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Independent Market Operator

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Dear Robert

2009 MARGIN PEAK AND MARGIN OFF-PEAK REPORT

The Independent Market Operator (IMO) is pleased to provide the Economic Regulation Authority (ERA) with the Margin Peak and Margin Off-Peak values (margin values) report for your consideration.

The IMO and ERA engaged McLennan Magasanik Associates (MMA) to provide an independent assessment of the margin values for the next Review Period. As outlined in this report, MMA proposes the margin values to be:

Margin Values	Current	Proposed
Margin Peak	15%	30%
Margin Off-Peak	12%	103%

According to clause 2.23.12(d) of the Wholesale Electricity Market Rules, margin values are determined by the ERA for each three-year Review Period. The next Review Period is from 1 July 2010 to 30 June 2013.

If you have any queries please do not hesitate to contact me on 9254 4333.

Yours sincerely

ALLAN DAWSON
CHIEF EXECUTIVE OFFICER

11 December 2009

Economic Regulation Authority 11 Dec 2009

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Report to

Independent Market Operator of Western Australia

2009 Margin_Peak and Margin_Off-Peak review

Final report v4.0

10 December 2009

McLENNAN MAGASANIK ASSOCIATES

Ref: J1829 Final report

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TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

VERSION

Version	Date	Comment	Approved
Draft 1.2		Initial draft for review by IMO	Nicola Falcon
Draft 2.0	15/10/09	Incorporating feedback from System Management, ERA and IMO	Nicola Falcon
Public version	26/10/09	Including description of methodology and with confidential data removed	Nicola Falcon
Public version 2	05/11/09	Some modification to description of methodology and data assumptions	Nicola Falcon
Public version 3	09/11/09	Further modification to methodology and data assumptions	Nicola Falcon
Draft report v1.0	16/11/09	Including results from modelling	Nicola Falcon
Draft report v2.0	25/11/09	Draft report incorporating feedback from IMO and ERA	Nicola Falcon
Final report v3.0	25/11/09	Final report incorporating feedback from IMO and ERA	Nicola Falcon
Final report v3.1 revised	8/12/09	Revision of margin values due to change in outage rates assumed for LMS 100 units. Does not include results from gas price sensitivities	Nicola Falcon
Final report v4.0	25/11/09	Final report with inclusion of results from gas price sensitivities	Nicola Falcon

ABBREVIATIONS

The following abbreviations are used in this report.

CPRS	Federal Government's Carbon Pollution Reduction Scheme
ERA	Economic Regulation Authority
IMO	Independent Market Operator of Western Australia
IPP	Independent Power Producer
LFR	Load Following Reserve
MCAP	Marginal Cost Administrative Price
MMA	McLennan Magasanik Associates
MW	Megawatt
MWh	Megawatt Hour
REC	Renewable Energy Certificate
RCM	Reserve Capacity Mechanism
SMP	System Marginal Price
SOO	Statement of Opportunities
SR	Spinning Reserve
SRMC	Short Run Marginal Cost
STEM	Short Term Energy Market
SWIS	South West interconnected system of Western Australia
WEM	Wholesale Electricity Market in the South West interconnected system of Western Australia

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 every three-year Review Period in accordance with the methodology set out in clause 2.23.12(d)(i) and 2.23.12(d)(ii) of the Market Rules.

In determining these margin values, the Market Rules require the 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 (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 ERA and the Independent Market Operator of Western Australia (IMO) engaged McLennan Magasanik Associates (MMA) to undertake market modelling of the Wholesale Electricity Market (WEM) to assess the reserve availability cost and hence determine margin values for the next three-year Review Period commencing July 2010.

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.

To assess the reserve availability cost that could reasonably be expected to be incurred by Verve Energy over the next Review Period, 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 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 next three-year Review Period are 30% for Margin_Peak and 103% for Margin_Off-Peak. Table 1 summarises the availability cost, peak and off-peak SMPs, that form the basis for this assessment.

Table 1 Parameter estimates for Review Period

	2010/11	2011/12	2012/13	All years
Margin_ Off-Peak	86%	152%	80%	103%
Margin_Peak	20%	38%	32%	30%
Availability cost ($M)	29.16	41.51	38.63	
Off-peak price ($/MWh)	35.21	26.69	33.32	
Peak price ($/MWh)	77.64	64.03	80.70	

In assessing these margin values, the following key assumptions were made:

- the price for new gas contracts was assumed to be $7.90/GJ in 2010/2011 declining in real terms to $7.04/GJ in 2012/13
- no Carbon Pollution Reduction Scheme (CPRS) was implemented within the Review Period
- 250 MW Collgar wind farm was commissioned in July 2011, resulting in an increase in LFR requirement from +/- 60 MW to +/- 150 MW
- two LMS 100 high efficiency gas turbine units were commissioned in November 2011 and these units could provide reserve
- no Ancillary Service contracts for SR or LFR were assumed
- start-up costs incurred due to provision of reserve were included as part of the reserve availability cost
- both constrained off and constrained on costs were considered in determining the reserve availability cost.

This last point is particularly relevant in relation to the high Margin_Off-Peak value proposed, which is greater than 100%. The provision of SR and LFR will result in some Verve Energy generators generating less in order to provide reserve or to allow other generators to be commissioned to provide reserve. Other generators will be generating more either to meet demand or to provide reserve when they would otherwise not have been operating. If units generating more are constrained on at minimum stable level, they may not be setting the price since lower cost generation options may still be marginal. If the minimum stable level is relatively high, and there is a large difference in cost between the unit constrained on and the marginal generator, then the reserve availability cost defined relative to the SMP could exceed 100% as indicated in the market simulations. This was further exacerbated after the commissioning of the Collgar wind farm. The higher LFR, coupled with the chance that the wind farm may be operating at high output overnight, resulted in more generators being constrained on to provide reserve.

Over time, as overnight load increased, fewer generators were constrained on, the off-peak SMP increased and the Margin_Off-Peak value as a ratio of SMP declined.

There was some uncertainty surrounding the price for new gas contracts and the assumptions relating to existing gas contracts. Therefore, to test the impact of these assumptions on the proposed margin values, two additional gas price scenarios were simulated:

1. A lower new gas price of $6.50/GJ was assumed
2. No existing gas contracts were modelled, so all gas off-take was priced at the new gas price of $7.90/GJ - $7.04/GJ.

The margin values were relatively insensitive to the change in new gas price assumption, with the lower gas price, with a 3% reduction in Margin_Peak and an 8% increase in Margin_Off-Peak. On average, total availability cost reduced by $2.7 million per year.

The margin values were more sensitive to the existing gas contract assumptions. The proposed margin values were based on the assumption that Verve Energy has access to approximately 100 TJ of gas per day at a price ranging over time from $4.64/GJ to $4.14/GJ, with any additional gas requirements priced at the new gas price. Without considering the lower costs associated with the existing gas contracts, the margin values were higher than the proposed values. This was particularly evident in the off-peak, when coal-fired generation was backed off and gas-fired generators were commissioned in order to ensure sufficient reserve was carried on the system.

If a CPRS were introduced, this would alter the merit order of dispatch, the SMP and the generation costs for Verve Energy. Therefore, it is recommended that the proposed margin values be reviewed if such a scheme were to be implemented within the Review Period.

1 INTRODUCTION

The Independent Market Operator of Western Australia (IMO) in conjunction with the Economic Regulation Authority (ERA) engaged McLennan Magasanik Associates (MMA) to assist in determining the appropriate margin values to be used for the next three-year Review Period commencing 1 July 2010.

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 clauses 2.23.12(d)(i) and (ii) 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 June 2009 dollars.

2 METHODOLOGY FOR CALCULATING MARGIN VALUES

Ancillary services for the Western Australian Wholesale Electricity Market (WEM) are currently all 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 Amending Rules (October 2009) (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 set by the ERA[1] as part of its determination of Allowable Revenue for the relevant three-year Review Period. 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 2.23.12 (d) stipulates that:

the determination of the Allowable Revenue of Ancillary Service provision must take into account the payment structure set out in clause 3.13, and the Economic Regulation Authority must determine values for:

i. the reserve availability payment margin applying for Peak Trading Intervals, Margin_Peak, which 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. the reserve availability payment margin applying for Off-Peak Trading Intervals, Margin_Off-Peak, which 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;

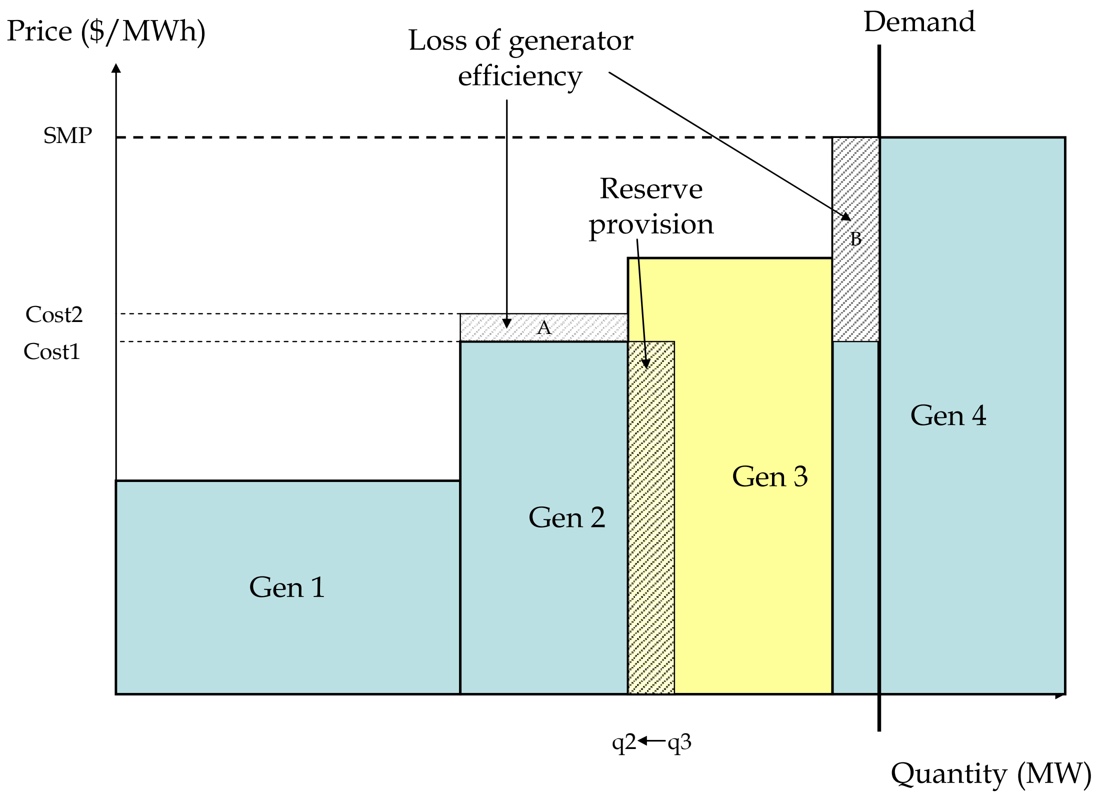
[1] MMA understand that a proposed rule change may result in IMO becoming responsible for setting these parameters in subsequent years (see RC_2009_23 on the IMO website).

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.

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.

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



Through market simulations, this 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 MMA's WEM database.

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.

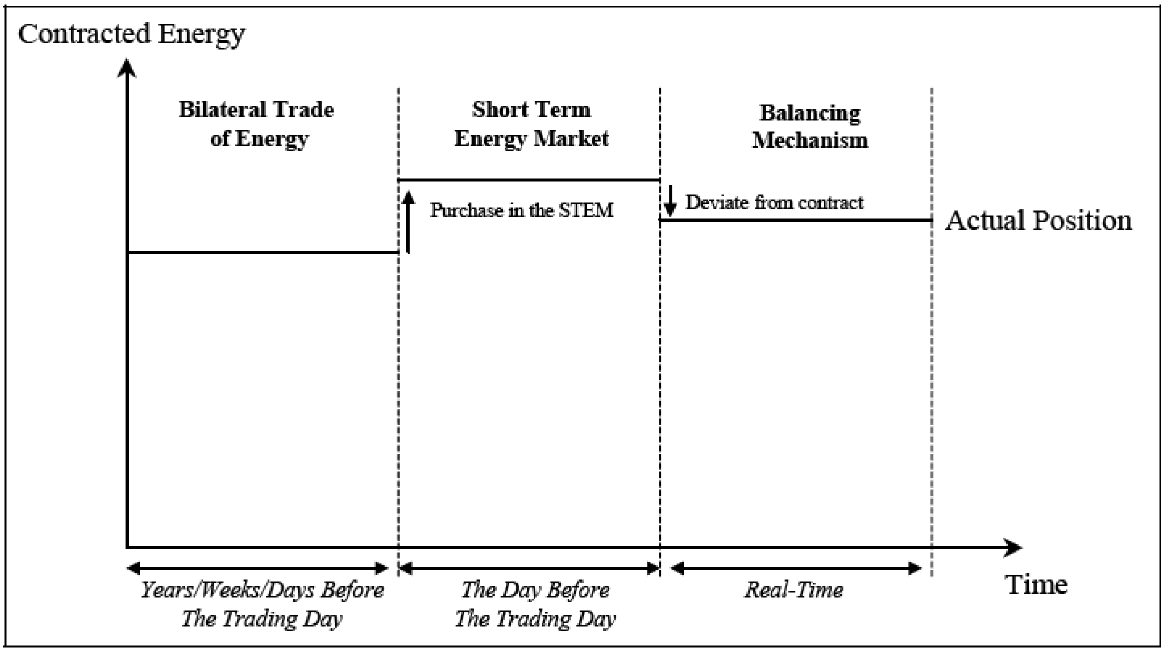
The STEM is a residual, day-ahead trading market which allows contract participants to trade out any imbalances. Market Participants (both Market Generators and Market Customers) can submit offers to sell energy to the STEM, or bids to buy energy from the STEM. Market generators may wish to buy energy 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. The MCAP is the price determined after supply and demand has 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, 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.

In PLEXOS, dispatch is optimised to meet load and ancillary service requirements at minimum cost subject to a number of operating constraints, which may include:

- generation constraints – availability (planned and unplanned outages), unit commitment and other technical constraints
- transmission constraints – availability (planned and unplanned outages), linearised DC optimal power flow equations, interconnector ratings, and other transmission constraints that may be a function of load, generation or line flow

- hydro constraints – hydro units may be energy-constrained, or more detailed storage models may be represented with stochastic hydro inflows (not applicable in the WEM)
- fuel constraints – for example, daily fuel limits or annual take-or-pay constraints
- ancillary service constraints – maximum unit response, calculation of dynamic risk
- emission constraints – limits on emission production may be imposed, or carbon prices specified.

Requirements for LFR and SR are modelled as two different services in the PLEXOS model, with the same MW of reserve contributing to both services.

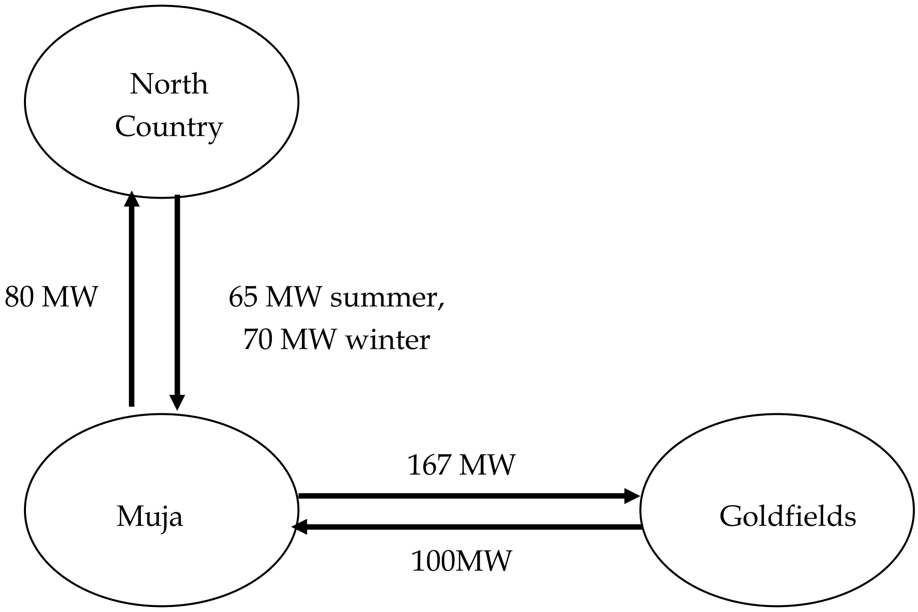
4 KEY MODELLING ASSUMPTIONS

This section outlines the key modelling assumptions used in the PLEXOS market simulations. These assumptions were reviewed by stakeholders prior to undertaking the analysis.

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 (330kV line from Geraldton to Perth), was assumed to lie outside of the horizon of this study.

Figure 4-1 3-node model of SWIS model



The Mungarra units, Geraldton GT and Alinta, Emu Downs and Kalbarri wind farms were located in the North Country, the West Kalgoorlie, Southern Cross and Parkeston units were located in the Goldfields region, and all other units were assumed to be located at the Muja node.

4.2 Demand assumptions

Table 4-1 shows MMA's assumptions for sent-out energy and summer and winter maximum demand across the three nodes. These values were based on the 2009 Statement of Opportunities (SOO) load forecasts, distributed among the three regions in accordance with the 2002/03 actual loads plus the trends in relative regional growth. Private loads (and generation) were also modelled to capture the effect of private generator outages on the system. Private loads were calculated based on the difference between the known maximum capacity for the facilities and the capacity reported in the SOO for export to the grid. The private loads were added to the energy and demand assumptions reported in Table 4-1.

Table 4-1 2011-2013 load assumptions

Financial year	Parameter	Muja (Perth)	Goldfields	North Country
2010/11	Energy (GWh)	15,714	842	1,169
	Summer Peak Demand 50% PoE (MW)	3,782	149	206
	Winter Peak Demand 50% PoE (MW)	2,921	137	169
	Flat private load (MW)	266	123	0
2011/12	Energy (GWh)	16,113	850	1,215
	Summer Peak Demand 50% PoE (MW)	4,084	155	220
	Winter Peak Demand 50% PoE (MW)	2,996	140	174
	Flat private load (MW)	266	123	0
2012/13	Energy (GWh)	17,909	930	1,368
	Summer Peak Demand 50% PoE (MW)	4,438	162	238
	Winter Peak Demand 50% PoE (MW)	3,263	152	190
	Flat private load (MW)	266	123	0

For the chronological modelling in PLEXOS, MMA used typical load profiles for the three nodes (based on 2002/03 historical data), which were then grown to match the energy and peak demand values in Table 4-1.

4.3 Fuel assumptions

The following fuels were represented in our modelling:

- coal: used by Muja, Collie, and the new Bluewaters units
- cogeneration contract gas 1: gas for Alcoa and one of the two Alinta cogeneration plants
- contract gas 2: gas under existing Verve Energy contracts
- Goldfields gas: gas under contract in the Goldfields region
- new gas: reflects the estimated price for new gas contracts
- distillate: used as a primary fuel by Geraldton and the West Kalgoorlie units, and as a secondary fuel for some of the other units once they used up their gas supply.

Multi-fuelled units were modelled as able to use more than one fuel.

4.3.1 Fuel costs

Table 4-2 shows our assumptions on fuel prices for the period from July 2010 to June 2013.

Table 4-2 Fuel prices (real June 09 dollars)

Name	Price ($/GJ) 2010/11	Price ($/GJ) 2011/12	Price ($/GJ) 2012/13
Coal	2.00	2.00	2.00
Cogeneration contract gas 1	2.56	2.41	2.27
Contract gas 2	4.64	4.39	4.14
New gas	7.90	7.45	7.04
Distillate	21.87	21.93	20.46

The coal price was converted from $/tonne, assuming an energy content of 19.5 GJ/tonne. MMA assumed that existing and new coal plants all pay the same for coal.

The two contract gases represent long-term gas contracts that were assumed to have been negotiated several years ago when gas commodity prices were significantly lower.

4.3.2 Fuel constraints

Based on our understanding of the market and historical data, MMA included gas constraints limiting the contract gas daily availability. Specifically, the following constraints were imposed:

- Alinta – one cogeneration unit at contract gas 1 price, the second unit at the new gas price
- Alcoa – all gas at the contract gas 1 priced
- Verve Energy – 100 TJ/day at contract gas 2 price, with any balance at new gas price
- Other gas-fired generators – all gas at the new gas price.

It was assumed that any gas used by Verve Energy or Alinta cogeneration plant in excess of the corresponding daily contract limit was purchased at the new gas price. This allowed us to reflect the likelihood that some of these long-term contracts may be nearing expiry, and will need to be renegotiated at current market prices.

MMA also included some constraints on the total gas available in different locations. For example, the total gas for Kemerton was assumed to be limited to 32 TJ/day and the gas in Goldfields 5 TJ/day, excluding non-generation use.

4.3.3 Fuel price sensitivities

During the stakeholder consultation process, concerns were expressed regarding the gas price assumptions for both contract gas and new gas, but stakeholders were understandably reluctant to offer alternative prices due to the commercially sensitive nature of gas contract negotiations. Consequently, three gas price scenarios were simulated to determine the sensitivity of the Margin_Peak and Margin_Off-Peak values to gas price assumptions. The following three gas price scenarios were modelled:

1. **Base :** use contract gas and new gas prices outlined in Section 4.3.1
2. **No contract gas:** assume there is no contract gas available, and all gas-fired generators must pay for gas at the new gas price outlined in Section 4.3.1
3. **Gas price sensitivity**: use the contract gas prices outlined in Section 4.3.1, but assume a new gas price of $6.50/GJ (real June 2009 dollars).

4.4 Carbon price assumptions

The Government's White Paper announced a 5% reduction target relative to 2000 emissions levels by 2020 as the Government's minimum commitment, with the possibility of a 15% reduction target, subject to international agreement. This position was modified in May 2009[2] when the introduction of the CPRS was delayed by one year to July 2011 start date, a maximum introductory carbon price of $10/t CO_2e was stipulated for the first year of the scheme, and a 25% reduction target was also tabled as a possibility, subject once again to international agreement.

At commencement of this study, no CPRS legislation had been passed by the Senate, and therefore the IMO requested that the scheme not be considered in this analysis. Introduction of the scheme would impact on generation costs, the merit order for dispatch, and the MCAP. It is therefore foreseeable that different margin values would be required to compensate Verve Energy for generation efficiency losses if the CPRS scheme were introduced.

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. The assumed private load is added to the load reported in Table 4-1 and constraints are imposed to ensure that, if available, the private generators generate to at least meet the private load.

Table 4-3 shows the existing generators in the model, and some of the key properties driving marginal costs. Some of the generators listed may represent the aggregation of one or more actual facilities. Most of the properties were obtained from publicly available information (SOO, planning reviews, IMO website, and companies' websites). Missing

[2] Media release by the Prime Minister, Treasurer and Minister for Climate Change and Water, "New measures for the Carbon Pollution Reduction Scheme", 4 May 2009 available at http://www.environment.gov.au/minister/wong/2009/mr20090504a.html. These new measures delayed the introduction of the CPRS until 1 July 2011, provided a one year fixed price period, set at $10/t CO2 for 2011/12, and provided a buffer to EITE industry by increasing assistance to 94.5% and 66% for a five year period from the start of the scheme.

parameters were estimated by MMA based on the nature and known characteristics of the facilities, or based on actual half-hourly dispatch information.

Although MMA are only reporting marginal heat rates at maximum capacity, the model includes polynomial heat rate functions to capture the relationship between output and efficiency. Short run marginal cost (SRMC) values in the table are estimated for 2010/11, based on the primary fuel only and considering the heat rate at maximum capacity.

Fuel transport charges, reflecting variable gas pipeline costs, were estimated for some of the generating units to reflect locational differences in estimated fuel prices.

For the wind farms and biomass plant, the assumed value of renewable energy certificates (REC) was 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.

4.5.2 Future generators

Table 4-4 shows the properties of future generators assumed to become operational within the Review Period. In summary, MMA considered the following units for commissioning/retirement:

- Perth Energy: open cycle gas turbines to be located in Muja region, 4 units expected from October 2010
- Collgar: 250 MW wind farm to be located in Muja region, with commissioning expected in mid 2011
- Bluewaters_G2: to be located next to Bluewaters_G1 unit, expected in December 2010
- Verve high efficiency gas turbines: two 100 MW LMS 100 units to be located at the existing Kwinana B site, with commissioning expected in November 2011
- Kwinana A G1 & 2: to be retired in October 2011.

4.5.3 Unit commitment

Unit commitment assumptions are critical to the assessment of margin values, particularly overnight when a number of units may prefer to stay on and generate at minimum stable level, rather than be decommissioned and incur high start-up costs in subsequent periods. In the PLEXOS simulations, unit commitment decisions were optimised within the model based on start-up costs and minimum stable level assumptions provided by the IMO. In reality, this portion of a generator's output may be bid into the STEM below SRMC, or even at negative cost.

Table 4-3 Properties of existing generators

Generator	Units	Max capacity per unit (MW)	Private load (MW)	Marginal HR at max (GJ/MWh)	Primary fuel	Fuel price 2010/11 ($/GJ)	Transport charge ($/GJ)	VO&M ($/MWh)	SRMC 2010/11 ($/MWh)
BW1_BLUEWATERS_G1	1	229	-	8.90	Coal	2.44	0	2.12	23.83
COLLIE_G1	1	330	-	7.94	Coal	2.44	0	1.06	20.42
MUJA_G5	1, retires 2020	200	-	11.04	Coal	2.44	0	4.24	31.16
MUJA_G6	1, retires 2021	200	-	11.04	Coal	2.44	0	4.24	31.16
MUJA_G7	1	200	-	9.24	Coal	2.44	0	3.98	26.51
MUJA_G8	1	200	-	9.24	Coal	2.44	0	3.98	26.51
ALINTA_PNJ_U1	1	142	-	6.52	Contract gas 1	2.56	0.98	2.26	25.31
ALINTA_PNJ_U2	1	142	-	6.52	New gas	7.90	0.98	2.26	60.16
ALCOA_KWI	1	75	70	6.51	Contract gas 1	2.56	1.07	5.37	28.97
ALCOA_PNJ	1	95	85	6.51	Contract gas 1	2.56	0	5.37	22.00
ALCOA_WGP	4	24.5	4x18.5	6.51	Contract gas 1	2.56	0	5.37	22.00
PPP_KCP_EG1	1	116	38.8	11.33	Contract gas 1	2.56	1.07	4.29	45.37
SWCJV_WORSLEY_COGEN	1, retires Feb 2014	123	-	7.93	Contract gas 1	2.56	1.12	3.87	33.02
TIWEST_COG1	1	38.1	-	10.09	Contract gas 2	4.64	1.1	0.58	58.54
COCKBURN_CCG1	1	240.8	-	9.27	Contract gas 2	4.64	1.12	3.66	57.10
KWINANA_G1	1, retires Oct 2011	120	-	12.25	Contract gas 2	4.64	1.12	4.67	75.28
KWINANA_G2	1, retires Oct 2011	120	-	12.25	Contract gas 2	4.64	1.12	4.67	75.28

Generator	Units	Max capacity per unit (MW)	Private load (MW)	Marginal HR at max (GJ/MWh)	Primary fuel	Fuel price 2010/11 ($/GJ)	Transport charge ($/GJ)	VO&M ($/MWh)	SRMC 2010/11 ($/MWh)
KWINANA_G5	1, retires 2016	200	-	11.69	Contract gas 2	4.64	1.12	4.08	71.47
KWINANA_G6	1, retires 2016	200	-	11.69	Contract gas 2	4.64	1.12	4.08	71.47
KWINANA_GT1	1	20.87	-	11.03	Contract gas 2	4.64	1.12	21.37	84.94
MUNGARRA_GT1	1	37.4	-	12.69	Contract gas 2	4.64	0.87	4.35	74.32
MUNGARRA_GT2	1	37.4	-	12.69	Contract gas 2	4.64	0.87	4.35	74.32
MUNGARRA_GT3	1	38.34	-	12.89	Contract gas 2	4.64	0.87	4.35	75.43
PINJAR_GT01	1	37.4	-	12.69	Contract gas 2	4.64	1.1	9.75	82.65
PINJAR_GT02	1	37.4	-	12.69	Contract gas 2	4.64	1.1	9.75	82.65
PINJAR_GT03	1	38.34	-	10.02	Contract gas 2	4.64	1.1	5.83	63.38
PINJAR_GT04	1	38.34	-	10.02	Contract gas 2	4.64	1.1	5.83	63.38
PINJAR_GT05	1	38.34	-	10.02	Contract gas 2	4.64	1.1	5.83	63.38
PINJAR_GT07	1	38.34	-	10.02	Contract gas 2	4.64	1.1	5.83	63.38
PINJAR_GT09	1	116.4	-	11.29	Contract gas 2	4.64	1.1	4.24	69.09
PINJAR_GT10	1	116.4	-	11.29	Contract gas 2	4.64	1.1	4.24	69.09
PINJAR_GT11	1	123.4	-	9.97	Contract gas 2	4.64	1.1	4.93	62.20
NEWGEN_KWINANA GT	1	160	-	11.45	Contract gas 2	4.64	1.12	2.12	46.09
NEWGEN_KWINANA ST	1	160	-	9.12	Waste heat /contract gas 2	4.64	1.12	2.12	54.65 (duct-firing)
STHRNCRS_EG_1-2	2	10	2x7.6	12.66	New gas	7.90	4.32	4.29	131.15
STHRNCRS_EG_3-4	2	38	2x28.9	11.58	New gas	7.90	4.32	4.29	120.35
KEMERTON_GT11	1	156	-	11.13	New gas	7.90	0	2.26	90.18
KEMERTON_GT12	1	156	-	11.13	New gas	7.90	0	2.26	90.18
ALINTA_WGP_GT	1	190	-	16.20	New gas	7.90	0.98	2.26	146.10

Generator	Units	Max capacity per unit (MW)	Private load (MW)	Marginal HR at max (GJ/MWh)	Primary fuel	Fuel price 2010/11 ($/GJ)	Transport charge ($/GJ)	VO&M ($/MWh)	SRMC 2010/11 ($/MWh)
ALINTA_WGP_GT2	1	190	-	16.20	New gas	7.90	0.98	2.26	146.10
NEWGEN_NEERABUP	2	165	-	11.63	New gas	7.90	1.12	2.26	107.16
PRK_AG	3	38	3x15.33	8.03	New gas	7.90	4.32	4.29	102.39
GERALDTON_GT1	1	21	-	15.27	Distillate	21.87	0	2.44	336.40
WEST_KALGOORLIE_GT2	1	38.4	-	14.75	Distillate	21.87	0	31.81	354.46
WEST_KALGOORLIE_GT3	1	24.8	-	14.75	Distillate	21.87	0	31.81	354.46
WA LANDFILL GAS	1	25.8	-	11.30	Landfill gas			-15.90	-15.90
Bridgetown Biomass	1	44	-	11.30	Biomass			-15.90	-15.90
ALBANY_WF1	12	1.8	-		Wind			-37.11	-37.11
ALINTA_WWF	54	1.65	-		Wind			-37.11	-37.11
KALBARRI_WF1	2	0.8	-		Wind			-37.11	-37.11
SKYFARM_WF1	3	0.70	-		Wind			-37.11	-37.11
BREMER BAY_WF1	1	0.66	-		Wind			-37.11	-37.11
EDWFMAN_WF1	48	1.65	-		Wind			-37.11	-37.11

* The numbers in the table are based on information derived from the SOO and other publically available data.

Table 4-4 Properties of future generators

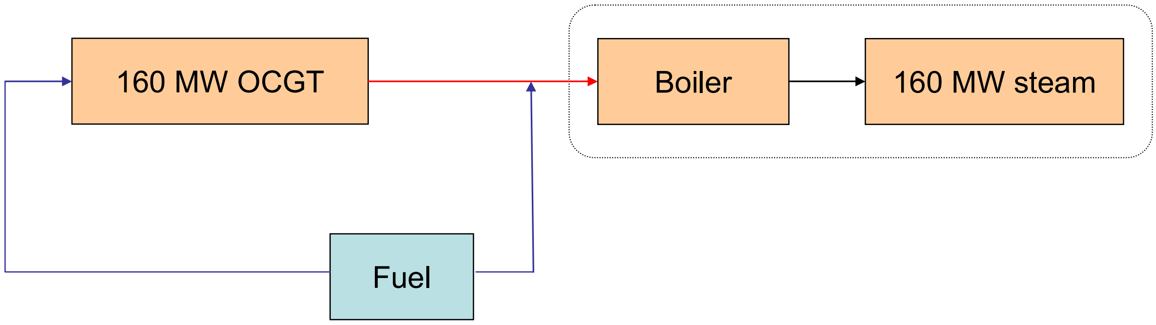
Generator	Units	Max capacity per unit (MW)	Marginal HR at max (GJ/MWh)	Primary fuel	Fuel price 2010/11 ($/GJ)	Transport charge ($/GJ)	VO&M ($/MWh)	SRMC 2010/11 ($/MWh)
COLLGAR	127 (July 2011)	2		Wind			-37.11	-37.11
BW1_BLUEWATERS_G2	1, (Sep 2010)	229	8.90	Coal	2.44	0	2.12	23.83
BW1_BLUEWATERS_G3	1, (Sep 2013)	204	8.90	Coal	2.44	0	2.12	23.83
PERTH_ENERGY_GT1	4 (Oct 2010)	30	11.60	New gas	7.90	1.12	4.24	108.87
VERVE HEGT	2, (Nov 2011)	100	8.44	Contract gas 2*	4.64	1.12	6.00	54.61

*Assuming that the high efficiency GT has access to the gas freed up by the shutdown of Kwinana B.

4.5.4 Kwinana NewGen

The Kwinana NewGen combined cycle gas turbine 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 80 MW available from the steam unit during peak periods through auxiliary duct firing. This configuration was modelled explicitly in PLEXOS, as shown in Figure 4-2.

Figure 4-2 Kwinana NewGen CCGT model in PLEXOS



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. An additional constraint was imposed in the PLEXOS model to ensure that this risk was appropriately considered in determining the SR requirement.

4.6 Reserve modelling assumptions

In determining the availability cost of providing ancillary services, both SR and LFR were modelled in PLEXOS.

4.6.1 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 capacities on other generating units and/or interruptible loads are made available to support system frequency in the event of a contingency.

In PLEXOS, reserve and energy are co-optimised. Therefore, the model will reduce the output from the largest generating unit if, in doing so, less reserve needs to be carried on the system and total system costs are reduced. In the WEM, this results in Collie being de-rated overnight in the PLEXOS simulations to reduce the level of SR requirement. This is particularly evident in the 2010/2011 year prior to the assumed increase in LFR (see next section). The LFR effectively acts as a floor on the SR requirement, so when the LFR requirement increases the benefit of de-rating Collie diminishes.

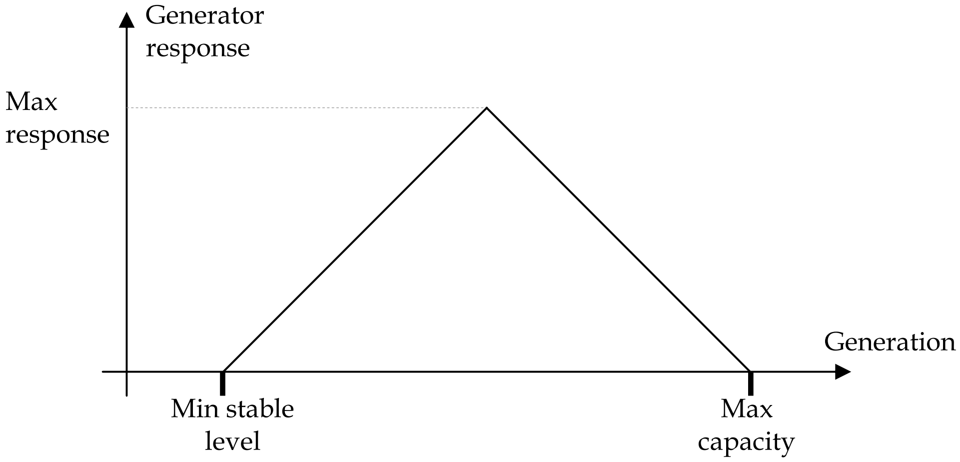
System Management has confirmed that Collie is de-rated overnight, although the primary reason is not to reduce the SR requirement, but rather to avoid decommissioning other base load generators overnight.

4.6.2 Load following reserve

LFR is required to meet fluctuations in supply and demand in real time. The current LFR requirement is +/- 60 MW and is a component of the SR. Therefore, the same MW of reserve may be used to meet both the LFR and SR requirements. Once the Collgar wind farm becomes operational mid-2011, it is expected that the LFR will increase to +/- 150 MW.

The generators providing LFR must be able to raise or lower their generation in response to automatic generation control (AGC) signals. For example, a generator with a maximum capacity of 170 MW and a minimum stable level of 50 MW will be able to offer up to +/- 60 MW of LFR by generating 110 MW. The concept is further illustrated in Figure 4-3.

Figure 4-3 Generator response for Load Following Reserve



While the dispatch of a LFR generator can vary from minute to minute to meet generation and demand fluctuations, for modelling purposes it was assumed that, on average across the half-hour period, a LFR generator is not load following. That is, intra-half-hour Lload 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 assumed in our database were based on confidential information provided by System Management.

4.6.4 Interruptible load

Some reserve may be provided by reducing load through interruptible load arrangements. Consistent with the Market Rule 3.11.11 Report[3], 50 MW of interruptible load was assumed to be available for the three years of the Review Period and can be used at all times to provide SR.

4.6.5 Ancillary service contracts

No Ancillary Service contracts for SR or LFR were assumed for the purposes of this study. Although it should be noted that System Management is currently preparing its LFR procurement process, with expressions of interest proposed to be published by the end of the 2009 calendar year.

4.6.6 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) was defined representing the cost per MWh of not meeting the reserve requirement. In PLEXOS, a VoRS of $1,000/MWh was assumed for the WEM.

[3] Western Power, *http://www.imowa.com.au/f161,48013/48013_2009AncillaryServiceReport.pdf* (last cited 26 Novebmer 2009)

5 RESULTS

In this section MMA present the Margin_Peak and Margin_Off-Peak values for the three gas price scenarios. 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_Peak and Margin_Off-Peak values applicable for the Review Period represent the average of each half-hour trading period within the three year period, weighted by the quantity of SR provided in each period.

An assessment of the margin values for individual years within the Review Period is also provided in this section, along with the off-peak and peak price outcomes and the total availability cost from which the margin values were calculated.

5.1 Base case

In the base case, MMA assumed a new gas price of $7.90/GJ in the 2010/2011 year, reducing in real terms to $7.04/GJ in 2012/2013. The margin values, availability cost and system marginal prices for this base case are presented in Table 5-1. The Margin_Off-Peak value was highly variable from one year to the next, and was sensitive to unit commitment assumptions, load growth, and the level of load-following reserve. The reasons for this variability are discussed in more detail in Section 6 on page 21. On average for the Review Period, a Margin_Off-Peak value of 103% is recommended, based on system marginal off-peak prices ranging between $26.69/MWh and $35.21/MWh.

For Margin_Peak, a weighted average value of 30% has been estimated, based on system marginal prices between $64.03/MWh and $80.70/MWh. The Margin_Peak values in 2011/2012 and 2012/2013 were greater than in 2010/2011 due in part to Verve Energy's contract gas supply constraining more frequently with the introduction of the LMS 100 high efficiency gas turbine units.

Table 5-1 Parameter estimates for base case

	2010/11	2011/12	2012/13	All years
Margin_ Off-Peak	86%	152%	80%	103%
Margin_Peak	20%	38%	32%	30%
Availability cost ($M)	29.16	41.51	38.63	
Off-peak price ($/MWh)	35.21	26.69	33.32	
Peak price ($/MWh)	77.64	64.03	80.70	

5.2 Gas price sensitivity

In this scenario, a lower new gas price of $6.50/GJ was used since Synergy suggested that a lower price was more reasonable than the $7.90/GJ assumed in the base case. Table 5-2 provides a summary of the parameter estimates based on this lower new gas price. The analysis indicated that the margin values were not as sensitive to new gas price assumptions as initially thought. The reduction in new gas price resulted in a 3% reduction in the Margin_Peak value and an 8% increase in the Margin_Off-Peak value. Overall, the total availability cost is slightly lower.

Table 5-2 Parameter estimates for gas price sensitivity (new gas price = $6.50/GJ)

	2010/11	2011/12	2012/13	All years
Margin_ Off-Peak	80%	159%	101%	111%
Margin_Peak	17%	33%	31%	27%
Availability cost ($M)	23.79	40.13	38.27	
Off-peak price ($/MWh)	33.78	26.50	31.68	
Peak price ($/MWh)	68.73	59.79	77.22	

5.3 No contract gas consideration

When no lower-cost Verve Energy contract gas was considered in the analysis, the margin values were higher than in the base case as shown in Table 5-3. This was particularly noticeable in the off-peak, when Verve Energy was backing off coal units and starting up gas-fired generators to provide reserve. The higher gas prices applied across Verve Energy's portfolio also exaggerated any generator efficiency losses arising from gas-fired generating units operating at a less-efficient point on the heat rate curve.

Table 5-3 Parameter estimates without Verve Energy contract gas

	2010/11	2011/12	2012/13	All years
Margin_ Off-Peak	91%	235%	119%	141%
Margin_Peak	28%	44%	25%	32%
Availability cost ($M)	40.77	63.49	41.41	
Off-peak price ($/MWh)	43.04	28.00	34.27	
Peak price ($/MWh)	90.48	72.45	85.02	

6 CONSTRAINING UNITS ON TO PROVIDE RESERVE

In the scenario results presented in the previous section, the Margin_Off-Peak value was consistently greater than 100 per cent when averaged across the three-year Review Period. On closer inspection it was found that this was largely due to two factors:

- On advice from System Management, when Muja units are providing reserve it is assumed that only half the spare capacity is available for SR provision. This means that, if one of these units were to provide 1 MW of SR, it would need to reduce its output by 2 MW, effectively doubling the availability cost. Typically, Muja units provided a greater proportion of total SR provision in off-peak periods than in peak periods.
- 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 the latter, consider again the simple four generator example introduced in Section 2 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 6-1). 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 minimum stable level (Figure 6-2). 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 could result in a margin value greater than 100%. In the WEM, this situation may arise if Cockburn is constrained on, as MMA understands that this unit has a relatively high minimum stable level.

Figure 6-1 Example of availability cost without Gen 4 constrained on

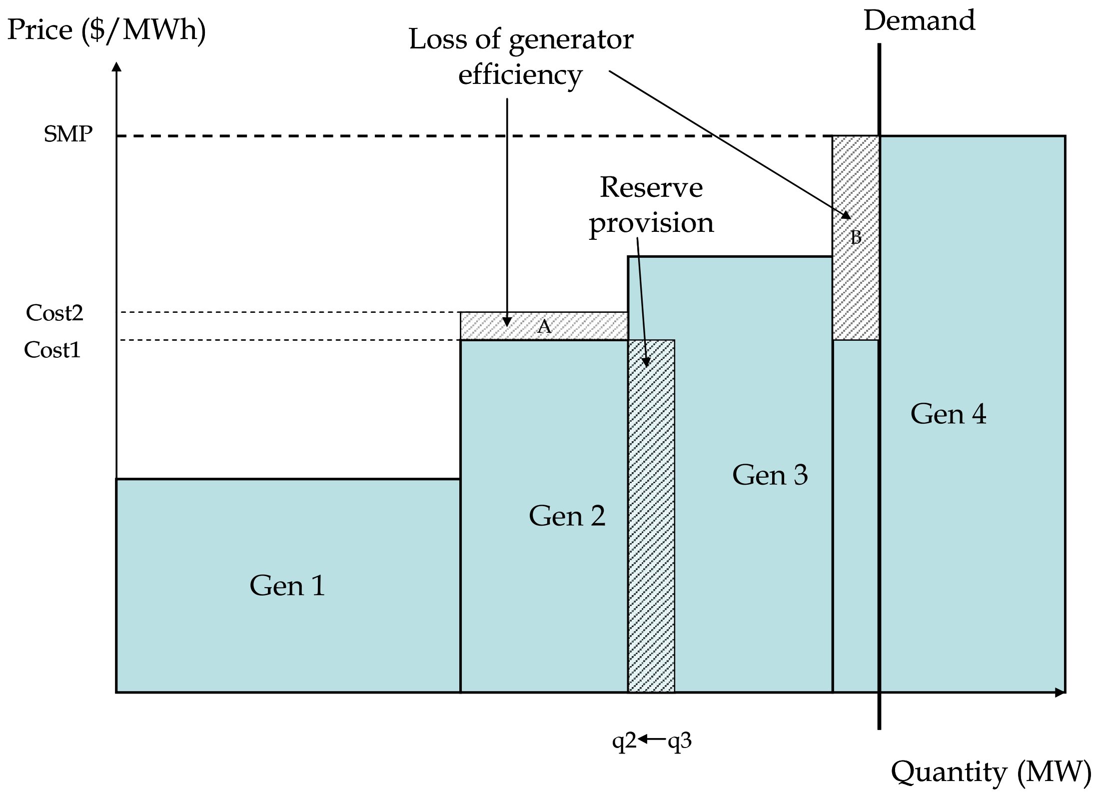
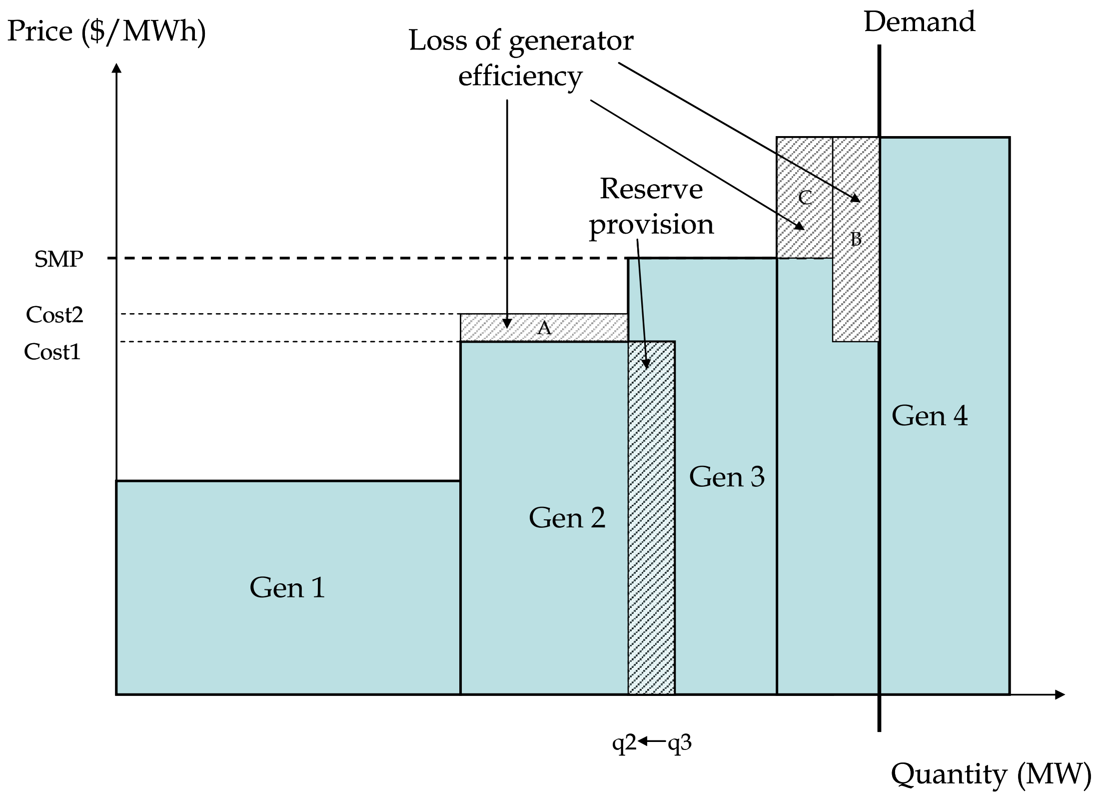


Figure 6-2 Example of availability cost with Gen 4 constrained on



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. This is particularly evident after the assumed introduction of the 250 MW Collgar wind farm in July 2011, resulting in a large increase in the Margin_Off-Peak value in that year. With the increased penetration of wind, the level of load-following reserve has been estimated by System Management to increase to approximately +/- 150 MW. To meet this requirement overnight, a number of Verve Energy units may be constrained on, and this may be exacerbated at times when the wind farm is also generating at high levels.

As load grows over time, the frequency of constrained on events will decrease. In 2013, the energy demand forecasts in the 2009 SOO increase significantly, as new mining loads are expected to come on line (see Table 4-1). Consequently, the Margin_Off-Peak values in the 2012/2013 year were considerably lower than in the 2011/2012 values.

To approximate the impact of the constrained on costs, an additional simulation was conducted whereby constrained on costs were ignored, and the availability cost was only calculated on Verve Energy generators with output reduced due to reserve provision.

This alternative assessment of the reserve availability cost is consistent with the approach adopted in the study conducted by MMA for the ERA earlier this year, investigating the impact of IPP SR provision in the WEM.[4]

The margin values calculated using this alternative approach are summarised in Table 6-1.

Table 6-1 Parameter estimates considering constrained off payments only

	2010/11	2011/12	2012/13	All years
Margin_ Off-Peak	21%	16%	26%	21%
Margin_Peak	33%	36%	45%	38%
Availability cost ($M)	27.04	22.52	36.04	

When the availability cost was only calculated on generators with output reduced due to reserve provision, the Margin_Off-Peak values were significantly lower since constrained on costs were not considered. Conversely, the Margin_Peak values were higher. 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. When only considering constrained off payments, any net benefits arising from sales revenue increases were not accounted for, and consequently Margin_Peak values were higher.

[4] MMA. May 2009. *Impact of IPP spinning reserve provision in the Wholesale Electricity Market*

7 CONCLUSIONS

Based on our market modelling, MMA recommend the following margin values for the next Review Period commencing July 2010:

- Margin_Peak 30%
- Margin_Off-Peak 103%.

These values are sensitive to a number of factors including:

- the price and volume assumptions relating to existing Verve Energy gas contracts
- the overnight unit commitment decisions, which are based on start-up costs, minimum stable level assumptions and the maximum reserve provision for each unit
- the LFR requirement once the Collgar wind farm is commissioned.

Moreover, these margin values have been developed assuming that no CPRS is implemented within the next Review Period and no Ancillary Service contracts for SR or LFR are negotiated. If any of these assumptions were to change, the margin values may need to be reviewed.