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Mr Greg Watkinson
Chief Executive Officer
Economic Regulation Authority
Level 4, Albert Facey House
Perth WA 6000

Dear Greg

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 2014.

The IMO engaged Sinclair Knight Merz (SKM) to provide an independent assessment of the margin values for the 2014/15 Financial Year. SKM'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 2014/15 Financial Year to be:

Margin Values	Proposed (FY 2014/15)	Current (FY 2013/14)
Margin Off-Peak	27%	27%
Margin Peak	14%	17%
Average Annual Spinning Reserve Capacity_Off-Peak (MW)	200.03	197.18
Average Annual Spinning Reserve Capacity_Peak (MW)	221.01	220.16
Estimated Annual Availability Cost ($M)	8.93	7.22
System Marginal Price_Off-Peak($/MWh)	48.89	47.01
System Marginal Price_ Peak ($/MWh)	60.78	50.81

In its review, SKM has reapplied the methodology it used in 2012 to determine margin values to apply during the 2013/14 Financial Year.

In general, the modelling assumptions used in the study were based on the assumptions used for the 2012 review, updated as appropriate from relevant sources (such as the 2013 Statement of Opportunities). The IMO and SKM undertook the following measures to improve the quality of the input assumptions.

- In preparation for the review, SKM undertook an analysis to compare modelled outcomes from the 2011 review against actual market outcomes for the 2012/13 Financial Year. In general there was close alignment between modelled and actual dispatch and pricing outcomes, with most of the differences attributable to variations between forecast and actual load. However, based on the analysis results adjustments were made to various modelling assumptions including start-up costs, outage rates, gas prices, output limits, assumptions around steam production and the "must run" status of some units.
- System Management reviewed the Ancillary Service modelling and network topography assumptions used in the study, and provided updated load profiles by region.
- SKM prepared a draft Assumptions Report outlining the methodology and assumptions proposed for the review. The full (confidential) version of this report was reviewed by the ERA and the IMO.
- A public version of the draft Assumptions Report, which excluded confidential Market Generator details, was published by the IMO on 11 September 2013. The IMO invited interested stakeholders to either request a meeting to consult directly with the IMO and SKM or to provide written submissions on the report. No requests for direct consultation were received during the formal consultation period, which closed on 25 September 2013. Community Electricity provided the only formal submission. The IMO and SKM's response to the points raised in Community Electricity's submission is available in SKM's Final Report.
- The IMO also requested feedback from nine large Market Generators on full extracts of the key assumptions for their Facilities. The IMO received feedback from six Market Generators, four suggesting changes to their Facility assumptions. The IMO also consulted with the ERA on the updated Facility assumptions received from Market Generators.
- SKM used the feedback provided by stakeholders to update input assumptions.

Assumptions relating to the continuation of carbon price under the Clean Energy Act 2011

On 1 July 2012, a price on carbon was introduced through the Clean Energy Act. As the legislation now stands, the price to apply for the 2014/15 Financial Year is \$25.40 per tonne of CO_2 equivalent emissions.

While the current Federal Government has indicated its intention to repeal the carbon price, this has not yet been reflected in amendments to the legislation and it is not certain whether such changes will be made prior to the 2014/15 Financial Year. Given the uncertainty surrounding the timing of any carbon price repeal, the current legislated carbon price has been assumed in the modelling of the proposed margin values. It should be noted that the proposed margin values are sensitive to changes in the carbon price, as the carbon price impacts on the short run marginal costs and relative dispatch order of generators.

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

Yours sincerely

ALLAN DAWSON
CHIEF EXECUTIVE OFFICER

28 November 2013

2014/15 Margin Peak and Margin Off-Peak Review

Final Report to IMO

SH43499 | 23rd November 2013

SINCLAIR KNIGHT MERZ

SKM

2014/15 Margin Peak and Margin Off-Peak Review

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Executive summary

The Independent Market Operator of Western Australia (IMO) engaged Sinclair Knight Merz (SKM) to assist in determining the appropriate margin values to be used for the financial year starting 1 July 2014.

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 production from higher cost Verve Energy plant 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
- a reduction in generation from Verve Energy plant and a corresponding increase in generation from Independent Power Producers (IPP), resulting in loss of profit for Verve Energy

To determine appropriate Margin_Peak and Margin_Off-peak parameters, we calculated the availability cost for spinning reserve in peak and off-peak periods, based on market simulations, and then re-arranged the equation in clause 9.9.2(f) of the Market Rules to calculate the required parameters.

The market simulations were 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. The Market Evolution Project (MEP) was responsible for the development of both the Balancing Market and the LFAS Market, with the objective to encourage more efficient dispatch outcomes in the WEM. With the implementation of these markets from July 2012, the WEM and PLEXOS market model outcomes are expected to be more closely aligned due to the expected improvements in market efficiency.

Prior to conducting this analysis, extensive consultation and comparison of modelled outcomes against actual were conducted.

To assess the reserve availability cost that could reasonably be expected to be incurred by Verve Energy for the 2014/15 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 selected Independent Power Producers on a competitive basis.

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).

The resulting margin values proposed for the financial year commencing July 2014 are 27% for Margin_Off-Peak and 14% for Margin_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 (refer to Table 6-2).

These parameters have been determined assuming that the legislated carbon price remains throughout the 2014/15 financial year.

■ **Table 1 Parameter estimates for 2014/15 financial year**

Parameter	Average	Standard error
Margin_Off-Peak	27%	0.7%
Margin_Peak	14%	0.6%
SR_Capacity_Off-Peak (MW)	200.03	0.38
SR_Capacity_Peak (MW)	221.01	0.06
Availability cost ($M)	8.93	0.25
Off-peak price ($/MWh)	48.89	0.11
Peak price ($/MWh)	60.78	0.22

1. Introduction

The Wholesale Electricity Market Rules (Market Rules) require the Independent Market Operator (IMO) to submit proposed values for Margin_Peak and Margin_Off-Peak (margin values) to the Economic Regulation Authority (ERA) for every financial year, in accordance with clause 3.13.3A of the Market Rules. Clause 3.13.3A requires the ERA to determine the margin values proposed by the IMO, subject to a public consultation process which must include publishing an issues paper and issuing an invitation for public submissions.

The IMO has engaged Sinclair Knight Merz (SKM) to assist in reviewing the appropriate margin values to be applied for the financial year commencing 1 July 2014.

To determine appropriate Margin_Peak and Margin_Off-Peak parameters for the period of interest, the availability cost for spinning reserve in peak and off-peak periods has been calculated based on market simulations and then the equation in clause 9.9.2(f) of the Market Rules has been rearranged to calculate the required parameters.

SKM simulated the Wholesale Electricity Market (WEM) for the South West interconnected system (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.

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

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 market clearing price set by the marginal generator. From previous modelling experience, we have 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.

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

All prices and costs in this report are given in June 2013 dollars, unless specified. Where the same cost assumptions have been adopted as previously used in the calculation of the 2013/14 financial year margin values that were determined by the ERA on 18 March 2013, the costs have been adjusted from June 2012 to June 2013 dollars using the Perth Consumer Price Index (All Groups) published by the Australian Bureau of Statistics.

2. Methodology for calculating margin values

Spinning reserve ancillary services for the WEM are currently provided by Verve Energy[1]. The IMO pays Verve Energy for these services in accordance with the formula prescribed in clause 9.9.2(f) of the Market 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 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 (SR) 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 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 Verve Energy could reasonably have been expected to earn on energy sales forgone due to the supply of Spinning Reserve during Peak Trading Intervals; and

2. 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;

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

2. 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 (resulting from reduced generation quantity due to the commitment of capacity for providing spinning reserve), which may be incurred through:

- movement to a less efficient point on a unit's heat rate curve
- an increase in production from higher cost Verve Energy plant 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
- a reduction in generation from Verve Energy plant and a corresponding increase in generation from Independent Power Producers (IPP), resulting in loss of profit for Verve Energy

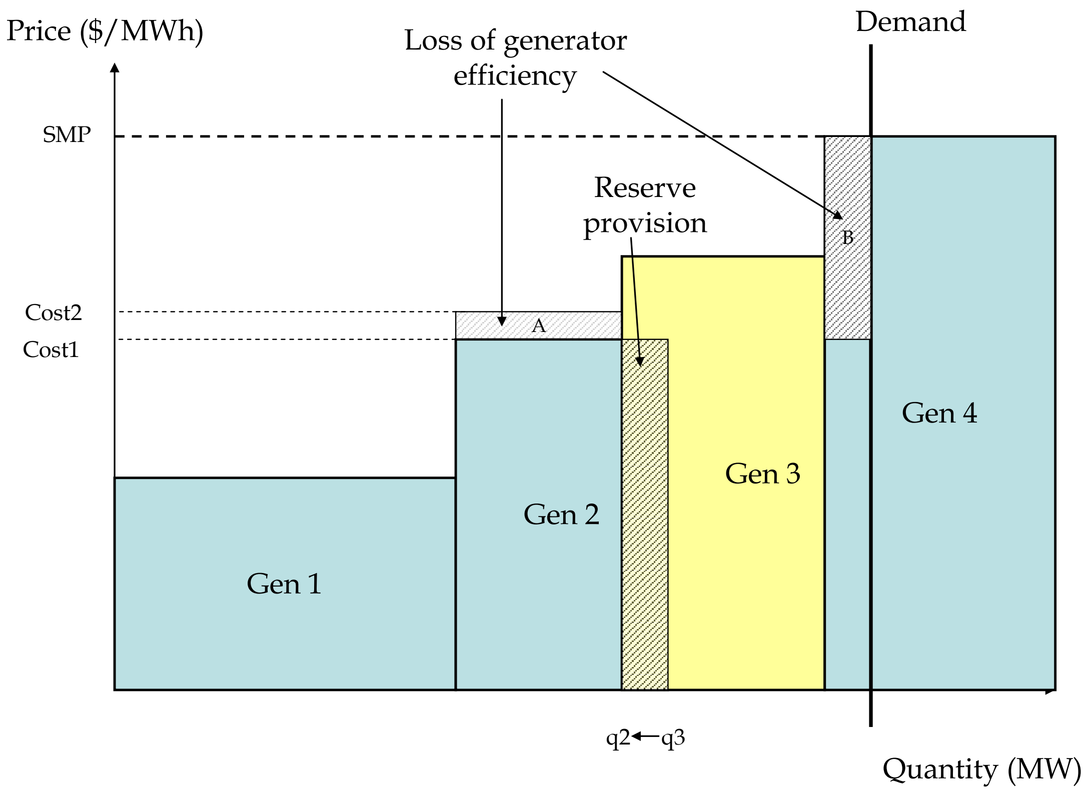
2.1 Constraining units off to provide reserve

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 SR and, in this period, SR is provided by backing off generation from Gen 2 (quantity q3 – q2). By reducing output, Gen 2's average

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

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

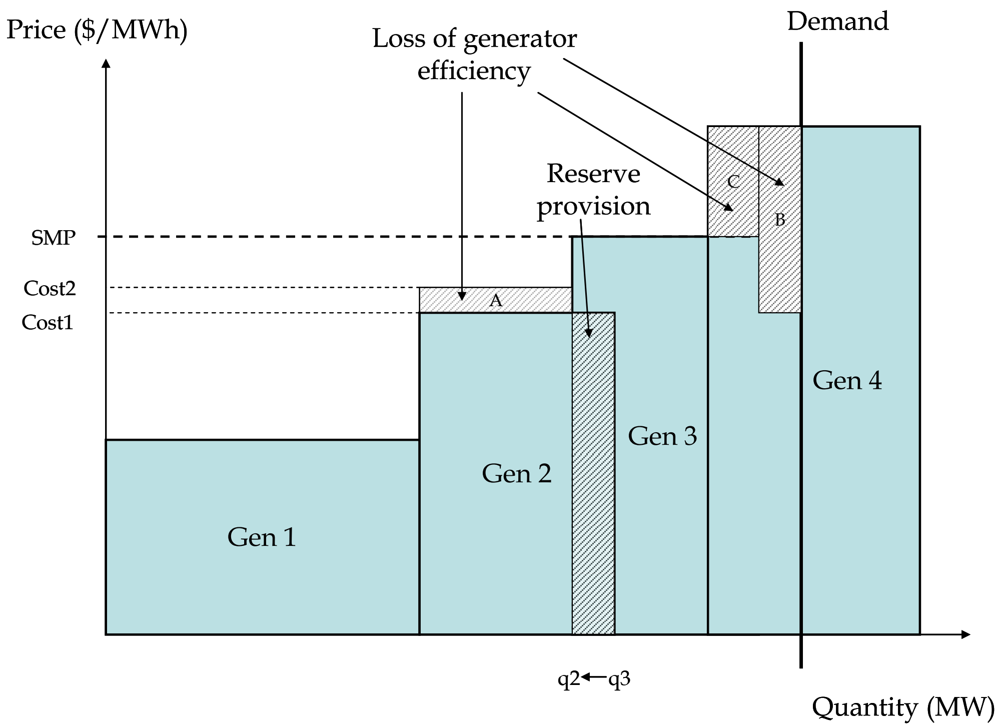
During the off-peak, some units may be constrained on at minimum generation level to meet the reserve requirements but a lower cost generator may be the marginal generator setting the price. Therefore, the availability cost could be quite high relative to the SMP.

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 generation 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 generation 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 generation 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 generation 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 this unit has a relatively high minimum generation 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 IPP's is relatively high, since Verve Energy is assumed to be the sole provider of SR (apart from Interruptible Load (IL)).

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 SR 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 SR provision

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

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

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

SMP = system marginal price with SR provision

For calculating losses in generator efficiency resulting from reducing output to provide SR, heat rate curves are considered within SKM's WEM database, as discussed in Section 5.8.6.

2.4 Calculating margin values

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, load following raise provision (LFR) and Balancing Price in the period.

In essence, if SR ancillary services are only provided by Verve Energy generators and IL, the availability cost defined by clause 9.9.2(f) is as follows:

Availability cost =

Margin Peak * ∑BalancingPrice_Peak * {SR_Capacity_Peak – LFR_Peak - IL} +

Margin OffPeak * ∑BalancingPrice_Offpeak * {SR_Capacity_Offpeak – LFR_Off-Peak - IL}

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 Ancillary Service Requirement for Spinning Reserve in the Trading Interval as specified by IMO under clause 3.22.1(e) and (f). These clauses define the Ancillary Service Requirement for SR 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 LFR parameter represents the amount of load following raise ancillary service required in the Trading Interval. Assumptions regarding this requirement are discussed in Section 5.9.2.

3. Modelling the wholesale electricity market

The WEM for the 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
- Balancing services, including a Balancing Market and Load Following Ancillary Service (LFAS) Market 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, Balancing Market, LFAS 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. Up to 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.

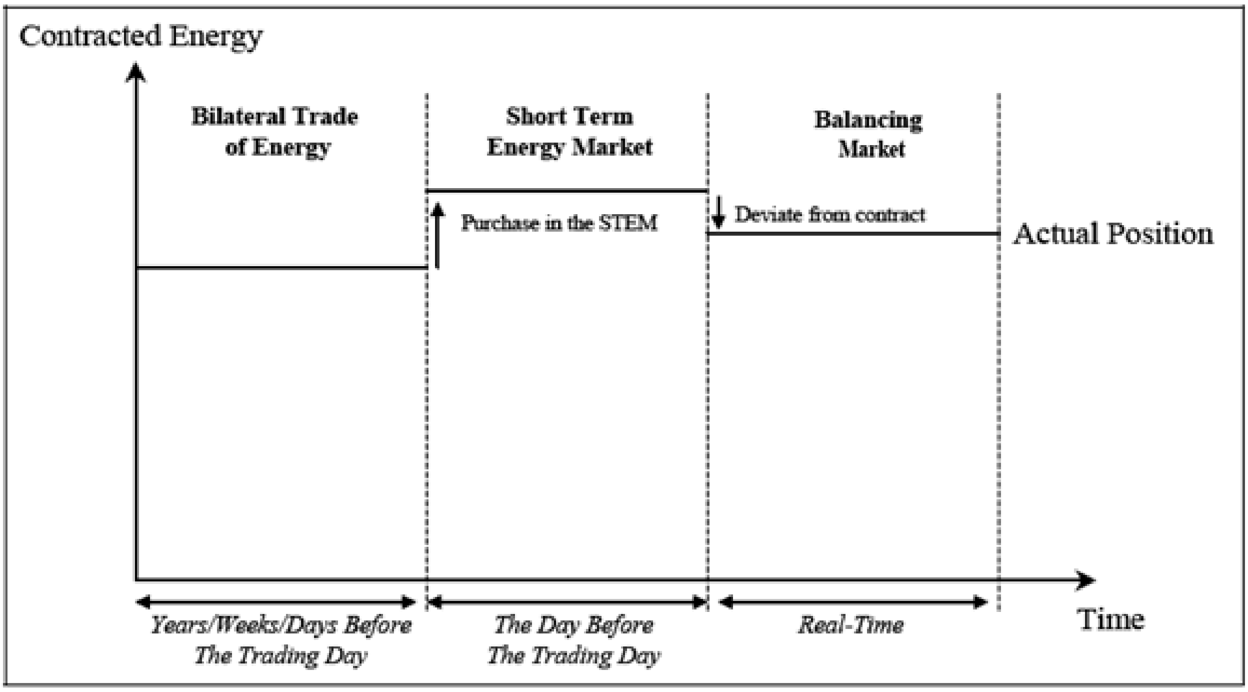
Market participants (both generators and retailers) can submit offers to sell energy to the STEM, or bids to buy energy from the STEM. Market generators may wish to buy energy from the market if the STEM price is lower than its marginal cost of generation. Alternatively, the generator may wish to sell 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.

All Balancing Facilities (Verve Energy and IPPs) are required to compete in a Balancing Market, which is used to determine the actual dispatch of each facility. Balancing Facilities 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 Market 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

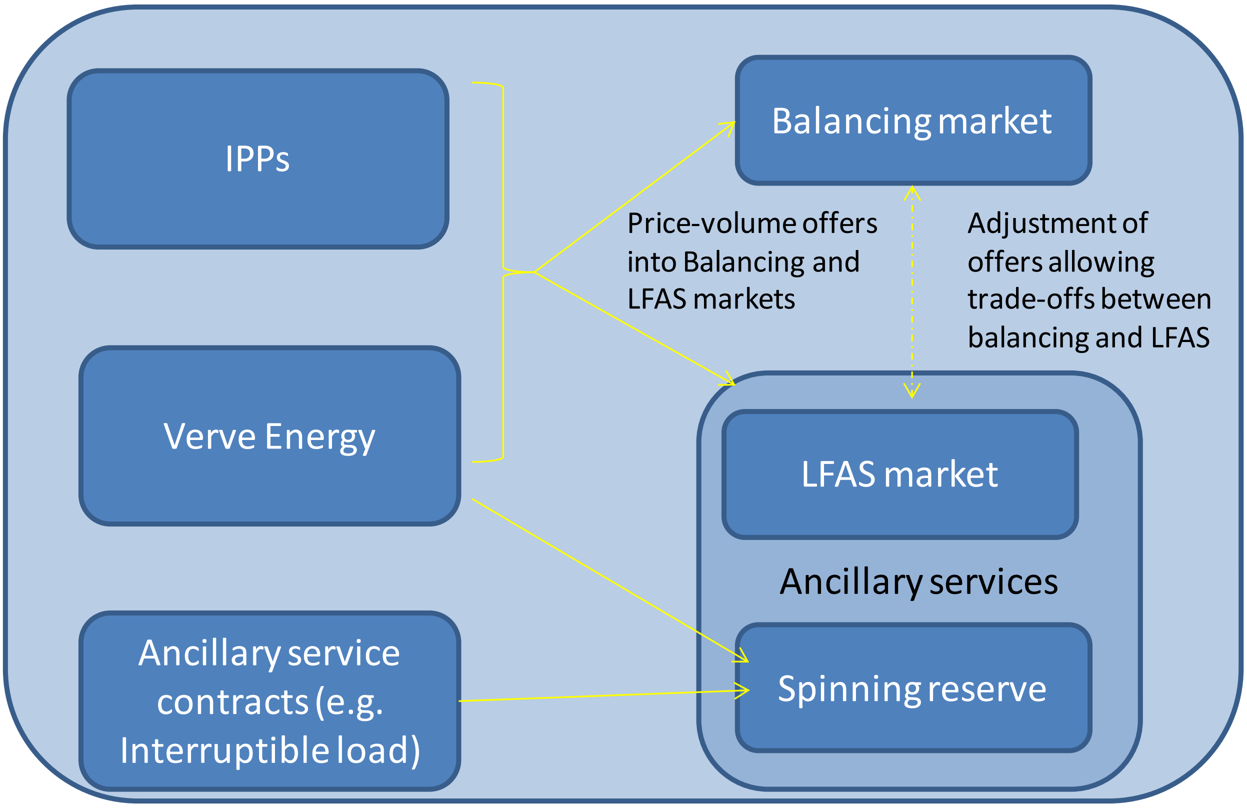


SOURCE: IMO (2006) The South West Interconnected System Wholesale Electricity Market: An Overview, adapted for MEP

Verve Energy is the default provider of all ancillary services. However, in the LFAS Market, IPPs can compete with Verve Energy for the provision of LFAS. Payment for LFAS is 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). SR can only be provided by Verve Energy or through Ancillary Service Contracts such as IL contracts. Figure 3-2 summarises participation by Verve Energy and IPPs in the Balancing Market, LFAS Market and provision of SR.

In the PLEXOS model SKM does not explicitly model the bilateral trades, STEM and the Balancing Market separately. Instead, a gross pool is modelled and energy and ancillary services are co-optimised, assuming economically efficient dispatch, The Market Evolution Project (MEP) was responsible for the development of both the Balancing Market and the LFAS Market, with the objective to encourage more efficient dispatch outcomes in the WEM. With the implementation of these markets from July 2012, the WEM and PLEXOS market model outcomes are expected to be more closely aligned due to the expected improvements in market efficiency.

Figure 3-2 Balancing Market and Ancillary Service Provision



4. Key changes to input assumptions for 2014/15 review

Compared to the 2013/14 margin values review, input assumptions related to demand and carbon price have been updated to reflect the expected values for the 2014/15 financial year. Moreover, cost assumptions adopted previously have been escalated to real June 2013 dollars using the Perth Consumer Price Index (All Groups) published by the Australian Bureau of Statistics. No new generation facilities have been considered.

Some input assumptions have been updated based on outcomes of a backcasting exercise conducted prior to undertaking this year's review, and other assumptions have been modified on receipt of more accurate information received by stakeholders through the public consultation process.

This section highlights some of these key changes to input assumptions. A more detailed summary of the current assumptions is included in Section 5.

4.1 Backcasting exercise

In 2011, SKM undertook a study to determine margin values applicable for the 2012/13 financial year. The margin values were determined from the outcomes of market simulations undertaken using PLEXOS, assuming the introduction of Balancing Market and LFAS Market as part of the MEP. Prior to undertaking modelling to assess the margin values for the 2014/15 financial year, an analysis was undertaken to compare modelled outcomes from the 2011 study against actual market outcomes for the 2012/13 financial year. In general, there was close alignment between modelled and actual dispatch and pricing outcomes, with most of the differences being attributable to variations between forecast and actual load. However, some changes to model input assumptions were also recommended to improve alignment between the model and the actual market. These recommendations, and the agreed implementation, are summarised in Table 4-1.

Table 4-1 Summary of key differences and recommendations relevant for 2014/15 modelling

Factor	Recommendation for 2014/15 modelling	Implemented
Average peak prices were slightly lower in the model despite higher peak demand. Off-peak prices were noticeably lower in reality due to zero and negative prices.	Increase start-up cost assumption for MUJA G5 and MUJA G6 to better approximate the unit commitment decisions for these units. Model MUJA G5 as must run. Use the 2012/13 wind profiles to reflect overnight availability, with wind offered into the market at the negative of the Large-scale Generation Certificate (LGC) price.	As recommended
The available spare capacity for reserve provision was lower in the modelling during off-peak periods because more units were assumed to shut down overnight.	As above. Assume that MUJA 5 is must run. Also reasonable to assume Kwinana NewGen is must run based on observed operation.	As recommended
More coal generation in modelling than in reality.	Re-assess forced outage and maintenance rates assumptions	IMO provided 'equivalent' outage rates, which combines partial and full outages.

Factor	Recommendation for 2014/15 modelling	Implemented
MUJA G1, MUJA G2, MUJA G3 and MUJA G4 problem in start-up resulting in suspension in recommissioning of MUJA G1 and MUJA G2. Units were assumed to be fully operational in the 2012/13 market modelling.	Assume MUJA G3 and MUJA G4 will be fully operational. There is uncertainty around recommissioning of MUJA G1 and MUJA G2, IMO to confirm status for 2014/15 modelling.	MUJA G1, MUJA G2, MUJA G3 and MUJA G4 assumed to be fully operational during 2014/15
It was observed that BLUEWATERS and KWINANA G5 and KWINANA G6 generated below maximum capacity except during high price conditions.	Model individual units of BLUEWATERS with a lower limit (based on historical observation) but allow generation up to maximum capacity during high price conditions. Model individual units of KWINANA G5 and KWINANA G6 with a lower limit (based on historical observation) but allow generation up to maximum capacity during high price conditions.	BLUEWATERS as recommended. KWINANA G5 and KWINANA G6 as recommended but price threshold increased based on confidential advice received during public consultation
ALINTA PINJARRA and TIWEST cogeneration plants generated more in the modelling than actual. The lower alumina and titanium dioxide commodity prices are likely to have reduced the value of steam, relative to what was assumed in the modelling.	Continue to model the units as must run, and limit total annual generation to the levels observed in 2012/13, assuming that the commodity prices remain at similar levels in 2014/15.	ALINTA PINJARRA modelled as must run and cost components unchanged but monthly generation limited to levels observed in 2012/13. ALCOA WGP has also been treated similarly since it is linked to the same commodity as ALINTA PINJARRA. ALCOA WGP annual dispatch is limited to the level observed in 2012/13 Removed steam value from VO&M of TIWEST but imposed minimum monthly generation level based on historically observed levels. PPP_KCP also had steam value removed, replaced by a minimum hourly generation constraint.
Newgen Kwinana CCGT was forecast to generate more than actually observed.	Prior to the 2011 modelling, the Kwinana NewGen price was reduced to better align with backcasting results and knowledge of gas prices around the time that this contract was negotiated, but the reductions may have been overstated. SKM recommends increasing NewGen gas price by $0.50/GJ for 2014/15 modelling.	As recommended

Factor	Recommendation for 2014/15 modelling	Implemented
Differences in load following reserve provision were observed for Newgen Kwinana CCGT.	Update maximum response assumption based on observation of actual load following reserve provision.	As recommended
Differences in the generation profile of COLLGAR wind farm were observed, with actual generation being more volatile than assumed.	Use actual 2012/13 generation profile and 2012/13 load profiles so that any correlation between wind farm output and load is captured.	As recommended

4.2 Public consultation process

Some input assumptions were updated as a result of the public consultation process. Most of these revised input assumptions are confidential, provided in response to a request for data. In general terms, the changes related to the:

- coal price for Muja G1-G4 units
- heat rates at maximum capacity for Muja G1-G4 units
- start-up costs for Muja G1-G4 units
- variable operating and maintenance (VOM) costs for Muja G1-G4
- merit order of Cockburn and PPP_KCP_EGP (adjusted through changes to heat rate assumptions)
- mean time to repair for Tiwest
- fuel price for Tiwest, which is no longer assumed to have access to Verve gas and relies solely on new gas for generation
- removal of some gas constraints that were previously assumed
- changes to the load following capability assumed for some Verve Energy units, based on advice from System Management.

Additionally, the IMO received one public submission from Community Electricity during the consultation period for the Draft Assumptions Report. A summary of the points raised in Community Electricity's submission is provided below.

Issue	IMO/SKM response
Requested confirmation of the appropriateness of allocating the Emu Downs, Collgar and Merredin Energy facilities to the Muja network node.	The IMO has confirmed with System Management that all three facilities should be allocated to the Muja network node.
Suggested that it might be appropriate to modify the actual output profile for Collgar to reflect its revised bidding strategy (i.e. to bid at the negative LGC rate rather than -$1,000/MWh).	The IMO and SKM do not consider that any modification is required. The 2012/13 financial year profile is being used to estimate the maximum output of Collgar over the modelling year – if the model prices go low enough then the facility's output would be reduced accordingly. It appears that Collgar did not change its bidding pattern until late May 2013, and so its output for the 2012/13 financial year should provide a reasonable basis for estimating its likely maximum output over the 2014/15 financial year.

Issue	IMO/SKM response
Noted an error in Table 6.1.	SKM has amended the table to correct what was a transcription error.
Noted with regard to section 7.1 that there is hearsay that the spot gas price is currently much cheaper than the estimated new gas price and queried whether this had been assessed.	The IMO and SKM are aware of the reports of cheaper spot prices, but have been provided with no information to suggest a significant reduction in spot gas prices that is likely to continue through the 2014/15 financial year.

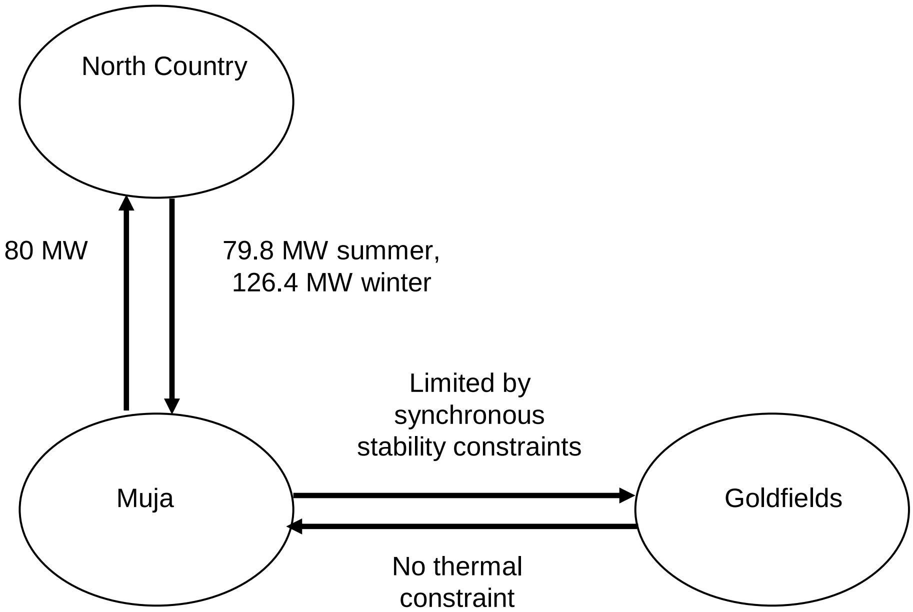
5. Key modelling assumptions

This section outlines the key modelling assumptions used in the PLEXOS market simulations. These assumptions were provided for public review during the consultation period[2], and adjusted where applicable based on stakeholder feedback received.

5.1 Network topography

The SWIS is modelled as a 3-node system with a single uniform price. Interconnectors between the 3 nodes, Muja, Goldfields and North Country, allow representation of the major congestion points in the system. Figure 5-1 shows the network configuration modelled in PLEXOS and the maximum flow limits assumed in each direction.

Figure 5-1 3-node model of SWIS



This network configuration has taken into consideration the impact of the commissioning of the Mid West Energy Project (MWEP), Southern Section, which will strengthen the network connection between Neerabup and Three Springs. Construction of this network augmentation is targeted for completion in the second quarter of 2014. Based on advice from System Management, it is therefore assumed to be fully operational for the entire 2014/15 financial year. With MWEP completed, the limits between Muja and North Country will represent constraints on flow between Three Springs and Geraldton.

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 65 MW, one Mungarra unit must be in operation, increasing to two units in operation when load exceeds 95 MW. The impact of the MWEP development on these voltage stability constraints has not yet been assessed. In the absence of any detailed study, System Management recommends retaining the constraints as currently formulated.

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[2] 2013 Margin Peak and Margin Off-peak Review, Assumptions and Methodology Report (Public) V7.0, 10th September 2013

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.

5.2 Demand assumptions

5.2.1 Regional demand forecasts

Table 5-1 shows our assumptions for sent-out energy and summer and winter maximum demand across the 3 nodes. These values are based on the 2013 Statement of Opportunities (SOO) load forecasts (medium growth scenario, 50% PoE), distributed among the three regions in accordance with the 2012/13 actual loads after separately accounting for the Karara mining development[3]. By 2014/15, the Karara mining development is assumed to be fully operational, with a maximum demand of 95 MW and an 85% load factor. The load split between North Country and Muja is based on the regional boundary definition we have assumed after commissioning of MWEP, with Three Springs being part of the Muja region. Intermittent non-scheduled load information was provided by the IMO.

Table 5-1 2014/15 load assumptions

Financial year	Parameter	Muja (Perth)	Goldfields	North Country	Total SWIS
2014/15	Energy (GWh)	17322	660	424	18406
	Summer Peak Demand 50% PoE (MW)	4120	114	158	4244
	Winter Peak Demand 50% PoE (MW)	3186	106	125	3287
	Nominated intermittent non-scheduled load (MW)	86	13	0	99

In Table 5-1, 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 2012/13 profiles, to calculate the individual region peaks at time of system peak for the 2014/15 financial year.

For our chronological modelling in PLEXOS, we use half hourly load profiles for the 3 nodes (based on 2012/13 historical data including losses), which are then grown to match the energy and peak demand values in Table 5-1. The energy and peak demand forecasts provided in Table 5-1 are net of IMO assumptions on small-scale solar PV uptake. For the 2014/15 financial year, IMO estimated that small-scale solar PV would contribute 110 MW during the summer peak demand[4]. As this will change the daily shape of the load profiles, we have grown the loads by adding back the small-scale solar PV peak and energy demand (estimated using an assumed solar

[3] Note that some of the values were shown incorrectly in the Public Assumptions Report for this review, due to a transcription error.

[4] IMO, Electricity Statement of Opportunities, June 2013, Table IV

PV capacity factor for Perth of 18.3%[5]), and then subtracting an assumed solar PV daily shape based on Bureau of Meteorological data collected from 1975 to 1981 for the Perth Airport site.

5.2.2 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 the nominated capacity of the associated Intermittent Load. These generators may also be dispatched in the SWIS up to their maximum scheduled generation level.

5.3 Fuel assumptions

The following fuels are represented in the modelling:

- Coal: used by Muja C and D, Collie and the Bluewaters units
- Vinalco coal: used by Muja A and Muja B
- 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 acts as a secondary fuel for some of the other units if they have used up their contract gas supply. May also include some proportion of spot gas purchases
- 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), although, in high priced periods it is assumed that these units switch to 100% gas so that they can operate at a higher capacity. 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.

5.3.1 Fuel costs

For Verve coal, some gas (Cogeneration, Verve Contract, IPP and New) and landfill gas the prices used are the same as the prices used in the calculation of the 2013/14 financial year margin values that were determined by the ERA on 18 March 2013, adjusted by Perth CPI.

The new gas price of $6.40/GJ, representing a mix of new contracts and spot gas, falls within the range of prices reported from industry sources in the Western Australian, November 2011[6] of $6 to $8/GJ for gas, albeit at the lower end of this range. Feedback on the appropriateness of this price was sought during the 2014/15 submission period. The IMO received one submission, noting there was hearsay that spot gas prices were currently lower and querying whether this had been assessed. However, no information was provided to suggest a significant reduction in spot gas prices that was likely to continue through the 2014/15 financial year.

During the public consultation process, Vinalco provided the IMO with revised information about the coal price for Muja G1-G4 units. We have used this confidential information in the model.

[5] CEC, Consumer Guide to Solar PV, 19 December 2012, http://www.cleanenergycouncil.org.au/cec/resourcentre/Consumer-Info/solarPV-guide

[6] http://au.news.yahoo.com/thewest/a/-/wa/12171777/gorgon-gas-deal-to-put-the-heat-on-power-bills/ last cited 31st August 2012

The contract gas price for NewGen Kwinana used in the previous two margin values assessments was estimated based on knowledge of gas prices around the time that this contract was negotiated. For this current margin values analysis, this price was increased by $0.50/GJ following benchmarking analysis in an attempt to better align modelled and actual dispatch for this generator.

Distillate prices come from SKM MMA's Energy Price Limits 2013 study[7], which estimated a nominal price of $21.65/GJ ($21.38/GJ in June 2013 dollars) applying a calorific value of 38.6 MJ/litre. The additional nominal transport cost to the Goldfields is estimated to be $0.97/GJ ($0.96/GJ in June 2013 dollars).[8]

Table 5-2 shows our assumptions on fuel prices:

Table 5-2 Fuel prices (real June 13 dollars)

Name	Price ($/GJ)
Coal	2.13
Vinalco Coal	CONFIDENTIAL
Cogeneration contract gas	2.73
Verve contract gas	3.20
NewGen contract gas	3.70
IPP contract gas	4.27
New gas	6.40
Landfill gas	2.33
Distillate	21.38

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 5-5.

The fixed component of the gas transport charge was converted to a variable cost per GJ assuming a load factor of 75%. For gas from the Dampier to Bunbury Natural Gas Pipeline (DBNGP), applying the same load factor, the resulting fixed cost component of the gas transport cost is approximately $1.59/GJ in real June 2013 dollars. 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. Adopting the same approach that was applied for the 2013/14 financial year margin values review, SKM has conservatively assumed that only 50% of the fixed cost component should be included in formulating the marginal costs for gas-fired generators. A detailed explanation of how the gas transport charges are derived is included in Appendix A.

5.3.2 Fuel constraints

Constraints limiting the daily availability of contract gas have been included in the modelling, based on our understanding of the market and historical data. Constraints on the total gas available in different locations have also been included. Where possible, these figures have been obtained from the capacities standing data listed in the Western Australia Gas Bulletin Board[9]. Otherwise, the figures correspond to estimations from historical dispatch data and liquid fuel usage for 2008, and fine-tuned in our PLEXOS model during previous SWIS back-casting exercises.

[7] http://www.imowa.com.au/f7185,4047613/SKM_MMA_2013_Energy_Price_Limits_Review.pdf

[8] Prices in SKM MMA "Energy Price Limits for the Wholesale Electricity Market in Western Australia from July 2013" report are nominal for the financial year 2013/14. In order to convert them to real June 2013 dollars, we assumed they are from December 2013 (mid-point of the 2013/14 financial year) and then scaled them back to June 2013 dollars assuming a Perth annual out-year inflation rate of 2.5%).

[9] https://gbb.imowa.com.au/#capacities

5.4 Carbon price and emission intensities

The former Federal Labor Government introduced a price on carbon through the Clean Energy Future scheme, which commenced on 1 July 2012. As the legislation now stands, the price to apply for the 2014/15 financial year is \$25.40/t CO_2-e (\$24.54/tCO_2-e in June 2013 dollars[10]). The newly elected Coalition has indicated that it will abolish the carbon price as soon as possible. However, its effectiveness in doing so by the beginning of the 2014/15 financial year depends on whether or not the repeal is obstructed in the Senate. Given the uncertainty surrounding the timing of any carbon price repeal, the current legislated carbon price has been assumed for this analysis.

The carbon price impacts on the marginal cost of supply, the merit order of dispatch and Balancing Prices in the market simulations. Consequently, the availability cost and resulting margin values are sensitive to carbon price assumptions.

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 5-3 and the basis for these assumptions are described in detail below. These emission production rates include both combustion and fugitive emissions. Thus the fuel prices are treated as not having any carbon emission based uplift. The heat rates are summarised in Table 5-5. 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 short run margin cost (SRMC) for the generator is then adjusted by multiplying this generation CO_2-e emission production by the carbon price. The resulting emission intensities and SRMCs for individual power stations, at maximum output, are included in Table 5-5, assuming the legislated carbon price of \$24.54/tCO_2-e.

Table 5-3 CO2 emission production rate assumed for each fuel (kg/GJ)

Fuel type	CO_2-e production rate (kg/GJ)
Coal	93.1
Vinalco coal	CONFIDENTIAL
Cogen gas	52.3
Verve gas	52.3
NewGen gas	52.3
IPP gas	52.3
New gas	52.3
Distillate	74.8

5.5 Coal fired generation

In Table 1 of the 2013 National Greenhouse Accounts (NGA) Factors[11] the emission intensity for black coal is assessed as 88.43 kg CO_2-e /GJ. However, this emission intensity is not location specific. Western Australia'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 is assumed, consistent with assumptions in Griffin Power's *Greenhouse Gas Abatement Programme, Bluewaters Project,* 2008[12]. It is assumed that this emission intensity includes fugitive emissions from mining.

[10] Australia CPI is assumed to be 2.5% pa in each year apart from 2014-15 when it is forecast to be 2%. SOURCE: Federal Government's Economic Statement August 2013 page 1 available at http://2013electionwatch.com.au/sites/default/files/docs/economicstatementaugust.pdf

11 http://www.climatechange.gov.au/sites/climatechange/files/documents/07_2013/national-greenhouse-accounts-factors-july-2013.pdf

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

During this year's public consultation process, Vinalco provided specific assumptions about heat rates at maximum capacity and has previously provided the average emission intensity at maximum output.

5.6 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[13]. The total emission of the Dampier to Bunbury Pipeline (DBNGP) is published in the NGERS Greenhouse and Energy Information for 2011/12[14] as 255,716 t CO_2-e. The average throughput of the pipeline in 2011/12 was projected to be approximately 748[15] TJ/day which gives an annual value of 273 PJ. Dividing the published emissions into the throughput gives a transport emission of 0.936 kg CO_2-e/GJ.

For the Gas to Goldfields Pipeline (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[16]. 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 105.71 TJ/day[17] gives a transport emission intensity of 0.963 kg CO_2-e /GJ delivered. These calculations are summarised in Table 5-4.

Table 5-4 Analysis of gas transport emissions

	Units	DBNGP	GGP
Energy consumption	TJ	4,744	490
Gas combustion	t CO_2-e	243,517	25,152
Pipeline	t CO_2-e	12,199	12,016
Total	t CO_2-e	255,716	37,168
NGER emissions	t CO_2-e	255,716	N/A
Transported	TJ	273,083	38,584
	TJ/day	748	106
Emissions	t CO_2-e /GJ	0.936	0.963

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

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

52.29 kg CO_2-e /GJ for the Goldfields.

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

14 http://www.cleanenergyregulator.gov.au/National-Greenhouse-and-Energy-Reporting/published-information/greenhouse-and-energy-information/Greenhouse-and-Energy-information-2011-2012/Pages/default.aspx

15 Revised Access Arrangement Model, 2011/12 system throughput, http://www.erawa.com.au/cproot/10187/4/20111222%20DBNGP%202010-2015%20-%20ERA%20model.XLS

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

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

5.7 Distillate fired generation

The combustion of distillate (described as diesel oil for stationary energy purposes) is assessed as 69.5 kg CO2-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 CO2-e /GJ from Table 40 of the NGA Factors. There is no distinction by location. We therefore apply a total emission of 74.8 kg CO2-e/GJ to represent the likely emission of distillate delivered to peaking generators.

5.8 Generation assumptions

5.8.1 Existing generators

The modelling of the existing generation system includes the larger private power stations owned by Alcoa and the Goldfields miners. Table 5-5 shows the existing generators in the model and some of the key properties driving the calculation of the SRMC.

MUJA G1 and MUJA G2 were being recommissioned in 2012/13 financial year; however there have been problems with the start-up of these units. For 2014/15 modelling, the IMO has advised SKM to assume that these units are fully operational.

Some of the power stations listed may represent the aggregation of one or more actual facilities.

5.8.2 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 were derived from assumptions provided in SKM MMA's 2013 Energy Price Limits report[18]. The start-up costs related to future maintenance have reduced compared to the previous year due to the reduction in the average number of starts per year assumed for that study, based on actual observations.

Start-up costs for some other facilities were updated in accordance with confidential advice provided by market participants. For the remaining facilities, start-up costs were based on a Perth CPI escalation of the values used in the 2013/14 financial year margin values review, which 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, Muja 5, Collie, Kwinana NewGen, cogeneration units and other generators meeting private loads are treated as units that must generate whenever they are available.

5.8.3 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.

[18] http://www.imowa.com.au/f7185,4047613/SKM_MMA_2013_Energy_Price_Limits_Review.pdf

Table 5-5 Properties of existing generators – fuel costs, carbon costs and short-run marginal costs

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 ($/GJ)	Tran-sport charge ($/GJ)	VO&M ($/MWh sent out)	Average CO2-e emission intensity at max (kg/MWh sent out)	Carbon cost ($/MWh sent out) at max	SRMC 2014/15 ($/MWh sent out) at max	MLF
BW1_BLUEWATERS_G2	9.75	10.79	Coal	2.13		2.33	908	22.27	45.39	1.00
BW2_BLUEWATERS_G1	9.75	10.79	Coal	2.13		2.33	908	22.27	45.39	1.00
COLLIE_G1	9.5	10.38	Coal	2.13		1.16	884	21.70	43.13	1.00
MUJA_G5	11.04	14.06	Coal	2.13		4.66	1028	25.22	53.43	1.00
MUJA_G6	11.04	14.06	Coal	2.13		4.66	1028	25.22	53.43	1.00
MUJA_G7	9.85	11.37	Coal	2.13		4.37	917	22.50	47.88	1.00
MUJA_G8	9.85	11.37	Coal	2.13		4.37	917	22.50	47.88	1.00
ALINTA_PNJ_U1	12	12	Cogen gas	2.73	1.09	-20.43*	627	15.39	40.86	0.99
ALINTA_PNJ_U2	12	12	New gas	6.40	1.09	-20.43*	627	15.39	84.89	1.01
ALCOA_WGP	12	12.62	Cogen gas	2.73	1.09	-25.01	627	15.39	36.28	0.99
PPP_KCP_EG1	9	10.48	Verve gas	3.20	1.09	4.72	470	11.54	54.91	1.02
SWCJV_WORSLEY_COGEN_COG1	12	12.02	Verve gas	3.20	1.09	-26.66	627	15.39	40.26	0.98
TIWEST_COG1	13	21.33	New gas	6.40	1.09	2.33	679	16.67	116.42	1.02
COCKBURN_CCG1	9	9.43	Verve gas	3.20	1.09	4.02	470	11.54	54.21	1.02
KWINANA_G5	11.7	14.42	Verve gas/Coal	2.67	1.09	4.48	850	20.86	69.35	1.02
KWINANA_G6	11.7	14.42	Verve gas/Coal	2.67	1.09	4.48	850	20.86	69.35	1.02
KWINANA_GT1	14.6	25.99	Verve gas/distillate	3.20	1.09	23.49	763	18.72	104.91	1.02
MUNGARRA_GT1	13.5	21.85	Verve gas	3.20	0.80	4.78	706	17.31	76.05	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 ($/GJ)	Tran-sport charge ($/GJ)	VO&M ($/MWh sent out)	Average CO2-e emission intensity at max (kg/MWh sent out)	Carbon cost ($/MWh sent out) at max	SRMC 2014/15 ($/MWh sent out) at max	MLF
MUNGARRA_GT2	13.5	21.85	Verve gas	3.20	0.80	4.78	706	17.31	76.05	1.04
MUNGARRA_GT3	13.2	21.56	Verve gas	3.20	0.80	4.78	690	16.93	74.47	1.04
PINJAR_GT01	13.5	21.85	Verve gas/distillate	3.20	1.09	confidential	706	17.31	confidential	1.03
PINJAR_GT02	13.5	21.85	Verve gas/distillate	3.20	1.09	confidential	706	17.31	confidential	1.03
PINJAR_GT03	13.2	22.46	Verve gas/distillate	3.20	1.09	confidential	690	16.93	confidential	1.03
PINJAR_GT04	13.2	22.46	Verve gas/distillate	3.20	1.09	confidential	690	16.93	confidential	1.03
PINJAR_GT05	13.2	22.46	Verve gas/distillate	3.20	1.09	confidential	690	16.93	confidential	1.03
PINJAR_GT07	13.2	22.46	Verve gas/distillate	3.20	1.09	confidential	690	16.93	confidential	1.03
PINJAR_GT09	12.08	19.28	Verve gas	3.20	1.09	4.66	653	16.03	74.37	1.03
PINJAR_GT10	12.08	19.28	Verve gas	3.20	1.09	4.66	653	16.03	74.37	1.03
PINJAR_GT11	12.01	21.74	Verve gas	3.20	1.09	5.42	638	15.64	73.45	1.03
NEWGEN_KWINANA_CCGT	confidential	confidential	NewGen gas	3.70	1.09	2.33	confidential	confidential	confidential	1.02
KEMERTON_GT11	12.2	13.25	Verve gas/distillate	3.20	1.09	2.49	638	15.64	70.52	1.01
KEMERTON_GT12	12.2	13.25	Verve gas/distillate	3.20	1.09	2.49	638	15.64	70.52	1.01
ALINTA_WGP_GT	11.5	16.2	New gas/distillate	6.40	0.00	2.49	601	14.75	103.41	1.01
ALINTA_WGP_GT2	11.5	16.2	New gas/distillate	6.40	0.00	2.49	601	14.75	103.41	1.01
NEWGEN_NEERABUP	confidential	confidential	New gas	6.40	1.09	2.49	confidential	confidential	confidential	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 ($/GJ)	Tran-sport charge ($/GJ)	VO&M ($/MWh sent out)	Average CO2-e emission intensity at max (kg/MWh sent out)	Carbon cost ($/MWh sent out) at max	SRMC 2014/15 ($/MWh sent out) at max	MLF
PRK_AG	confidential	confidential	IPP gas/distillate	4.27	3.94	4.71	confidential	confidential	confidential	1.20
GERALDTON_GT1	15.25	15.95	Distillate	21.38		2.68	1141	27.99	356.75	1.05
WEST_KALGOORLIE_GT2	13.5	13.5	Distillate	21.38	0.96	34.96	1010	24.78	361.34	1.15
WEST_KALGOORLIE_GT3	14.75	14.75	Distillate	21.38	0.96	34.96	1103	27.07	391.56	1.15
GENERIC LANDFILL GAS <<refer to table of projects>>	11.3	11.3	Landfill Gas	2.33		-26.15			0.12	1.05
ALBANY_WF1			Wind			-35.51			-35.51	1.07
ALINTA_WWF			Wind			-35.51			-35.51	0.96
EDWFMAN_WF1			Wind			-35.51			-35.51	0.99
SKYFRM_MTBARKER_WF1			Wind			-35.51			-35.51	1.10
KALBARRI_WF1			Wind			-35.51			-35.51	1.28
COLLGAR			Wind			-35.51			-35.51	1.01
PERTH_ENERGY_GT1	10.7	16.06	New gas/distillate	6.40	1.09	17.60	559	13.72	111.51	1.02
KWINANA_GT2	9.35	15.23	Verve gas/distillate	3.20	1.09	6.62	486	11.93	58.49	1.02
KWINANA_GT3	9.35	15.23	Verve gas/distillate	3.20	1.09	6.62	486	11.93	58.49	1.02
TESLA_PICTON	14.44	14.44	Distillate	21.38		2.68	1080	26.50	337.94	1.02
KALAMUNDA	15.27	18.7	Distillate	21.38		2.68	1142	28.02	357.22	1.05
TESLA_GERALDTON_G1	14.44	14.44	Distillate	21.38		2.68	1080	26.50	337.94	1.04
GRASMERE_WF			Wind			-35.51			-35.51	1.07

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 ($/GJ)	Tran-sport charge ($/GJ)	VO&M ($/MWh sent out)	Average CO2-e emission intensity at max (kg/MWh sent out)	Carbon cost ($/MWh sent out) at max	SRMC 2014/15 ($/MWh sent out) at max	MLF
NAMKKN_MERR_SG1	12.58	12.58	Distillate	21.38		4.78	941	23.09	296.86	1.04
MUJA_G1	confidential	confidential	Vinalco coal	confi-dential		confidential	confidential	confidential	confidential	1.00
MUJA_G2	confidential	confidential	Vinalco coal	confi-dential		confidential	confidential	confidential	confidential	1.00
MUJA_G3	confidential	confidential	Vinalco coal	confi-dential		confidential	confidential	confidential	confidential	1.00
MUJA_G4	confidential	confidential	Vinalco coal	confi-dential		confidential	confidential	confidential	confidential	1.00
GREENOUGH SOLAR FARM (PV)			Solar			-35.51			-35.51	1.02
TESLA_KEMERTON_G1	14.44	14.44	Distillate	21.38		2.68	1080	26.50	337.94	1.01
TESLA_NORTHAM_G1	14.44	14.44	Distillate	21.38		2.68	1080	26.50	337.94	0.95
Mumbida Wind Farm			Wind			-35.51			-35.51	1.04
DWCL_Denmark_WF			Wind			-35.51			-35.51	1.33
Blairfox Karrakin WF			Wind			-35.51			-35.51	1.04

* Negative VOM attempts to approximate the impact of the value of steam on economic dispatch of these cogeneration units. Relatively low commodity prices for alumina and titanium dioxide have led to reductions in the steam value assumed, compared to the 2012/13 margin values review. The magnitude of the steam value reduction has been estimated based on previous backcasting exercises but has not been verified. Consequently the dispatch of these units is limited to the historical levels observed in 2012/13 rather than rely solely on merit order dispatch. NOTE: For Tiwest, we have removed the steam value completely and imposed a monthly minimum generation level constraint based on historical output. We have also removed steam value completely from PPP_KCP and imposed a minimum hourly generation constraint of 53.2 MW, which represents its nominal minimum generation level.

5.8.4 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 were 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. Outage rates have been provided by the IMO, based on historical full and partial outage data and consideration of major outages planned for 2014/15. No outage rates are included for wind farms since the historical generation profiles of these units will already include outages.

5.8.5 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 divided by the marginal loss factor (MLF) to determine the merit order of dispatch. The assumed MLFs have been obtained from the IMO website for 2013/14[19] and are listed for each facility in Table 5-5.

The SRMC values in Table 5-5 are estimated for 2014/15, 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 VOM costs were estimated by SKM, considering the nature and known characteristics of the facilities, or based on actual half-hourly dispatch information. The VOM cost for Perth Energy was derived from the Energy Price Limits report 2011[20], taking the reported VOM cost per hour of $270.00 in March 2012 dollars[21] adjusted to June 2013 dollars, multiplying by an estimate of hours operating based on 2012/13 actual data, and then dividing by an estimate of annual generation also based on the 2012/13 actual data. More recent Energy Price Limit reports have not provided any updated to these VOM assumptions.

For the wind farms and landfill gas plants, the assumed value of Large-scale generation certificates (LGC) has been subtracted from the variable operating and maintenance costs, resulting in a negative SRMC. Even with a Balancing Price of $0/MWh, renewable generators would be foregoing LGC revenue if they were shut down. The LGC price assumed in this study is $35.51/MWh in real June 2013 dollars, based on 2014 and 2015 prices currently being traded. Generation profiles for Albany, Emu Downs, Collgar and Alinta wind farms use 2012/13 historical data so that they are properly correlated to the load profile. For the smaller wind farms such as Denmark and Blairfox Karrakin, an average annual capacity factor is assumed.

5.8.6 Heat rates

The sent out heat rates presented in Table 5-5 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

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

[20] http://www.imowa.com.au/f4153,1608610/SKM_MMA_Final_2011_EPL_Report_v1.1.pdf

[21] Prices in the SKM MMA "Energy Price Limits for the Wholesale Electricity Market in Western Australia from October 2011" report are nominal for the year commencing October 2011. In order to convert them to real June 2013 dollars, we assumed they are from March 2012 (mid-point of the year commencing October) and then scaled up to June 2013 dollars assuming a Perth annual out-year inflation rate of 2.5%).

a request for details made by the IMO as part of the consultation process for this review and for previous margin values reviews. The figures in Table 5-5 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.

The marginal heat rate at any level of output is defined as the gradient of the heat input curve. 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 5-5 are likely to be slightly over-estimated.

In some instances, no information on the heat input function is 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 market, 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 market is operating at a relatively efficient point on its heat rate curve.

5.8.7 Future generators

No new generators are assumed to be committed within the review period.

5.9 Reserve modelling assumptions

In determining the availability cost of providing ancillary services, both SR and LFAS have been modelled in PLEXOS.

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

5.9.1 Spinning reserve

The SR 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.

5.9.2 Load following reserve

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

There are two LFAS's in the WEM: raise and lower. Based on the estimate of the LFAS requirement provided in System Management's Ancillary Service Report for 2013[22], for the 2014/15 financial year we assume a LFAS requirement of 72 MW for raise and 72 MW for lower with a ramp rate of +/- 14.4 MW/min. System Management is able to reduce the LFAS requirement for some Trading Intervals where, for example, calm conditions are forecast. However, as no guidelines are available to support the modelling of such reductions, the modelling assumed the full ± 72 MW requirement for all Trading Intervals.

The generators providing LFAS 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 LFAS. Indeed, the LFAS market allows participants to offer for one and not the other. However, in aggregate across all generators providing LFAS the total required amounts of raise and lower service must be available.

[22] http://www.imowa.com.au/f2841,4116159/2013_Ancillary_Service_Report_FINAL.pdf

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.

5.9.3 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 LFAS, and some may not be suitable for providing reserve at all, depending on their operational flexibility and the commercial objectives of their owners. Both Verve Energy and IPPs are able to provide LFAS subject to meeting technical requirements (i.e. being connected to AGC). At present NewGen Kwinana is the only IPP providing LFAS. System Management has confirmed that no other IPP is currently in the process of qualifying as an LFAS Facility, and during the consultation period no other IPP advised the IMO of an intention to provide LFAS over the 2014/15 modelling period. We have therefore assumed that NewGen Kwinana will remain the only IPP providing LFAS during this period. SR is provided by Verve Energy or through ancillary service contracts.

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 SR and LFAS. For LFAS, the maximum response represents a unit’s ability to increase or decrease output within a 5 minute period. Both LFAS raise and lower could be provided by a unit simultaneously. For SR, additional restrictions are imposed on some units, as suggested by System Management.

5.9.4 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 2013[23], 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 SR.

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

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

70% largest generating unit – 42 MW interruptible load – 72 MW load following reserve.*

5.9.5 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 to ensure that the reserve is met in most circumstances except when involuntary load shedding would occur.

[23] http://www.imowa.com.au/f2841,4116159/2013_Ancillary_Service_Report_FINAL.pdf

6. Results

In each half-hour Trading Interval, 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).

The margin values, availability cost and system marginal prices are presented in Table 6-1 averaged over 12 random outage samples. The table also provides a comparison with the 2013/14 parameter estimates.

Table 6-1 Parameter estimates

Parameter	Average (2014/15)	Standard error (2014/15)	Average (2013/14)
Margin_Off-Peak	27%	0.7%	27%
Margin_Peak	14%	0.6%	17%
SR_Capacity_Off-Peak (MW)	200.03	0.38	197.18
SR_Capacity_Peak (MW)	221.01	0.06	220.16
Availability cost ($M)	8.93	0.25	7.22
Off-peak price ($/MWh)	48.89	0.11	47.01
Peak price ($/MWh)	60.78	0.22	50.81

On average, a Margin_Off-Peak value of 27% is recommended, based on time-weighted average system marginal off-peak prices of $48.89/MWh. For Margin_Peak, an average value of 14% has been estimated, based on time-weighted average system marginal peak prices of $60.78/MWh.

These values are similar to the parameter estimates recommended for the 2013/14 financial year, although the Margin_Peak value has reduced from 17% to 14%. One reason for the reduction is that the projected marginal peak price has increased (from $50.81/MWh to $60.78/MWh). This peak price increase is driven by a combination of factors including changes to assumptions on unit availability, increases in carbon prices, increases in the marginal costs assumed for of some units, and constraints on cogeneration in excess of the host demand for steam. As a point of comparison, the actual time-weighted average peak price for the SWIS across the 2012/13 financial year was $58.65/MWh.

Table 6-2 shows how the Margin_Peak and Margin_Off-Peak values vary between Monte Carlo samples. This variation is largely due to differences in forced outages and wind availability between samples.

Table 6-2 Parameter estimates by sample

Sample	S01	S02	S03	S04	S05	S06	S07	S08	S09	S10	S11	S12	Average[24]
Margin off-peak	26%	24%	28%	26%	31%	24%	29%	25%	26%	23%	29%	26%	27%
Margin peak	15%	13%	13%	16%	15%	16%	15%	17%	12%	10%	17%	15%	14 %
Availability cost ($M)	$8.85	$8.20	$8.91	$9.31	$9.65	$9.25	$9.35	$9.50	$7.89	$7.01	$10.08	$9.10	$8.93
OP availability cost ($M)	$3.91	$3.86	$4.42	$4.03	$4.76	$3.75	$4.39	$3.88	$4.08	$3.64	$4.47	$4.06	$4.10
P availability cost ($M)	$4.94	$4.35	$4.49	$5.28	$4.89	$5.50	$4.96	$5.62	$3.82	$3.37	$5.61	$5.04	$4.82
Off-peak price ($/MWh)	$48.57	$49.21	$49.28	$49.33	$48.53	$49.06	$48.98	$49.00	$48.51	$49.32	$48.69	$48.23	$48.89
Peak price ($/MWh)	$60.33	$61.14	$61.56	$61.87	$60.13	$61.02	$61.38	$60.90	$59.71	$61.57	$60.27	$59.52	$60.78
SR_Capacity_Peak (MW)	220.86	220.83	221.20	220.83	221.00	221.15	221.13	220.86	221.08	221.35	220.65	221.23	221.01
SR_Capacity_Off-Peak (MW)	199.57	201.69	201.10	198.37	199.46	201.51	197.34	199.07	200.50	200.90	200.60	200.24	200.03

[24] Note that taking the average of the sample values as displayed yields slightly different average values due to rounding.

7. Conclusions

Based on the market modelling, and assuming the legislated carbon price is not repealed before July 2015, SKM recommends the following margin values for the financial year commencing July 2014:

- Margin_Off-Peak 27%
- Margin_Peak 14%.

These values are sensitive to a number of factors including:

- the price and volume assumptions relating to existing and new gas contracts
- the unit commitment decisions, which are based on start-up costs, minimum generation assumptions and the maximum reserve provision for each unit
- the extent of IPP participation in the LFAS market
- whether or not the carbon price is repealed before July 2015

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 2014/15 financial year.

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

Appendix A Pipeline tariffs

A.1 DBNGP tariffs

A.1.1 Tariff components

Dampier to Bunbury Natural Gas Pipeline (DBNGP) tariffs have been calculated using the same approach as that which was used for the 2012 margin values review.

The relevant tariffs for all but one shipper are those paid under the Standard Shipper Contract (SSC) which is available on the DBP website. Although the Base T1 Tariff referred to in the SSC is $1.053 at 1 January 2003, this does not take into account tariff adjustments for capacity expansions. When account is taken of this, ACIL Tasman referred to an SSC T1 tariff at 1 January 2010 of $1.4942 which, when escalated at the Perth Consumer Price Index (All Groups)[25] results in a tariff of $1.5411/GJ at 1 January 2011. This 2011 tariff has been confirmed by DBP which quotes a tariff paid under this contract of $1.5411/GJ.

According to the SSC, from 1 January 2012 to 1 January 2016 Base T1 tariffs escalate at Perth CPI-2.5%. However, our understanding is that the Aggregate Tariff Adjustment Factor (ATAF) to account for capacity reservation increases continues to escalate at the full CPI.

Thus, we have calculated tariffs in two parts:

- A Base T1 Tariff of $1.348/GJ at 1 January 2011 (calculated by escalating the $1.053/GJ referred to in the SSC) which we assume escalates at Perth CPI-2.5%
- An ATAF adjustment of $0.192/GJ at 1 January 2011 (calculated by difference from the $1.5411) which we assume escalates at full Perth CPI[26].

A.1.2 CPI numbers and estimates

The Perth CPI for 2012-13 was 2.5%. The Western Australian 2013-14 budget forecasts for Perth CPI were 2.5% each year from 2013-14 to 2016-17.

In its calculations, SKM has used the following September to September quarter Perth CPI increases:

- 3.1% for Sept 2009 to Sept 10 actual which determined the pricing for calendar year 2011
- 2.8% for Sept 2010 to Sept 11 actual which determined the pricing for calendar year 2012
- 2.0% for Sept 2011 to Sept 12 (including carbon price effect) actual which set the price for calendar year 2013
- 2.5% for Sept 2012 to Sept 2013, which will set the price for calendar year 2014
- 2.5% for Sept 2013 to Sept 2014, which will set the price for calendar year 2015

Where relevant, SKM has assumed that Australia CPI[27] will be 2.5% pa in each year apart from 2014-15 when it is forecast to be 2%[28] .

[25] The Perth Consumer Price Index (All Groups) published by the Australian Bureau of Statistics is referred to in this report as Perth CPI.

[26] We note that the reference period for the CPI calculations was changed by the ABS in 2012. We have used the new reference period in our calculations. As a result, there are minor rounding differences from our previous report.

[27] In this report Australia CPI refers to the Consumer Price Index All Groups weighted average for All Capital Cities published by the Australian Bureau of Statistics.

[28] Federal Government's Economic Statement August 2013 page 1 available at http://2013electionwatch.com.au/sites/default/files/docs/economicstatementaugust.pdf

A.1.3 Full-haul tariff calculations in nominal dollars

The Perth CPI assumptions and tariffs calculated are provided in Table A-1.

Table A- 1 Actual and forecast CPI and tariffs for the DBNGP, nominal dollars

	Calendar 2012	Calendar 2013	Calendar 2014	Calendar 2015
Perth CPI increase*	2.8%	2.0%	2.5%	2.5%
Base Tariff	$ 1.35	$ 1.35	$ 1.35	$ 1.35
ATAF	$ 0.20	$ 0.20	$ 0.21	$ 0.21
Total	$ 1.55	$ 1.55	$ 1.55	$ 1.56

* From September to September. Calendar 2014 is based on Sept 2012 to forecast Sept 2013 Perth CPI and Calendar 2015 tariffs based on forecast Sept 2013 to forecast Sept 2014 Perth CPI. Note that numbers in the table may not add to total due to rounding.

A.1.4 Full-haul tariff calculations in real dollars of June 2013

Based on our calculations and assumptions we have estimated that the tariffs will be $1.55/GJ for calendar year 2014 and $1.56 for calendar year 2015 in nominal terms.

Assuming equal quantities off-taken in each of the four quarters and using the Perth CPI Index of 103.0 in June 2013 as the base and assuming that Perth CPI growth will be 2.5% pa between June 2013 and 2015, we have estimated the average tariff in 2014-15 in real June 2013 dollars to be $1.49/GJ at 100% load factor.

A.1.5 Commodity and capacity components

The Base Tariff has a capacity reservation to commodity ratio of approximately 80% to 20%. As a result we have assessed:

- The capacity reservation tariff to be $1.194/GJ of capacity reserved
- The commodity component to be $0.299/GJ of gas transported.

A.1.6 Part haul transport

All gas which is delivered south of Compressor Station 9 (north of the Muchea offtake point) is deemed to be full haul, regardless of inlet point.

Part haul transport, for gas delivered north of Compressor Station 9, is essentially calculated at the full haul tariff multiplied by the distance factor. The distance factor as defined in the Part Haul Shipper Contract is the distance from the inlet to the outlet points divided by 1400.

For the tariffs calculated above, the part-haul tariffs in real $June 2013 are:

- A capacity reservation tariff of $0.000853/GJ of capacity reserved multiplied by the distance transported
- A commodity tariff of $0.000213/GJ transported multiplied by the distance transported.

A.2 Goldfields Gas Pipeline (GGP)

A.2.1 Tariffs for transport through uncovered expansions

While part of the GGP is regulated by the ERA, uncovered expansions, such as those under which new gas supply contracts would likely be transported, are not regulated. As a result, applicable tariffs are not readily available in the public arena.

The GGP website provides a tariff range which it states are rates that typically apply. These are :

- Toll charge: $0.243512 - $0.294649/GJ MDQ
- Capacity reservation charge: $0.001685 - $0.002040/GJ MDQ/km
- Throughput charge $0.000634 - $0.000767/GJ/km.

These rates are at June 1997 with quarterly indexation using the Australia All Groups CPI, for which the June 1997 index value was 66.9.

The upper end of the range applies to shorter contracts (1-5 years) and the lower end of the range to long contracts (15-20 years). In addition, tariffs are negotiated, taking into account the particular needs of the shipper.

Given the high price of gas plus transport through the GGP, we expect that prices can be negotiated towards the lower end of the range. As a result, while we do not expect transportation contracts to be 15-20 years duration, we have used the lower end of the range in our calculation and escalated prices from June 1997. This approach is similar to that taken by ACIL Tasman in its February 2013 draft report to IMO entitled Gas Prices in Western Australia[29].

The escalation of tariffs at 100% Australia CPI between June 1997 and June 2012 results in a Toll charge of $0.374/GJ MDQ, a Capacity reservation charge of $0.00259/GJ MDQ/km and a Commodity charge of $0.000974/GJ/km applicable in September 2013.

In order to calculate the tariffs, the Toll charge is multiplied by the contracted capacity, the Capacity reservation charge is multiplied by the contracted capacity times the pipeline distance from the inlet to the offtake point and the Commodity charge is multiplied by the throughput times the pipeline distance from the inlet to the offtake point.

This results in an indicative tariff of $5.29/GJ for a 100% load factor customer in Kalgoorlie (1380 km) in September 2013[30].

However, we have assumed that the Australian CPI rate is 2% pa in 2014-15, lower than the assumed Western Australian rate of 2.5% pa in that year. This means that real prices are expected to reduce slightly with a tariff in 2014-15 of $5.24/GJ in June 2013 dollars[31].

A.3 Transport costs for SWIS generators in 2014-15

Based on the above analysis, the transport costs for individual generators in the SWIS are set out below in Table A-2.

The calculations show the variable and fixed components in $/GJ, assuming a 75% load factor of which only 50% is included in the calculation and take account of distances specified by ACIL Tasman where relevant.

[29] ACIL Tasman draft report to the Independent Market Operator, "Gas prices in Western Australia: 2013-14 review of inputs to the Wholesale Electricity Market", February 2013. available at http://www.imowa.com.au/docs/default-source/rules/other-wem-consultation-docs/2013/gas_prices_in_wa_2013-14_draft_for_consultation.pdf?sfvrsn=2

[30] Thus, for Parkeston, for example, which has a pipeline distance of 1380 km at an annual load of 365 GJ at 100% load factor this results in a Toll Charge of (0.371 x 365) plus a Capacity reservation charge of ($0.00257 x 365 x 1380) plus a Throughput charge of ($0.000965 x 365 x 1380) all divided by the throughput (365 GJ) = $5.29/GJ in September 2013. Assuming a 75% load factor, the Toll Charge and Capacity Reservation Charge are divided by 0.75 resulting in a transportation charge of $6.61GJ.

[31] We note that this results in an indicative transportation tariff which is almost double the current Reference Tariff.

Table A- 2 Transport costs for SWIS generators in 2014-15 in $June 2013/GJ

Generator	Tariff used	Distance	Variable transport charge	Fixed transport charge, 75% LF, $June 2013	Total transport charge (50% of fixed component) $June 2013
Alinta Pinjarra	DBNGP T1		0.30	1.59	1.09
Alcoa Wagerup	DBNGP T1		0.30	1.59	1.09
PPP_KCP_EG1	DBNGP T1		0.30	1.59	1.09
SWCJV Worsley	DBNGP T1		0.30	1.59	1.09
TiWest	DBNGP T1		0.30	1.59	1.09
Cockburn	DBNGP T1		0.30	1.59	1.09
Perth Energy	DBNGP T1		0.30	1.59	1.09
Kwinana	DBNGP T1		0.30	1.59	1.09
Mungarra	DBNGP P1	1020	0.22	1.16	0.80
Pinjar	DBNGP T1		0.30	1.59	1.09
NewGen Neerabup	DBNGP T1		0.30	1.59	1.09
NewGen Kwinana	DBNGP T1		0.30	1.59	1.09
Goldfields Power Parkeston	GGP	1380	1.33	5.21	3.94
Kemerton	DBP T1		0.30	1.59	1.09
Alinta Wagerup	DBP T1		0.30	1.59	1.09

SKM estimates of tariffs. ACIL Tasman distances