Independent Market Operator

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Dear Rob

MARGIN VALUES PROPOSAL FOR 2012/13 FINANCIAL YEAR

The Independent Market Operator (IMO) is pleased to provide the Economic Regulation Authority (ERA) with its proposal for the values of the parameters Margin Peak and Margin Off-Peak (margin values), to apply under the new Balancing and Load Following Ancillary Services (LFAS) Markets during the Financial Year commencing 1 July 2012 (2012/13 Financial Year).

Under the current Wholesale Electricity Market Rules (Market Rules), the margin values are used in the calculation of availability payments to Verve Energy for the provision of LFAS and Spinning Reserve Service.

The Market Evolution Program (MEP) Rule Change Proposal: Competitive Balancing and Load Following Market (RC_2011_10) will introduce a competitive Market for the provision of LFAS in the Wholesale Electricity Market (WEM). These changes, which are expected to commence on 1 July 2012, will require the determination of new margin values, as the availability payments made to Verve Energy will no longer include compensation for the provision of LFAS.

To support the transition to the new market arrangements RC_2011_10 introduces a new clause 3.13.3AB, which prescribes the requirements for margin values to apply during the 2012/13 Financial Year. Clause 3.13.3AB states:

3.13.3AB. During the period:

(a) from 8:00 AM on the Balancing Market Commencement Day to 8:00 AM on 1 July 2013:

i. the Margin_Peak value is, subject to clause 3.13.3AB(b), the value determined by the Economic Regulation Authority and published on the Market Web Site; and

ii. the Margin_Off-Peak value is, subject to clause 3.13.3AB(b), the value determined by the Economic Regulation Authority and published on the Market Web Site;

(b) if the Economic Regulation Authority has not determined a Margin_Peak or Margin_Off-Peak value under clause 3.13.3AB(a) by 8:00 AM on the Balancing Market Commencement Day, then any such value is to be the value determined by the IMO

and published on the Market Web Site as soon as reasonably practicable after the Balancing Market Commencement Day;

(c) in determining values for Margin_Peak and Margin_Off-Peak under clause 3.13.3AB(a) the Economic Regulation Authority must undertake a public consultation process, which must include publishing an issues paper and issuing an invitation for public submissions;

(d) when determining a value for the parameter Margin_Peak under this clause 3.13.3AB the Economic Regulation Authority or the IMO, as applicable, must take account of

i. the margin Verve Energy could reasonably have been expected to earn on energy sales foregone due to the supply of Spinning Reserve during Peak Trading Intervals; and

ii. the loss in efficiency of Verve Energy Registered Facilities that System Management has scheduled to provide Spinning Reserve during Peak Trading Intervals that could reasonably be expected due to the scheduling of those reserves; and

(e) when determining a value for the parameter Margin_Off-Peak under this clause 3.13.3AB the Economic Regulation Authority or the IMO, as applicable, must take account of:

i. the margin Verve Energy could reasonably have been expected to earn on energy sales foregone due to the supply of Spinning Reserve during Off-Peak Trading Intervals; and

ii. the loss in efficiency of Verve Energy Registered Facilities that System Management has scheduled to provide Spinning Reserve during Off-Peak Trading Intervals that could reasonably be expected due to the scheduling of those reserves.

This proposal has been developed to assist the ERA with its determination under clause 3.13.3AB and to ensure consistency with the margin value determination process for other Financial Years. The IMO expects that the margin values presented in this submission are the values it would determine and publish on the Market Web Site, if required under clause 3.13.3AB(b).

Development of the margin values proposed in this submission

The IMO engaged Sinclair Knight Merz / McLennan Magasanik Associates (SKM MMA) to provide an independent assessment of the margin values for the 2012/13 Financial Year under the new market arrangements. SKM MMA's Final Report to the IMO is attached for your consideration. In accordance with the recommendations of this report, the IMO proposes the margin values for the 2012/13 Financial Year to be:

Margin Values	**Proposed (FY 2012/13)**	**Current (FY 2011/12)**	**FY 2012/13 (Non-MEP)**
Margin Peak	32%	25%	25%
Margin Off-Peak	31%	43%	32%
Estimated Annual Availability Cost	\$12.51 M	\$18.46 M	\$22.48 M

In its review, SKM MMA has re-applied the methodology it used in 2011 for the review of margin values for the 2012/13 Financial Year conducted under the current Market Rules (2011 review). SKM MMA's Final Report for the 2011 review was submitted to the ERA on 30 November 2011. The methodology has been modified to account for the introduction of the new competitive LFAS Market and its impact on Verve Energy availability payments. SKM MMA compared revenue and generation cost outcomes from two market simulations, one in which Spinning Reserve (excluding Interruptible Load) was provided by Verve Energy and the other in which no Spinning Reserve was provided. In each of the simulations LFAS was provided by Verve Energy and Independent Power Producers (IPPs) on a competitive basis, reflecting the introduction of the new LFAS Market under RC_2011_10.

In general, the modelling assumptions used in the study were based on the assumptions used for the 2011 review. However, some additional assumptions were required around the provision of LFAS by IPP Facilities. The IMO and SKM MMA undertook the following measures to develop the new assumptions and improve the quality of the existing assumptions.

- The IMO and SKM MMA consulted directly with System Management and five of the larger IPPs to develop baseline assumptions about the participation of IPP Facilities in the LFAS Market.
- SKM MMA prepared a draft Assumptions Report outlining the methodology and assumptions proposed for the review. The full (confidential) version of this report was reviewed by System Management and the IMO.
- A public version of the draft Assumptions Report, which excluded confidential Market Generator details, was published by the IMO on 23 January 2012. The IMO invited interested stakeholders to either request a meeting to consult directly with the IMO and SKM MMA or to provide written submissions on the report. No formal submissions were received during the consultation period, which closed on 10 February 2012. System Management and one Market Participant did however provide feedback on an informal basis, around likely LFAS entry dates and DBNGP average throughput.
- The IMO also requested feedback from six of the largest Market Generators on full extracts of the key assumptions for their Facilities. (Another Market Generator had provided an update on its Facility assumptions the previous month.) Three of the six Market Generators provided feedback on their Facility assumptions.
- SKM MMA used the feedback provided by stakeholders to update the input assumptions for the 2012 review.

Please call me on 9254 4333 if you have any queries or would like to discuss this further.

[redacted]

ALLAN DAWSON
CHIEF EXECUTIVE OFFICER

28 March 2012

Margin Peak and Margin Off-Peak Review 2012/13 – Market Evolution Program

FINAL REPORT TO IMO

- V3.0
- 26 March 2012

FINAL REPORT TO IMO

- V3.0
- 26 March 2012

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Contents

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V2.0	19th March 2012		N.Falcon	19th March 2012	Draft report incorporating suggested changes from IMO
V3.0	26th March 2012	N.Falcon	R.Gawler	26th March 2012	Final report

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Executive Summary

Under the current Wholesale Electricity Market Rules (Market Rules), the parameters Margin_Peak and Margin_Off-Peak (margin values) are used in the calculation of availability payments to Verve Energy for the provision of load following ancillary services (LFAS) and spinning reserve services.

As part of the Market Evolution Program (MEP), the Rule Change Proposal: Competitive Balancing and Load Following Market (RC_2011_10) proposes changes to the Market Rules relating to balancing and LFAS market arrangements[1]. These changes will impact on the choice of margin values to be used in calculating availability payments to Verve Energy, as availability payments will provide compensation for the provision of spinning reserve only and will no longer provide compensation for the provision of load following.

The Final Rule Change Report for RC_2011_10 was published on 23 February 2012 and the proposed amendments are expected to commence on 1 July 2012. To support the transition to the new markets RC_2011_10 includes a new clause 3.13.3AB, which outlines the requirements for the margin values for the 2012/13 financial year.

In preparation for the proposed MEP changes, the Independent Market Operator (IMO) engaged SKM MMA to undertake market modelling of the Wholesale Electricity Market (WEM) to assess the reserve availability cost and hence determine margin values for the 2012/13 financial year, under the assumption that the MEP changes commence on 1 July 2012.

In determining these margin values, the Market Rules require the IMO and the Economic Regulation Authority (ERA) to take into account the energy sales foregone and the generation efficiency losses that could reasonably be expected to be incurred by Verve Energy as a consequence of providing spinning reserve. These energy sales foregone and generation efficiency losses (reserve availability costs) may be incurred through:

- movement to a less efficient point on a unit's heat rate curve
- an increase in either production from higher cost Verve Energy plant or Short Term Energy Market (STEM) or Balancing Market purchases, to counteract lower cost generation backed off to provide reserve
- additional start-up costs that may be incurred due to commitment of additional units that would otherwise not have been required.

[1] http://www.imowa.com.au/RC_2011_10

The market modelling was undertaken using PLEXOS simulation software, which co-optimised energy and reserve provision to determine least-cost dispatch, treating the WEM as a gross pool market. Although bilateral trades, the STEM and Balancing Market were not modelled explicitly, the dispatch outcomes from simulation of a gross pool assuming short run marginal cost (SRMC) bidding should be equivalent to economically efficient WEM outcomes. Any discrepancies between the WEM and a PLEXOS market model are expected to be reduced by the introduction of the Balancing and LFAS Markets under RC_2011_10, as this will bring the WEM closer towards the dispatch and competitive behaviour that would be expected in a gross pool model of operation.

Prior to undertaking the modelling for the 2012/13 financial year, the market modelling approach was validated, and input assumptions verified, through comparison of the 2010/11 actual market outcomes against market modelling outcomes from the margin value review for the 2010/11 financial year, and through stakeholder review of the proposed assumptions and methodology. As a result, the following input assumption modifications have been adopted for the current review to improve the accuracy of the forecasts:

- Modify minimum generation levels, as advised by System Management
- Reduce gas price assumptions
- Increase the value of steam revenue assumed for cogeneration units
- Include any known large outages scheduled for the review period.

Additionally, the following key assumptions have been made:

- The price of cogeneration, Verve Energy, NewGen Kwinana and other IPP contracts gas were assumed to be \$2.64/GJ, \$3.09/GJ, \$3.09/GJ and \$4.12/GJ respectively for the 2012/13 financial year
- The price for new gas contracts was assumed to be \$6.18/GJ for the 2012/13 financial year
- A carbon price of \$23/t CO_2-e (nominal) was implemented for the 2012/13 financial year, equivalent to approximately \$22.1/t CO_2-e in real June 2011 dollars
- Approximately 30 MW of new Tesla diesel units were available from August 2012
- Two Merredin Energy distillate fired gas turbine peaking units (82 MW) were available from August 2012
- Muja 1-4, 60 MW coal units currently being recommissioned, were assumed to be fully operational by July 2012
- The 10 MW Greenough solar farm and the 13.8 MW Grasmere wind farm were both operational from August 2012, with the 55 MW Mumbida wind farm being available from December 2012

- Load following reserve requirement of ± 90 MW, to be provided by Verve Energy and two identified IPPs
- Ancillary Service contracts were assumed to provide spinning reserve capacity (from Interruptible Loads) of 42 MW
- Start-up costs incurred due to provision of reserve were included as part of the reserve availability cost.

To assess the reserve availability cost that could reasonably be expected to be incurred by Verve Energy for the 2012/13 financial year, revenue and generation cost outcomes were compared from two market simulations with and without spinning reserve provision. That is:

Availability cost = GenCost_Res – GenCost_NRP + (GenQ_NRP – GenQ_Res)*SMP

where:

GenCost_Res	= Verve Energy's total generation costs, including start-up costs, with spinning reserve provision
GenCost_NRP	= Verve Energy's total generation costs, including start-up costs, without any spinning reserve provision
GenQ_Res	= Verve Energy's total generation volume, with spinning reserve provision
GenQ_NRP	= Verve Energy's total generation volume, without any spinning reserve provision
SMP	= system marginal price with spinning reserve provision

In each of the simulations load following was provided by Verve Energy and Independent Power Producers on a competitive basis, reflecting the introduction of the new LFAS Market under RC_2011_10.

Having determined the reserve availability cost, average annual SR_Capacity_Peak and SR_Capacity_Off-Peak and System Marginal Price (SMP) through market simulations, the margin values were calculated by re-arranging the formula in clause 9.9.2(f) of the proposed new rules.

The resulting margin values proposed for the financial year commencing July 2012 are 32% for Margin_Peak and 31% for Margin_Off-Peak. Table 1 summarises the availability cost, SR_Capacity_Peak and SR_Capacity_Off-Peak, and peak and off-peak SMPs that form the basis for this assessment, averaged over 12 random outage samples.

■ **Table 1 Parameter estimates for 2012/13 financial year**

Parameter	Average	Standard Error
Margin_Off-Peak	31%	2.3%
Margin_Peak	32%	2.1%
SR_Capacity_Off-Peak	205.78	0.25
SR_Capacity_Peak	221.49	0.06
Availability cost ($M)	12.51	0.84
Off-peak price ($/MWh)	52.57	0.14
Peak price ($/MWh)	55.93	0.25

1. Introduction

As part of the Market Evolution Program (MEP), the Rule Change Proposal: Competitive Balancing and Load Following Market (RC_2011_10) proposes changes to the Wholesale Electricity Market Rules (Market Rules) relating to balancing and load following ancillary service (LFAS) market arrangements[2]. These changes will impact on the choice of margin values to be used in calculating availability payments to Verve Energy, as availability payments will provide compensation for the provision of spinning reserve only and will no longer provide compensation for the provision of load following.

The Final Rule Change Report for RC_2011_10 was published on 23 February 2012 and the proposed amendments are expected to commence on 1 July 2012.

The Independent Market Operator (IMO) has engaged SKM MMA to assist in determining the appropriate margin values to be applied for the 2012/13 financial year, under the assumption that the proposed MEP changes commence on 1 July 2012.

This report summarises the results of this analysis and outlines the key assumptions and methodology adopted in developing the proposed margin values.

All prices in this report are given in real June 2011 dollars.

[2] http://www.imowa.com.au/RC_2011_10

2. Methodology for calculating margin values

Load following and spinning reserve ancillary services for the Wholesale Electricity Market (WEM) are currently provided by Verve Energy[3]. The IMO pays Verve Energy for these services in accordance with the formula prescribed in clause 9.9.2(a) of the Market Rules. Under the changes proposed in RC_2011_10, Independent Power Producers (IPPs) will also be able to offer provision of load following services by bidding into the LFAS market. Load following providers will no longer be compensated through availability payments (for Verve Energy) or Ancillary Service Contract payments (for IPPs). Spinning reserve services will still be provided by Verve Energy, with payment determined in accordance with clause 9.9.2(f) under the proposed new rules.

Two of the key parameters of the formula in clause 9.9.2(f) are the Margin_Peak and Margin_Off-Peak, which are to be proposed by the IMO to the Economic Regulation Authority (ERA) each financial year. These parameters are intended to reflect the payment margin (i.e. as a percentage of the Balancing Price in either the peak or off-peak periods) that, when multiplied by the volume of spinning reserve provided and the Balancing Price, will compensate Verve Energy for energy sales foregone and losses in generator efficiency resulting from backing off generation to provide spinning reserve.

To support the transition to the new market arrangements, new clause 3.13.3AB specifically prescribes the requirements for the margin values to apply during the 2012/13 financial year. These requirements include consideration of the same factors as those that will be considered in margin value determinations for future years under clause 3.13.3A.

Clause 3.13.3AB stipulates that:

3.13.3AB. During the period:

(a) from 8:00 AM on the Balancing Market Commencement Day to 8:00 AM on 1 July 2013:

i. the Margin_Peak value is, subject to clause 3.13.3AB(b), the value determined by the Economic Regulation Authority and published on the Market Web Site; and

[3] With the exception of a small quantity of spinning reserve provided by Interruptible Load under Ancillary Service Contracts.

ii. the Margin_Off-Peak value is, subject to clause 3.13.3AB(b), the value determined by the Economic Regulation Authority and published on the Market Web Site;

(b) if the Economic Regulation Authority has not determined a Margin_Peak or Margin_Off-Peak value under clause 3.13.3AB(a) by 8:00 AM on the Balancing Market Commencement Day, then any such value is to be the value determined by the IMO and published on the Market Web Site as soon as reasonably practicable after the Balancing Market Commencement Day;

(c) in determining values for Margin_Peak and Margin_Off-Peak under clause 3.13.3AB(a) the Economic Regulation Authority must undertake a public consultation process, which must include publishing an issues paper and issuing an invitation for public submissions;

(d) when determining a value for the parameter Margin_Peak under this clause 3.13.3AB the Economic Regulation Authority or the IMO, as applicable, must take account of

i. the margin Verve Energy could reasonably have been expected to earn on energy sales foregone due to the supply of Spinning Reserve during Peak Trading Intervals; and

ii. the loss in efficiency of Verve Energy Registered Facilities that System Management has scheduled to provide Spinning Reserve during Peak Trading Intervals that could reasonably be expected due to the scheduling of those reserves; and

(e) when determining a value for the parameter Margin_Off-Peak under this clause 3.13.3AB the Economic Regulation Authority or the IMO, as applicable, must take account of:

i. the margin Verve Energy could reasonably have been expected to earn on energy sales foregone due to the supply of Spinning Reserve during Off-Peak Trading Intervals; and

ii. the loss in efficiency of Verve Energy Registered Facilities that System Management has scheduled to provide Spinning Reserve during Off-Peak Trading Intervals that could reasonably be expected due to the scheduling of those reserves.

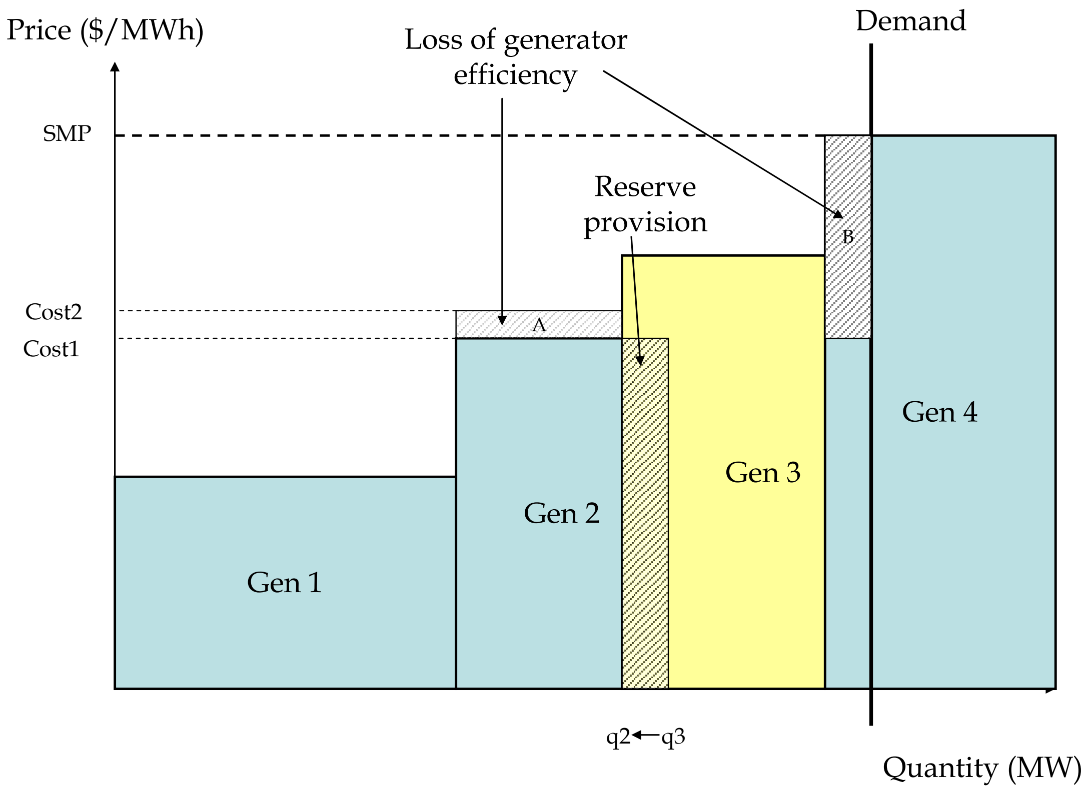
The reserve availability payment to Verve Energy should be equal to the sum of generator efficiency losses and energy sales foregone, which may be incurred through:

- movement to a less efficient point on a unit's heat rate curve
- an increase in either production from higher cost Verve Energy plant or Short Term Energy Market (STEM) or Balancing Market purchases, to counteract lower cost generation backed off to provide reserve
- additional start-up costs that may be incurred due to commitment of additional units that would otherwise not have been required.

2.1. Constraining units off to provide reserve

By way of example, consider a simple system consisting of four generators, three of which are owned by the Market Generator (Gen 1, Gen 2 and Gen 4), and one which is owned by an IPP (Gen 3). In this example, summarised diagrammatically in Figure 2-1, only the Market Generator can provide spinning reserve and, in this period, spinning reserve is provided by backing off generation from Gen 2 (quantity q3 – q2). By reducing output, Gen 2's average generation cost has increased from Cost 1 to Cost 2, as it is generating less efficiently. Additionally, energy production costs have increased due to the commitment of Gen 4. Consequently, the reserve availability cost incurred by the Market Generator is equivalent to the sum of the shaded areas A and B plus the cost of starting up Gen 4. If Gen 4 had been an IPP, Area B would represent the margin the Market Generator could have earned on energy sales foregone due to reserve provision.

- **Figure 2-1 Example of generator efficiency losses resulting from reserve provision**



2.2. Constraining units on to provide reserve

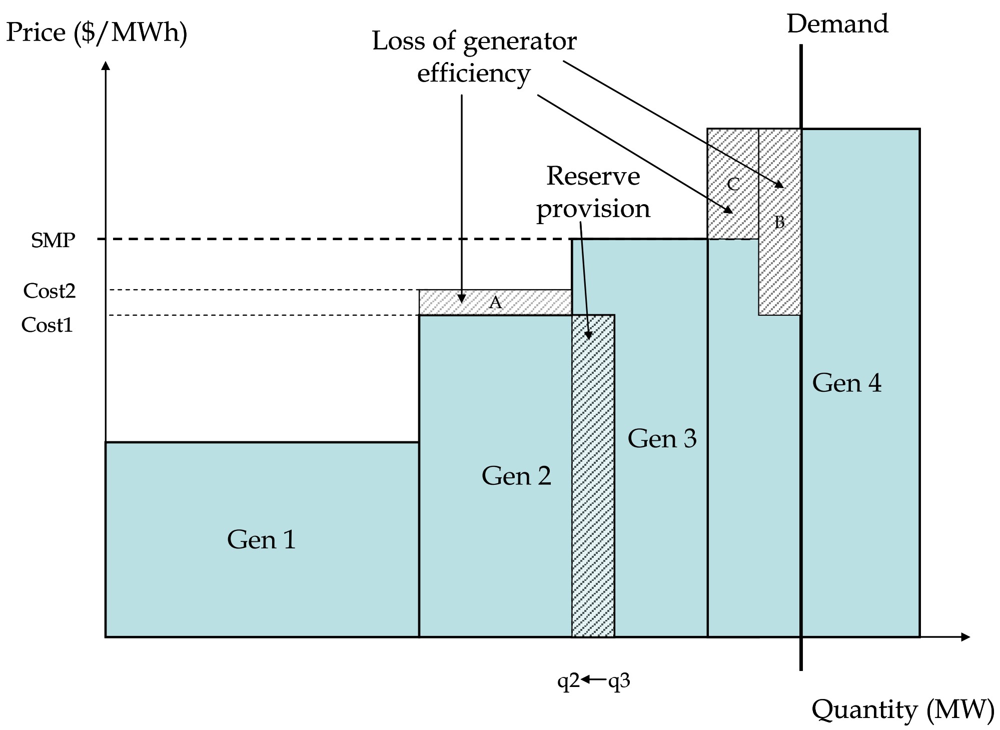
During the off-peak, some units may be constrained on at minimum level to meet the reserve requirements but a lower cost generator may be the marginal generator setting the price. Therefore, the availability cost could be quite high relative to the System Marginal Price (SMP).

To illustrate this situation, consider again the simple four generator example introduced earlier although, this time, assume that all generators are owned by the same Market Generator. In the original example, Gen 2 was backed off to provide reserve, and Gen 4 was committed to meet demand (Figure 2-1). Gen 4's dispatch was equal to the level of reserve provided (q3 – q2) and the reserve availability cost was equal to area A + area B.

Now, consider the situation whereby Gen 4 has a minimum level greater than (q3 – q2). In order to meet the reserve requirement, Gen 2 must still back off generation from q3 to q2, but Gen 4 is now constrained on to its minimum level. Consequently, Gen 3's output is reduced as there is insufficient demand for Gen 3 to operate at maximum capacity and for Gen 4 to operate at minimum level (Figure 2-2). At the margin, any variations in demand will be met by Gen 3. Therefore, Gen 3 is the marginal generator setting the price, not Gen 4. The reserve availability cost is the sum of areas A, B and C, representing the increase in generation costs incurred by Market Generator as a consequence of providing reserve.

If Gen 4's generation costs are significantly larger than the cost of the marginal generator, and if Gen 4's minimum level is greater than the level of reserve provision required, then it is possible that this availability cost may result in relatively high margin value (greater than 100%, as we observed in the 2009 review). In the WEM, this situation may arise if Cockburn is constrained on to provide reserve, as SKM MMA understands that this unit has a relatively high minimum level.

- **Figure 2-2 Example of availability cost with Gen 4 constrained on**



It is also possible to have more than one Verve Energy unit constrained on to provide reserve if demand is low and the level of generation from IPPs is relatively high, since Verve Energy is assumed to be the sole provider of spinning reserve (apart from Interruptible Load).

2.3. Calculating availability cost

Through market simulations, the availability cost is calculated for peak and off-peak periods by comparing Verve Energy's total generation costs and generation quantities, with and without providing spinning reserve but with load following reserve provided in both simulations. That is:

Availability cost = GenCost_Res – GenCost_NRP + (GenQ_NRP – GenQ_Res)*SMP

where:

GenCost_Res	= Verve Energy's total generation costs, including start-up costs, with spinning reserve provision
GenCost_NRP	= Verve Energy's total generation costs, including start-up costs, without any spinning reserve provision
GenQ_Res	= Verve Energy's total generation volume, with spinning reserve provision
GenQ_NRP	= Verve Energy's total generation volume, without any spinning reserve provision
SMP	= system marginal price with spinning reserve provision

For calculating losses in generator efficiency resulting from reducing output to provide spinning reserve, heat rate curves are considered within SKM MMA's WEM database, as discussed in Section 4.5.7.

2.4. Calculating Margin Values

New clause 9.9.2(f) of the Market Rules provides a formula for calculating the total availability cost in each Trading Interval as a function of the Margin value, SR_Capacity, LF_Up_Capacity and Balancing Price in the period. Margin values can therefore be calculated by rearranging this formula and using key outputs from the market simulations.

The SR_Capacity(t) parameter represents the capacity necessary to cover the Ancillary Service Requirement for spinning reserve in the Trading Interval as specified by IMO under clauses 3.22.1(e) and (f). These clauses define the Ancillary Service Requirement for spinning reserve as being equal to the requirement assumed in calculating the Margin values, with a different value used for peak and off-peak trading periods (SR_Capacity_Peak and SR_Capacity_Off-Peak). Therefore, the SR_Capacity_Peak and SR_Capacity_Off-Peak are key parameters to extract from the market simulations. In PLEXOS, the spinning reserve requirement varies dynamically from period to period. These values are therefore averaged over the year in order to determine a single SR_Capacity_Peak and SR_Capacity_Off-Peak value for use in the formula in clause 9.9.2(f).

The LF_Up_Capacity parameter represents the amount of load following upwards ancillary service required in the Trading Interval. Assumptions regarding this requirement are discussed in Section 4.6.2.

3. Modelling the wholesale electricity market

The WEM for the South West interconnected system (SWIS) commenced operation on 21 September 2006. Currently this market consists of three components:

- An energy market, which is an extension of the previous bilateral contract arrangements, with a residual day-ahead energy market (Short Term Energy Market – STEM)
- A services component, to balance supply and demand, dispatch spinning reserve and ensure supply reliability and quality
- A reserve capacity mechanism, to ensure that there is adequate capacity to meet demand each year.

The energy market and the reserve capacity mechanism are operated by the IMO. Other services are controlled by System Management.

The WEM is relatively small, and a large proportion of the electricity demand is for mining and industrial use, which is supplied under long-term contracts. Over 90% of energy sales in the SWIS are traded through bilateral contracts that closely follow the individual customer's load.

The STEM is a residual day ahead trading market which allows contract participants to trade out any imbalances.

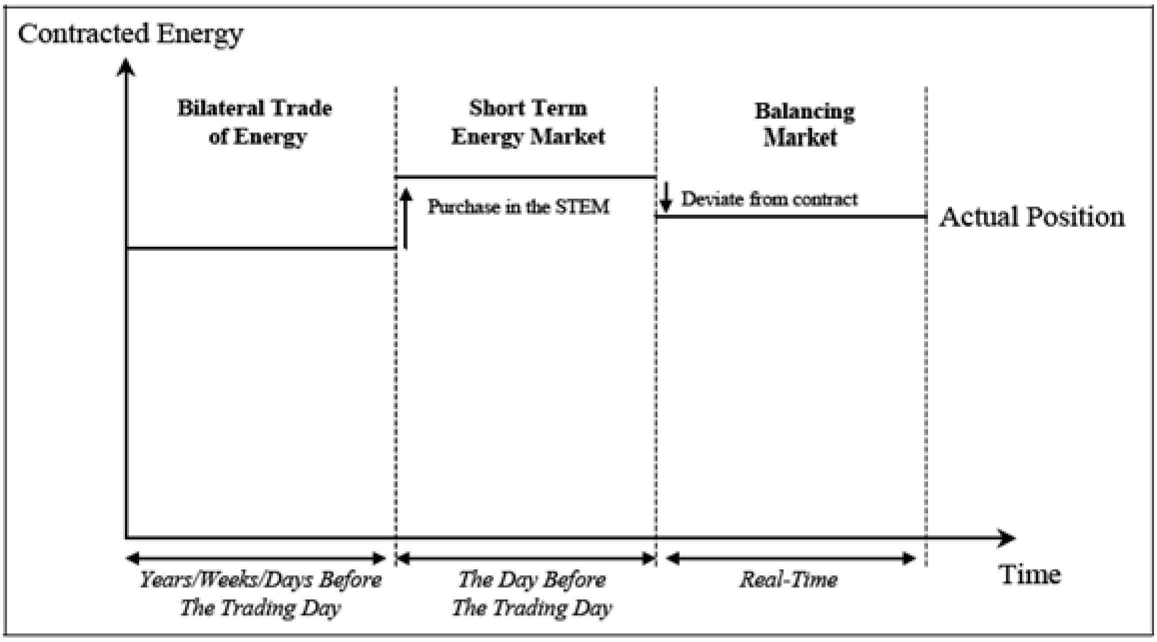
Market participants (both generators and retailers) can submit offers to sell energy to the STEM, or bids to buy energy from the STEM. Market generators may wish to buy energy from the market if the STEM price is lower than its marginal cost of generation. Alternatively, the generator may wish to sell energy in excess of its bilateral contract into the STEM. Similarly, retailers may use the STEM to trade out imbalances between the bilateral contract position and expected demand.

The IMO is responsible for clearing the offers and bids in the STEM. The STEM price is set at the point where the marginal offer price and marginal bid price are equal.

There will inevitably be slight differences between the day-ahead net contract volumes and the real time demand. Under the changes resulting from RC_2011_10, all Balancing Facilities (Verve Energy and IPPs) will be required to compete in a Balancing Market to accommodate these deviations and maintain system security. Balancing Facilities will be required to participate in the Balancing Market through price-based submissions, using multiple price-volume bands to represent the facility's willingness to generate at different levels of output. The Balancing Price is the price determined in the Balancing Market after supply and demand have been balanced in real time, and is calculated in accordance with clause 7A.3.10 of the proposed Amending Rules.

Figure 3-1 shows the relationship between bilateral trades, the STEM and the Balancing Market over time.

Figure 3-1 Components of the Energy Trading Market



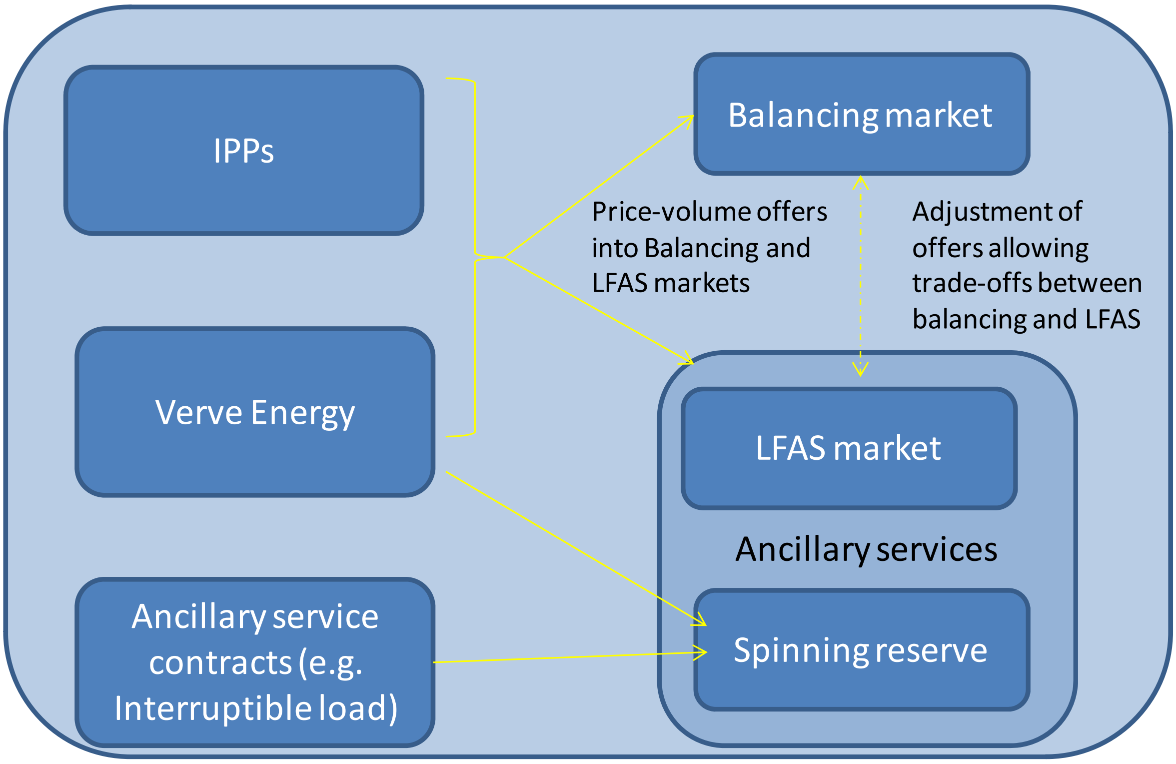
SOURCE: IMO (2006) *The South West Interconnected System Wholesale Electricity Market: An Overview, adapted for MEP*

Additionally, the proposed rule changes allow IPPs to compete with Verve Energy for the provision of load following reserve through an LFAS Market. Payment for LFAS will be determined based on the market price for this service (excluding payments made for any emergency backup LFAS provided by Verve Energy on a "pay as bid" basis).

Verve Energy will remain the default provider of all ancillary services. Moreover, spinning reserve will only be provided by Verve Energy or through Ancillary Service Contracts such as interruptible load contracts. Figure 3-2 summarises participation by Verve Energy and IPPs in the Balancing Market, LFAS Market and provision of spinning reserve. A more detailed explanation of the new Balancing and LFAS Markets can be found in IMO (2011) *New Balancing Market Proposal: Design Details*[4].

[4] http://www.imowa.com.au/f4799,1958190/RC_2011_10_Final_12_Boxes.pdf

▪ **Figure 3-2 Balancing Market and Ancillary Service Provision**



3.1. PLEXOS simulation software

SKM MMA simulates the WEM for the SWIS using PLEXOS, commercially available software developed in Australia by Energy Exemplar. PLEXOS is a Monte Carlo mathematical program that co-optimises both the energy and reserve requirements in the WEM, using the same techniques that are used to clear the National Electricity Market (NEM), New Zealand and Singaporean electricity markets.

In the PLEXOS model, SKM MMA does not explicitly model the bilateral trades, STEM and Balancing Market separately. Instead, a gross pool is modelled, assuming economically efficient dispatch, and energy and ancillary services are co-optimised. Any discrepancies between the WEM and a PLEXOS market model are expected to be reduced by the introduction of the Balancing and LFAS Markets under RC_2011_10, as this will bring the WEM closer towards the dispatch and competitive behaviour that would be expected in a gross pool model of operation.

Dispatch is optimised to meet load and ancillary service requirements at minimum cost subject to a number of operating constraints. In the WEM model, these operating constraints include:

- generation constraints – availability (planned and unplanned outages), unit commitment and other technical constraints

- transmission constraints –line ratings and other generic constraints
- fuel constraints – for example, daily fuel limits
- ancillary service constraints – maximum unit response, calculation of dynamic risk

3.2. Assumptions review

The availability cost resulting from backing-off generation to provide spinning reserve will depend on both the marginal costs of the generators providing the reserve, and the Balancing Price set by the marginal generator. From previous modelling experience, SKM MMA has found that this availability cost can be sensitive to key assumptions such as fuel costs (for new and existing plant), unit commitment (based on start-up cost assumptions) and the ability of various units to provide load following reserve.

In recognition of the importance of these assumptions, SKM MMA prepared an Assumptions Report that was reviewed initially by the IMO and System Management. The public version of this report, which excluded confidential Market Generator details, was published on the IMO website on 23 January 2012 for public consultation. The IMO received no submissions on the Assumptions Report during the consultation period, which closed on 10 February 2012.

In addition, market participants were requested to confirm the assumptions made with regard to their own facilities. Several market participants provided updated facility details to the IMO on a confidential basis, which SKM MMA has taken into account when finalising the assumptions for this review.

Furthermore, to validate the modelling methodology and verify the reasonableness of assumptions used, the previous market modelling outcomes used in the assessment of the margin values for the 2010/11 review period were compared against actual market outcomes for that financial year. Some differences in market outcomes were observed, most notably, the market modelling was projecting much higher MCAP prices and a greater level of Verve Energy generation than observed in reality. MCAP prices on average were 38% lower than the modelled outcomes, and Verve Energy generation was 13% lower than the modelled outcomes. Much of these discrepancies was attributed to inaccuracies in input assumptions relating to demand, system outages, minimum generation levels and new entrant timing, assumptions which would result in differences in outcomes regardless of forecasting technique used.

To assess the impact of the inaccuracy in these input assumptions, a back-cast was undertaken to remove variations in results due to differences in input assumptions outside our control such as actual load, timing of new entry and unit availability. With these input assumptions corrected, modelled market outcomes for the 2010/11 were much closer to actual outcomes, although actual MCAP prices were still lower than projected, as summarised in Table 3-1.

- **Table 3-1 Variation rate before and after improved assumptions**

Item	Actual	Modelled	% variation from original modelled outcome	Back-cast	% variation from back-cast outcome
MCAP, $/MWh (TWA)	37.08	59.99	-38%	47.55	-22%
Peak	45.90	77.64	-41%	58.60	-22%
Off Peak	23.37	35.21	-34%	32.03	-27%
Verve Energy generation, TWh[5]			-12%		7%

On close inspection of the market modelling outcomes from the analysis of the 2010/11 outcomes, and the back-casting exercise, the following input assumption modifications were adopted for this Margin Value review to improve the accuracy of the forecasts:

- Modify minimum generation levels, as advised by System Management
- Reduce gas price assumptions
- Increase value of steam revenue assumed for cogeneration units
- Include any known large outages scheduled for the review period.

[5] Actual generation volume confidential

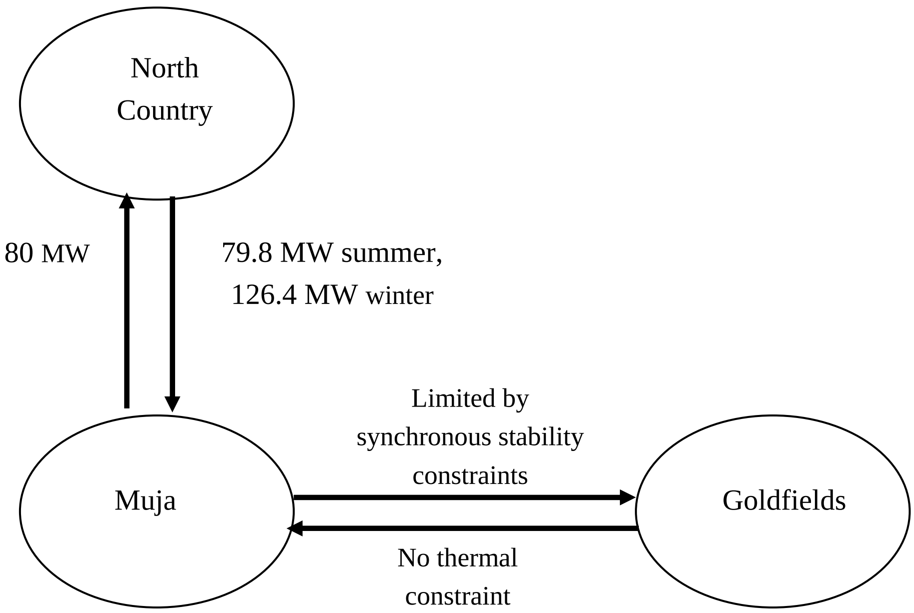
4. Key modelling assumptions

This section outlines the key modelling assumptions used in the PLEXOS market simulations.

4.1. Network topography

We model the SWIS as a 3-node system with a single uniform price. Interconnectors between the 3 nodes: Muja, Goldfields and North Country, allow us to represent the major congestion points in the system. Figure 4-1 shows the network configuration modelled in PLEXOS and the maximum flow limits assumed in each direction.

■ **Figure 4-1 3-node model of SWIS**



The Mungarra units, Verve Geraldton GT, Tesla Geraldton, Greenough Solar Farm and the Alinta Walkaway, Mumbida and Kalbarri wind farms are located in the North Country, the West Kalgoorlie, Southern Cross and Parkeston units are located in the Goldfields region, and all other units, including Emu Downs and Collgar wind farms and Merredin Energy gas turbine units, are assumed to be located at Muja.

Voltage stability constraints in the North Country influence unit commitment decisions for the Mungarra units. On advice from System Management, when North Country load exceeds 67 MW, one Mungarra unit must be in operation, increasing to two units in operation when load exceeds 77 MW.

From North Country back to Muja, thermal limits constrain flow to 84 MVA in summer and 133 MVA in winter. While the MW equivalent rating changes throughout the day, System Management has suggested a power factor of 0.95 be used for both seasons. The resulting constraint limits flow south to 79.8MW in summer and 126.4 MW in winter.

Additionally, transient stability issues constrain the level of import into the Goldfield's region, effectively limiting the size of the load that can be supplied within the region. The Goldfield's load cannot exceed 130 MW, and the combined export (generated less self load of approximately 110 MW) of Parkeston and Southern Cross is limited to 85 MW.

4.2. Demand assumptions

4.2.1. Regional demand forecasts

Table 4-1 shows the assumptions for sent-out energy and summer and winter maximum demand across the 3 nodes. These values are based on the 2011 Statement of Opportunities (SOO) load forecasts (medium growth scenario, 50% PoE), distributed among the three regions in accordance with the 2009/10 actual loads. Intermittent non-scheduled load information was provided by the IMO.

- **Table 4-1 2012/13 load assumptions**

Financial year	Parameter	Muja (Perth)	Goldfields	North Country	Total SWIS
2012/13	Energy (GWh)	18118	664	686	19468
	Summer Peak Demand 50% PoE (MW)	4123	149	143	4340
	Winter Peak Demand 50% PoE (MW)	3146	143	107	3328
	Intermittent non-scheduled load (MW)	98.3	46	0	144.3

In Table 4-1, the regional peaks are not coincident (i.e. they occur at different times), therefore the sum of the individual peak demands is slightly higher than the total SWIS demand. Coincidence factors are derived from the 2009/10 profiles, to calculate the individual region peaks at time of system peak for the 2012/13 financial year.

For our chronological modelling in PLEXOS, we use half hourly load profiles for the 3 nodes (based on 2009/10 historical data including losses), which are then grown to match the energy and peak demand values in Table 4-1.

4.2.2. Intermittent loads

Generators servicing Intermittent Loads are also modelled in PLEXOS. In case one of these generators is offline as a result of an outage, the system will need to supply their nominated capacity. These generators may also be dispatched in the SWIS up to their maximum scheduled generation level.

4.3. Fuel assumptions

The following fuels are represented in the model:

- Coal: used by Muja, Collie and the Bluewaters units,
- Cogeneration contract gas: gas for Alcoa Wagerup and one of the two Alinta cogeneration units
- Verve Contract gas: gas under existing Verve Energy contracts,
- NewGen contract gas: gas for NewGen Kwinana plant
- IPP contract gas: gas under contract for existing IPP plants,
- New gas: reflects the estimated price for new gas contracts, and as a secondary fuel for some of the other units if they have used up their contract gas supply,
- Distillate: used as a primary fuel by the Geraldton, West Kalgoorlie, Tesla, Merredin Energy and Kalamunda units, and as a secondary fuel for some of the other units if they have used up their gas supply.

Multi-fuelled units are modelled as able to use more than one fuel. Kwinana G5 and Kwinana G6 are modelled as burning a mix of 50% gas and 50% coal (on a fuel energy basis). The units using contract gas can use new gas if the contracted gas for the portfolio is insufficient. The Kemerton units, Pinjar GT1-5 and 7, Kwinana GT1-3, Alinta Wagerup units, Parkeston and Perth Energy's Kwinana facility can operate on either gas or distillate, but will only use distillate if the supply of gas for the respective portfolio is insufficient.

4.3.1. Fuel costs

Table 4-2 shows our assumptions on fuel prices. For coal, gas and landfill gas, but excluding the NewGen contract gas, the prices used are the same as the prices used in the calculation of the FY2011/12 margin values that were determined by the ERA on 31 March 2011, adjusted by CPI. The gas price for NewGen contract gas was estimated based on publicly available data referring to contract gas prices negotiated around the time that the NewGen Kwinana gas contract was negotiated, and observed dispatch outcomes for the unit which indicated that the marginal price offered into the market was lower than previously estimated through the SKM MMA market modelling.

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Table 4-2 Fuel prices (real June 11 dollars)

Name	Price ($/GJ)
Coal	2.06
Cogeneration contract gas	2.64
Verve contract gas	3.09
NewGen contract gas	3.09
IPP contract gas	4.12
New gas	6.18
Landfill gas	2.25
Distillate	22.15

Distillate prices come from SKM MMA's Draft Electricity Price Limits 2011 study[6], which estimated a price of $22.61/GJ applying a calorific value of 38.6 MJ/litre. The additional transport cost to the Goldfields is estimated to be $0.67/GJ.[7]

Gas transport charges, reflecting variable gas pipeline costs, vary based on the generator's geographic location. The gas transport charges assumed for each unit are presented in Table 4-5. These charges have been provided by the IMO based on advice provided by ACIL Tasman. The fixed component of the gas transport charge in the ACIL Tasman numbers was converted to a variable cost per GJ assuming a load factor of 75%. For gas from the Dampier to Bunbury Pipeline (DBPNG), the resulting fixed cost component of the gas transport cost was approximately $1.65/GJ. Given that many of the gas-fired generators will have take-or-pay contracts, much of this fixed cost component may be considered a sunk cost which does not appear to be fully included within the bid price for gas-fired generators. After discussion with the IMO, SKM MMA has therefore conservatively assumed that only 50% of the fixed cost component should be included in formulating the marginal costs for gas-fired generators. This equates to a reduction in gas transport cost from the DBPNG of approximately $0.80/GJ, and a reduction of approximately $2.20/GJ from the Goldfield's Gas Pipeline (GGP).

The gas transport charges provided by ACIL Tasman were assumed to be in December 2012 dollars, and have been de-escalated back to real June 2011 dollars assuming annual out-year inflation for 2012 and 2013 of 2.75%, consistent with the CPI assumptions made by ACIL Tasman.

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6 http://www.imowa.com.au/f4153,1540757/SKM_MMA_Draft_2011_EPL_Report.pdf

7 Prices in the SKM MMA "Energy Price Limits for the Wholesale Electricity Market in Western Australia from October 2011" report are nominal for the capacity year 2011/12. In order to convert them to real June 2011 dollars, we assumed they are from March 2012 (mid-point of the 2011-12 capacity year) and then scaled them back to June 2011 dollars using a CPI index estimated for March 2012 of 182.1 (obtained assuming an annual out-year inflation rate of 2.75%).

4.3.2. Fuel constraints

Constraints limiting the daily availability of contract gas have been included in the modelling, based on understanding of the market and historical data. Constraints on the total gas available in different locations have also been included. These figures correspond to estimations from historical dispatch data and liquid fuel usage for 2008, and have been fine-tuned in the PLEXOS model during previous SWIS backcasting exercises.

4.4. Carbon price and emission intensities

The Federal Government intends to introduce a price on carbon through the Clean Energy Future scheme starting on 1 July 2012. The price will be set at \$23/t CO_2-e (nominal) for the 2012/13 financial year; equivalent to approximately \$22.1/t CO_2-e in real June 2011 dollars.

The introduction of a carbon price will impact on the marginal cost of supply and Balancing Prices in the market simulations. For a given carbon price, PLEXOS recalculates the SRMC for each generator, adjusting the merit order accordingly. Key assumptions for this calculation include the carbon price, the emission production rate for each fuel type, and the heat rate of each generator. The CO_2-e emission production rates assumed for each fuel are listed in Table 4-3 and the basis for these assumptions are described in detail in the following sections.

- **Table 4-3 CO2 emission production rate assumed for each fuel (kg/GJ)**

Fuel type	CO_2-e Production Rate (kg/GJ)
Coal	93.1
Cogen gas	52.3
Verve gas	52.3
NewGen gas	52.3
IPP gas	52.3
New gas	52.3
Distillate	74.8

These emission production rates include both combustion and fugitive emissions. The heat rates are summarised in Table 4-5. The resulting CO_2-e emission production rate for an individual generator is the product of the heat rate and the fuel emission production rate. The SRMC for the generator is then adjusted by multiplying this generation CO_2-e emission production by the \$22.1/t carbon price. The resulting emission intensities for individual power stations, at maximum output, are included in Table 4-5.

4.4.1. Coal fired generation

In Table 1 of the National Greenhouse Accounts (NGA) Factors[8] the emission intensity for black coal is assessed as 88.43 kg CO_2-e /GJ. However, this emission intensity is not location specific. WA's coal typically has a higher moisture and carbon content than black coal in other regions of Australia. Therefore, SKM MMA used an emission intensity of 93.1 kg CO_2-e /GJ, consistent with assumptions in Griffin Power's *Greenhouse Gas Abatement Programme, Bluewaters Project,* 2008[9]. It is assumed that this emission intensity includes fugitive emissions from mining.

4.4.2. Gas fired generation

The combustion of natural gas is assessed as 51.33 kg CO_2-e GJ from Table 2 of the NGA Factors.

The transport of natural gas depends on pipeline distance. The relevant transmission factor is 8.72 t CO_2-e /km of pipeline[10]. The total emission of the DBNGP is published in the National Greenhouse and Energy Reporting (NGER) Greenhouse and Energy Information for 2009/10[11] as 357,468 t CO_2-e. The average throughput of the pipeline is approximately 756[12] TJ/day which gives an annual value of 276 PJ. Dividing the published emissions into the throughput gives a transport emission of 1.295 kg CO_2-e/GJ.

For the GGP, there is no separately published level of emissions. Assuming maximum gas consumption for compressors of 490 TJ per year and applying the assumed gas combustion figure of 51.33 kg CO_2-e/GJ, we obtain a total pipeline emission combustion figure of 25,151.7 t CO_2-e. The pipeline is 1,378 km from Yarraloola to Kalgoorlie[13]. Based on the transmission factor of 8.72 t CO_2-e/km, the standard emission for the pipeline would be 12,016 t CO_2-e, resulting in a total emissions of 37,168 t CO_2-e. Dividing this quantity into the estimated contract capacity of 105.64 TJ/day[14], gives a transport emission intensity of 0.964 kg CO_2-e /GJ delivered. These calculations are summarised in Table 4-4.

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8 http://www.climatechange.gov.au/~/media/publications/greenhouse-acctg/national-greenhouse-factors-july-2010-pdf.pdf

9 Greenhouse Gas Abatement Programme for Bluewaters Power Station, cited http://www.griffinenergy.com.au/default.aspx?MenuID=76

10 Table 15: Natural gas transmission emission factors, NGA Factors.

11 http://www.climatechange.gov.au/government/initiatives/national-greenhouse-energy-reporting/publication-of-data/nger-greenhouse-energy-information-2009-10.aspx

12 Revised Access Arrangement Model, ERA website http://www.erawa.com.au/3/1086/48/dampier_to_bunbury_natural_gas_pipeline__revised_a.pm

13 http://www.apa.com.au/media/176981/ggt%20approved%20proposed%20revised%20access%20arrangement%20information%20for%20ggp.pdf

14 http://www.apa.com.au/media/176981/ggt%20approved%20proposed%20revised%20access%20arrangement%20information%20for%20ggp.pdf

- **Table 4-4 Analysis of gas transport emissions**

	Units	DBNGP	GGP
Energy Consumption	TJ	N/A	490
Gas Combustion	t CO_2-e	345269	25152
Pipeline	t CO_2-e	12199	12016
Total	t CO_2-e	357468	37168
NGER Emissions	t CO_2-e	357468	N/A
Transported	TJ	275940	38558.6
	TJ/day	756	105.64
Emissions	t CO_2-e /GJ	1.295	0.964

The total emission factor for gas is therefore considered to be:

> 52.63 kg CO_2-e /GJ for Muja and North Country
>
> 52.26 kg CO_2-e /GJ for the Goldfields.

The emissions are slightly higher for the Perth area due to slightly higher transport emissions on the DBNGP relative to throughput.

4.4.3. Distillate fired generation

The combustion of distillate (described as diesel oil for stationary energy purposes) is assessed as 69.5 kg CO_2-e /GJ from Table 3 of the NGA Factors.

For distillate supplied to these peaking plants, the notional allowance for transport of distillate is 5.3 kg CO_2-e /GJ from Table 39 of the NGA Factors. There is no distinction by location. We therefore apply a total emission of 74.8 kg CO_2-e /GJ to represent the likely emission of distillate delivered to peaking generators.

4.5. Generation assumptions

4.5.1. Existing generators

Table 4-5 shows some of the key properties of existing generators in the model[15], including the larger private power stations owned by Alcoa and the Goldfields miners. Some of the power stations listed may represent the aggregation of one or more actual facilities.

[15] Note that Bremer Bay wind farm has been excluded as its effect is considered to be negligible. Mt Herron has also been excluded following advice from the IMO that the facility is not expected to generate during the 2012/13 financial year.

4.5.2. Kwinana NewGen

The Kwinana NewGen CCGT consists of a 160 MW open cycle gas turbine, and a 160 MW steam turbine. In base load operation, 240 MW of power may be provided, with an additional 80MW available from the steam unit during peak periods through auxiliary duct firing. The steam turbine cannot operate without the gas turbine. Therefore, the contingency risk that this unit imposes on the system is equal to the combined output from the power station.

4.5.3. Unit commitment

Unit commitment is determined within the PLEXOS simulations to minimise total system costs taking cognisance of unit start-up costs. Start-up costs for Pinjar units 1 – 7 and the Perth Energy facility were derived from assumptions provided in SKM MMA’s 2011 Energy Price Limits report. Start-up costs for other Verve and non-Verve facilities were provided by the IMO.

For some units that typically operate as “must-run”, unit commitment is imposed on the model. Specifically, the Bluewaters units, Alinta Pinjarra, Muja 7 and 8, Collie, cogeneration units and other generators meeting private loads are treated as units that must generate whenever they are available. The current Market Rules require the order in which the units are shutdown to be Cockburn, Muja 5/6, Collie and Muja 7/8 then Windfarms/Kwinana Newgen/Bluewaters depending on the Dispatch Merit Order provided by the IMO unless there is a security issue. In the absence of MEP proposed rule changes, the margin value assessment for 2012/13 assumed that Kwinana NewGen was also must-run, as the observed operating profile to date has indicated that this unit rarely shuts down. However, for this MEP analysis, this assumption was relaxed since Kwinana NewGen can now participate in the Balancing Market and so should be allowed to shut down if economic to do so.

Table 4-5 Properties of existing generators

Generator	Average Electrical HR (GJ/MWh sent out HHV) at max	Average Electrical HR (GJ/MWh sent out HHV) at min	Primary Fuel	Fuel Price ($/GJ)	Transport charge ($/GJ)	VO&M ($/MWh sent out)	Average CO2-e emission intensity at max (kg/MWh sent out)	Carbon cost ($/MWh sent out)	SRMC 2012/13 ($/MWh sent out)	MLF
BW1_BLUEWATERS_G2	9.75	10.79	Coal	2.06		2.25	908	20.04	42.37	1.00
BW2_BLUEWATERS_G1	9.75	10.79	Coal	2.06		2.25	908	20.04	42.37	1.00
COLLIE_G1	9.5	10.38	Coal	2.06		1.12	884	19.53	40.22	1.00
MUJA_G5	11.04	14.06	Coal	2.06		4.50	1028	22.70	49.94	1.00
MUJA_G6	11.04	14.06	Coal	2.06		4.50	1028	22.70	49.94	1.00
MUJA_G7	9.85	11.37	Coal	2.06		4.22	917	20.25	44.76	1.00
MUJA_G8	9.85	11.37	Coal	2.06		4.22	917	20.25	44.76	1.00
ALINTA_PNJ_U1	12	12	Cogen gas	2.64	1.09	-27.41*	632	13.94	31.25	0.99
ALINTA_PNJ_U2	12	12	New gas	6.18	1.09	-27.41*	632	13.94	73.77	1.01
ALCOA_WGP	12	12.62	Cogen gas	2.64	1.09	-24.11*	632	13.94	34.54	0.99
PPP_KCP_EG1	8	10.48	Verve gas	3.09	1.09	-25.25*	421	9.30	17.47	1.03
SWCJV_WORSLEY_COGEN _COG1	12	12.02	Verve gas	3.09	1.09	-25.70*	632	13.94	38.40	0.99
TIWEST_COG1	13	21.33	Verve gas	3.09	1.09	-29.19*	684	15.11	40.24	1.03
COCKBURN_CCG1	8	8.43	Verve gas	3.09	1.09	3.88	421	9.30	46.61	1.01
KWINANA_G5	11.7	14.42	Verve gas/Coal	2.58	1.09	4.33	852	18.82	66.02	1.01
KWINANA_G6	11.7	14.42	Verve gas/Coal	2.58	1.09	4.33	852	18.82	66.02	1.01
KWINANA_GT1	14.6	25.99	Verve gas	3.09	1.09	22.68	768	16.97	100.66	1.01
MUNGARRA_GT1	13.5	21.85	Verve gas	3.09	0.79	4.61	710	15.69	72.74	1.02
MUNGARRA_GT2	13.5	21.85	Verve gas	3.09	0.79	4.61	710	15.69	72.74	1.02
MUNGARRA_GT3	13.2	21.56	Verve gas	3.09	0.79	4.61	695	15.34	71.22	1.02

Generator	Average Electrical HR (GJ/MWh sent out HHV) at max	Average Electrical HR (GJ/MWh sent out HHV) at min	Primary Fuel	Fuel Price ($/GJ)	Transport charge ($/GJ)	VO&M ($/MWh sent out)	Average CO2-e emission intensity at max (kg/MWh sent out)	Carbon cost ($/MWh sent out)	SRMC 2012/13 ($/MWh sent out)	MLF
PINJAR_GT01	13.5	21.85	Verve gas	3.09	1.09	confidential	710	15.69	confidential	1.03
PINJAR_GT02	13.5	21.85	Verve gas	3.09	1.09	confidential	710	15.69	confidential	1.03
PINJAR_GT03	13.2	22.46	Verve gas	3.09	1.09	confidential	695	15.34	confidential	1.03
PINJAR_GT04	13.2	22.46	Verve gas	3.09	1.09	confidential	695	15.34	confidential	1.03
PINJAR_GT05	13.2	22.46	Verve gas	3.09	1.09	confidential	695	15.34	confidential	1.03
PINJAR_GT07	13.2	22.46	Verve gas	3.09	1.09	confidential	695	15.34	confidential	1.03
PINJAR_GT09	12.5	19.28	Verve gas	3.09	1.09	4.50	658	14.53	71.26	1.03
PINJAR_GT10	12.5	19.28	Verve gas	3.09	1.09	4.50	658	14.53	71.26	1.03
PINJAR_GT11	12.2	21.74	Verve gas	3.09	1.09	5.23	642	14.18	70.39	1.03
NEWGEN_KWINANA_CCGT	confidential	confidential	NewGen gas	3.09	1.09	2.25	confidential	confidential	confidential	1.02
STHRNCRS_EG	confidential	confidential	IPP gas	4.12	2.41	4.55	confidential	confidential	confidential	1.26
KEMERTON_GT11	12.2	13.25	Verve gas/distillate	3.09	1.09	2.40	642	14.18	67.56	1.01
KEMERTON_GT12	12.2	13.25	Verve gas/distillate	3.09	1.09	2.40	642	14.18	67.56	1.01
ALINTA_WGP_GT	11.5	16.2	New gas/distillate	6.18	1.09	2.40	605	13.36	99.36	1.01
ALINTA_WGP_GT2	11.5	16.2	New gas/distillate	6.18	1.09	2.40	605	13.36	99.36	1.01
NEWGEN_NEERABUP	confidential	confidential	New gas	6.18	1.09	2.40	confidential	confidential	confidential	1.04
PRK_AG	confidential	confidential	IPP gas	4.12	2.40	4.55	confidential	confidential	confidential	1.30
GERALDTON_GT1	15.25	15.95	Distillate	22.15		2.59	1141	25.19	365.61	1.04

Generator	Average Electrical HR (GJ/MWh sent out HHV) at max	Average Electrical HR (GJ/MWh sent out HHV) at min	Primary Fuel	Fuel Price ($/GJ)	Transport charge ($/GJ)	VO&M ($/MWh sent out)	Average CO2-e emission intensity at max (kg/MWh sent out)	Carbon cost ($/MWh sent out)	SRMC 2012/13 ($/MWh sent out)	MLF
WEST_KALGOORLIE_GT2	13.5	13.5	Distillate	22.15	0.66	33.76	1010	22.30	363.99	1.22
WEST_KALGOORLIE_GT3	14.75	14.75	Distillate	22.15	0.66	33.76	1103	24.36	394.57	1.22
GENERIC LANDFILL GAS	11.3	11.3	Landfill Gas	2.25		-25.26			0.12	1.02
ALBANY_WF1			Wind			-39.55			-39.55	1.04
ALINTA_WWF			Wind			-39.55			-39.55	0.95
EDWFMAN_WF1			Wind			-39.55			-39.55	1.00
SKYFRM_MTBARKER_WF1			Wind			-39.55			-39.55	1.04
KALBARRI_WF1			Wind			-39.55			-39.55	1.04
COLLGAR			Wind			-39.55			-39.55	1.13
PERTH_ENERGY_GT1	10.7	16.06	New gas	6.18	1.09	19.94	563	12.43	110.15	1.03
KWINANA_GT2	9.3	15.23	Verve gas/distillate	3.09	1.09	6.40	489	10.81	56.07	1.01
KWINANA_GT3	9.3	15.23	Verve gas/distillate	3.09	1.09	6.40	489	10.81	56.07	1.01
TESLA_PICTON	14.44	14.44	Distillate	22.15		2.59	1080	23.85	346.33	1.00
KALAMUNDA	15.27	18.7	Distillate	22.15		2.59	1142	25.22	366.08	1.01

* Negative VOM attempts to approximate the impact of the value of steam on economic dispatch of these cogeneration units

4.5.4. Planned maintenance and forced outages

Planned maintenance is modelled in PLEXOS in one of two ways: either explicitly with users specifying the period over which the unit will not be available, or via maintenance rates. If maintenance rates are used, PLEXOS schedules the maintenance to occur in periods of high reserve, where possible, by allocating maintenance in such a way that the minimum reserve level across the year is maximised.

Forced outages are unplanned, and can occur at any time. These are randomly determined in PLEXOS and differ in each Monte Carlo simulation. Twelve Monte Carlo simulations have been run for this analysis. In each simulation, the frequency with which forced outages occur is determined by the forced outage rate and mean-time-to-repair parameters in the model. The outage rates have been sourced from SKM MMA's *Assessment of Reliability of the South West Interconnected System 2012 – 2022*, prepared for the IMO in 2011. The forced outage rates are derived from outage data provided over the period from 2008 to 2010. The maintenance requirements are based on the requirements assumed for 2012/13 in that study, provided by the IMO for nominated plant. No outage rates are included for wind farms since the historical generation profiles of these units will already include outages.

4.5.5. Short run marginal cost calculations

Within the PLEXOS software, the SRMC is calculated as follows:

*SRMC = marginal heat rate * (fuel price + variable transport charge) + VOM cost + carbon cost*

This SRMC is then multiplied by the marginal loss factor prior to determining the merit order of dispatch. The assumed marginal loss factors have been obtained from the IMO website for 2011/12[16] and are listed for each facility in Table 4-5.

The SRMC values in Table 4-5 are estimated for 2012/13, based on the primary fuel only and considering the average heat rate and carbon cost at maximum capacity. Most of the input values were obtained from publicly available information (SOO, planning reviews, IMO website, and companies' websites). In some cases, Market Participants have provided more accurate details on a confidential basis.

Missing parameters such as variable operating and maintenance (VOM) costs were estimated by SKM MMA, considering the nature and known characteristics of the facilities, or based on actual half-hourly dispatch information. The high VOM cost for Perth Energy was derived from the 2011 Energy Price Limits report, taking the reported VOM cost per hour of $270 adjusted to real June

[16] http://www.imowa.com.au/market-data-loss-factors

2011 dollars, multiplying by an estimate of hours operating based on 2010/11 actual data, and then dividing by an estimate of annual generation also based on the 2010/11 actual data.

For the wind farms and landfill gas plants, the assumed value of Large-scale Generation Certificates (LGCs) has been subtracted from the variable operating and maintenance costs, resulting in a negative SRMC. Even with an MCAP of $0/MWh, renewable generators would be foregoing LGCs revenue if they were shut down. The LGC price assumed in this study is $39.55/MWh based on 2013 prices currently being traded. Generation profiles for Albany, Emu Downs, and Alinta wind farms use historical data so that they are properly correlated to the load profile.

4.5.6. Future generators

Table 4-6 show the properties of future generators assumed to become operational within the review period. In summary, SKM MMA has considered the following units for commissioning:

- Bridgewater Biomass: This plant will be excluded from the analysis following advice from IMO that it is not expected to be available during the 2012/13 financial year
- Tesla Kemerton 9.9 MW of diesel units in Muja region assumed to be available from August 2012
- Tesla Northam 9.9 MW of diesel units in Muja region assumed to be available from August 2012
- Tesla Geraldton 9.9 MW of diesel units in North Country region assumed to be available from August 2012
- 13.8 MW Grasmere Wind Farm assumed to be available for all of 2012/13
- Merredin Energy 2 x 41 MW GE Frame 6 distillate fired gas turbine peakers located in the Muja region assumed to be available from August 2012
- Muja 1-4 60 MW coal units that are being recommissioned and assumed to be in service for all of 2012/13
- 55 MW Mumbida Wind Farm, assumed to be available from December 2012 (based on publicly available information)
- Greenough 10 MW Solar Farm (PV), assumed to be available from August 2012.

Table 4-6 Properties of future generators

Generator	Average Electrical HR (GJ/MWh sent out HHV) at max	Average Electrical HR (GJ/MWh sent out HHV) at min	Primary fuel	Primary Fuel Price ($/GJ)	Transport charge ($/GJ)	VO&M ($/MWh sent out)	Average CO2-e emission intensity at max (kg/MWh sent out)	Carbon cost ($/MWh sent out)	SRMC 2012/13 ($/MWh sent out)	MLF
TESLA_GERALDTON_G1	14.44	14.44	Distillate	22.15	-	$2.59	1080	23.85	346.33	1.04
TESLA_KEMERTON_G1	14.44	14.44	Distillate	22.15	-	$2.59	1080	23.85	346.33	1.01
TESLA_NORTHAM_G1	14.44	14.44	Distillate	22.15	-	$2.59	1080	23.85	346.33	1.00
GRASMERE_WF			Wind		-	-$39.55			-39.55	1.04
NAMKKN_MERR_SG1	12.58	12.58	Distillate	22.15	-	$4.61	941	20.78	304.08	1.03
MUJA_G1	12.43	12.89	Coal	2.06	-	$4.50	1157	25.55	55.66	1.00
MUJA_G2	12.43	12.89	Coal	2.06	-	$4.50	1157	25.55	55.66	1.00
MUJA_G3	12.43	12.89	Coal	2.06	-	$4.50	1157	25.55	55.66	1.00
MUJA_G4	12.43	12.89	Coal	2.06	-	$4.50	1157	25.55	55.66	1.00
Mumbida Wind Farm			Wind		-	-$39.55			-39.55	0.95
Greenough Solar Farm (PV)			Solar		-	-$39.55			-39.55	1.04

4.5.7. Heat rates

The sent out heat rates presented in Table 4-5 are based on available published or calculated values, using engineering judgement, for the rated plant capacities at ISO conditions, expressed as Higher Heating Value (HHV). In some instances, generators have provided more accurate information on a confidential basis, following requests for details made by the IMO as part of the consultation processes for this review and for the 2012/13 financial year review under the current Market Rules. It should be noted that the marginal HHV heat rate is typically lower than the average HHV heat rate at maximum sent-out rated capacity so the SRMC values are likely to be slightly over-estimated in Table 4-5. In the market modelling, polynomial heat input functions are specified for most generators, and the SRMC at any output level is calculated based on the marginal heat rate at that point on the curve.

In some instances, no information on the heat input function was available. For these units, a static heat rate value is assumed regardless of output level. These units are not ones that would be expected to provide reserve, so the lack of heat input function is not considered material for this analysis.

For the generators servicing intermittent load only an average heat rate is assumed, since the full capacity range of the generator is not modelled in the simulation. For these generators, only the generation in addition to the private load is offered into the STEM, up to the maximum scheduled generation volume. On average, it is assumed that a generator servicing private load that is offering additional generation into the STEM is operating at a relatively efficient point on its heat rate curve.

4.6. Reserve modelling assumptions

In determining the availability cost of providing ancillary services, both spinning reserve and load following reserve have been modelled in PLEXOS.

System Management has been consulted on the information in this section to verify its accuracy.

4.6.1. Spinning reserve

The spinning reserve requirement in the WEM is equivalent to 70% of the generating unit producing the largest total output in that period. Spare capacity on other generating units and/or interruptible load is made available to support system frequency in the event of a contingency.

4.6.2. Load following reserve

Load following reserve is required to meet fluctuations in supply and demand in real time. The load following reserve is a component of the spinning reserve. Therefore, the same MW of reserve may be used to meet both the load following and spinning reserve requirements. The total spinning reserve requirement in the WEM is therefore reduced by the amount of load following reserve that is being provided.

Based on the estimate of the load following requirement following the commissioning of Collgar provided in System Management's Ancillary Service Report for 2011[17], we assume a load following requirement of ± 90 MW for the 2012/13 financial year with a ramp rate of +/- 18 MW/min. This increases the load following requirement from 60 MW prior to the commissioning of the Collgar wind farm. Under the new arrangements, System Management will be able to reduce the load following requirement for some Trading Intervals where, for example, calm conditions are forecast. However, as System Management has not been able to provide an estimated pattern for these reductions, the modelling has assumed the full ± 90 MW requirement for all Trading Intervals.

While the dispatch of a load following generator can vary from minute to minute to meet generation and demand fluctuations, for modelling purposes it is assumed that, on average across the half hour period, a load following generator is not providing any load following. That is, intra-half-hour load following fluctuations in their generation average out.

4.6.3. Reserve provision

PLEXOS requires the user to specify which generators can provide a particular type of reserve. Some may be better suited for providing spinning reserve than load following reserve, and some may not be suitable for providing reserve at all, depending on their operational flexibility and the commercial objectives of their owners.

Under the new LFAS Market arrangements, both Verve Energy and IPPs may provide load following reserve subject to meeting technical requirements. The generators providing load following reserve must be able to raise or lower their generation in response to Automatic Generation Control (AGC) signals. The same generator does not need to provide both the raise and lower load following reserve, provided that in aggregate across all generators providing load following reserve the total required amounts of raise and lower service are available.

System Management has advised that at present only NewGen Kwinana and NewGen Neerabup are able to meet these technical requirements and it is unlikely that others will be able to meet the requirements in less than 6 months. The IMO sought advice from selected IPPs regarding their intention to participate in the LFAS market over the review period. Two IPPs indicated an intention to participate in the LFAS market within the review period, albeit potentially not at market start, and have been included in the market modelling accordingly. Spinning reserve continues to be provided by Verve Energy or through ancillary service contracts under the new MEP arrangements.

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[17] *http://www.imowa.com.au/f2841,1297737/Ancillary_Service_Report_2011_FINAL.pdf*

For all generators specified as being able to provide reserve, PLEXOS assumed by default that, if a unit is generating, all spare capacity could contribute to providing reserve. This is not always possible, so PLEXOS allows users to specify a *Reserve.Generator.Max response* for each generator that can provide reserve. If used, this property limits the reserve provided by a generator in a given period to the minimum of the *Max response* and the spare capacity on the generating unit.

The maximum responses currently assumed are based on information provided by System Management. For some units, all spare capacity is assumed to be available for providing spinning reserve and load following reserve. For load following reserve, the maximum response represents a unit's ability to increase or decrease output (or some combination of the two) within a 10 minute period. For spinning reserve, additional restrictions are imposed on some units, as suggested by System Management.

4.6.4. Ancillary service contracts

Some spinning reserve may be provided by reducing load through interruptible load Ancillary Service Contracts. Consistent with System Management's Ancillary Service Report for 2011[18], provided to the IMO under clause 3.11.11, 42 MW of interruptible load is assumed to be available. This interruptible load can be used at all times to provide spinning reserve.

No other Ancillary Service Contracts for spinning reserve are assumed for the purposes of this study.

Effectively, the spinning reserve requirement to be provided by Verve Energy is therefore equal to:

70% largest generating unit – 42 MW interruptible load – 90 MW load following reserve.*

4.6.5. Value of reserve shortage

Clause 3.10.2 (d) of the Market Rules states that the spinning reserve requirement may be relaxed if:

"…all reserves are exhausted and to maintain reserves would require involuntary load shedding".

To ensure that reserve levels are relaxed prior to involuntary load shedding, a value of reserve shortage (VoRS) is defined representing the cost per MWh of not meeting the reserve requirement. In PLEXOS, a VoRS of $1,000/MWh is assumed for the WEM.

[18] http://www.imowa.com.au/f2841,1297737/Ancillary_Service_Report_2011_FINAL.pdf

5. Results

In each half-hour trading period, the availability cost was calculated using the methodology described in Section 2 and a margin value was determined by rearranging the formula specified in clause 9.9.2 (f) of the proposed new rules.

The margin values, availability cost and system marginal prices are presented in Table 5-1 averaged over 12 random outage samples. Unlike previous modelling, the Margin_Peak and Margin_Off-Peak in about half of the samples differ from the mean by more than 5%.

Table 5-1 Parameter estimates

Parameter	Average	Standard Error
Margin_Off-Peak	31%	2.3%
Margin_Peak	32%	2.1%
SR_Capacity_Off-Peak	205.78	0.25
SR_Capacity_Peak	221.49	0.06
Availability cost ($M)	12.51	0.84
Off-peak price ($/MWh)	52.57	0.14
Peak price ($/MWh)	55.93	0.25

On average, a Margin_Off-Peak value of 31% is recommended, based on time-weighted average system marginal off-peak prices of $52.57/MWh. For Margin_Peak, an average value of 32% has been estimated, based on time-weighted average system marginal peak prices of $55.93/MWh. In some instances during peak periods, IPP generation was backed off and total Verve Energy output was increased in order to meet the spinning reserve requirements. If the resulting increase in sales revenue was greater than the increase in cost, the net benefit reduced the reserve availability cost.

In the 2010 review simulations SKM MMA recommended a Margin_Peak value of 25% and a Margin_Off-Peak value of 43% for the financial year 2011/12. For the 2012/13 financial year, the Margin_Peak value has increased and the Margin_Off-Peak value has decreased. However, the estimated availability payment has reduced, since Verve Energy is now only compensated for spinning reserve provision through these payments.

There are several modelling changes causing the differences between the 2010 review's and this review's simulations:

- Update on input assumptions for generator properties such as minimum generation levels, which affect the unit commitment decisions
- The introduction of a carbon price, which has a greater impact on off-peak prices where coal plants tend to be the price setter
- Changes in the modelling approach to load following reserve such that a generator is not required to provide both raise and lower services, provided that the total raise is provided in the WEM is equal to the total lower. This relaxes the load following reserve constraints in the market modelling, allowing reserve to be provided at lower cost. This has most impact in the off-peak when any unit providing load following reserve had to be operating above minimum generation level in the previous analysis.
- Lower gas prices, due to revised gas transport charges and contract prices, arising from back-casting and stakeholder consultation.

Additionally, the introduction of the RC_2011_10 changes influences the results in two opposing ways:

- The incremental cost of backing off generation to provide spinning reserve is greater than the average cost of providing both load following reserve and spinning reserve in the off-peak, resulting in an increase in margin values
- The total cost of providing load following and spinning reserve is lower due to the participation of IPPs in the LFAS market.

Analysis conducted by SKM MMA for the 2012/13 financial year without the RC_2011_10 changes indicates that the rule change would have most impact on the Margin_Off-Peak values, moderating the magnitude of the reduction that would otherwise have been observed with the introduction of a carbon price, reduction in gas prices, and other modelling assumptions outlined above.

The larger variation in Margin_Peak and Margin_Off-Peak values under the new market arrangements is due to the sensitivity of availability cost to start-up costs of generators providing spinning reserve. The margin value analysis is now conducted comparing market outcomes with and without spinning reserve, but including load following reserve in both simulations. Maximising economically efficient dispatch, whilst providing load following reserve, relies heavily on optimising the unit commitment decisions, particularly in the off-peak. SKM MMA has attempted to maintain a high level of precision in simulating the unit commitment decisions. Nonetheless, slight variations in these unit commitment decisions between runs with and without spinning reserve are leading to larger variations in the sample results than previously experienced. SKM MMA confirmed this by removing the start-up and shutdown cost in calculating availability costs and resulted in Margin_Peak and Margin_Off-Peak values that have less variations and lower standard errors.

Therefore, whilst variations in unit commitment decisions are expected between the runs with and without spinning reserve, it is possible that some of the variations are an artefact of the modelling rather than due to the provision of spinning reserve. SKM MMA has run as many samples as possible within the time frame available in order to minimise this “noise” whilst still maintaining a high level of precision in the modelling (which increases run times), but acknowledges that the variation in twelve samples is still relatively high, as demonstrated in Table 5-2.

Table 5-2 Key margin value parameters by sample

Sample	S01	S02	S03	S04	S05	S06	S07	S08	S09	S10	S11	S12	Average
Margin off-peak	33%	38%	17%	34%	21%	30%	46%	25%	23%	34%	36%	32%	31%
Margin peak	34%	36%	28%	37%	24%	33%	50%	24%	33%	23%	30%	33%	32%
Availabilty cost ($M)	$13.34	$14.42	$9.35	$13.93	$9.08	$12.69	$19.74	$9.66	$11.65	$10.65	$12.79	$12.85	$12.51
OP availability cost ($M)	$4.67	$5.27	$2.40	$4.75	$2.95	$4.29	$6.68	$3.52	$3.15	$4.91	$4.98	$4.51	$4.34
P availability cost ($M)	$8.67	$9.15	$6.94	$9.17	$6.14	$8.40	$13.06	$6.15	$8.50	$5.74	$7.81	$8.34	$8.17
Off-peak price ($/MWh)	$52.36	$52.61	$52.15	$51.80	$52.07	$52.75	$53.47	$52.82	$52.97	$53.02	$52.18	$52.63	$52.57
Peak price ($/MWh)	$55.89	$55.76	$54.88	$54.52	$55.62	$55.88	$57.56	$57.01	$56.73	$55.85	$56.19	$55.24	$55.93
SR_Capacity_Peak (MW)	221.64	221.36	221.47	221.86	221.35	221.53	221.61	221.27	221.13	221.44	221.46	221.79	221.49
SR_Capacity_Off-Peak (MW)	206.86	205.30	206.04	207.19	205.65	205.44	206.21	204.71	204.49	206.55	204.72	206.24	205.78

6. Conclusions

Based on our market modelling, SKM MMA recommends the following margin values for the financial year commencing July 2012:

- Margin_Off-Peak 31%
- Margin_Peak 32%.

These values are sensitive to a number of factors including:

- the price and volume assumptions relating to existing gas contracts
- the unit commitment decisions, which are based on start-up costs, minimum generation assumptions and the maximum reserve provision for each unit
- carbon price assumptions
- the extent of IPP participation in the new LFAS market
- the market rules determining which facilities can provide Ancillary Services.

Moreover, these margin values have been developed assuming that no Ancillary Service Contracts for spinning reserve (apart from the existing contracts for Interruptible Load) are negotiated for the 2012/13 financial year.

If any of these assumptions were to change, the margin values may need to be reviewed.