Working Draft Confidential Report to

The Independent Market Operator

Valuing the Capacity of Intermittent Generation in the South-west Interconnected System of Western Australia

29 January 2010

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Ref: J1836 d0.5

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VERSION

Version	Date	Comment	Approved
Draft 0.1	10 December 2009	Issued to IMO as a working draft. The international review is complete. The analysis is preliminary and being revised and extended.	Ross Gawler
Draft 0.2	16 December 2009	Updated results with latest simulations (in progress). Added discussion on market rule changes. (Internal draft)	
Draft 0.3	23 December 2009	Included new results with additional simulations, discussion of the uncertainty of results and a preliminary	Ross Gawler

		justification of the capacity values obtained.	
Draft 0.4	20 January 2010	Amended LOLP functions based on additional samples and improvements to curve fit.. Added Executive Summary	Ross Gawler
Draft 0.5	29 January 2010	Added discussion of assumptions for future years, added results of LOLP capacity for future years, modified uncertainty estimate for solar resources.	Ross Gawler

EXECUTIVE SUMMARY

Background

The wholesale electricity market in the south-west of Western Australia (WEM) includes a reserve capacity mechanism to ensure that reliability of supply is maintained. Each registered power generation and demand side facility may be allocated a capacity value which provides the basis for payment for capacity either through bilateral contracts or through receipt of a capacity payment. Intermittent generation in the WEM is allocated a capacity based on average output recorded in the last three capacity years. For new projects, modelling of the anticipated resource conducted by an independent expert may be used to assess a suitable capacity value.

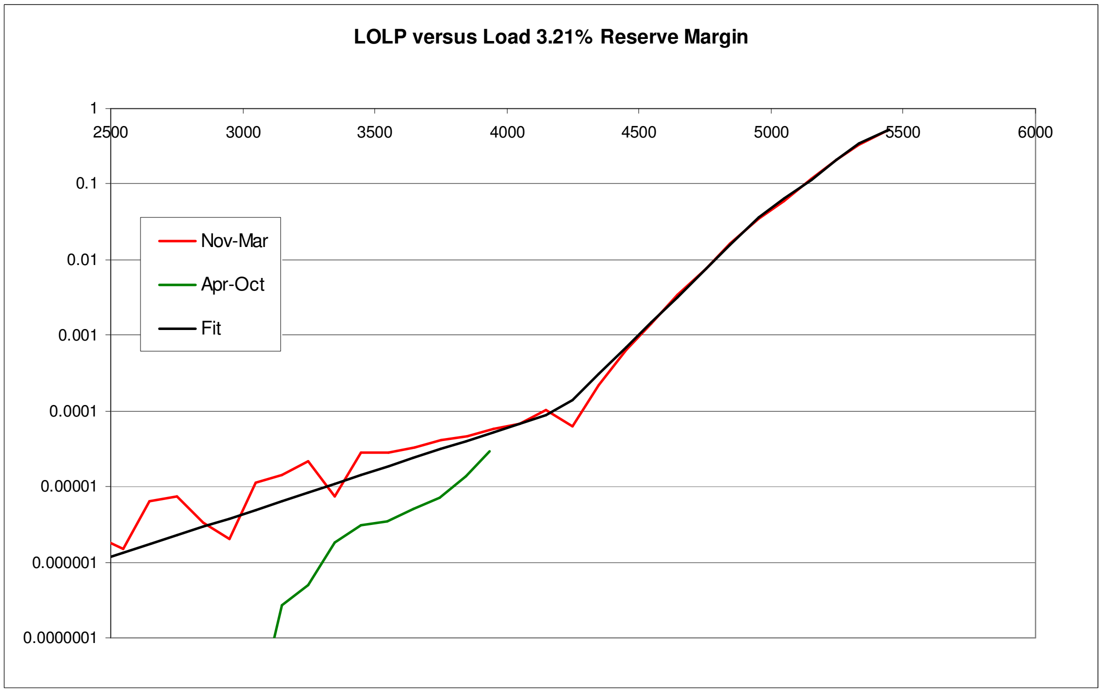
Due to the increase in the Renewable Energy Target to 45,000 GWh of new renewable energy, it is expected that there will be a substantial increase in intermittent generation in the WEM over the period to 2020. Higher levels of intermittent generation and the establishment of new technologies based on solar energy are expected to invalidate the current method of assigning capacity to intermittent generation. There is currently some doubt as to whether the average power method properly values wind power in the WEM. On the east coast of Australia, the capacity value is assessed as mostly less than 20%. Further, it is expected that capacity assessments based on average power for solar thermal plants without storage would grossly under-value such resources because they produce most of their power in the afternoon when demand is high on hot summer days. Thus the IMO commissioned a review of the measure of capacity in the WEM for intermittent generation to be conducted by McLennan Magasanik Associates (MMA).

Approach based on Loss of Load Probability

MMA's approach to this study was to investigate methods based on ensuring that the reliability of the system and the reserve capacity required would be consistently analysed for both scheduled and intermittent generation. The preferred approach was to find the equivalent firm capacity matched to each intermittent resource that would leave the reliability of the system unchanged, equivalent to 0.002% expected unserved energy having regard to the variation in annual peak demand that occurs due to weather uncertainty.

To provide a simplified analysis method that could be used without extensive market simulations, MMA also proposed a weighting method based on calculating Loss of Load Probability (LOLP) on a trading interval basis. The LOLP would be calculated as a function of the load to be supplied from scheduled generation, rather than total system load. This would enable the function to respond to the effect of changing penetration of intermittent generation. It is the load imposed on the scheduled generation which is the main driver of reliability, so this approach is more accurate than relating LOLP to system load. The LOLP function on this basis is shown on a logarithmic scale in Exec Figure 1 for the 2012/13 capacity year. The black line shows the regression function applied over the

Exec Figure 1 LOLP versus load for scheduled generation for 2012/13 capacity year



whole year. The redline shows the applicable function over the warmer months of November to March and the green line shows the function in the April to October period. It has not been necessary to model the LOLP function seasonally because the scheduled generation outages can be well accommodated during the milder seasons without influencing system reliability significantly.

Comparison with other methods

The project also compared capacity valuations using alternative methods:

- Reliability equalisation based on system simulations with up to 300 samples
- Average power over the whole year as currently applied
- Average power over selected trading intervals corresponding to high system loads.

It was found that the reliability equalisation method was in principle the most accurate but that some 500 simulations would be needed to obtain any reasonable accuracy. This is quite time consuming. However, it was demonstrated, despite the uncertainty in the results, that the aggregate capacity value of the wind farms was greater than the sum of their values assessed individually by this method. This is reasonable because of the diversity of the observed energy wind power project outputs on a half-hour basis.

The average power method for wind power was found to be a good approximation to the values based on reliability analysis, either by LOLP weighting or reliability equalisation. However it was confirmed that this method is unsuitable for solar energy based resources because their peak production during the day has a high correlation with system peak demand.

The average power by peak load trading intervals does have the advantage of greater simplicity and offering a good approximation to the values based on LOLP weighting. The analysis of wind power and solar thermal project models shows that an average over 750 trading intervals would be a practical interim approach until there are sufficient data to make LOLP based analysis a less volatile measure.

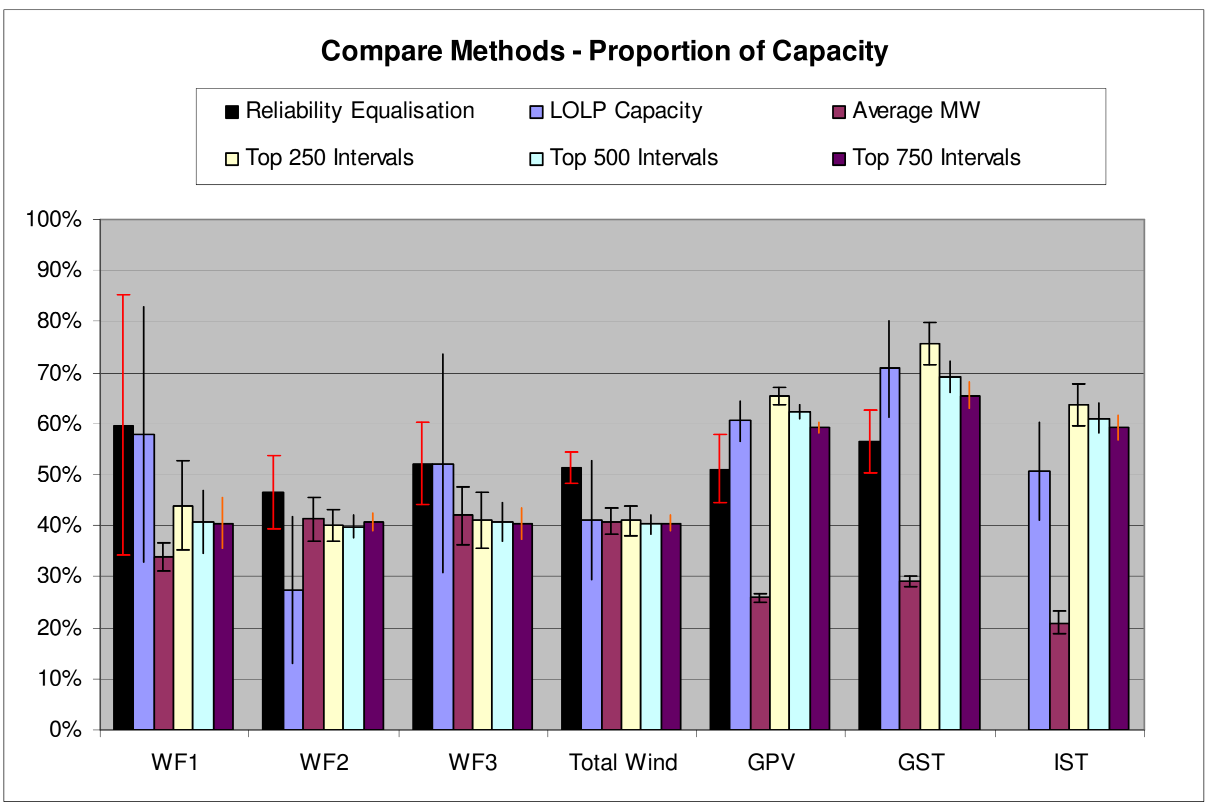
Uncertainty of measures

The underlying problem is that there is a shortage of good observations for the production from the existing resources under extreme system conditions. About 95% of the capacity value occurs under 0% to 20% POE conditions (using 10% POE as the measure), so the real value is determined by relatively few observations, with 2002/03 capacity year providing the primary observations for this purpose. Thus any measure which is based on these observations that attempts to assess the underlying impact on reliability is going to be uncertain. Using average power methods would give a lower level of uncertainty in the measure as assessed but would not necessarily be more accurate.

Summary of results

Exec Figure 2 provides a summary of the capacity values assessed for the wind farms and three solar options as a proportion of their rated capacity by various methods for the 2012/13 capacity year. The error bars show the 80% confidence range of the assessment based on a simple model of the uncertainty of the output of the various resources and

Exec Figure 2 Capacity assessments by various methods for 2012/13



the correlation of their outputs among nearby trading intervals. The following features are evident in the results in Exec Figure 2:

- The capacity value of the wind farms based on reliability equalisation is similar to the sum of the values assessed individually. This is not clear cut in the results due the significant uncertainty in the individual assessments. However, it has credibility as a principle because the wind farm outputs have low correlation on a half-hour basis, less than 50% correlation coefficient over the months from October to March.
- The assessed capacity values based on LOLP weighting are comparable to the values assessed by reliability equalisation for all technologies, having regard to the uncertainty in the assessment.
- The capacity values assessed according to peak load trading intervals between 250 and 750 intervals per year also show a good approximation to values based on reliability analysis. Overall, an average based on 750 trading intervals provides the best approximation to the LOLP method and this approach could be considered until the penetration of intermittent generation achieves levels above 500 MW above existing levels.

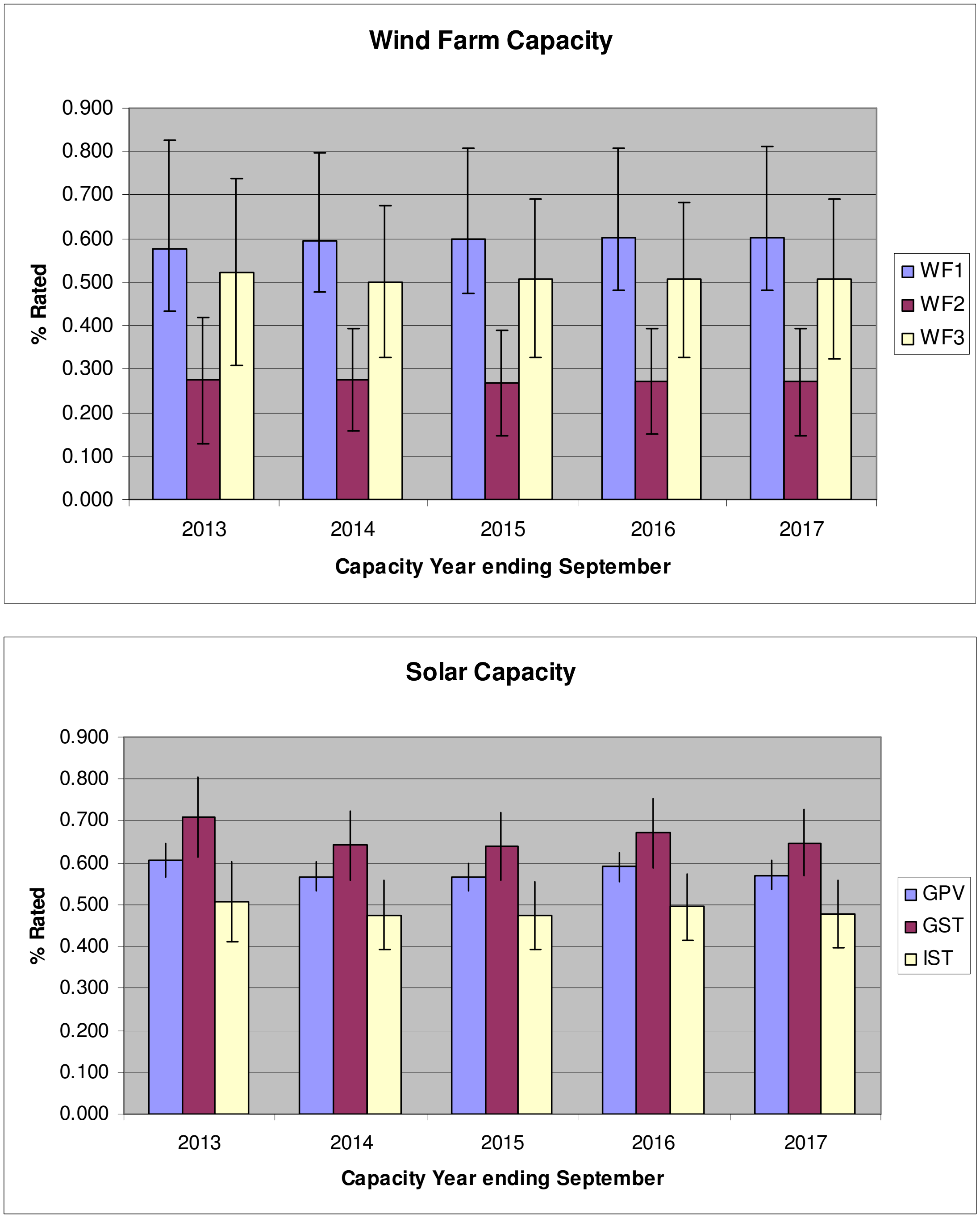
The year to year variation in the capacity assessed using the LOLP method is shown in Exec Figure 3 for each of the resources. There is some variation within the model error bands. In the long-term the major source of uncertainty would be due to changes in the information about the performance of the intermittent generation sources, particularly for wind which is more variable on hot summer days.

A capacity assessment based on historical output at times of system peak would not vary much from year to year unless there was a significant change in the load shape itself. The main factor in variation in the assessment would be additional information based on more recent system conditions being taken into account.

Recommendations

The analysis has shown clearly that the average power method will not provide a suitable capacity measure for solar thermal and photovoltaic resources, whereas it is suitable for the incumbent wind farms in the South-west, based on the available data on performance and system load. The analysis has also shown that LOLP weighting methods and trading interval averages provide similar assessed values of capacity based on the modelling of supply conditions in 2012/13. Therefore, an interim step would be to move to trading interval average values at times of high system demand, and eventually establish a method based on LOLP functions. It has been shown that such a method can be applied simply and that it can respond to changing system conditions as needed to provide market participants with efficient incentives to manage their generating plant.

Exec Figure 3 Variation of LOLP based capacity over five years



Therefore, the recommended process is to:

1. Finalise the analysis for the remaining years based on LOLP weighting;
2. Confirm that the current method for valuing capacity can remain for wind farms until new rules are developed that are suitable for other intermittent generation resources;

3. Consult with key stakeholders on the results of this analysis and the issues identified;
4. In association with stakeholders, decide whether to base the next phase on LOLP weighted output or trading interval averages based on coincident output with high system demand
    - If the interim method is to be based on trading intervals, then decide the duration. At this stage 750 trading intervals is preferable to match the results obtained from reliability based analysis;
    - If the next stage is LOLP weighted methodology, then confirm the details of the methodology in terms of transitional issues, fleet based assessments versus individual project assessments and the basis for developing an LOLP function;
5. Prepare draft rule changes for the next stage of development as decided by step (4); and
6. Conduct rule change process.

MMA considers that due to a lack of data the trading interval average would be a suitable interim step whilst the need for an LOLP based assessment based on high levels of penetration of intermittent generation is explored. The preliminary analysis showed that capacity values declined by about 0.3% per 100 MW of solar thermal plant added, so there is some scope for augmentation before the overall level of penetration becomes a major problem.

1 INTRODUCTION

1.1 Background to the Wholesale Electricity Market

In late 2002, the Government of Western Australia committed to the establishment of a Wholesale Electricity Market (WEM) within the South West Interconnected System (SWIS).

A set of market rules was developed with extensive input from industry, which was gazetted in October 2004. These provide for a market with several key elements:

- the Reserve Capacity Mechanism (RCM) which ensures that sufficient generation and demand side management (DSM) resources are available to meet the overall SWIS forecast demand;
- Bilateral Contracts through which suppliers and customers can establish contracts for purchase of energy and capacity;
- a day-ahead Short Term Energy Market through which buyers and sellers can adjust their contract positions; and
- a Balancing Service to accommodate the inevitable short term fluctuations between market participants' contract positions and actual performance.

The energy trading elements of the WEM commenced operation in July 2006. Further information on the WEM, including the full Market Rules, can be found at the website of the IMO at www.imowa.com.au.

1.2 The Independent Market Operator (IMO)

In December 2004, the Government established the Independent Market Operator (IMO) as a Government-owned, non-for-profit, statutory corporation, to administer and operate the Wholesale Electricity Market.

The IMO's functions and responsibilities are prescribed by the Wholesale Electricity Market Rules as well as the relevant regulations establishing the Market Rules and the IMO (the *Electricity Industry (Wholesale Electricity Market) Regulations 2004* and the *Electricity Industry (Independent Market Operator) Regulations 2004)*.

In general, the IMO's functions and responsibilities include:

- Power System Security and Reliability
    - To carry out long term generation adequacy forecasts and to publish the Statement of Opportunities Report
    - To operate the Reserve Capacity mechanism
    - To identify the need for any Supplementary Reserve Capacity Auction

- The Energy Market and Dispatch
  - To operate the Short Term Energy Market and the balancing process
  - To accept IPP bilateral schedules
- Settlement
  - To calculate balancing prices and settle market transactions
- Market Information
  - To publish information required to be published by the Market Rules
- Market Documents
  - To develop amendments to, and to make available copies of, the Market Rules and Procedures
- Monitoring, Enforcement and Audit
  - To monitor Rule Participants' compliance with the Market Rules, to investigate potential breaches of the Market Rules, and where appropriate, initiate enforcement action
  - To support the Economic Regulation Authority in its market surveillance role and in its role of monitoring market effectiveness
- Participant Registration
  - To process applications for participation, and for the registration, de-registration and transfer of facilities
- Network Control Service Contracts
  - To administer tender processes and to enter into Network Control Service Contracts

1.3 The IMO'S role in the Reserve Capacity Mechanism

The context of this report and analysis is the management of the Reserve capacity Mechanism with particular reference to the measurement of reserve value of intermittent generation resources.

While the IMO operates central market mechanisms for both reserve capacity and energy, participants can trade both energy and reserve capacity bilaterally. The Reserve Capacity Mechanism ensures that sufficient generation and Demand Side Management (DSM) resources are available to meet the overall SWIS forecast peak demand.

The reserve capacity market process operates on an annual basis. The market cycle commences in year n to secure reserve capacity for the 12 months from 1 October of year n+2. This 12-month period is called a Capacity Year. There are exceptions to this rule to deal with newly commissioned and decommissioned generators, and to address the commencement of the energy market.

The IMO commenced the Reserve Capacity Mechanism in 2004. The associated acquisition of capacity and assignment of capacity credits for the periods 21 September 2006 to 1 October 2008 and 1 October 2008 to 1 October 2009 have been completed.

1.4 The Expanded National Mandatory Renewable Energy Target Scheme

The Commonwealth Government's Mandatory Renewable Energy Target scheme, in operation since 2001, is designed to achieve the generation of an additional 9,500 gigawatt hours (GWh) of electricity from renewable energy sources each year by 2010. The scheme supported investment in new renewable energy generation in the South West Interconnected System (SWIS) such that penetration has increased from less than 1 per cent in 2002-03 to just over five per cent in 2007-08. Eighty per cent of the growth in renewable energy generation has come from new wind farms.

The Commonwealth Government has recently legislated to expanding the Mandatory Renewable Energy Target (MRET) scheme to achieve a national target of 20 per cent, or 45,000GWh, of renewable generation in 2020. This is more than four times more new renewable energy generation in 2020 than the previous target.

The expanded national scheme replaces existing state and territory mandatory renewable energy target schemes, including the scheme formerly being developed by the Western Australian Government. The Western Australian Government has participated in the development of the new national scheme through the Council of Australian Governments.

1.5 Potential Growth in Intermittent Generation in the SWIS

The expanded Renewable Energy Target (RET) scheme is likely to be a major driver of investment in new renewable energy projects located in the SWIS. Commonwealth modelling of the expanded RET suggests renewable energy penetration in Western Australia could more than triple within the next five years. This new generation is expected to come from wind and plantation waste energy.

The number of wind projects developed in the SWIS will ultimately depend upon how competitive wind is with other renewable energy technologies, such as biomass based electricity generation, and the economics of projects in other jurisdictions. Based on investment for the existing MRET scheme, wind power is likely to be highly competitive among renewable energy technologies due its comparatively low cost and the technological maturity of the turbine industry.

The capacity market, referred to as the Reserve Capacity Mechanism (RCM) has been designed to incentivise investment in capacity, either through generation capacity or through demand side management. This mechanism broadly works on the basis of assigning notional Capacity Credits to generation and demand side management facilities. For scheduled generation, Capacity Credits are assigned at a level equivalent to the level of electrical output produced on a sent-out basis at 41 degrees Celsius. Intermittent generation Facilities, which include wind farms, are currently assigned Capacity Credits based on their average capacity factor over a three-year period. This is a matter for review in this current project with respect to all intermittent generation sources such as wind, solar, wave and tidal power.

Additional incentive schemes, such as national and state-based renewable energy targets and emissions trading schemes have the potential to further incentivise wind farm developments within the SWIS.

1.6 Overview of Works Program Issues

The impact of various state and federal policy developments in respect of renewable energy targets and emissions cost incentives creates a degree of complexity extending over the longer term timeframe. Questions about how the RCM and Energy market should be developed to incentivise appropriate levels of investment in renewable energy developments within the SWIS are beginning to surface.

Concerns have been raised about the impacts of increasing intermittent generation for the power system in respect of these intermittent generation technologies and their ability to deliver electricity during peak demand times, especially given the current provisions for certification of Reserve Capacity. An assessment of the likely outcomes from a policy perspective is required along with suggestions of how provisions within the WEM can be best aligned with these policy directives without compromising system security and reliability.

Because there is limited history available on the performance of intermittent generators within the SWIS, it is difficult to develop clear conclusions on performance during peak demand times. It is also currently unclear what the contribution of intermittent generation to system reliability is in the Western Australian environment. The lack of clarity arises from the limited data available on peak period performance of the existing and prospective generation projects in relation to conditions that cause high levels of demand and lower output from thermal generators.

One of the primary outcomes required through the completion of the four part Works Program (of which this is Part 2) will be to provide an assessment of the appropriate level at which intermittent generators should receive Capacity Credits in order to support the requirements of the RCM. Notwithstanding the RCM issues, being a small and isolated electrical system, the requirements to schedule plant to balance fluctuating output of intermittent generators, to maintain frequency stability throughout the day and to follow load overnight, raise technical considerations when high levels of intermittent generation penetration is prevalent.

Understanding the technical requirement to maintain power system security and reliability and to ensure frequency stability in the future is required so that the IMO and System Management may plan, procure, schedule and recover the costs of appropriate levels of ancillary services. Overlaying this technical issue onto the economics of the WEM, questions are raised about where additional or incremental Ancillary Service cost components should be placed.

It is possible that there are both technical and market solutions for the issues associated with each work package. A thorough investigation into the possible solutions with appropriate references to other electricity jurisdictions where these have been applied, and the outcome, is in progress.

To ensure the continued development of viable and commercial generation while sustaining the operation of the market and the power system, each work package requires consideration of the immediate challenges and solutions within the existing frameworks, together with consideration of sustainable long term solutions.

1.7 Related Work

Other bodies of work have been completed, or are nearing completion, and are envisaged to be incorporated into the Works Program. These projects, which include work coordinated by the Renewable Energy Generation Working Group (REGWG) and other bodies, will serve as valuable sources of information. The scope of this Work Program is related to:

- the allocation of Capacity Credits to intermittent generation facilities in the WEM;
- system ancillary service requirements and the impacts of low overnight loads;
- the industry roadmap being developed by the Economic Regulation Authority; and
- the AEMC review of Energy Market Frameworks in light of Climate Change Policies.

1.8 Work Package 2

The REG WG has established an overall Work Program to address the issues associated with increased intermittent generation in the WEM. The scope of work for the Work Program has been separated into four Work Packages with the aim of grouping elements of work that are considered to be closely related. This report relates to only Work Package 2, which is described in the next Chapter.

Given the pressures for increasing development of intermittent generation and concern at the present capacity assessment processes, it is important to quickly provide certainty to new developers on assessment methodologies going forward. Important in this regard are the need to subsequently progress any recommendations through the market rule change process and the commencement of the next capacity certification process mid-2010.

2 WORK PACKAGE 2: RESERVE CAPACITY AND RELIABILITY IMPACTS

2.1 Background

The existing Reserve Capacity Mechanism (RCM) within the WEM recognises that intermittent generators make a contribution towards system security and reserve capacity. As penetration levels rise it will be necessary to more accurately determine the contribution that intermittent generators make and the appropriate method for remunerating the capacity they provide.

An outcome of this Work Package is recommendations that address how intermittent generators should be assessed with regard to their contribution to capacity and the revisions to the present certification methods and/or complementary mechanisms that may be introduced to more accurately account for the contribution made by intermittent generators.

2.2 Summary of Issues Considered in Work Package 2

The issues which were to be considered in Work Package 2 were stated by the IMO as follows:

- The assessment of the reliability contribution of existing and potential intermittent plant types both at present and potential future levels of intermittent generation penetration should be undertaken in the context of the context of the Reserve Capacity Mechanism and the Planning Criterion and relative to the reliability contribution of scheduled plant.
- The assessment should take due account of :
    - any correlation between system demand and plant output;
    - nominal low, medium and high penetration scenarios as suggested by the consultant.
- The assessment of potential future plant should consider all intermittent technologies to the extent necessary to cover the range of likely performance characteristics relevant to reliability assessment encompassing:
    - wind
    - solar thermal (with and without nominal storage)
    - solar photovoltaic
    - landfill gas
    - tidal; and
    - wave power.
- In selecting a suitable methodology for the assessment of the capacity contribution made by intermittent generators due account should be taken of reliability assessment methodologies and capacity credit allocation methods in other jurisdictions.

- The methodology should represent a reasonable balance of the need to accurately reflect the contribution of intermittent generators, while not presenting an unwarranted complexity and administrative burden on the Market.
  - In particular the selected methodology should:
    - be operationally simple and minimize associated cost, complexity, volatility and uncertainty;
    - enable the calculation of capacity contribution values by plant owners using simple mathematical methods
    - derive values of capacity contribution from computations based on plant output (either recorded for existing plant or modelled for new plant) rather than through power system reliability modelling, but should be designed to provide results generally consistent with those that might be expected from a reliability modelling approach;
    - provide credits consistent with the contribution to reliability relative to scheduled plant and at penetration levels that might reasonably be expected over the coming decade;
    - provide sufficiently reliable results when applied to all anticipated intermittent generator types including wind, solar thermal, solar photovoltaic, wave and tidal power; and
    - adequately discriminate between individual plants based on reliability contribution and provide appropriate incentives for the appropriate design and location of new plant.
- Proposed changes to the Market Rules or Market Procedures should be developed in the context of the change processes under the Market Rules.

2.3 Key Outcomes of Work Package 2

The key outcomes that were expected from Work Package 2 were stated by the Imo as follows:

- An assessment of the reliability contribution of existing and potential intermittent plant types both at present and potential future levels of intermittent generation penetration:
  - relative to the reliability contribution of scheduled plant; and
  - in the context of the Reserve Capacity Mechanism and the Planning Criterion.
- A recommended methodology for the assessment of the capacity contribution made by intermittent Generators, supported by an assessment of that methodology against the present method and alternative approaches in other jurisdictions.
- Recommended changes to Market Rules and Market Procedures that would be required to implement the recommended methodology, together with draft rule change proposals and supporting arguments and analysis to demonstrate that the recommended changes would be consistent with the Wholesale Market Objectives.

3 METHODOLOGY

3.1 Overview

The approach to meeting the stated requirements was to use generation system reliability modelling to derive parameters than can be used to approximate capacity values with acceptable accuracy both at an aggregate and incremental[1] level. If the modelling indicates that incremental assessments as proposed have the risk of overstating the aggregate value, some scale-back might be applied by the IMO. Alternatively, if the incremental values under-state the aggregate value, then scale-up may be applied. Essentially, capacity allocation would match the aggregate value in proportion to incremental value. This approach is to ensure that there is consistency between the capacity allocated to intermittent and scheduled resources and the capacity required to maintain system reliability.

The study was designed to assess the risk of capacity volume mismatch and the simplified method was developed to avoid such outcomes if possible so that each party can make an independent assessment based on an updated model provided by the IMO.

The model was tested using historical data for existing wind farms as well as prospective profiles for new technologies such as solar thermal plants.

3.2 Stages of Work

The project approach followed the steps outlined in Table 3-1. The key elements were:

- A review of historical and expected future data and information related to the temporal and spatial characteristics of load, generation, and renewable energy resources. The review also considered regulatory and market reforms, generation technologies and other information that may inform the potential, appropriateness and reliability of alternative methods. Particular attention was given to the transitional impacts of the CPRS and enhanced RET on the WA industry, to identify factors that may be relevant to the ongoing resilience of proposed methods and to their associated market rules. The smoothing effects that geographically dispersed and technologically varied resources can have on the system reserve capacity margin were included in the method.

[1] Incremental means that the capacity requirement of the system with and without the resource would be calculated and the difference would represent the incremental capacity value. This is not marginal in the sense of the contribution of the last MW of capacity.

Table 3-1 Project Approach

Step	Task	Inputs	Outputs	Current Status
1	Project Inception Conference to confirm objectives and process with the Renewable Energy Working Group.	Proposal as accepted	Presentation on the methodology and program of work. Requested comments on approach from stakeholders. Request for relevant data.	Complete
2a	Collect and review background data and information	Task 1 output	Chapter 4 summarising international methods. Alternative forms of simplification of the quantification of capacity value.	Complete
2b	Prepare draft approach report including review of international methods	Task 1 output	Draft report outlining the issues, options and recommended study methodology	Working draft issued
2c	Consultation on the approach	2b output	Final report discussing consultation inputs and final methods for evaluation	In progress
3a	Obtain historical SWIS load profiles net of historical embedded intermittent generation	IMO / WP data sources	Adjusted profile for total system load including allowance for embedded load.	Complete
3b	Establish reliability model of the SWIS for previous year's load profiles adjusted to meet 0.002% for Capacity Year 2012/13 with and without historical intermittent generation	2c output	Developed two cases with expected unserved energy above and below the standard level.	In progress
			Calculate Loss of load probability at each load level by season.	Complete
			Develop a metric which offsets the load to match 0.002% unserved energy without running a power system simulation.	Complete

Step	Task	Inputs	Outputs	Current Status
3c	Develop a regression relationship between system load level and loss of load probability (LOLP) and a method to calculate capacity equivalence	3b output	Regression function relating load level to LOLP by season. Method for weighting resource output by LOLP to calculate equivalent capacity. Draft evaluation model in Excel.	Draft model complete
3d	For existing intermittent resources test the capacity equivalence by replacing each resource by the assessed capacity modelled as a gas turbine.	3c output	Comparison of capacity equivalence and reliability analysis for plants with existing data. Calibrated method if needed to better match capacity equivalence for selected profiles.	In progress
3e	For prospective profiles of load for solar thermal, schedulable plant, photovoltaic, wave and tidal power profiles, confirm the validity of capacity equivalence for small and large projects	3c output	Comparison of capacity equivalence and reliability analysis for plants with sample data.	In progress
4a	Calculate estimates for alternative methods, including for new facilities and assess robustness		Evaluation of alternative methods including those based on LOLP and averages based on time based or loading based periods.	Method complete – data to be finalised
4b	Prepare a draft report of the analysis and the methods developed and tested for consultation purposes	Outputs from phase 3 tasks	Draft report on the analytical work	Working draft in progress
5a	Develop a method to evaluate combinations of projects that together would provide reliability at 0.002%	Outputs from phase 3 tasks	Methodology for calculating capacity values for projects on an average by technology, marginal project basis or whole of semi-scheduled class basis.	In progress

Step	Task	Inputs	Outputs	Current Status
5b	Develop an approach to rule making and evaluation that would meet the market objectives	Previous tasks	A methodology for processing project data given a set of data for committed projects. Determine what kind of tool can be provided to proponents and incumbents so they can evaluate their own projects consistent with the proposed Market Rules	In progress. Pilot software tool under construction
5c	Draft report on rule changes and evaluation process	5b output	Draft Rule Change Report	Commenced
5d	Consultation on Rule Change and amendments as necessary to address issues identified.	5c output	Add discussion of consultation to Draft Rule Change Report and issue as Final	
6a	Develop an Excel workbook application for general use for the next Capacity Year and thereafter as appropriate.	Previous Tasks.	Excel Application into which a profile of generation is entered for a historical period of weather and from which incremental capacity value is assessed to meet 0.002% unserved energy.	Pilot model under development

- A report outlining the technical and commercial issues as well as a set of options to be considered as the basis for the analysis of potential methods. The report identified potential methods that would be evaluated, including key modelling assumptions. Multiple methods will be considered to accommodate intermittent plants that are either existing (with demonstrated performance data) or new (no demonstrated performance data). Potential refinements to the proposed methods were identified and tested for materiality in the analysis where practicable.
- The development of the market data needed to support the evaluation of methods
- The testing of the methods with some example cases to compare their accuracy and volatility
- The potential refinement of the methods to improve accuracy without undue complexity
- The design of a workable method based on these results
- A draft report for consultation purposes on the methodology and prospective Rule Changes
- A draft Rule Change report after the methodology has achieved broad acceptance by stakeholders
- Two final reports covering the analysis and the recommended Rule Changes.
- The development of an Excel workbook application for general use for the next Capacity Year and thereafter as appropriate.

3.3 Potential Methods

A rigorous capacity valuation methodology would typically require a full modelling of the power system at a detailed temporal and spatial resolution, using this as the basis for a stochastic assessment of the probabilities of each electric facility experiencing outage. This is obviously a complex approach that requires a comprehensive set of grid data. Understandably, Work Package 2 specifies a requirement for an operationally simple approach that can enable the calculation of capacity contribution values by plant owners using simple mathematical methods. The current market rules do not provide locational signals for capacity value, or even account for transmission capacity losses, so it is not immediately necessary to consider spatial effects. MMA consulted with the IMO on the extent to which it may be necessary to model the more remote parts of the system and their transmission characteristics relative to Muja. In the work to date this has been deferred due to the current approach to quantifying capacity credits.

There are several potential methods that could be both operationally simple and reliable. These are summarised below. Each of the potential methods was considered for validation and assessment as per the proposed work-plan.

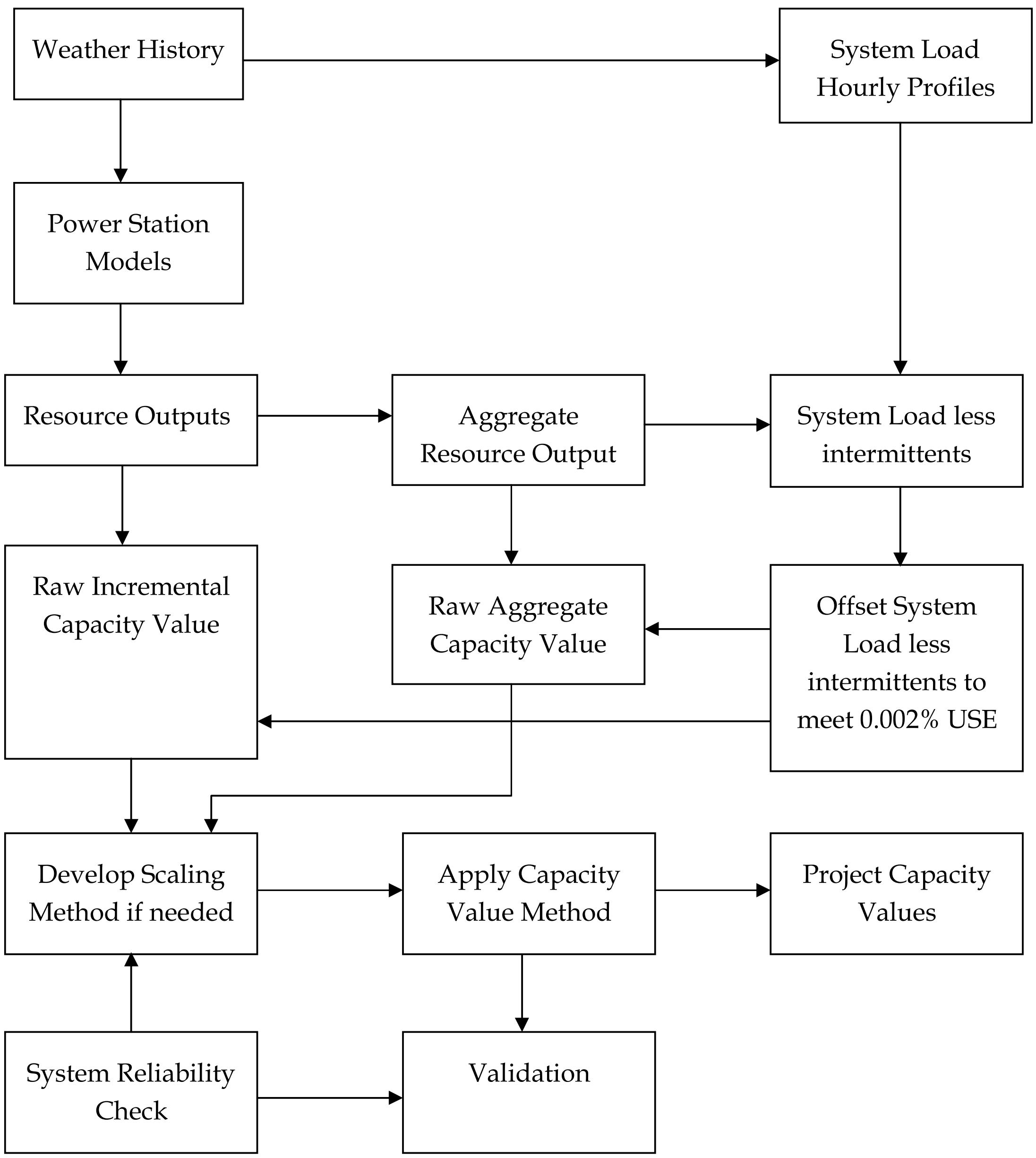
Our philosophy was to model the reliability of the SWIS in sufficient detail so that we could test the viability of simplified methods and assess their accuracy and volatility.

Stakeholders should not interpret our detailed approach as indicating that the IMO's ultimate application and user tools would be complex to understand and use. MMA appreciates the importance of simplicity in the application phase.

3.3.1 LOLP-based approach

One methodology for developing the capacity valuation method that would meet the project criteria is illustrated in Figure 3-1. This provides the basis for evaluation of more simplified methods.

Figure 3-1 Outline of Development of Capacity Valuation Methodology



The concept for evaluation is based on the assumption that:

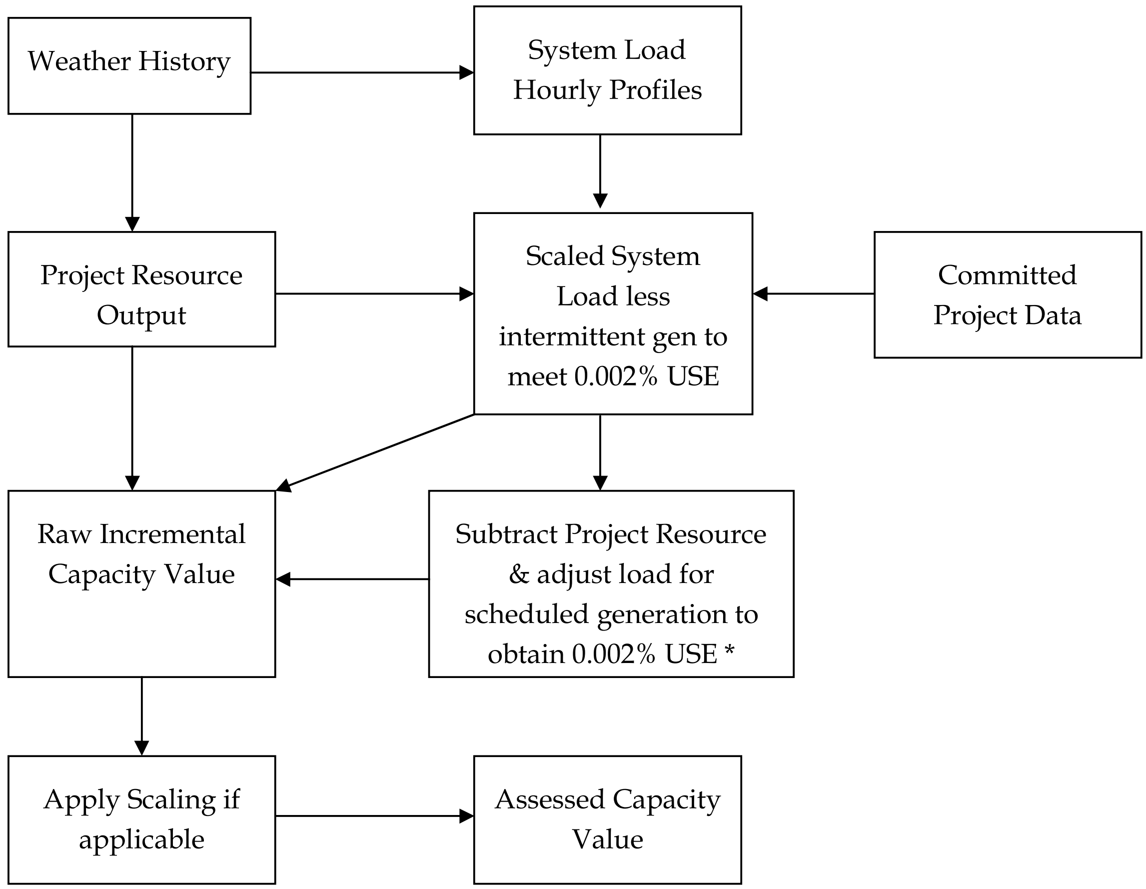
- The timing of output of intermittent generation resources can be related to weather assumptions if applicable, including derating and energy available
- The profile of intermittent generation output can be related to system load that would occur under those conditions less the output of the other committed resources on the same weather basis. The load not supplied by intermittent generation (defined as the load for scheduled generation (LSG)) is then reliant on the capacity and reliability provided by the scheduled generation.
- The relationship to system load can be linked to the corresponding loss of load probability at that LSG level using a regression equation, probably exponential in nature.
- The system load with and without each resource can be profiled or offset to meet 0.002% unserved energy so that the impact of the level of penetration of intermittent generation can be represented.

Figure 3-2 shows how the methodology would be implemented for a specific project having regard to the committed projects. It is proposed, subject to confirmation of viability and significance that if a project is committed its generation is added to the base intermittent generation profile so that the effect of the new resource is included in the load for scheduled generation (LSG). If the project is uncommitted its generation is subtracted from the LSG profile as it represents a new resource. Until a resource is committed it would be measured as incremental to the existing fleet. When a project is committed it becomes part of the future existing fleet and its capacity value would be assessed as the same value in this way.

The IMO would provide an updated tool whenever new projects are committed and the basis for capacity valuation has changed.

The method should also work for scheduled generation based on its expected generation availability if only to meet the non-discriminatory objective of the Wholesale Electricity market. However, it is not expected to be used to value scheduled generation, except perhaps some small biomass based resources which may have a seasonal energy capability.

Figure 3-2 Implementation of Capacity Valuation Methodology



* Note: If the project is committed its load is added to the base profile, if the project is uncommitted its load is subtracted from the base profile.

3.3.2 Other Potential Methods

Other more simplistic approaches that we may consider in our evaluation include the following:

- Demonstrated facility output/capacity factor during an appropriate limited subset of historical operating periods. The subset of historical operating periods may be determined on the basis of season, month, day, time of day or other factor that is relevant to a measure of system reliability. The calculated value may be an average, median or alternative measure of demonstrated performance;
- LOLP profiled assessment whereby a reference model is used to calculate the actual LOLP for each hour of a reference period, and a proportion of these hours, say 30%, is used to define the data basis for calculating the demonstrated facility output/capacity factor of each electric facility;

- LOLP profiled and weighted assessment whereby the above approach is used to calculate an actual LOLP hourly profile that is then normalised and used as weights to calculate an average facility capacity factor; and
- The calculation of fixed or variable default capacity values for facilities with an insufficient operating history, as might be applied by technology class. This method is currently used basis on historical average output for the last three capacity years.

The proposed analysis leads us to assess how we can simplify the analysis without loss of accuracy. For example, periods when loss of load probability is less than 0.1% could be neglected as immaterial.

3.4 Analysis of requirements

The following Table 3-2 summarises how the specified requirements of the capacity valuation would be met.

Table 3-2 Review of requirements

Stated Requirement	MMA Approach
Account for any correlation between system demand and plant output	Link plant output to prevailing system load for the stated time and weather conditions and link the load to loss of load probability.
Account for nominal low, medium and high penetration scenarios	Build a scheduled demand profile according to the penetration and assess the reliability impact based on the net scheduled load profile. Apply scaling if needed to match aggregate to incremental capacity requirements
Use penetration levels that might reasonably be expected over the coming decade	
Consider all available technologies	Based solely on a production profile related to time and weather.
Consider reliability methodologies	Use system reliability modelling to assess probability of load shedding as affected by intermittent production and system load level.
Consider international approaches	We will review the approaches used in a selection of other markets, including the NEM, NZ, and a selection from North America and Europe. This will inform us of potential alternative methods that may be useful.
Balance accuracy and simplicity	See next page

Stated Requirement	MMA Approach
Enable the calculation of capacity contribution values by plant owners using simple mathematical methods	Simple weighting and scaling method can be applied to production profile for specified time and weather.
Derive values of capacity contribution from computations based on plant output that would match reliability based calculations.	
Provide credits consistent with the contribution to reliability relative to scheduled plant	Weighting by LOLP would give similar assessment to that for scheduled plant's capacity at times of high demand. Comparative value for scheduled resources would be derived from plant availability, not dispatch.
Provide sufficiently reliable results	This will be confirmed in the model validation by comparing the simple model with reliability equalisation assessment for selected cases.
Adequately discriminate between individual plants based on reliability contribution and provide appropriate incentives for the appropriate design and location of new plant.	Correlation with system demand is fully valued which would provide suitable locational incentives to capture capacity value.

3.5 Treatment of forced outages

One of the important issues to be addressed is how to treat forced outages and Capacity Refunds for intermittent generation. In this report, this matter been considered in two stages:

1. Firstly, how capacity should be measured; does it make provision for forced outages in the measurement?
2. Secondly, if the capacity measurement excludes provision for forced outages, how should the Capacity Refund mechanism be modified to allow for the effect of forced outages in actual operation. This is considered in Chapter 8.

In relation to the first matter, the current method of using average output for intermittent generation includes the effect of forced outages on historical performance and therefore does not require application of the Refund Table. The proposed method based on using Loss of Load Probability weighting could be applied to the actual output including forced outages or it could be applied to historical output adjusted to replace the energy lost from plant outages (or a perfectly reliable model for planned resources) and then Capacity Refunds could apply.

The appropriate approach depends to how the Reserve Capacity Price is set. The Maximum Reserve Capacity Price is assessed as the annual fixed cost of a liquid fuelled gas turbine on a $/kW/year basis without any allowance for the expected payments under the Refund Table. Based on the relative duration of each period in the Refund Table and the factor, on average 1.446 times the forced outage rate would be lost from the capacity payments. When suppliers bid to supply reserve capacity in a Reserve Capacity Auction they may adjust their bids to include the risk and expected capacity payment refunds. However, if the Maximum Reserve Capacity Price were to apply it may not include an adequate margin to allow for expected outages depending on the prevailing costs of gas turbine plant.

In this report we have taken the incumbent historical generation to include the loss of production from outages and therefore the capacity that is assessed ought not to be exposed to capacity payment refunds.

However for new plants, the profiles offered do not appear to allow for forced outages and it might be appropriate to discount the values to make them consistent with the values applied to incumbent resources. The possible options are summarised in Table 3-3.

Table 3-3 Comparison of methods for treatment of forced outages

Feature of the Process	Current	LOLP with FOR (Incumbents)	LOLP without FOR
Forced Outages included in the performance profile	Yes	Yes	No
Application of capacity payment refunds	No	No	Yes
Maximum Reserve Capacity Price allowing Forced Outages	No	Yes	Yes

4 INTERNATIONAL REVIEW

Organised energy markets around the world are continuing to accommodate substantial investments in intermittent generation resources, resulting in ongoing increases in the contribution of this generation, both as a proportion of installed capacity, and as a quantum of energy production across the dispatch cycle. The pattern of this investment has in part been affected by current and anticipated energy policies. This has required jurisdictions to manage an extent and rate of change that is different from the more predictable pattern that has traditionally accompanied technological innovation in the energy sector.

The energy characteristics of intermittent resources such as wind, solar, landfill gas, tidal and wave-power are distinct from that of conventional fossil-based resources, and also from each other. Combined with a rapid increase in investment, particularly in wind generation, this is presenting grid management and market development issues that are requiring changes to the design and operation of the organised markets. In many jurisdictions these changes are progressing in a stepwise manner, requiring initial adjustments to the design logic of the wholesale markets to manage low penetrations of less controllable intermittent generation, followed typically by wind integration studies that are defining requirements and impacts associated with higher penetrations of ten percent or more of intermittent generation. These studies are informing further requirements for change, including more substantial adjustments to the management and planning of operational and capacity reserves required with these higher penetration levels.

This section briefly summarises the challenges that are faced by the organised energy markets as a result of rapid increases in intermittent generation; it relates these challenges to the valuation of the contribution of intermittent capacity within the context of increasing penetration levels of this generation resource.

This section summarises the types of approaches that jurisdictions have considered in valuing the contribution of intermittent generation capacity, and presents a table that shows the approaches by specific energy markets in the United States and Europe.

4.1 Challenges that must be resolved by the market design

4.1.1 Accommodating significant penetration levels of plant that is subject to volatile resource constraints

Conventional energy resources such as coal and gas can be available on demand, supported by fuel resources that are managed to provide a reliable supply in support of generation needs. Once committed, the capacity of this thermal plant is therefore assumed to be substantially available, albeit subject to the known characteristics of planned and forced outages.

The installed capacity of intermitted generation resources is largely subject to volatile resource constraints, with generation output affected by the vagaries of resource supply. Resources such as wind, solar, waves and tides are volatile, with the extent of their availability affected by natural physical processes that cannot be reliably controlled to provide the same certainty of generation supply that has been typical of thermal plant. As a result, accommodating high penetration levels of intermittent generation can present challenges for the short and long-term management of the grid and of associated market processes.

Indeed, the volatile output of intermittent generation, particularly wind generation, has been managed in many energy markets as an adjustment to system demand, therefore reducing the quantum of scheduled generation that is required to balance the market. At higher penetration levels some markets, such as Ireland, are finding that high wind events are causing some base-load plant to two-shift across the scheduling horizon, with consequential effects for boiler management and unit commitment costs, as well as increasing the flexibility that is required of grid assets. In a longer term context, capacity market mechanisms are having to recognise that intermittent generation capacity is now a significant contribution to reserve requirements, requiring such mechanisms to accommodate resource volatility. In many US capacity markets the capacity contribution of thermal plants is typically measured by discounting maximum plant capacity by their effective forced outage rates. This approach is not satisfactory for intermittent generation however, requiring adjustments to the market design, which in the case of the New York market for example, now uses the demonstrated (actual) production factors of these plants over an historical reference period. This is the method currently used in the WEM in Western Australia.

4.1.2 Timescales of natural cycles of renewable energies

Organised energy markets have traditionally been designed to accommodate the load profile and growth characteristics of demand, with operations managed according to predictable load profiles affected by a combination of 24-hour, day of week, monthly, seasonal and annual consumption cycles. These known cycles are a feature of many demand forecasting methodologies, and are therefore an input into the short-term market operations and the longer-term planning processes of system operators. These cycles shape the temporal profile of intraday unit commitment decisions, the temporal profile of price outcomes and contract decisions, and in part incentivise investment outcomes to achieve an efficient technology mix between base load, mid-merit and peak load generation resources.

High penetration of intermittent generation is causing the natural cycles of renewable resources to become an issue for system operators, adding disturbance to the traditional consumption cycle influence on market outcomes and investment behaviour. The major issue is lack of correspondence between the natural variations in resource availability, and the load profile characteristics of consumers. This lack of correspondence, and the high levels of volatility that affect both load and intermittent resources, affect system balancing, and potentially a need for greater levels of back-up in the form of operational and capacity reserves. Indeed, it has potential, and is in some markets, changing the equilibrium settings that are required of the short and long-term elements that define the market and participant behaviour.

An example of this influence is the large installation of wind generation in markets such as Ireland. Like the dispatch logic of many energy markets, wind in the Irish market is treated as a subtraction from forecast demand. It therefore affects the shape of scheduled demand, therefore introducing wind volatility as a disturbance to the typical dispatch schedule applying to base, mid merit and peak load generation. While low production factors may make intermittent generation a less significant contribution to reserve capacity than in the case of thermal plant, resource volatility across trading intervals can make wind generation a very significant contribution to supply, lowering the capacity factors of thermal plant, and changing unit commitment and dispatch profiles. It is not uncommon for wind in the Irish market to offset the traditional morning and afternoon load peaks. When wind resources are strong at night, wind generation can cause some base-load units to operate at minimum generation, or to even shut down, the latter having consequences for prices and unit availability during the next day. This can result in reduced reliability as cycling of inflexible base load units reduces operating life and increases forced outage probability.

These disturbances to the traditional pattern of load, as penetration levels increase, will affect dispatch, investment and capacity market mechanisms, requiring adaptation within the market design and operational practice. For this reason, many markets are measuring the contribution of intermittent capacity on a time-basis, using demonstrated output during peak hours, and sometimes on a seasonal basis, to define the contribution of this capacity.

The following summarise the natural cycles that affect a range of energy-limited generation technologies:

- Wind –Wind can vary based on cycles that range from annual and seasonal cycles to daily, hourly and sub-hourly.
- Solar –Similar to wind, solar resources typically have cycles that range from annual and seasonal cycles to daily, hourly and sub-hourly.
- Tide –Tidal activity has seasonal, monthly, daily and hourly cycles
- Hydro –Often dictated by water/flow management activity, hydro resources can have an annual, seasonal, monthly and daily cycles.

4.1.3 Deliverability and locational constraints

Traditional market and industry development processes have anticipated more gradual and incremental change in directions consistent with past performance. The background premise of traditional planning processes, for example, has sought to maintain reliability standards in the context of ongoing predictable demand growth and a forecast of required incremental new generation that is weighted in favour of thermal plant. The transmission system has been developed to transport electricity along established paths, from generation regions having significant fossil fuel resources, to the load centres surrounding major cities and towns. The capacity of the transmission system and the management of the wholesale market have also developed to accommodate the generation characteristics predominantly associated with both coal and gas.

Increasing investment in intermittent generation will occur in areas of significant resource availability that in many cases will not align with established coal and gas regions, or therefore with the backbone of the transmission system. Indeed, much of this new generation may be located at the extremities of the transportation system, causing the contribution of intermittent resources to be constrained by transmission capacity. As the industry adapts to a new system topography, it is possible that deliverability concerns may become an issue for this generation. The PJM market in the United States explicitly addresses deliverability concerns within the design of its capacity market. New York, to address load-pocket constraints around New York City and Long Island, have introduced capacity regions and locational reserve capacity requirements within its control area. The New York market is also investigating whether new capacity resources should be subject to deliverability tests that may affect the amount of capacity that is contributable to the capacity market.

4.2 Measuring the contribution of intermittent generation capacity

International energy markets have adopted various approaches in evaluating the contribution of intermittent generation capacity. The following provides a categorisation and summary description of the main approaches that have been adopted or considered. Many jurisdictions have adopted a composite of the following approaches.

4.2.1 System modelling approaches

The most common system modelling approach is the calculation of Effective Load Carrying Capability (ELCC). This is the basis of the approach that MMA has proposed for the SWIS.

ELCC approaches have most commonly been adopted in planning processes to determine a generator's contribution to capacity reserve requirements, based on the planning criterion and reliability goals of the system operator, utility, or regulator. Many markets have also used this approach to produce wind integration studies related to high penetration levels of these resources.

Although not as common, ELCC approaches can also be used to calculate the appropriate level of payments to entities that provide capacity to help meet system reliability goals, including payments to new capacity that may not have a sufficient production history to inform the payment mechanism.

While ELCC can be calculated using alternative techniques, in general, the method uses a system model to calculate the amount of additional load that can be served at a selected reliability level (typically using a measure such as Loss of Load Expectation (LOLE), with the addition of a given amount of generation from a generation source that is the subject of the analysis (the intermittent generation source, for example).

The calculation of a generator's ELCC therefore measures the contribution of the generator to system reliability. The approach can distinguish between generators with different characteristics, including operational characteristics, levels of reliability, size, location and unit commitment behaviour. For intermittent generation plants, the approach can accommodate the temporal and locational influence of natural resource cycles such as wind and solar availability.

Depending on data availability, the ELCC approach may use either generic data for a class of generation technology and for the meteorological conditions at an actual or proxy location, or actual demonstrated performance data for the generator that is the subject of the analysis. Typically, the choice depends on whether the generator is new or existing.

The main limitations of this method are caused by:

- The quality and quantity of data available to derive an accurate model of the resource variability in relation to regional weather and system load
- The cost, complexity and uncertainty involved in modelling system reliability and the reliability equivalence.

Consequently this method is not favoured when the penetration of intermittent generation is low and when the amount of historical performance data is insufficient to develop robust models of plant performance for the intermittent resources.

4.2.2 Approximation methods

The use of the ELCC approach is therefore often limited due to data availability, particularly in the case of new plants, but this may also be the case if the subject generator falls into a technology class that is new to the control area of the system operator. An example of this new technology may include generators that rely on tide or wave power in the case of the SWIS.

The most common approximation method uses a time-period basis to approximate a generator's contribution of useful capacity. These methods assume a high correlation between hourly demand and the Loss of Load Probability (LOLP) of the system.

In many cases time-based approximation methods use the actual production history of the intermittent facilities to inform a production factor or capacity factor of the facility, measured as a proportion of installed capacity. The time-period basis typically includes the hours of peak load, sometimes differentiating between winter and summer seasons.

Time-based approximation methods are most commonly used in jurisdictions that feature a capacity market mechanism.

Other approximation techniques include risk-based techniques, however these are not commonly used to support the valuation of intermittent capacity in a capacity market context.

Risk-based techniques develop an approximation to the utility's LOLP curve throughout the year. Risk-based methods utilize hourly LOLP information either from an actual reliability model run or as an approximation.

These approximation methods are suitable at moderate penetration levels for intermittent generation when some years of performance data are available. However they can become unsuitable at higher levels of penetration if the pattern of generation is significantly correlated with peak system demand. Under these conditions, the critical performance period may shift away from the traditional peak demand time especially with high penetration of solar thermal and photovoltaic resources in a summer peaking system with low cloud cover at times of peak demand.

4.3 Capacity valuation in a selection of international markets

4.3.1 Markets sharing a similar design logic with the SWIS:

The following provides a summary of how international markets that are similar to that of the SWIS value intermittent generation. The selection of markets that have been reviewed includes those that feature (1) an energy market, (2) a reserve capacity requirement, and (3) a capacity market.

4.3.1.1 New York

Reserve requirements in the New York Control Area are based on the Installed Reserve Margin (IRM) determined by the New York State Reliability Council (NYSRC), a non-profit corporation established by the New York Independent System Operator (NYISO). In determining the IRM, the NYSRC uses a Monte Carlo based probabilistic program to determine the amount of installed capacity required to meet a "one day in ten years" Loss of Load Probability (LOLP) standard, based on the daily peak loads and recognizing transmission constraints and support from neighbouring systems. Wind generators are modelled as an hourly load modifier, using actual hourly wind data that is collected at defined sites for a reference year. The IRM for the 2008/2009 capacity year is 16.6% of expected peak load. This becomes the aggregate installed capacity (ICAP) requirement for the control area.

The NYISO converts the ICAP requirement into a measure of unforced capacity (UCAP), which is then traded between suppliers and loads serving entities in the bilateral and organised capacity markets. Separate UCAP requirements are determined for the New York City, Long Island and Rest of State regions.

The capacity value (UCAP) of resources that are not intermittent resources (not wind, solar or land-fill gas) in the New York market is based on the product of the unit's installed capacity, and a measure of its Effective Forced Outage Rate (EFOR), using twelve months of historical data corresponding to the winter and summer Capability Periods.

UCAP from intermittent resources that depend on wind as their energy source are able to operate in the capacity market. UCAP from wind generation is determined by calculating the production factor for a particular resource, based on its operating data for the prior equivalent capability period. For the summer capability period the production factor is based on average production during the 14:00 to 18:00 hours for the months of June, July and August during the prior year. Unforced Capacity from a wind generator for the winter Capability Period is based on average production during the 16:00 to 20:00 hours for the months of December, January, and February during the Prior Equivalent Capability Period.

For wind generators having less than sixty (60) days of historic operating data in the prior equivalent capability period, the initial UCAP is set using default values based on an ELCC-based study of the contribution of wind generation to the control area.

The industry in New York has used ELCC techniques to perform a wind integration study, designed to inform the market of impacts associated with high penetration levels of this resource, thereby providing a basis for further reform to the market, and to system operation.

4.3.1.2 PJM

PJM is a Regional Transmission Organisation that encompasses all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia.

Similar to New York, reserve requirements in the PJM balancing area are set using a 1 day in 10 year LOLP criterion, thereby determining an installed reserve margin that is applied to a measure of forecast peak internal demand (adjusted for contracted interruptible load) for the capacity year. Generation from wind and biomass is treated as capacity. Unlike New York, wind is not a load-modifier in PJM's method for determining the peak load basis of its installed capacity reserve margin.

PJM has implemented a forward capacity market, based on their Reliability Pricing Model mechanism.

The capacity value for an intermittent capacity resource represents that amount of generating capacity, expressed in MW, that it can reliably contribute during summer peak hours and which can be offered as unforced capacity into the PJM capacity markets. In particular, a capacity factor (similar to New York's production factor) is calculated for intermittent generation. The methodology depends on whether the resource is a mature intermittent resource (defined by reference to operating history):

- For a mature intermittent resource, the calculation of the capacity value for the capacity year is performed by first computing its unique single year capacity factors for each of the prior three summers; these are based upon operating data for each of the summer periods, covering hours from 2 p.m. to 6 p.m., from June 1st through August 31st. The mean of single year capacity factors for each of the prior three years results in a Capacity Factor representative of the three prior years. That Capacity Factor, when multiplied by the current Net Maximum Capacity (nameplate output less station load), yields the current capacity value for that intermittent capacity resource.

- In the case of an immature resource, a resource without an operating history that includes the three most recent summers, the single year capacity factor is assigned the value of the Class Average Capacity Factor for each summer where there is no or incomplete data. The Class Average Capacity Factor for wind generation is currently 13%, based on the average capacity factor during the 2 – 6 p.m. hours from June through August for all wind generators that have been in operation for three years or more in PJM. The Class Average Capacity Factor for solar is currently 38%. The Owners of immature intermittent units may substitute an alternate Class Average Capacity Factor with suitable documentation and approval by PJM.

PJM also sets minimum and maximum amounts that wind generators can bid into PJM's capacity auction, setting as a minimum of 85% of the capacity value of a wind project, and the maximum as the capacity value of either the individual wind generator (if more than three years of operational experience is available), or the capacity credit class average for wind at the time of the auction. The 15% approximately represents the standard deviation from the mean of the annual capacity value of wind generators now operating in PJM. The minimum and maximum bid amounts for wind were implemented in order for wind generators to minimize the potential for being penalized for under-delivering, such as lower-than-expected wind resource patterns.

4.3.1.3 New England ISO

New England ISO (NE-ISO) is a Regional Transmission Organisation that manages the control area encompasses Maine, New Hampshire, Vermont, Massachusetts and Connecticut.

NE-ISO defines intermittent generation resources as wind, solar, run-of-river hydro-electric and other renewable resources that do not have direct control over their net power output.

Reserve requirements for the control area are set using a 1 day in 10 year LOLP criterion, applied to measure of forecast peak internal demand for the capacity year. Generation from intermittent resources is treated as capacity, and not as a load modifier.

Similar to PJM, NE-ISO has implemented a Forward Capacity Market. The Forward Capacity Market features Forward Capacity Auctions for each Capability Year, with the objective of satisfying the resource adequacy obligations of all New England market participants within the control area. The Capability Year Installed Capacity Requirement (ICR) is a key input in the Forward Capacity Auction. The ICR is a measure of the installed resources that are projected to be necessary to meet adequacy standards in light of total forecasted load requirements for the New England Control Area and to maintain sufficient reserve capacity from a resource adequacy perspective. Specifically, the ICR is the amount of resources needed to meet the LOLP planning criterion.

The capacity value of an intermittent capacity resource within the context of NE-ISO's ICM is estimated on a seasonal basis:

- Summer Qualified Capacity is calculated as the median of the net output during the Summer Reliability Hours, of the most recent five summer periods. The Summer Intermittent Reliability Hours are the hours ending 1400 through 1800 in June through September. After June 1, 2010, Summer Reliability Hours will also include hours in which the ISO has declared a system-wide Shortage Event (if a Resource was located in an import-constrained Capacity Zone, Summer Reliability Hours will also include all Shortage Events within that Capacity Zone); and
- Winter Qualified Capacity of an Intermittent Power Resource is the resource's net output in the Winter Intermittent Reliability Hours, which include the hours ending 1800 and 1900 in (October through May). After June 1, 2010, Winter Reliability Hours will also include hours in which the ISO has declared a system-wide Shortage Event and if the Intermittent Power Resource or Intermittent Settlement Only Resource was located in an import-constrained Capacity Zone, Winter Reliability Hours will also include all Shortage Events in that Capacity Zone.

Currently, the ICM calculations for each prospective capacity year are based only on existing resources. New resources are not included in the determination of the ICM.

4.3.2 Other markets

The following summarises how intermittent capacity is valued in a range of markets that feature a capacity payment mechanism, or that require the capacity of intermitted generation to be valued as part of the determination of capacity reserve requirements.

4.3.2.1 Republic of Ireland and Northern Ireland

The All-Island Market for Electricity (AIME) encompasses the Republic of Ireland and Northern Ireland. The market is managed by the Single Electricity Market Operator (SEMO).

The market sets a Capacity Requirement based on a LOLP planning criterion.

The market features a Capacity Payment Mechanism that distributes a pool of money to generation resources to cover their fixed costs, which under agreement with the Regulatory Authorities, are not to be included in their energy market offers. The pool of money is calculated as the multiple of a Volume element (in megawatts, the capacity required to adequately serve the market demand), and a Price element (in €/ kilowatt, the annualised fixed costs of the Best New Entrant (BNE) generator, defined as a peaking plant). The pot is fixed and published four months prior to the commencement of the Trading Year.

During the Trading Year, Capacity Charges are levied on participants who purchase energy from the pool, therefore providing the revenue source for the Capacity Payment Mechanism. Payments are then concurrently distributed to participants who provide generation capacity to the market. Within this mechanism, intermittent generation capacity, such as wind generation, is allocated payments based on their capacity contribution, estimated by the ratio of their average wind capacity credit (based on actual production that is adjusted when the units are constrained-down by the system operators) and a time-weighted measure of their total capacity (installed capacity). The allocation measure is therefore similar to a production factor.

The industry in Ireland has used ELCC techniques to perform a wind integration study, designed to inform the market of impacts associated with high penetration levels of this resource, thereby providing a basis for further reform to the market, and to system operation.

4.3.2.2 *Markets without an organised capacity market or capacity payment mechanism, but that have a capacity reserve requirement*

4.3.2.2.1 California

Although California does not have an organised capacity market, or a capacity payment mechanism, it does require load serving entities to demonstrate that they have procured sufficient capacity to meet their forecasted loads plus a Planning Reserve Margin (PRM) one a year ahead for the next summer, and then each month during the year. There is therefore a significant bilateral market for capacity.

The California Energy Commission has adopted ELCC as the capacity valuation method to help load serving entities to determine the least-cost and best-fit generation to meet reliability and adequacy goals. The ELCC approach is applied to all renewable generators to value the contribution of their capacity, and to help determine the ranking of bids from these generators. These calculations are used in setting long term supply contracts.

The data basis for assessing the contribution of wind generation to the market's reserve requirement adopts a time-based methodology, using a three-year rolling average of the monthly average of wind energy generation between 12 and 6 p.m. for the months of May through September.

4.3.2.2.2 Texas

Texas has an energy-only market that does not have a capacity market, or a capacity payment mechanism.

Wind generation is included in capacity reserve margin calculations at 8.7% of nameplate capacity, based on a stochastic analysis of effective load carrying capability.

4.4 Summary of concepts

Table 6-8 provides a summary of the above discussion. The principles which may be derived from this analysis are:

- Where there are sufficient data, and in markets where the penetration level of intermittent generation is significant, methods based on equivalent load carrying capacity (ELCC) are used to value the capacity contribution of intermittent generation.
- Where data are insufficient for a particular project, then class level capacity values are applied until project specific historical data can be captured to make a more specific assessment
- ELCC may be applied in aggregate with individual projects receiving a share of the credit based on historical production in peak load periods. This is applied during the transition to full ELCC based credits for all projects as they accrue historical performance data.
- Average production levels over peak periods of 3 to 6 hours according to seasonal load profiles are used to approximate ELCC based values.

The apparent stages of evolution are:

- Capacity based on average production levels over 3 or more years when the interaction between intermittent generation and system load are not well understood and where the penetration of intermittent generation is low;
- Move toward capacity assessments based on specific time based periods that correspond on average to system peak demands on a seasonal basis. This method is applied as more data become available. The capacity value may be adjusted to reflect aggregate assessments of specific technologies by class to ensure that the aggregate capacity valuation is consistent with system reliability models;
- Apply reliability equalisation methods to individual projects and technology classes as more sophisticated models of project and system performance are developed. Simpler models continue to be applied for new projects and new technologies where data do not justify the more precise methods.
- Monitor the capacity assessment on a rolling time period so that capacity assessments can adapt to changes in market penetration of intermittent generation. Capacity assessments do not remain static.

4.5 Applicability in Western Australia

This analysis suggests that the IMO would be expected to move to reliability based assessments as more relevant data on the relationship between system reliability and intermittent generation performance become available.

4.6 Summary of concepts for capacity valuation

Jurisdiction	Type of Market	Reliability Equalisation – risk based	Average Output over defined period	Average output in critical period periods – time based	Comments
WEM (WA)	Net pool bilateral market		Based on average output over three years	Initial market Rules averaged output over 250 trading intervals based on peak system load	Simplicity and convenience are the objective given the absence of sufficient data for more complex methods and low penetration.
NEM (Aust)	Gross energy only market			Equivalent capacity based on correlation with peak loads.	Jurisdictions make an estimate based on observations about the correlation between resource output and peak demand in each region. There is no common rigorous method across the NEM.
New York	Independent System Operator in bilateral market	Used to assess aggregate value of wind generation and to assess initial capacity value if historical data are not available.		Average production between 2 pm and 6 pm in summer and 4 pm to 10 pm in winter in prior period.	Wind is treated as a load modifier.

Jurisdiction	Type of Market	Reliability Equalisation – risk based	Average Output over defined period	Average output in critical period periods – time based	Comments
PJM	Regional Transmission Organisation with capacity mechanism			Average production between 2 pm and 6 pm in summer in the previous 3 years.	Wind is treated as capacity. Technology call average applied if data are insufficient from the last 3 years. Only 85% of assessed capacity may be bid onto the capacity auction, based on standard deviation of annual capacity value.
New England ISO	Regional Transmission Organisation with capacity mechanism			Average production between 3 pm and 6 pm in summer and from 5 pm to 7 pm in winter in the previous 5 years, plus System Shortage periods as they occur.	Wind is treated as capacity.
Republic of Ireland	Capacity and energy market	Equivalent load carrying capacity analysis has been conducted to guide market development for high levels of wind power.	Based on a production factor adjusted for constrained operation.		

Jurisdiction	Type of Market	Reliability Equalisation – risk based	Average Output over defined period	Average output in critical period periods – time based	Comments
California	Bilateral capacity market	ELCC applied to valuation of all renewable energy generators		Use a three year rolling average of monthly wind generation between noon and 6pm in May to September.	
Texas	No capacity mechanism	ELCC assessed using stochastic analysis to allow 8.7% of rated capacity in capacity assessments.			

5 DATA PREPARATION

5.1 Selection of candidate years

The IMO provided system loading data at sent out level from 1 October 2001 until 30 September 2009. Based on a confidential report provided to the IMO from the National Institute of Economic and Industry Research (NIEIR), it was assessed that the following historical years would provide loading profiles that would be close to the nominated percentile levels of peak demand as shown in Table 5-1. The profiles for these years were then adjusted for the system demand to match the summer and winter peak demands as forecast for the WEM.

Table 5-1 Selection of Capacity Years

Capacity Year from October	Extremity of the Summer	Extremity of the Peak Demand	Nominated for Percentile of Exceedance	Weighting for USE	Proportion of USE (2012/13)
2003	60%	10%	10%	37.48%	90.2%
2004	75%	45%	30%	6.78%	6.1%
2002	15%	75%	50%	5.00%	0.9%
2006	70%	75%	70%	23.31%	1.9%
2008	50%	90%	90%	27.42%	0.9%

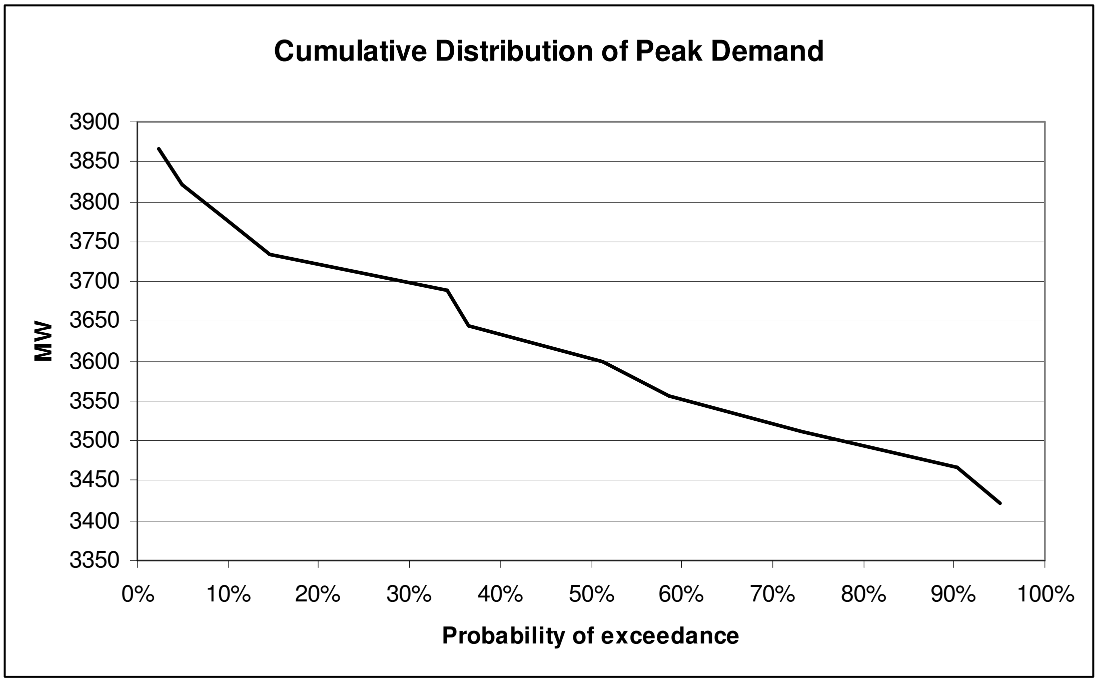
Source: NIEIR data and MMA analysis

With respect to the on-going evaluation of capacity, it might be expected that these years will be supplemented or replaced over time as new information on weather changes and intermittent generation indicate that sampling of years could be replaced by more detailed stochastic models or more relevant years selected. Our analysis shows that the capacity value should focus on the 10% and 30% POE years as the capacity value in the other milder periods is not as critical, as they represent only 4% of the capacity risk in terms of unserved energy.

5.2 Weighting for unserved energy

The weighting to be ascribed to the five annual profiles to represent the distribution of peak demand was assessed using the Miller and Rice method to align the moments of the discrete distribution with the moments of the continuous distribution. The continuous distribution was assessed using a linear function of peak demand versus average daily temperature provided to the IMO by NIEIR. This linear relationship was applied to historical average daily Perth temperatures from 1970 to 2009 from which a continuous distribution was derived as shown in Figure 5-1. It may be seen that the pattern of peak demand is accentuated slightly toward the 5% to 30% probability of exceedance.

Figure 5-1 Estimated distribution of peak demand based on average daily temperature in Perth



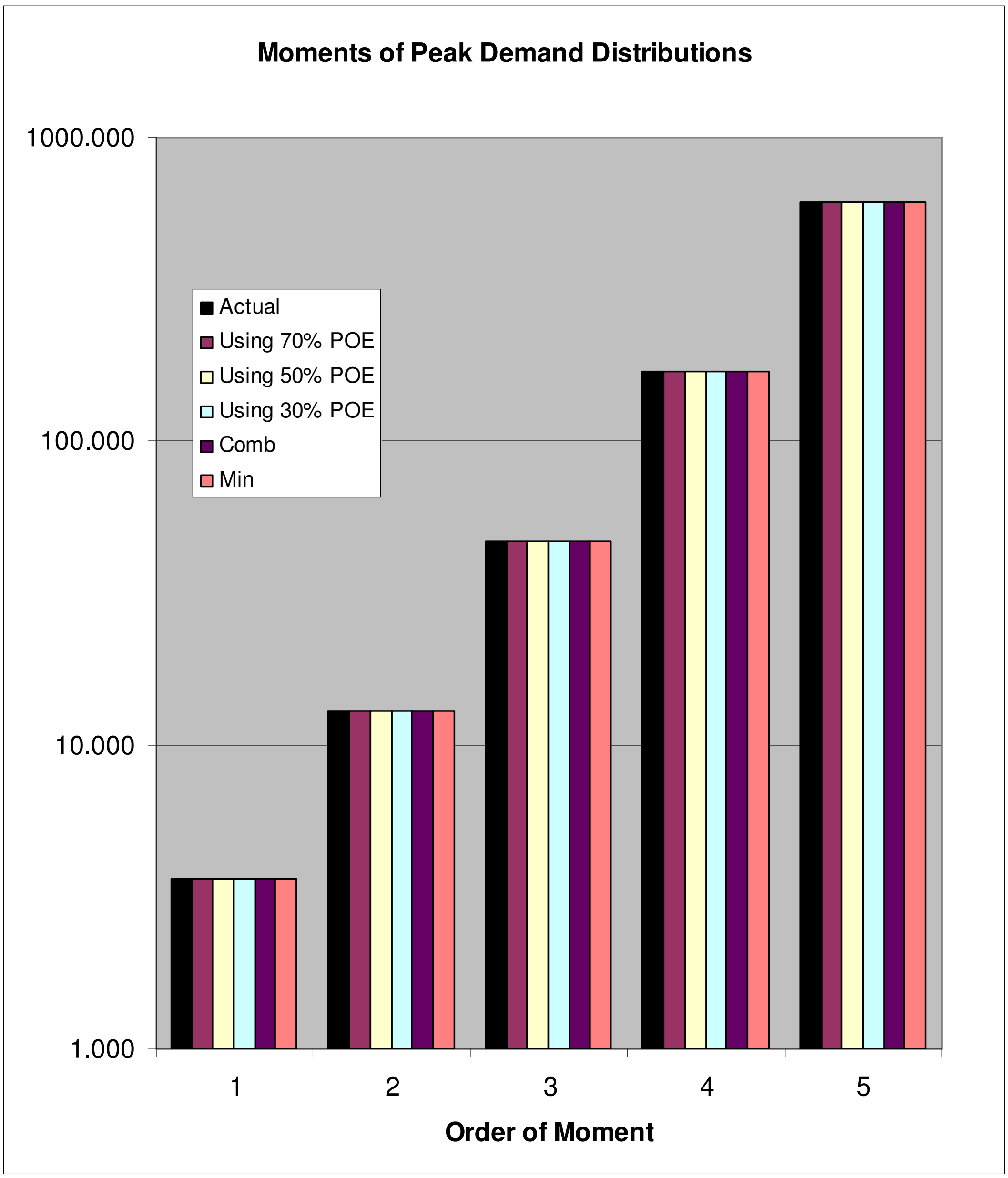
These data points were then used to assess a suitable weighting of the five scenarios at 10%, 30%, 50%, 70% and 90% probability of exceedance to represent this continuous distribution. It was found that using the 10%, 70% and 90% POE cases would be optimal as shown in Table 5-1 for the case with minimum square errors for the first five moments. This was an almost perfect fit. However it was deemed unsuitable for our purposes due to the large weighting to the 70% and 90% POE cases which would not be expected to contribute significantly to unserved energy. Using this profile would place undue reliance on the 10% POE profile for assessment of unserved energy.

Table 5-2 Possible weights given to peak demand profiles

Case	10%	30%	50%	70%	90%	Sum of Square Errors of Estimated Moments
Minimum Error	42.53%	0%	0%	36.56%	20.91%	0.0225
Using 50% POE	38.77%	0%	24.88%	0%	36.35%	0.2509
Using 30% POE	15.93%	42.06%	0%	0%	42.02%	0.9157
Using Minimum 5%	37.48%	6.78%	5%	23.31%	27.42%	0.1230
Using Minimum 10%	32.38%	13.65%	10%	10%	33.97%	0.3057

For this reason we also examined using the 30% or 50% POE case instead of the 70% POE case. We also examined using a minimum of at least 5% or 10% weighting for each scenario. The relative weightings are shown in Table 5-1. Using the alternative cases gives less weighting to the 10% POE case and more to the other POE cases. The errors are much higher in absolute terms but the relative errors in the five moments which are shown in Table 5-2 are seen as still negligible as shown in Figure 5-2. We have adopted the minimum 5% mix of weightings to give some weight to all cases to reduce variability and to give some weighting to the 30% POE case without unduly increasing the fir error. Using the best fit with the 10%, 70% and 90% POE cases would give almost entire reliance on the 10% POE case.

Figure 5-2 Comparison of moments of distributions



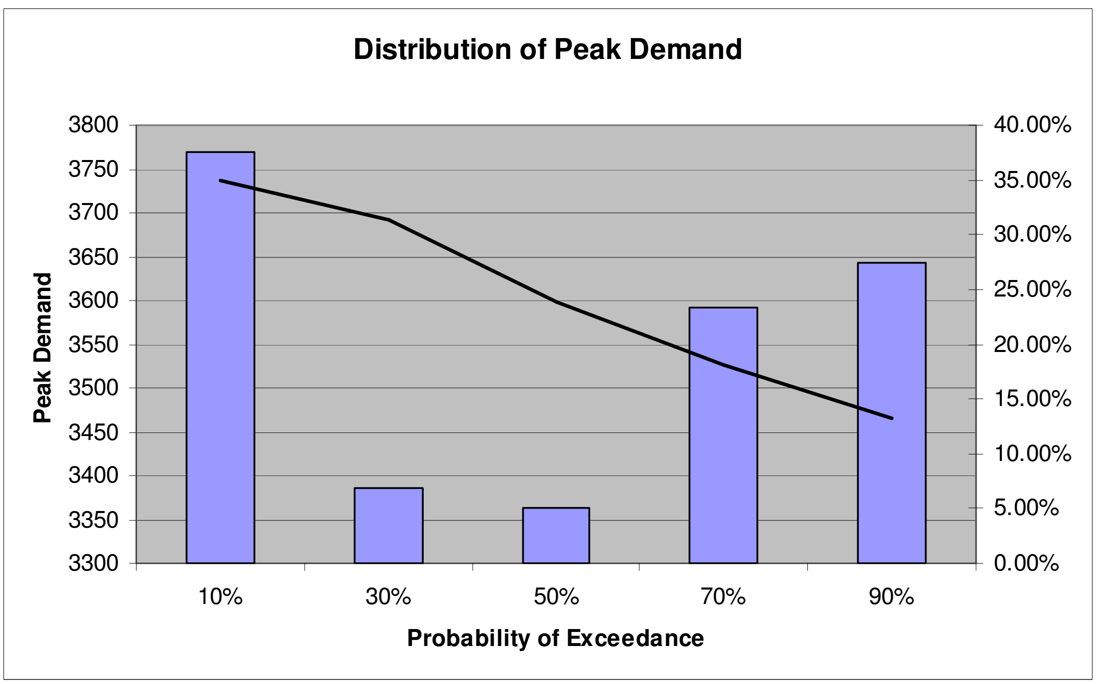
The resulting weights and the cumulative distribution are shown in Figure 5-3. The figure shows the probability weights that were used to approximate the continuous distribution of peak demand as a discrete distribution based on a minimum 5% contribution for each case.

5.3 Proportion of USE for capacity value

The proportion of the expected unserved energy which is attributable to each loading profile based on the 2012/13 simulated capacity year is also shown in Table 5-1. These proportions would serve to weight the capacity value attributable to each historical loading profile due to the relative contribution to reliability and expected unserved energy. These proportions show that 96.3% of the unserved energy would occur for the 30% POE profile and greater. From a reliability viewpoint these profiles are the more important in assessing capacity value. For the purposes of assessing the sensitivity of unserved energy to capacity levels we have run the 10% and 30% POE cases and calculated the expected unserved energy over the five cases using the approximation of the form:

Expected USE = (37.48% (10% POE USE) + 6.78% (30% POE USE)) / (96.3%)

Figure 5-3 Distribution if Peak Demand and Discrete Distribution Weights



This approach obviates the need to run the 50%, 70% and 90% POE cases for the purposes of estimating expected unserved energy. In should be accurate enough for practical purposes having regard to the quality of information about the performance of renewable energy projects and the factors affecting future supply reliability.

6 RELIABILITY AND LOLP ANALYSIS FOR 2012/13

6.1 Analysis for 2012/13 capacity year

The first stage of the analysis was based upon a detailed model of the 2012/13 capacity year from 1 October 2012 until 30 September 2013. In this analysis the three existing wind farms were treated as the only existing and committed resources. Other resources were treated on an incremental basis with capacity evaluated with the projects as mutually exclusive. This was a matter of convenience to reduce the number of project combinations that were considered, with priority on the existing resources.

6.1.1 Demand profile

A PLEXOS simulation was developed for the five standard load profiles with winter and summer peak demands including private loads as shown in Table 6-1. The peak demand data are shown in Figure 6-1 and Figure 6-2. The 70% POE peak demand was assessed by quadratic interpolation between the published values for 10%, 50% and 90% POE. However the 30% POE summer peak demand is evidently higher than an interpolated value by this means as evident in Figure 5-3. Thus we amended the 30% POE value by calculating the quadratic interpolated value and increasing it by 17.6% of the difference between the 50% and 10% POE values. The distortion from the smooth interpolation is evident in Figure 6-1.

Table 6-1 Summer and winter peak demand and annual energy

Medium Growth - Summer Peak System Peak MW	90%	70%	50%	30%	10%	Energy GWh
2012/13	4926	5018	5155	5338	5565	23656
2013/14	5208	5306	5451	5644	5885	25049
2014/15	5246	5347	5499	5700	5951	25098
2015/16	5421	5527	5684	5893	6154	25505
2016/17	5571	5681	5846	6064	6336	26057

Medium Growth - Winter Peak System Peak MW	90%	70%	50%	30%	10%
2012/13	3943	3990	4033	4073	4108
2013/14	4125	4173	4217	4258	4294
2014/15	4173	4221	4266	4308	4345
2015/16	4264	4314	4360	4403	4441
2016/17	4323	4374	4421	4464	4504

6.1.2 Capacity levels

The simulations were conducted for three capacity levels representing reserve margin factors of 3.21%, 7.27% and 9.48%. These cases were denoted RM3, RM7 and RM9 respectively. The RM7 and RM9 cases were initially set up to target the required level of unserved energy but after correction of some scheduled and forced outage rates, the RM3 case was needed because the USE levels were substantially reduced. The original RM7 and RM9 cases represent a scenario with a lower level of plant performance. The focus has therefore been with the RM3 and RM7 cases, the latter representing a low level of unserved energy but with close to the standard reserve margin. The relevant parameters for the two simulations are shown in Table 6-2. Since it is impractical to be able to create a solution that exactly corresponds to the 0.002% expected unserved energy, we have elected to use two simulations and interpolate between them.

Figure 6-1 Summer peak demands

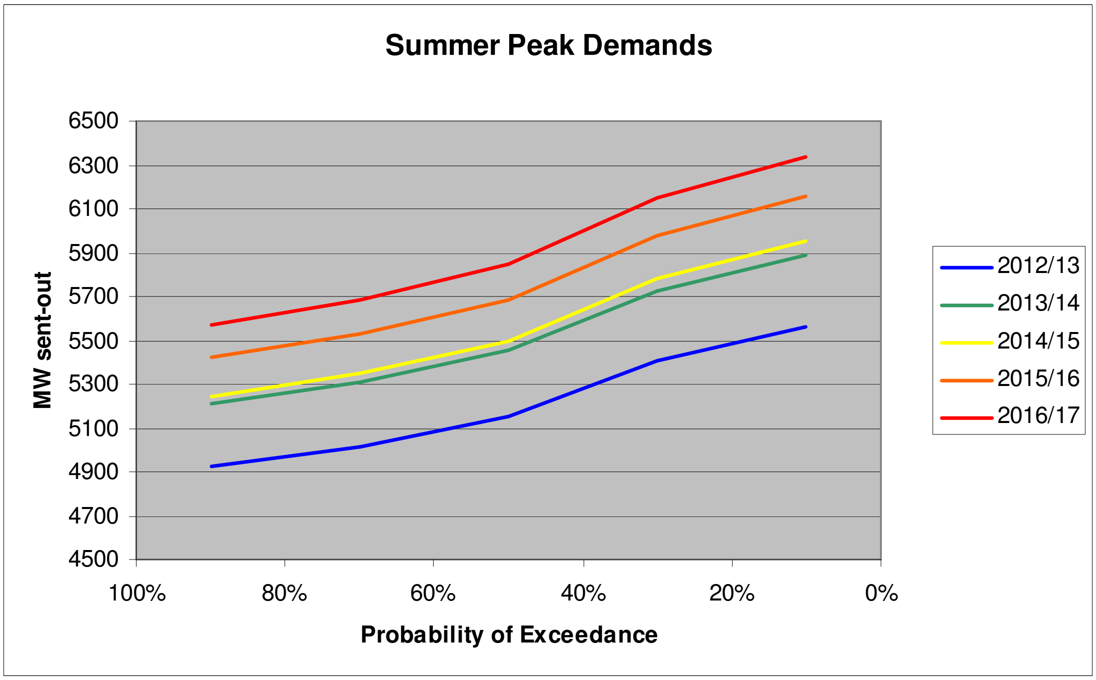
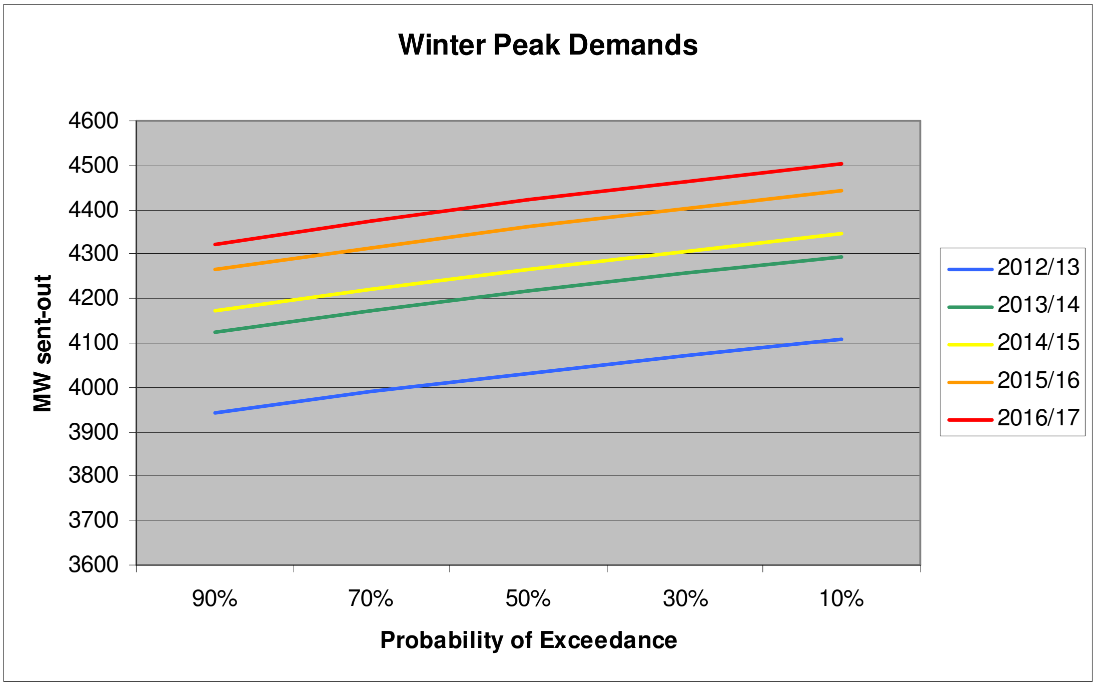


Figure 6-2 Winter peak demands



The interpolated state is also shown in Table 6-2. The interpolation of capacity was based on the logarithm of the expected unserved energy as this is more accurate than using a linear interpolation on expected unserved energy.

Table 6-2 Parameters for two capacity states for 2012/13

	Target USE	RM3	RM7	RM9	RM7(a)	RM9(a)
Summer Peak Capacity at 41°C (MW)		5,787	5,997	6,072	5,997	6,072
10% POE Peak Demand (MW)	5535	5535	5535	5535	5535	5535
Reserve Ratio	3.21%	3.21%	7.27%	9.48%	7.27%	9.48%
Expected Unserved Energy (GWh)	0.473	0.4653	0.1202	0.0380	0.504	0.343

Note (a) These cases were formulated with incorrect higher levels of forced outage rates

For the 2012/13 year a function was derived of the half-hourly loss of load probability as a function of the load for scheduled (thermal) generation (LSG). This is shown in Figure 6-3 for the three states: the two studied cases and an interpolated function that is intended to match the standard reliability conditions. The interpolated function is very close to the RM3 case as the unserved energy in RM3 was 444 MWh versus 473 MWh as the standard value. Thus the target LOLP function is slightly above the RM3 function.

The function was made up of two linear segments of which the maximum value was selected and a linear function multiplied by an inverse tangent function with a maximum value of zero. The structure of the function is shown in Equations (1) to (4). The structure was chosen to best fit the observed data.

The linear equations were:

$$X = Ax + B \tag{1}$$

$$Y = Cx + D \tag{2}$$

$$Z = (Ex + F)\ \left(1 - \text{Arctan}\left(\ 2\,G\,(x - H)\ /\ \pi\ \right)/2\right. \tag{3}$$

$$LOLP = \text{Exp}\left(\ \text{Min}\left(\ \max(X,Y),\ \text{Min}\,(0,\ Z)\ \right)\ \right) \tag{4}$$

Where:

LOLP is the loss of load probability

x is the load presented to scheduled generation in GW

Exp is the exponential function

Arctan is the inverse tangent function

Min ( ) calculates the minimum of the variables in the brackets

Max( ) calculates the maximum of the variables in the brackets

X and Y are linear functions of x

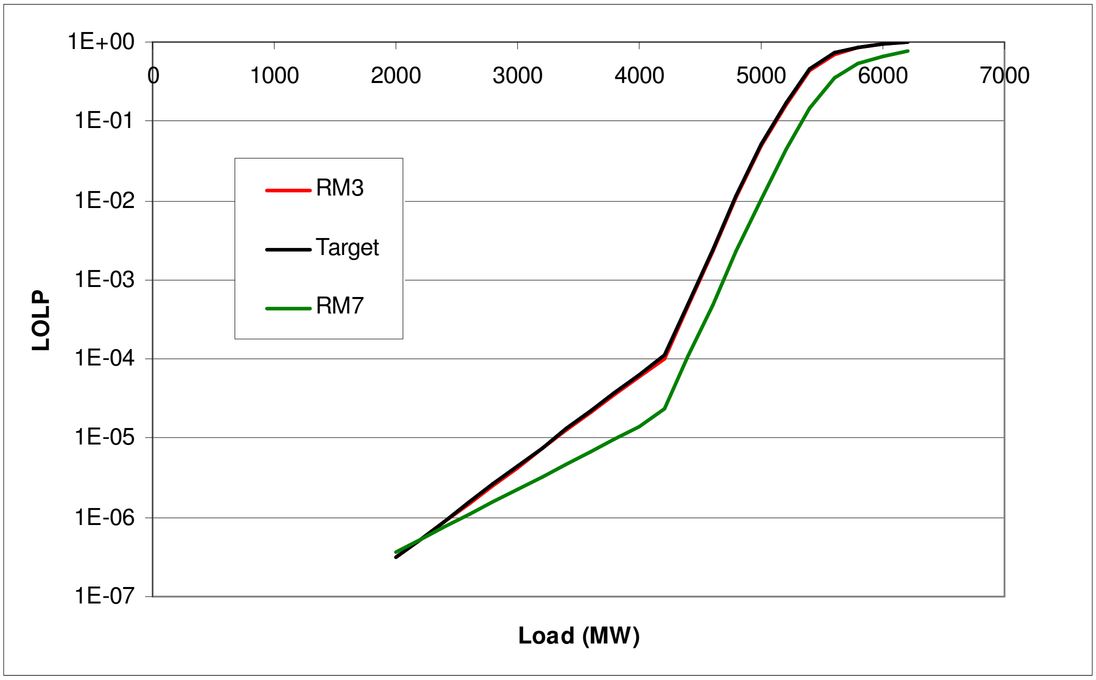
Z is the primary representation of LOLP for high demand levels.

A, B, C. D, E, F, G and H are constants

The interpolated function was formulated by interpolating each of the function parameters in accordance with the logarithm of the expected unserved energy. The target unserved energy was just outside the range set by the two reference cases and was equivalent to 3.21% reserve margin factor.

The linear functions dominate the low load part of the function and the arctangent dominates the higher demand portion. There did not seem to be much variation among the seasons, especially for the higher demands, hence the one LOLP function has been used for the whole year. A seasonal representation of LOLP versus LSG could be implemented if necessary to better represent seasonal effects with higher levels of

Figure 6-3 LOLP versus the load for scheduled generation



scheduled maintenance of if there were seasonal fuel constraints for example. This preliminary analysis uses the same function for the whole year. The relative importance of the peak season is very high so seasonal variations are not material if the system is reliable within the minimum requirements for reserve and unserved energy.

Using the Equations (1) to (4), it is possible to show how many trading intervals contribute to the load shedding risk by summing the loss of load probability over the intervals with the highest level of LOLP and dividing by the sum of annual values. This is illustrated in Figure 6-4 for RM3 and Figure 6-5 for RM7. Note that 90% of the load shedding risk occurs in 0.29% of the year, 95% in 0.58% of the year and 98% in 1.32% of the year for the RM3 profile based on 1000 samples. For the RM7 scenario where unserved energy is much lower, the relative risk is spread over a similar period of time. For example, 90% of the risk occurs in 0.20% of the time and 98% of the risk in 0.77% of the time. We have found that these estimates are quite volatile and that 200 or 300 samples are not sufficient to obtain reasonable estimates. These risk exposures relative to reserve margin are shown in Table 6-3. It is apparent that with sufficient samples, that 98% of the risk occurs in about 1% of the time.

Table 6-3 Proportion of LOLP Risk

Proportion of Risk	98%	95%	90%
At 3.21% Reserve (RM3)	1.32%	0.58%	0.29%
At 7.27% Reserve (RM7)	0.77%	0.29%	0.20%

Figure 6-4 Proportion of load shedding risk according to proportion of the year (RM 3.21%)

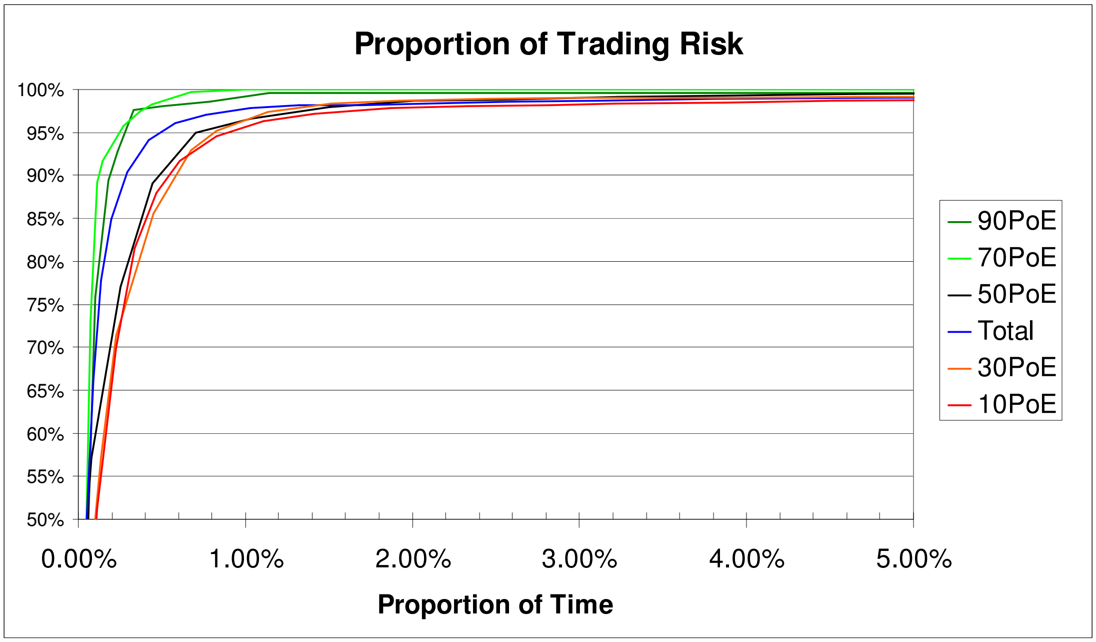
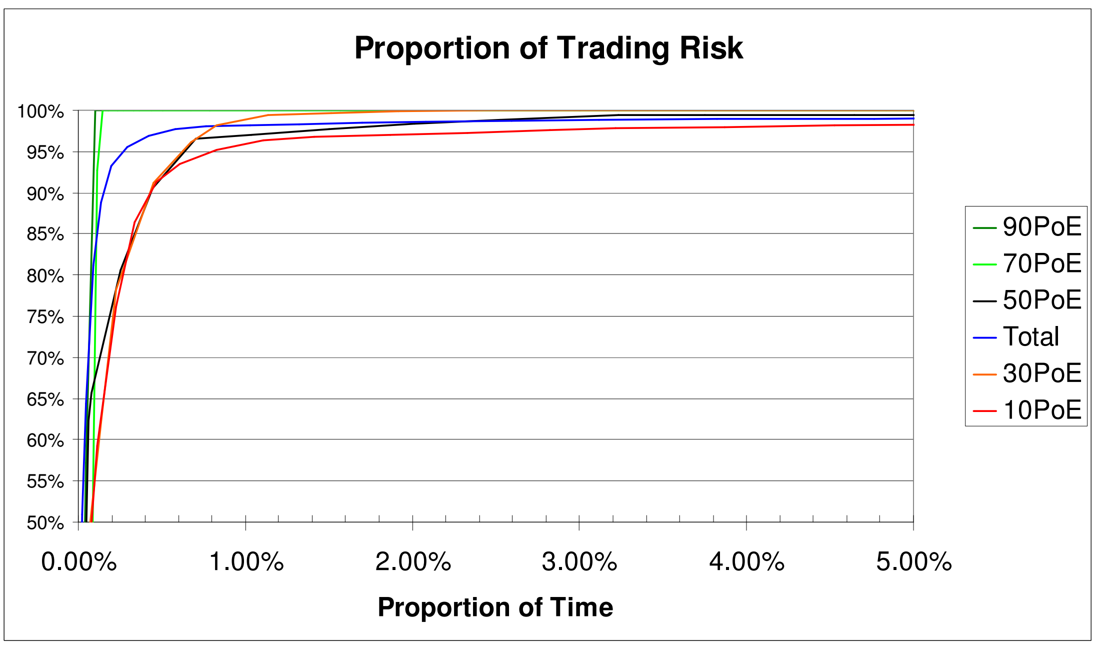


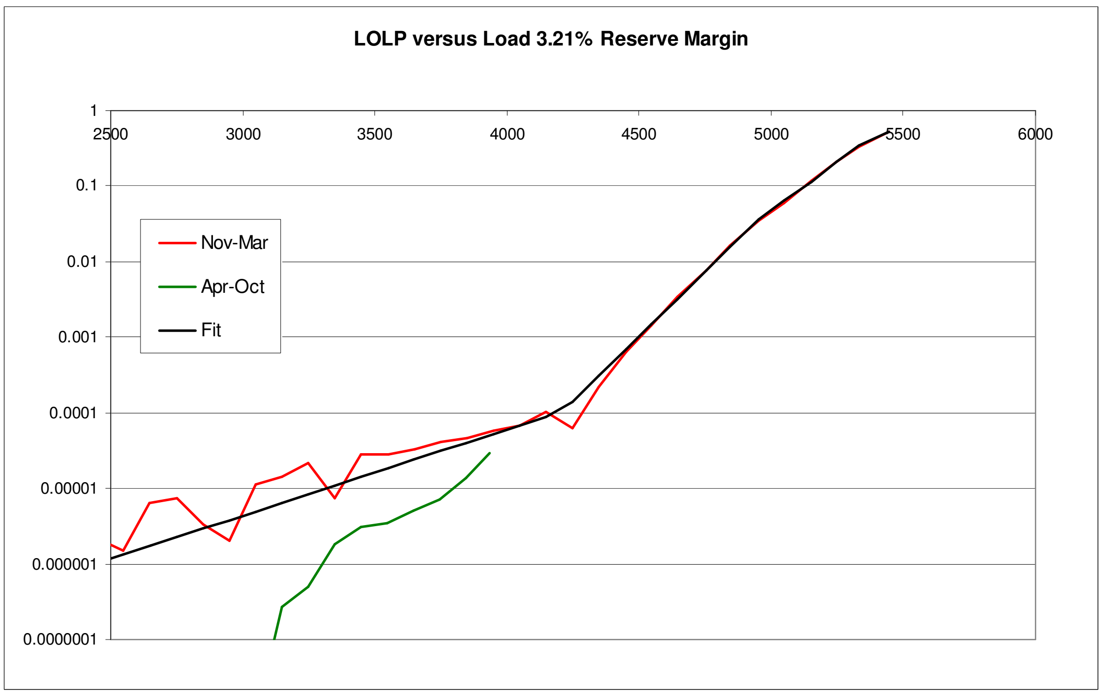
Figure 6-5 Proportion of load shedding risk according to proportion of the year (RM 7.27%)



Analysis of 2012/13 reliability showed that the load shedding risk was negligible in the winter period and slightly higher in the off-peak autumn and spring period, due to scheduled maintenance at that time. All of the load shedding events occurred in the October to March period in the various load profile cases. Therefore, we do not need to be concerned with the period outside the hot season between April and September unless there is a much greater than normal scheduled maintenance or power plants are retiring immediately after the hot season.

The LOLP versus load differed immaterially between the summer and winter profile as shown in Figure 6-6 for the RM3 scenario. The chart also shows the fitted function used for the LOLP analysis. The low load part of the profile does not significantly influence system reliability and therefore we propose to develop the initial commercial model based solely on generation profiles between October and March. We would expect the IMO to monitor system reliability based on maintenance schedules and require an extension of the portion of the year to be considered if necessary in special circumstances where there is scheduled maintenance well above normal levels or end of year plant retirements. However, MMA considers it unlikely that such conditions would lead to markedly different capacity assessments.

Figure 6-6 LOLP versus load for scheduled generation by season for 2012/13 for RM3



6.2 Wind farm capacity value based on LOLP

The essence of this project was to evaluate capacity based on reliability considerations and to this end we have evaluated the capacity of Albany, Walkaway and Emu Downs wind farms for 2012/13 capacity year in terms of:

- Their aggregate equivalent capacity value based on matching the expected unserved energy over the 10% and 30% POE load profiles
- Their individual values with the other projects in service but replaced by equivalent thermal plant

- Their capacity contribution under each of the five reference load profiles based on
  - LOLP weighting of half-hourly output
  - Average output over the whole capacity year as currently applies but based on the same years as used for the reliability analysis, not the last three years
  - Average output at the times of highest system loading at 1.43%, 2.85% and 4.28% of the year (taken as 250, 500 and 750 trading intervals)

These results are summarised in Table 6-4. The following sections discuss the derivation and limitations of this assessment. To preserve confidentiality the results are presented as a portion of rated capacity. The average power assessment is based on the nominated historical load profiles that were used for the LOLP basis, not the last three years. This ensures the comparison is based on using data from the same periods of time.

Table 6-4 Summary analysis of capacity value

	WF1	WF2	WF3	Total Value
Individual Reliability Equalisation value	60%	46%	52%	50%
Individual LOLP Capacity Value				
10% POE	57%	26%	53%	41%
30% POE	73%	51%	36%	47%
50% POE	22%	32%	69%	47%
70% POE	35%	27%	18%	24%
90% POE	42%	31%	27%	30%
Weighted by USE	58%	27%	52%	41%
By average power	34%	41%	42%	41%
Average of Top 250	34%	41%	42%	41%
Average of Top 500	44%	40%	41%	41%
Average of Top 750	41%	40%	41%	40%

Source: MMA analysis

6.2.1 Replacement firm capacity to match expected unserved energy

The first part of this process was to establish to cases for 2012/13 capacity year, with and without the existing and committed intermittent generation (ECIG) resources. The five loading profiles were simulated for the forecast peak demand to assess the expected unserved energy based on 1,000 statistical simulations. The results are tabulated in Table 6-5. The reference level of expected unserved energy is 473 MWh for total system load of

Table 6-5 Reliability equalisation for wind farms for 2012/13 capacity year RM3 at 3.21% (MWh)

Scenario	WF Capacity Adjustment (MW)	10%	30 %	50 %	70 %	90 %	Expected
With ECIG		1108	285	47	18	10	444
Without ECIG	70	1389	314				
	95	1140	267				
	120	987	217				
with interpolation	97.40						444

Table 6-6 Reliability equalisation for wind farms for 2012/13 capacity year RM7 at 7.27% (MWh)

Scenario	WF Capacity Adjustment (MW)	10%	30 %	50%	70 %	90%	Expected
With ECIG		260	61	11	2	0	103
Without ECIG	70	325	64				
	95	253	54				
	120	211	39				
with interpolation	90.78						112

23,656 GWh including estimated private loads. Assuming that the expected unserved energy is exponential with capacity, the interpolated capacity value of the above resources was 97.40 MW for the RM3 case. The corresponding analysis for the less stressed case RM7 is shown in Table 6-6. In that case the estimated aggregate wind farm equivalent capacity was 90.78 MW.

These results gives:

- 97.40 MW for RM3
- 90.78 MW for RM7
- 97.69 MW estimated for the target 0.002% unserved energy.

The reliability equalisation results were interpolated in accordance with the variation in unserved energy and the value of 97.69 MW was calculated to represent the capacity level at 0.002% unserved energy. This is positioned just above the RM3 level.

Based on the LOLP method, the aggregate value of these resources was:

- 77.9 MW for RM3
- 77.1 MW for RM7
- 77.9 MW estimated for the target 0.002% unserved energy.

This level which differs from the reliability equalisation value by

20.0% for the RM3 case

15.0% for the RM7 case

20.2% for the estimated 0.002% unserved energy.

There is quite some discrepancy between the values obtained by reliability equalisation and those using the LOLP method. The next section discusses the uncertainty in these estimates and why it is difficult to estimate the reliability equalisation value due to the number of simulations required to reduce the estimation error to an acceptable level. Due to the variations observed in the measures of unserved energy as the numbers of simulations was increased, and the way the studies were set up, it is considered that the reliability equalisation values obtained to date are probably on the high side for the wind farms and the low side for the solar thermal resources.

6.3 Uncertainty in the estimated capacity values

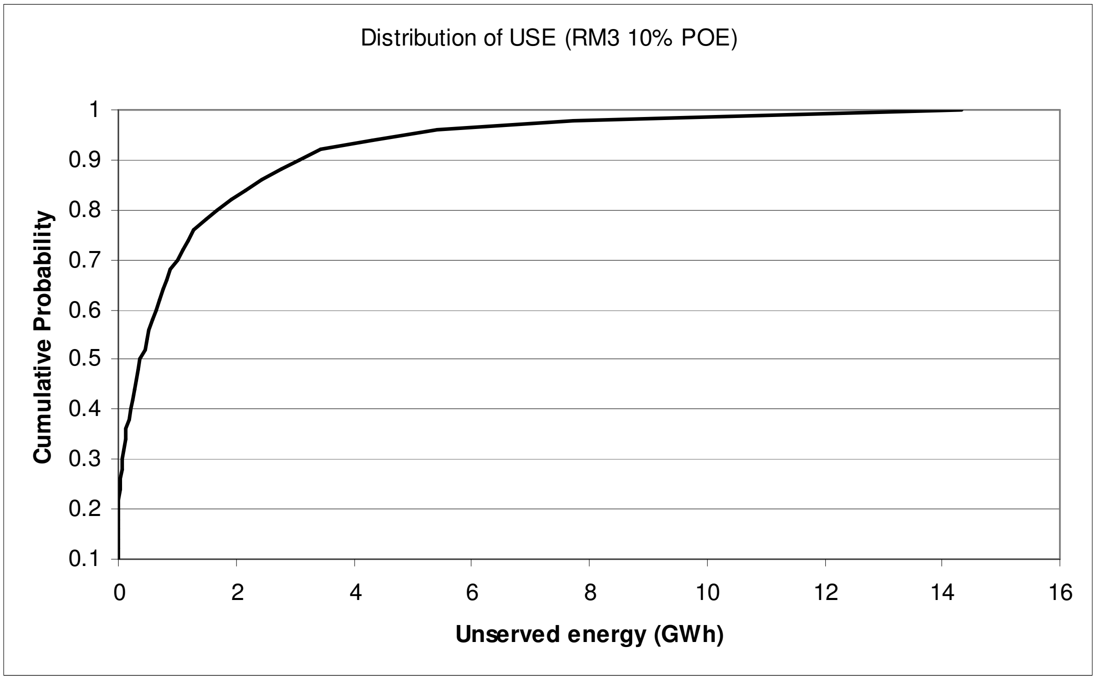
The level of accuracy in the above comparison must be assessed in the context of the underlying uncertainty in the analysis given that it is dependent on:

- Statistical sampling in the case of the reliability equalisation analysis;
- The difference between the cases with and without the intermittent generation; and
- The limited data on the output of the wind farms at times of high system load in the case of the LOLP based analysis.

6.3.1 Uncertainty in the statistical simulation for reliability equalisation

In conducting the reliability equalisation analysis, the uncertainty of the expected unserved energy was estimated as a standard error from the sampled values. This is fraught with difficulty because the unserved energy distribution is highly skewed as shown for the 10% POE RM3 case in Figure 6-7. The sample standard deviation for the 10% POE samples was about 1.72 times the mean value. In 16% of the simulations there was no unserved energy. It is therefore difficult to obtain an accurate assessment of expected unserved energy by statistical simulation. If we were to obtain a value of unserved energy at 2% accuracy, with 90% confidence, we would need some 20,000 simulations. This shows the limitations of trying to obtain accurate estimates for such

Figure 6-7 Distribution of unserved energy for 10% POE RM3 simulations



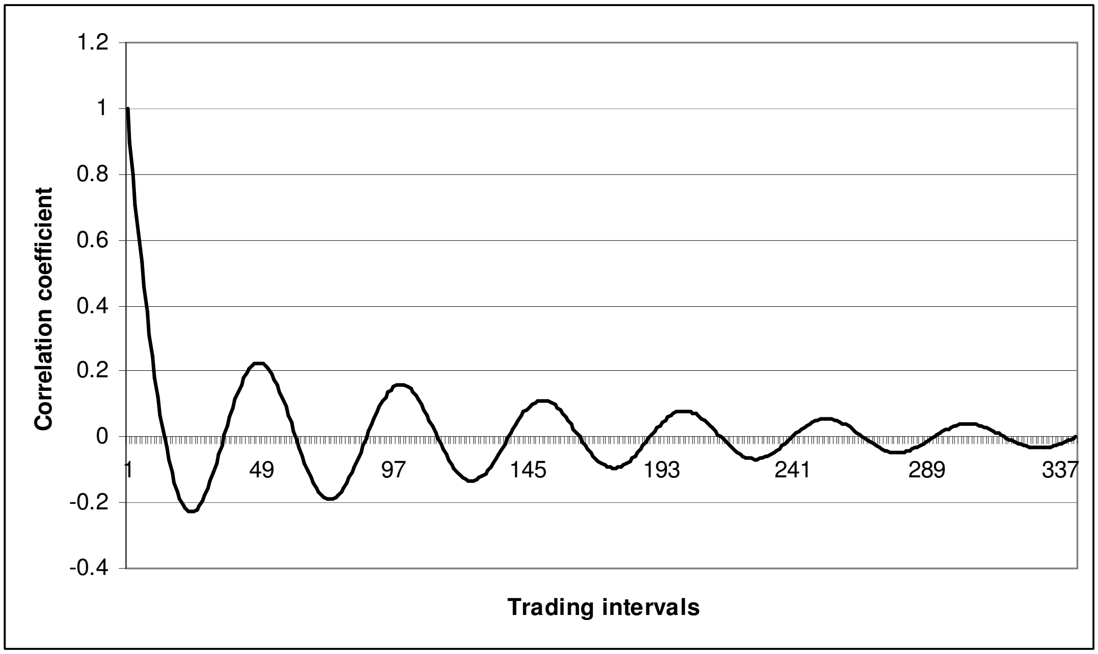
heavily skewed distributions. Even 10% accuracy with 80% confidence requires 490 simulations for these data. In the end we simulated each load profile 1,000 times and have estimated the expected unserved energy to a standard error of 2.6% for RM3 and 5.2% for RM7. It is considered that enough simulations have been conducted at this stage to show that equivalent results with the other methods can be expected if enough simulations are conducted to achieve the required accuracy. In particular, it would be desirable to conduct more simulations in the cases where the intermittent generation has been replaced, but this has been prevented due to the resources budgeted and the time and computers available.

When combining the uncertainty in the two cases, with and without the wind farm, it was possible to assess the standard error of the capacity valuation using reliability equalisation. These results are discussed below in section 6.5.

6.3.2 Uncertainty in the LOLP analysis

The uncertainty in the LOLP analysis was estimated by examining the variability of the wind farm resources on the hottest days recorded or simulated with maximum temperature above 40ºC. Typically the standard deviation of trading interval output was about 30% of rated capacity throughout the day with some variation during the day for some of the sites. We also examined the correlation of wind farm output for up to 5 days away from a sequence of hot days so as to assess the extent to which output could be high or low consistently over a period versus rapidly cycling. More frequent variations and lower correlation over time intervals reduced the estimating uncertainty for the LOLP method. A correlation function was developed as a decaying sine wave as the time interval between samples increases. An example of the derived characteristic is shown in Figure 6-8. Here is a higher correlation between wind farm outputs at 24, 48 and 72 trading interval separation due to the diurnal wind patterns observed. However after about 4 days the correlation becomes less than 10% for all sites.

Figure 6-8 Example of correlation of wind farm output between trading intervals



A simple correlation model was thus developed to estimate the uncertainty in the LOLP measure having regard to the variability of output observed by time of day on hot days.

More sophisticated forms of the correlation would be needed to accurately estimate the volatility in the LOLP index. However, at this stage it is sufficient to estimate the magnitude of this uncertainty for comparison with other methods.

6.4 Wind project assessments

Individual wind farms were then analysed one at a time from a reliability equalisation point of view assuming that the other projects remained in the market. This was an incremental analysis. A comparison of the incremental and aggregate values for the projects considered is summarised in Table 6-7 based on reporting the ratio of capacity value to rated capacity to preserve confidentiality. The values shown for reliability equalisation are subject to significant error due to the limited number of simulations conducted. They are considered to be on the upper end of expectations. The LOLP weighted values were scaled up to match the 51.5% ratio derived from reliability equalisation for the total wind farm contribution. This gives a small boost to all wind farms. Given the uncertainty of the magnitude of the capacity values based on reliability equalisation as discussed in section 6.3, it is not recommended at this stage that the capacity values be scaled to match reliability equalisation values assessed thus far. MMA

Table 6-7 Incremental and Aggregate Capacity by Reliability Equalisation

	WF1	WF2	WF3	Total Wind
Incremental Reliability Equalising Capacity Value (% Rated)	59.8%	46.4%	52.2%	50.3%
Aggregate value based on Reliability Equalisation (% Rated)	61.1%	47.5%	53.4%	51.5%
LOLP Weighted Value (% Rated)	57.8%	27.4%	52.2%	41.2%
LOLP Weighted Value In Proportion to the Aggregate Capacity Value (% Rated)	59.1%	28.0%	53.4%	51.5%

does not expect this to be a practical approach because of the significant cost in generating sufficient simulations and the limited information on wind farm performance necessary to make an accurate assessment. Even if many simulations are conducted, the analysis is still based on limited data about wind farm behaviour at times if system stress.

The capacity levels assessed for reliability equalisation were by means of interpolation between two near solutions based on assuming that unserved energy is exponential with capacity. The analysis is shown in more detail in Appendix A. The results show that the sum of the incremental capacities for the wind farms using LOLP weighting approximated the aggregate value of the value of the wind farm capacity based on reliability equalisation to within 20%. The aggregate value was 51.5% of rated capacity. Since this ratio is rather high and comparable to the accuracy achieved as discussed below, there is no need to apply scaling factors to align assessed capacities to match aggregate values.

6.5 Equivalence to LOLP value

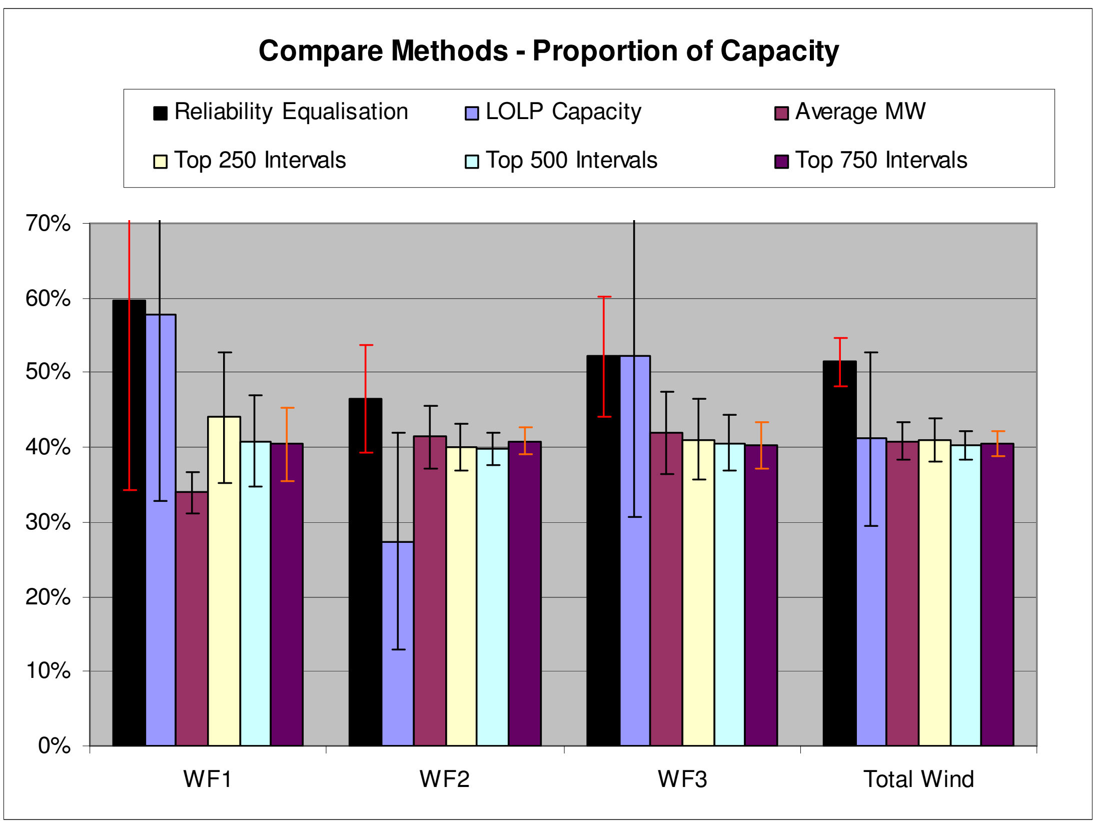
The next step was to compare these values in Table 6-7 with the values obtained using the LOLP method and the value based on averaging outputs over selected time or load periods. At this stage we also compared the volatility of the various measures based on the limited data available. The earlier Market Rules considered the top 250 trading intervals for system load. In this analysis the levels of 500 and 750 trading intervals were also evaluated. The existing method of averaging output over all time periods in the selected years was assessed but based on the same capacity years that were used for the alternative methods. These results are tabulated in Table 6-8 for the expected values.

Table 6-8 Summary analysis of assessed capacity value

	Total (MW)	WF1 (%)	WF2 (%)	WF3 (%)
Reliability equalisation value	97.69			
Individual LOLP Capacity Value	77.92	57.8%	27.4%	52.2%
By average power	77.23	34.0%	41.4%	42.0%
Average of Top 250	77.50	44.0%	40.1%	41.1%
Average of Top 500	76.25	40.8%	39.9%	40.6%
Average of Top 750	76.78	40.5%	40.8%	40.3%

The accuracy of the various methods for the solution at the target level of unserved energy is shown in Figure 6-9. Note that we have assessed the variability of the average output in the chart based on the eight simulated or actual years.

Figure 6-9 Comparison of capacity valuation methods for incumbent wind farms



The following assessment has been made from these results:

- All methods have significant levels of uncertainty and produce equivalent results with overlapping error bands at 80% confidence level.
- The reliability equalisation result for the wind farms individually and in aggregate does seem to be at the high end of possibilities. This may be an artefact of the 200 simulations conducted for the reliability equalisation cases and the fact that the base case was conducted with 1000 simulations. It is apparent that more simulations for the cases without the intermittent generation would be desirable to get a more accurate answer. However the current results are sufficient for our immediate purpose to check the overall level of capacity value.
- The long-term average power method would provide the least volatile measure, although over three years it is as volatile as the other averaging methods.
- When taken as a fleet the results are more consistent as the production output is less volatile and there are compensating effects. It is therefore reasonable that individual assets should not be unduly penalised just because there is greater volatility in their particular energy source. The evidence is that the diversity of the existing wind resources is significant in providing a net capacity value.
- Surprisingly, the average power method does not over-estimate the capacity value of the wind farms and therefore any delay in preparing a revised assessment is not critical for this technology.

Moving to an LOLP based method would not significantly change the assessed value of wind farms but would introduce more volatility into the measure until more market data are available for high load days. The variability among the wind farms of the assessment is significant and yet the overall contribution is unchanged. The variability among the wind farms may be a statistical artefact as the variations are within the 80% confidence range and are therefore not very significant. It would therefore be reasonable to provide stability in the assessment by giving the wind farms a credit based on the current fleet until a more accurate assessment is possible. It would be best to await the longer term assessment to 2016/17 before finalising such a decision. Also the impact on other technologies must also be considered.

At this stage there is no compelling evidence to change the assessment method for wind farms apart from the potential unsuitability of some of these methods for other technologies.

6.6 Solar resources

Loading profiles were also provided for solar photovoltaic and solar thermal resources for a favourable location near Geraldton. The data was developed by Senergy. Initial solar radiation data obtained from recorded Bureau of Meteorology data from automatic weather station #8051.

All modelling inputs and assumptions are as described in detail in Senergy Econnect Projects 2426 "Review of the Treatment of Solar Generating Facilities in the SWIS Capacity Market" and 3413 "The Treatment of Intermittent Generation in the SWIS Reserve Capacity Market". Both are available through the IMO.

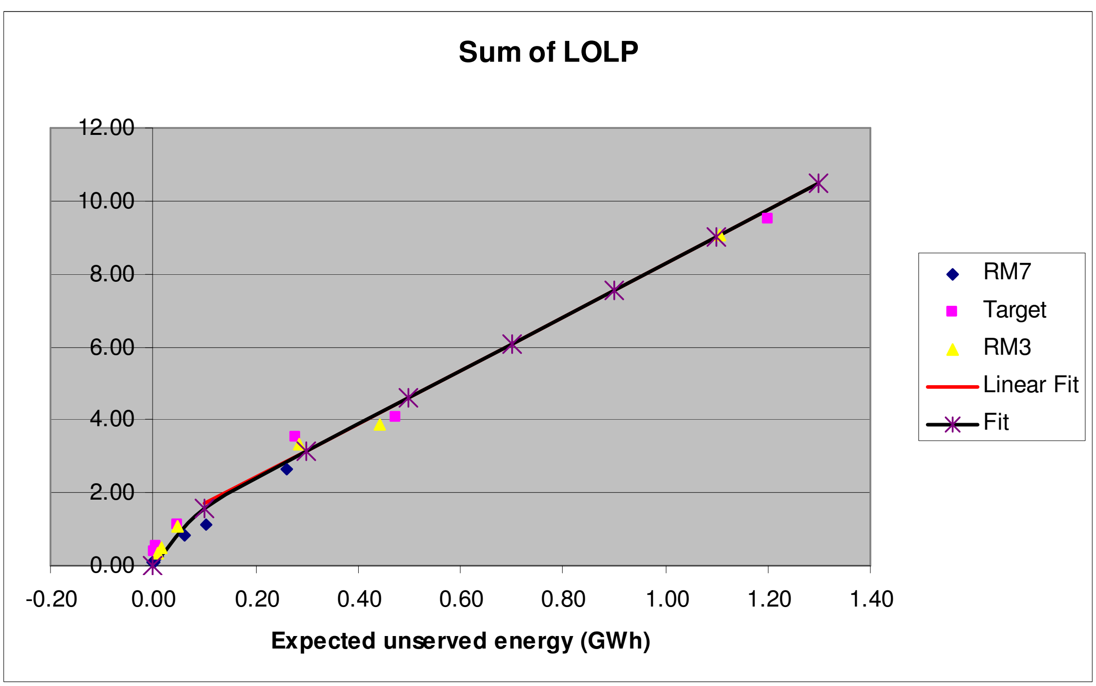
Solar thermal generation excludes thermal storage capability.

No data were available after 20 June 2006 and on some days some half-hour data were not available as suitable replacement hours were not available. Senergy had filled the 2006 days with 2001 data apparently irrespective of weather conditions. Such an approach does not meet this project's requirements to align generating with weather conditions and system load. On days when there were missing data values, MMA replaced the whole day with the nearest equivalent day based on temperature and wind speed observations from Geraldton. The resulting half-hourly generation profiles were then subtracted from the net load for scheduled generation calculated with the three incumbent wind farms.

6.6.1 Adjustment of load for scheduled generation

Unlike the analysis of the wind data, a further adjustment was made to the load for scheduled generation after subtraction of the solar technology profiles. A load was added to the load for scheduled generation to bring the sum of the LOLP values to a level that matches the target level of expected unserved energy. It had been found that the sum of the half-hourly LOLP values is also approximately linear with expected unserved energy as shown in Figure 6-10. A combination of exponential and linear functions was found to provide a suitable fit over the range. The various sampled values apply for the RM3 and RM7 cases as well as the interpolated cases with the target expected unserved energy. In

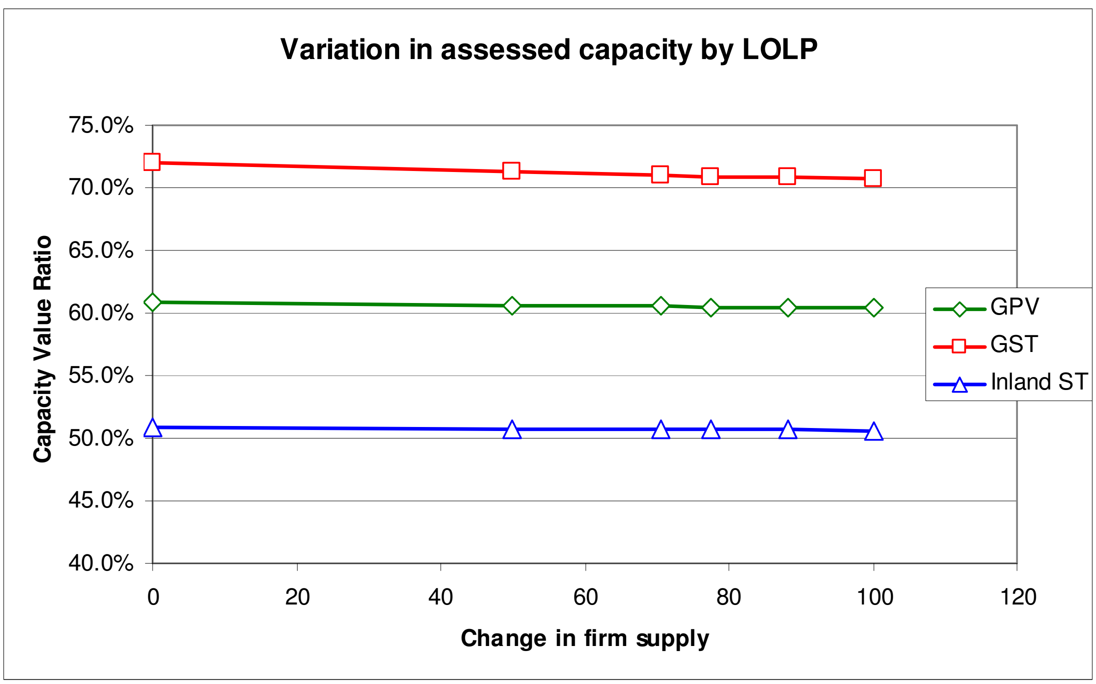
Figure 6-10 Sum of LOLP versus the expected unserved energy



the range around the target value of 0.473 GWh, the relationship is quite linear. We therefore conclude that we can adjust the load for scheduled generation to set a level of summated LOLP that would approximate the standard reliability conditions for which sufficient capacity is required. This would achieve the objective of being able to adapt the measure to the level of penetration of intermittent generation resources, without re-running system simulations.

It was found that the assessed capacity is not very sensitive to this adjustment for solar technology resources. This low sensitivity is shown in Figure 6-11 for the three solar technologies. For these examples, adjusting the load for scheduled generation makes only a 0.3% difference to the assessed capacity. This may not be worth doing except for very large projects well above 100 MW in size. The circles in the chart show the offsets which match the expected unserved energy for each option taken mutually exclusively. It is included that adjusting for project size is not a critical requirement unless new solar projects are expected to exceed 500 MW. However, it is not difficult to make analytical provision for this adjustment.

Figure 6-11 Sum of LOLP versus the expected unserved energy



The comparative results for the solar technologies with the load for scheduled generation adjusted by an offset to match the standard reliability conditions are shown in Table 6-9 together with the wind farm data. The estimates of the capacity for the solar resources by the reliability equalisation method was based on leaving the wind farm in the model and taking away capacity from the case until the reliability was equalised.

Figure 6-12 shows the assessed capacity values for three solar technology projects on an exclusive basis and with the reliability adjusted back to 0.002% expected unserved energy in the case of the LOLP method. The 80% confidence limits are also shown.

Table 6-9 Summary analysis of capacity value (% of rating)

	Incumbents			Incremental*		
	WF1	WF2	WF3	GPV	GST	IST
Individual Reliability Equalisation Value	60%	46%	52%	51%	56%	N/A
Individual LOLP Capacity Value	58%	27%	52%	60%	71%	51%
10% POE	57%	57%	57%	61%	72%	51%
30% POE	73%	73%	73%	46%	54%	47%
50% POE	22%	22%	22%	58%	62%	61%
70% POE	35%	35%	35%	59%	75%	47%
90% POE	42%	42%	42%	68%	75%	81%
By average power	34%	41%	42%	26%	29%	21%
Average of Top 250	44%	40%	41%	65%	76%	64%
Average of Top 500	41%	40%	41%	62%	69%	61%
Average of Top 750	40%	41%	40%	59%	66%	59%

Note: * The solar technology capacity values are incremental to the wind power portfolio for a 100 MW capacity. The wind capacity values have not been recalculated if solar thermal plants are added.

6.7 Assessment of uncertainty for solar resources

The assessment of the uncertainty for solar resources initially followed the same method as for wind. However, it was soon realised that the assessed uncertainty was too great because the correlation was assessed over all time periods whereas the solar resources are very strongly diurnal with no output between 7pm and 7 am. The correlation of output was then separated into the within day effects and the between day effects and the time of day was represented as well. It was found that within each trading interval of the day, the day to day correlation was generally zero and less than 10% as shown for a hot week in Figure 6-13. It may be seen that the correlation after one day is about -10%, so the day to day effects on the uncertainty were treated as negligible. If anything, they would slightly reduce the assessed uncertainty if they were included.

Figure 6-12 Comparison of capacity valuation methods for solar resources

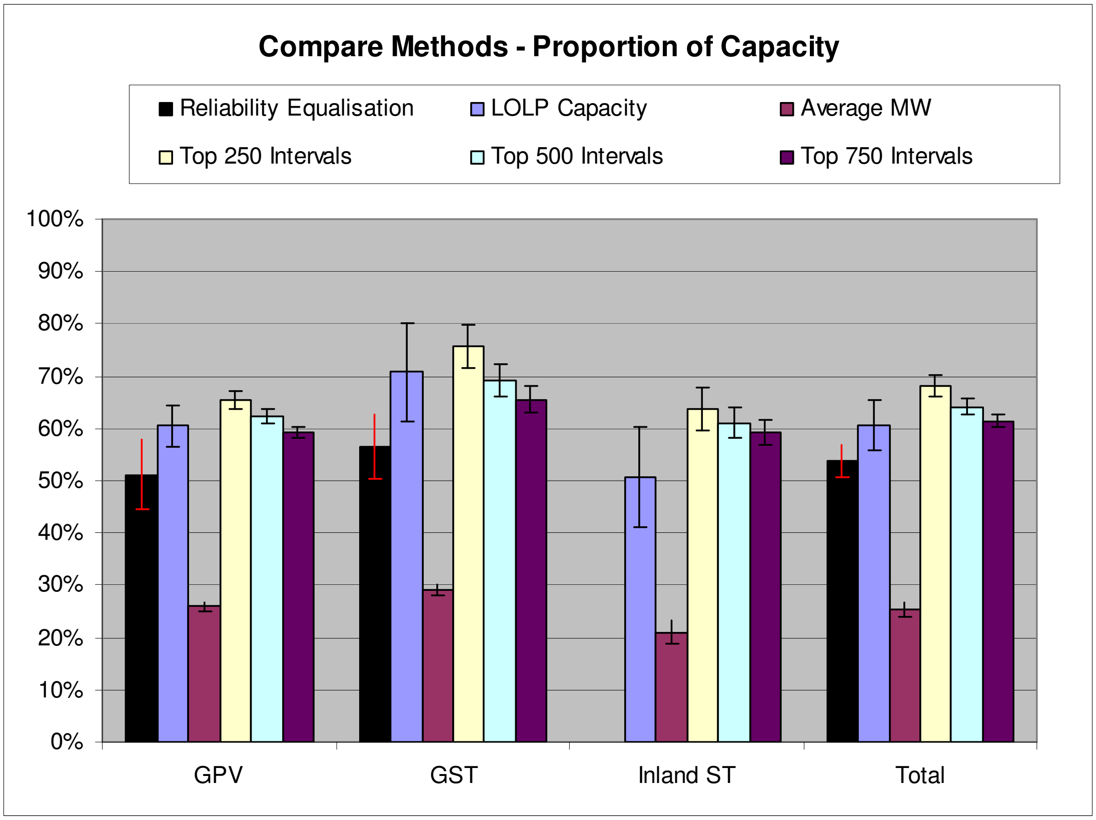
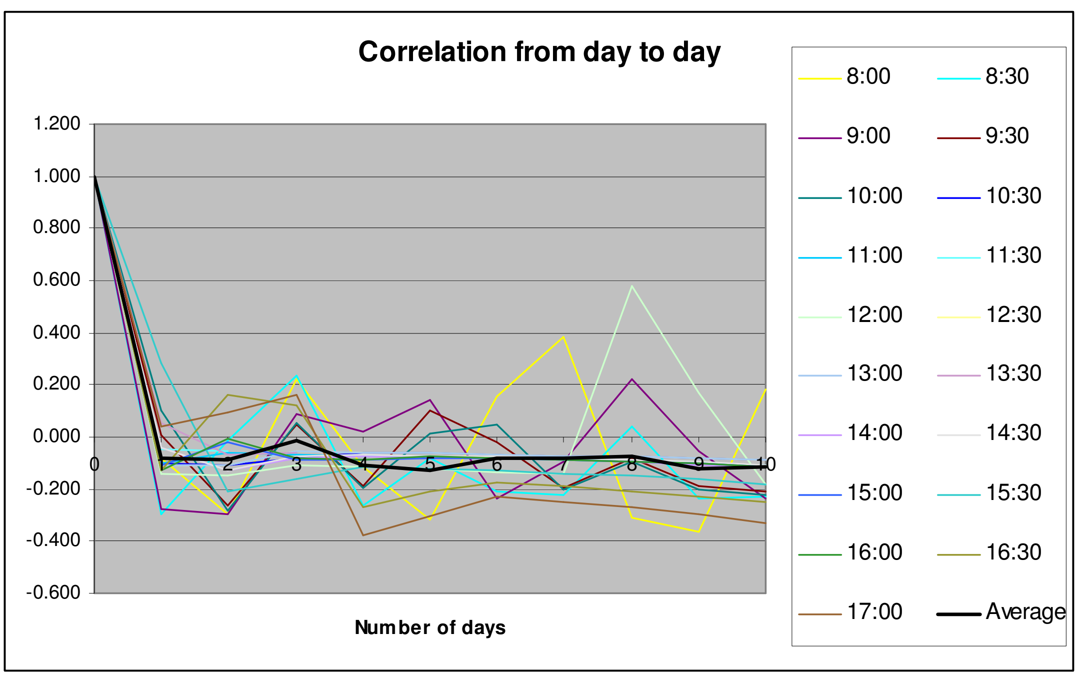


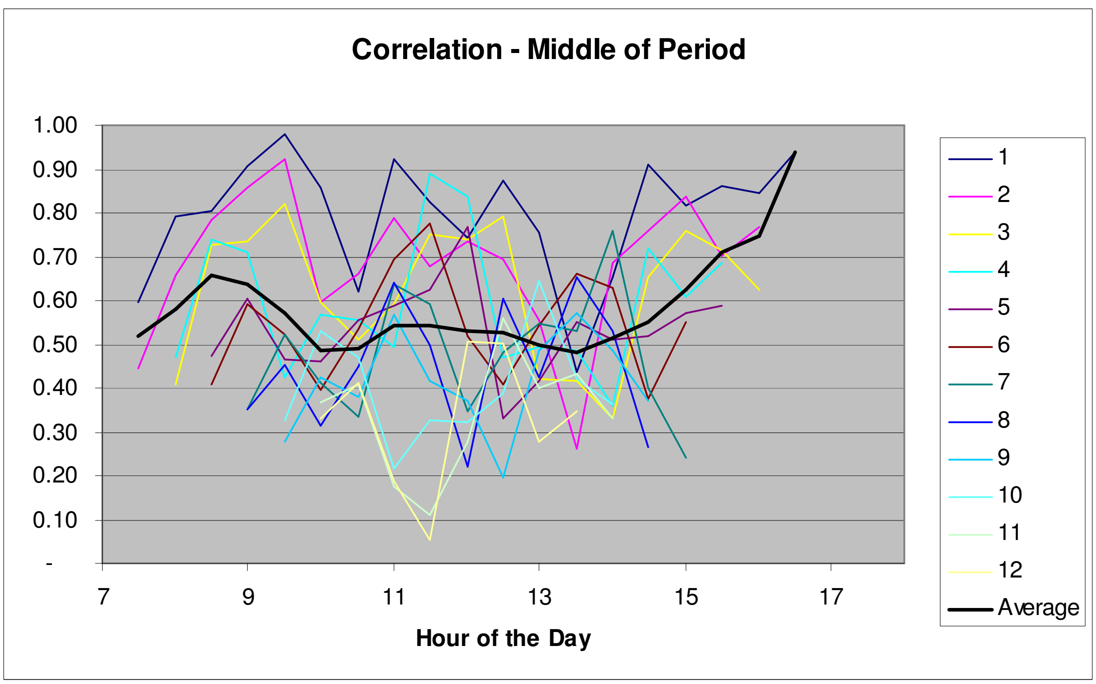
Figure 6-13 Correlation of solar thermal output from day to day by trading interval of day based on a series of hot days in 2007



The covariance within the day was assessed as depending on the time of day and the time between the sampled periods. Figure 6-14 shows the average correlation of two hot day sequences in summer 2007. The individual lines correspond to different time interval differences. The horizontal axis is the half-hour of the day that represents the average of the times of the two trading intervals (rounded down to the nearest half-hour). The correlation over short periods is greater at the beginning and end of day for this resource and lower in the early afternoon. The correlation decreases as the time difference increases, as would be expected due to the changeability of weather.

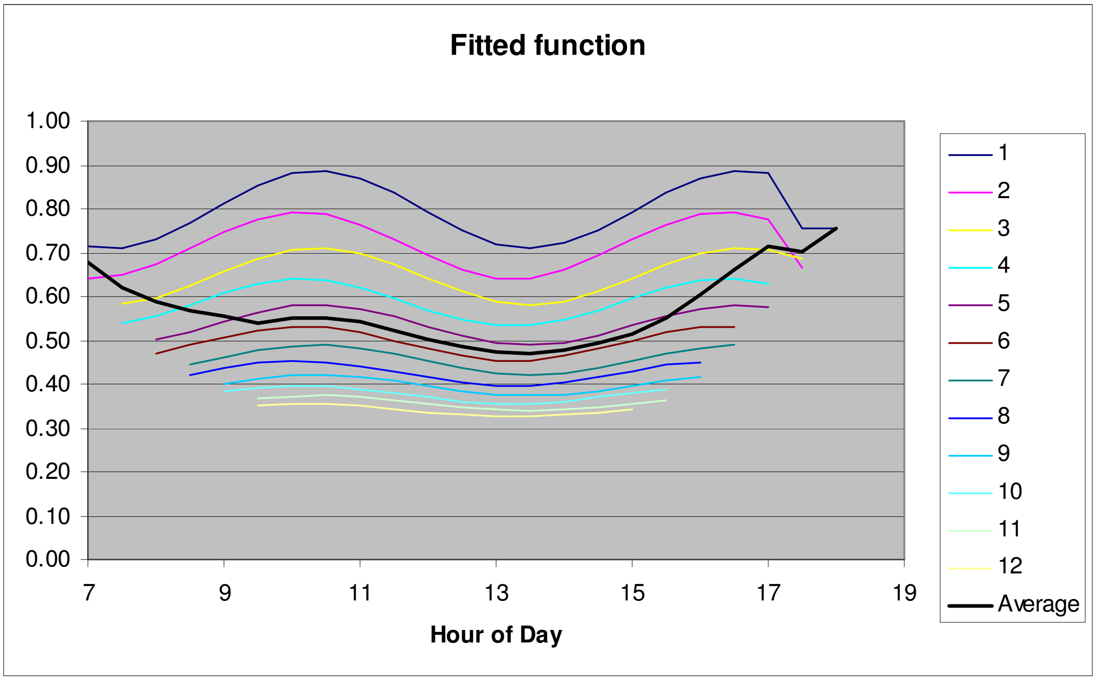
A fitted function was developed as shown in Figure 6-15 to consist of a cosine to represent time of day effects and an exponential to represent the reduction in the correlation as the time difference increased. The function in Figure 6-15 captures the trends in the data of Figure 6-14. The fitted function was then used to assess the variability of the measures of solar output based on the LOLP or the trading interval selection as appropriate. A different function was derived for each solar resource evaluated based on this same period of time.

Figure 6-14 Correlation of solar thermal with a day by trading interval of day



Note: The individual lines represent trading interval gaps with the hour of the day assessed as the average time of the two time intervals for the correlation

Figure 6-15 Fitted correlation of solar thermal with a day by trading interval of day



Note: The individual lines represent trading interval gaps with the hour of the day assessed as the average time of the two time intervals for the correlation

6.8 Assessment for solar resources

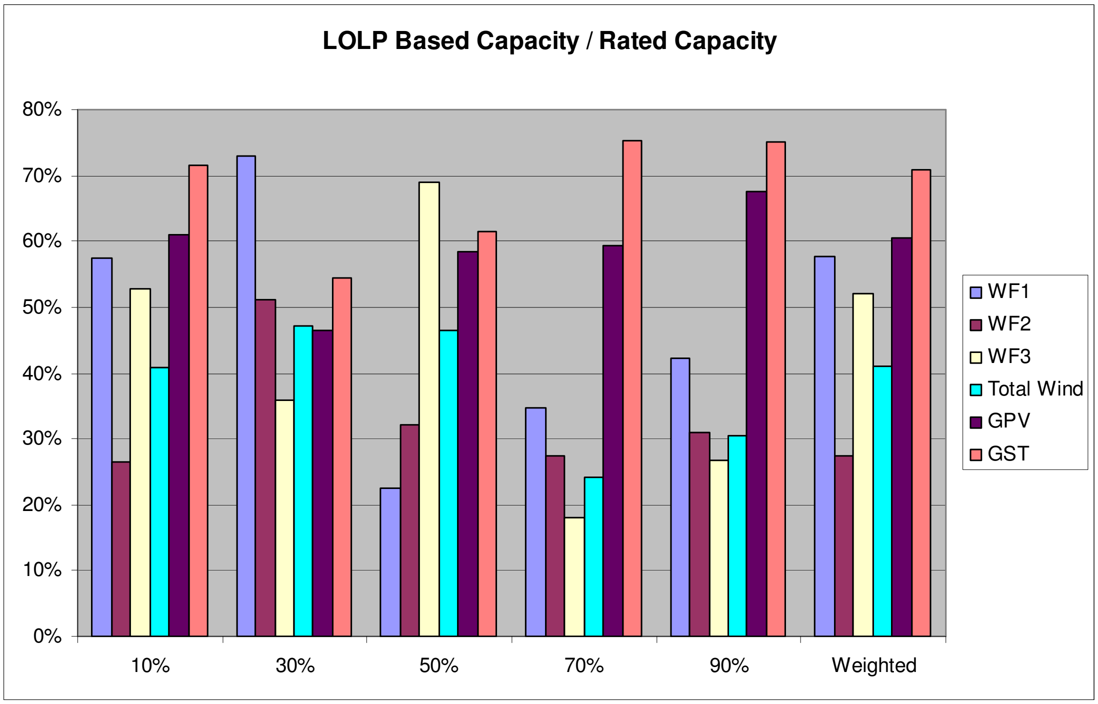
From Figure 6-12, it is evident that for solar resources:

- The variability on the top 250 to 750 interval outputs is small due to the low correlation of output from day to day around the hot weather periods.
- The average power method is clearly inadequate as has been expected by stakeholders consulted during this project.
- The reliability equalisation analysis is yet to be completed for the Inland Solar Thermal project (IST). The other reliability equalisation values are comparable with the LOLP assessment within the bands of uncertainty.
- The nearest approximation to the LOLP capacity value is the 750 trading interval average for two of the three schemes and for the aggregate capacity. This could be adopted as a simple measure for solar thermal resources, although the 250 trading intervals matches the wind farm capacity value with slightly less error than the 750 trading intervals. To maintain consistency independent of technology, a compromise of 750 trading intervals would likely be acceptable as a compromise. More often than not it is conservative.

The results confirm that average power is not suitable for solar energy resources and that the LOLP gives values that are comparable to those derived by reliability equalisation.

Figure 6-16 shows the variability of the resource assessments based on the five capacity years chosen as modelled for 2012/13 capacity year. The variability of the wind and solar resources over the five years modelled is comparable with the variation about 13% of the mean for solar resources and 35% to 40% for the wind farms and 25% for the wind in aggregate.

Figure 6-16 Capacity ratio for wind and solar technologies for 2012/13



Based on these results for wind and solar technologies, we have confirmed that:

- The limited amount of data on the performance of intermittent generation resources in Western Australia means that any measure of capacity value will be subject to significant uncertainty which will diminish over time as more data become available.
- The average power method as currently employed would not be viable for solar thermal technologies, although it is a good measure for the existing wind farms.
- A method based on output at the times of high system load would be viable for both technologies as it is comparable with capacity values assessed by means of LOLP weighting and reliability equalisation. This measure has much less variability than the LOLP based method for the solar resources.
- The LOLP weighting method would be expected to provide the more accurate results when the output behaviour of these resources under extreme system loading conditions is better quantified. It has the potential to adapt to changes in system conditions that affect reliability.
- It is costly and time consuming using statistical simulation to obtain an accurate value of the equivalent reliability value of wind farms and solar thermal resources, and it is

not highly accurate given the limited data on performance in association with periods of high system demand.

6.9 Impact of reliability level

A key question is whether the LOLP analysis should be based on 0.002% expected unserved energy or the 8.2% standard reserve margin level. This was tested in the study by using three LOLP functions:

- One based on a study close to 0.002% (RM3)
- One based on a reserve margin that was much closer to the standard level (RM7)
- One interpolated to match the 0.002% expected unserved energy.

Since the Target case is very close to the RM3 case, we show the LOLP capacities and their 80% confidence ranges for the Target USE and RM7 cases in Figure 6-17. The corresponding data are tabulated in Table 6-10. It may be noticed that the uncertainty is slightly greater for the case with higher reserve margin. This arises because the LOLP versus capacity does not flatten out near high loads and therefore the result is affected by fewer trading intervals when the reserve margin is high. There is some variability but no obvious consistency, with four higher and three lower for higher reserve margin. The variation is within the 80% confidence range that has been assessed for the target unserved energy. It does not seem to matter at what level of unserved energy the LOLP analysis is conducted.

MMA proposes that the tighter supply conditions are more relevant to the capacity valuation because that is when the capacity really matters. This is especially important if there is concern about the variability in the intermittent generation increasing the risk of unserved energy. It would therefore be preferable to make the assessment as it has been done above, with conditions that represent critical system conditions for acceptable reliability.

Figure 6-17 LOLP weighted capacity value for two scenarios

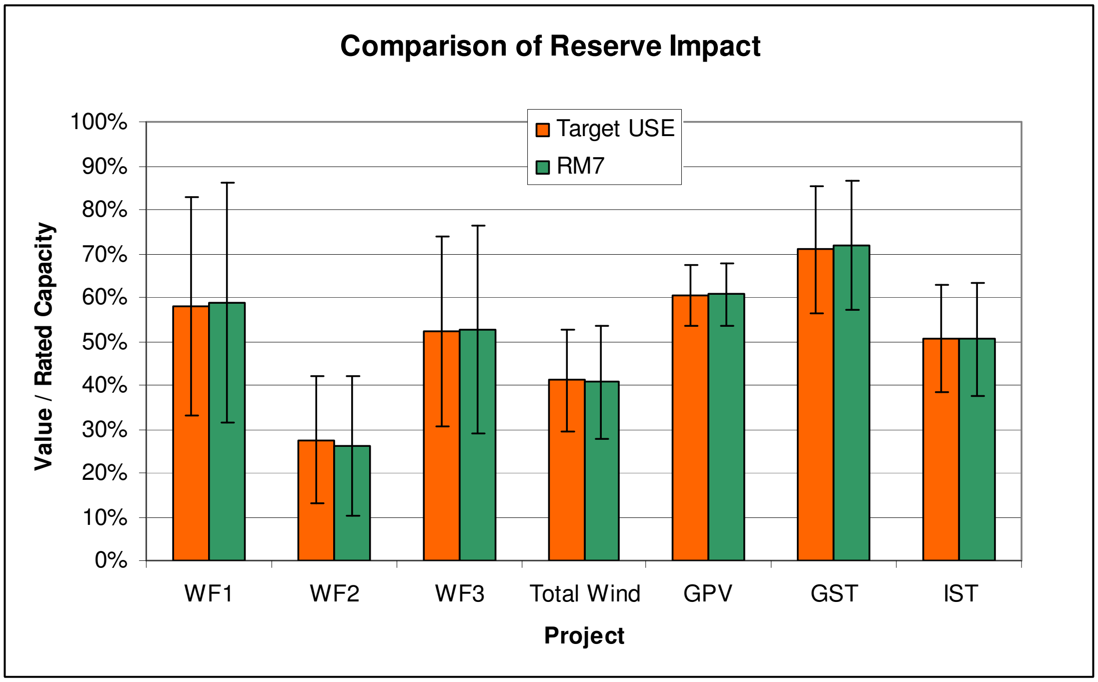


Table 6-10 LOLP weighted capacity value for two scenarios

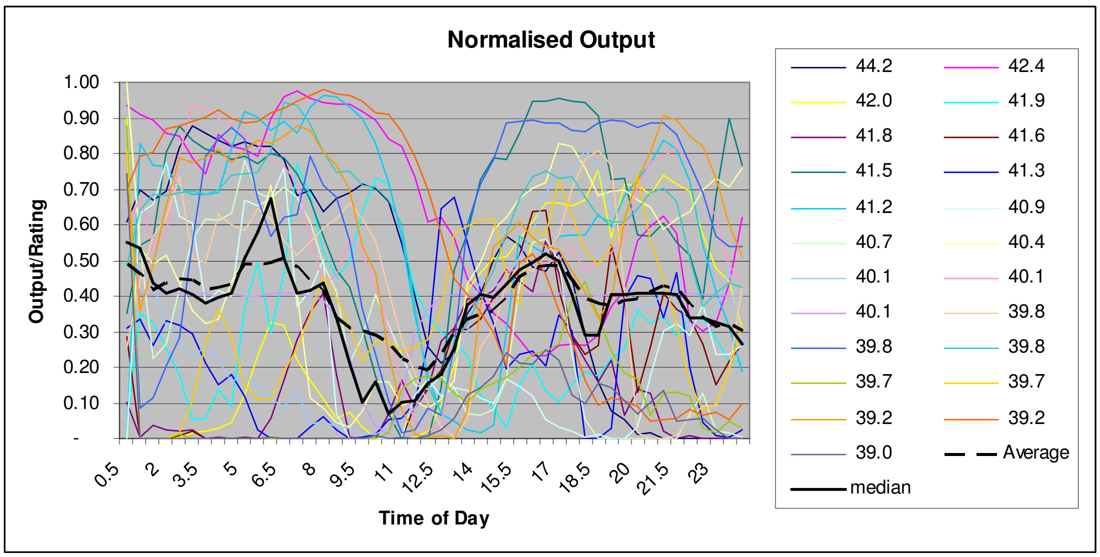
	Value of Capacity as % of Rated		Error Band either side as % of Rated	
Comparison by Scenario	Target USE	RM7	USE	RM7
WF1	58%	59%	25%	27%
WF2	27%	26%	14%	16%
WF3	52%	53%	22%	24%
Total Wind	41%	41%	12%	13%
GPV	60%	61%	7%	7%
GST	71%	72%	14%	15%
IST	51%	51%	12%	13%

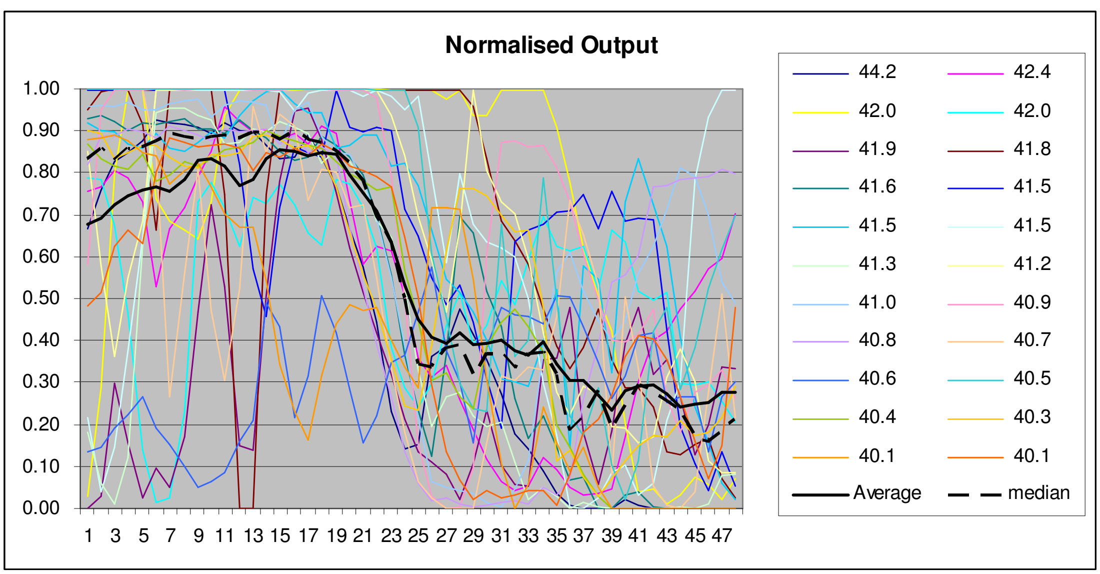
6.10 Justification of the capacity level

Early consultation on these results indicated that there would be widespread disbelief that the capacity values would be comparable to the level already provided based on average power. This may be because the performance of the wind farms is considered as if they were independent elements rather than part of a system. Figure 6-18 shows some of the historical data for hot day profiles for two wind farms. It is observed that the average afternoon output is typically between 30% and 50% of capacity. The corresponding 25 percentile levels are about 15% and 30% of capacity and it would be these low levels which might be considered when thinking about the equivalent firm capacity.

The impact on reliability is not defined by the lowest likely output of all intermittent resources evaluated together but rather the average level taking the resources as one, and the risk that output would be near zero at critical times. There is a high probability of some 90% that none of the six largest units in the system will be out of service on a hot day (say 0.98^6 = 89%). This gives room for the aggregate wind farm output of 170 MW to be operating at 20% of rated capacity without there being a need to shed load, even though operating reserves might be low and load might be at risk. Certainly we have shown that on the basis of unserved energy as well as relative risk of load shedding, the wind farms do make a significant contribution to reliability and can justify their current capacity values on a collective basis. The LOLP weighted capacity in aggregate was 41% which is in the range of 30% to 50% observed in Figure 6-18.

Figure 6-18 Hot day wind profiles





This consideration does not detract from the additional operating issues that follow from high level of intermittent generation. However, these can be mitigated through short-term forecasting, providing adequate load following reserve and providing incentives for the wind farms to contribute to frequency control when necessary to support system security at times of low load. However these considerations are being considered in Work Packages 3 and 4 and are not addressed here.

6.11 Analysis for later capacity years

The system simulations were extended to the capacity years to 2016/17 to assess whether the LOLP analysis would be likely to change if no further hot periods were experienced between now and then. It is obvious that the assessment would change if there were 10% to 30% POE conditions or more extreme and that would provide additional information on the relationship between peak load and intermittent generation.

6.11.1 System expansion

The two cases were extended to provide conditions close to the reference reserve margin as well as close to 0.002% unserved energy. Table 6-11 provides a summary of the reference cases. In most cases the lower reserve case has close to the minimum expected unserved energy weighted across the five load profiles modelled.

Table 6-11 Comparison of Reference Cases for 2012/13 to 2016/17 Capacity Years

Scenario variable ▼	Capacity Year ►	2012/13	2013/14	2014/15	2015/16	2016/17
RM3						
Energy Supplied	GWh so					
10% POE Peak Demand	MW so	5565.00	5885.00	5951.00	6154.00	6336.00
Total Capacity	MW so	5785.31	6193.31	6193.31	6410.31	6575.31
Reserve Factor	%	3.20%	4.63%	3.38%	3.50%	3.11%
Expected Unserved Energy	(GWh)	0.444	0.293	0.505	0.432	0.527
	%	0.0019%	0.0012%	0.0020%	0.0017%	0.0020%
RM7						
10% POE Peak Demand	MW so	5565.00	5885.00	5951.00	6154.00	6336.00
Total Capacity	MW so	5995.31	6403.31	6403.31	6620.31	6785.31
Reserve Factor	%	7.29%	8.48%	7.18%	7.17%	6.66%
Expected Unserved Energy	(GWh)	0.103	0.073	0.151	0.112	0.159
	%	0.0004%	0.0003%	0.0006%	0.0004%	0.0006%
Standard USE	(GWh)	0.473	0.501	0.502	0.510	0.521

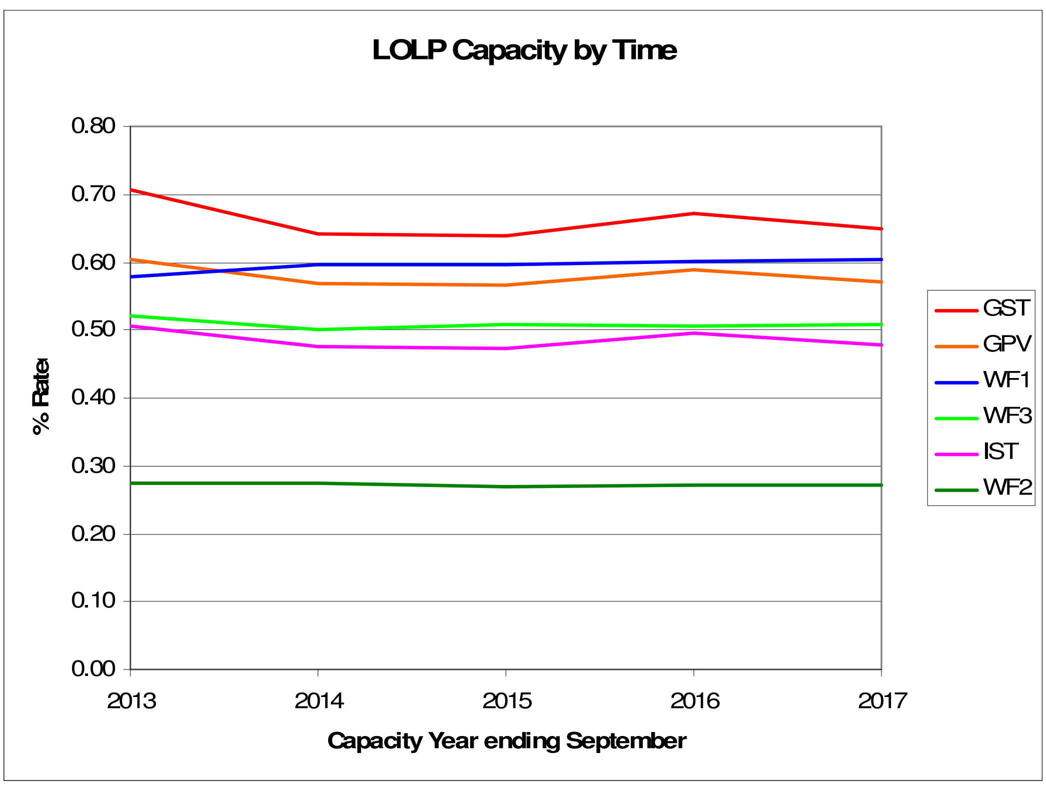
For all the capacity years, the RM7 case has 210 additional MW (from OCGT plants) with respect to the RM3 case. In order to keep the reserve margins close to the reference levels, the following additions and retirements were modelled for both the RM3 and the RM7 case (with respect to the 2012/13 capacity year):

- 2013/14: Added Bluewaters 3 & 4 (408 MW in total)
- 2014/15: No additions or retirements.
- 2015/16: Added 2 Coolimba units (400 MW) and a 165 MW OCGT. Kwinana 5 and 6 were retired.
- 2016/17: Added 1 OCGT unit (165 MW).

6.11.2 Capacity values for all years

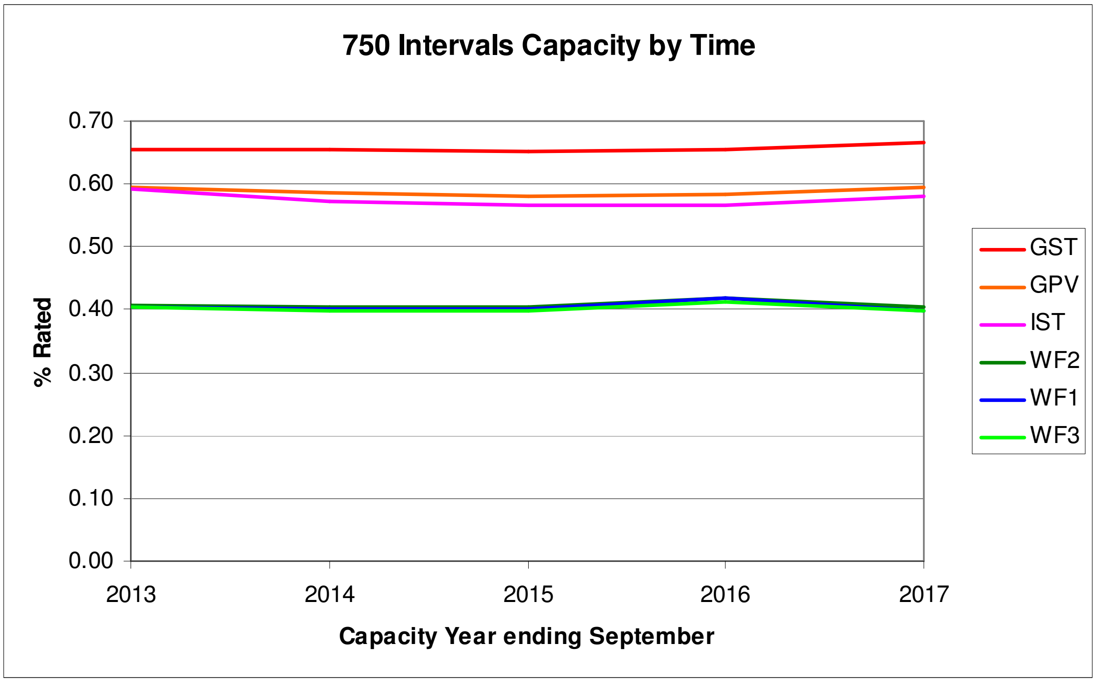
Figure 6-19 shows the assessed LOLP based capacity over the five years studied. There is a moderate amount of variation which is within the uncertainty band of any one year. The uncertainty due to the underlying data about intermittent generation remains a major source of uncertainty comparable with year to year variations in supply conditions within the normal range of system conditions. Large amounts of scheduled maintenance or a loss of a major power source could make a material difference to the capacity assessment. The assessed level of uncertainty was fairly stable from year to year.

Figure 6-19 Capacity values based on LOLP



The equivalent data for the capacity based on 750 trading intervals is shown in Figure 6-20. The assessed capacity may vary because the top 750 trading intervals may change in forecast periods as the load shape changes. However, this would lead to quite minor variations if conducted on such a basis. If only historical system load shapes were used, then the assessment would not change until new historical data became available.

Figure 6-20 Capacity values based on 750 Trading Intervals



The uncertainty over the years for the various resources as well as there assessed capacity values are shown in Table 6-12 and Table 6-13. For the 750 trading intervals, the uncertainty and the values are quite stable.

Table 6-12 Assessed capacity values and 80% uncertainty band (±) using LOLP

Capacity Year	2013	2014	2015	2016	2017
WF1	0.578	0.596	0.597	0.602	0.603
WF2	0.274	0.274	0.269	0.273	0.271
WF3	0.522	0.501	0.508	0.505	0.507
GPV	0.605	0.567	0.567	0.590	0.570
GST	0.708	0.642	0.640	0.671	0.648
IST	0.507	0.475	0.473	0.495	0.477
80% Error Bands (±)					
WF1	0.249	0.201	0.210	0.207	0.211
WF2	0.145	0.117	0.122	0.121	0.123
WF3	0.215	0.175	0.181	0.180	0.183
GPV	0.041	0.035	0.034	0.035	0.034
GST	0.095	0.083	0.080	0.082	0.081
IST	0.095	0.083	0.080	0.080	0.081

Table 6-13 Assessed capacity values and 80% uncertainty band (±) for 750 Trading Intervals

Capacity Year	2013	2014	2015	2016	2017
WF1	0.405	0.401	0.401	0.417	0.398
WF2	0.408	0.405	0.404	0.418	0.405
WF3	0.403	0.399	0.399	0.412	0.399
GPV	0.594	0.585	0.582	0.584	0.594
GST	0.656	0.655	0.651	0.653	0.665
IST	0.592	0.571	0.567	0.565	0.580
80% Error Bands (±)					
WF1	0.050	0.049	0.049	0.049	0.049
WF2	0.018	0.018	0.018	0.018	0.018
WF3	0.030	0.030	0.030	0.030	0.030
GPV	0.010	0.010	0.010	0.010	0.010
GST	0.026	0.025	0.025	0.025	0.025
IST	0.024	0.024	0.024	0.024	0.024

The assessed capacity values for the wind farms with their 80% confidence range are shown in Figure 6-21. The corresponding data for the solar resources are shown in Figure 6-22. These charts show that the LOLP capacity variations from year to year for both wind and solar resources are well within the uncertainty band for the assessment based on the inherent volatility of these resources.

Figure 6-21 Assessed LOLP capacity values for wind farms

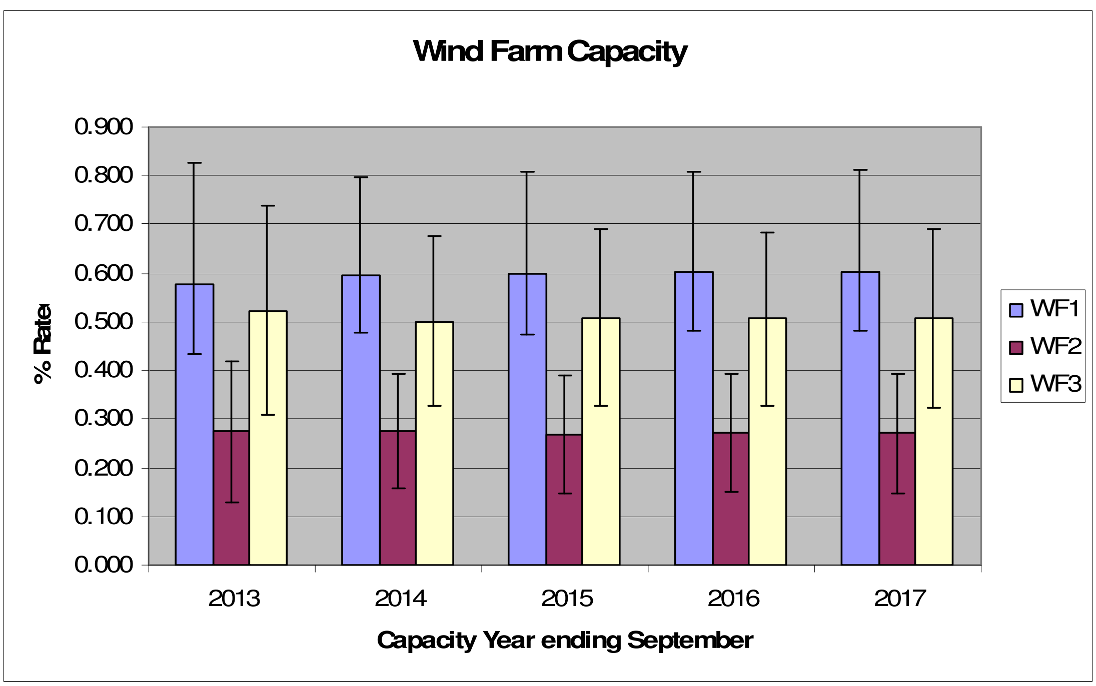
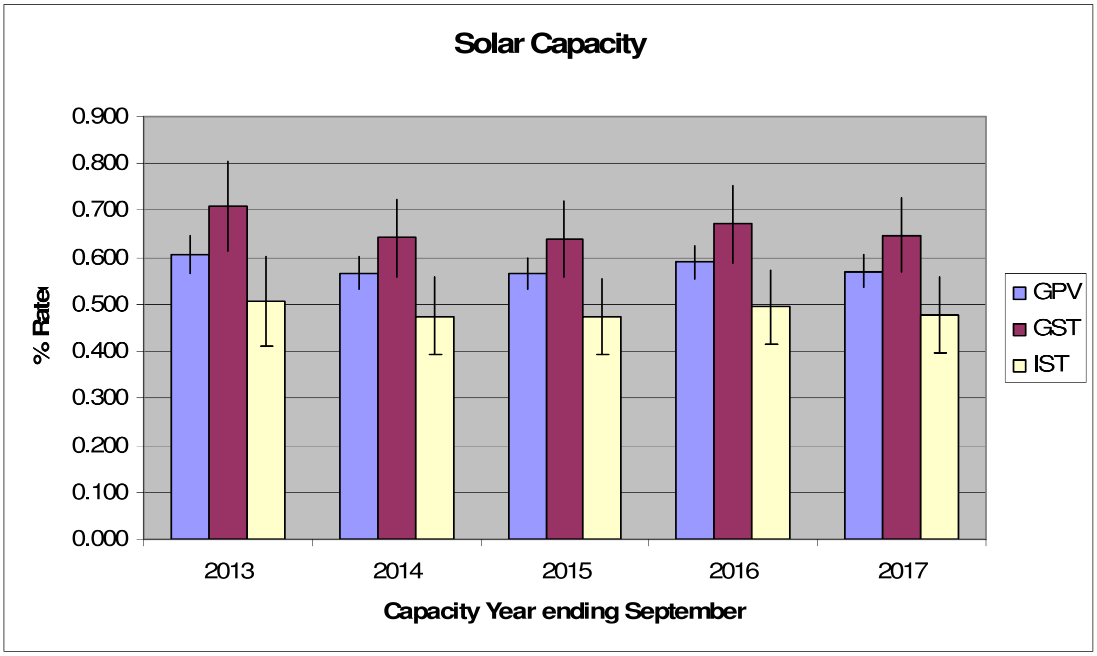


Figure 6-22 Assessed LOLP capacity values for solar resources



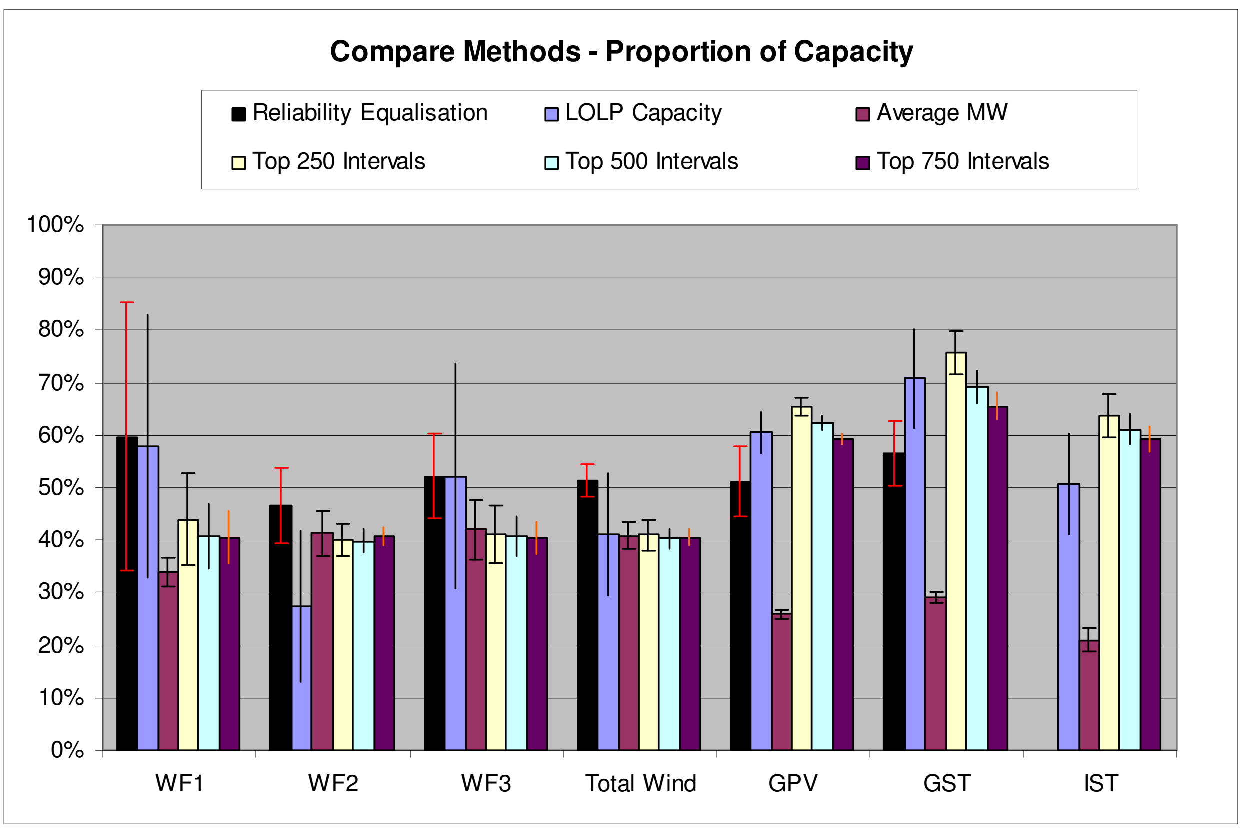
7 BASIS FOR SIMPLIFICATION

7.1 Value of reliability equalisation

Ideally, MMA favours the method based on reliability equalisation with simplification based on the LOLP method when sufficient data are available. Averages based on highest loading periods do adequately represent capacity value for wind farms but are less accurate for other intermittent technologies. For controllable resources based on stored energy such as land-fill gas, the choice of method is not critical. Due to the high weighting given to the 10% POE loading profile based on system risk, it might be acceptable to use this historical loading profile alone.

Figure 7-1 illustrates that the proposed LOLP method has the potential to provide a realistic estimate of the true capacity value of intermittent resources. The chart shows the assessed capacity value of each wind farm as a proportion of its rated capacity together with an 80% confidence range of uncertainty based on the analysis to date. The wind farms are not identified so as to preserve confidentiality of potential impact of methods. The methods based on particular peak load periods do work satisfactorily for the incumbent wind projects when weighted over a number of years but they do not work as

Figure 7-1 Comparison of Methods



well for some technologies and are therefore not favoured in principle. However, during the time when wind and solar technologies are being introduced, a capacity value based on trading interval measures would be practicable and sufficiently accurate given the data currently available. A period of 750 trading intervals is best for solar technology and 250 trading intervals for wind by a slight margin. Hence selecting 750 trading intervals would be a workable compromise, if the LOLP method is deemed too difficult to understand. Certainly the trading interval method would have a lower cost of implementation and be more objective because it would not depend on system reliability models.

The aggregate value of the wind farms assessed by reliability equalisation was 2% above the sum of the capacities that were assessed individually. This is reasonable as there is some diversity among their outputs. The average correlation between trading interval outputs in the warmer months from October to March is as shown in Table 7-1 together with the values by capacity year ending September. The capacity year 2003/04 represents the 10% POE peak demand and it has lower than average correlation which helps to support the capacity valuation. There is a moderate correlation between the outputs of WF2 and WF3 and low correlation with the output of WF1. The low correlation means that WF1 is worth more capacity in the presence of WF2 and WF3 than it would offer alone because there is a reasonable chance that a low output would be compensated by higher output elsewhere.

Table 7-1 Correlation coefficient of half-hourly wind farm outputs by capacity year ending September

From	WF1	WF2	WF3	POE
To	WF2	WF3	WF1	
2002	0.041	0.375	0.116	
2003	-0.008	0.487	0.049	50%
2004	-0.021	0.430	0.047	10%
2005	0.054	0.472	0.135	30%
2006	-0.036	0.377	-0.035	
2007	0.036	0.611	0.174	70%
2008	-0.012	0.579	0.092	
2009	0.020	0.573	0.055	90%
Average	0.009	0.488	0.079	

7.2 Simplified Model

So the question remains as to how to build a simple tool based on LOLP weighting that can be used by incumbents and proponents to value their resources in terms of equivalent firm capacity. To this end we have proposed the method described in Chapter 3. This results in the capacity values shown in Table 7-2 which were assessed for the existing and committed intermittent generation resources and are compared to the values for the 2011/12 capacity year. The bold values in the table are as approved using the current method. The other values for future resources are based on the data provided to date. The impact of the proposed method is to increase the recognition of the capacity value of wind in aggregate by 2%, from 40.3% to 41.2%.

Table 7-2 Capacity Credits as a Proportion of Rated Capacity

Capacity Year	Resource Type	2011/12	2012/13	Change
WF1	Wind	**33.7%**	57.8%	71%
WF2	Wind	**37.7%**	52.2%	38%
WF3	Wind	**44.1%**	27.4%	-38%
Total		40.3%	41.2%	2%
New Solar Resources				
Geraldton PV	Solar		60.5%	
Geraldton ST	Solar		70.8%	
Inland ST	Solar		50.7%	
Total			60.7%	

It may be noted that:

- the overall assessment for wind farms is that capacity values would not change significantly from current values, although there may be some relative changes among the incumbents. Given the lack of data and level of uncertainty in the measure, the average power could remain a part of the assessed value to reduce the volatility of the measure. For example, one could take 50% of the average power value and 50% of the LOLP assessed value;
- the overall assessment for solar thermal resources is a potential improvement relative to the current method.

8 PROPOSED CHANGES TO THE MARKET RULES AND ASSOCIATED MARKET PROCEDURES

8.1 Approach

This section proposes changes to the Market Rules and the Market Procedures to accommodate the recommended methodology for assessing the capacity contribution of intermittent generators. In particular, it proposes changes to the Market Rules and Market Procedures that are specific to the Reserve Capacity Mechanism and to the Planning Criterion.

In determining the suite of Market Rule changes that are required, the following review process was followed:

1. Review of issues that may require treatment in the rules

   We reviewed the outcomes of our quantitative and qualitative analysis to determine whether there are any important issues that could require special treatment in the Market Rules.

2. Adequacy of the current Market Rules

   Based on the previous steps, we considered the adequacy of the current Market Rules, thereby identifying Market Rules that may need to change or to be developed.

3. Proposed changes to the Market Rules and Market Procedures

   - Proposed changes to the Market Rules
     - We considered the structure and adequacy of the Market Rules and identified amendments to the extent possible. Some potential rule changes require feed-back from the IMO on various issues. We have included placeholders in the report where further rule changes may be proposed pending the IMO's response to issues raised in this draft report.
   - Proposed changes to the Market Procedures
     - We will propose changes to the Market Procedures in the next iteration of this report when there is more clarity on the choice of the simplified method for capacity valuation.

The outcomes from this review process are summarised in sections below.

8.2 Issues that may require treatment in the Market Rules

8.2.1 Special treatment for some Renewable Generation technologies

Ultimately capacity values would be evidence based, using actual generation and /or weather observations and data to measure Certified Reserve Capacity. Renewable technologies such as wave/tidal power, or generation resources that include biomass, solar and some hydro, are yet to feature in the installed generation capacity of the SWIS. For this reason the determination of Certified Reserve Capacity will require some approximation and use of estimated or default data for new installations of these renewable technologies.

Although the Market Rules appropriately manage the estimation of Reserve Capacity for new installations of these renewable generation technologies, in particular by using advice from the report of an accredited expert, the Market Procedure relating to the determination of Certified Reserve Capacity will require review to ensure that the expert is appropriately guided.

8.2.2 Immature resources

Immature generation resources can be defined as those that are either newly commissioned, committed but not yet commissioned, or that lack a sufficient operating history to satisfy the data requirements of the methodology for estimating Reserve Capacity.

The Market Rules and associated Market Procedures will likely need to distinguish between mature and immature facilities in the determination of Certified Reserve Capacity. Mature resources could rely of observations of generation output or local weather observations that would inform a performance model. Immature resources could rely on more distant measurements or accept a measure based on incomplete data in conjunction with simplified default measures.

8.2.3 Treatment of Forced Outages

The current Market Rules implicitly recognise forced outage events in the determination of an intermittent generators Relevant Level; the calculated average capacity factor that is the output of the Market Rule 4.11.3A includes the reduced availability from forced outage events.

Changes to the methodology for valuing the capacity of intermittent generation will require a consideration of how to treat forced outage events. If the changed methodology discounts estimated Reserve Capacity for the effects of forced outages, then the current exemption of these facilities from forced outage penalties, as is the case in Market Rule 4.26, is appropriate. If the changed methodology assumes full availability, therefore not adjusting availability for the effects of forced outages, then the Refund Table and penalty mechanism will need to be changed, to include Intermittent generation in the penalty regime.

8.2.4 Capacity refunds for intermittent generation

The arrangements for scheduled generation under the Market Rules make provision for the refund of capacity payments in the event that generating plant is unavailable. The relevant rules are in section 4.26. The magnitude of the refund depends on the time at which the outage occurs in accordance with the Refund Table in 4.26.1. For an extended outage in the summer period, it is possible for all of the capacity payments to be refunded.

Currently intermittent generation is not deemed to have a capacity obligation and therefore is not exposed to capacity payment refunds. Whilst this may be acceptable with low penetration of intermittent generation it becomes more inequitable as the quantity of intermittent generation increases in the market.

Further, in the case of intermittent generation, clause 4.11.3A of the Market Rules implicitly recognises forced outage events in the determination of a generation facility's Relevant Level; the calculated average capacity factor that is the output of the Market Rule includes the reduced availability from forced outage events. Consistent with this treatment, the Refund Table of Market Rule 4.26 exempts intermittent facilities from forced outage penalties.

There are two aspects which influence the capacity value in the market:

- the variability of the energy production with the plant fully available, and
- the availability of plant.

The former is outside the control of the owner as it depends on environmental conditions. The later factor depends on good design and operation practices and is within the owner's control. The energy value of the renewable energy resource is dependent on the former and is an unavoidable risk to the owner. The question to be considered is the extent to which the risk concerning the capacity value of the project should be allocated to the owner or to the market participants. As the capacity payment is only a small component of the revenue for a renewable energy project, especially for wind power, and less so for solar resources, it may be reasonable for the full capacity risk to be carried by the owner, in which case, loss of output due to plant performance or energy availability could be treated in the same way. That approach would provide the maximum incentive to construct reliable plant with a reliable energy resource. However, to the extent that resources are diverse across the region, it may have the consequence that not all the resources are appropriated and thereby reduce the overall diversity of renewable energy sources.

MMA is of the view that the application of the Refund Table to Intermittent Generation resources depends in part on how forced outage performance is treated in the methodology for calculating Certified Reserve Capacity:

- If the method discounts for forced outage performance, then the Refund Table should not be applied to intermittent generation as this would in effect levy a double penalty

- If the method does not discount for forced outage performance, therefore assuming full availability, then it is appropriate that the Refund Table apply to intermittent generation resources. In this case MMA considers that it would be reasonable to apply a Refund Table to intermittent generation resources in relation to their plant availability in the same way that it is applied to scheduled plant and to accept that the variability of energy production is a risk already borne by the proponent in the energy market and which can be diversified and passed to the market as a whole with respect to the capacity value.

Loss of load probability and the Refund Table

In the course of the study, the relative risk in each of the specified time periods of the Refund Table (reproduced in simplified form in Table 8-1) was analysed in terms of the loss of load probability. It is understood that the market participants may not want yet another review of the Refund Table and MMA is similarly reluctant to recommend another change. However, it is instructive to calculate what these factors would look like if they were based on the relative risk. Taking the results of the analysis for 2012/13 contract year based on only the three incumbent winds in service and no other large scale intermittent generation resources, the applicable factors averaged equally over the five contract years would be as shown in Table 8-2. These values are normalised to the current aggregate penalty level of 21.5 sum of the factors. Further analysis would be required to align these levels with the cost of load shedding to customers. Such work was not within the scope of this project.

Table 8-1 Refund Table factors (Rule 4.26.1)

From	Hours	1-Apr	1-Oct	1-Dec	1-Feb
To		1-Oct	1-Dec	1-Feb	1-Apr
Bus Off-Peak	10	0.25	0.25	0.50	0.75
Bus Peak	14	1.50	1.50	4.00	6.00
Non-Bus Off-Peak	10	0.25	0.25	0.50	0.75
Non-Bus Peak	14	0.75	0.75	1.50	2.00

Table 8-2 Refund Table factors based on 2012/13 modelling

From	Hours	1-Apr	1-Oct	1-Dec	1-Feb
To		1-Oct	1-Dec	1-Feb	1-Apr
Bus Off-Peak	10	0.03	0.02	0.03	0.04
Bus Peak	14	0.15	0.18	2.58	17.83
Non-Bus Off-Peak	10	0.01	0.01	0.02	0.02
Non-Bus Peak	14	0.06	0.03	0.21	0.27

It is apparent that:

- The relative risk on the off-peak periods is much less than provided in the standard table
- The non-business day peak risk is about 10% to15% of the standard values

- The peak season and business peak period risk is up to three times the standard value.

Thus if a new Table were developed specifically for intermittent generation on the basis of this modelling then there would be discrimination without any fundamental economic value.

The existing Refund Table could represent a situation with much more scheduled maintenance and higher forced outage rates which would smear the risk into the off-peak season and peak day periods. So the Refund Table may be realistic under some circumstances, but not for the market conditions anticipated as likely in 2012/13.

MMA considers that this leaves a possible progressive process as follows if this aspect is to be reformed. The analysis of options is provided in Table 8-3.

Table 8-3 Analysis of options for intermittent generation (IG)

Step	Action/Change	Advantage	Disadvantage	Rationale for Action
1	No Capacity Refunds for IG	Simplicity while IG is limited in scale.	No incentive to align availability to market need for capacity	Capacity at risk is too small to be concerned with.
2	Use current Refund Table based on IG plant availability	Removes discrimination in favour of IG. Minor Rule Change.	Requires monitoring process for multi-unit plant availability	Non-discrimination based on technology when IG becomes significant.
3	Apply a revised Refund Table for IG, keep current Refund Table for scheduled plant.	No change for scheduled generation with efficient incentive for IG	Perpetuates discrimination based on technology for no economic reason	Interim step toward establishing an efficient Refund Table based on current market conditions.
4	Provide a new revised Refund Table for all technologies	Removes uneconomic discrimination and provides an efficient incentive regime.	Involves yet another change for scheduled generation.	Provide efficient capacity delivery regime when IG becomes a significant portion of the market. Make the Refund Table relevant to the prevailing supply conditions.

- The first step would be status quo: no capacity refunds. This may be satisfactory whilst intermittent generation (IG) is a small part of the supply but does involve some inefficiency in reliability management. This option is appropriate if the methodology for determining Certified Reserve Capacity takes into account the forced outage performance of the intermittent generator, as is the case with the current Market Rules.
- The next step would be to apply the current regime to IG. This would be simple to apply but would require an availability reporting regime for multi-unit facilities. It would be non-discriminatory. If this option is preferred, for reasons of equity, the methodology for determining Certified Reserve Capacity should then not discount estimated capacity for the forced outage performance of the generator, thereby avoiding the potential incidence of a double penalty.
- The third step would be to introduce a new Refund Table for IG but leave scheduled generation unaffected. Thus could only reasonably be a short-term option because it would create a discriminatory regime as the Table 8-1 and Table 8-2 show quite different parameters. The new Refund Table could be more adaptive to prevailing market conditions in terms of scheduled maintenance, the impact of IG at higher levels of penetration and forced outage performance over the medium term. Again, this would mean that the methodology for determining Certified Reserve Capacity should not discount estimated capacity for the forced outage performance of the generator, thereby preventing the potential incidence of a double penalty.
- The final step would be to align all resources to be exposed to an adaptive Refund Table. This would be essential to meet the market objectives for an efficient and non-discriminatory regime. In this case, the methodology for determining Certified Reserve Capacity should not discount estimated capacity for the forced outage performance of the generator.

If Market Participants do not support a change in the Refund Table or its adaptation to prevailing market conditions as per Table 8-2, then only step 2 would be acceptable at the current time. MMA recommends that further consideration be given to aligning the parameters in the Refund Table to the actual risk of load shedding. The current Refund Table does not reflect what the market modelling shows as being accurate from a reliability and loss of load risk viewpoint.

8.2.5 Penetration thresholds

[Findings from the analysis will be included when complete]

8.2.6 Locational Issues

[Findings from the analysis will be included when complete]

8.2.7 Temporal Issues

[Findings from the analysis will be included when complete].

8.2.8 Deliverability Issues

[Findings from the analysis will be included when complete]

8.3 Adequacy of the current Market Rules

The following lists a set of Market Rule components that are potentially affected by the proposed methodology for calculating the capacity value of intermittent generation resources. This is based on a review of the Market Rules, of the proposed methodology, of identified issues, and of international practice.

For each Market Rule component, an adequacy assessment has been conducted, with the findings summarised below.

8.3.1 Market Rule components related to the Planning Criterion

The Long Term SWIS Capacity Requirements

- ***Long Term Projected Assessment of System Adequacy***
  - Market Rule 4.5.9 defines the Planning Criterion that is to be used by the IMO in undertaking its Long Term PASA Study, and therefore the basis of the Statement of Opportunities Report and the Reserve Capacity Requirement.
  - Market Rule 4.5.10 defines the scenarios that the IMO must use in assessing the extent to which the anticipated installed generation capacity and Demand Side Management capacity is capable of satisfying the Planning Criterion. In particular, it requires that the Reserve Capacity Target for a Capacity Year is the capacity required to meet the Planning Criterion in that year under the scenario one in ten year peak demand scenario assuming expected demand growth.
    - ***The scenarios determined to support the proposed methodology for assessing the contribution of intermittent generation should be consistent with those that are used to define the Planning Criterion.***

8.3.2 Market Rule components related to the Reserve Capacity Mechanism

The Reserve Capacity Expression of Interest

- ***Information to be included in Requests for Expression of Interest***
  - Market Rule 4.3 defines what information is to be included in a Request for Expression of Interest for a Reserve Capacity Cycle.
    - ***In the event that the proposed methodology for calculating the capacity contribution of intermittent generation is adopted, and includes a supporting spreadsheet tool, the Market Rules should require the IMO to publish with the Reserve Capacity request for Expressions of Interest, information on how to obtain a guideline and supporting spreadsheet tool for estimating the capacity value of intermittent generation.***

- ***Information to be Included in Expressions of Interest***
  - Market Rule 4.4 defines what information is to be included in an Expression of Interest for a Reserve Capacity Cycle.
    - ***In the case of intermittent generators Market Rule 4.4.1 should be amended to require the provision of an estimate of the capacity value of the generation Facility, using guidelines and/or methodologies that are published by the IMO for the purpose of calculating an estimate of the capacity value of an intermittent generation resource sharing the same technology.***

Certification of Reserve Capacity

- ***Information Required for the Certification of Reserve Capacity***
  - Market Rule 4.10.3 requires that an application for certification of Reserve Capacity for an Intermittent Generator that is yet to enter service must include a report prepared by an expert accredited by the IMO, in accordance with the Reserve Capacity Procedure, where this report is to be used to assign the Certified Reserve Capacity for that Facility in accordance with clause 4.11.1(e).
    - ***The Reserve Capacity Procedure is a capitalised term in the Market Rules but yet is not defined in the Glossary. The Market Rules should include a definition of this term in the Glossary of the Market Rules.***
    - ***The Reserve Capacity Procedure will require amendment to accommodate the proposed LOLP-based (or trading interval) methodology for intermittent generation facilities.***
- ***Setting Certified Reserve Capacity***
  - Market Rule 4.11.1(d) requires the IMO to assign Certified Reserve Capacity for Intermittent Generators that are already operating equal to the Relevant Level determined in accordance with clause 4.11.3A but subject to (b), (c), (f), (g), (h) and (i) of clause 4.11.1.
    - ***For Intermittent Generators that are already operating Market Rule 4.11.1(d) will need to be modified to require the IMO to assign Certified Reserve Capacity according to a new clause that defines the basis of the proposed approach. This new clause will need to manage immature intermittent generation facilities that have an operating history that does not span the required reference period of the proposed LOLP-based methodology.***
  - Market Rule 4.11.1(e) requires the IMO to assign Certified Reserve Capacity for Intermittent Generators that are yet to commence operation based in part on an estimate contained in a report that is produced by an accredited expert that accords with the Reserve Capacity Procedure.

- ***Although Market Rule 4.11.1(e) is satisfactory in accommodating the proposed LOLP-based approach, the Reserve Capacity Procedure that guides the estimation of Reserve Capacity will require amendment to accommodate the proposed approach.***

Failure to Satisfy Reserve Capacity Obligations

- See section 8.2.4
- MMA is of the view that the application of the Refund Table to Intermittent Generation resources depends in part on how forced outage performance is treated in the methodology for calculating Certified Reserve Capacity:
  - ***If the method discounts for forced outage performance, then the Refund Table should not by applied to intermittent generation as this would in effect levy a double penalty***
  - ***If the method does not discount for forced outage performance, therefore assuming full availability, then it is appropriate that the Refund Table apply to intermittent generation resources. In this case MMA considers that it would be reasonable to apply a Refund Table to intermittent generation resources in relation to their plant availability in the same way that it is applied to scheduled plant and to accept that the variability of energy production is a risk already borne by the proponent in the energy market and which can be diversified and passed to the market as a whole with respect to the capacity value.***

8.3.3 Issues not treated by the current Market Rules

Immature Generating Facilities

- In the absence of an operating history that spans the data reference period of the proposed methodology, or in the case when the IMO considers that the data set is not sufficiently complete, the Reserve Capacity Procedure will require instructions on the source and use of default data to manage data gaps and deficiencies.
  - ***The Reserve Capacity Procedure should be amended to include the source and use of default data to overcome the data gaps and deficiencies that may be experienced to immature generation facilities.***
  - ***The Market Rules should require the use of default data to manage the issue described above.***

Forced Outages

- The current Market Rule 4.11.3A implicitly recognises forced outage events in the determination of a generation facility's Relevant Level; the calculated average capacity factor that is the output of the Market Rule includes the reduced availability from forced outage events. Appropriately, the Refund Table of Market Rule 4.26 exempts intermittent facilities from forced outage penalties.

- ***Changes to the methodology for valuing the capacity of intermittent generation will require a consideration of how to treat forced outage events. If the changed methodology discounts estimated Reserve Capacity for the effects of forced outages, then the current exemption of these facilities from forced outage penalties, as is the case in Market Rule 4.26, is appropriate. If the changed methodology assumes full availability, therefore not adjusting availability for the effects of forced outages, then the Refund Table and penalty mechanism will need to be changed, to include Intermittent generation in the penalty regime.***

- ***The proposed methodology for valuing the capacity of intermittent generation explicitly adjusts estimated capacity for the effects of forced outages, by weighting a forced outage factor by the load period weighted average penalty (1.446) in the Refund Table of Market 4.26.***

Availability Monitoring

- The Reserve Capacity Performance Monitoring Procedure, and the provisions of Market Rule 4.27 require the IMO to monitor Planned Outages. Depending on how forced outages are treated in the methodology to calculate capacity credits for intermittent generation, the monitoring provisions of the Market Rules, and also in the associated Market Procedure, may need to be enhanced to better manage the reporting, validation and monitoring of forced outages.

  - ***The proposed methodology for valuing the capacity of intermittent generation explicitly adjusts estimated capacity for the effects of forced outages. The IMO will therefore need to review its availability monitoring arrangements, potentially enhancing these to better track forced outages, and to use the collected data to determine default forced outage rates for facilities with an insufficient operating history.***

Locational Factors and Deliverability Limitations

- The IMO's responsibilities for determining the Long Term SWIS Capacity Requirement requires, in part, a consideration of locational transmission constraints, and therefore capacity shortfalls that could be caused by deliverability limitations in the transmission system. Although this locational assessment does not feature in the determination of the Planning Criterion, it does anticipate the potential for deliverability limits to be material, indicating a potential future need for the explicit recognition of calculated locational or sub-regional capacity requirements within the Reserve Capacity Mechanism.

- ***The design of the Market Rules should anticipate a potential future need for the Reserve Capacity Mechanism to include deliverability tests for installed and potential generation capacity, as well as the inclusion of a zonal, regional or locational artifacts to the capacity market design.***

Seasonality

[Findings from the analysis will be included when complete].

8.4 Proposed changes to the Market Rules

This section will be further enhanced, and will include a market objectives assessment pending initial feedback from the IMO.

8.4.1 Changes to section 4.3

4.3. Information to be Included in Requests for Expression of Interest

4.3.1. A Request for Expression of Interest for a Reserve Capacity Cycle must include the following information:

(a) a request for a response by interested parties not later than the relevant time specified in clause 4.1.5;

(b) the preliminary Reserve Capacity Requirement for the Reserve Capacity Cycle determined in accordance with clause 4.6.3;

(c) for each of the three previous Reserve Capacity Cycles (if applicable):

i. the Reserve Capacity Requirement determined in accordance with clause 4.6.1;

ii. the Availability Curve referred to in clause 4.5.10(e) applicable to that Reserve Capacity Cycle;

iii. the Reserve Capacity Auction Requirement for any Reserve Capacity Auction held;

iv. the number of Capacity Credits acquired by the IMO;

v. the Maximum Reserve Capacity Price;

vi. the Reserve Capacity Price; and

vii. the Monthly Reserve Capacity Price;

(d) the number of Capacity Credits which the IMO expects to be traded bilaterally;

(e) the amount of capacity expected to be required from new Facilities, where this figure is based on the difference between the preliminary Reserve Capacity Requirement for the Reserve Capacity Cycle as determined in accordance with clause 4.6.3 and the

latest information available to the IMO as to the aggregate available capacity for the SWIS during the period to which the Reserve Capacity Requirement relates;

(f) *the then current Maximum Reserve Capacity Price;*

(g) *a brief summary of the eligibility requirements for Reserve Capacity to be certified under clause 4.11;*

(h) *information on how to obtain the Market Rules from a web-site ;*

(i) *the following information on timetables and processing times for the Reserve Capacity Cycle:*

i. *the date and time from which the lodgement of applications for certification of Reserve Capacity will be allowed;*

ii. *the date and time by which applications for certification of Reserve Capacity must be lodged;*

iii. *the date and time that applicants for Certified Reserve Capacity will be notified of the Certified Reserve Capacity assigned;*

iv. *the date and time by which a Market Participant which holds Certified Reserve Capacity must notify the IMO as to how much of that capacity will be traded bilaterally, offered into a Reserve Capacity auction, or not be made available to the market in accordance with clause 4.14.1;*

v. *the date and time by which the IMO will announce whether the Reserve Capacity Auction will be cancelled;*

vi. *the date and time from which the lodgement of Reserve Capacity Offer submissions will be allowed;*

vii. *the last date and time at which lodgements of Reserve Capacity Offer will be allowed;*

viii. *the date and time the Reserve Capacity Auction results will be published; and*

ix. *the last date and time by which:*

1. *Long Term Special Price Arrangements can be accepted by Market Participants; and*

2. *Market Participants can inform the IMO of the Facilities which will provide Capacity Credits;*

(j) *the information required to be included in an Expression of Interest and the format in which that information is to be presented;*

(ja) *information on how to obtain from a website the Market Procedure and supporting documents and tools for estimating Certified Reserve Capacity;*

(k) the closing date and time for submission of Expressions of Interest; and

(l) who to contact with questions and responses to the Expression of Interest, including that person's contact details.

8.4.2 Changes to section 4.4

4.4. Information to be Included in Expression of Interests

4.4.1. An Expression of Interest for a Reserve Capacity Cycle must include the following information:

(a) the identity of the person proposing to provide Reserve Capacity and contact details;

(b) for each Facility covered by the Expression of Interest, its name and location and whether it is:

i. an Intermittent Generator;

iA. a non-Intermittent Generator not serving Intermittent Load;

ii. a non-Intermittent Generator serving Intermittent Load; or

iii. a form of Demand Side Management;

(c) the maximum Reserve Capacity anticipated to be available from each Facility;

(cA) for non-Intermittent Generators serving Intermittent Load, the maximum capacity anticipated to be required to serve the Intermittent Load;

(Cb) for Intermittent Generators, an estimate of Reserve Capacity that is calculated using the Market Procedure and supporting documents and tools for estimating Certified Reserve Capacity;

(d) for each Facility:

i. the expected earliest date that the Facility will be able to be fully operational;

ii. the status of any applications for Access Offers in respect of that Facility;

iii. the status of any applications for Environmental Approvals required in respect of that Facility;

iv. details of the type and quantity of fuel expected to be available to that Facility ;and

v. the hours during a typical week when the Facility will not be available to be dispatched due to staffing restrictions or other factors.

8.4.3 Changes to section 4.11

4.11. Setting Certified Reserve Capacity

4.11.1(d) the IMO must assign Certified Reserve Capacity for Intermittent Generators that are already operating equal to the Relevant Level determined in accordance with clause ~~4.11.3A~~ 4.11.3B but subject to (b), (c), (f), (g), (h) and (i).

4.11.3B. The Relevant Level in respect of an Intermittent Generator at a point in time is determined by the IMO using a guideline and supporting information that is published by the IMO pursuant to clause 4.3.1(ja).

8.4.4 Changes to section 4.26

Proposed revisions to the Market Rules will be considered pending the IMO's consideration and comment on the preferred treatment of forced outages in the determination of Certified Reserve Capacity.

8.4.5 Changes to section 4.27

Proposed revisions to the Market Rules will be considered pending the IMO's consideration and comment on the preferred treatment of forced outages in the determination of Certified Reserve Capacity.

If estimations of Reserve Capacity discount for the effects of forced outages, thereby reducing the measured availability and hence capacity of the plant, then an enhanced performance monitoring regime may be needed, requiring changes to the Market Rules and the IMO's Market Procedures. These changes would likely require the collection of forced outage data, the determination of actual forced outage rates, the determination of class-average or default forced outage rates to be applied to new or immature plant, and provisions for investigation and dispute handling.

8.5 Proposed changes to the Market Procedures

To be included later once the IMO has provided feedback on the proposed methodology, and the suggested Market Rule changes.

9 RECOMMENDED PROCESS

The analysis has shown clearly that the average power method will not provide a suitable capacity measure for solar thermal and photovoltaic resources, whereas it is suitable for the incumbent wind farms in the South-west, based on the available data on performance and system load. The analysis has also shown that LOLP weighting methods and trading interval averages provide similar assessed values of capacity based on the modelling of supply conditions in 2012/13. Therefore, an interim step would be to move to trading interval average values at times of high system demand, and eventually establish a method based on LOLP functions. It has been shown that such a method can be applied simply and that it can respond to changing system conditions as needed to provide market participants with efficient incentives to manage their generating plant.

Therefore, the recommended process is to:

1. Finalise the analysis for the remaining years based on LOLP weighting;
2. Confirm that the current method for valuing capacity can remain for wind farms until new rules are developed that are suitable for other intermittent generation resources;
3. Consult with key stakeholders on the results of this analysis and the issues identified;
4. In association with stakeholders, decide whether to base the next phase on LOLP weighted output or trading interval averages based on coincident output with high system demand
    - If the interim method is to be based on trading intervals, then decide the duration. At this stage 750 trading intervals is preferable to match the results obtained from reliability based analysis;
    - If the next stage is LOLP weighted methodology, then confirm the details of the methodology in terms of transitional issues, fleet based assessments versus individual project assessments and the basis for developing an LOLP function;
5. Prepare draft rule changes for the next stage of development as decided by step (4); and
6. Conduct rule change process.

MMA considers that due to a lack of data the trading interval average would be a suitable interim step whilst the need for an LOLP based assessment based on high levels of penetration of intermittent generation is explored. The preliminary analysis showed that capacity values declined by about 0.3% per 100 MW of solar thermal plant added, so there is some scope for augmentation before the overall level of penetration becomes a major problem.

APPENDIX A RELIABILITY EQUALISATION CALCULATIONS

The calculation of equivalent capacity using reliability equalisation was conducted by estimating the required capacity and then taking approximately 20% less and 20% more as alternative examples. The three capacity states were executed for the 10% POE and 30% POE cases and the expected unserved energy was determined using the equation:

EUSE = (37.48% A (10% POE USE) + 6.78%B (30% POE USE)) / (37.48% + 6.78%)

Where A = 0.401 for RM3 and 0.398 for RM7

B = 1.558 for RM3 and 1.677 for RM7

The A and B ratios were derived from the base simulations and indicate the inverse of the ratio in the 10% POE and 30% POE cases relative to the expected value of unserved energy. The values 37.48% and 6.78% indicate the weigthing given to the POE cases in representing the variation of peak demand based on weather observations. The aim of this calculation is to estimate the expected unserved energy solely from the 10% POE and 30% POE cases.

An example of the six cases and the resulting capacity estimate is shown in Table A- 1 for the assessment of total equivalent wind capacity for 2012/13 capacity year. The unserved energy was converted to a logarithm and interpolated on the logarithmic scale to obtain the same value as for the Reference Case with the wind farms included.

Table A- 1 Calculation of equivalent capacity 2012/13 for the total ECIG wind resources

All Wind Farms	Capacity (% Rated)	10% POE	30% POE	Weighted USE
Low Capacity USE	37.0%	1.389	0.314	0.387
Middle Capacity USE	50.2%	1.140	0.267	0.450
High Capacity USE	63.4%	0.987	0.217	0.387
Reference Case USE	ECIG	1.108	0.285	0.444
Interpolated Capacity (MW)	51.5%			0.444

The calculations for the individual wind farms are provided in Table A- 2 to Table A- 4.

Table A- 2 Calculation of equivalent capacity 2012/13 for wind farm 1

WF1	Capacity (%	10%	30%	Weighted

	Rated)	POE	POE	USE
Zero Capacity USE	0.0%	1.227	0.300	0.488
Low Capacity USE	33.3%	1.173	0.285	0.466
Middle Capacity USE	42.9%	1.156	0.281	0.459
High Capacity USE	52.4%	1.134	0.276	0.450
Reference Case USE	WF1	1.108	0.285	0.444
Interpolated Capacity (MW)	59.8%			0.444

Table A- 3 Calculation of equivalent capacity 2012/13 for wind farm 2

WF2	Capacity (% Rated)	10% POE	30% POE	Weighted USE
Low Capacity USE	38.2%	1.183	0.293	0.471
Middle Capacity USE	47.1%	1.104	0.282	0.442
High Capacity USE	56.1%	1.056	0.257	0.419
Reference Case USE	WF2	1.108	0.285	0.444
Interpolated Capacity (MW)	46.4%			0.444

Table A- 4 Calculation of equivalent capacity 2012/13 for wind farm 3

WF3	Capacity (MW)	10% POE	30% POE	Weighted USE
Low Capacity USE	42.9%	1.206	0.256	0.470
Middle Capacity USE	53.0%	1.131	0.243	0.442
High Capacity USE	63.1%	1.086	0.225	0.422
Reference Case USE	WF2	1.108	0.285	0.444
Interpolated Capacity (MW)	52.2%			0.444