Your ref:
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Enquiries: Suzanne Frame

Mr Robert Pullella
Executive Director
Economic Regulation Authority
Level 6, Governor Stirling Tower
197 St Georges Terrace
PERTH WA 6000

Dear Rob,

SUBMISSION UNDER CLAUSE 3.13.3A(a)

In accordance with clause 3.13.3A(a) of the Wholesale Electricity Market Rules (Market Rules), 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 during the Financial Year commencing 1 July 2012 (2012/13 Financial Year).

The margin values presented in this submission have been developed under the current Market Rules, which require the IMO to submit a proposal to the ERA by 30 November 2011. It should be noted that the Market Evolution Program (MEP) Rule Change Proposal: Competitive Balancing and Load Following Market (RC_2011_10) proposes significant changes to the provision of Load Following Ancillary Services (LFAS) in the Wholesale Electricity Market (WEM). These changes, which have an expected implementation date of 1 April 2012, will require the determination of alternative margin values as the availability payments made to Verve Energy will no longer include compensation for the provision of LFAS. To meet this new requirement the IMO has commenced work on the development of a methodology and input assumptions for the determination of margin values to support RC_2011_10.

We look forward to working with the ERA on establishing these new values.

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. 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	Current	Proposed
Margin Peak	25%	25%
Margin Off-Peak	43%	32%

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In its review, SKM MMA has re-applied the methodology it used for the reviews of margin values conducted in 2009 and 2010. The methodology has been modified to account for the expected price on carbon resulting from the implementation of the Clean Energy Future scheme on 1 July 2012.

In general, the modelling assumptions used in the study were based on the assumptions used for the 2010 review and updated as appropriate from the relevant sources (such as the 2011 Statement of Opportunities). However, the IMO and SKM MMA undertook the following additional measures to improve the quality of the input assumptions.

- The IMO sought advice from ACIL Tasman on expected gas transport costs for gas generators in the WEM for the 2012/13 Financial Year.
- In preparation for the 2011 review SKM MMA undertook an analysis of modelled versus actual MCAP and generation volumes for the 2010/11 Financial Year. Based on the outcomes of this analysis SKM MMA recommended several changes to the assumptions for the 2011 review. These included the correction of some minimum generation levels, changing the status of the Kwinana NewGen Facility to "must run", the reduction of some gas price assumptions, an increase in the assumed value of steam for cogeneration units and changes to the source of outage assumptions.
- System Management revised the network topography assumptions and provided updated load profiles by region.
- SKM MMA prepared a draft Assumptions Report outlining the methodology and assumptions proposed for the review. System Management reviewed and provided feedback on the full (confidential) version of this report.
- A public version of the draft Assumptions Report, which excluded confidential Market Generator details, was published by the IMO on 6 October 2011. 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 draft Assumptions Report.
- The IMO received one request for direct consultation and met with Verve Energy and SKM MMA to discuss the Assumptions Report on 17 October 2011. Verve Energy also provided the only submission received during the consultation period, which closed on 20 October 2011.
- The IMO also requested feedback from six of the largest Market Generators on full extracts of the key assumptions for their Facilities. Two Market Generators provided feedback on their Facility assumptions.
- SKM MMA used the feedback provided by stakeholders to update the input assumptions for the 2011 review.

If you have any queries please do not hesitate to contact me.

[redacted]

ALLAN DAWSON
CHIEF EXECUTIVE OFFICER

30 November 2011

2011 Margin Peak and Margin Off-Peak Review

V2.0 FINAL REPORT TO IMO

- 29 November 2011

2011 Margin Peak and Margin Off-Peak Review

V2.0 FINAL REPORT TO IMO

- 29 November 2011

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Contents

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SINCLAIR KNIGHT MERZ SKM MMA

Executive summary

The Wholesale Electricity Market Rules (Market Rules) require the Economic Regulation Authority (ERA) to determine Margin_Peak and Margin_Off-Peak values for each financial year in accordance with the methodology set out in clause 3.13.3A (a) of the Market Rules. Under clause 3.13.3A(a) the Independent Market Operator (IMO) must submit a proposal for these values to the ERA by 30 November each year for the following financial year.

In determining these margin values, the Market Rules require IMO 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 (SR). 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) 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.

Accordingly, the 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 financial year commencing July 2012.

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 Mechanism were not modelled explicitly, the dispatch outcomes from simulation of the gross pool assuming short run marginal cost (SRMC) bidding should be equivalent to economically efficient WEM outcomes.

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 for this year's review.

Some differences in market outcomes were observed during the 2010/11 analysis, 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 were 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 0-1.

■ **Table 0-1 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	9.4	10.7	-12%	8.8	7%

On close inspection of the market modelling outcomes from the analysis of the 2010/11 outcomes, and the back-casting exercise, it was recommended that the following input assumption modifications be adopted for the current 2012/13 Margin Value review to improve the accuracy of the forecasts:

- Correct minimum generation levels, as advised by System Management
- Make the Kwinana NewGen unit ‘must run’
- Reduce gas price assumptions
- Increase value of steam revenue assumed for cogeneration units
- Endeavour to include any known large outages scheduled for the review period.

These assumption modifications have been included in this year’s analysis.

To assess the reserve availability cost that could reasonably be expected to be incurred by Verve Energy for the financial year starting 1 July 2012, revenue and generation cost outcomes were compared from two market simulations with and without SR and Load Following Reserve (LFR) 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 reserve provision

GenCost_NRP = Verve Energy's total generation costs, including start-up costs, without any reserve provision

GenQ_Res = Verve Energy's total generation volume, with reserve provision

GenQ_NRP = Verve Energy's total generation volume, without any reserve provision

SMP = system marginal price with reserve provision

Having determined the reserve availability cost, average annual Capacity_R_Peak and Capacity_R_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(a) of the Market Rules.

The resulting margin values proposed for the financial year commencing July 2012 are 25% for Margin_Peak and 32% for Margin_Off-Peak. Table 2 summarises the availability cost, Capacity_R_Peak and Capacity_R_Off-Peak, and peak and off-peak SMPs that form the basis for this assessment, averaged over 10 random outage samples.

Table 2 Parameter estimates for 2012/13 financial year

Parameter	Average	Standard Error
Margin_Off-Peak	32%	0.4%
Margin_Peak	25%	0.4%
Capacity_R_Off-Peak	207.8	0.2
Capacity_R_Peak	219.9	0.1
Availability cost ($M)	22.48	0.25
Off-peak price ($/MWh)	52.00	0.23
Peak price ($/MWh)	55.71	0.27

In assessing these margin values, the following key assumptions were 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 July 2012
- Two Merredin Energy distillate fired gas turbine peaking units (82 MW) were available from July 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 by July 2012, with the 55 MW Mumbida wind farm being available from December 2012
- LFR requirement of ± 90 MW, which can only be provided by Verve Energy
- Ancillary Service contracts were assumed to provide Spinning Reserve capacity (from Interruptible Loads) of 42 MW
- No Ancillary Service contracts for LFR were assumed
- Start-up costs incurred due to provision of reserve were included as part of the reserve availability cost.

1. Introduction

The Independent Market Operator of Western Australia (IMO) engaged SKM MMA to assist in determining the appropriate margin values to be used for the financial year starting 1 July 2012.

In assessing the Margin_Peak and Margin_Off-Peak values, market modelling and analysis was conducted taking into account the factors for determining the margin values as prescribed in clause 3.13.3A (a) of the Market Rules.

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.

SINCLAIR KNIGHT MERZ SKM MMA

2. Methodology for calculating margin values

Ancillary services for the Western Australian Wholesale Electricity Market (WEM) are currently provided by Verve Energy. The IMO pays Verve Energy for these services in accordance with the formula prescribed in clause 9.9.2(a) of the Wholesale Electricity Market Rules (Market Rules).

Two of the key parameters of the formula in 9.9.2(a) are the Margin_Peak and Margin_Off-Peak, which are to be proposed by the IMO to the ERA each financial year. These parameters are intended to reflect the payment margin (i.e. as a percentage of the Marginal Cost Administrative Price (MCAP) in either the peak or off-peak periods) that, when multiplied by the volume of reserve provided and the MCAP, will compensate Verve Energy for energy sales foregone and losses in generator efficiency resulting from backing off generation to provide Spinning Reserve (SR). Clause 3.13.3A(a) stipulates that:

(a) by 30 November prior to the start of the Financial Year, the IMO must submit a proposal for the Financial Year to the Economic Regulation Authority:

i. *for the reserve availability payment margin applying for Peak Trading Intervals, Margin_Peak, the IMO must take account of:*

   1. *the margin the Electricity Generation Corporation could reasonably have been expected to earn on energy sales forgone due to the supply of Spinning Reserve during Peak Trading Intervals;*

   2. *the loss in efficiency of the Electricity Generation Corporation 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;*

ii *for the reserve availability payment margin applying for Off-Peak Trading Intervals, Margin_Off-Peak, the IMO must take account of:*

   1. *the margin the Electricity Generation Corporation could reasonably have been expected to earn on energy sales forgone due to the supply of Spinning Reserve during Off-Peak Trading Intervals;*

   2. *the loss in efficiency of the Electricity Generation Corporation 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;*

If only Verve Energy provides Ancillary Services, the reserve availability cost is 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) 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 Independent Power Producer (IPP) (Gen 3). In this example, summarised diagrammatically in Figure 2-1, only the Market Generator can provide reserve and, in this period, SR 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.

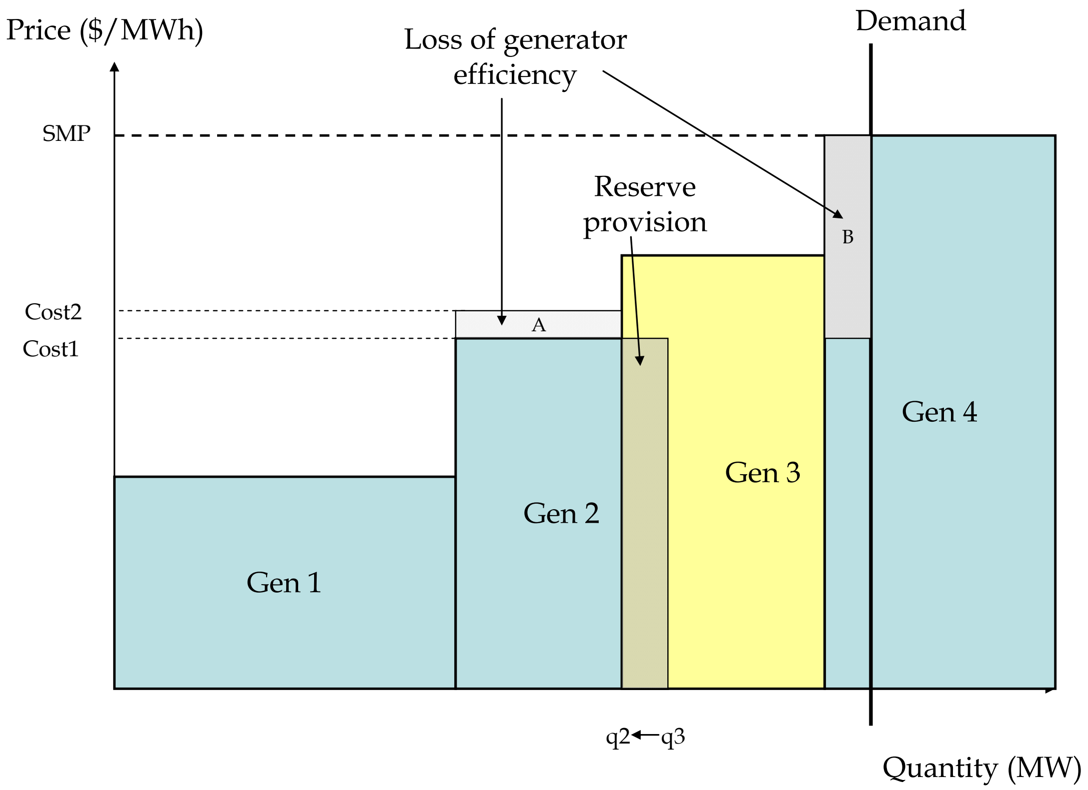
2.2. Constraining units on to provide reserve

During the off-peak, some units may be constrained on at minimum stable 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 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 stable 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 stable 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

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

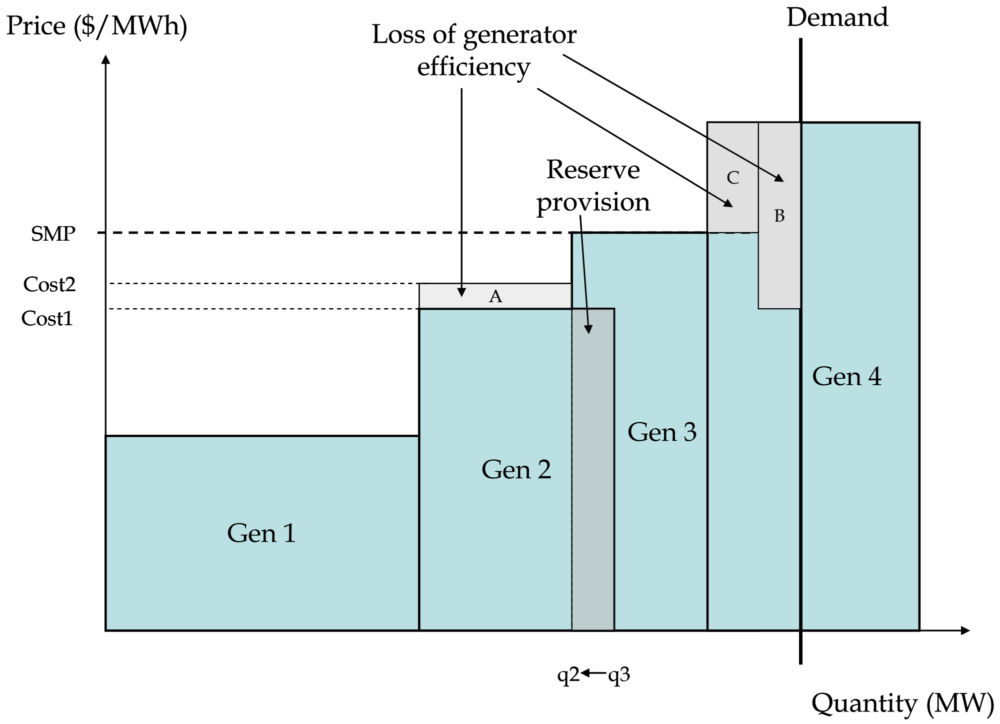


minimum stable level (Figure 2-2). At the margin, any variations in demand will be met by Gen 3. Therefore, Gen 3 is the marginal generator setting the price, not Gen 4. The reserve availability cost is the sum of areas A, B and C, representing the increase in generation costs incurred by Market Generator 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 stable 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 last year's review). In the WEM, this situation may arise if Cockburn is constrained on, as SKM MMA understands that this unit has a relatively high minimum stable level.

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 IPP's is relatively high, since Verve Energy is assumed to be the sole provider of SR.

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



2.3. Calculating availability cost

Through market simulations, the availability cost was calculated for peak and off-peak periods by comparing Verve Energy's total generation costs and generation quantities, with and without providing reserve. 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 reserve provision
GenCost_NRP	= Verve Energy's total generation costs, including start-up costs, without any reserve provision
GenQ_Res	= Verve Energy's total generation volume, with reserve provision
GenQ_NRP	= Verve Energy's total generation volume, without any reserve provision
SMP	= system marginal price with reserve provision

For calculating losses in generator efficiency resulting from reducing output to provide SR, heat rate curves were considered within SKM MMA's WEM database.

2.4. Calculating Margin Values

Clause 9.9.2(a) of the Market Rules provides a formula for calculating the total availability cost each month as a function of the Margin_Peak, Margin_Off-Peak, Capacity_R_Peak, Capacity_R_Off-Peak, and MCAP prices. Margin Values can therefore be calculated by rearranging this formula and using key outputs from the market simulations.

The Capacity_R_Peak and Capacity_R_Off-Peak parameters represent the capacity necessary to cover Ancillary Service Requirement for Spinning Reserve as specified by IMO under clause 3.22.1(e) and (f), which defines the Ancillary Service Requirement as being equal to the requirement assumed in calculating the Margin values. Therefore, the Capacity_R_Peak and Capacity_R_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 were therefore averaged over the year in order to determine a single Capacity_R_Peak and Capacity_R_Off-Peak value for use in the formula in clause 9.9.2(a).

3. Modelling the wholesale electricity market

The WEM for the South West interconnected system (SWIS) commenced operation on 21 September 2006. 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
- a services component, to balance supply and demand, dispatch SR and ensure supply reliability and quality
- a Reserve Capacity Mechanism (RCM), to ensure that there is adequate capacity to meet demand each year.

The energy market and the RCM 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.

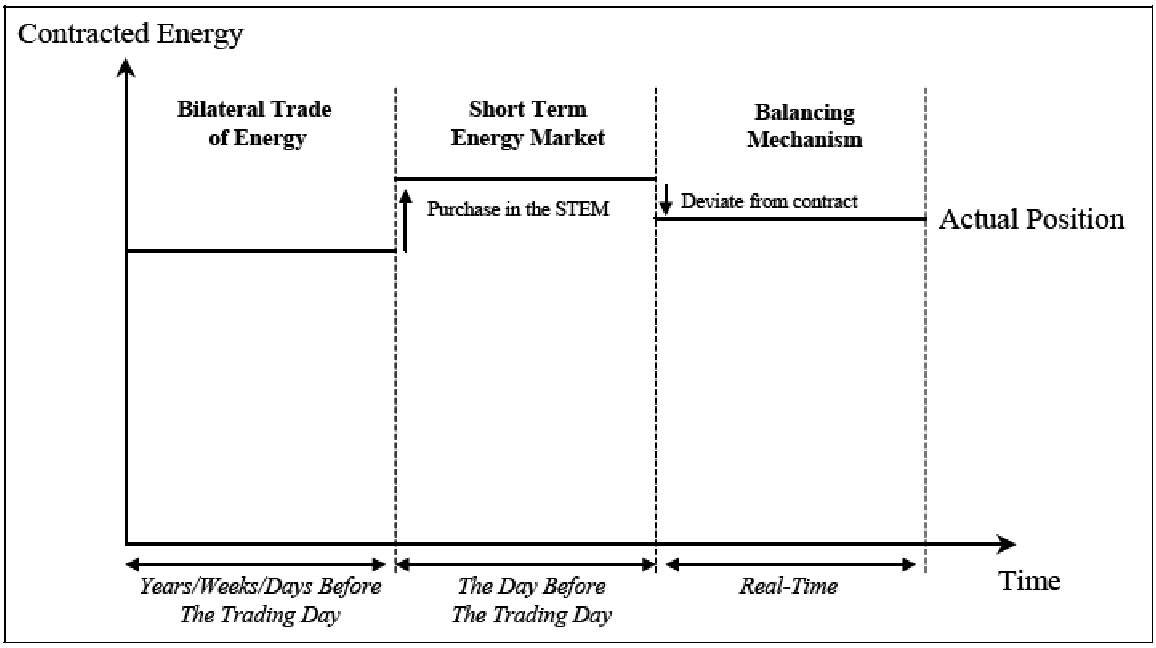
The STEM is a residual, day-ahead trading market which allows contract participants to trade out any imbalances. Market Participants (both Market Generators and Market Customers) can submit offers to sell energy to the STEM, or bids to buy energy from the STEM. Market generators may wish to buy energy 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, Market Customers 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 balancing mechanism, System Management may instruct Verve Energy to alter its scheduled dispatch in real time to accommodate these deviations and maintain system security. If necessary, IPPs may also be instructed to vary generation volumes, although this currently occurs very rarely. The MCAP is the price determined after supply and demand have been balanced in real time, and is calculated in accordance with Section 6.14 of the Market Rules.

Figure 3-1 shows the relationship between bilateral trades, the STEM and the balancing mechanism.

■ **Figure 3-1 Components of the Energy Trading Market**



SOURCE: IMO. 2006. *The South West Interconnected System Wholesale Electricity Market: An Overview*

3.1. PLEXOS simulation software

For this analysis the WEM was simulated 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 markets in the WEM, using the same techniques that are used to clear the NEM, New Zealand and Singaporean electricity markets.

In the PLEXOS model, SKM MMA did not explicitly model the bilateral trades, STEM and balancing market separately. Instead, a gross pool was modelled, assuming economically efficient short-run marginal cost dispatch. In theory, the same economically efficient dispatch outcomes should be achievable from the STEM as from a gross pool, with lowest cost resources scheduled first. Prior to undertaking this review, a back-casting exercise was undertaken to test this premise, based on the 2010/11 year. Outcomes of this back-casting exercise are discussed in SKM MMA's *Ancillary Services Market Review – Task 1*, (October 2011).

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

- generation constraints – availability (planned and unplanned outages), unit commitment and other technical constraints
- transmission constraints –linearised DC optimal power flow (OPF) equations and line ratings
- fuel constraints – for example, daily fuel limits
- ancillary service constraints – maximum unit response, calculation of dynamic risk.

Requirements for LFR and SR are modelled as two different services in the PLEXOS model, with the SR requirement being equal to the total ancillary service requirement less the amount of LFR provision.

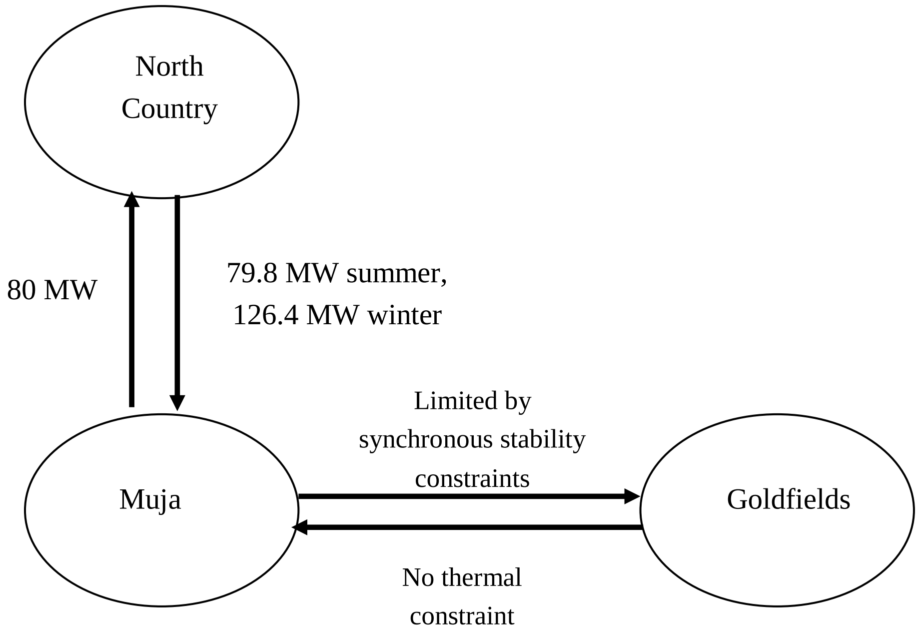
4. Key modelling assumptions

This section outlines the key modelling assumptions used in the PLEXOS market simulations. Since the previous margin value review, some of these assumptions have been adjusted through back-casting analysis, and have been reviewed by the IMO and System Management. In addition, market participants were requested to confirm the assumptions made with regard to their own facilities.

4.1. Network topography

The SWIS was modelled as a three-node system with a single uniform price. Interconnectors between the three nodes: Muja, Goldfields and North Country, allowed 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. The transmission upgrade from North Country to Muja (Mid West Energy Project), was assumed to lie outside the horizon of this study.

▪ **Figure 4-1 3-node model of SWIS model**



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 diesel unit, 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, synchronous stability constraints constrain levels of generation in the Goldfields 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 our assumptions for sent-out energy and summer and winter maximum demand across the three 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)	18,123	633	712	19,468
	Summer Peak Demand 50% PoE (MW)	4,120	143	150	4,340
	Winter Peak Demand 50% PoE (MW)	3,181	139	108	3,328
	Intermittent non-scheduled load (MW)	110.3	46	0	156.3

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 year.

For our chronological modelling in PLEXOS, we use half hourly load profiles for the three 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

We are representing the following fuels in our modelling:

- Coal: used by Muja, Collie and the Bluewaters units,
- Cogeneration contract gas: gas for Alcoa Wagerup and the equivalent of one of the two Alinta cogeneration units
- Verve Contract gas: gas under existing Verve Energy contracts,
- NewGen contract gas: contract gas to supply the Kwinana NewGen CCGT
- 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:

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

Name	Price ($/GJ) 2012/13
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

For coal, gas and landfill gas, excluding the NewGen contract gas, the prices used are those approved by the ERA for the 2010 review, 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 observation of 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.

Distillate prices come from SKM MMA's Draft Electricity Price Limits 2011 study[1], which estimated a nominal 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 67c/GJ.[2]

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 report 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

[1] http://www.imowa.com.au/f4153,1540757/SKM_MMA_Draft_2011_EPL_Report.pdf

[2] 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%).

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.

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.

4.3.2. Fuel constraints

Based on our understanding of the market and historical data, we have included gas constraints limiting the contract gas daily availability. We also included some constraints on the total gas available in different locations. These figures correspond to estimations from historical dispatch data and liquid fuel usage for 2008, and have been fine-tuned in our 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. In real June 2011 dollars, this is equivalent to approximately $22.1/t CO_2-e.

The introduction of a carbon price will impact on the marginal cost of supply and MCAP in the market simulations. For a given carbon price, PLEXOS automatically recalculates the short-run marginal cost 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 below.

- **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

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 marginal 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 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[3] 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, 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[4].

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[5]. The total emission of the Dampier to Bunbury Pipeline is published in the NGERS Greenhouse and Energy Information for 2009/10[6] as 357,468 t CO_2-e. The average throughput of the pipeline is approximately 1000 TJ/day which gives an annual value of 365 PJ. Dividing the published emissions into the throughput gives a transport emission of 0.979 kg CO_2-e/GJ.

For the Gas to Goldfields Pipeline, 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[7]. 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 37,185 t CO_2-e. Dividing this quantity into the estimated

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

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

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

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

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

contract capacity of 105.64 TJ/day[8], gives a transport emission intensity of 0.964 kg CO_2-e /GJ delivered. These calculations are summarised in Table 4-4.

Table 4-4 Analysis of gas transport emissions

	Units	DBNP	GGT
Energy Consumption	TJ	N/A	490
Gas Combustion	t CO_2-e	345269	25152
Pipeline	t CO_2-e	12199	12034
Total	t CO_2-e	357468	37185
NGER Emissions	t CO_2-e	357468	N/A
Transported	TJ	365000	38558.6
	TJ/day	1000	105.64
Emissions	t CO_2-e /GJ	0.979	0.964

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

52.31 kg CO_2-e /GJ for Muja and North Country

52.29 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 Dampier to Bunbury Pipeline 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

The modelling of the existing generation system includes the larger private power stations owned by Alcoa and the Goldfields miners. Table 4-5 shows some of the key properties of existing

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

generators in the model[9]. Some of the objects listed may represent the aggregation of one or more actual facilities.

4.5.2. 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. System Management has advised that the 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. However, System Management has also indicated that actual shutdown depends on the reserve margin for the next day. If the reserve margin is expected to be tight, windfarms and Kwinana NewGen may get shut down ahead of Muja 5/6 as they are expected to have a higher probability of return to service after shutdown.

Based on the 2010/11 observed operating profile, it would appear that Kwinana NewGen very rarely gets shutdown. Therefore, for the purpose of this analysis, we have also treated this CCGT as a must-run unit.

[9] 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.

■ Table 4-5 Properties of existing generators

Generator	Units	Average Electrical HR (GJ/MWh sent out HHV) at max	Average Electrical HR (GJ/MWh sent out HHV) at min	Primary Fuel	Fuel Price 2012/13 ($/GJ)	Transport charge ($/GJ)	VO&M ($/MWh sent out)	Carbon cost ($/MWh sent out)	SRMC 2012/13 ($/MWh sent out)	MLF
BW1_BLUEWATERS_G2	1	9.75	10.79	Coal	2.06		2.25	20.88	43.21	1.00
BW2_BLUEWATERS_G1	1	9.75	10.79	Coal	2.06		2.25	20.88	43.21	1.00
COLLIE_G1	1	9.5	10.38	Coal	2.06		1.12	20.34	41.04	1.00
MUJA_G5	1	11.04	14.06	Coal	2.06		4.50	23.64	50.88	1.00
MUJA_G6	1	11.04	14.06	Coal	2.06		4.50	23.64	50.88	1.00
MUJA_G7	1	9.85	11.37	Coal	2.06		4.22	21.09	45.61	1.00
MUJA_G8	1	9.85	11.37	Coal	2.06		4.22	21.09	45.61	1.00
ALINTA_PNJ_U1	1	12	12	Cogen gas	2.64	1.09	-20.19*	14.43	48.46	0.99
ALINTA_PNJ_U2	1	12	12	New gas	6.18	1.09	-20.19*	14.43	90.98	1.01
ALCOA_WGP	1	12	12.62	Cogen gas	2.64	1.09	-16.89*	14.43	51.75	0.99
PPP_KCP_EG1	1	8	10.48	Verve gas	3.09	1.09	-25.25*	9.62	53.94	1.03
SWCJV_WORSLEY_COGEN _COG1	1	12	12.02	Verve gas	3.09	1.09	-25.70*	14.43	78.19	0.99
TIWEST_COG1	1	13	21.33	Verve gas	3.09	1.09	-29.19*	15.64	80.88	1.03
COCKBURN_CCG1	1	8	8.43	Verve gas	3.09	1.09	3.88	9.62	53.27	1.01
KWINANA_G5	1	11.7	14.42	Verve gas/Coal	2.58	1.09	4.33	19.56	76.02	1.01
KWINANA_G6	1	11.7	14.42	Verve gas/Coal	2.58	1.09	4.33	19.56	76.02	1.01
KWINANA_GT1	1	14.6	25.99	Verve gas	3.09	1.09	22.68	17.56	112.82	1.01
MUNGARRA_GT1	1	13.5	21.85	Verve gas	3.09	0.79	4.61	16.24	81.08	1.02
MUNGARRA_GT2	1	13.5	21.85	Verve gas	3.09	0.79	4.61	16.24	81.08	1.02
MUNGARRA_GT3	1	13.2	21.56	Verve gas	3.09	0.79	4.61	15.88	79.38	1.02
PINJAR_GT01	1	13.5	21.85	Verve gas	3.09	1.09	confidential	16.24	confidential	1.03

Generator	Units	Average Electrical HR (GJ/MWh sent out HHV) at max	Average Electrical HR (GJ/MWh sent out HHV) at min	Primary Fuel	Fuel Price 2012/13 ($/GJ)	Transport charge ($/GJ)	VO&M ($/MWh sent out)	Carbon cost ($/MWh sent out)	SRMC 2012/13 ($/MWh sent out)	MLF
PINJAR_GT02	1	13.5	21.85	Verve gas	3.09	1.09	confidential	16.24	confidential	1.03
PINJAR_GT03	1	13.2	22.46	Verve gas	3.09	1.09	confidential	15.88	confidential	1.03
PINJAR_GT04	1	13.2	22.46	Verve gas	3.09	1.09	confidential	15.88	confidential	1.03
PINJAR_GT05	1	13.2	22.46	Verve gas	3.09	1.09	confidential	15.88	confidential	1.03
PINJAR_GT07	1	13.2	22.46	Verve gas	3.09	1.09	confidential	15.88	confidential	1.03
PINJAR_GT09	1	12.5	19.28	Verve gas	3.09	1.09	4.50	15.04	81.67	1.03
PINJAR_GT10	1	12.5	19.28	Verve gas	3.09	1.09	4.50	15.04	81.67	1.03
PINJAR_GT11	1	12.2	21.74	Verve gas	3.09	1.09	5.23	14.68	80.55	1.03
NEWGEN_KWINANA_CCGT	1	7.9	7.9	NewGen gas	3.09	1.09	2.25	9.50	59.15	1.02
STHRNCRS_EG_1-2	1	12.66	12.66	IPP gas	4.12	2.41	4.55	15.23	130.82	1.26
STHRNCRS_EG_3-4	1	11.6	11.6	IPP gas	4.12	2.41	4.55	13.95	120.24	1.26
KEMERTON_GT11	1	12.2	13.25	Verve gas/distillate	3.09	1.09	2.40	14.68	77.72	1.01
KEMERTON_GT12	1	12.2	13.25	Verve gas/distillate	3.09	1.09	2.40	14.68	77.72	1.01
ALINTA_WGP_GT	1	11.5	16.2	New gas/distillate	6.18	1.09	2.40	13.83	108.93	1.01
ALINTA_WGP_GT2	1	11.5	16.2	New gas/distillate	6.18	1.09	2.40	13.83	108.93	1.01
NEWGEN_NEERABUP	2	11.7	12.06	New gas	6.18	1.09	2.40	14.07	110.79	1.04
PRK_AG	1	10.15	19.66	IPP gas	4.12	2.40	4.55	12.21	105.52	1.30
GERALDTON_GT1	1	15.25	15.95	Distillate	22.15		2.59	26.24	366.66	1.04
WEST_KALGOORLIE_GT2	1	13.5	13.5	Distillate	22.15	0.66	33.76	23.23	364.92	1.22
WEST_KALGOORLIE_GT3	1	14.75	14.75	Distillate	22.15	0.66	33.76	25.38	395.58	1.22
GENERIC LANDFILL GAS	1	11.3	11.3	Landfill Gas	2.25		-25.26		0.12	1.02

Generator	Units	Average Electrical HR (GJ/MWh sent out HHV) at max	Average Electrical HR (GJ/MWh sent out HHV) at min	Primary Fuel	Fuel Price 2012/13 ($/GJ)	Transport charge ($/GJ)	VO&M ($/MWh sent out)	Carbon cost ($/MWh sent out)	SRMC 2012/13 ($/MWh sent out)	MLF
ALBANY_WF1	12			Wind			-39.55		-39.55	1.04
ALINTA_WWF	54			Wind			-39.55		-39.55	0.95
EDWFMAN_WF1	48			Wind			-39.55		-39.55	1.00
SKYFRM_MTBARKER_WF1	1			Wind			-39.55		-39.55	1.04
KALBARRI_WF1	2			Wind			-39.55		-39.55	1.04
COLLGAR	127			Wind			-39.55		-39.55	1.13
PERTH_ENERGY_GT1	4	10.7	16.06	New gas	6.18	1.09	19.94	12.87	119.06	1.03
KWINANA_GT2	1	9.3	15.23	Verve gas/distillate	3.09	1.09	6.40	11.19	63.81	1.01
KWINANA_GT3	1	9.3	15.23	Verve gas/distillate	3.09	1.09	6.40	11.19	63.81	1.01
TESLA_PICTON	1	14.44	14.44	Distillate	22.15		2.59	24.84	347.32	1.00
KALAMUNDA	1	15.27	18.7	Distillate	22.15		2.59	26.27	367.13	1.01

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

4.5.3. 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. Ten Monte Carlo simulations are to be conducted 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.

4.5.4. 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[10] 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).

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 Energy Price Limits report, taking the reported VOM cost per hour of $270 adjusted to real June 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. In the case of

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

the Pinjar units, Verve Energy provided corrected VOM data, and this information has been treated as confidential, which is why the assumptions have not been included in Table 4-5.

For the wind farms and landfill gas plants the assumed value of renewable energy certificates (REC) 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 REC revenue if they were shut down. The REC price assumed in this study is $39.55/MWh based on 2012/13 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 50POE load profile.

4.5.5. Future generators

Table 4-6 shows the SRMC related properties of future generators assumed to become operational within the review period. In summary, we have considered the following units for commissioning:

- Bridgewater Biomass: This plant will be excluded from our 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 July 2012
- Tesla Northam 9.9 MW of diesel units in Muja region assumed to be available from July 2012
- Tesla Geraldton 9.9 MW of diesel units in North Country region assumed to be available from July 2012
- 13.8 MW Grasmere WF assumed to be available from July 2012
- Merredin Energy 2 x 41 MW GE Frame 6 distillate fired peakers located in the Muja region assumed to be available from July 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 WF, assumed to be available from December 2012 (based on publicly available information)
- Greenough 10 MW Solar Farm (PV), assumed to be available from July 2012 (based on publicly available information)

▪ Table 4-6 Properties of future generators

Generator	Units	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 2012/13 ($/GJ)	Transport charge ($/GJ)	VO&M ($/MWh sent out)	Carbon cost ($/MWh sent out)	SRMC 2012/13 ($/MWh sent out)	MLF
TESLA_GERALDTON_G1	1	14.44	14.44	Distillate	22.15	-	$2.59	24.84	347.32	1.04
TESLA_KEMERTON_G1	1	14.44	14.44	Distillate	22.15	-	$2.59	24.84	347.32	1.01
TESLA_NORTHAM_G1	1	14.44	14.44	Distillate	22.15	-	$2.59	24.84	344.73	1
GRASMERE_WF	6			Wind		-	-$39.55		-39.55	1.04
NAMKKN_MERR_SG1	2	12.58	12.58	Distillate	22.15	-	4.61	21.64	300.33	1.03
MUJA_G1	1	12.43	12.89	Coal	2.06	-	$4.50	26.62	56.72	1
MUJA_G2	1	12.43	12.89	Coal	2.06	-	$4.50	26.62	56.72	1
MUJA_G3	1	12.43	12.89	Coal	2.06	-	$4.50	26.62	56.72	1
MUJA_G4	1	12.43	12.89	Coal	2.06	-	$4.50	26.62	56.72	1
Mumbida Wind Farm	22			Wind		-	-$39.55		-39.55	0.95
Greenough Solar Farm (PV)	1			Solar		-	-$39.55		-39.55	1.04

4.5.6. 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 HHV. These figures represent the average sent out heat rate at maximum capacity. However, 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.

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 in Table 4-5 are likely to be slightly over-estimated.

4.6. Reserve modelling assumptions

In determining the availability cost of providing ancillary services, both spinning reserve (SR) and load following reserve (LFR) were 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[11], we assume a load following requirement of ± 90 MW for the 2012/13 year with a ramp rate of +/- 18 MW/min. This

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

increases the load following requirement from 60 MW prior to the commissioning of the Collgar wind farm.

The generators providing load following reserve must be able to raise or lower their generation in response to 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.

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 SR than LFR, and some may not be suitable for providing reserve at all, depending on their operational flexibility and the commercial objectives of their owners.

For all generators specified as being able to provide reserve, PLEXOS is set up to assume 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 within a 5 minute period. For spinning reserve, additional restrictions are imposed on some units, as recommended by System Management.

4.6.4. Ancillary service contracts

Some reserve may be provided by reducing load through interruptible load ancillary service contracts. Consistent with System Management’s Ancillary Service Report for 2011, 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 or Load Following 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 SR 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.

4.6.6. 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.

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 (a) of the Market Rules.

The margin values, availability cost and system marginal prices are presented in Table 5-1 averaged over 10 random outage samples. The Margin_Peak and Margin_Off-Peak values vary slightly between random samples, but never more than 5%.

- **Table 5-1 Parameter estimates**

Parameter	Average	Standard Error
Margin_Off-Peak	32%	0.4%
Margin_Peak	25%	0.4%
Capacity_R_Off-Peak	207.8	0.2
Capacity_R_Peak	219.9	0.1
Availability cost ($M)	22.48	0.25
Off-peak price ($/MWh)	52.00	0.23
Peak price ($/MWh)	55.71	0.27

On average, a Margin_Off-Peak value of 32% is recommended, based on system marginal off-peak prices around $52.00/MWh. For Margin_Peak, an average value of 25% has been estimated, based on system marginal prices around $55.71/MWh. In some instances during peak periods, IPP generation was backed off and total Verve Energy output was increased in order to meet the SR and LFR 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 we obtained a Margin_Peak value of 25% and a Margin_Off-Peak value of 43% for the base case in the financial year 2011/12. The Margin_Peak value has remained largely the same while the Margin_Off-Peak value has decreased. There are several changes with respect to our previous modelling causing the differences between the 2010 review's and this review's simulations:

- Update on input assumptions for generator properties such as min 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.

6. Conclusions

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

- Margin_Off-Peak 32%
- Margin_Peak 25%.

These values are sensitive to a number of factors including:

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

Moreover, these margin values have been developed assuming that no Ancillary Service contracts for SR or LFR (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.