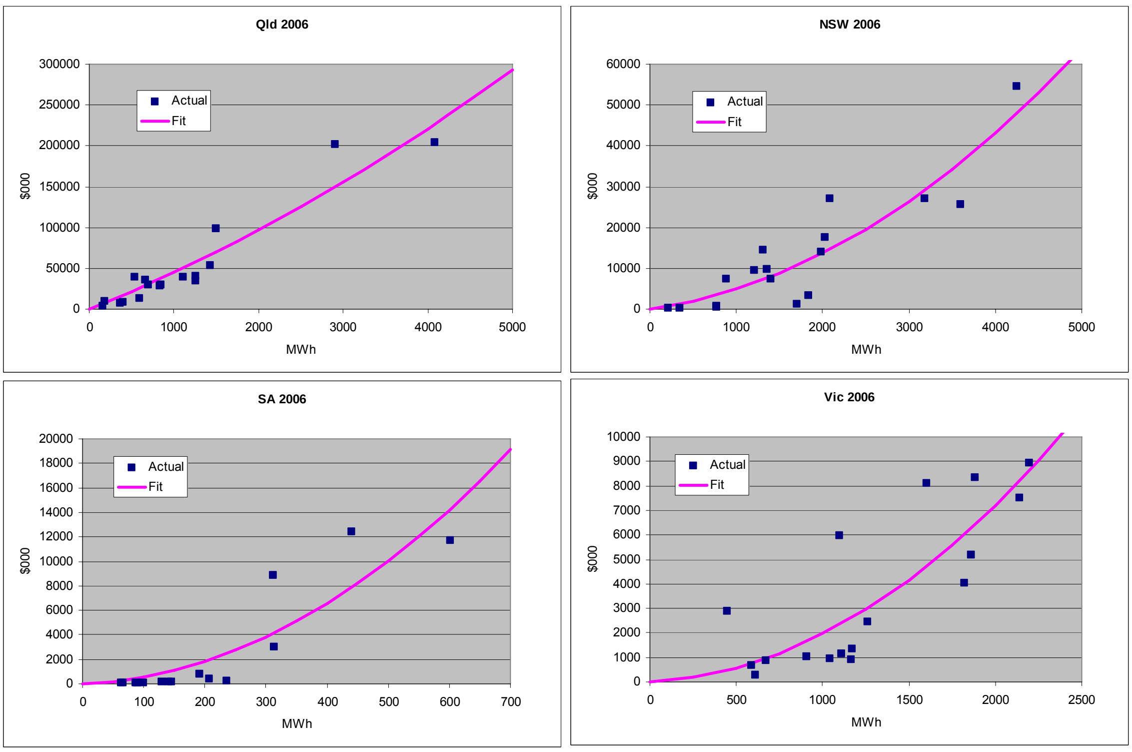
We conclude from this analysis that there is not enough smoothing in the average cost and unserved energy and the number of capacity states to obtain a robust result using this method. Based upon the shape of the function in Figure 4.3 it is also unlikely that a quadratic function adequately describes the cost/capacity relationship for the purpose of finding the optimal capacity value. Therefore the calculation of the optimal capacities is probably distorted by this factor as well as the sampling error. Therefore we do not favour this method or the results obtained as providing a good indication of optimal reliability apart from confirming that the current standard is not too far wrong.

4.9 UNSERVED ENERGY COST VERSUS UNSERVED ENERGY

The second method which is easier to apply and gives more robust results with the limited number of samples involved a regression of the unserved energy cost and the unserved energy level for each region as shown in Figure 4.9 for 2006. The following features of these charts are evident:

- The Queensland cost function is flatter because of the assumption that unserved energy is shared across all sectors rather than dispatched economically
- The quadratic component is evident in the other regions as we move from low cost resources to higher cost resources
- There is a great deal of scatter in the results due to the asymmetry of the unserved energy cost incidence as observed in Figure 4.9. Thus the relationship between unserved energy cost and volume varies markedly depending on what kinds of events occur and their relative incidence.

Figure 4.9 Expected Unserved Energy Cost Versus Expected Unserved Energy for 2006



- The pink line in each chart represents the quadratic regression function that was used for the optimal reliability assessment.

It is quite possible that with more data points we could assess a more complex relationship between cost and unserved energy but it is clearly never going to be stable and always subject to sampling error because of the asymmetry of the distribution of costs and the practicality of obtaining a large number of simulation events. There is the additional problem that using normal mean time to repair of thermal units of some 30 hours also increases the number of samples needed to obtain a stable estimate of unserved energy. It may be necessary to run two studies in practice:

- One series with very short mean time to repair (one dispatch period) to obtain the expected unserved energy versus capacity
- A second series with many more simulations with normal mean time to repair for obtaining estimates of the duration and magnitude of unserved energy events for costing purposes.

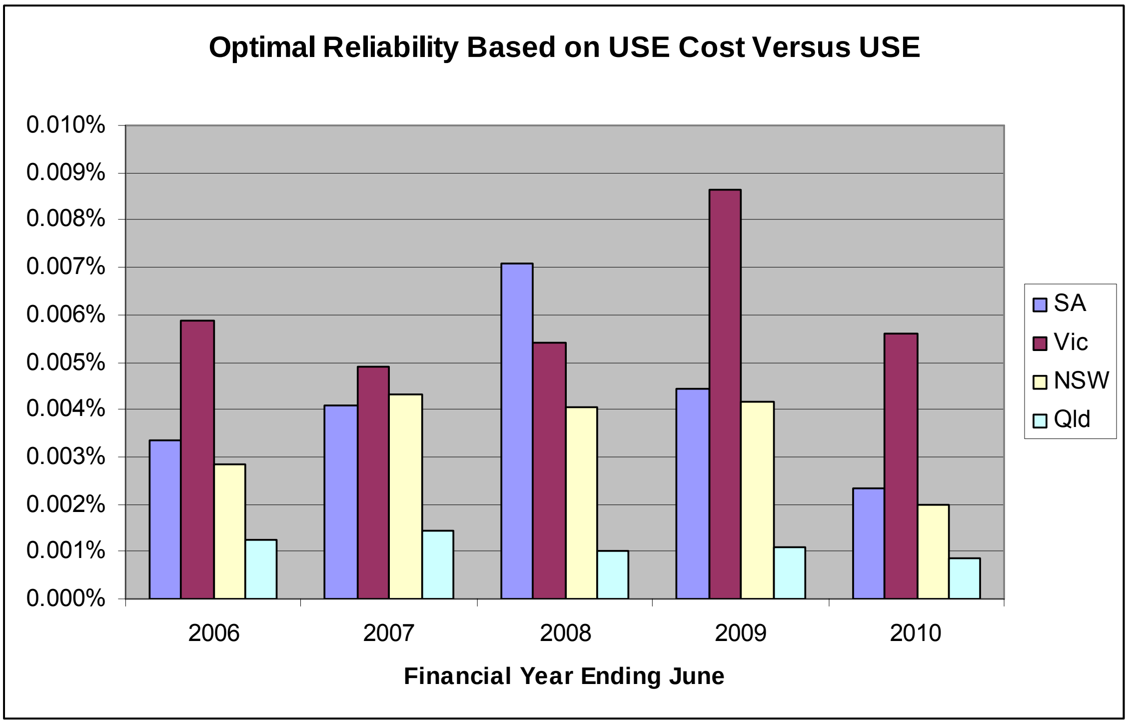
MMA accepted that an approximate relationship was sufficient for our purposes if all we were trying to do was assess a long-term economic relationship between unserved energy cost, unserved energy and installed capacity. It is apparent that the methods can be further improved as computing power becomes cheaper and faster.

These functions were then solved as shown in Appendix E . The corresponding unserved levels are shown in Table 4.11 and Figure 4.10. The features of these results are:

Table 4.11 Optimal Unserved Energy Levels Derived from Expected Unserved Energy Cost versus Expected Unserved Energy Level

	2006	**2007**	**2008**	**2009**	**2010**	Average
SA	0.0033%	0.0041%	0.0071%	0.0044%	0.0024%	0.0043%
Vic	0.0059%	0.0049%	0.0054%	0.0086%	0.0056%	0.0061%
NSW	0.0028%	0.0043%	0.0041%	0.0042%	0.0020%	0.0035%
Qld	0.0012%	0.0015%	0.0010%	0.0011%	0.0008%	0.0011%
Average	0.0033%	0.0037%	0.0044%	0.0046%	0.0027%	0.0037%

Figure 4.10 Optimal Reliability Levels Based Upon Minimum Total Expected Reliability Cost Versus Expected Unserved Energy



- The unserved energy levels are clearly higher in Victoria and SA as expected.
- The higher level of unserved energy in Victoria and NSW occurs because of the low cost allowed for the aluminium smelter interruptions.
- The unserved energy levels are higher overall than obtained from Method 1 except in Queensland where they line up with values obtained by other methods. This would be due to the apparent policy of sharing the load shedding incidence around rather than targeting low cost resources first as occurs in the other states.
- The unserved energy levels are much higher than the current standard of 0.002% except in Queensland
- The year to year variation is less than obtained from Method 1 because it is more stable and less exposed to sampling and modelling error.

The average level of unserved energy cost at these critical reliability levels is shown in Table 4.12.

The average cost is lower in Victoria and NSW because of the availability of smelter loads to cover more the smaller load shedding events. The costs are higher in Queensland because of the equal sharing load shedding policy.

Table 4.12 Average Unserved Energy Cost at the Optimal Unserved Energy Level Derived from Expected Unserved Energy Cost versus Expected Unserved Energy Level

	2006	2007	2008	2009	2010	Average
SA	$17.25	$16.51	$22.84	$30.28	$35.63	$24.50
Vic	$5.09	$6.46	$3.64	$9.03	$10.16	$6.88
NSW	$7.01	$8.57	$5.59	$6.06	$6.26	$6.70
Qld	$43.45	$29.64	$41.89	$32.17	$41.98	$37.83
Average	$18.20	$15.29	$18.49	$19.39	$23.51	$18.98

The marginal level of unserved energy cost at these critical reliability levels is shown in Table 4.13. As for the average cost, the marginal cost is lower in Victoria and NSW because of the availability of smelter loads to cover the smaller load shedding events. The costs are higher in Queensland because of the equal sharing load shedding policy and higher in South Australia because of the limited amount of water pumping load available.

Interestingly the average marginal cost of load shedding over the four regions is $27/kWh which is close to the typically used vale of $30/kWh used in the earlier simplified analysis. This means that the previous results should be comparable to the simplified analysis conducted in sections 4.4.1 and 4.4.2. In any case, we could use the scaling factor of $30/$27.37 to adjust the results for the unserved energy factor. Alternatively we could apply the annual or average values from Table 4.13.

Table 4.13 Marginal Unserved Energy Cost at the Optimal Unserved Energy Level Derived from Expected Unserved Energy Cost versus Expected Unserved Energy Level

	2006	2007	2008	2009	2010	Average
SA	$32.61	$34.10	$43.48	$54.04	$56.27	$44.10
Vic	$9.86	$15.63	$6.25	$17.85	$18.85	$13.69
NSW	$11.13	$11.57	$7.20	$9.26	$9.81	$9.79
Qld	$45.47	$39.15	$43.95	$38.91	$42.05	$41.91
Average	$24.77	$25.12	$25.22	$30.01	$31.75	$27.37

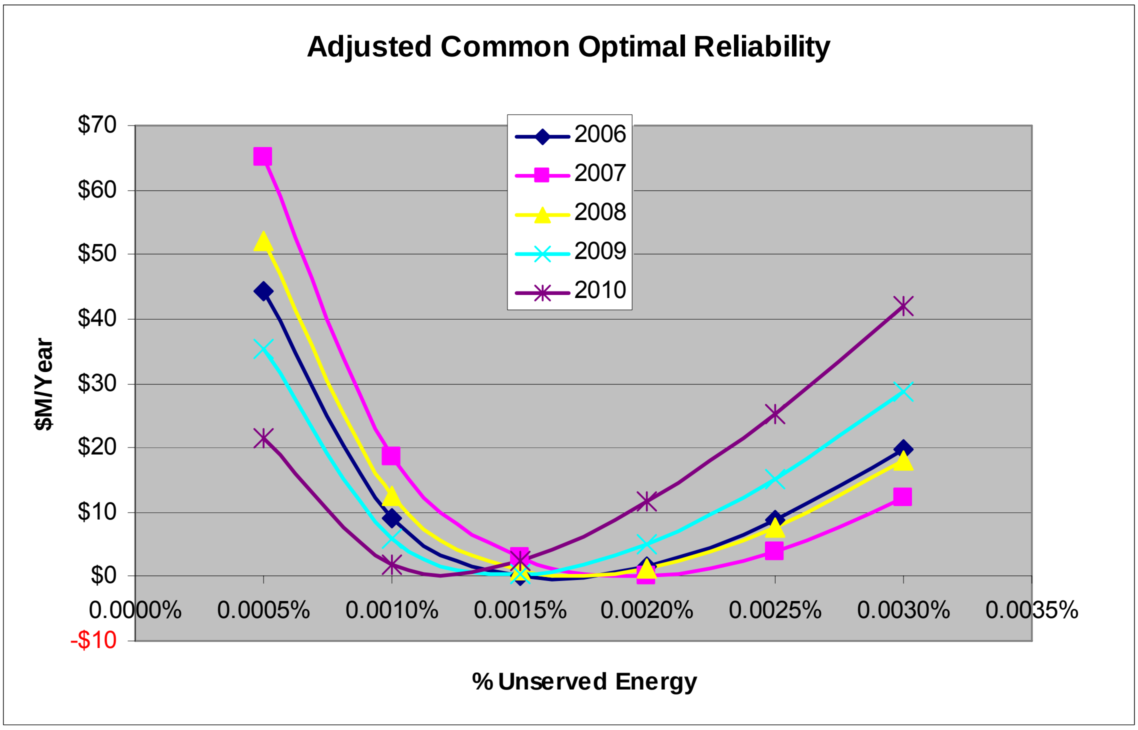
4.10 THE POTENTIAL COST OF MAINTAINING THE CURRENT STANDARD

One of the objectives of this study was to assess the potential cost of leaving the current standard as is, compared to having a time varying and geographically varying standard assessed on an annual basis having regard to the actual plant reserves and the scope for inter-regional support. The analysis we have undertaken can provide a guide to the level of costs.

4.10.1 Maintaining a common standard

If maintaining a common standard throughout the NEM is inviolate, then the potential cost over the next five years based upon the analysis shown in Figure 4.11 where the minimum costs have been set up is zero. The corresponding values shown in Table 4.14 are the difference between the annual cost in each year at 0.002% and the annual cost at the optimal level assuming that there was time to make the transition in capacity resources at the reserve capacity rate of $100/kW/year. A levelised cost is included at 7% real discount rate. The table results show that even a non-optimal common standard could cost about$3.5 M per year over the next five years in present value terms. This is comparable to the initial estimate made when formulating this project of $4.5 M as discussed in section 4.1.

Figure 4.11 Cost Functions for Estimate of a Common Standard for Expected Unserved Energy



4.10.2 Maintaining Regional Standards based on an Arbitrary Cost

If we allow ourselves the complexity of having different standards among the regions each year and we assume that capacity planning can adapt to varying standards as set, then we can increase the savings over the next five years eightfold to as much as $33 M per year. This is summarised in Table 4.15. Of course, this benefit would not be achieved if there is already surplus capacity to a less stringent standard. However, apart from South Australia, the optimal standard is higher (target is lower) than the current standard so this means that the additional peaking resources above that required to meet the 0.002% target are already beneficial in NSW and Queensland. This may help to explain why the NEM has delivered more capacity than needed to meet the 0.002% target if we assume that market participants already know that the capacity has economic benefit to their portfolios.

Table 4.14 Potential Cost of an Unchanged Common Standard (from .002%) ($M/year in June 2005 Dollars)

Levelised Annual Cost	2006	2007	2008	2009	2010
$3.54	$1.52	$0.00	$1.12	$5.12	$11.58

Table 4.15 Potential Cost of a Common Standard (at 0.002%) Relative to Regional Optimal Standards at $100/kW/year and $30/kWh ($M/year in June 2005 Dollars)

Levelised Annual Cost	2006	2007	2008	2009	2010
$32.68	$6.70	$22.99	$60.95	$42.47	$35.75

4.10.3 Optimising for Actual Load at Risk

Assuming that our cost model is appropriate to evaluate the average cost of load shedding, we estimate a cost penalty relative to that alternative standard. We found that the marginal cost of load shedding in each region in each years for 0.002% unserved energy was estimated to be about $21/kWh as shown in Table 4.16. It ranges between $17 and $27 on an annual basis and between $4.65 and $47 on a regional basis with Queensland having the highest marginal cost.

The average marginal values are lower than the previously assumed average $30/kWh because of the potential usage of the smelter loads in rotational mode to manage modest supply constraints.

Table 4.16 Marginal Cost of Load Shedding by Region for Capacity to Deliver 0.002% Unserved Energy $/kWh Shed or at Risk Without Restrictions

Levelised Annual Cost	2006	2007	2008	2009	2010	Average
SA	$20.33	$16.10	$13.89	$27.92	$50.09	$25.67
Vic	$3.57	$4.74	$2.96	$4.31	$7.67	$4.65
NSW	$8.68	$8.35	$5.56	$5.94	$9.91	$7.69
Qld	$47.98	$46.27	$47.90	$49.81	$42.25	$46.84
Average	$20.14	$18.87	$17.58	$22.00	$27.48	$21.21

The additional cost of continuing with the 0.002% standard as compared to optimal levels in each year is shown in Table 4.17 assuming that:

- the market could track the changes exactly
- the event outage costs and constraints have been accurately modelled.

Table 4.17 Potential Benefits of Cost Reflective Reliability Standard Based Upon Outage Event Costs ($M/year in June 2005 Dollars)

Levelised	2006	2007	2008	2009	2010
$39.46	$33.47	$26.15	$96.49	$31.10	$7.29

The levelised value is nearly $40 M per annum. In practice the benefits would be much lower and the savings due to a particular standard would need to take into account committed and existing projects and the scope for the targeted capacity levels to be achieved. This would require further detailed analysis which is not warranted unless proper information on load shedding policies and constraints is made available. However there is sufficient potential benefit to justify further clarification of these matters.

The potential additional cost of the current standard over than which would apply if event costs were more explicitly considered is not as readily estimated because the jurisdictional co-ordinators have refused to release the relevant information for the purposes of this study. However, taking MMA's assumptions as realistic, Table 4.18 shows the potential cost impost relative to 0.002% using these cost structures for a common standard or a regional standard.

Table 4.18 Potential Cost of a Reliability Standard (at 0.002%) Relative to Common or Regional Optimal Standards Based on Event Costs ($M/year in June 2005 Dollars)

	Levelised Annual Cost	2006	2007	2008	2009	2010
Common Based on Standard Average Costs	$3.54	$1.52	$0.00	$1.12	$5.12	$11.58
Regional Based on Standard Average Costs	$32.68	$6.70	$22.99	$60.95	$42.47	$35.75
Based on Outage Event Cost Modelling	$39.46	$33.47	$26.15	$96.49	$31.10	$7.29

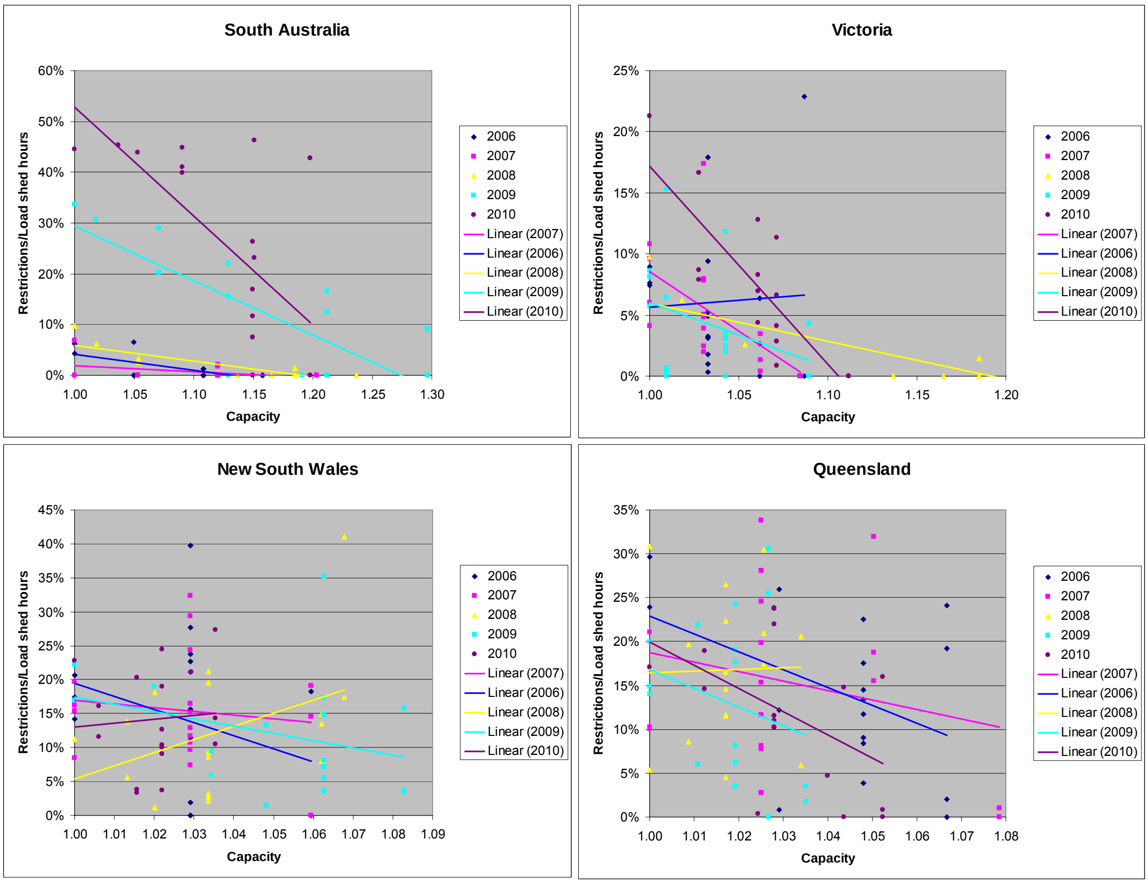
4.11 RELATIONSHIP BETWEEN THE PROBABILITY OF RESTRICTIONS AND CAPACITY

We also examined the relationship between the likelihood of restrictions being imposed and the level of capacity in each state in the NEM. The probability of restrictions in this instance is defined as the number of hours of restrictions being imposed as a percentage of the total number of hours where load is shed in a particular state in any one year.

Based on the thirty simulations for each capacity scenario, we have generally found that as capacity increases the probability of restrictions applying reduces in each year of the study period. There are some unexpected years where the probability of restrictions increases as capacity increase. We believe that this is due to the small number of simulations rather than a real relationship between capacity and probability of restrictions. The relationships found are shown in Figure 4.12. Capacity shown on the X axis is the ratio of installed capacity of the capacity scenario over minimum installed capacity scenario. The table showing this data is found in Appendix D .

If we use these regression equations and apply the capacity levels that correspond to the optimal reliability level in Table 4.11 we obtain the probability that load shed hours would be replaced by restriction hours as shown in Table 4.20. The values show that there would be about 10% probability that load shedding events would precipitate restrictions using the model parameters we have developed.

Figure 4.12 Probability of Restrictions versus Capacity



4.12 SUMMARY OF RESULTS ON OPTIMAL RELAIBILITY

Table 4.19 provides an overall summary of the calculations of optimal unserved energy.

It is concluded that the most effective method for conducting the analysis of optimal reliability involves modelling the relationship between expected unserved energy cost and expected unserved energy in each region by analysing the actual events which would occur including the incidence of restrictions.

Of course the effectiveness of the method depends on an accurate assessment of the load shedding policies and the direct and indirect costs incurred by customers or their willingness to pay extra to reduce the risk of interruptions.

Table 4.19 Summary of Optimal Reliability Analysis

Method	Capacity Cost $/kW/year	Unserved Energy Cost $/kWh	Average of the 5 Years and Regions	Range over the Years	Range over the Regions	Value compared with 0.002% $M/Year	Credibility
Simplified Strategist Model for 2006/07	$100	$30	0.0026% for 2006/07 only			$4.3 in 2007	**Useful:** Less accurate model of unserved energy than for Plexos but not exposed to sampling error.
Common Standard in all regions with Plexos	$100	$30	0.0016%	0.0012 – 0.0019%		Up to $11.6 in 2010 Up to $3.5 levelised over 5 years	**Good:** A good fit of the results provides a suitable common standard.
Standard optimised for each region	$100	$30	0.0028%	0.0022 – 0.0037%	0.0012 - 0.0071%	Up to $60.9 in 2008 Up to $32.7 levelised over 5 years	**Good Except for SA:** The reliability standard for SA averaging 0.0071% seems too high. The range 0.0012% to 0.0016% looks more reasonable.

Method	Capacity Cost $/kW/year	Unserved Energy Cost $/kWh	Average of the 5 Years and Regions	Range over the Years	Range over the Regions	Value compared with 0.002% $M/Year	Credibility
Using Unserved Energy Cost versus Capacity	$100	Unserved Energy Cost Model	0.0023%	0.0019 – 0.0027%	0.0010 – 0.0039%	Up to $101 in 2009 $53 levelised over 5 years	**Poor – misleading results:** The cost of 0.002% standard using this method is not credible due to the poor fit of the regression of unserved energy cost and capacity.
Using unserved energy cost versus unserved energy	$100	Unserved Energy Cost Model	0.0037%	0.0027 – 0.0033%	0.0011 – 0.0061%	Up to $96. $40 levelised over 5 years	**Good:** Results reflect assumptions about interruption costs ore accurately than other methods.

Table 4.20 Probability that Load Shed Hours will be Replaced with Restrictions for Optimal Unserved Energy Levels Derived from Expected Unserved Energy Cost versus Expected Unserved Energy Level

	2006	2007	2008	2009	2010	Average
SA	2.8%	1.4%	1.3%	7.7%	33.7%	9.4%
Vic	6.2%	3.7%	2.3%	7.3%	7.3%	5.4%
NSW	14.0%	15.0%	12.9%	10.7%	13.8%	13.3%
Qld	15.2%	14.4%	16.8%	15.6%	9.8%	14.4%
Average	9.6%	8.6%	8.3%	10.3%	16.1%	10.6%

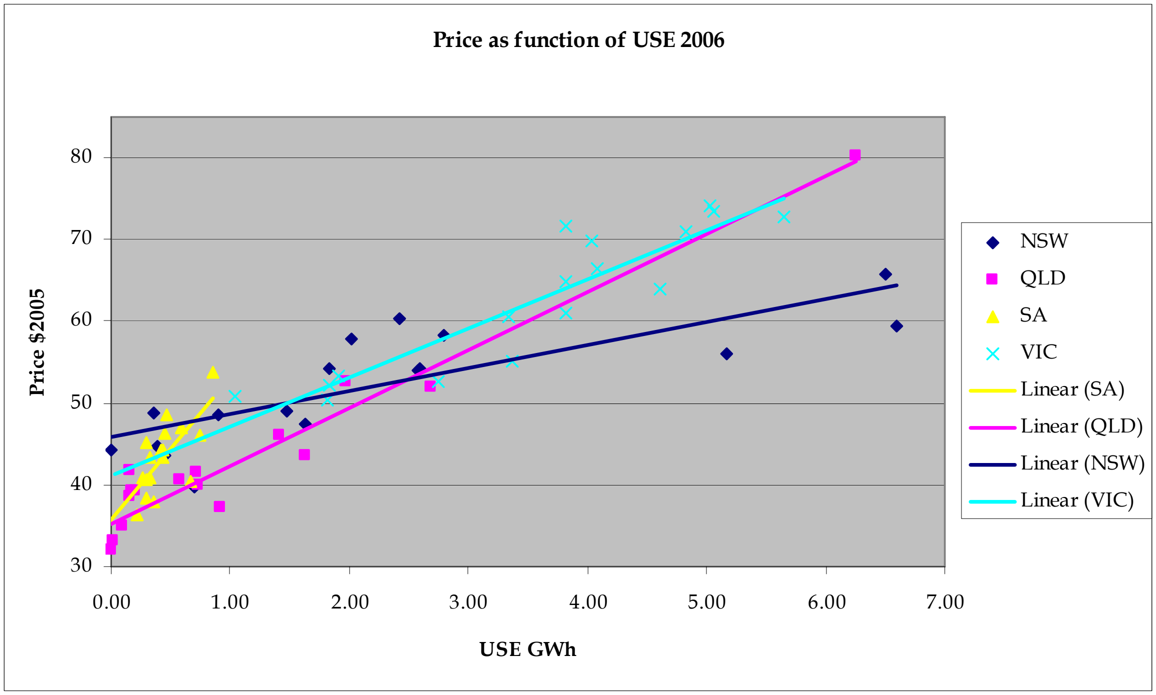
4.13 EFFECT OF USE STANDARD ON ANNUAL REGIONAL POOL PRICES

The remaining question to be considered was whether the revised standard would be commercially viable. Would it result in prices that are below the new entry cost? If so then we would expect that intervention would be necessary to maintain it.

We analysed the relationship between time weighted pool prices and the expected unserved energy level. As expected a linear relationship between expected spot price and unserved energy provided an adequate characterisation of the data as shown in Figure 4.13. Each region is shown separately versus its own unserved energy. As illustrated in Figure 3.2 above, the intercept at zero unserved energy can be understood to represent the average short-run marginal cost plus a market power pricing premium. The regression lines in Figure 3.2 suggest that this premium is greater in NSW and Victoria and lower in the other states. MMA considers that the higher price in Victoria reflects the impact of NSW prices on Victoria rather than a measure of market power in Victoria alone.

Linear regression was used to assess the relationship between time weighted prices and the unserved energy in each region. A matrix of coefficients is shown in Table 4.21. Any negative regression coefficients were regarded as not statistically significant as increased unserved energy cannot cause prices to fall. The corresponding terms were removed from the regression data and the remaining coefficients recalculated. The diagonal terms are dominant and unserved energy in remote regions does not

Figure 4.13 Example of Time Weighted Spot Price versus Expected Unserved Energy for 2006



affect local price because of the diversity of peak loading. When prices peak in one region due to unserved energy, the price increase rarely flows to other regions because of import transmission constraints.

These regressions were then used to determine the expected price under the existing and proposed reliability standards. These prices were compared to estimated short-run marginal costs and new entry costs in each region allowing for emission abatement revenues. The results of this analysis are shown in Figure 4.14 and Table 4.22 below. The results demonstrate that the regional annual pool price for both the current and the proposed target USE levels are above the new entry cost for all states in all years, with the exception of SA in 2006. As part of this analysis it has been confirmed that the annual price is affected more by the frequency and duration of USE events than the magnitude of energy in the USE incidents.

Comparing the constant terms on the right hand side of Table 4.21 with the short-run marginal cost (rounded) in Table 4.22 (SRMC), shows that all regions have significant market power to deliver prices well above marginal costs.

Table 4.21 Coefficients of Time Weighted Price versus Expected Unserved Energy

Coefficients of Price/USE	SA	Vic	N	Q	Const
2006					
SA	14.331	0	0	0	31.54
Vic	0	5.434	0.797	0	41.36
NSW	0	0.042	2.669	0.569	45.39
Qld	0	0	0	7.076	35.29
2007					
SA	9.321	0.345	0	0	38.52
Vic	0	4.277	4.378	0	39.39
NSW	0	0.627	7.020	0	38.09
Qld	0	0	1.840	5.999	35.16
2008					
SA	11.834	0.415	0.110	0	37.63
Vic	0	3.243	2.022	0	48.19
NSW	0	0	3.453	0.497	47.30
Qld	0	0	0.228	3.610	35.57
2009					
SA	6.272	2.600	0	0	36.36
Vic	0	5.470	2.015	0	41.47
NSW	0	0	5.812	0.200	40.46
Qld	0	0	0.367	3.747	32.57
2010					
SA	2.160	0.576	0	0	47.80
Vic	0	5.787	2.517	0	41.07
NSW	0	0	3.028	0	45.63
Qld	0	0	0.869	4.930	31.88

Thus we can be assured that both the current reliability target at 0.002% and the economically efficient target of 0.001% for Queensland and 0.004% for the other states would be commercially viable. Providing that new entry is competitive, NEMMCO should not need to intervene to maintain these standards unless there has been a forecasting error that has lead to an inadvertent capacity shortage. It would be unlikely that adopting these lower standards would jeopardise supply reliability for firm customer demand.

Figure 4.14 Spot Prices that Match Reliability Standards

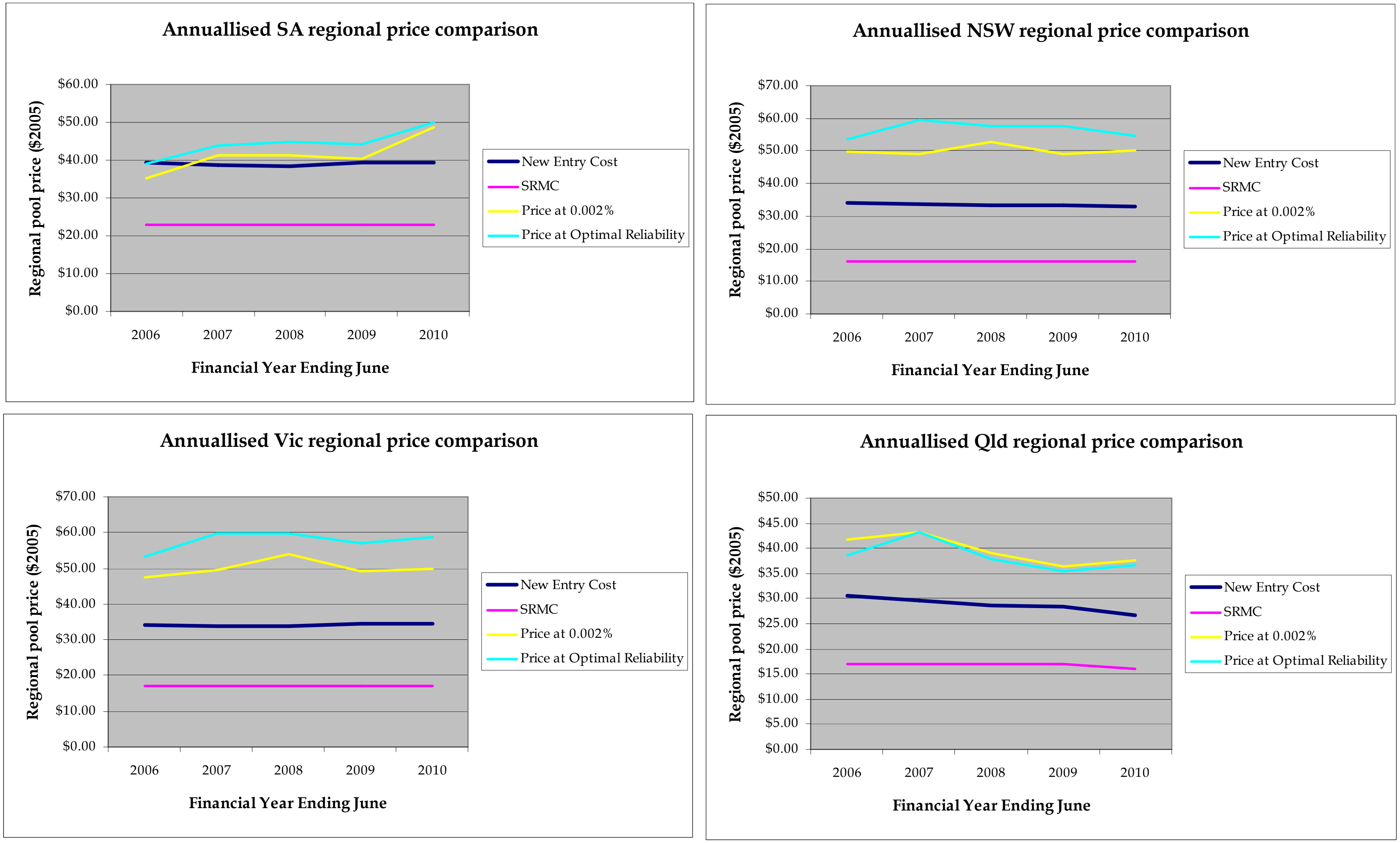


Table 4.22 Expected Spot Market Prices for Alternative Reliability Standard

Region		2006	2007	2008	2009	2010
SA	New Entry Cost	$39.42	$38.85	$38.50	$39.22	$39.44
	SRMC	$23.00	$23.00	$23.00	$23.00	$23.00
	Price at 0.002%	$35.27	$41.25	$41.23	$40.28	$48.87
	Price at Optimal Reliability	$38.99	$43.97	$44.84	$44.19	$49.94
Vic	New Entry Cost	$34.13	$33.95	$33.64	$34.39	$34.38
	SRMC	$17.00	$17.00	$17.00	$17.00	$17.00
	Price at 0.002%	$47.31	$49.54	$53.99	$49.23	$49.84
	Price at Optimal Reliability	$53.25	$59.70	$59.80	$56.99	$58.60
NSW	New Entry Cost	$34.17	$33.61	$33.21	$33.20	$33.02
	SRMC	$16.00	$16.00	$16.00	$16.00	$16.00
	Price at 0.002%	$49.83	$48.89	$52.79	$49.12	$50.06
	Price at Optimal Reliability	$53.51	$59.69	$57.60	$57.52	$54.48
Qld	New Entry Cost	$30.55	$29.63	$28.57	$28.37	$26.74
	SRMC	$17.00	$17.00	$17.00	$17.00	$16.00
	Price at 0.002%	$41.66	$43.25	$39.15	$36.48	$37.58
	Price at Optimal Reliability	$38.47	$43.24	$37.86	$35.33	$36.64

Based upon the assumptions made and the results derived in this project we may conclude the following:

- The current 0.002% reliability standard is apparently inconsistent with the load shedding policies in each jurisdiction and the associated exposure to load shedding on an expected value basis.
- The reliability standard could be made more stringent in Queensland where load shedding risk is understood to be shared equitably. Based upon the model developed in this work a standard closer to 0.001% to 0.0012% would be more appropriate.
- In Victorian and NSW where aluminium smelters may be available for addressing short-term capacity shortages and depending on the nature of contractual constraints and commercial arrangements, there is potential to relax the reliability standard in the range 0.003% to 0.004%. It would be necessary to confirm the commercial arrangements for smelter load shedding and the load shedding arrangements for residential and business customers and revising the analysis accordingly to confirm an appropriate value.
- In South Australia the reliability standard could also be relaxed to 0.004% on an expected value basis depending on the constraints on the interruption of water

pumping load and the ability to use the Heywood interconnection and Murraylink to provide emergency supplies.

- If these standards were introduced and the capacity levels were commensurate with these standards in all NEM regions then there would be sufficient price incentive to maintain these standards or better them. This analysis confirms why the existing standard has been delivered in the NEM. There is evidence of sufficient market power to deliver reliable supply to meet the reliability standard.

- The potential savings in customer and generators costs would be up to $40 M per annum if the reliability standard was defined on a regional and annual basis and tracked closely by new entrants.

- The volatility of unserved energy costs on an annual basis is quite startling and suggests that this methodology should be further developed to provide an additional criterion that looks at the expected frequency of extreme events equivalent to 0.01% to 0.02% unserved energy. A 30 to 50 year time frame is the typical incidence of major network shut-downs caused by secondary equipment failure or operational errors with cascading outages and this exposure would be appropriate to such events arising solely from co-incident generator outages on a statistically independent basis.

- Before new reliability standards can be defined, further work is needed to quantify the impact of load shedding policies and the costs of the resources applied so that the methodology developed here can be used to provide an economic justification for revised reliability standards. The commitment of Governments to release this information will be needed before a robust and credible analysis can be provided.

5 ECONOMIC ISSUES FOR IMPLEMENTATION

5.1 ISSUES

The key issue with achieving the reliability standard in practice is that the committed capacity over the next five years already exceeds the capacity required to meet the current reliability standard of 0.002% and the alternative standard of 0.001%/0.004%. The surplus of capacity in all states means that extra capacity may be required in SA in 2008 but it would be offset by a possible capacity reduction in Victoria. Over the two regions there is no need for additional capacity.

NEMMCO has a more stringent security criterion (10% POE peak demand + largest unit) that requires more capacity than required to meet the reliability criterion. It is arguable that the additional capacity should be provided by demand side withdrawal rather than generating capacity because of its very low utilisation. However in this chapter we look at the economic impacts if generating capacity were only provided to meet the reliability standard and not the security criterion.

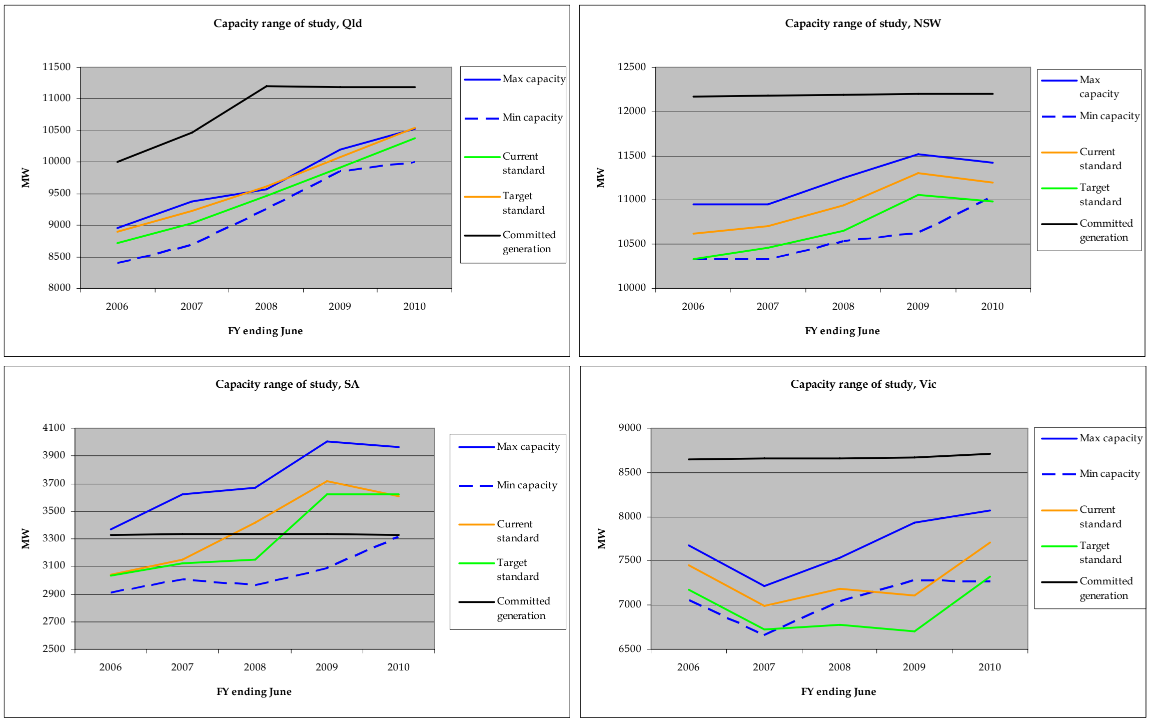
The oversupply of capacity means that the full economic benefit of the new economic standard as evaluated in the previous chapters would not be fully realised within the study period. In fact to gain real economic benefit from the new standard would require mothballing of surplus capacity. It is unlikely this would result in economic benefit for the consumer unless the market was much more competitive. This is consistent with the analysis which showed that market prices would be above new entry costs if the new standard were achieved. However in this analysis we ignore the possibility that the new reliability standard would never be achieved due to competitive new entry.

The following analysis shows that the potential economic benefit that could be gained by just moving from the committed capacity to the current standard has been assessed as $55.1M per annum annualised (7% real discount rate 2006 – 2010). Improving to the target standard would gain an extra $8.8M per annum annualised over the period to 2010. This assessment was based upon assuming that $30/kW/year could be saved by mothballing surplus capacity.

5.2 COMMITTED CAPACITY

As illustrated in Figure 5.1 the committed capacity exceeds the capacity levels sufficient to deliver the current and economic reliability standard in all states. The maxima and minima capacities in Figure 5.1 represent the band of capacities simulated in the NEM simulations in this study. It is apparent that in most years and regions the optimal

Figure 5.1 Committed capacities, required capacities to meet current and target standards



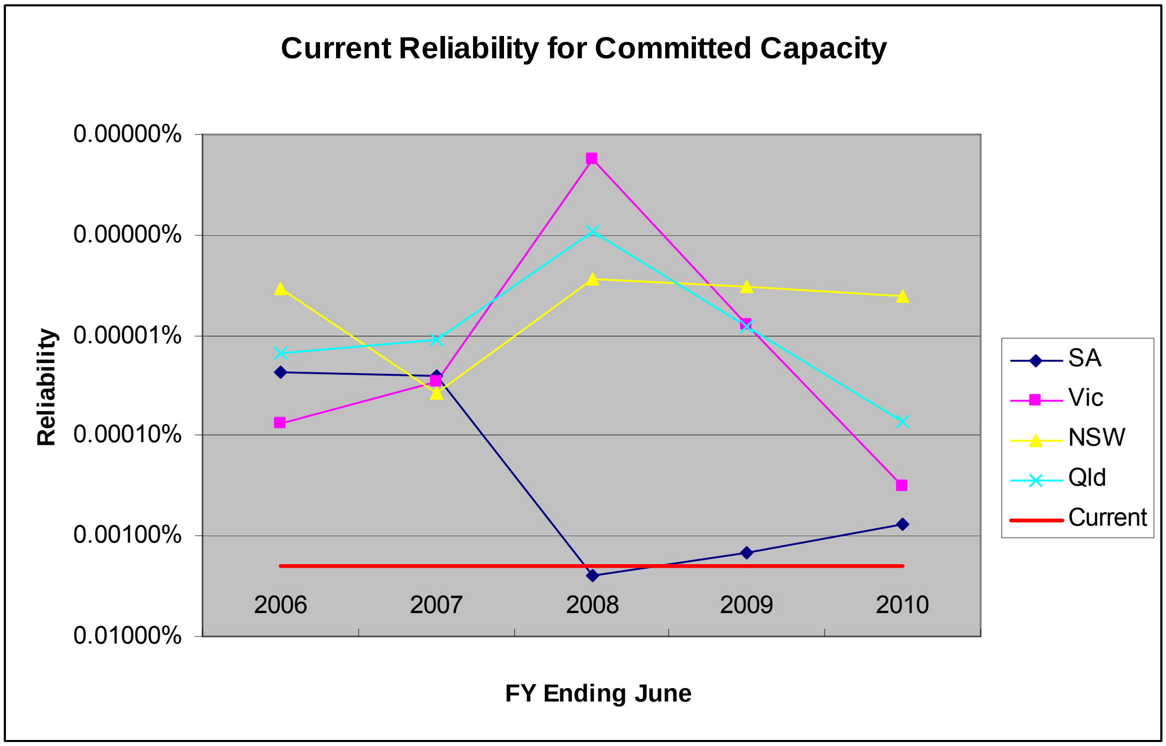
capacity is within the range we have studied and therefore we should be able to use the regression functions we have created to assess the costs and benefits of moving from the current committed installations to an optimal configuration. There is some distortion for the results in 2009 due to sampling errors and their effective on the regression functions but the overall trend is fairly robust.

It is clear that the market capacities far exceed the requirements for both standards for the study period. SA is the exception, where capacity is required in 2008 for the current standard or 2009 for the target standard. This is compensated for by reduced capacity in Victoria. However the 2009 regressions of unserved energy versus capacity were not quite credible and we are using an average of the 2008 and 2010 functions for this year[1]. Therefore the capacity results for 2009 for Victoria and South Australia are not deemed to be accurate for this purpose, although the combined Vic/SA total is probably reasonably indicative.

[1] This problem was discussed in section 4.4.

The expected levels of USE for the committed capacities to 2010 are in Figure 5.2. The vertical scale is inverted so that the measure is in effect a reliability measure. Higher reliability is at the top of the vertical axis. Again it is clear that SA is the only state that is

Figure 5.2 Reliability for the committed capacity, as per NEMMCO SOO 2005



not over supplied for the whole period. In fact SA is the only state that could adjust to meet the current reliability standard (in 2008) without mothballing existing capacity.

To achieve the reliability standards the committed capacity needs to be adjusted by the capacities set out in Table 5.1. These capacities are the same data as included in Figure 5.1 except that we have also added a combined Vic/SA assessment. NEMMCO combines these regions for reserve analysis purposes. Capacity needs to be greatly reduced in all regions except SA to match current or economic reliability standards. The NEM has delivered installed capacity sufficient to provide a much higher reliability level than is deemed sufficient. Victoria and South Australia capacity changes have an inverse relationship because the two regions are strongly linked and therefore capacity increase in one region allows a capacity reduction in the neighbouring region with a similar magnitude. The distortion in the 2009 USE/capacity regression exaggerates this relationship for the data presented.

Table 5.1 Capacity increase required from committed levels to exactly match the reliability standards, MW

	2006	2007	2008	2009	2010
Current standard					
SA/Vic	-1491	-1853	-1395	-1177	-727
SA	-292	-188	80	386	281
Vic	-1200	-1665	-1475	-1563	-1007
NSW	-1546	-1470	-1244	-894	-1003
Qld	-1293	-1435	-1731	-1279	-806
Target standard					
SA/Vic	-1772	-2148	-2068	-1672	-1091
SA	-296	-213	-188	291	295
Vic	-1476	-1935	-1880	-1963	-1387
NSW	-1836	-1725	-1535	-1139	-1211
Qld	-1109	-1244	-1575	-1114	-650

5.3 ANALYSIS OF CAPACITY SAVINGS AND USE COSTS

The benefit of moving to the current standard is about $40M annualised[2] at 7% real discount rate from 2006 to 2010 assuming that reserve capacity is valued at $100/kW pa fixed cost. If the current surplus capacity was mothballed it would most likely produce a saving in fixed costs related to operations and maintenance of about $20 to $50/kW pa.

Assuming $30/kW pa fixed cost saving, achieving the current standard would have an annualised saving for the market of $55.1M per annum and the target standard of $63.9M per annum relative to the committed capacity continuing to operate fully. Thus the saving in moving to the new standard from the old standard would be only $8.8M pa ($63.9 - $55.1) in levelised terms. However, most of the saving (the $55.1 M pa) would be achieved by removing capacity to achieve the **current** standard. This is a measure of inefficiency in the NEM relative to the intended minimum reliability standard. From a policy development perspective, increasing the role of demand side and discouraging surplus capacity should be the primary focus if an average unserved energy criterion is to be maintained.

[2] Annualising the savings is achieved by taking the present value of the total savings over the period and dividing it by the present value factor at the same discount rate. This is an equivalent annual amount in each year of the period that has the same net present value as the individual yearly amounts.

The key factor in savings comes from capacity reduction through mothballing. Figure 5.3 shows the benefit of the target standard over the current standard as a function of mothballing value, in annualised terms. The relationship is linear on mothballing value, the higher the mothballing value the more benefit to be gained from the target standard.

Figure 5.3 Annualised benefit of target standard over current standard

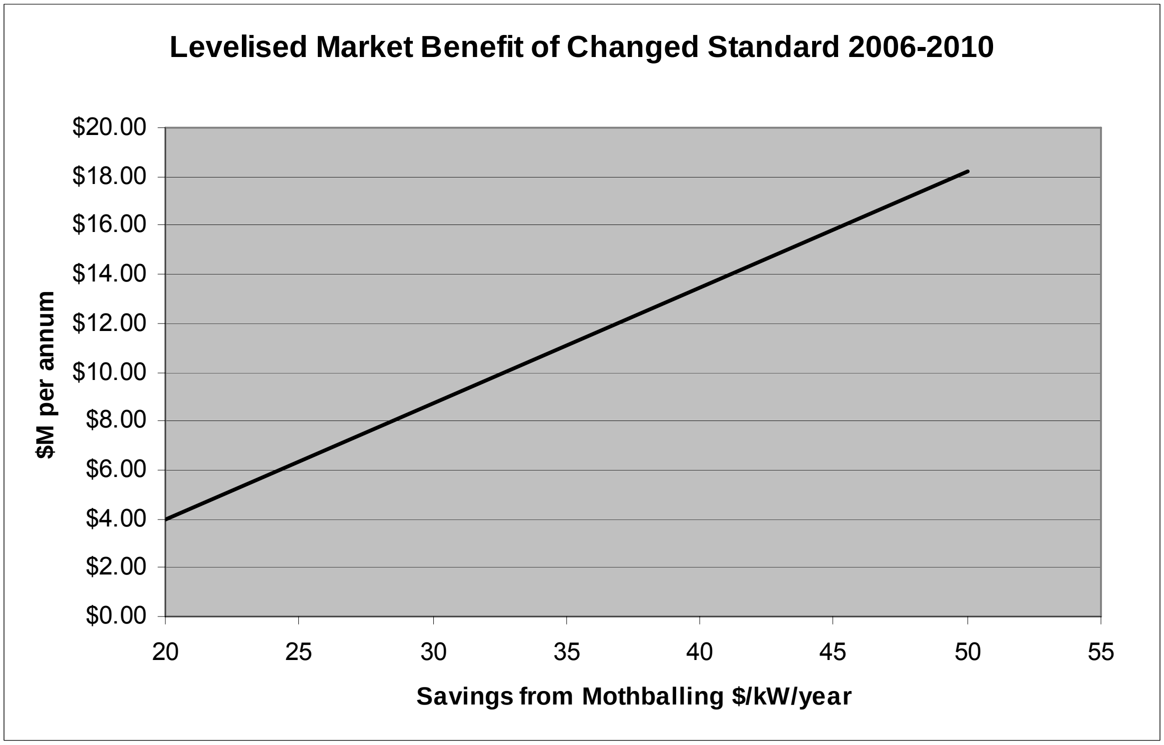
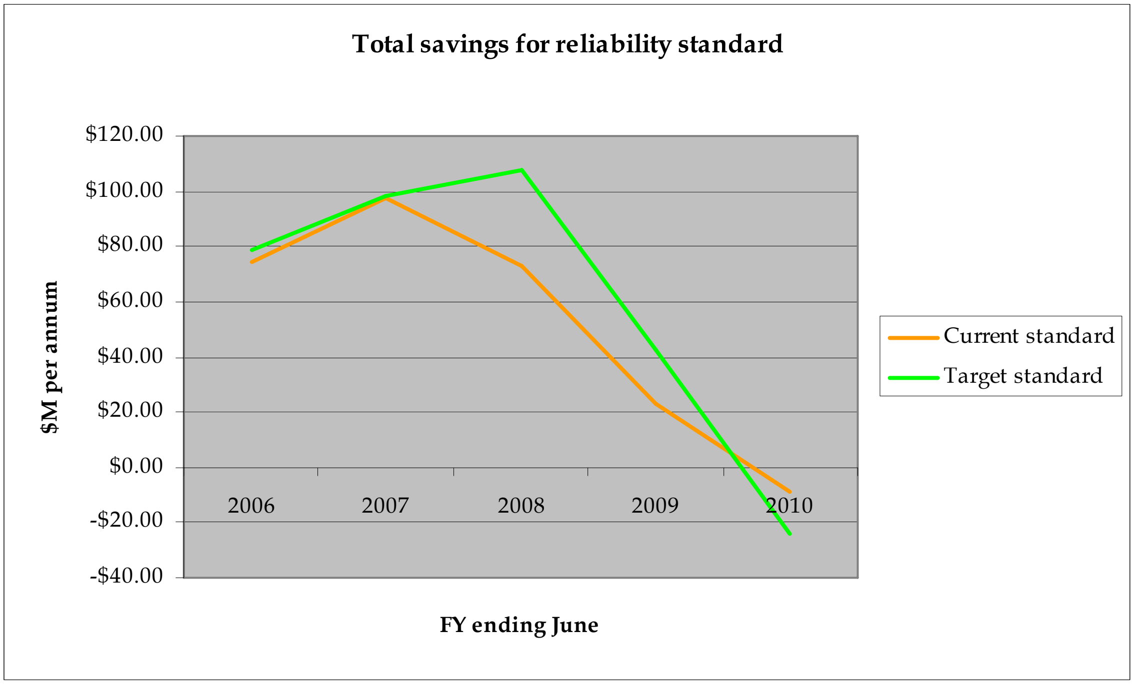


Figure 5.4 shows the potential annual savings for the NEM for achieving the reliability

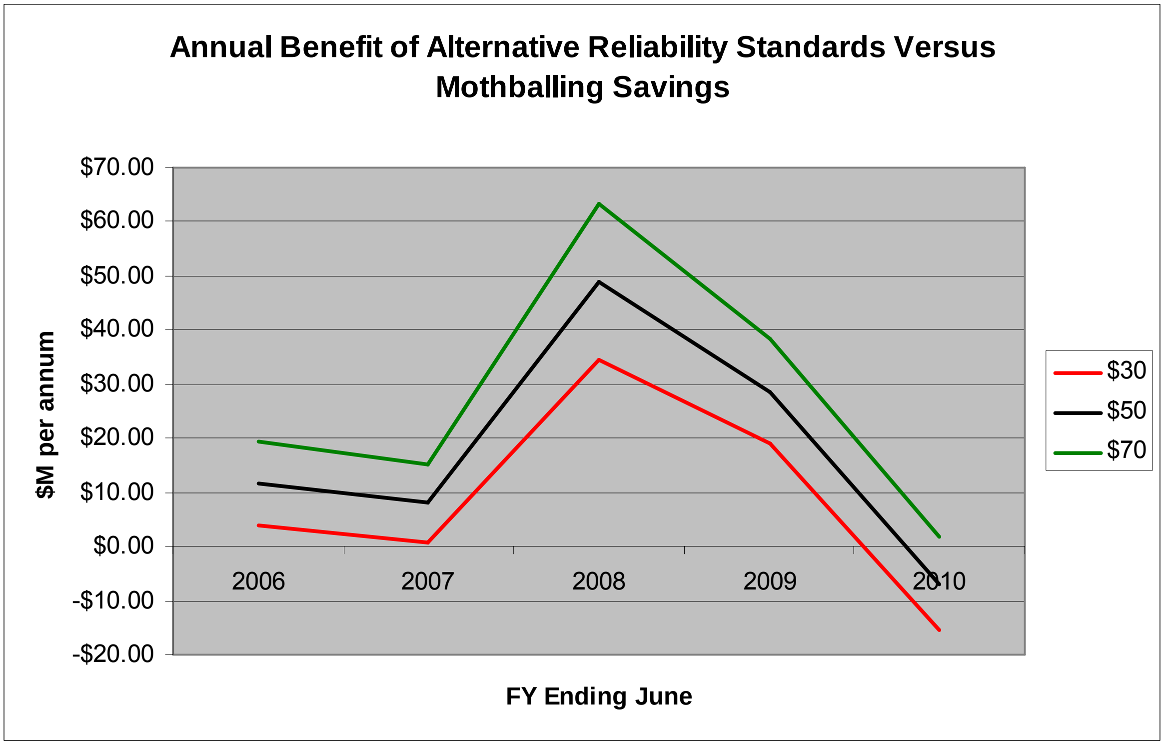
Figure 5.4 Total savings across the NEM for the reliability standards



standards, assuming $30/kW pa for mothballing. Clearly by 2010, mothballing would not likely be beneficial as capacity approaches the standard levels. This is mainly due to growth in demand increasing the unserved energy to match the economic reliability standard for the committed capacities. The target standard requires more capacity in Queensland, so there is even less economic benefit to be gained from mothballing capacity.

Figure 5.5 shows the annual benefit to be gained from mothballing capacity for various capacity values across the period. As stated above the higher the value of mothballing, the higher the benefit of the new standard. What is more visible here is the dependence of annual benefit on mothballing value. At around $16/kW/year mothballing value, neither standard has an economic benefit from mothballing.

Figure 5.5 Benefit of target reliability over standard, for different mothballing values



5.4 IMPLICATIONS FOR MOVING TO A NEW STANDARD

The strategic implications of this analysis may be summarised as follows:

- 85% of the benefits of the new standard could be achieved by encouraging the market to deliver to the current standard even though it is not economic itself. This would be achieved with
    - Improved entry for DSM
    - Less Government invention providing surplus capacity
    - Development policies that maintain competitive new entry
- There is no urgency to move to a new economic standard because there is surplus capacity and the price rises resulting with the current market structure may be deleterious for customers.
- In longer term, strategies to stimulate DSM and improved arrangements to enable smelter and other industrial loads to manage moderate capacity shortages through demand side withdrawal would enable a more efficient management of capacity risk and unserved energy

- Adopting a less stringent standard in the short-term would however discourage NEMMCO intervention in the NEM and facilitate the emergence of DSM activity.
- Adopting a higher standard in Queensland would not impose additional capacity costs because the required capacity is already committed to 2010.
- The question stills remains as to whether the average unserved energy standard is an adequate measure of customer impact and if not how to quantify an extreme event standard. This should be a focus of future work with greater attention to the costs and mechanisms of load shedding and restrictions under supply shortage conditions.

5.5 IMPACTS ON CUSTOMERS

The ability of the market to deliver the benefits of lower costs to customers depends on the level of competition in the market, especially under capacity constrained conditions when prices can approach $10,000/MWh and supply competition is least. The effective implementation of the current or a lower reliability standard would depend on an active demand side market that would compete with peaking generators and reduce the incidence of $10,000/MWh prices when supply shortages are approached or realised.

The analysis in this project has not examined what would be needed to achieve an outcome that benefits customers. Rather it has been shown that the NEM is carrying excessive costs that are not economically related to the value of reliability based upon current practices and recent assessments of unserved energy costs. These costs are being borne by small customers through maximum tariffs that support excess reserve capacity for very infrequent duty. It is clear that better outcomes would be possible as customers become better informed about their opportunities and their participation in the peak market is facilitated.

6 CONCLUSIONS

6.1 POTENTIAL METHODOLOGICAL ENHANCEMENTS

Before we draw the final conclusions from this study, we note the following limitations that have been identified and how they could be reduced in a more detailed examination of the data and with further market research.

- The costing of the events of unserved energy was severely limited by the lack of data available on operational processes and the cost of customer impacts. The classification could be refined for each NEM region and further input from NEMMCO and the Jurisdictional Co-ordinators could be very useful to improve the methodology and relate it to actual rather than notional load shedding behaviour. Further examination of actual system loading shedding events could be used to improve the structure of the model.

- The range of uncertainty in the conclusions and the lack of precision in defining an optimal reliability level reflect the underlying uncertainties in the electricity market as well as modelling deficiencies such as the limited number of Monte Carlo samples that could be analysed. A robust measure would require additional capacity scenarios (perhaps 25) and more simulations per scenario (perhaps 100 covering the three peak demand profiles). The peak demand profiles should be developed from suitable historical years. Such enhancements will become more feasible over time as computing power increases.

- The three main limitations of the method were:

  - The uncertainty about the cost of unserved energy events, although the results do seem reasonable

  - The uncertainty about the actual procedures followed in shedding load which affects how much of each type of load is disconnected. We have formulated an approach that matches objectives stated by the Jurisdictional Co-ordinators.

  - The difficulties in developing a functional relationship between unserved energy and capacity in each region. This would require more statistical samples and a review of the non-linearities in the relationship. Some analysis has indicated that the log-linear model of unserved energy versus capacity could be improved with more samples and with some second-order capacity coefficients.

6.2 OPTIMAL RELIABILITY

However despite these limitations, the project has confirmed several hypotheses that were considered prior to the project and identified that some savings of up to $40M per year could be achieved in the NEM by having an economic basis for the reliability standard on a time and regional basis rather than having one common standard reviewed infrequently.

The results that confirmed MMA's expectations about the issue of optimal reliability were as follows:

1. The optimal level of reliability as measured by the percentage of demand that is lost as unserved energy

    a. Varies approximately as the marginal cost of unserved energy between $15/kWh and $60/kWh, and

    b. Varies approximately inversely as the cost of reserve plant between $50/kW/year and $150/kW/year.

2. Such linear and inverse sensitivities of the standard could be used to readily adjust the standard to reflect short—term variations in marginal costs of capacity and unserved energy without requiring a full economic analysis each year.

3. The optimal level of reliability in each region of the National Electricity Market decreases as the load pattern becomes more high temperature weather sensitive on extreme days. The optimal level of reliability is highest for Queensland, then NSW, then Victoria, and then South Australia with the lowest level if measured on a percent unserved energy criterion[3].

4. The optimal level of reliability can be lower when there are lower cost interruptible resources available such as smelter loads and water pumping. Demand side participation rules should be designed to ensure that the role of these resources is encouraged and maximised to reduce the need for reserve plant that is hardly ever used.

5. There is a large analytical effort required to capture and process sufficient statistical samples of unserved energy events so that the sampling error is reduced to an acceptable level. Extreme events are an important component of this cost

[3] Tasmania was not considered in this study because MMA using Plexos was unable to adequately represent unserved energy arising from hydrological uncertainty. This would require a detailed model of Hydro Tasmania's assets using confidential information.

analysis because when they occur they often make customers think that the reliability standards are inadequate.

6. Treatment of averages is an inadequate way to characterise system reliability from a customer's perspective because when a serious event happens it has multiplier effects through the economy as restrictions are imposed to share the pain. This inevitably increases the total pain because restrictions are a very coarse method balancing supply and demand on a real time basis.

6.3 THE BENEFITS OF CHANGING THE UNSERVED ENERGY CRITERION

In addition to the quantitative information provided in this report, the following specific conclusions can be drawn about the unserved energy reliability criterion in the NEM assuming that it is retained in its present form:

7. The optimal level of reliability in the National Electricity Market over the next five years if applied on a common basis throughout the NEM and if used to determine generating capacity investments could remove unnecessary costs on customers of up to $63M per year initially relative to current commitments and up to $40 M per year after 2010 relative to the current reliability standard.

8. The actual cost penalty of the current standard relative to the optimal standard is only about $9 M per year in the period to 2010 because the capacity that is required in Queensland to achieve the optimal standard has already been committed so some of these excess costs will be avoided.

9. The uncertainty in the level of unserved energy and its cost in any one year is quite substantial and it calls into question why an expected unserved energy criterion is appropriate. It would seem that a more effective model would reduce the risk of extreme events as well as optimise an average outcome. The economic analysis of such a policy would require a more detailed analysis of the consequences of load shedding for customers based on actual processes.

10. Applying a criterion that minimises expected total interruption cost would produce a higher standard of optimal reliability than assuming a constant average cost of unserved energy because of the incidence of extreme events and the asymmetry of customer impact around the average unserved energy level. Since average unserved energy cost is about 70% of the marginal unserved energy cost based upon these studies, optimal reliability would be about 44% higher (standard 30% lower) if based upon marginal unserved energy cost rather than average unserved energy cost.

6.4 RECOMMENDATIONS FOR A NEW STANDARD

In terms of the policy discussion and the recommendations previously made by MMA and summarised in section 2.2, the following recommendations are added:

11. The reliability standard could be improved by establishing more stringent levels for Queensland at about 0.001% to 0.0012%

12. The reliability standard could be relaxed to 0.004% in the southern states if the aluminium smelters and water pumping loads were fully exploited to cover short-term capacity shortages. This level would vary according to the actual commercial arrangements that affect the economics of smelter participation to the wholesale market.

13. The reliability standard for the purposes of intervention by NEMMCO should be adjusted to reflect new entry cost for reserve capacity and whether new capacity is needed on a short or long lead time to meet the standard. If reserve capacity is already available then the implied reserve capacity cost would be halved and the standard expressed in % would be halved also. This would ensure that incentive to maintain surplus plant for reserve purposes is adequate.

14. The optimal reliability standard should be recalculated using MMA's methodology or an enhancement of it as data allow, to set appropriate standards separately in each state perhaps retaining 0.004% as a maximum level above which the standard would not be increased even if the economic analysis supported the higher level. This cap might be removed when demand side response and the assessment of customer costs has been substantially improved to provide a robust basis for analysis.

6.5 MARKET PRICE IMPLICATIONS OF THE RELIABILITY STANDARD

The analysis of spot market prices as a function of unserved energy using the Plexos model has confirmed that:

- at low levels of unserved energy, base load prices are well above short-run marginal cost and show evidence of market power which can serve to secure reliability standards
- At the current standard level of reliability the market prices would be 10% to 50% above the new entry costs. This is consistent with the fact that the NEM has delivered sufficient capacity to meet the current reliability standard.

- For the optimal level of reliability (0.001%/0.004%) the prices would also be well above new entry costs and therefore could be delivered commercially without the need for intervention providing that barriers to entry are minimal and new entry is competitive.

6.6 CUSTOMERS ROLE

The EUAA can promote a more efficient market by encouraging greater demand side participation and a supportive regulatory environment. Adjustment of reliability standards to economic levels must progress in step with increased demand side participation to ensure that the economic benefits of reduced reserve generating capacity are shared with customers and do not result in increased prices to customers and windfall gains to generators.

In view of the apparent inefficiency of the load shedding arrangements in Queensland, there is an opportunity for an enhanced economic role for the large industrial loads in Queensland to contribute through demand side participation in the load shedding arrangements if a more efficient reliability standard is to be adopted.

APPENDIX A ANALYSIS OF REFERENCES

A.1 References

The references that were used to formulate the parameters in this study were as follows:

1. Power System Incident Report - Friday 13 August 2004, Load Shedding Report, NEMMCO 12 October 2004

2. Power System Incident Report on December 4th 2002, NSW Bushfires, NEMMCO Final Report

3. Trial of a Demand Side Response Facility for the National Electricity Market, Independent Consultant's Report. Pareto Associates Ltd April 2004 for the Energy users Association of Australia.

4. Assessment of Demand Management and Metering Strategy Options, Charles Rivers Associates, August 2004

5. Value of Lost Load Study for Victorian Power Exchange, Kahn, M E, and Conlon, M F, Monash University Centre for Electrical Power Engineering, Melbourne, 1997

6. Assessment of the Value of Customer Reliability, Charles Rivers Associates, December 2002

7. Development of an Electricity Distribution Service Quality Regime to Take Effect in Future Regulatory Periods, Draft Report, Meyrick and Associates and Pacific Economics Group, 11 August 2003

A.2 Information Extracted

Table A-1 shows the information that was extracted from each of these reports and used in the current project.

Report (1) concerned a multiple loss of generation in NSW on 13 August 2004 following an equipment fault. It was not the result of inadequate generating capacity and therefore the distribution of load shedding followed under-frequency load shedding systems operation. The report indicated that more load was shed in Victoria and Queensland than should have been and this is being addressed by NEMMCO. The report does not indicate what types of loads were disconnected but that some "sensitive loads" received priority for reconnection. We would expect that these loads would generally have load customer cost and deem the under-frequency load shedding component to be a lower bound on the amount of residential load that would be at risk for supply shortages.

Table A. 1 Data Obtained from References

Ref	Information Obtained	How it was applied	Comment
1	Distribution of load disconnected following sudden loss of generation (Table A. 2)	Gives an indication of low level loads that may be disconnected without high costs. We deem the under-frequency load shedding levels in this case to represent primarily residential load levels and interruptible industrial loads.	

Table A. 2 Summary of Load Shedding on 13 August 2004

Sequence	Time (sec)	Region	Reduction (MW)	Trip settings
1	1.3	SA	17.6	49.6 Hz
2	3.2	NSW	268	49.2 Hz
3	5.3	VIC	119	49.0 Hz
4	5.7	VIC	279	48.95 Hz
5	5.7	NSW	93	48.95 Hz
6	7.4	QLD	210	48.9 Hz
7	16.5	VIC	90	48.9 Hz
8	18.5	NSW	101	48.9 Hz
9	23.6	QLD	307	49.0 Hz 8 sec delay

Report (2) which addressed loss of load during bushfire conditions in NSW was of no value for this project because it related to involuntary load shedding caused by voltage collapse and feeder trips.

Report (3) identified the possibility that some 3.5% of the peak demand in the NEM could be available for demand side response for between $1000 and $1129/MWh with a capacity weighted average price of $1046/MWh.

Table A. 3 Total Load Lost 13 August 2004

Region	SA	Vic	NSW	Qld
Under Frequency Load Shedding	17.6	488	462	542
Other Load Lost	0	50	342	0
Total	17.6	538	804	542
Notes:		Private load tripped	Included power station auxiliary load	
Interpretation:				
Presumed minimum residential loads[4]		490	460	540

Report (4) assessed the net benefits of using Demand-Side Management (DSM) and pricing signals in combination with interval metering, to defer augmentation of constrained network elements on ETSA Utilities' distribution system. It identified that in the large commercial and industrial sector, some DSM is available via curtailable load, standby generation, thermal storage and power factor correction. In the medium business sector, voluntary reduction is available while in the residential and small business sector, direct load controls may be possible in providing DSM. The most cost effective means was found to be power factor correction at a cost of $73/KVA followed by $184/KVA for standby generation. Direct load control was next at between $251/KVA and $257/KVA. Curtailable loads costs $345/KVA while voluntary load control programmes were the most expensive at a cost of $1,084/KVA.

[4] We would expect much more than this level of load to be available at residiential costs. No reasonable estimate is made for South Australia here.

Report (5) was undertaken in 1997 by Monash University to study of the cost of disruption to electricity supply for the then Victorian Power Exchange. The objective of the study was to calculate the cost to electricity customers of interruptions to electricity supply to estimate the Value of Lost Load (VoLL).

Consumers were asked to suppose that a power outage occurred, without warning, at the worst possible time (time of day, day of week, and month). Estimates of the losses arising from outages of various durations are summarised below:

Outage Duration	Value of Lost Load ($/kWh not supplied)			
	Residential	Commercial	Agricultural	Industrial
2 seconds		45,534.06		4,902.30
1 minute		1,317.94	3,684.19	276.10
20 minutes		151.98	266.07	23.96
1 hour		88.16	123.35	17.95
2 hours		35.48	74.77	7.70
4 hours	1.75	31.64	113.17	7.94
8 hours	2.18	50.79	92.53	10.27
1 day	3.35	22.99	84.75	5.24
2 days	3.87			

Report (6) replicates and updates the Monash Study (Report 5), to evaluate the value of customer reliability in the residential sector, and the direct cost to the commercial, industrial and agriculture sectors.

The State-level VCR value for Victoria is $29.60/kWh of unserved electricity. This value is very similar to, and only marginally higher, than the VoLL figure of $28.89/kWh estimated in the Monash study.

	Residential		Commercial		Agricultural		Industrial	
Interruptio Duration	**$/kWh**	**$/kW**	**$/kWh**	**$/kW**	**$/kWh**	**$/kW**	**$/kWh**	**$/kW**
20 minutes			$64.9	$21.6	$88.4	$29.5	$48.8	$16.3
1 hr	$21.1	$21.1	$42.2	$42.2	$35.9	$36.0	$19.0	$19.0
2 hr			$63.8	$127.6	$64.6	$129.1	$16.7	$33.4
4 hr	$12.7	$51.0	$81.7	$326.8	$85.3	$341.2	$15.9	$63.4
8 hr	$7.8	$62.0	$67.2	$537.4	$56.1	$448.9	$14.6	$116.8
24 hr	$3.8	$90.5	$23.4	$562.1	$42.5	$1,020	$7.9	$189.1

APPENDIX B NEM GENERATORS INCLUDED IN THE PLEXOS MODEL

Region	Generator	Max capacity (MW)	Summer rating (MW)	Winter rating (MW)	Forced outage rate (%)	Scheduled Maintenance (weeks p.a.)	Availability (%)
NSW	Bayswater 1	690	675	690	0.5	2.5	94.7
	Bayswater 2	690	675	690	0.5	2.5	94.7
	Bayswater 3	690	675	690	0.5	2.5	94.7
	Bayswater 4	690	675	690	0.5	2.5	94.7
	Blowering	80	80	80	0.1	0	99.9
	Eraring 1	660	660	660	2.5	2.5	92.7
	Eraring 2	660	660	660	2.5	2.5	92.7
	Eraring 3	660	660	660	2.5	2.5	92.7
	Eraring 4	660	660	660	2.5	2.5	92.7
	Hume NSW	58	0	0	0.0	0	100.0
	Hunter Valley	26	22	26	3.5	4	88.8
	Liddell 1	515	513	515	1.5	2.5	93.7
	Liddell 2	515	513	515	1.5	2.5	93.7
	Liddell 3	515	513	515	1.5	2.5	93.7
	Liddell 4	515	513	515	1.5	2.5	93.7
	Mt Piper 1	660	660	660	3.0	3	91.2
	Mt Piper 2	660	660	660	3.0	3	91.2
	Munmorah 3	300	300	300	9.6	4	82.7
	Munmorah 4	300	300	300	9.6	4	82.7
	Redbank	148	148	148	2.3	2	93.9
	Shoalhaven	240	240	240	0.1	0	99.9
	Smithfield	160	160	160	3.0	3	91.2
	Vales Pt 5	660	605	660	6.0	3	88.2
	Vales Pt 6	660	605	660	6.0	3	88.2
	Wallerawang 7	500	500	500	6.0	4	86.3
	Wallerawang 8	500	500	500	6.0	4	86.3
Qld	Barcaldine	55	54	55	3.0	3	91.2
	Barron Gorge 1	30	30	30	0.1	0	99.9
	Barron Gorge 2	30	30	30	0.1	0	99.9

Regio n	Generator	Max capacity (MW)	Summer rating (MW)	Winter rating (MW)	Forced outage rate (%)	Scheduled Maintenance (weeks p.a.)	Availability (%)
	Braemar 1	150	150	150	2.0	2	94.2
	Braemar 2	150	150	150	2.0	2	94.2
	Braemar 3	150	150	150	2.0	0	98.0
	Callide A 1	30	30	30	5.0	3	89.2
	Callide A 2	30	30	30	5.0	3	89.2
	Callide A 3	30	30	30	5.0	3	89.2
	Callide A 4	30	30	30	5.0	3	89.2
	Callide B 1	350	350	350	3.0	2	93.2
	Callide B 2	350	350	350	3.0	2	93.2
	Callide Power 3	460	455	460	3.0	3	91.2
	Callide Power 4	460	455	460	3.0	3	91.2
	Collinsville 1	30	30	30	5.0	3	89.2
	Collinsville 2	30	30	30	5.0	3	89.2
	Collinsville 3	30	30	30	5.0	3	89.2
	Collinsville 4	30	30	30	5.0	3	89.2
	Collinsville 5	65	65	65	5.0	3	89.2
	Gladstone 1	280	280	280	4.2	2.5	91.0
	Gladstone 2	280	280	280	4.2	2.5	91.0
	Gladstone 3	280	280	280	4.2	2.5	91.0
	Gladstone 4	280	280	280	4.2	2.5	91.0
	Gladstone 5	280	280	280	4.2	2.5	91.0
	Gladstone 6	280	280	280	4.2	2.5	91.0
	Kareeya 1	22	22	22	0.1	0	99.9
	Kareeya 2	22	22	22	0.1	0	99.9
	Kareeya 3	22	22	22	0.1	0	99.9
	Kareeya 4	22	22	22	0.1	0	99.9
	Kogan Creek	750	750	750	3.0	3	91.2
	Mackay GT	33	30	33	2.0	2	94.2
	Millmerran 1	430	430	430	3.0	3	91.2
	Millmerran 2	430	430	430	3.0	3	91.2
	Mt Stuart 1	147	144	147	2.0	2	94.2

Region	Generator	Max capacity (MW)	Summer rating (MW)	Winter rating (MW)	Forced outage rate (%)	Scheduled Maintenance (weeks p.a.)	Availability (%)
	Mt Stuart 2	147	144	147	2.0	2	94.2
	Oakey 1	160	138	160	2.0	2	94.2
	Oakey 2	160	138	160	2.0	2	94.2
	Roma 7	30	25	30	5.0	4	87.3
	Roma 8	30	25	30	5.0	4	87.3
	Stanwell 1	350	350	350	4.0	2	92.2
	Stanwell 2	350	350	350	4.0	2	92.2
	Stanwell 3	350	350	350	4.0	2	92.2
	Stanwell 4	350	350	350	4.0	2	92.2
	Swanbank B 1	125	123	125	10.0	3	84.2
	Swanbank B 2	125	123	125	10.0	3	84.2
	Swanbank B 3	125	123	125	10.0	3	84.2
	Swanbank B 4	125	123	125	10.0	3	84.2
	Swanbank E	385	370	385	2.0	2	94.2
	Tarong 1	350	350	350	4.0	2	92.2
	Tarong 2	350	350	350	4.0	2	92.2
	Tarong 3	350	350	350	4.0	2	92.2
	Tarong 4	350	350	350	4.0	2	92.2
	Tarong Nth	443	443	443	3.0	3	91.2
	Wivenhoe 1	250	250	250	0.1	0	99.9
	Wivenhoe 2	250	250	250	0.1	0	99.9
	Yabulu CCGT	223	223	223	2.0	3	92.2
SA	Angaston	40	40	40	2.0	2	94.2
	Dry Creek 1	49	37	49	3.5	4	88.8
	Dry Creek 2	49	38	49	3.5	4	88.8
	Dry Creek 3	49	42	49	3.5	4	88.8
	Hallet	183	153	183	4.4	4	87.9
	Ladbroke 1	37	35	37	2.3	3	91.9
	Ladbroke 2	37	35	37	2.3	3	91.9
	Mintaro	88	70	88	4.6	4	87.7
	Northern 1	265	263	265	2.5	4	89.8

Regio n	Generator	Max capacity (MW)	Summer rating (MW)	Winter rating (MW)	Forced outage rate (%)	Scheduled Maintenance (weeks p.a.)	Availability (%)
	Northern 2	265	263	265	2.5	4	89.8
	Osbourne	190	183	190	2.3	2	93.9
	Pelican Point	490	470	490	4.4	3	89.8
	Playford	240	240	240	5.0	6	83.5
	Pt Lincoln	48	38	48	3.0	3	91.2
	Quarantine 1	22	19	22	3.5	4	88.8
	Quarantine 2	22	19	22	3.5	4	88.8
	Quarantine 3	22	19	22	3.5	4	88.8
	Quarantine 4	22	19	22	3.5	4	88.8
	Snuggery	63	54	63	4.6	4	87.7
	Torrens Is A 1	126	123	126	5.0	4	87.3
	Torrens Is A 2	126	123	126	5.0	4	87.3
	Torrens Is A 3	126	123	126	5.0	4	87.3
	Torrens Is A 4	126	123	126	5.0	4	87.3
	Torrens Is B 1	206	201	206	5.0	4	87.3
	Torrens Is B 2	206	201	206	5.0	4	87.3
	Torrens Is B 3	206	201	206	5.0	4	87.3
	Torrens Is B 4	206	201	206	5.0	4	87.3
Snowy	Guthega	60	60	60	0.9	0	99.1
	Lower Tumut	1500	1500	1500	0.9	0	99.1
	Murray	1518	1509	1500	0.9	0	99.1
	Upper Tumut	616	616	616	0.9	0	99.1
Vic	Anglesea	160	159	160	1.5	1	96.6
	Bairnsdale 1	45	35	45	1.0	3	93.2
	Bairnsdale 2	45	35	45	1.0	3	93.2
	Dartmouth	137	137	117	0.9	0	99.1
	Eildon 1	60	60	55	0.9	0	99.1
	Eildon 2	60	60	55	0.9	0	99.1
	Hazelwood 1	205	195	205	6.0	4	86.3
	Hazelwood 2	210	198	210	6.0	4	86.3

Regio n	Generator	Max capacity (MW)	Summer rating (MW)	Winter rating (MW)	Forced outage rate (%)	Scheduled Maintenance (weeks p.a.)	Availability (%)
	Hazelwood 3	220	218	220	6.0	4	86.3
	Hazelwood 4	220	218	220	6.0	4	86.3
	Hazelwood 5	220	218	220	6.0	4	86.3
	Hazelwood 6	210	205	210	6.0	4	86.3
	Hazelwood 7	210	198	210	6.0	4	86.3
	Hazelwood 8	210	198	210	6.0	4	86.3
	Hume Vic	58	29	0	1.2	0	98.8
	Jeeralang A 1	58	50	58	1.0	2.1	95.0
	Jeeralang A 2	58	50	58	1.0	2.1	95.0
	Jeeralang A 3	58	50	58	1.0	2.1	95.0
	Jeeralang A 4	58	50	58	1.0	2.1	95.0
	Jeeralang B 1	85	72	85	1.0	2.1	95.0
	Jeeralang B 2	85	72	85	1.0	2.1	95.0
	Jeeralang B 3	85	72	85	1.0	2.1	95.0
	Laverton Nth 1	156	156	156	2.3	2	93.9
	Laverton Nth 2	156	156	156	2.3	2	93.9
	Loy Yang A 1	580	555	580	3.5	2	92.7
	Loy Yang A 2	510	500	510	3.5	1	94.6
	Loy Yang A 3	530	515	530	3.5	1	94.6
	Loy Yang A 4	520	510	520	3.5	1	94.6
	Loy Yang B 1	510	505	510	3.0	2.5	92.2
	Loy Yang B 2	510	505	510	3.0	2.5	92.2
	McKay 1	80	80	65	0.9	0	99.1
	McKay 2	80	80	61	0.9	0	99.1
	Morwell 1	55	53	55	4.0	5	86.4
	Morwell 2	33	31	33	4.0	5	86.4
	Morwell 3	65	60	65	4.0	5	86.4
	Newport	510	475	510	3.0	2.1	92.9
	Somerton	157	123	157	5.0	4	87.3
	Valley Power 1	51	44	51	1.0	2.1	95.0
	Valley Power 2	60	44	60	1.0	2.1	95.0

Regio n	Generator	Max capacity (MW)	Summer rating (MW)	Winter rating (MW)	Forced outage rate (%)	Scheduled Maintenance (weeks p.a.)	Availability (%)
	Valley Power 3	60	44	60	1.0	2.1	95.0
	Valley Power 4	50	40	50	1.0	2.1	95.0
	Valley Power 5	50	40	50	1.0	2.1	95.0
	Valley Power 6	50	40	50	1.0	2.1	95.0
	West Kiewa 1	41	35	41	0.9	0	99.1
	West Kiewa 2	41	35	41	0.9	0	99.1
	Yallourn W 1	360	355	360	6.0	3	88.2
	Yallourn W 2	360	355	360	6.0	3	88.2
	Yallourn W 3	380	370	380	6.0	3	88.2
	Yallourn W 4	380	370	380	6.0	3	88.2

APPENDIX C CAPACITY STATES INCLUDED IN THE PLEXOS STUDIES

Table C. 1 shows the capacity sates that were analysed in the Plexos Studies.

Table C. 1 Capacity States Analysed

Capacity State	Year	SA	Vic	NSW	Qld	Year	SA	Vic	NSW	Qld
1	2006	3224	7292	10633	8800	**2007**	3369	6860	10633	8907
2		3367	7060	10633	8800		3618	6656	10633	8907
3		3367	7292	10333	8800		3618	6860	10333	8907
4		3367	7292	10633	8642		3618	6860	10633	8690
5		3054	7497	10633	8800		3167	7070	10633	8907
6		3224	7497	10333	8800		3369	7070	10333	8907
7		3224	7497	10633	8642		3369	7070	10633	8690
8		3054	7292	10947	8800		3167	6860	10947	8907
9		3224	7060	10947	8800		3369	6656	10947	8907
10		3224	7292	10947	8642		3369	6860	10947	8690
11		3054	7292	10633	8957		3167	6860	10633	9127
12		3224	7060	10633	8957		3369	6656	10633	9127
13		3224	7292	10333	8957		3369	6860	10333	9127
14		3224	7673	10633	8397		3007	6860	10633	9372
15		2909	7673	10633	8800		3007	7220	10633	8907
16		3367	7292	10633	8397		3369	6656	10633	9372
17		2909	7292	10633	8957		3369	7220	10333	8907
Min		2909	7060	10333	8397		3007	6656	10333	8690
Mode		3224	7292	10633	8800		3369	6860	10633	8907
Max		3367	7673	10947	8957		3618	7220	10947	9372
1	2008	3516	7293	10888	9416	**2009**	3744	7587	11299	10048
2		3669	7046	10888	9416		4004	7276	11299	10048
3		3669	7293	10674	9416		4004	7587	10999	10048
4		3669	7293	10888	9257		4004	7587	11299	9858
5		3373	7533	10888	9416		3488	7928	11299	10048
6		3516	7533	10674	9416		3744	7928	10999	10048
7		3516	7533	10888	9257		3744	7928	11299	9858
8		3373	7293	11188	9416		3488	7587	11514	10048
9		3516	7046	11188	9416		3744	7276	11514	10048
10		3569	7361	11225	9276		3812	7692	11539	9871
11		3373	7293	10888	9571		3488	7587	11299	10203
12		3516	7046	10888	9571		3744	7276	11299	10203
13		3456	7101	10534	9495		3679	7346	10845	10122
14		3126	7101	11247	9337		3307	7346	10633	9965
15		3020	7101	11247	9337		3307	7346	11145	10122
16		3126	7101	10746	9495		3143	7346	11145	10122
17		2966	7101	10746	9495		3089	7346	10633	9965
Min		2966	7046	10534	9257		3089	7276	10633	9858
Mode		3516	7293	10888	9416		3744	7587	11299	10048
Max		3669	7533	11247	9571		4004	7928	11539	10203
1	2010	3808	7782	11276	10281					
2		3966	7465	11276	10281					
3		3966	7782	11101	10281					
4		3966	7782	11276	10125					
5		3611	8075	11276	10281					
6		3808	8075	11101	10281					
7		3808	8075	11276	10125					
8		3611	7782	11426	10281					
9		3808	7465	11426	10281					
10		3943	8016	11539	10186					
11		3611	7782	11276	10438					
12		3808	7465	11276	10438					
13		3810	7706	11035	10402					
14		3486	7706	11208	10525					
15		3810	7264	11208	10525					
16		3311	7706	11208	10525					
17		3432	7706	11358	10245					
Min		3311	7264	11035	10125					
Mode		3808	7782	11276	10281					
Max		3966	8075	11539	10525					

APPENDIX D PERCENTAGE OF TOTAL LOAD SHEDDING HOURS THAT ARE MEET BY GENERAL RESTRICTIONS BY CAPACITY SCENARIOS

		2006		2007		2008		2009		2010	
	Scenario	Capacity	Percent	Capacity	Percent	Capacity	Percent	Capacity	Percent	Capacity	Percent
SA	1	3,224	0.00%	3,369	1.72%	3,516	0.00%	3,744	0.00%	3,808	16.95%
	2	3,367	0.00%	3,618	0.00%	3,669	0.00%	4,004	0.00%	3,966	42.74%
	3	3,367	0.00%	3,618	0.00%	3,669	0.00%	4,004	9.09%	3,966	0.00%
	4	3,367	0.00%	3,618	0.00%	3,669	0.00%	4,004	0.00%	3,966	0.00%
	5	3,054	0.00%	3,167	0.00%	3,373	0.00%	3,488	15.45%	3,611	41.05%
	6	3,224	0.00%	3,369	0.00%	3,516	0.00%	3,744	16.67%	3,808	7.55%
	7	3,224	0.00%	3,369	0.00%	3,516	0.00%	3,744	12.50%	3,808	0.00%
	8	3,054	6.51%	3,167	0.00%	3,373	0.00%	3,488	0.00%	3,611	39.81%
	9	3,224	0.00%	3,369	2.08%	3,516	1.47%	3,744	0.00%	3,808	11.72%
	10	3,224	0.00%	3,369	0.00%	3,516	0.00%	3,744	0.00%	3,808	0.00%
	11	3,054	0.00%	3,167	0.00%	3,373	0.00%	3,488	22.07%	3,611	44.80%
	12	3,224	1.30%	3,369	0.00%	3,516	0.00%	3,744	0.00%	3,808	26.32%
	13	3,224	0.00%	3,369	0.00%	3,456	0.00%	3,679	0.00%	3,810	23.08%
	14	3,224	1.35%	3,007	6.84%	3,126	3.32%	3,307	29.07%	3,486	43.85%
	15	2,909	6.25%	3,007	0.00%	3,020	6.25%	3,307	20.19%	3,810	46.34%
	16	3,367	0.00%	3,369	0.00%	3,126	2.56%	3,143	30.63%	3,311	44.55%
	17	2,909	4.24%	3,369	0.00%	2,966	9.76%	3,089	33.68%	3,432	45.30%
Vic	1	7,292	9.41%	6,860	3.90%	7,293	0.00%	7,587	3.37%	7,782	2.87%
	2	7,060	7.42%	6,656	10.79%	7,046	4.76%	7,276	8.59%	7,465	7.92%
	3	7,292	3.26%	6,860	7.98%	7,293	4.44%	7,587	11.78%	7,782	4.13%
	4	7,292	1.01%	6,860	4.82%	7,293	2.89%	7,587	2.48%	7,782	6.64%
	5	7,497	6.37%	7,070	1.32%	7,533	0.00%	7,928	0.00%	8,075	0.00%
	6	7,497	0.00%	7,070	3.44%	7,533	0.00%	7,928	0.00%	8,075	0.00%
	7	7,497	2.65%	7,070	0.42%	7,533	0.00%	7,928	4.30%	8,075	0.00%
	8	7,292	0.30%	6,860	5.04%	7,293	0.93%	7,587	0.00%	7,782	0.89%
	9	7,060	7.65%	6,656	4.14%	7,046	6.39%	7,276	5.72%	7,465	16.67%
	10	7,292	1.82%	6,860	1.96%	7,293	2.59%	7,587	1.98%	7,782	2.86%
	11	7,292	4.93%	6,860	7.84%	7,293	0.00%	7,587	3.07%	7,782	11.37%
	12	7,060	8.94%	6,656	9.61%	7,046	3.03%	7,276	8.15%	7,465	8.72%
	13	7,292	5.26%	6,860	17.35%	7,101	1.10%	7,346	15.25%	7,706	6.96%
	14	7,673	22.89%	6,860	2.43%	7,101	0.00%	7,346	0.68%	7,706	4.38%
	15	7,673	0.00%	7,220	0.00%	7,101	0.00%	7,346	0.36%	7,264	21.26%
	16	7,292	17.89%	6,656	6.02%	7,101	1.11%	7,346	0.00%	7,706	12.81%
	17	7,292	3.12%	7,220	0.00%	7,101	6.79%	7,346	6.43%	7,706	8.30%
NSW	1	10,633	21.16%	10,633	24.32%	10,888	3.19%	11,299	5.49%	11,276	10.00%
	2	10,633	22.69%	10,633	16.51%	10,888	19.54%	11,299	14.75%	11,276	24.44%
	3	10,333	17.37%	10,333	19.75%	10,674	13.90%	10,999	5.84%	11,101	11.54%
	4	10,633	1.90%	10,633	9.73%	10,888	2.76%	11,299	7.14%	11,276	19.01%
	5	10,633	23.76%	10,633	32.35%	10,888	2.14%	11,299	8.09%	11,276	9.04%
	6	10,333	20.64%	10,333	8.47%	10,674	5.59%	10,999	9.38%	11,101	16.06%
	7	10,633	0.00%	10,633	7.40%	10,888	8.64%	11,299	17.33%	11,276	12.67%
	8	10,947	0.00%	10,947	14.53%	11,188	13.50%	11,514	15.75%	11,426	10.45%
	9	10,947	18.25%	10,947	19.05%	11,188	7.96%	11,514	3.45%	11,426	14.35%
	10	10,947	0.00%	10,947	0.00%	11,188	14.92%	11,514	3.70%	11,426	27.38%
	11	10,633	0.00%	10,633	11.72%	10,888	21.25%	11,299	35.22%	11,276	3.65%
	12	10,633	0.00%	10,633	12.94%	10,888	9.35%	11,299	3.64%	11,276	10.39%
	13	10,333	14.21%	10,333	15.34%	10,534	11.23%	10,845	18.98%	11,035	22.86%
	14	10,633	27.75%	10,633	10.71%	11,247	17.48%	10,633	22.18%	11,208	3.40%
	15	10,633	11.41%	10,633	15.13%	11,247	41.07%	11,145	13.28%	11,208	20.25%
	16	10,633	39.78%	10,633	29.36%	10,746	18.15%	11,145	1.46%	11,208	3.85%
	17	10,633	15.66%	10,333	16.27%	10,746	1.17%	10,633	17.00%	11,358	21.11%
Qld	1	8,800	13.41%	8,907	24.59%	9,416	4.56%	10,048	6.21%	10,281	23.72%
	2	8,800	11.69%	8,907	15.32%	9,416	11.53%	10,048	17.60%	10,281	10.98%
	3	8,800	17.58%	8,907	33.76%	9,416	26.49%	10,048	24.32%	10,281	21.99%
	4	8,642	0.80%	8,690	10.25%	9,257	30.84%	9,858	14.06%	10,125	18.89%
	5	8,800	14.52%	8,907	2.73%	9,416	22.33%	10,048	19.06%	10,281	10.14%
	6	8,800	3.85%	8,907	11.63%	9,416	16.51%	10,048	8.08%	10,281	11.50%
	7	8,642	25.95%	8,690	21.10%	9,257	5.38%	9,858	14.84%	10,125	14.62%
	8	8,800	9.05%	8,907	19.82%	9,416	11.68%	10,048	3.54%	10,281	10.21%
	9	8,800	8.44%	8,907	28.10%	9,416	14.62%	10,048	3.53%	10,281	23.81%
	10	8,642	12.18%	8,690	10.06%	9,257	17.00%	9,858	19.95%	10,001	17.06%
	11	8,957	2.04%	9,127	18.77%	9,571	20.56%	10,203	3.51%	10,438	14.81%
	12	8,957	0.00%	9,127	15.50%	9,571	5.91%	10,203	1.79%	10,438	0.00%
	13	8,957	19.18%	9,127	31.97%	9,495	20.98%	10,122	25.53%	10,402	4.73%
	14	8,397	23.91%	9,372	0.00%	9,337	19.69%	9,965	21.86%	10,525	0.00%
	15	8,800	22.56%	8,907	7.73%	9,337	8.56%	10,122	0.00%	10,525	0.79%
	16	8,397	29.65%	9,372	1.02%	9,495	30.47%	10,122	30.59%	10,525	15.96%
	17	8,957	24.07%	8,907	8.16%	9,495	17.48%	9,965	5.96%	10,245	0.35%

APPENDIX E ANALYSIS OF OPTIMAL RELIABILITY BASED ON EVENT COSTS

The final method that was adopted was in three steps:

1. Determine the expected unserved energy as a exponential function of a linear function of the regional installed sent-out capacities for each of the 17 capacity scenarios

2. Determine the expected unserved energy cost as a quadratic function of expected unserved energy for each of the 17 capacity scenarios

3. Determine the total unserved energy cost over the whole NEM by summing the unserved energy cost for each region

4. Solve for the capacity which minimises the sum of the unserved energy cost and the reserve capacity cost.

The unserved energy for each region (i) and capacity (x_j) was defined by means of regression as:

$$y_i = \exp(a_i + \Sigma\, b_{ij}\, x_j) \qquad (1)$$

where a_i and b_{ij} are constants determined by regression

x_i is the installed sent-out capacity

For each region (i) the unserved energy cost z_i was defined means of regression as:

$$z_i = c_i\, y_i + d_i\, y_i^2 \qquad (2)$$

where c_i and d_i are constants determined by regression. The function is designed to go through the y/z origin.

The total unserved energy cost is $\Sigma\, z_i$

The reliability cost is the sum of the unserved energy cost and the reserve capacity cost:

$$w_i = \Sigma\, z_i + 1000\, k\, \Sigma\, (x_i - X_i) \qquad (3)$$

where Xi is the mean of the values of xi over the 17 scenarios.

K is the cost of capacity in $/kW/year

The capacity states which minimise the unserved energy are determined by solving the four partial derivatives equal to zero. These equations are of the form:

$$\frac{\partial wi}{} = \frac{\partial wi}{} * \frac{\partial zi}{} * \frac{\partial yi}{} = 0 \qquad (4)$$

$\partial xi \quad \partial zi \quad \partial yi \quad \partial xi$

Therefore:

$(c_i + 2 d_i y_i) \Sigma y_i b_{ij} + 1000k = 0$

$(c_i y_i + 2 d_i y_i^2) \Sigma b_{ij} + 1000k = 0$ (5)

It is convenient that the equations for the derivative can be expressed solely in terms of unserved energy and not capacity. This then enables the quadratic equation form to be solved analytically.

Therefore using the standard solution of the quadratic equation:

$y_i = (- c_i \Sigma b_{ij} - \mathrm{SQRT}((c_i \Sigma b_{ij})^2 - 8 d_i \Sigma b_{ij} 1000 k))/(4 d_i \Sigma b_{ij})$ (6)

This solves directly for the expected unserved energy which minimises the expected unserved energy cost for each region. The use of the exponential of the linear function of capacity is the underlying reason why the quadratic equations can be described by the unserved energy without any capacity terms. The equivalent capacity in each region equivalent to the state based standards may be obtained by using the equations that related unserved energy in each region to the installed capacity.