Discussion Paper:

2012 Wholesale Electricity Market Report to the Minister for Energy

16 November 2012

Economic Regulation Authority

WESTERN AUSTRALIA

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Invited Comments

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Discussion Point 2

Stakeholders are invited to comment on whether there should be a limit set for the amount of Capacity Credits that the IMO can procure in excess of the Reserve Capacity Requirement and if so, on what basis this limit should be determined.

Discussion Point 3

Stakeholders are invited to comment on the effectiveness of the Reserve Capacity Price that has been set using the administrative formula with reference to the Maximum Reserve Capacity Price and the Excess Capacity Adjustment and whether an alternative calculation formula should be explored.

Discussion Point 4

Stakeholders are invited to comment on Lantau's proposal for changing the Reserve Capacity Price calculation formula in the Market Rules.

Discussion Point 5

The Authority invites stakeholders to comment on the value provided by DSM under the current market design and the cost of DSM to the market. The Authority also invites stakeholders to comment on whether alternative treatments of DSM could provide a more cost effective way to the market for the efficient use of DSM.

Discussion Point 6

Stakeholders are invited to comment on the application of clause 4.11.1(h) of the Market Rules and any appropriate modification that may be required to improve its effectiveness.

Discussion Point 7

Stakeholders are invited to comment on the provisions of clause 4.27 of the Market Rules and whether the incentives for plant availability could be improved.

Discussion Point 8

Stakeholders are invited to comment on whether the current market design provides appropriate incentives for retirement of inefficient generating units.

Discussion Point 9

Stakeholders are invited to comment on issues that are impacting on the efficient operation of the new LFAS market.

Discussion Point 10

Stakeholders are invited to comment on whether the current information regime under the Market Rules presents a potential barrier to entry and what, if any, improvements can be made in promoting more efficient market outcomes.

Discussion Point 11

Stakeholders are invited to comment on how effective the IMO, System Management and the Authority have been in carrying out their respective functions in the WEM.

1 Introduction

The purpose of this discussion paper is to assist interested parties in making submissions on any operational, strategic, policy or otherwise high-level issues, including those raised in this discussion paper, that are considered to be impacting on the effectiveness of Western Australia's Wholesale Electricity Market (**WEM**) in meeting the Wholesale Market Objectives (**Market Objectives**).

Submissions on this discussion paper close at 4:00pm (WST) on Tuesday, 18 December 2012. See Section 1.5 for further information on how to make a submission.

The *Wholesale Electricity Market Rules* (**Market Rules**) require that the Economic Regulation Authority (**Authority**) provide a report to the Western Australian Minister for Energy (**Minister's Report**), at least annually, on the effectiveness of the WEM in meeting the Market Objectives.

Submissions from interested parties on issues impacting the effectiveness of the WEM will assist the Authority in preparing its 2012 Minister's Report, which will be provided to the Minister following consideration of the submissions received in response to this discussion paper, and analysis of the available market data. A public version of the report will be published on the Authority's website after consultation with the Minister.

1.1 Wholesale Market Objectives

Under the Market Rules, the Authority is responsible for monitoring the effectiveness of the market in meeting the Market Objectives and providing to the Minister a report that includes the Authority's assessment of the effectiveness of the market. The Market Objectives[1] are:

- to promote the economically efficient, safe and reliable production and supply of electricity and electricity related services in the South West Interconnected System (**SWIS**)[2];
- to encourage competition among generators and retailers in the SWIS, including by facilitating efficient entry of new competitors;
- to avoid discrimination in that market against particular energy options and technologies, including sustainable energy options and technologies such as those that make use of renewable resources or that reduce overall greenhouse gas emissions;
- to minimise the long-term cost of electricity supplied to customers from the SWIS; and
- to encourage the taking of measures to manage the amount of electricity used and when it is used.

1 Refer to clause 1.2.1 of the Market Rules http://www.imowa.com.au/market-rules

2 The SWIS is defined in the *Electricity Industry Act 2004* and refers to the interconnected transmission and distribution systems located in the South West of the State, extending between Kalbarri, Albany and Kalgoorlie. See the State Law Publisher website, *Electricity Industry Act 2004*.

1.2 Reporting requirements

According to clause 2.16.12 of the Market Rules, the Authority's report to the Minister must contain (but is not limited to) the following:

- a summary of the information and data compiled by the Independent Market Operator (**IMO**) and the Authority under clause 2.16.1;
- the Authority's assessment of the effectiveness of the market, including the effectiveness of the IMO and System Management in carrying out their functions, with discussion of the following:
  - the Reserve Capacity Market
  - the market for bilateral contracts for capacity and energy
  - the Short Term Energy Market (**STEM**)
  - Balancing
  - the dispatch process
  - the planning processes
  - the administration of the market, including the Market Rule change process
  - Ancillary Services;
- an assessment of any specific events, behaviour or matters that impacted on the effectiveness of the market; and
- any recommended measures to increase the effectiveness of the market in meeting the Market Objectives to be considered by the Minister.

1.3 Summary of the 2011 Minister's Report

The Authority provided its 2011 Minister's Report to the Minister in April 2012, and published a public version of that report on its website in May 2012. In the report, the Authority concluded that outcomes in the WEM, over the five and a half years since market commencement, had indicated that the market was functioning well, to the benefit of electricity consumers. The volume of trading in the STEM was at its highest level since market commencement, and the average STEM prices were at their lowest levels. The price for capacity had fluctuated over time but it had recently been reduced by one third, and there was greater competition in the market, particularly in the generation sector. The Authority noted that over $2 billion of private funds have been invested in electricity generation in the SWIS. These are good outcomes for electricity consumers and taxpayers in Western Australia.

Nevertheless, the Authority cited a number of concerns that require resolution and that have the potential to affect the market's successful evolution and efficient operation.

The Authority reiterated its on-going concern in regard to the continuing domination of the market by Verve Energy and Synergy because of the importance of competition to the effectiveness of the market. The Authority recognised the concerns among Market Participants about the proposed merger between Verve Energy (the largest generator in the market) and Synergy (the largest retailer in the market). The Authority considered that a move toward merging the two entities would likely obstruct the attainment of the Market Objectives by discouraging future private investment, reducing competitive tension and transparency, and increasing the need for regulatory oversight. It was the Authority's view that this would ultimately be to the detriment of electricity consumers.

The Authority highlighted some significant cost pressures affecting the market, including the cost of the excess capacity procured under the Reserve Capacity Mechanism (**RCM**) and the increasing cost of the Demand Side Management (**DSM**). The Authority considered that it was appropriate to examine whether the benefits provided by DSM justify the costs and recommended that alternative models be considered to allow for a greater alignment between the payment received by providers of DSM and the value provided by DSM.

The Authority noted its concern about the increase in intermittent generation[3] and its impact on the economic dispatch of base-load generation in low demand periods, the use of gas turbines to maintain frequency control during these periods, and the increasing costs of Load Following Ancillary Services (**LFAS**). The Authority considered that the introduction of the new competitive Balancing and LFAS markets from July 2012, in which Independent Power Producers (**IPPs**) can compete alongside Verve Energy for the provision of these services, would deliver more efficient outcomes.

The Authority highlighted the excessive Planned Outage rates, and a number of instances in which price spikes coincided with these outages, and raised its concerns as to whether the incentives for plant availability provided by the market are appropriate. The Authority considered that the threshold for monitoring plant availability in the Market Rules could be set too high and that this issue should be investigated further. The Authority suggested that there may be options to improve incentives for plant availability, such as the amendment of refund payments so that they are higher if capacity is scarce at the time of an outage, thereby increasing the incentive for availability at times when it is more highly valued.

Whilst the Authority remained satisfied with the IMO's performance, it recognised the increasing concerns raised by Market Participants in regard to the potential for a conflict of interest where the IMO fulfils dual roles as the rule maker and rule administrator. The Authority recommended a review of governance arrangements within the market, to be undertaken by the newly established Public Utilities Office (**PUO**).

1.4 Approach and focus for the 2012 Minister's Report

As stated in its 2011 Minister's Report, the Authority expected the WEM to continue to evolve and considered the work program of activities, largely led by the IMO, to bring further competition into the market and set the next stage of market development to deliver more efficient market outcomes.

The Authority notes that the energy market in the WEM has gone through some significant changes recently with the implementation of the competitive balancing market. This has provided opportunities for IPPs to participate in balancing energy provision alongside with Verve Energy.

There is also a newly established market for the provision of LFAS whereby IPPs can compete with Verve Energy for providing this service.[4]

[3] Intermittent generation includes generation from wind farms, photovoltaic generators and some small generators fuelled by landfill gas. Currently, wind generation constitutes the majority of intermittent generation in the WEM.

[4] Verve Energy was assigned as the sole provider for the provision of balancing energy and LFAS from market commencement until 1 July 2012 when the new competitive balancing and LFAS market was implemented in the WEM.

Because the competitive balancing and LFAS markets have been in operation only for a short period of time (since 1 July 2012) there is limited operational data for the Authority to assess and comment on the effectiveness of these markets at this stage. However, the Authority is open to receiving feedback from stakeholders on issues associated with the operation of these markets.

For this report, the Authority intends to focus mainly on issues surrounding the operation of the capacity market. These issues include the:

- role of Reserve Capacity Auctions;
- Capacity Credits assigned by the IMO;
- responsiveness of the Reserve Capacity Price to market conditions;
- treatment of DSM as a separate product/service; and
- incentives for plant availability and retirement of inefficient plant.

The Authority invites comments from stakeholders on these specific issues.

Beyond these specific issues, the Authority welcomes comments from stakeholders on any other strategic, policy or high-level issues that are impacting on the effectiveness of the WEM in meeting the Wholesale Market Objectives. However, due to the Authority's focus on issues surrounding the operation of the capacity market, the Authority may defer consideration of these other issues for inclusion in the next Minister's Report, in 2013.

The structure of this discussion paper is set as follows:

- Section 2 provides a summary of key activities and outcomes of the WEM since its inception.
- Section 3 discusses the key issues surrounding the operation of the capacity market that the Authority intends to focus on for the 2012 Minister's Report.

1.5 How to make a submission

Submissions on the issues outlined in this discussion paper or on any operational, strategic, policy or otherwise high-level issues that are thought to be impacting on the effectiveness of the WEM in meeting the Market Objectives, should be marked to the attention of the Assistant Director Markets.

Email address:	publicsubmissions@erawa.com.au
Postal address:	PO Box 8469, PERTH BC WA 6849
Office address:	Level 4, Albert Facey House, 469 Wellington Street, PERTH WA 6000

Submissions must be received by **4:00 pm (WST) on Tuesday, 18 December 2012**.

Confidentiality

Submissions made to the Authority will be treated as in the public domain and placed on the Authority's website unless confidentiality is claimed. The submission or the parts of the submission for which confidentiality is claimed should be clearly marked. Any claim of confidentiality will be dealt with in the same way as is provided for in section 55 of the *Economic Regulation Authority Act 2003*.

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2 Outcomes in the Wholesale Electricity Market

Electricity markets can be organised in different ways. Broadly, they can be categorised into two types of markets, energy only markets and markets with separate capacity and energy components. The National Electricity Market (**NEM**) operating in the eastern states is an energy only market. In the NEM, a generator receives only one payment stream from the market through the energy output it has produced and made available to the market.

The Wholesale Electricity Market (**WEM**) in Western Australia is a market with separate capacity and energy components. The capacity market component seeks to ensure that supply capacity is sufficient, whilst the energy market component provides a platform in which electricity generators and retailers interact to supply and purchase electricity. In the WEM, therefore, a generator will receive two payment streams, the capacity payment for making its capacity available to the market and the energy payment for the amount of electricity that it has produced and made available to the market.

This section provides a brief overview of outcomes in the capacity and energy market from market commencement in September 2006 to the end of June 2012.

2.1 The capacity market

The Reserve Capacity Mechanism (**RCM**) is a key design feature of the WEM which underpins the operation of the capacity market of the WEM. The provision for a separate capacity mechanism in the WEM design was driven by a strong focus on supply security in consideration that the SWIS is isolated from electricity systems in other jurisdictions. The aim of the RCM is to ensure that sufficient capacity will be available to meet system peak demand throughout the year.

Under the RCM, the IMO is responsible for centrally determining the capacity requirement, the Reserve Capacity Requirement (**RCR**), two years in advance in accordance with the Planning Criterion based on peak demand and energy forecasts.[5]

To ensure sufficient capacity is installed in the SWIS, the RCM includes a concept of Capacity Credits. A Capacity Credit represents one megawatt (MW) of capacity that is allocated by the IMO. Capacity Credits are allocated to supply capacity from both generators and DSM providers. To apply for Capacity Credits, a capacity provider must go through the capacity certification process whereby the IMO will determine the maximum quantum of capacity that can be allocated to a facility after the IMO has conducted its due diligence assessment and technical review of the capability of the facility. Capacity Credits are tradable in the WEM, i.e. they can be traded between Market Participants and with the IMO. Capacity Credits are only valid for a particular Capacity Year.[6] Hence the process of capacity certification and allocation of Capacity Credits is repeated each year.

The RCM has so far successfully secured sufficient capacity for each Capacity Year up to 2014/15. Figure 1 provides a summary of the Capacity Credits assigned to participants in each Capacity Year, as well as the RCR for that year (shown as the vertical black line for each Capacity Year). It is clear from Figure 1 that in each Capacity Year the number of Capacity Credits assigned to participants (in aggregate) has exceeded the RCR. The excess of Capacity Credits assigned to participants has ranged from 2.2 per cent (in the

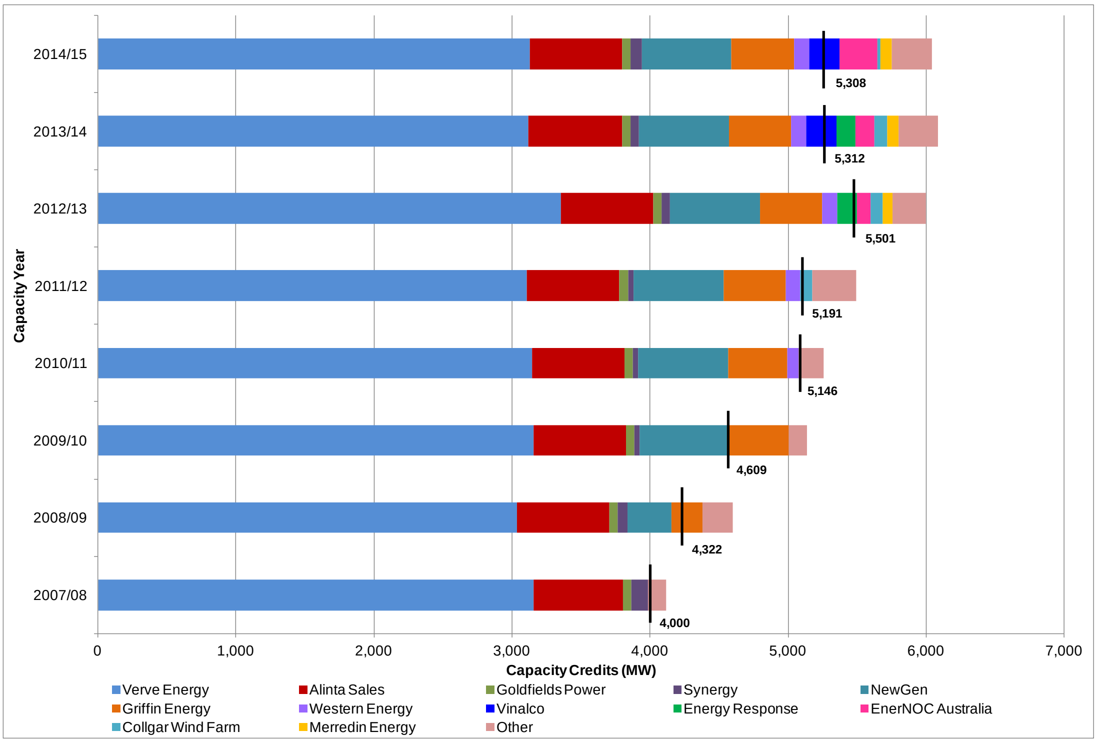
[5] For further detail on the Planning Criterion for setting the RCR, refer to clause 4.5.9 of the Market Rules.

[6] A Capacity Year is a period of 12 months commencing at the start of the Trading Day on 1 October and ending at the end of the Trading Day on 30 September of the following year.

2010/11 Capacity Year) to 14.6 per cent (in the 2013/14 Capacity Year), with an average of 8.5 per cent over the eight Capacity Years from 2007/08 to 2014/15.

Figure 1 also shows that the Capacity Credits assigned to new entrants continues to increase. For Capacity Year 2014/15, Verve Energy is expected to provide approximately 52 per cent of the total SWIS certified capacity, compared to approximately 90 per cent when the WEM commenced.

Figure 1 Capacity Credits (MW) assigned by the IMO to Market Participants



Note: In the figure above, the vertical black lines with the corresponding value represent the Reserve Capacity Requirement in each Capacity Year.

Under the Market Rules, the Reserve Capacity Price (**RCP**) is calculated in accordance with a prescribed formula in the Market Rules using the Maximum Reserve Capacity Price (**MRCP**)[7] when no Reserve Capacity Auction is held. As no Reserve Capacity Auction has been held since market commencement, the value of the RCP for each Capacity Year has been calculated based on the MRCP value.

Table 1 sets out the RCP values for the period from market commencement in 2006 to the 2014/15 Capacity Year. Pursuant to the Market Rules, these values are calculated as 85 per cent of the MRCP and adjusted by the ratio of the RCR to the total number of Capacity Credits assigned by the IMO for the relevant Capacity Year.

Table 1 also sets out the implied value of Capacity Credits for each Capacity Year, which is calculated as the RCP times the total Capacity Credits assigned in each Capacity Year. The implied value of Capacity Credits for the 2014/15 Capacity Year is markedly lower than the value for the 2013/14 Capacity Year as a result of the reduced MRCP.

[7] This value is determined in accordance with the MRCP Market Procedure with reference to a 160 MW Open Cycle Gas Turbine peaking facility with a capacity factor of 2%.

Table 1: Reserve Capacity Prices

Period	Reserve Capacity Price (per MW per year)	Maximum Reserve Capacity Price (per MW per year)	Implied value* of Capacity Credits ($ million per year)
21/09/06 to 01/10/06	$127,500	$150,000	
01/10/06 to 01/10/07	$127,500	$150,000	477
01/10/07 to 01/10/08	$127,500	$150,000	525
01/10/08 to 01/10/09	$97,835	$122,500	450
01/10/09 to 01/10/10	$108,459	$142,200	557
01/10/10 to 01/10/11	$144,235	$173,400	758
01/10/11 to 01/10/12	$131,805	$164,100	724
01/10/12 to 01/10/13	$186,001	$238,500	1,115
01/10/13 to 01/10/14	$178,477	$240,600	1,086
01/10/14 to 01/10/15	$122,427	$163,900	739

** Note: The actual value of Capacity Credits settled under bilateral contracts is determined by the prices set in bilateral contracts. In this table the implied value is the Reserve Capacity Price multiplied by the total Capacity Credits allocated by the IMO for each Capacity Year.*

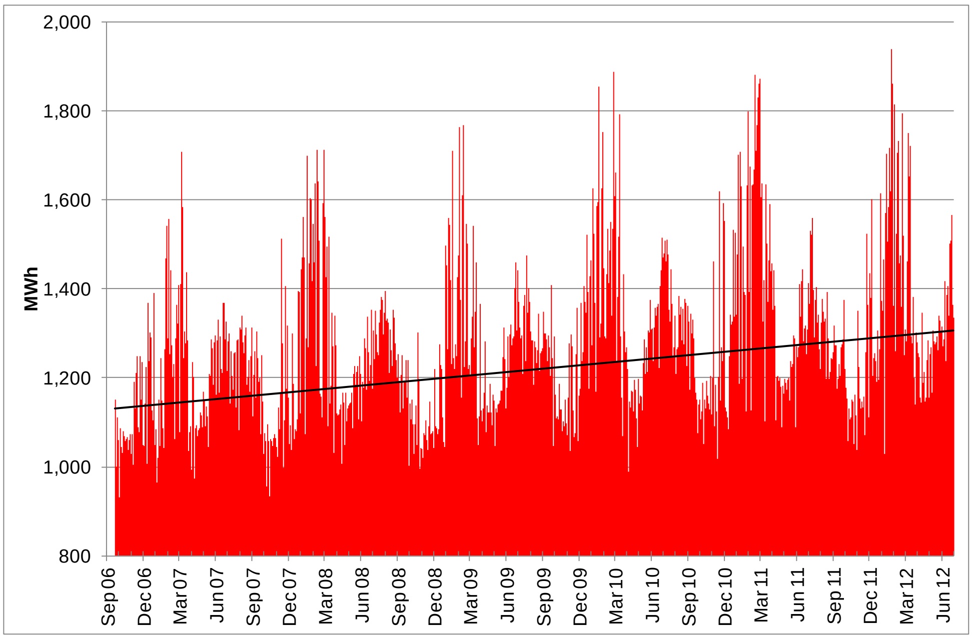
2.2 The energy market

Figure 1 illustrates the maximum SWIS demand each day (measured in megawatt hour (MWh) per Trading Interval[8]) from market commencement (21 September 2006) to 30 June 2012. A trend line based on linear regression is also provided in Figure 1, which has shown a consistent upward trend in the daily maximum demand. Peak demand days regularly occur in January, February and March. The highest daily maximum demand recorded for the current reporting period[9] was 1,939.7 MWh (or 3,879 MW), which was observed during the 4:30 pm Trading Interval on 25 January 2012. This is also the highest maximum demand observed since market commencement.

[8] A Trading Interval is a period of 30 minutes commencing on the hour or half-hour during a day. Settlement calculations in the WEM are based on Trading Interval data.

[9] The current reporting period covers the period from 1 August 2011 to 30 June 2012.

Figure 1: Daily maximum demand (21 September 2006 to 30 June 2012)



2.2.1 The Short Term Energy Market

The daily average STEM Clearing Prices during Peak and Off-Peak Trading Intervals[10] from market commencement to 30 June 2012 are presented in Figure 2 and Figure 4, respectively. The 30-day, 90-day and annual moving averages of these prices are also included in these figures.

Following a period of high prices immediately after market commencement, STEM Clearing Prices were relatively stable in 2007 and in 2008 prior to the Varanus Island incident in June 2008.[11] The incident resulted in significant gas supply curtailment and prices in the STEM increased significantly, reaching a daily average in excess of $400/MWh during Peak Trading Intervals and a daily average of close to $200/MWh during Off-Peak Trading Intervals. Prices have trended down subsequently, with prices averaging around $38.65/MWh during Peak Trading Intervals and $19.51/MWh during Off-Peak Trading Intervals in the 2009/10 Reporting Year.[12] Since then, there has been an upward trend in the STEM Clearing prices. The average Peak and average Off-Peak STEM Clearing prices increased to $46.63/MWh and $25.68/MWh in the 2010/11 Reporting Year. For the current Reporting Period from 1 August 2011 to 30 June 2012, the average Peak and average Off-Peak STEM Clearing prices were $51.68/MWh and $26.17/MWh, respectively.

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10 Peak Trading Intervals refer to Trading Intervals occurring from 8 AM to 10 PM and Off-Peak Trading Intervals refer to Trading Intervals occurring from 10 PM to 8 AM.

11 The incident was caused by the rupture of a corroded pipeline and subsequent explosion at a processing plant on Varanus Island on 3 June 2008. The plant, operated by Apache Energy, which normally supplied a third of the State's gas, was shut down for almost two months while a detailed engineering investigation and major repairs were carried out. Gas supply from the plant partially resumed in late August. By mid-October, gas production was running at two-thirds of normal capacity, with 85 per cent of full output restored by December 2008.

12 Reporting Year is from 1 August to 31 July of the following year except for this Reporting Year. The current Reporting Year covers the period from 1 August 2011 to 30 June 2012 in consideration of the significant changes occurred in the market resulting from the implementation of the competitive balancing and load following ancillary service market from 1 July 2012.

Figure 2: **Daily average STEM Clearing Price (Peak Trading Intervals, 21 September 2006 to 30 June 2012)**

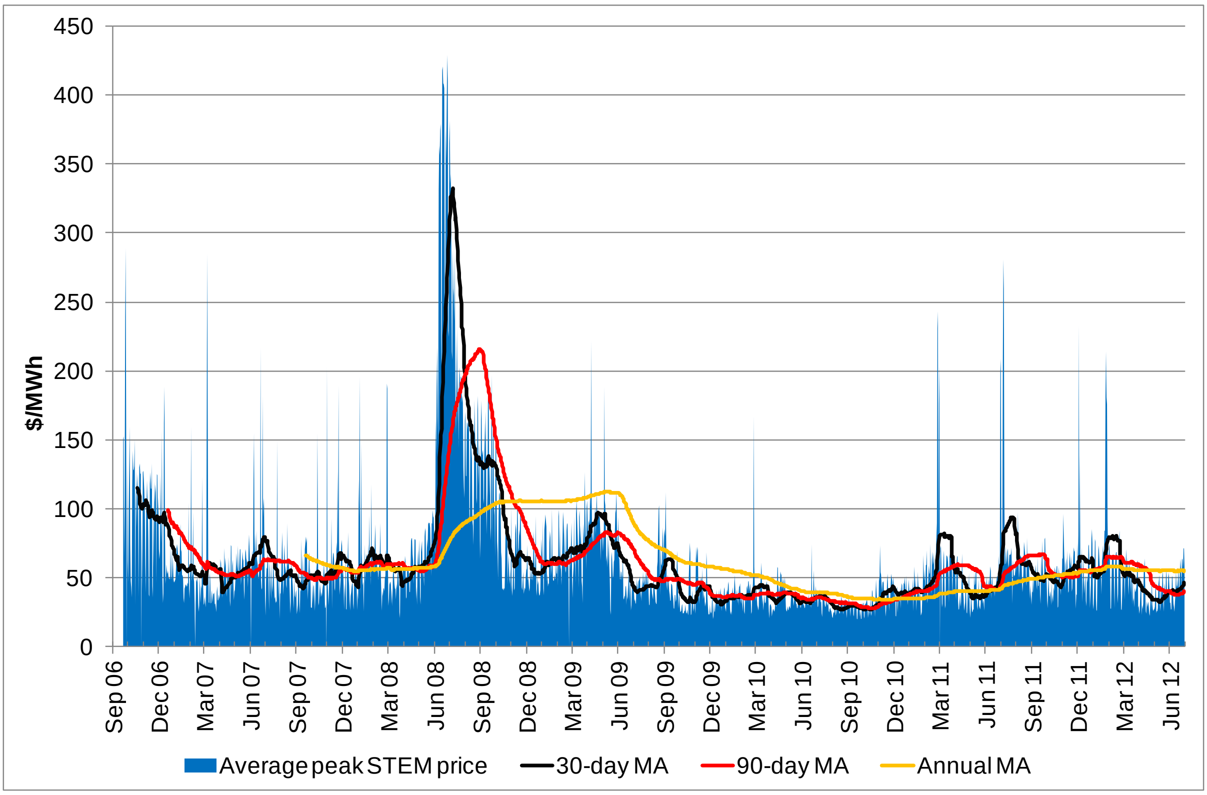


Figure 3: **Daily average STEM Clearing Price (Off-Peak Trading Intervals, 21 September 2006 to 30 June 2012)**

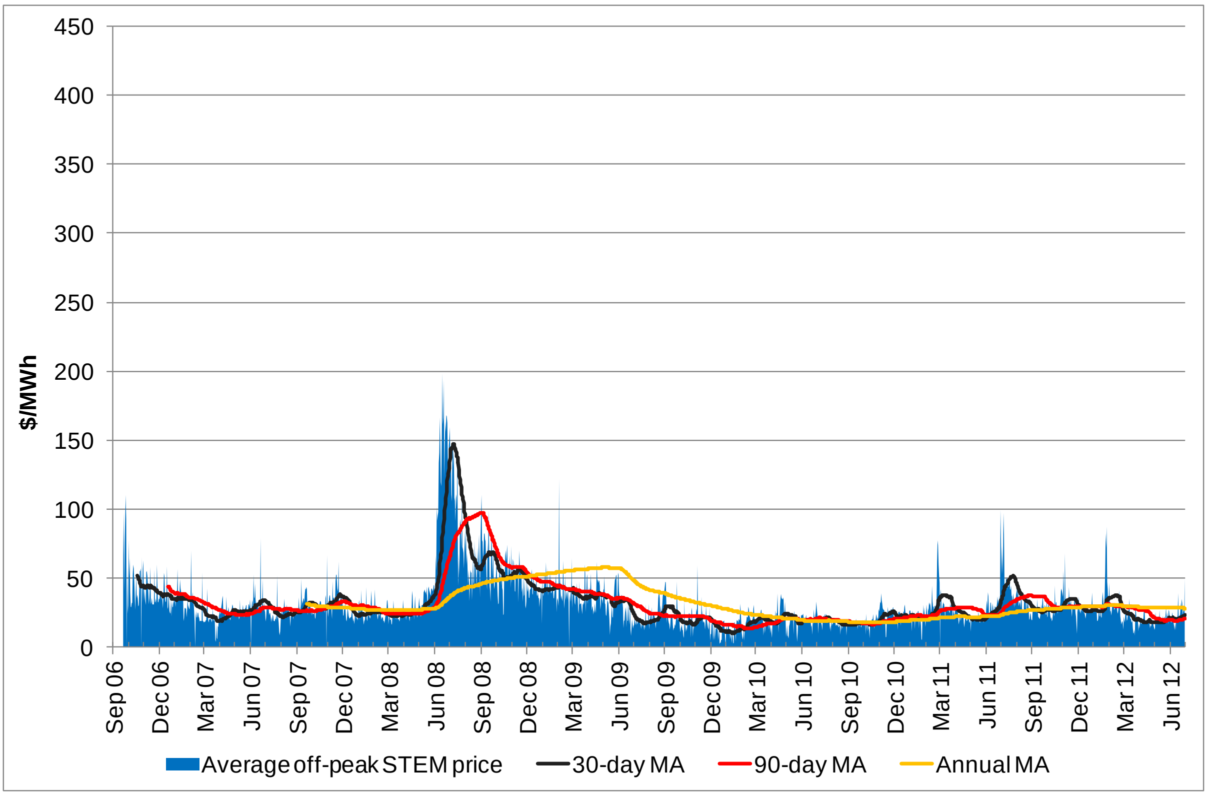
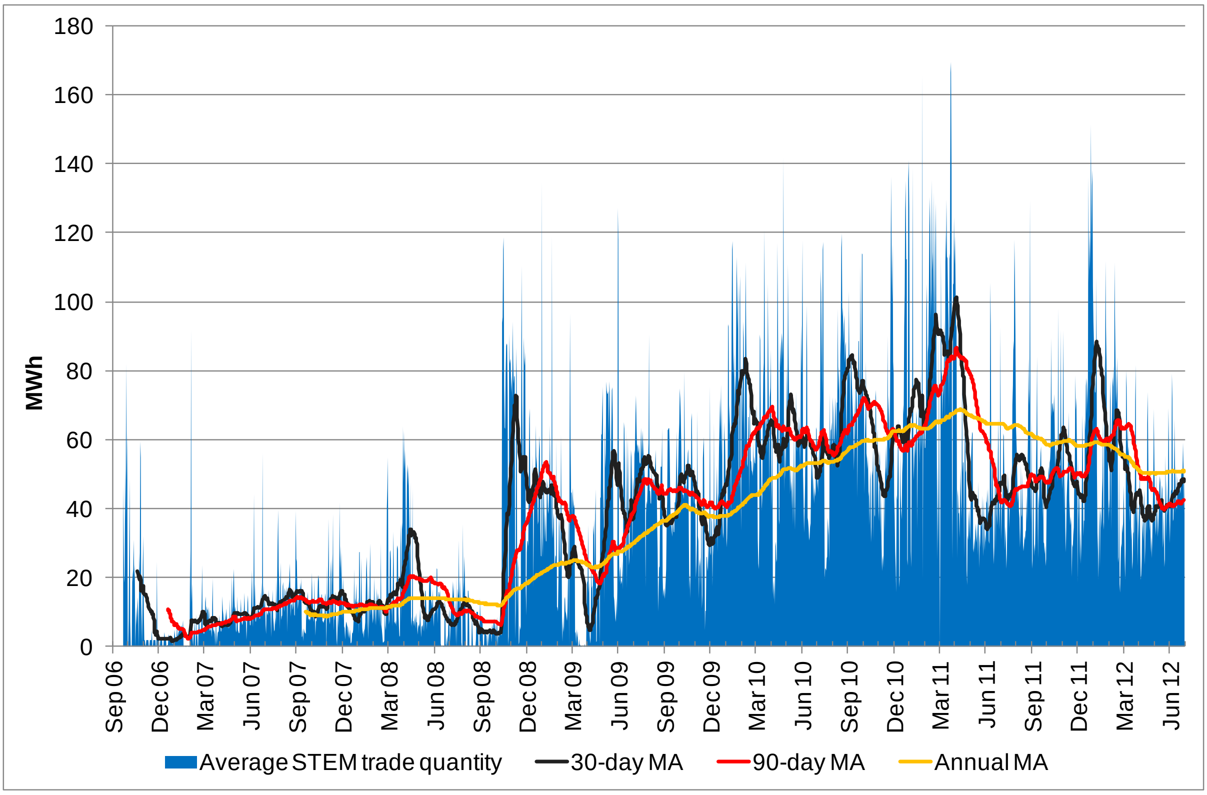


Figure 4 illustrates daily average quantities traded in the STEM from market commencement until 30 June 2012. The historical volume traded in the STEM remained relatively low until the commencement of the 2008/09 Capacity Year (in October 2008). The Authority understands the step change at the commencement of the 2008/09 Capacity Year was largely attributable to the entry of NewGen's Kwinana facility and Griffin Power's first unit at Bluewaters in that year. Increased STEM trade volume carried on into the 2009/10 and 2010/11 Capacity Years. The average quantity traded in the STEM since October 2008 is approximately 52 MWh per Trading Interval.

Figure 4: Daily average quantities traded in the STEM (21 September 2006 to 30 June 2012)



2.2.2 Balancing

Figure 5 and Figure 6 illustrate, respectively, the daily average Peak and Off-Peak balancing prices from market commencement to 30 June 2012. The balancing price shown in these figures is the Marginal Cost Administered Price (**MCAP**).[13]

The balancing prices have followed similar patterns to the STEM prices. Following a period of high prices immediately after market commencement, both Peak and Off-Peak Balancing prices were relatively stable until June 2008 when the Varanus Island incident occurred. Following that event, and the subsequent curtailment of gas supplies, Balancing prices increased significantly in June 2008 and remained at elevated levels for a number of months. Balancing prices have returned to lower levels since that time, with average prices at or below those experienced before the 2008 Varanus Island incident.

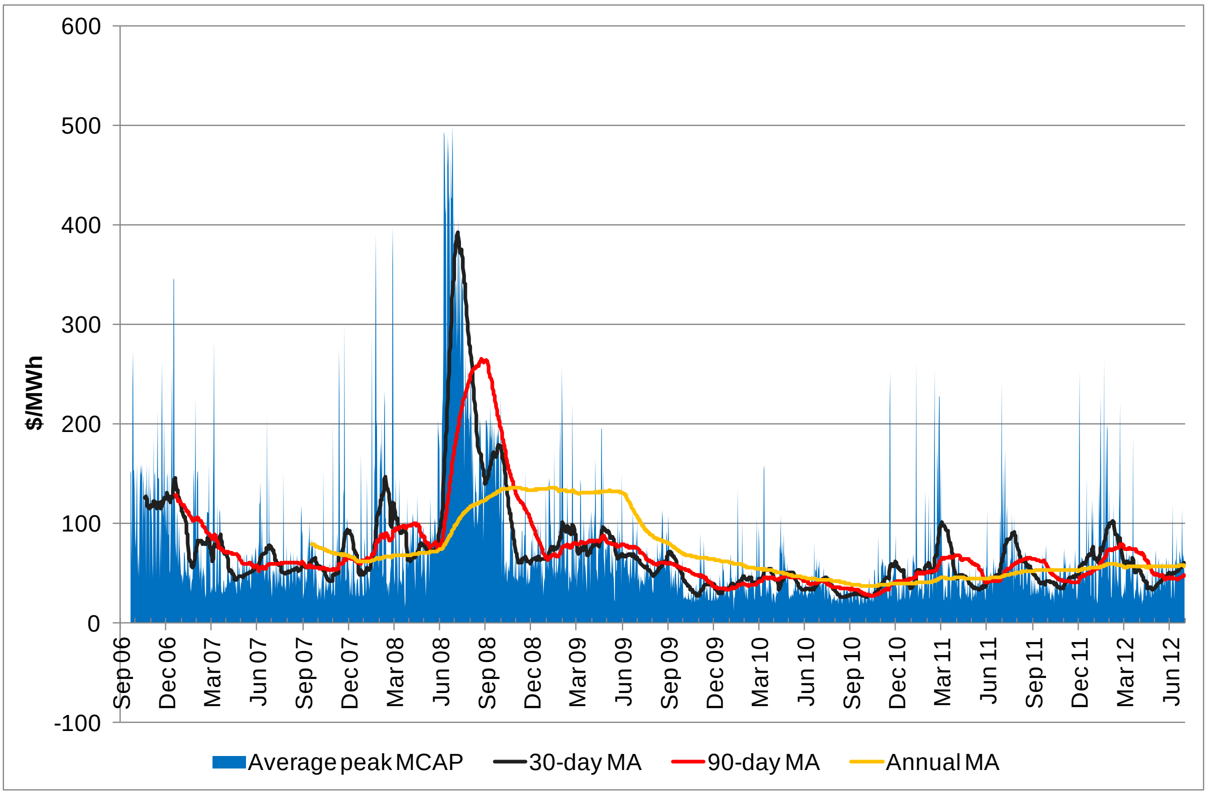
[13] The method for determining the Balancing price has changed from 1 July 2012 due to the implementation of the new competitive balancing market.

The MCAP reached $314.00/MWh (the Maximum STEM Price) in late June 2011 to early July 2011. This was associated with a large volume of Planned Outages approved by System Management at that time, coupled with some unexpected Forced Outages of plant. As a result, Dispatch Instructions were issued by System Management for Out-of-Merit dispatching of IPP facilities at 'pay as bid' prices in order to mitigate high risk system operating state for security purposes.[14] Some high MCAP events were also observed in the first week of August 2011 and in November 2011 due to the high level of Planned Outages.

MCAP reached $314.00/MWh (the Maximum STEM Price) in December 2011, January 2012 and February 2012. The majority of these high MCAP events occurred during periods of high summer demand (ranged between 3,000 MW to 3,880 MW) as a result of high temperature and a number of these high MCAP events were triggered by Forced Outages of plant.

The lowest MCAP during the current Reporting Period reached negative $53.39/MWh at 2:00 am on 10 June 2012, which was the lowest MCAP observed since market commencement. This negative MCAP value was attributed by overnight low demand, falling under 1,300 MW, and very high Intermittent Generation (242 MW).

Figure 5: Daily average Balancing prices (Peak Trading Intervals, 21 September 2006 to 30 June 2012)



[14] Until 30 June 2012, Verve Energy was the sole provider of balancing energy. Under this arrangement, System Management would only dispatch IPP facilities for balancing purposes in the event that Verve Energy's facilities were unable to provide the balancing energy required. IPP facilities that were dispatched out of the dispatch merit order were paid at their bid prices rather than the MCAP.

Figure 6: Daily average Balancing prices (Off-Peak Trading Intervals, 21 September 2006 to 30 June 2012)

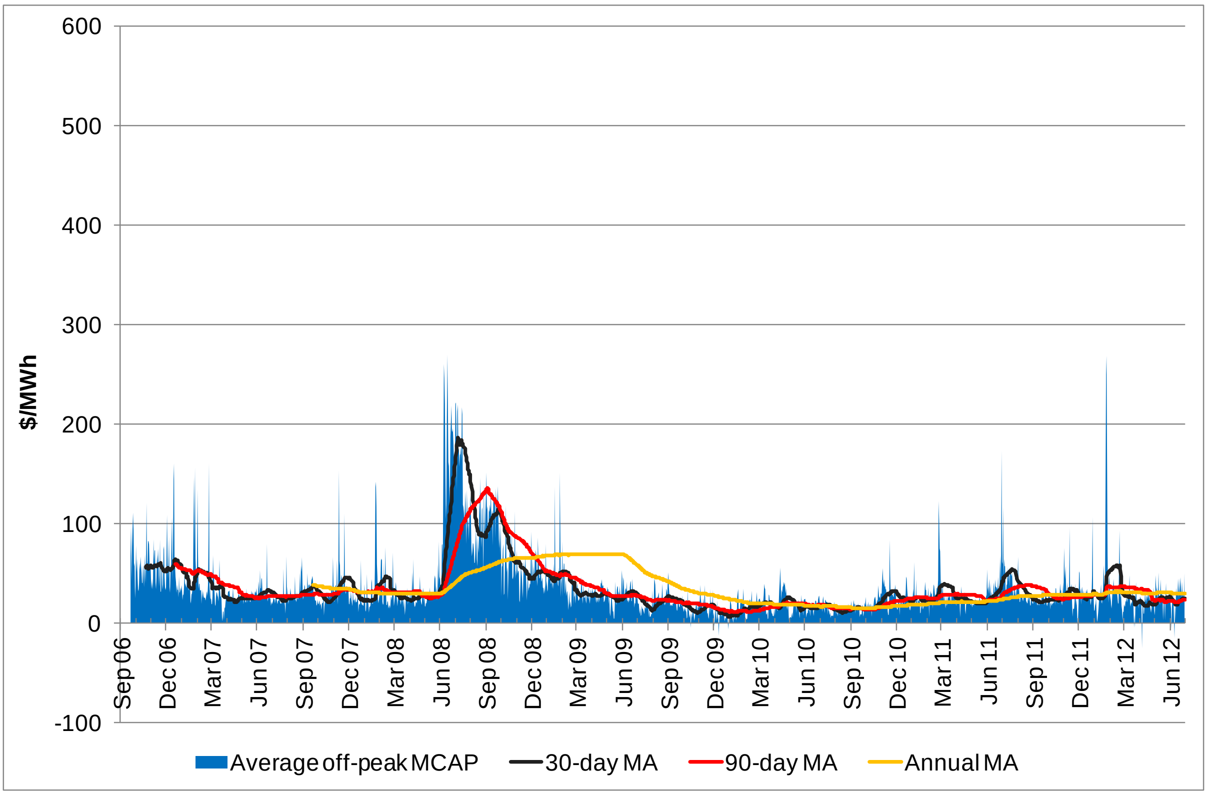


Figure 7 below illustrates the daily average quantity per Trading Interval purchased and sold in Balancing by Verve Energy as the sole balancing agent (from market commencement until 30 June 2012).[15] There appears to have been a dominance of purchases by Verve Energy since 2009, the higher values are shown by comparing the blue line to the red line in Figure 7.

There are two main reasons that may cause Verve Energy, acting as the sole balancing agent, to purchase through Balancing:

- Whilst Scheduled Generators[16] in the market were required to follow their Resource Plan committed one day ahead, the Market Rules allowed Intermittent Generators[17] to spill energy into Balancing without any pre-commitment. This energy would contribute to purchases by Verve Energy. There has been an increase in capacity and output from wind generators in recent years. The higher purchase quantity by Verve Energy can be attributed in part to the impact of the addition of wind generators, in particular the commissioning of the Collgar wind farm since June 2011.

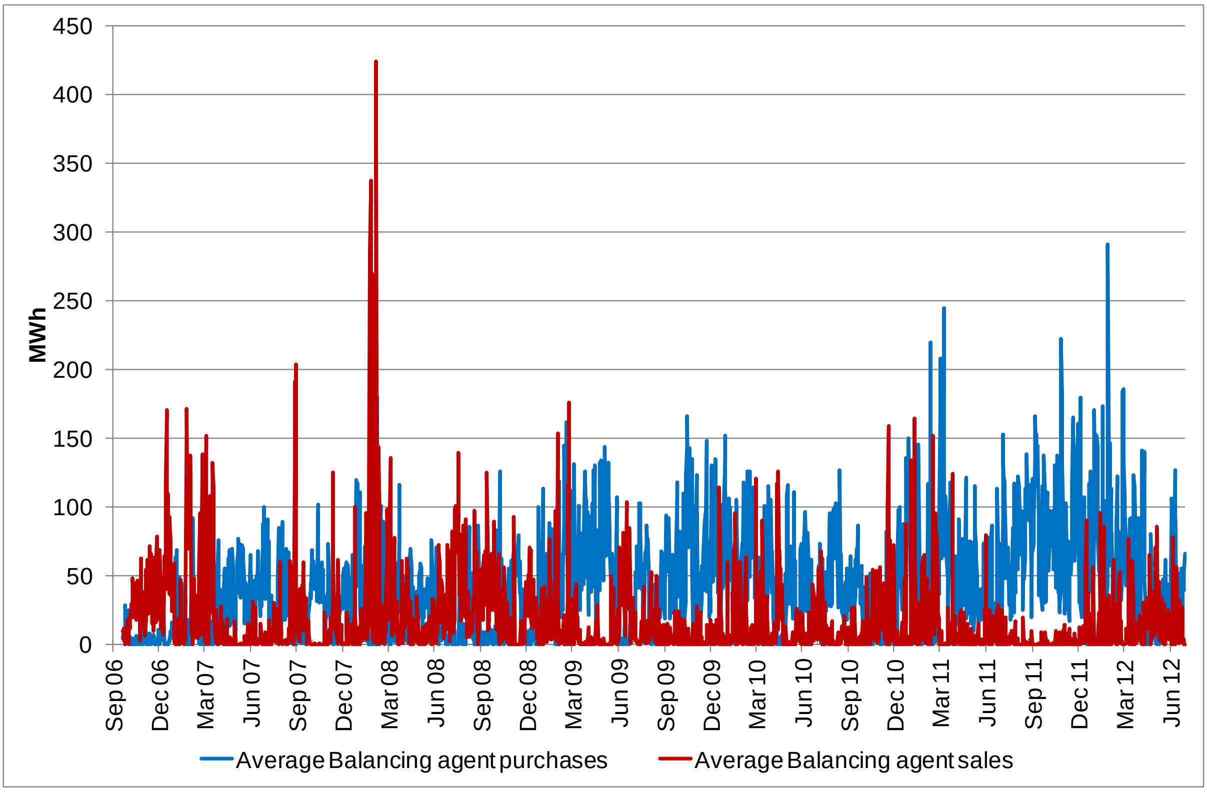
[15] The daily average quantity per Trading Interval bought is calculated as the total quantity purchased by Verve Energy each day divided by 48 Trading Intervals. Similarly, the daily average quantity per Trading Interval sold is calculated as the total quantity sold by Verve Energy each day divided by 48 Trading Intervals.

[16] Scheduled Generators refer to generators that can increase or decrease the quantity of electricity they generate in response to instructions from their operators.

[17] Intermittent Generators refer to generators that cannot be scheduled because their output level is dependent on factors beyond the control of their operators, e.g. wind, solar, etc.

- Forecast errors by Market Customers[18] may also contribute to Verve Energy's purchase quantity in Balancing. When a Market Customer requires less energy than it has committed through bilateral nomination and trading in the STEM, the difference will constitute a Balancing purchase by Verve Energy. As the costs to a Market Customer associated with being somewhat short of its actual requirement can exceed the costs associated with being equivalently long, there is a commercial incentive to commit somewhat more than the expected requirement under certain market conditions.[19]

Figure 7: Daily average quantities traded in Balancing[20] (21 September 2006 to 30 June 2012)



2.3 Competition in the contestable electricity market

The electricity industry in Western Australia is not fully deregulated. Currently, only customers with annual electricity consumption of more than 50 MWh can choose their electricity suppliers in the SWIS. Synergy is the sole supplier of electricity to customers that use less than 50 MWh of electricity per annum in the SWIS. The dominance of Synergy and the slow progress of competition in the retail electricity market has been a concern raised by the Authority previously.[21]

[18] Market Customers are retailers and DSM providers registered to participate in the WEM. Market Generators are generators registered to participate in the WEM

[19] Clause 6.7.4 of the Market Rules provides a Market Customer must not significantly over-state its consumption as indicated by its Net Contract Position with a regularity that cannot be explained by a reasonable allowance for forecast uncertainty or the impact of Loss Factors.

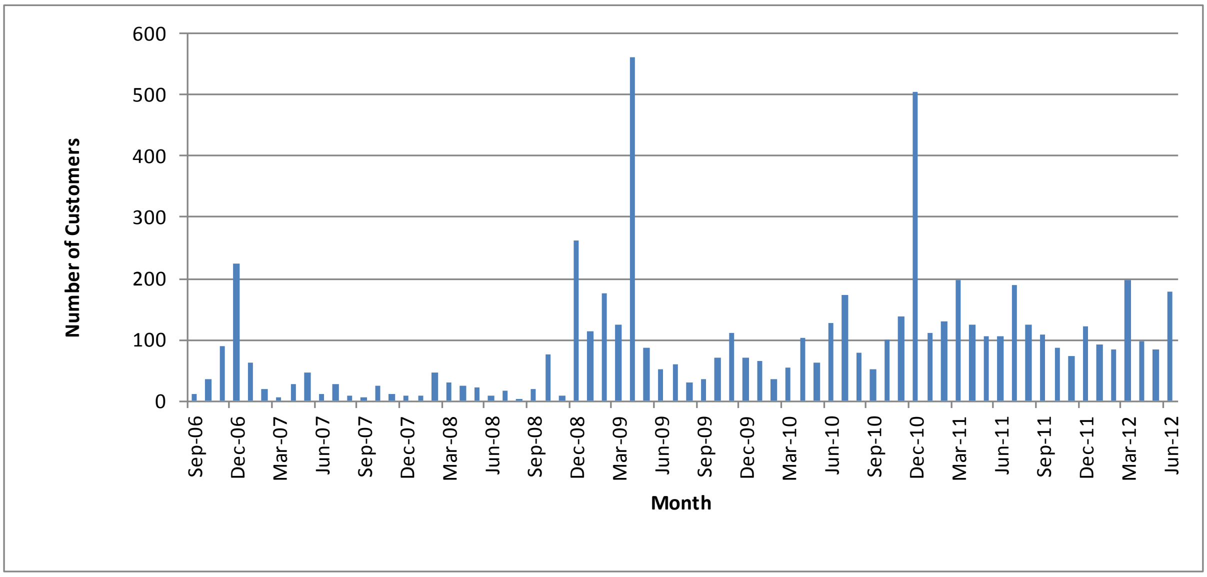
[20] Data sourced from the IMO website: 'Balancing Quantity (MWh)' for the period 21 September 2006 – 30 March 2011 from the *Balancing Information - 6 Month Summary* webpage http://imowa.com.au/n4841.html; and 'Balancing Trade Estimate' for the period 31 March 2011 – 30 June 2012 is sourced from the *Weekly Market Report* webpage http://imowa.com.au/market-data-weekly-market-report

[21] ERA, *2008 Wholesale Electricity Market Report to the Minister for Energy*, http://www.erawa.com.au.

Figure 8 illustrates the level of customer transfer between retailers in the contestable section of the electricity market in the SWIS. At the commencement of the WEM in 2006, there was a progressive increase in the monthly customer transfer number which reached 225 customers in December 2006. Customer transfer numbers then moderated and remained relatively low throughout 2007 and for the majority of 2008. The long term general trend has been towards a steady increase in the number of customers changing retailers since December 2008, which likely reflects the Government's decision to increase tariffs in 2009. Notably, customer transfer numbers spiked in April 2009 (561 customers) and again in December 2010 (506 customers).

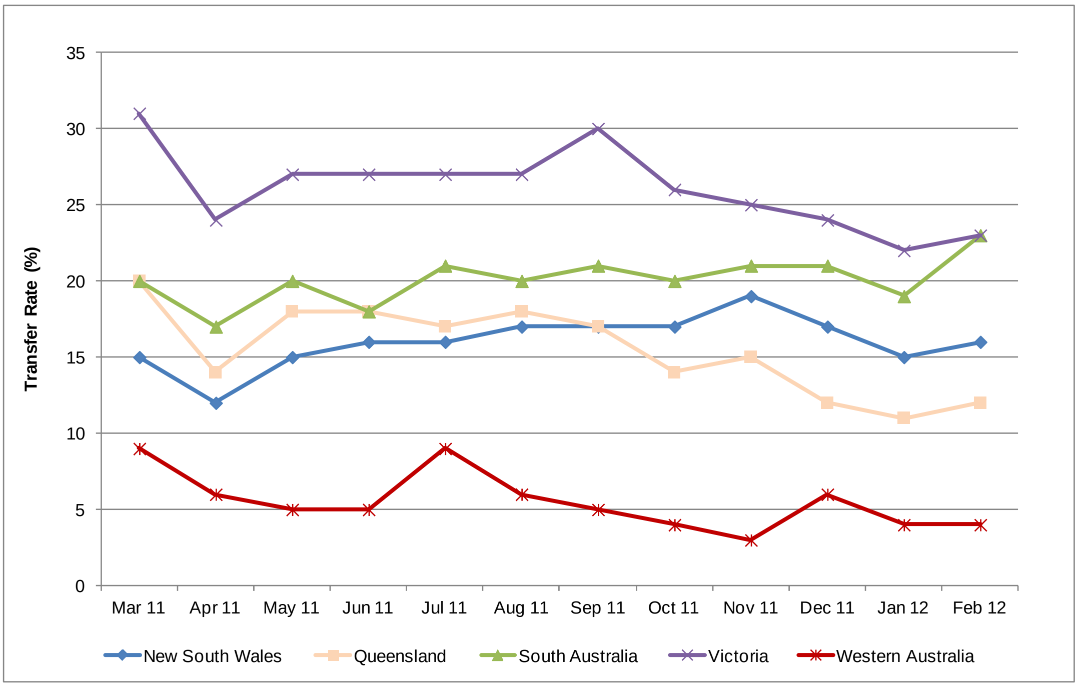
However, customer transfer numbers each month appear to have stabilised since December 2010. The number of customers changing retailers over the 2011/12 financial year averaged at around 120 customers each month. Compared to the total number of contestable electricity customers in the SWIS (approximately 26,000), the average monthly customer churn rate was approximately 0.5 per cent, with the maximum rate of 0.8 per cent in March 2012 and the minimum rate of 0.3 per cent in November 2011.

Figure 8: Number of customers changing retailer per month (September 2006 to June 2012)



The Authority notes that the monthly customer churn rate in the SWIS is relatively low compared to the eastern states as shown in Figure 10 below. This is a reflection of the lack of retail competition in the SWIS in the contestable section of the market and the fact that full retail contestability has not been implemented in the SWIS.

Figure 9: Annualised customer transfer rates in Australian jurisdictions (March 2011 to February 2012) [22]



[22] The one-month annualised transfer rates are calculated by projecting the small consumer (i.e. annual consumption less than 160MWh for all jurisdictions except Queensland, which is less than 100MWh) transfer volume for that month over a 12-month period, and calculating the percentage churn that would occur if the transfer rate was maintained over the year. This value is then rounded to the nearest percentage. See the AEMO website http://www.aemo.com.au/data/retail_transfers.html. The Western Australian transfer rates are calculated based on the assumption that the total number of customers in the SWIS is 26,000 over the period represented in the figure.

3 Key Wholesale Electricity Market Matters

The implementation of the WEM is aimed at providing a competitive market for trading electricity. The WEM consists of two market components, the capacity market and the energy market. Since the commencement of the WEM, competition in the energy market has evolved substantially. This has led to downward pressure on energy prices observed in both the Short Trading Energy Market (**STEM**) and the Balancing market as shown in section 2.2.

However, the Authority considers that the capacity market has not functioned as it was intended. The operation of the Reserve Capacity Mechanism (**RCM**) that underpins the capacity market in the WEM has, so far, never utilised the Reserve Capacity Auction. The auction was intended to allow a competitive tender process for the IMO to procure capacity for meeting the capacity requirement of the market. As sufficient capacity has always been nominated for bilateral trade by market participants there has been no auction. As a result, the Reserve Capacity Price has been set administratively in accordance with the prescribed formula in the Market Rules rather than being competitively determined in the market. The amount of excess capacity, i.e. capacity that has been procured by the IMO in excess of the capacity requirement of the market, has been significant and this has consequently imposed a significant cost on the market.

As discussed in section 1.4, for the 2012 Minister's Report, the Authority intends to mainly focus on issues surrounding the operation of the capacity market of the WEM. Hence, this discussion paper focuses mainly on the following issues:

- The role of Reserve Capacity Auctions.
- Capacity Credits assigned by the IMO.
- Responsiveness of the Reserve Capacity Price to market conditions.
- Treating Demand Side Management (**DSM**) as a separate product/service.
- Incentives for plant availability and retirement of inefficient plant.

Other operational issues that the Authority intends to discuss and seek comments from stakeholders are:

- Competition in the load following ancillary service (**LFAS**) market.
- Information transparency and accessibility.

The above issues will be discussed in more detail in the following sections.

3.1 Operation of the Reserve Capacity Mechanism

As illustrated in Figure 1, the current market design has continuously resulted in more supply capacity than has been required to maintain a secure electricity system, leading to inefficient over-investment in supply capacity and higher costs to consumers. This outcome was not envisaged at the time when the original Market Rules were established in 2006.

3.1.1 The capacity market as originally intended

The original intention was that the market design would include a capacity market to ensure that sufficient capacity is procured to meet a level of projected demand determined by the

IMO. The aim of the capacity mechanism is to ensure the SWIS can be self sufficient in times of peak demand or an emergency as it cannot rely on supply from the National Electricity Market (**NEM**) operating in the eastern states or other markets. The intent of having a separate capacity mechanism was also to mitigate high price spike events that occur in an energy only market from time to time and provide a market signal for new entry/investment.

The IMO is responsible for setting the capacity requirement two years ahead to meet projected peak demand plus a reserve margin and to limit expected energy shortfalls to 0.002 per cent of annual energy consumption.[23]

The projected peak demand, two years ahead, was to be a conservative estimate in that it was only likely to be exceeded if there was a one-in-ten year set of circumstances that caused demand to be unusually high.

The reserve margin above the projected peak demand was to be based on the aggregation of three components:

- An amount of capacity to protect against a situation where the largest generator in the system is not available to meet the peak demand, or an amount that is equal to 8.2 per cent of the projected peak demand whichever is larger.
- An amount of capacity to provide for the ability to deal with frequency fluctuations during the peak demand event (i.e. capacity for load following).
- An amount of capacity to provide for the risk that loads that normally have their own sources of supply might need to be supplied by the system (i.e. capacity for intermittent loads).

The IMO was to monitor the capacity available in the market that had been negotiated and contracted bilaterally among market participants and in the event that there was insufficient capacity identified two years ahead, the IMO was to operate an auction to procure the capacity shortfall.

The Market Rules are designed in a way that makes it clear to the IMO whether there would be insufficient capacity. This was achieved by allocating Capacity Credits to providers of capacity (either generators or demand side management) that meet certain pre-conditions.

The capacity certification process requires the IMO to satisfy itself that any facility assigned Capacity Credits will be able to meet its obligations and provide capacity when required. A market participant applying for capacity certification needs to provide the IMO with information such as details of its facility's capacity; evidence of network access arrangements; information on environmental approvals; evidence of contracted fuel supplies; information about the expected availability of the facility; and key project dates for new facilities.

Following the capacity certification process, a market participant holding certified capacity can obtain Capacity Credits in two ways: by declaring the capacity that would be traded bilaterally (i.e. the Bilateral Trade Declaration); or by participating in the Reserve Capacity Auction. Capacity Credits are tradable, i.e. they can be traded between market participants and with the IMO.

[23] The Planning Criterion that the IMO must use when setting the capacity requirement is defined in clause 4.5.9 of the Market Rules.

Capacity Credit holders are obliged to make that capacity available to the market for the relevant capacity year. In the event that the capacity is not made available, a penalty is applied (either a refund of the capacity payment or forfeiture of a security deposit).

Retailers, in aggregate, are obliged to procure capacity up to the amount deemed necessary by the IMO. Each retailer is allocated a capacity obligation based on its contribution to system peak demand.

In the event that retailers procured insufficient capacity to meet their capacity obligations, any shortfall would be allocated to them via the IMO capacity procurement at the prevailing capacity price. This price would be the price determined in an auction (if an auction occurs). When the market was designed, it was expected that retailers would have a preference to contract directly for capacity rather than risk an uncertain price resulting from an auction.

The Market Rules limited the price that could be set at an auction to a price based on the cost of a peaking generator connecting to the system. This cap on the price was intended to avoid any potential misuse of market power in the auction process.

The expectation was that the price of capacity would be predominantly determined through bilateral trading between market participants and that the price resulting from an auction or calculated by the IMO in the event that an auction was not held, would be an exception and not the norm.

This situation was expected to be similar to what would happen if there was no separate capacity market and all capacity was procured entirely with reference to an energy only market. The additional protection in the WA Wholesale Electricity Market was provided by way of a capacity auction in the event that insufficient capacity was procured.

3.1.2 The capacity market that eventuated

The Market Rules provided for more capacity to be credited than required. This was expected to occur in two circumstances: if retailers in aggregate procured more than necessary to meet their expected reserve capacity obligations; or if the IMO procured more at an auction than necessary due to the lumpiness of generation capacity.

When an auction was held, the clearing price of the auction would set the capacity price. In the event that no capacity auction was undertaken, the Market Rules provided for the IMO to calculate a price for capacity. This price was based on the maximum price that would be permitted under an auction. The Market Rules prescribed that the price for capacity in the absence of an auction would be calculated as 85 per cent of the maximum price in the event that the exact amount of reserve capacity is available to meet the capacity requirement determined by the IMO. If more reserve capacity has been credited than is required, the price would be further reduced to account for this (e.g. if 10 per cent more capacity is procured than is required, the maximum price would be adjusted by a further 91 per cent[24], i.e. 91 per cent * 85 per cent * maximum price). It is not clear, how or on what basis, the 85 per cent figure was originally derived.

However, the trading of Capacity Credits among market participants has not occurred to the extent originally envisaged. In its paper presented to the Market Advisory Committee (**MAC**), the Lantau Group reported that there has been a dramatic surge in Capacity Credits paid for by the IMO directly based on the calculated price (rather than being transacted

[24] Pursuant to clause 4.29.1, the adjustment factor is calculated as the ratio of the Reserve Capacity Requirement divided by the total Capacity Credits allocated. In the case that 10 per cent more capacity is procured than required, the ratio is RCR divided by 110 per cent of RCR, i.e. $1/1.1 \approx 0.91$ or 91 per cent.

between market participants under their bilateral contracts) and the percentage was over 50 per cent in late 2010[25] It is possible that this situation has arisen because some providers of capacity see the calculated capacity price as generous and have preferred to be funded with reference to the calculated capacity price rather than through bilateral negotiations. There could also be reluctance among market customers to contract if they consider the RCP to be high and could drop in later years. This may be particularly the case for peaking facilities because the capital cost of a peaking facility can be largely met by the calculated capacity price at the level the price has been set.[26] However, in the case of base load generators, the capital cost of the plant would not be covered by the calculated capacity price. Demand side management, on the other hand, would be attracted to enter the market with reference to the calculated capacity price given the relatively low upfront capital cost compared to peaking generators.

Under the original market design, the expectation was that suppliers of capacity would accurately declare to the IMO how much of their capacity is bilaterally traded and how much is not. The IMO requires this information to establish whether or not they will need to operate an auction to procure additional capacity in order to meet the capacity requirement.

However, it appears that providers of capacity have an incentive to declare that they have the intention to trade all of their capacity bilaterally and in doing so will receive guaranteed Capacity Credit allocation from the IMO. The provider is not obliged to provide any evidence to the IMO that it in fact has a bilateral contract for the amount of capacity that it has declared. In addition, there is no limit to the amount of Capacity Credits that the IMO can issue.

As a result, almost every MW of certified capacity is allocated a Capacity Credit by the IMO at the Bilateral Trade Declaration stage and consequently no Reserve Capacity Auction has been held since market commencement.[27] The number of Capacity Credits issued by the IMO has exceeded the Reserve Capacity Requirement in all years. This excess has ranged from 2.2 per cent (in the 2010/11 Capacity Year) to 14.6 per cent (in the 2013/14 Capacity Year) as shown in Table 2. This outcome was not envisaged when the market was established.

3.1.3 Implications

The operation of the RCM has been successful in ensuring adequate capacity is available to meet the capacity requirements of the market. It has also played a key role in facilitating investment in new capacity. There has been no incidence of the system being unable to meet demand because of a capacity shortage in the SWIS since the commencement of the RCM.

[25] The Lantau Group, "*Review of RCM: Issues and Recommendations*", presented at the Market Advisory Committee (MAC) meeting No. 43, held on 5 October 2011. See http://www.imowa.com.au/MAC_43. p.5.

[26] The calculated capacity price has been derived based on the MRCP which is determined with reference to a 160 MW open cycle gas turbine (OCGT) with a capacity factor of 2 per cent in accordance with the MRCP Market Procedure. In its report prepared for the Authority's inquiry into the efficiency of Synergy's costs and electricity tariffs (*LRMC of Regulated Tariffs – Final Report*, p.12), Frontier Economics listed the capital costs of various plant types. These capital costs, in 2011/12 real dollar, are $1,138 per kW for a typical open cycle gas turbine (OCGT) which will normally operate as mid-merit or peaking facility; $1,627 per kW for a typical combined cycle gas turbine (CCGT) which often operates as base-load facility; and $3,471 per kW for a small scale supercritical plant fuelled by black coal. See http://www.erawa.com.au/inquiries/efficiency-of-synergys-costs-and-electricity-tariffs/related-papers.

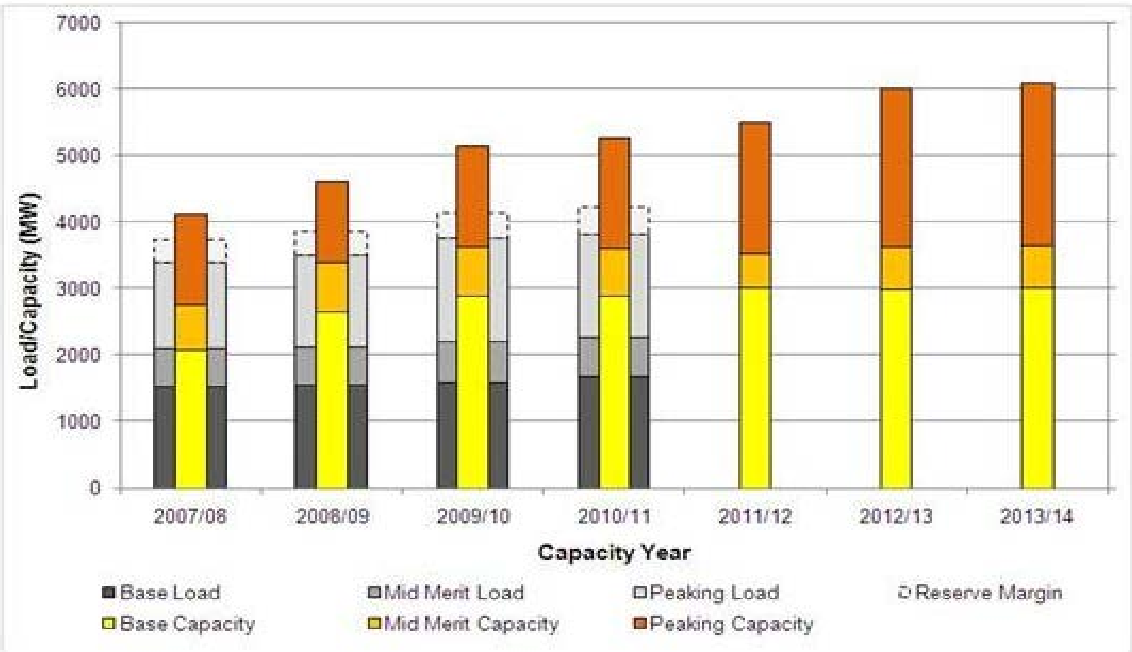
[27] A market participant with certified capacity may withdraw its capacity before the start of the Capacity Credits allocation process.

However, the Authority is concerned that the amount of excess capacity has been substantial and sustained in recent years. As shown in Table 2 below, the amount of Capacity Credits allocated by the IMO in excess of the Reserve Capacity Requirement (**RCR**) is 495 MW for the 2012/13 Capacity Year. This will increase to 775 MW for the 2013/14 Capacity Year and remain at 732 MW for the 2014/15 Capacity Year. This may indicate that the reserve capacity mechanism is not working effectively, leading to inefficient over-investment. The RCR is set in accordance with the Planning Criterion determined by the IMO under the Market Rules which has already included a reserve margin for contingencies. Capacity Credits procured in excess of the RCR will be capacity that is not required by the market.

The Authority is concerned about the cost of excess capacity to the market, which is eventually borne by consumers. The cost implications to consumers will be discussed in more detail in section 3.1.3.1.

Furthermore, the Authority is concerned about the type of capacity that has been attracted to the market in recent years. Figure 10 below is an extract from the IMO's 2012 Statement of Opportunities (**SOO**) report.[28] It shows that there has been a substantial increase in peaking capacity from 2010/11 to 2013/14, attributable to the entry of a large volume of DSM capacity and investment in liquid-fuelled generation capacity.

Figure 10: SWIS Load Characteristics and Capacity Mix



The Authority considers that a well functioning market mechanism is essential for providing efficient investment signals and promoting investment in efficient technologies. Section 3.1.3.2 provides further discussion on this point.

[28] IMO, 2012 SOO, p. 26. "Base load has been defined as the level of demand that is exceeded for 75% of the year, mid-merit load as the additional load that is exceeded for 25% of the year and peaking load is the level of demand that is only present for less than 25% of the time. The available capacity is similarly classified according to the amount of time that each facility is operated."

3.1.3.1 *Cost of excess capacity to consumers*

Excess capacity is capacity that is not required for the efficient operation of the market. The costs associated with excess capacity are inefficient costs which are paid by the market. Under the Market Rules, each MW of excess capacity is paid at the calculated capacity price as defined above. Hence, the direct cost of excess capacity to consumers can be calculated by multiplying the amount of excess capacity by the prevailing capacity price. This is shown in Table 2 as the product of column (A) (excess Capacity Credits) and column (B) (calculated capacity price). The direct cost of excess capacity in the 2010/11 Capacity Year was $40 million. This will increase to $138 million in the 2013/14 Capacity Year.

Table 2: Excess Capacity Credits assigned to Market Participants

Period	Reserve Capacity Requirement MW	Capacity Credits Assigned MW	Excess Capacity Credits MW (A)	Excess Capacity Credits %	Calculated capacity price ($/MWh) (B)	Direct Cost of Excess Capacity Credits $ million (A*B)
01/10/07 to 01/10/08	4,000	4,115	115	2.9%	$127,500	15
01/10/08 to 01/10/09	4,322	4,600	278	6.4%	$97,835	27
01/10/09 to 01/10/10	4,609	5,136	527	11.4%	$108,459	57
01/10/10 to 01/10/11	5,146	5,259	113	2.2%	$144,235	16
01/10/11 to 01/10/12	5,191	5,493	302	5.8%	$131,805	40
01/10/12 to 01/10/13	5,501	5,996	495	9.0%	$186,001	92
01/10/13 to 01/10/14	5,312	6,087	775	14.6%	$178,477	138
01/10/14 to 01/10/15	5,308	6,040	732	13.8%	$122,427	90
Average			**417**	**8.3%**		

Under the Market Rules, Capacity Credits procured by the IMO are funded by Market Customers. Each Market Customer is assigned a capacity obligation based on its contribution to system maximum demand. The total obligations assigned to Market Customers match the RCR. A Market Customer who does not hold enough Capacity Credits through bilateral trade to meet its obligation will be required to pay the IMO for its Capacity Credits shortfall.

The IMO also recovers the cost of excess Capacity Credits that it has acquired above the RCR from Market Customers (in proportion to their capacity obligations). The magnitude of this cost charged directly to Market Customers is shown in column (A*B) in Table 2 above.

As explained previously in section 3.1.2, the formula for calculating the capacity price in the Market Rules includes an adjustment to scale down the price if more Capacity Credits are assigned by the IMO than what is required.[29] The effect of this reduced price, however, is diluted by the bilaterally traded Capacity Credits. The reduced capacity price is not applicable to the total Capacity Credits but only those paid through the IMO in meeting the RCR as well as the excess over the RCR. Hence, the cost impact of excess capacity comes in two directions: a reduction in the cost of the Capacity Credits paid through the IMO in

[29] The Excess Capacity Adjustment is calculated as RCR divided by total Capacity Credits assigned. When the total Capacity Credits allocated by the IMO is greater than the RCR, the Excess Capacity Adjustment will be less than 1. Hence it reduces the calculated RCP value.

meeting the RCR; and an additional cost for the excess amount of Capacity Credits over the RCR.[30]

Leaving aside the direct cost impact to Market Customers, the existence of persistent excess capacity in the market indicates an inefficient utilisation of resources to the economy as a whole. The associated costs must be paid by some parties, i.e. either the shareholders of Market Generators via a lower return on investment or Market Customers or retailers who then pass the cost through to consumers in the form of higher electricity prices.

In its inquiry into the Efficiency of Synergy's Costs and Electricity Tariffs, the Authority has acknowledged that Synergy cannot avoid the cost impost due to the excess capacity presented in the market and recommended that the efficient cost reflective retail price be increased to reflect this cost.[31]

3.1.3.2 *Sub-optimal plant mix*

The Market Objectives include the economically efficient production and supply of electricity. This will require the use of the most efficient plant mix to meet demand, characterised by the load duration curve.

Generation plant varies in size, technology, efficiency, fuel type and cost. For example, base-load plant generally comes in a relatively larger size and higher upfront capital investment but with relatively higher efficiency and lower operating cost. On the other hand, peaking plant generally requires less upfront capital investment but higher operating costs.

Investment incentives for a particular type of plant are influenced by a range of factors, including market related factors and factors that are outside the market, such as government policies and decisions, e.g., the Renewable Energy Target Scheme, etc.

The Authority has observed the types of supply capacity that have been attracted to the market over recent years and is concerned about how this trend may affect the efficiency of the market in delivering the economically least cost electricity supply options to consumers.

Demand Side Management

There has been a rapid increase in Capacity Credits allocated to DSM providers over recent years as shown in Table 3 below. Table 3 also shows the proportion of Capacity Credits allocated to DSM providers and the implied value (payment) of the Capacity Credits provided by DSM providers based on the prevailing RCP. According to the 2012 SOO report published by the IMO, the level of DSM is thought to be approaching saturation with DSM penetration reaching similar levels to other mature jurisdictions and growth in DSM is anticipated to slow.

[30] This net impact can be illustrated as follows. For the 2011/12 Capacity Year, the RCR is 5,191 MW and the number of Capacity Credits assigned by the IMO is 5,493 MW (refer to Table 2). The excess Capacity Credits procured is 302 MW and the associated cost of excess capacity is $40 million at the prevailing RCP of $131,805 per MW per year (refer to Table 1). The MRCP for the 2011/12 Capacity Year is $164,100 per MW per year. The RCP would have been $139,485 per MW per year if no excess Capacity Credits were allocated. Assuming 50 per cent of the RCR is settled bilaterally among Market Participants, the number of Capacity Credits up to the RCR that will be paid through the IMO is 2,596 MW. The price reduction due to the presence of excess capacity in this component can be calculated as 2,596 MW x ($139,485/MW – $131,805/MW) ≈ $20 million. This benefit is much smaller compared to the direct cost of excess capacity (i.e. $40 million). Hence, under the current market arrangement which is dominated by bilateral contracts, excess capacity represents a net cost to retailers, leading to higher costs to consumers.

[31] ERA, *Synergy's Costs and Electricity Tariffs, Final Report*, p.56.

Table 3: Capacity Credits allocated to Demand Side Management providers

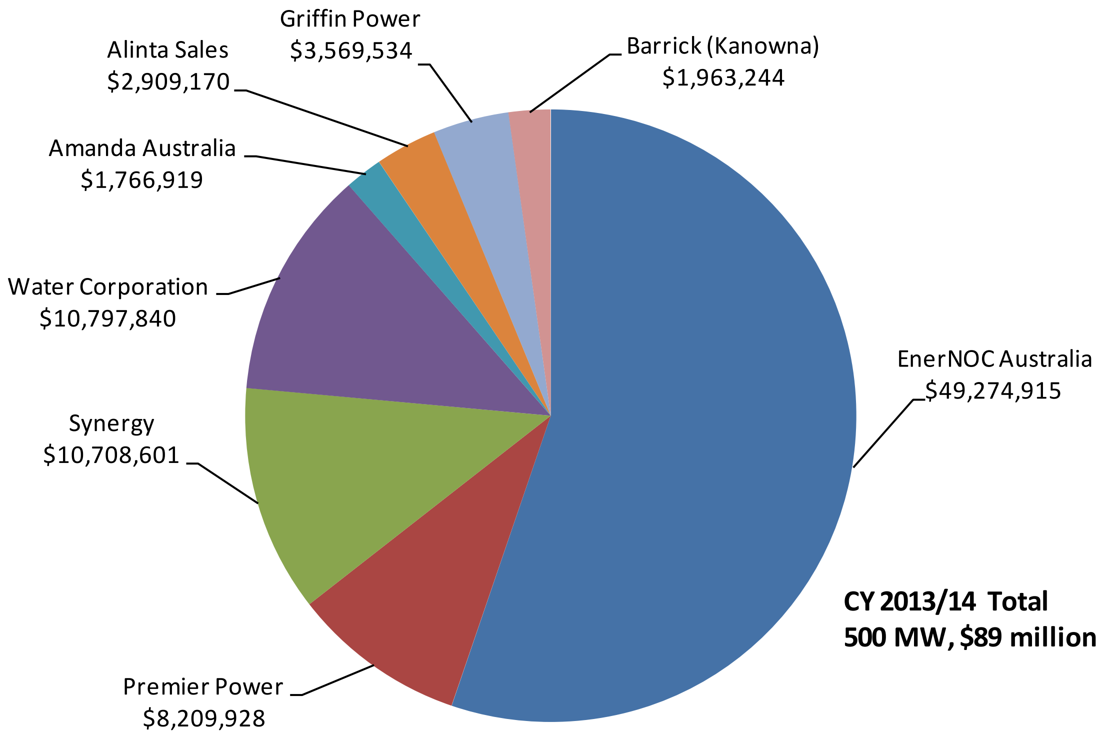
Period	Capacity Credits allocated to DSM	Proportion of total Capacity Credits provided by DSM	Implied value of Capacity Credits provided by DSM ($ million per year)*
21/09/06 to 01/10/06	111	3.14%	
01/10/06 to 01/10/07	111	2.96%	14
01/10/07 to 01/10/08	131	3.18%	17
01/10/08 to 01/10/09	128	2.78%	13
01/10/09 to 01/10/10	99	1.92%	11
01/10/10 to 01/10/11	154	2.92%	22
01/10/11 to 01/10/12	260	4.73%	34
01/10/12 to 01/10/13	454	7.58%	85
01/10/13 to 01/10/14	500	8.21%	89
01/10/14 to 01/10/15	524	8.67%	64

* This implied value is calculated as Capacity Credits allocated to DSM multiplied by the prevailing Reserve Capacity Price for the relevant Capacity Year.

As can be seen from Table 3, the cost to the market for procuring DSM capacity is significant, up to $89 million in 2013/14.

Figure 11 provides a breakdown of the share of DSM providers. EnerNOC Australia has become the dominant DSM provider since its entry to the market in 2009. EnerNOC Australia was allocated 90 MW of Capacity Credits for its DSM capacity for the 2011/12 Capacity Year (worth approximately $12 million). The rapid growth of EnerNOC Australia in providing DSM capacity will see it taking on more than 50 per cent of the total DSM capacity for the 2013/14 Capacity Year, with total allocated Capacity Credits of 276 MW, worth close to $50 million.

Figure 11: **Share of DSM providers in the 2013/14 Capacity Year**



In its previous Minister's Reports, the Authority raised its concerns about the value provided and the payment received by DSM when the market has already carried a substantial amount of excess capacity from scheduled generators. The Authority recommended that the treatment of DSM in the WEM should be reviewed by the RCMWG and that the Public Utilities Office should be involved in the working group and ensure that the outcome of the working group is consistent with broader energy market policy. The Authority also recommended that the working group's consideration of the treatment of DSM should consider the merits of models adopted in other jurisdictions, including the option of changing the payment received by DSM to reflect the value provided by DSM.

Peaking Capacity

Due to the provision of a separate capacity mechanism, i.e. the RCM, the WEM provides a greater incentive to new entry of capacity into the market, in particular, peaking capacity, in comparison to an energy only market. This is because capacity providers receive a secure income stream from capacity payments. This mechanism has worked in securing sufficient investment in supply capacity for meeting the capacity requirement in the WEM. However, the types of peaking capacity that have been attracted to the WEM in recent years have caused some concern to the Authority and the associated cost implications to consumers as consumers pay the total cost of capacity and energy. Whilst the upfront capital costs are cheaper for peaking facilities in comparison to base-load facilitates, the energy costs are likely to be higher due to differences in thermal efficiency and fuel types.

Peaking facilities that entered the market, driven in part by the reserve capacity mechanism, include:

1. NewGen's Neerabup gas fired unit (330 MW) in 2009
2. Tesla's distillate units at various locations (4 x 9.9 MW) in 2011 and 2012

3. Western Energy's Kwinana Swift units, which can be fired on both gas and distillate (4 x 27 MW) in 2010
4. Merredin Energy's distillate units (2 x 41 MW) in 2012

NewGen's Neerabup facility and Western Energy's Kwinana Swift units have been grouped as peaking plant as these facilities are believed to have no firm, long-term gas contracts in place. As a result, they often bid into the market at or close to the maximum energy prices.

In addition to the above listed investment from the private sector, the State Government has also contributed to new additions of capacity through its trading entity, Verve Energy. Verve Energy invested in two high efficiency gas turbine (**HEGT**) units (2 x 95.2 MW) at the Kwinana power station to replace retired facilities at the same site. These two HEGT units were commissioned in October 2012. In a joint venture with Inalco, Verve Energy also refurbished Muja A and B (4 x 55 MW coal fired units), which are expected to be commissioned in December 2012. The refurbishment of the Muja A and B units was partly motivated by fuel supply security considerations to reduce gas dependence by the State Government. According to Verve Energy, these units will operate as mid-merit peaking plant with a ten to 15 year lifespan.[32]

It is noteworthy that the IMO's 2012 SOO report has highlighted the substantial investment in peaking capacity in recent years in comparison to the rate of growth of the peaking load observed in the system (shown previously in Figure 10). This also contrasts considerably with the continuing limited contribution of mid-merit capacity to the capacity mix.[33]

Retention of inefficient plant

The decision to refurbish the Muja A and B coal fired units, which were well over 40 years old and were mothballed in April 2007, has raised questions in regard to whether the current reserve capacity mechanism could result in inefficient generating units being kept on the system past normal retirement age.

In its 2011 Minister's Report, the Authority highlighted a number of facilities from Verve Energy that had extremely high Planned Outage rates in the 2010/11 Capacity Year. These facilitates include:

- Kwinana G5 (174 MW), which was commissioned in 1976 and can be fired on coal, gas or oil, had a Planned Outage rate of 53.6 per cent;
- Kwinana G6 (174 MW), which was commissioned in 1978 and can be fired on coal, gas or oil, had a Planned Outage rate of 49.6 per cent; and
- Muja G7 (211 MW), which was commissioned in 1980 and is a coal-fired generation plant, had a Planned Outage rate of 42.7 per cent.

The above Planned Outage rates can be compared to industry standard Planned Outage rates of between 3 per cent to 6 per cent for coal-fired generation, between 3.5 per cent to 4 per cent of open cycle gas turbine, and between 1.5 per cent to 6.5 per cent of open cycle gas turbine in the Australian Energy Market Operator's (**AEMO**) National Transmission Network Development Plan.[34]

[32] Refer to Verve Energy website: http://www.verveenergy.com.au/projects/more-projects.

[33] Refer to Figure 11 'SWIS Load Characteristics and Capacity Mix' (pp. 21) http://www.imowa.com.au/f176,2338348/2012_SOO_rev0.pdf

[34] Refer to AEMO website: http://www.aemo.com.au/Electricity/Planning/Reports/National-Transmission-Network-Development-Plan/Overview

It is worth noting that these facilities received full capacity payments whilst they were unavailable for extended periods on Planned Outage.

Kwinana G5 and Kwinana G6 facilities are also known as Kwinana Stage C. In its 2012 SOO report, the IMO has anticipated the decommissioning of Verve Energy's Kwinana Stage C facilities for the 2016/17 Capacity Year but indicates that the timing of this retirement is subject to a commercial decision by Verve Energy. At the current level of the RCP, it is possible that the capacity payment may be attractive for keeping these facilities in the system.

3.2 Issues

The Authority is particularly interested in submissions from stakeholders in regard to whether the Market Rules need to be changed to:

- increase the role of reserve capacity auctions;
- limit the amount of Capacity Credits issued by the IMO to the RCR;
- adjust the calculated price in a way that is more reflective of market conditions;
- treat DSM as a separate product/service; and
- increase incentives for plant availability and ensure appropriate incentives for retirement of inefficient plant.

The following sections address these issues.

3.2.1 Role of reserve capacity auctions

The Reserve Capacity Auction provision in the Market Rules allows the IMO to procure any capacity shortfall between the RCR and the bilaterally traded capacity via a competitive tender process. However, this provision has not been triggered since the commencement of the market.

As explained previously, only holders of Capacity Credits will receive payments from a bilateral counterparty or the IMO. There are two ways for a capacity provider to receive Capacity Credits from the IMO: by lodging its intention to bilaterally trade its capacity through the Bilateral Trade Declaration process (which is not binding); or by offering its capacity into an auction. Capacity that has been lodged for bilateral trade will receive guaranteed Capacity Credits from the IMO. However, capacity that has been offered into an auction will be granted Capacity Credits only if an auction is held and the capacity is cleared in the auction. Hence there is a risk of not receiving any Capacity Credits if a capacity provider decides to put its capacity into an auction.

At the current level of excess capacity, the possibility for a Reserve Capacity Auction is very low. Under this circumstance, a capacity provider receives more certainty by declaring its intention to bilaterally trade its capacity rather than to take the risk of offering it into an auction which may not occur. The ongoing incentive for this behaviour further reduces the possibility for an auction to be held. Unless there is external intervention, this pattern is likely to continue.

The Authority is interested in stakeholders' views on how the Market Rules may be improved so that a Reserve Capacity Auction can be used by the IMO for the procurement of any capacity shortfall in meeting the RCR and whether the Bilateral Trade Declaration of capacity should be made as a binding commitment between Market Participants similar to the Bilateral Submission in the energy market of the WEM.

Discussion Point 1

Stakeholders are invited to comment on how the Market Rules may be improved so that the Reserve Capacity Auction provision can be utilised by the IMO for the procurement of any capacity shortfall in meeting the Reserve Capacity Requirement and whether the Bilateral Trade Declaration of capacity should be made as a binding commitment between Market Participants similar to the Bilateral Submission in the energy market of the WEM.

3.2.2 Capacity Credits assigned by the IMO

There is currently no ceiling on the amount of Capacity Credits that the IMO can allocate to capacity providers. There is also no limit on the costs of Capacity Credits procured by the IMO beyond the RCR that the IMO charges to retailers.

Under the Market Rules, the RCR is set in accordance with the Planning Criterion which has already included a reserve margin for contingencies. Capacity Credits procured in excess of the RCR will be capacity that is not required by the market in accordance with the Planning Criterion. This excess represents an inefficient over-investment.

The Authority invites stakeholders to comment on the current market design that sets no limit on the amount of Capacity Credits that the IMO can procure in excess of the RCR and the associated costs that the IMO charges to Market Customers.

Discussion Point 2

Stakeholders are invited to comment on whether there should be a limit set for the number of Capacity Credits that the IMO can procure in excess of the Reserve Capacity Requirement and, if so, on what basis this limit should be determined.

3.2.3 Responsiveness of Reserve Capacity Price to market conditions

Under the Market Rules, when no Reserve Capacity Auction is held, the Reserve Capacity Price will be determined in accordance with a defined formula. The formula includes an adjustment, i.e. the Excess Capacity Adjustment to scale down the price if more Capacity Credits are assigned by the IMO than what is required. The RCP in this case is determined, per its design, by spreading the 'theoretical' total cost of the required Capacity Credits over the number of Capacity Credits that have actually been assigned. The 'theoretical' total cost of the required Capacity Credits is calculated as 85 per cent of the MRCP times the Reserve Capacity Requirement.

Since no Reserve Capacity Auction has ever been held in the market, the RCP value has been calculated administratively using this formula from the MRCP. This price setting mechanism does not capture the workings of an effective capacity market. In such a market, excess capacity would be worth little and the capacity price will rise when capacity is in short supply. It is arguable whether this calculation sets a fair cost benchmark of the required Capacity Credits under all market conditions. The Authority considers that the lack of appropriate price signals to encourage efficient investment could be a contributor to the substantial excess capacity situation in the market.

The Authority seeks comments from stakeholders on the effectiveness of the Reserve Capacity Price that has been set using the administrative formula in the Market Rules with reference to the MRCP and the Excess Capacity Adjustment.

Discussion Point 3

Stakeholders are invited to comment on the effectiveness of the Reserve Capacity Price that has been set using the administrative formula with reference to the Maximum Reserve Capacity Price and the Excess Capacity Adjustment and whether an alternative calculation formula should be explored.

The Authority is aware of the work program that has been undertaken by the Reserve Capacity Mechanism Working Group (**RCMWG**) which was formed under the Market Advisory Committee (**MAC**), led by the IMO. The Authority is also aware of Lantau's recommendation to the RCMWG for changing the capacity price calculation formula in the Market Rules so the price can be more sensitive to excess capacity.[35] Lantau proposed to relate the capacity price to excess capacity using a greater negative slope than the current slope of negative 1, starting with an initial value of negative 3.25. Lantau also proposed to change the 85 per cent multiplier to MRCP to 110 per cent to align incentives more symmetrically for balanced risk management. Lautau did not recommend that a capacity auction should be held, citing that it would add complexity to the WEM as a small lumpy market and would introduce further volatility and risk.[36]

The Authority understands that this proposal will produce a higher capacity price than that under the existing Market Rules until the excess capacity reaches more than 15 per cent. Given the current level of excess capacity in the market (i.e. 13.8 per cent for the 2014/15 Capacity Year) is unlikely to reduce significantly in the short term, this will result in a higher cost of excess capacity that will be passed through to electricity consumers.

The Authority seeks comments from stakeholders on Lantau's proposal for changing the RCP formula in the Market Rules to make the capacity price more responsive to market conditions.

Discussion Point 4

Stakeholders are invited to comment on Lantau's proposal for changing the Reserve Capacity Price calculation formula in the Market Rules.

3.2.4 Treating DSM as a separate product/service

Since market commencement, DSM capacity has been dispatched only a limited number of times. These events are summarised in Table 4 below. DSM was dispatched in January 2008 and in February 2011 when gas supply was significantly disrupted due to extreme circumstances.

[35] Refer to IMO website: http://www.imowa.com.au/RCMWG.

[36] The Lantau Group Presentation to the RCMWG meeting no. 8 held on 11 October 2012. http://www.imowa.com.au/f5415,2873740/IMO_RCM_October_WG_to_IMO_Updated.pdf

Table 4: Summary of events when DSM capacity was dispatched[37]

Date	Duration	Maximum MW Dispatched	Reason
22/11/2007	4pm - 8pm	11	Not clear
3/01/2008	11am - 5:30pm	60	Emergency state due to severe gas curtailment
24/01/2008	11am - 5:00pm	53	Not clear
24/02/2011	12pm - 8pm	121	Gas supply disruption due to tropical Cyclone Carlos forced temporary closure of the Varanus Island gas processing plant
25/02/2011	12pm - 8pm	117	
26/02/2011	12pm - 8pm	50	
28/02/2011	12pm - 8pm	117	

The Authority notes that no DSM was dispatched during the 2011/12 Capacity Year. Whilst excess capacity in the market totalled more than 300 MW in the year, the market paid $34 million for 260 MW of DSM.

The Authority considers that the efficient use of DSM can provide benefits to the market in reducing system peak demand and the required investment in generation and network capacity for meeting the peak demand. DSM can also provide a valuable alternative when the power system security is under threat due to fuel shortages.

Under the current Market Rules, DSM capacity is treated as equal in value as generation capacity despite their differences in availabilities. There are certain limitations provided for DSM with regard to the number of times each year that the DSM capacity can be called on and the number of hours that can be used when DSM capacity is called.

In its 2011 Minister's Report, the Authority recommended that the treatment of DSM in the WEM should be reviewed, with consideration of the merits of alternative models adopted in other jurisdictions, including the option of changing the payment received by DSM to reflect the value provided by DSM.

In its submission to the Authority's discussion paper for the preparation of the 2011 Minister's Report, Synergy argued that DSM has a function in the market not because it can operate like a peaking generator but because it can provide a cheaper source of capacity to meet the top few hours of peak demand in the load duration curve. Hence, an alternative approach would be to recognise the unique role of DSM and construct pricing and performance expectations which allow DSM to continue operating in a limited way. This could be achieved by setting a pricing structure with a lower fixed payment for capacity availability and a higher dispatch payment to reflect the foregone production revenue when DSM capacity is called.

The Authority seeks comments from stakeholders on the value provided by DSM under the current market design and the cost of DSM to the market. The Authority is also interested in stakeholders' views on whether DSM should be treated as a separate product or service in the context of the WEM and whether this could provide a more cost effective way for the efficient use of DSM.

[37] Information in the table is sourced from the IMO.

Discussion Point 5

The Authority invites stakeholders to comment on the value provided by DSM under the current market design and the cost of DSM to the market. The Authority also invites stakeholders to comment on whether alternative treatments of DSM could provide a more cost effective way for the efficient use of DSM.

3.2.5 Incentives for plant availability and retirement of inefficient plant

Under the Market Rules, facilities that are allocated with Capacity Credits must satisfy the Reserve Capacity Obligations and the IMO has a responsibility to monitor this compliance. Under clause 4.11.1(h) of the Market Rules, the IMO may decide not to certify a Market Generator's capacity if it believes that the facility is not likely to be available. Under clause 4.27 of the Market Rules, the IMO may impose conditions on planned outages.

IMO's discretion on Reserve Capacity Certification

Under clause 4.11.1(h) of the Market Rules, the IMO may decide not to assign Certified Capacity to a facility if it has operated for at least 36 months, and has had a poor availability record. The criteria are a forced outage rate of greater than 15 per cent or a combined planned and forced outage rate of greater than 30 per cent over the preceding 36 months.

There is, however, some difficulty for the IMO in exercising its discretion under clause 4.11.1(h) of the Market Rules. One question is whether it is appropriate to use the past outage rate to predict a facility's availability in future years for the purpose of capacity certification. A likely claim on the part of the capacity provider could be that past outages enabled maintenance and enhancement work that would bring about higher availability in the future. It would require an engineering expert to make such a judgement and even then the expert could be challenged by other experts in the field before the IMO could reach its conclusion.

Given the difficulty for the IMO in exercising its discretion under clause 4.11.1(h) of the Market Rules, one approach could be to remove the discretion and substitute it with some pre-determined adjustment to reflect the recorded outage rates over the preceding three years. This would incentivise the capacity provider to take its availability record into consideration in its outage planning and investment planning.

The Authority invites stakeholders to comment on how the effectiveness of clause 4.11.1(h) of the Market Rules can be improved.

Discussion Point 6

Stakeholders are invited to comment on the application of clause 4.11.1(h) of the Market Rules and any appropriate modification that may be required to improve its effectiveness.

IMO's discretion to seek explanation on extended Planned Outage

Pursuant to clause 4.27 of the Market Rules, the IMO is required to monitor Planned Outages undertaken by Market Generators only when the resulting system availability is dropped to a certain threshold as defined under clause 4.27 of the Market Rules.[38] Hence, a facility with a poor availability record, e.g. on Planned Outage for extended periods of time, may not be called to explain its availability problems if the system availability threshold is not reached.

In its 2011 Minister's Report, the Authority raised its concerns that the high Planned Outage rate observed in the market may indicate an issue with the incentives for plant availability provided by the market, leading to negative consequences for energy price outcomes in the market. The Authority considered that the threshold for the IMO's monitoring of individual plant availability under clause 4.27 of the Market Rules could be set too high and that this issue should be examined fully. The Authority recommended that the incentives for plant availability created by the inter-relationship between the RCM and the Reserve Capacity Refund payments should be reviewed by the RCMWG.

The Authority is interested in stakeholders' views and comments on the provisions of clause 4.27 of the Market Rules and how the incentives for plant availability may be improved.

Discussion Point 7

Stakeholders are invited to comment on the provisions of clause 4.27 of the Market Rules and whether the incentives for plant availability could be improved.

Retirement of inefficient plant

As discussed previously in section 3.1.4, the Authority has observed a number of generation facilities on the system with poor availability performance. These facilities received full capacity payments whilst they were unavailable to the market, i.e. on Planned Outage, for extended periods of time. This has led to the question of whether the capacity payment under the RCM has contributed to delaying retirement of some plant with poor availability performance. It also raises the question of whether this is an efficient market outcome.

In an energy only market, this situation is unlikely to occur as availability will be a key factor for a generator to make a return on its investment. A plant with poor availability is more likely to be retired on economic terms.

The Authority invites stakeholders to comment on whether the current market design provides incentives for retention of inefficient plant in the system past its retirement age.

[38] Clause 4.27 of the Market Rules outlines the role of the IMO in monitoring Reserve Capacity performance, with the total availability of capacity on a particular day measured in terms of the total Capacity Credits held by Market Participants on that day, less the maximum amount of capacity unavailable due to Planned Outages. The IMO must assess, by the 25th day of each month, the number of days in the preceding 12 calendar months, where the total available capacity in the SWIS has dropped below 80% (in the Hot Season), and 70% (in either the Intermediate or Cold Season), of the total Capacity Credits held by Market Participants, for more than six hours on the day.

If the maximum amount of capacity unavailable due to Planned Outages has exceeded the above threshold for more than 40 days, the IMO must require reports to be filed by Market Participants for each facility that has been unavailable due to planned outages for more than 1000 hours during the past 12 calendar months.[38] The report must include explanations of all Planned Outages in the preceding 12 months, a statement of the expected maximum number of days of Planned Outages to be taken by the facility in each of the next 24 months (with explanations), and proposed measures for increasing the availability of the facility.

The IMO must then consult with System Management on the implications of the report. If the IMO considers that the maximum expected number of days that the facility will be on Planned Outage in the ensuing 24 months is unjustified, it may, at its sole discretion, limit the number of days that the facility can have Planned Outages in each of those 24 months. In such a case, the IMO's determination as to whether extended periods of Planned Outage are justified is to be based on "good industry practice" (Market Rules pp. 244).

Discussion Point 8

Stakeholders are invited to comment on whether the current market design provides appropriate incentives for retirement of inefficient generating units.

3.3 Other Issues

3.3.1 Competition in the LFAS market

The market for LFAS commenced on 1 July 2012. However, no LFAS submissions were made by Market Participants other than Verve Energy as at the end of September 2012. Hence, Verve Energy continued to be the sole provider of LFAS. The Authority understands that one constraint for new entrants to the LFAS market was due to the process issues surrounding the connection requirements for the Automatic Generation Control (AGC) whilst System Management was working through the exact technical requirements and the contractual operating arrangements to cover its legal liabilities. These process issues were largely resolved in October 2012, allowing some Market Participants to complete modifications to their control system in accordance with the required specifications and trial LFAS submissions via the market interface.

In its market debrief held on 21 September 2012, the IMO highlighted the LFAS cost in July 2012 totalled $6.6 million, which represented a sixfold increase compared to the previous monthly LFAS cost. The IMO also reported an increase of LFAS cost in August 2012 to $7.4 million at its market debrief held on 19 October 2012.

The Authority considers one explanation for the LFAS cost increase is that the LFAS market clears on the pricing of the marginal unit whilst the previous mechanism is based on the total cost differential between two scenarios, one with LFAS by the provider and another without LFAS by the provider, which is then converted to an average pricing formula. It is expected that the implementation of the new LFAS market will result in an increase in payment for LFAS due to the change in the pricing mechanism. However, whether the quantum of six to seven times increase is justified will require further investigation.

Due to the lack of competition observed so far in the LFAS market, the Authority considers the effectiveness of the IMO's monitoring regime becomes more important for providing confidence to the market. The Authority invites comments from stakeholders on issues associated with the operation of the LFAS market.

Discussion Point 9

Stakeholders are invited to comment on issues that are impacting on the efficient operation of the new LFAS market.

3.3.2 Information transparency and accessibility

Under clause 10.2.3(g) of the Market Rules, when assigning a confidentiality status to an item of information, the IMO must seek to maximise the number of parties that may view the information or document. This requirement promotes greater transparency in the market and facilitates a better understanding of the operation of the market. It also allows the market to self monitor some aspects of the market outcomes. At present, only the IMO and the Authority have access to all market information and documents. Other parties that can access this information include the Electricity Review Board and other regulatory or government agencies in accordance with applicable laws.

The Authority considers that in instances where there is no specific reason as to why certain information or documents are not to be classified as 'public', they should be classified as public in order to promote greater transparency in the market. Increased transparency will contribute to more efficient market operations and outcomes. Better access to market information will enable potential investors to be more informed about the market and facilitate their decision making and provide a more attractive environment for investment.

The Authority notes the improvement in regard to information transparency and accessibility as part of the implementation of the competitive balancing and LFAS market. The Authority also notes that the IMO is progressing its Rule Change Proposal (RC_2012_11) to add more transparency to the outage planning process.[39] These are positive developments in the market.

The Authority is seeking stakeholder feedback on any issues of information reliability, transparency and accessibility in the market, with particular regard to the suitability of the current audit process to meeting the Market Objectives. In particular, the Authority is interested in stakeholders' views with regard to whether the transparency and accessibility of information in the market presents a potential barrier to entry, and what, if any, improvements can be made in promoting more efficient market outcomes.

Discussion Point 10

Stakeholders are invited to comment on whether the current information regime under the Market Rules presents a potential barrier to entry and what, if any, improvements can be made in promoting more efficient market outcomes.

3.3.3 Other matters

The Authority has highlighted a number of issues that it intends to review as part of the 2012 Minister's Report. In addition, the Authority is required under the Market Rules to assess the effectiveness of the IMO and System Management in carrying out their functions under the regulations, the Market Rules and the Market Procedures.

The Authority is interested in stakeholders' views on the effectiveness of the IMO and System Management in the operation of the WEM. Further, the Authority is interested in stakeholders' views on the effectiveness of the Authority in its role in monitoring the effectiveness of the WEM.

Discussion Point 11

Stakeholders are invited to comment on how effective the IMO, System Management and the Authority have been in carrying out their respective functions in the WEM.

[39] The IMO is due to publish its final report on this Rule Change Proposal on 4 December 2012. For more detail, refer to http://www.imowa.com.au/RC_2012_11.

APPENDICES

Appendix 1 Acronyms

AEMO	Australian Energy Market Operator
AGC	Automatic Generation Control
CCGT	Combined Cycle Gas Turbine
DSM	Demand Side Management
HEGT	High Efficiency Gas Turbine
IMO	Independent Market Operator
IPP	Independent Power Producer
LFAS	Load Following Ancillary Service
MAC	Market Advisory Committee
MCAP	Marginal Cost Administered Price
MRCP	Maximum Reserve Capacity Price
NEM	National Electricity Market
OCGT	Open Cycle Gas Turbine
PUO	Public Utilities Office
RCM	Reserve Capacity Mechanism
RCMWG	Reserve Capacity Mechanism Working Group
RCP	Reserve Capacity Price
RCR	Reserve Capacity Requirement
SOO	Statement of Opportunities
STEM	Short Term Energy Market
SWIS	South West Interconnected System
WEM	Wholesale Electricity Market