2018-19 Margin Peak and Margin Off-peak Review

AUSTRALIAN ENERGY MARKET OPERATOR

Final report - PUBLIC

3.0

9 March 2018

JACOBS

JACOBS

2018-19 Margin Peak and Margin Off-peak Review

Project no:	RO095900
Document title:	Final report – PUBLIC
Document no:	3.0
Date:	9 March 2018
Client name:	Australian Energy Market Operator
Client no:	
Project manager:	Paul Nidras
Author:	Paul Nidras
File name:	I:\MMA\Projects\RO095900 AEMO MVR\Report\Final Report - PUBLIC v3.0.docx

Jacobs Group (Australia) Pty Limited
ABN 37 001 024 095
Floor 11, 452 Flinders Street
Melbourne VIC 3000
PO Box 312, Flinders Lane
T +61 3 8668 3000
F +61 3 8668 3001
www.jacobs.com

Document history and status

Version	Date	Description	By	Review	Approved
1.0	29/11/2017	Draft final report derived from the confidential version	G Gilotra, S Hyland	P Nidras	P Nidras
1.1	30/11/2017	Finalised report	P Nidras		P Nidras
1.2	6/12/2017	Minor correction made to margin value calculation	P Nidras		P Nidras
1.3	14/12/2017	Clarified commentary on results	S Hyland	P Nidras	P Nidras
2.0	31/01/2018	Revised results	S Hyland	P Nidras	P Nidras
3.0	9/03/2018	Finalised results	S Hyland	P Nidras	P Nidras

JACOBS

Contents

Important note about your report

The sole purpose of this report and the associated services performed by Jacobs is to determine margin peak and margin off-peak values that will apply to Synergy for its provision of Spinning Reserve Ancillary Services in the WEM in accordance with the scope of services set out in the contract between Jacobs and the Client. That scope of services, as described in this report, was developed with the Client.

In preparing this report, Jacobs has relied upon, and presumed accurate, any information (or confirmation of the absence thereof) provided by the Client and/or from other sources. Except as otherwise stated in the report, Jacobs has not attempted to verify the accuracy or completeness of any such information. If the information is subsequently determined to be false, inaccurate or incomplete then it is possible that our observations and conclusions as expressed in this report may change.

Jacobs derived the data in this report from information sourced from the Client (if any) and/or available in the public domain at the time or times outlined in this report. The passage of time, manifestation of latent conditions or impacts of future events may require further examination of the project and subsequent data analysis, and re-evaluation of the data, findings, observations and conclusions expressed in this report. Jacobs has prepared this report in accordance with the usual care and thoroughness of the consulting profession, for the sole purpose described above and by reference to applicable standards, guidelines, procedures and practices at the date of issue of this report. For the reasons outlined above, however, no other warranty or guarantee, whether expressed or implied, is made as to the data, observations and findings expressed in this report, to the extent permitted by law.

This report should be read in full and no excerpts are to be taken as representative of the findings. No responsibility is accepted by Jacobs for use of any part of this report in any other context.

This report has been prepared on behalf of, and for the exclusive use of, Jacobs's Client, and is subject to, and issued in accordance with, the provisions of the contract between Jacobs and the Client. Jacobs accepts no liability or responsibility whatsoever for, or in respect of, any use of, or reliance upon, this report by any third party.

Executive summary

The Australian Energy Market Operator (AEMO) engaged Jacobs to assist in determining the appropriate margin values to be used for the financial year starting 1 July 2018. The values for the Margin_Peak and Margin_Off-Peak parameters are used in the ancillary service settlement calculations under clause 9.9.2 of the Market Rules for the compensation of costs incurred by Synergy as the default provider of the Spinning Reserve Ancillary Service. Spinning Reserve Ancillary Services is reserve that is synchronised to the system that can respond almost immediately and provide frequency or voltage support for a short duration. These parameters reflect the margins applied to the Balancing Price in the settlement calculations of the availability costs to be paid to Synergy for the provision of Spinning Reserve Ancillary Services. The Market Rules also allow other generators to provide Spinning Reserve Ancillary Service through a contract with AEMO, provided it is a less expensive alternative.

In determining these margin values, the Market Rules require AEMO and the Economic Regulation Authority (ERA) to take into account the energy sales forgone and the generation efficiency losses that could reasonably be expected to be incurred by Synergy as a consequence of providing spinning reserve. These energy sales forgone 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 Synergy 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; and
- a reduction in generation from Synergy plant and a corresponding increase in generation from Independent Power Producers (IPP), resulting in loss of profit for Synergy.

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. We took into account the impact of Load Rejection Reserve (LRR) in this calculation to ensure that only the cost of SR was being included in the margin value calculation because Synergy is the default provider for both SR and LRR.

The market simulations were undertaken using PLEXOS simulation software, which co-optimised energy and reserve provision to determine least-cost dispatch. With the introduction of the Balancing Market in 2012, which operates as a gross dispatch pool market, the WEM and PLEXOS market model outcomes are expected to be closely aligned.

Prior to conducting this analysis, extensive consultation and comparison of modelled outcomes against actual were conducted to ensure that the model was as accurate as possible. Jacobs undertook a backcasting exercise this year to benchmark the model against the actual results of the market. A summary of the backcasting exercise is included in Appendix B. This backcasting exercise showed that the model is reproducing dispatch and pricing outcomes in the market well, though it also led to several updates to the model. The major updates related to the behaviour of the Alinta Pinjarra cogeneration plant and the NewGen Kwinana CCGT facility, which were generating more than the modelling had been predicting, and the Synergy coal-fired generators, which were generating less than the modelling had been predicting. The increased dispatch of the gas-fired units in aggregate indirectly has a significant impact on the availability cost calculated for Synergy.

To assess the reserve availability cost that could reasonably be expected to be incurred by Synergy for the 2018-19 financial year, revenue and generation cost outcomes were compared from four market simulations with and without SR provision and also with and without LRR provision[1]. That is:

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

where:

GenCost_Res	= Synergy's total generation costs, including start-up costs, with reserve provision
GenCost_NRP	= Synergy's total generation costs, including start-up costs, without any reserve provision apart from LFAS
GenQ_Res	= Synergy's total generation volume, with reserve provision
GenQ_NRP	= Synergy's total generation volume, without any reserve provision apart from LFAS
Balancing Price	= The modelled system marginal price for dispatch with SR and LRR reserve provision

In each of the simulations, load following was provided by Synergy and selected Independent Power Producers on a competitive basis.

It is necessary to calculate the availability cost relative to a specific reserve configuration, since this is the only way to separate out the cost contribution of each reserve type. For example, the availability cost of providing SR can be modelled relative to a base case where LRR is also modelled (where both market simulations include LRR), or relative to a base case where no LRR is modelled (where neither market simulation includes LRR).

Simulation of SR costs in the previous study revealed that there is often an interaction cost effect between the cost of providing SR, and the cost of providing LRR. That is, the cost of providing both forms of reserve is generally not the same as the sum of providing each reserve separately. The difference between these two quantities is labelled as the Interaction Cost. This cost can be negative when the cost of providing SR without considering LRR is greater than the cost of providing SR with LRR. Both positive and negative interaction costs have been observed over the last few years, and it is not possible to predict a priori what the sign of this cost will be as it is driven by complex market interactions.

The availability cost for Synergy to provide SR is determined separately from the provision of LRR. This is due to clause 13.3.3B, which requires the ERA to make a separate determination for the recovery of Synergy's costs for LRR and utilises a different settlement mechanism for recovery of costs. Following consultation with AEMO, it was determined that the availability cost of providing SR should be the weighted average of the Base SR availability cost[2] and the SR availability cost with LRR also included, where the weights are a function of the average level of SR required across the study horizon relative to the sum of the SR and LRR requirements[3].

That is[4]:

Availability Cost(SR) = Availability Cost(SR only)* [1 – SR_Proportion] +

Availability Cost(SR given LRR) * SR_Proportion

where:

[1] All simulations did however include Load Following Ancillary Services (LFAS)
[2] That is, the availability cost of providing SR only, with no provision of LRR.
[3] This is identical to last year's formulation (the formulas have been re-arranged – see section 2.3) but intuitively easier to interpret.
[4] This formula is derived in section **Error! Reference source not found.** and Appendix C.

SR_Proportion = Average SR provision / (Average SR provision + Average LRR provision)

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

The methodology used to estimate the margin values was unchanged from last year's review. Key changes to input assumptions include changes to the running characteristics of several IPP plant based on their observed dispatch in the market, capping total generation from Synergy's coal fleet in peak periods and the retirements of several Synergy facilities.

The resulting margin values proposed for the financial year commencing July 2018 are 71% for Margin_Off-Peak and 34% for Margin_Peak. Exec Table 1 summarises the availability cost, SR_Capacity_Peak and SR_Capacity_Off-Peak, and peak and off-peak prices that form the basis for this assessment, averaged over 10 random outage samples (refer to Table 8). SR_Capacity_Peak and SR_Capacity_Off-Peak denote the average total quantity of SR required by the WEM for peak and off-peak periods respectively. The availability cost is the estimated cost to Synergy of providing SR for the 2018-19 financial year. The peak and off-peak prices are the average Balancing Price for peak and off-peak periods respectively. The product of the peak/off-peak price and the peak/off-peak margin value represents the amount of compensation received by Synergy for the provision of 1 MWh of SR.

Exec Table 1 Parameter estimates for 2018-19 financial year

Parameter	Proposed (2018-19)	Standard error (2018-19)	Approved (2017-18)	Standard error (2017-18)
Margin_Off-Peak	71%	1.1%	64%	1.8%
Margin_Peak	34%	0.8%	36%	0.7%
SR_Capacity_Off-Peak (MW)	189.0	0.34	190.2	0.23
SR_Capacity_Peak (MW)	224.1	0.29	221.8	0.17
Availability cost ($M)	13.15	0.23	13.29	0.27
Off-peak price ($/MWh)	39.52	0.06	39.56	0.07
Peak price ($/MWh)	54.44	0.12	56.27	0.17

The results of the off-peak and peak margin values compared with last year's Margin Value Review can be explained as follows:

- A Margin_Off-Peak value of 71% is proposed, based on an average system marginal off-peak price of $39.52/MWh. The Margin_Off-Peak parameter is 7% higher than what was recommended for the 2017-18 financial year. This increase in the Margin_Off-Peak value is primarily explained by the 9% increase in the off-peak availability cost. In contrast, off-peak price is only 0.1% lower relative to last year's value, but the volume of SR required to be supplied by Synergy in the off-peak has decreased by 2%, which puts upward pressure on the Margin_Off-Peak value as there is less volume over which to spread the off-peak availability cost.

- For Margin_Peak, an average value of 34% has been proposed, based on an average system marginal peak price of $54.44/MWh. The Margin_Peak parameter is 6% lower than what was recommended for the 2017-18 financial year. This decrease is primarily explained by the 7% decrease in the availability cost during peak periods. The other two factors contributing to the decrease in the Margin_Peak value are the peak price[5], which is 3% lower than last year's price, and an increase of 3% in average SR provision by Synergy during peak periods.

- The availability cost has decreased slightly relative to last year's study, from $13.29M to $13.15M. However, it has increased in off-peak periods and decreased in peak periods, and these movements mostly explain the movement of the Margin_Off-Peak and Margin_Peak values respectively.

- This increase in availability costs for off-peak periods ($5.16M compared with $4.72M in last year's modelling) is mainly due to increased dispatch costs of Kemerton, Pinjar and Kwinana high efficiency GT (HEGT) facilities. These are an indirect result of the increased dispatch of the IPP facilities for Alinta Pinjarra cogeneration and NewGen Kwinana CCGT in off-peak periods,which displace more of Synergy's generation. The dispatch of these facilities was increased in this year's modelling compared to 2017-18, based on the backcasting exercise (see Appendix B). The increased dispatch of Alinta Pinjarra and NewGen Kwinana CCGT increases the off-peak availability cost to Synergy because it more frequently puts the system in a state where some Synergy units – primarily the Kwinana and Pinjar GTs and the Kemerton HEGTs – are only online because of the ancillary services requirements. When these units are switched on to provide reserve the availability cost is incurred in the increased number of starts of the GTs, as well as the cost of foregoing cheaper generation to bring GTs online to their minimum operating levels.

- The key drivers leading to the lower availability cost for peak periods this year ($8.00M compared with $8.57M in last year's modelling) include the lower marginal cost of fuel for the Synergy peakers, the introduction of the constraint on Synergy coal in peak periods which results in more Synergy gas-fired generation in the no SR cases and the increase in the SR and LRR provision capabilities of the Muja C and D coal-fired generators (7.4 MW additional provision capability, which represents a 9% increase), and the increase in the LFAS provision capabilities of the Kwinana HEGTs (50% increase in capability), Pinjar GTs (125% increase) and Mungarra GTs (119% increase). The last two factors represent an increase in SR supply capacity, which naturally puts downward pressure on the SR cost.

- The increased dispatch of the Alinta Pinjarra units and NewGen Kwinana CCGT in the peak is mitigated by the maximum generation constraint imposed on Synergy's coal plant in peak periods. This explains why this factor has an impact during off-peak periods, but not in peak periods.

[5] A decrease in the price results in an increase in the Margin Value. The reason is that the Margin Values are expressed as a percentage of the system price, and decreasing the price means that the Margin Value should be raised to recover the same availability cost.

1. Introduction

The Australian Energy Market Operator (AEMO) has engaged Jacobs to assist in determining the appropriate margin values to be applied for the financial year commencing 1 July 2018. The values for the Margin_Peak and Margin_Off-Peak parameters are used in the ancillary service settlement calculations under clause 9.9.2 of the Market Rules for the compensation of costs incurred by Synergy as the default provider of the Spinning Reserve Ancillary Service. Spinning Reserve Ancillary Services is reserve that is synchronised to the system that can respond almost immediately and provide frequency support for a short duration. These parameters reflect the margins applied to the Balancing Price in the settlement calculations of the availability costs to be paid to Synergy for the provision of Spinning Reserve Ancillary Services. The Market Rules also allow other generators to provide Spinning Reserve Ancillary Service through a contract with AEMO, provided it is a less expensive alternative.

To determine appropriate Margin_Peak and Margin_Off-Peak parameters for the period of interest, we calculated the availability cost for Spinning Reserve Ancillary Service (SR) 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.

We 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; and
- ancillary service constraints – maximum unit response, calculation of dynamic risk.

The availability cost resulting from backing-off generation to provide SR will depend on both the marginal costs of the generators providing the reserve, and the market clearing price (Balancing Price) set by the marginal generator. From previous modelling experience, we have found that this availability cost can be sensitive to 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 Ancillary Service (LFAS). In recognition of the importance of these assumptions, we have prepared this Assumptions Report for review by key stakeholders prior to undertaking any analysis.

All prices and costs in this report are given in June 2017 dollars, unless otherwise specified. Where the same cost assumptions have been adopted as previously used in the calculation of the 2017-18 financial year margin values that were determined by the Economic Regulation Authority (ERA) on 31 March 2017, the costs have been adjusted from June 2016 to June 2017 dollars using the Perth Consumer Price Index (All Groups) published by the Australian Bureau of Statistics.

2. Methodology for calculating margin values

SR for the WEM is, by default, provided by Synergy, although System Management may also contract with other market participants to provide SR where it is cost-effective to do so. AEMO pays Synergy for its 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 AEMO 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 SR determined and the Balancing Price, will compensate Synergy for energy sales forgone 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, AEMO 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, AEMO must take account of:

1. the margin Synergy could reasonably have been expected to earn on energy sales forgone due to the supply of Spinning Reserve Service during Peak Trading Intervals; and

2. the loss in efficiency of Synergy's Scheduled Generators that System Management has scheduled (or caused to be scheduled) to provide Spinning Reserve Service 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, AEMO must take account of:

1. the margin Synergy could reasonably have been expected to earn on energy sales forgone due to the supply of Spinning Reserve Service during Off-Peak Trading Intervals; and

2. the loss in efficiency of Synergy's Scheduled Generators that System Management has scheduled (or caused to be scheduled) to provide Spinning Reserve Service during Off-Peak Trading Intervals that could reasonably be expected due to the scheduling of those reserves[.]

The reserve availability payment to Synergy should be equal to the sum of generator efficiency losses and energy sales forgone (resulting from reduced generation quantity due to the commitment of capacity for providing SR), which may be incurred through:

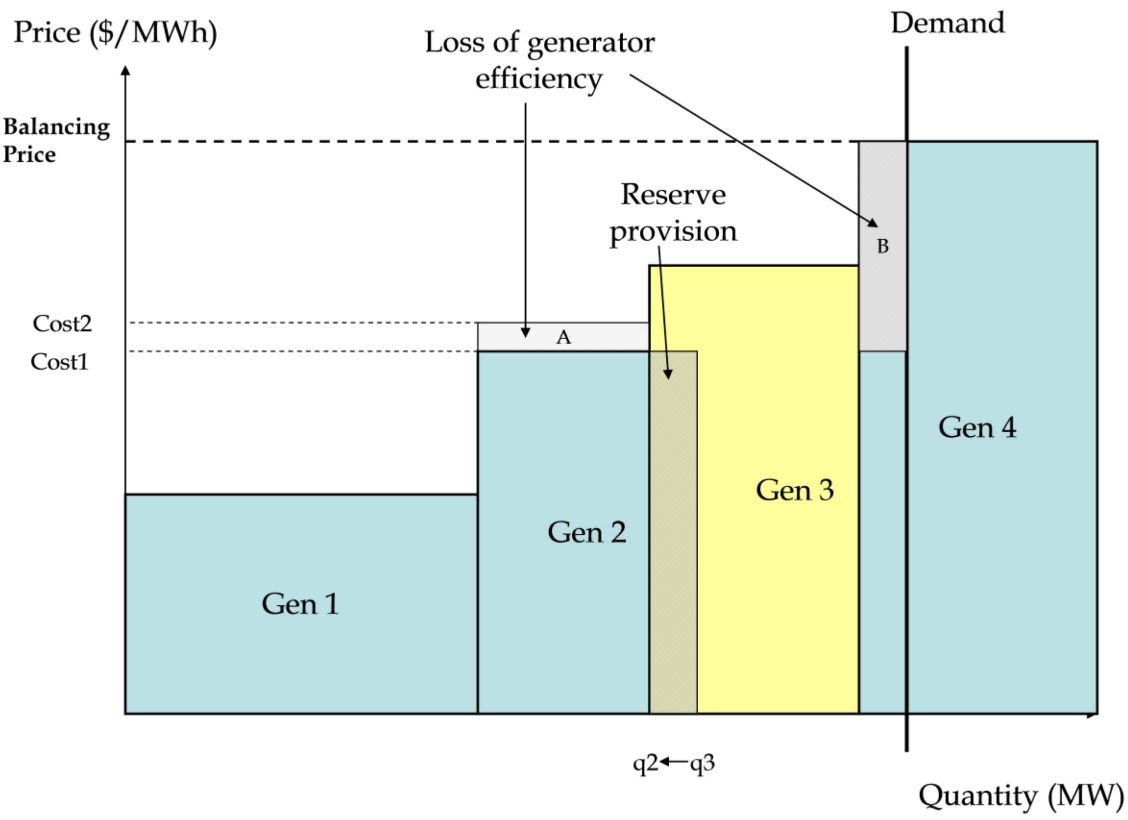
- movement to a less efficient point on a unit's heat rate curve;
- an increase in production from higher cost Synergy plant to counteract lower cost generation backed off to provide reserve;
- additional start-up costs that may be incurred due to commitment of additional units that would otherwise not have been required;
- a reduction in generation from Synergy plant and a corresponding increase in generation from Independent Power Producers (IPP), resulting in loss of profit for Synergy.

Reserve availability payments are calculated in the modelling by simulating the power system as it currently operates with reserve provisions and comparing those outcomes to a counterfactual case without reserve provisions. The difference in Synergy's generation costs between the two cases addresses Synergy's loss in efficiency. Synergy's loss of revenue is calculated as the difference in Synergy's generation multiplied by the price from the simulation including reserve provision. The choice of price for this part of the calculation is important because if Synergy was not providing SR, some other party would have to. The price must therefore be the market price with both SR and LRR requirements being met, and energy demand being satisfied.

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 default provider (Gen 1, Gen 2 and Gen 4), and one which is owned by an IPP (Gen 3). In this example, summarised diagrammatically in Figure 1 , only the default provider 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 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 default provider 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 default provider could have earned on energy sales forgone due to reserve provision.

Figure 1 Example of generator efficiency losses resulting from reserve provision



2.2 Constraining units on to provide reserve

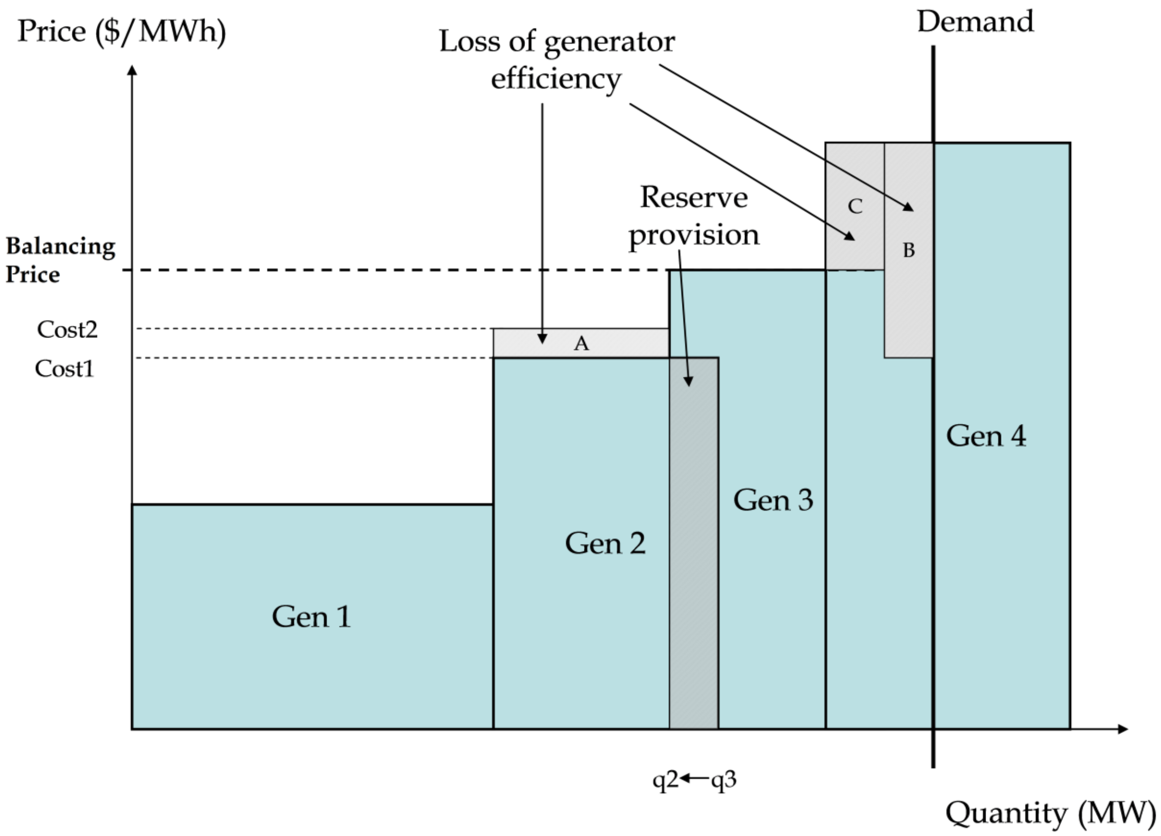
During the off-peak, some units may be constrained on at minimum generation level to meet the reserve requirements but a lower cost generator may be the marginal generator setting the price. Therefore, the availability cost could be quite high relative to the Balancing Price.

To illustrate this situation, consider again the simple four generator example introduced earlier although, this time, assume that all generators are owned by the default provider. In the original example, Gen 2 was backed off to provide reserve, and Gen 4 was committed to meet demand (Figure 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). 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 the default provider 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 Margin Value Review).

Figure 2 Example of availability cost with Gen 4 constrained on



It is also possible to have more than one Synergy unit constrained on to provide reserve if demand is low and the level of generation from IPP's is relatively high, since Synergy provides the majority of SR in the WEM.

The PLEXOS simulation package's criterion for meeting the WEM's SR requirements for any given period is that it does so at least cost. PLEXOS will therefore implement the necessary generation response required to supply an adequate level of SR by considering all available options, including the two described above, but it will ultimately choose the least cost option, and this is the outcome reflected in the simulation outputs.

2.3 Calculating availability cost

Prior to 2014, the availability cost was calculated for peak and off-peak periods by comparing Synergy's total generation costs and generation quantities, with and without providing SR. This approach changed in 2014 because Load Rejection Reserve (LRR), which is a reserve lower service accommodating the sudden disconnection of large loads, was also included in the modelling of the SWIS, and this meant that the cost impact of including LRR had to be separated from the cost of providing SR. LRR constraints were introduced to the Jacobs WEM model in mid- 2014 when modelling LRR costs for System Management. To maximise the model accuracy, it was decided to continue to use these enhancements in all studies from 2014 onwards, including this year's study. The methodology for separating Synergy's cost of providing LRR from its cost of providing SR is given below.

The formula for calculating the availability cost for providing a reserve service is as follows:

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

where:

GenCost_Res = Synergy's total generation costs, including start-up costs, with reserve provision

GenCost_NRP = Synergy's total generation costs, including start-up costs, without any reserve

provision apart from LFAS[6]

GenQ_Res = Synergy's total generation volume, with reserve provision

GenQ_NRP = Synergy's total generation volume, without any reserve provision apart from LFAS

Balancing Price = the modelled system marginal price for dispatch, with SR and LRR reserve provision

It is necessary to calculate the availability cost relative to a specific set of reserve requirements, since this is the only way to separate out the cost contribution of each reserve type. This is relevant to the margin values calculation because Synergy is the default reserve provider for both SR and LRR. For example, the availability cost of providing SR can be modelled relative to a base case where LRR is also modelled (where both market simulations include LRR), or relative to a base case where no LRR is modelled (where neither market simulation includes LRR).

Simulation of SR costs in the 2015/16 margin values study revealed that there is often an interaction cost effect between the cost of providing SR and the cost of providing LRR. That is, the cost of providing both forms of reserve is generally higher than the sum of providing each reserve separately. The difference between these two quantities is labelled as the Interaction Cost.

The availability costs for Synergy to provide SR is determined separately from the provision of LRR. This is due to clause 3.13.3B of the Market Rules, which requires the ERA to make a separate determination for the recovery of Synergy's costs for LRR and utilise a different settlement mechanism for recovery of costs. Following consultation with AEMO, it was determined that the availability cost of providing SR should be the

[6] Load Following Ancillary Services

Base SR availability cost[7] plus the Interaction cost of providing both SR and LRR, allocated proportionally to the average level of SR required across the study horizon relative to the sum of the SR and LRR requirements.

That is:

Availability Cost(SR) = Availability Cost(SR only) + [Interaction Cost * SR_Proportion]

where:

Interaction Cost = Availability Cost(SR given LRR) – Availability Cost(SR only)

SR_Proportion = Average SR provision / (Average SR provision + Average LRR provision)

The derivation of the formula for the Interaction Cost is presented in Appendix C.

A more intuitive formulation of the Availability Cost for SR can be obtained by substituting the above definition of the Interaction Cost into the formula for *Availability Cost (SR)*. This yields:

Availability Cost(SR) = Availability Cost(SR only) + [Availability Cost (SR given LRR) – Availability Cost (SR Only)] * SR_Proportion

which simplifies to:

Availability Cost(SR) = Availability Cost(SR only) * [1 – SR_Proportion] +

Availability Cost (SR given LRR) * SR_Proportion

In other words, the Availability Cost of SR is the weighted average of the Availability Cost of providing SR with no LRR requirement, and the Availability Cost of providing SR with an LRR requirement. The weights are the proportion of LRR provision and the proportion of SR provision respectively, relative to the sum of SR and LRR provision (approximately 40% and 60% respectively for the current set of simulations).

For calculating losses in generator efficiency resulting from reducing output to provide SR, heat rate curves are used from Jacobs' WEM database, as discussed in Section 8.1.4.

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, Spinning Reserve Capacity (SR_Capacity), Load Following Raise provision (LF_Up_Capacity) and Balancing Price[8] in the period t:

$$\mathrm{SR\_Availability\_Payment}(t) = 0.5 * \mathrm{Margin}\ (t) * \mathrm{BalancingPrice}(t) * \max(0, \mathrm{SR\_Capacity}(t) - \mathrm{LF\_Up\_Capacity}(t) - \mathrm{Sum}(c \in \mathrm{CAS\_SR}, \mathrm{ASP\_SRQ}(c,t))) + \mathrm{Sum}(c \in \mathrm{CAS\_SR}, \mathrm{ASP\_SRPayment}(c,m) / \mathrm{TITM})$$

where CAS_SR is the set of contracted SR services, ASP_SRQ(c,t) is the quantity determined by System Management for contracted SR service c, in time period t, multiplied by 2 to convert to units of MW, ASP_SRPayment(c,m) is the payment for contracted SR service c, in month m, and TITM is the number of trading intervals in trading month m. In practice and for the purposes of settlement, the LF_Up_Capacity term in

[7] The availability cost of providing SR only, with no provision of LRR.

[8] In this model the Balancing Price cannot be a negative number – if it is negative then it is adjusted upwards to zero.

the above formula includes LFAS raise (LFR) from all facilities, regardless of whether the LFR is eligible to contribute to SR (see section 9.2) and has been identified as a constraint that exists in AEMO's settlement model. Any LFR that is ineligible to contribute to SR needs to be supplied by Synergy facilities with SR capability to avoid a shortfall in SR provision. Therefore, in the modelling we have modified the SR_Capacity(t) term to include LF_Up_Capacity(t) that is ineligible to contribute to SR in order to represent the required SR amount that needs to be sourced from Synergy for settlement purposes.

Synergy's annual availability cost can be derived from the above equation by dropping the last term in the equation in clause 9.9.2(f) of the Market Rules, which relates to contracted SR ancillary services (which Synergy does not provide), noting that SR_Capacity(t) refers only to Synergy generators, and summing over all trading intervals in the year, as follows:

$$\mathrm{Availability\ Cost} = 0.5 * \sum_t \mathrm{Margin(t)} * \mathrm{BalancingPrice(t)} * \max(0, \mathrm{SRCapacity(t)} - \mathrm{LFR(t)} - \sum_{c \in CAS\_SR} \mathrm{ASP\_SRQ(c,t)})$$

This can then be decomposed to differentiate peak and off-peak periods, while constraining the margin parameter to be a constant for the peak and off-peak time periods as follows:

$$\mathrm{Availability\ Cost} = 0.5 * (\mathrm{Margin_{Peak}} * \sum_{t \in \mathrm{Peak}} \mathrm{BalancingPrice(t)} * \max(0, \mathrm{SRCapacity(t)} - \mathrm{LFR(t)} - \sum_{c \in CAS\_SR} \mathrm{ASP\_SRQ(c,t)}) + \mathrm{Margin_{Off-Peak}} * \sum_{t \in \mathrm{Off-Peak}} \mathrm{BalancingPrice(t)} * \max(0, \mathrm{SRCapacity(t)} - \mathrm{LFR(t)} - \sum_{c \in CAS\_SR} \mathrm{ASP\_SRQ(c,t)}))$$

Margin values can therefore be calculated by rearranging this formula and using key outputs from the market simulations.

The SR_Capacity(t) parameters represent the capacity necessary to cover the Ancillary Service Requirement for SR in the Trading Interval as specified by clause 3.22.1(e) and (f) of the Market Rules. 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 (we refer to these as 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 SR requirement varies dynamically from period to period. Per-period values are therefore averaged over the relevant periods of 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) of the Market Rules. These quantities now include an adjustment for the LFR provision of facilities that have not been modelled to also contribute to SR (see section 9.2), to more accurately represent the reserve requirement and settlement amount that needs to be attributed to Synergy as the default provider.

The LFR parameter represents the amount of LFAS raise service required in the Trading Interval. Assumptions regarding this requirement are discussed in Section 9.2.

3. Modelling the wholesale electricity market

The WEM commenced operation in the SWIS on 21 September 2006. Currently this market consists of three components:

- A gross dispatch pool energy market with net settlement. Participants may trade bilaterally and via the Short Term Energy Market (STEM), a day-ahead energy market, to hedge their exposure to the market (balancing) energy price.
- A Load Following Ancillary Services (LFAS) Market to allow IPPs to contribute to Load Following Raise and Lower Services.
- A Reserve Capacity Mechanism, to ensure that there is adequate capacity to meet demand each year.

The Balancing Market, STEM, LFAS Market and the Reserve Capacity Mechanism are operated by AEMO. The services are controlled by System Management with costs allocated via AEMO's settlements process.

The WEM is relatively small compared to other energy markets, and a large proportion of the electricity demand is for mining and industrial use, which is supplied under long-term contracts. Up to 85% of energy sales in the WEM occur through bilateral contracts.

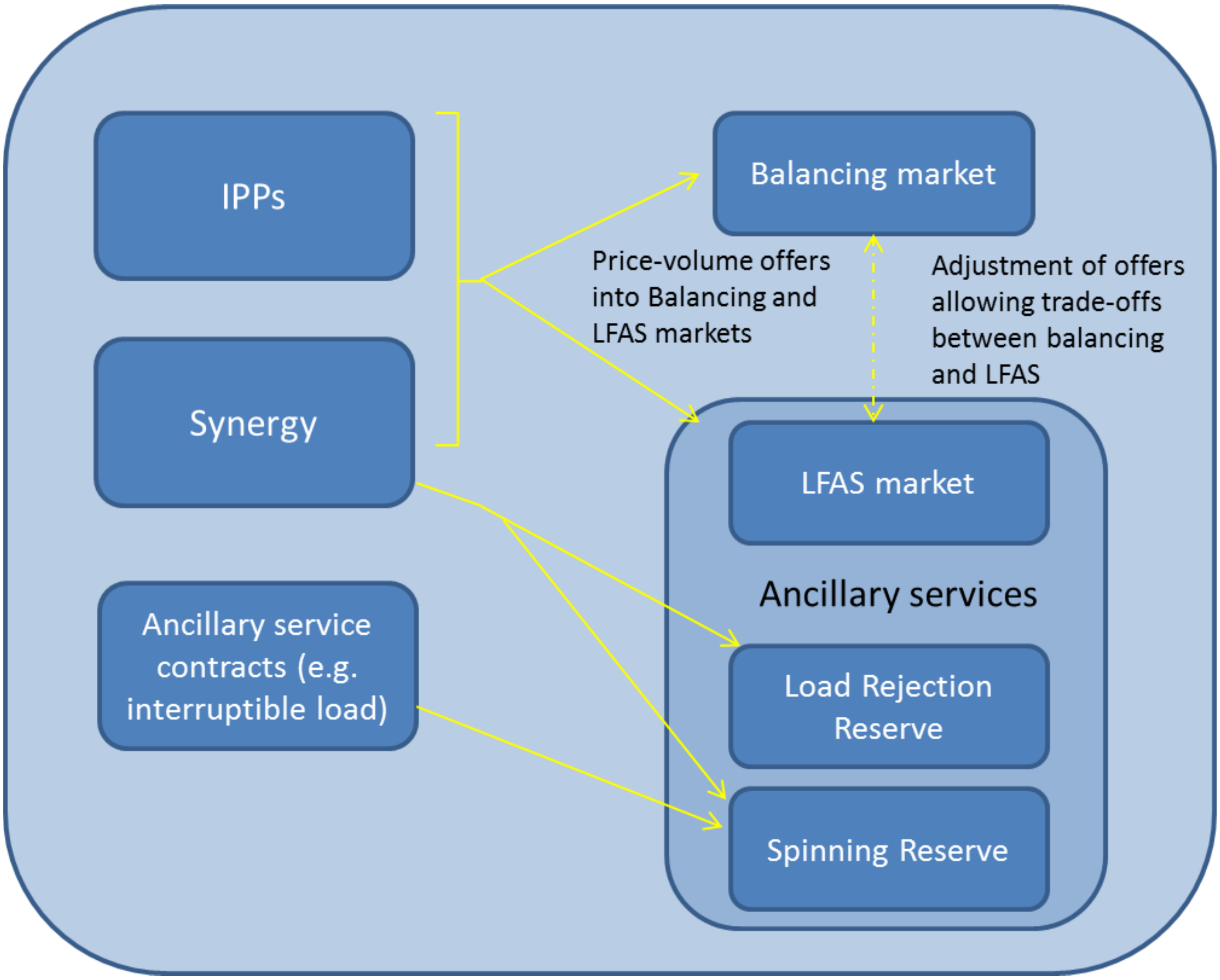
The STEM is a residual day ahead trading market which allows contract participants to trade out any imbalances in bilateral positions and expected load or generation. It is essentially a financial hedge allowing users to lock in a price one day ahead rather than be exposed to the real-time balancing price.

All Balancing Facilities (Synergy 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. AEMO settles the balancing market as the net of actual (metered) generation and consumption, bilateral contracts, and STEM position.

Synergy is the default provider of all ancillary services in the WEM. However, in the LFAS Market, IPPs can compete with Synergy 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 Synergy on a "pay as bid" basis). SR can only be provided by Synergy or through Ancillary Service Contracts. Figure 3 summarises participation by Synergy and IPPs in the Balancing Market, LFAS Market and provision of SR.

In the PLEXOS model Jacobs does not explicitly model the bilateral trades, STEM and the Balancing Market separately.

Figure 3 Balancing Market and Ancillary Service Provision



4. Key changes to input assumptions for 2018-19 review

Compared to the 2017-18 margin values review, input assumptions related to demand have been updated to reflect the expected values for the 2018-19 financial year. Projected 2018-19 energy demand is about 0.7% higher than the projected 2017-18 energy demand used in last year's simulations. A more detailed summary of demand assumptions can be found in section 6.1.

There have been some broad changes to fuel assumptions. Synergy's coal price has increased and its gas price has also increased relative to last year's review.

Cost assumptions for cogeneration facilities have in some cases changed markedly. These reflect large changes in the 2016-17 dispatch of these facilities relative to their 2015-16 dispatch. In particular, the two Alinta Pinjarra units have markedly increased their output in 2016-17 and their assumed marginal cost has been adjusted down to reflect this. The Synergy PPP_KCP unit has decreased its dispatch in 2016-17, and its marginal costs have been increased to reflect the reduction in dispatch.

Some input assumptions have been updated based on outcomes of a back-casting 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 the remaining sections of this report.

4.1 Back-casting exercise

Prior to undertaking this year's Margin Value review modelling, Jacobs undertook a back-casting exercise for the 2016/17 year to improve modelled PLEXOS outcomes with respect to actual market outcomes. Outcomes of this exercise are summarised in Appendix B. The methodology was to use actual 2016/17 demand and generator outages. Modelled outcomes were then compared against actual outcomes, and adjustments were made to the model to achieve better alignment with the historical market outcomes. In general, there was reasonable alignment between modelled and actual dispatch and off-peak pricing outcomes. Observed differences in peak prices could not be fully reconciled through the back-casting, and would reflect factors such as lack of temperature de-rating of modelled results, and also the fact that dispatch in the WEM is not fully co-optimised with spinning reserve as it is in the PLEXOS model.

A number of adjustments were made to the PLEXOS model to achieve better alignment in individual generator dispatch and pricing outcomes. Jacobs made a number of recommendations to be incorporated into the modelling based on the learnings from the back-casting exercise. These recommendations, and the agreed implementation, are summarised in Table 1.

Table 1 Summary of key factors and recommendations for 2017 back-casting exercise

Factor	Recommendation for 2018-19 modelling	Implementation
Peak prices substantially lower, despite higher demand in model.	Use an increased contract gas price for the Synergy generators.	Used Synergy's updated gas contract price.

Factor	Recommendation for 2018-19 modelling	Implementation
Spare capacity available for spinning reserve was lower in the modelling during most periods because more units are shut down overnight than actual, and less units are operating throughout most of the day than actual.	Reassess start-up costs assumptions, especially for MUJA C. Jacobs recommends a small increase in the start cost of the Muja C units. The updated gas price assumption for Cockburn CCGT should resolve the unit commitment issue during shoulder and some peak periods.	As recommended.
Synergy coal generators generating at maximum capacity for longer duration in model than actual.	Revise coal price assumptions by increasing the coal price.	The Synergy coal price has been increased slightly. Also, constrained annual coal output in peak for Synergy based on last five years of historical output.
Mismatch in modelled output and actual output for Synergy energy gas generators.	Increasing Synergy's contract gas price should resolve this issue.	Used Synergy's updated gas contract price.
ALINTA PINJARRA cogeneration plants generation output in model was less than actual.	It is likely that a higher value of steam affected the generation of these plants in 2016/17. For 2018/19, we would lower the marginal costs of these plants to achieve a higher level of dispatch.	As recommended.
Differences in max capacity and min stable level.	Discuss with AEMO and assess changes and update (if necessary) prior to modelling.	Maximum capacity and minimum generation levels are based on observations of actual market outcomes for financial year (FY) 2016/17.
NEWGEN KWINANA generated slightly less in the model than actual.	Slightly decrease NEWGEN gas price.	As recommended.
MUMBIDA generated more than in model than actual.	Discuss with AEMO whether it is necessary to model the transmission constraint affecting Mumbida for FY2018/19.	Using average capacity factor, reflecting actual output of the plant over the last 4 financial years
Unit commitment – NEWGEN KWINANA CCGT is operating less frequently in model than actual.	Recommend modelling NEWGEN KWINANA CCGT as "must-run" to reflect actual market operation	As recommended.

4.2 AEMO System Management

During the consultation process, Jacobs received updated information from AEMO System Management for the reserve capability and ramp rates for the following Synergy facilities:

- Maximum SR and LRR provision capability of Muja C unit 5 was increased
- Maximum SR and LRR provision capability of Muja C unit 6 was increased
- Maximum SR and LRR provision capability of both Muja D units was increased
- Maximum LFAS Up and Down provision capabilities of Mungarra and Pinjar units 1-5 and unit 7 were increased.
- Maximum LFAS Up and Down provision capability of Kwinana GT units 2 and 3 were increased.

4.3 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 for data. The changes related to the following:

- For NewGen Kwinana CCGT:
  - its heat rate at maximum output was increased;
  - its fuel cost was decreased;
  - its VO&M cost was increased;
  - its start cost was decreased; and
  - its fuel transport cost was decreased.
- For Bluewaters:
  - the delivered fuel cost was decreased;
  - the heat rate at maximum output for one unit was decreased; and
  - the start cost was increased.
- For the Goldfields generators the fuel cost was increased.
- For NewGen Neerabup the fuel cost was decreased and the VO&M cost was increased.
- For Perth Energy:
  - the fuel cost was decreased;
  - the fuel transport charge was increased; and

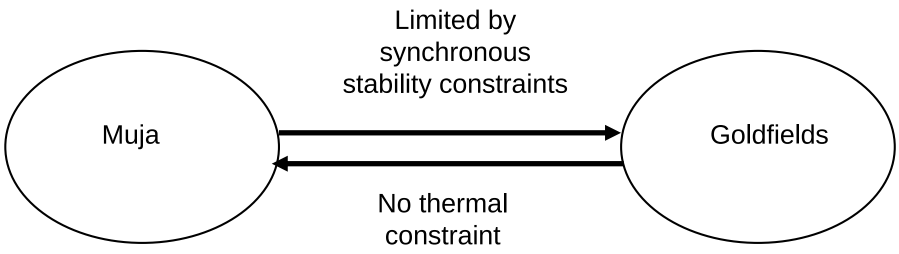
  - and the VO&M cost was increased.

- For Synergy, the portfolio’s gas price was increased, its coal price was increased and Cockburn CCGT’s start cost was decreased.
- For Tiwest Cogen the delivered fuel cost was decreased and the start cost was increased.
- For Alcoa Wagerup its fuel price was increased and its heat rate at maximum output was also increased.

5. Network topography

The SWIS is modelled as a 2-node system with a single uniform price. Interconnectors between both nodes, Muja and Goldfields, allow representation of the major congestion points in the system. Figure 4 shows the network configuration modelled in PLEXOS.

Figure 4 2-node model of SWIS



This network configuration has taken into consideration the impact of the commissioning of the MWEP, Southern Section, which has strengthened the network connection between Neerabup and Three Springs. Construction of this network augmentation was completed in March 2015. The completion of the MWEP eliminated the congestion between Muja and what was previously represented in the model as the North Country node. As a result, the thermal limits that existed between Muja and North Country have been removed from the model. These changes were first implemented in the model in the 2015 study.

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 units, are assumed to be located at Muja.

Synchronous stability constraints constrain levels of generation in the Goldfields region. The Goldfield’s total generation cannot exceed 155 MW, and the combined export (generated less self-load of approximately 110 MW) of Parkeston and Southern Cross is limited to 85 MW.

6. Demand assumptions

6.1 Regional demand forecasts

Table 2 shows our assumptions for sent-out energy and summer and winter maximum demand across the 2 nodes. These values are based on the 2017 ESOO load forecasts (expected scenario, 50% PoE), distributed among the two regions in accordance with the 2014-15 actual loads after separately accounting for the Karara mining development. The 2014-15 year was chosen as the base year since this is the closest recent match to a 50% POE peak demand year, and a 50% POE wind generation output year. The Muja load now includes what was previously assigned to the North Country node.

Projected 2018-19 energy demand is about 0.7% higher than the projected 2017-18 energy demand used in last year's simulations. The 2017 ESOO notes that average electricity consumption per connection has fallen in recent years, especially in the residential sector, mainly due to growth in rooftop PV, improved energy efficiency standards and changing demographics. This has reduced the expected growth rate of operational demand. PLEXOS will model the lower level of energy demand through slightly higher average half-hourly demand levels relative to last year's demand trace. Assumed generation supply is the same as last year, and therefore the supply-demand balance due to the slight increase in demand is expected to be approximately the same, or slightly tighter.

Table 2 2018-19 load assumptions

Financial year	Parameter	Muja (Perth)	Goldfields	Total SWIS
2018-19	Energy (GWh)	18,263	699	18,962
	Summer peak demand 50% PoE (MW)	3,899	106	3,968
	Winter peak demand 50% PoE (MW)	3,293	111	3,316
	Nominated intermittent non-scheduled load (MW)	20	36	56

In Table 2, 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 2014-15 profiles to calculate the individual region peaks at time of system peak for the 2018-19 financial year.

For our chronological modelling in PLEXOS, we use half hourly load profiles for the 2 nodes (based on 2014-15 historical data including losses), which are then grown to match the energy and peak demand values in Table 2. The energy and peak demand forecasts provided in Table 2 are net of AEMO assumptions on small-scale solar PV uptake. For the 2016-17 financial year[9], AEMO estimated that small-scale solar PV contributed 265 MW during the summer peak demand[10]. 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 PV capacity factor for Perth of 18.3%[11]), and then subtracting an assumed solar PV daily shape based on solar output data available to Jacobs that has been adjusted appropriately to account for the typical diversity observed in aggregate rooftop PV output. The diversified rooftop PV output for the SWIS is derived from a

[9] We have presented the 2016-17 impact of rooftop PV on peak demand because this is based on actual data, not projections.
[10] AEMO, 2017 Electricity Statement of Opportunities for the Wholesale Electricity Market, June 2017, p.2.
[11] CEC, Consumer Guide to Solar PV.

dataset of rooftop PV systems and locational Global Horizontal Irradiance (GHI) data from the Bureau of Meteorology (BOM). These datasets are used to create a model of the output of an average rooftop PV system under different irradiance conditions, capturing the effect of different panel configurations and orientations. We then use this model, in combination with the known installed capacity of rooftop solar systems in the SWIS (derived from CER postcode installation data) to estimate the historic output of rooftop PV systems in the SWIS on an hourly basis over past years.

6.2 Intermittent loads

Generators servicing Intermittent Loads are 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.

7. Fuel assumptions

The following fuels are represented in the modelling:

- Coal: used by Muja C and D and Collie
- Griffin coal: used by the Bluewaters units
- Cogeneration contract gas: gas for Alcoa Wagerup and one of the two Alinta cogeneration units
- Synergy contract gas: gas under existing Synergy contracts
- NewGen contract gas: gas for NewGen Kwinana plant
- NewGen peak contract gas: gas for NewGen Neerabup plant
- Parkeston contract gas: gas under contract for Parkeston plant
- Goldfields Contract gas: gas under contract for Southern Cross plant.
- Perth Energy contract gas: gas for Perth Energy's Kwinana Swift GT
- 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. It may also include some proportion of spot gas purchases
- Distillate: used as a primary fuel by the West Kalgoorlie, Tesla, Kalamunda and Merredin Energy units, and as a secondary fuel for some of the other units if they have used up their gas supply

The Synergy 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.

7.1 Fuel costs

Table 3 shows our assumptions on fuel prices (exclusive of transport charges):

Table 3 Fuel prices (real June 17 dollars)

Name	Price ($/GJ)	Source
Coal	2.60	Based on back-cast
Griffin Coal	Confidential	Updated by Participant
Cogeneration contract gas	2.88	Escalated by CPI from previous year
Synergy contract gas	Confidential	Updated by Participant
NewGen contract gas	Confidential	Back-casting recommendation
NewGen contract peak gas	Confidential	Updated by Participant
Parkeston contract gas	Confidential	Updated by Participant
Goldfields Contract gas	Confidential	Based on back-cast
Perth Energy contract gas	Confidential	Updated by Participant
New gas	5.91	AEMO GSOO
Landfill gas	Confidential	Escalated by CPI from previous year

Name	Price ($/GJ)	Source
Distillate	16.23	Jacobs Energy Price Limits Study 2017

All fuel costs used in the modelling are quoted on a higher heating value (HHV) basis with respect to the unit of fuel (GJ) as this is the standard way of expressing fuel costs in Australia. Consequently, heat rates for thermal generators are also quoted on the same basis to ensure consistency and that generation fuel costs are estimated correctly.

The gas fuel prices have been escalated by Perth CPI since last year's review with some exceptions. Some of the coal prices were also escalated by Perth CPI from last year's estimate, with the exception of Synergy's coal price. In the case of the latter, a more substantial price increase was applied. The new gas price of $5.91/GJ was sourced from the 2018-19 forecast contract gas price reported in AEMO's December 2016 Gas Statement of Opportunities for Western Australia (GSOO), which is reflecting some weakening demand in the gas market resulting in a lower gas price relative to that used in last year's review.

It is noted that the new gas price assumption is higher than where the spot market has been trading over the last 12 months (about $4.60/GJ on average). This is acceptable because it is understood that only a minor proportion of the new gas price is based on spot gas as the volumes for spot gas are thin. Further supporting this approach is the fact that in last year's review the differential between the spot gas price and the contract price was larger, and yet the spot price remained below $5/GJ for the whole year.

Distillate prices come from Jacobs Energy Price Limits 2017 study[12], which estimated a nominal price of $16.43/GJ ($16.23/GJ in June 2017 dollars) applying a calorific value of 38.6 MJ/litre. The additional nominal transport cost to the Goldfields is estimated to be $1.40/GJ ($1.38/GJ in June 2017 dollars).[13] The estimated nominal transport cost to the Perth region is estimated to be $0.35/GJ in June 2017 dollars.[14]

7.1.1 Gas transport charges

Gas transport charges, reflecting variable gas pipeline costs, vary based on the generator's geographic location.

The fixed component of the gas transport charge was converted to a variable cost per GJ using a load factor of 77%. For gas from the DBNGP, applying the same load factor, the resulting fixed cost component of the gas transport cost is approximately $1.79/GJ[15] in real June 2017 dollars. As many gas-fired generators have take-or-pay contracts, much of this fixed cost component is 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 2017-18 financial year Margin Value Review, Jacobs 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.

7.2 Fuel constraints

Based on our understanding of the market and historical data, we have included gas constraints limiting the contract gas daily availability. Two of these constraints relate to the contract gas that is available to Synergy. The first of these is a minimum daily take-or-pay gas obligation, whereby the Synergy portfolio in the model is

[12] https://www.aemo.com.au/Stakeholder-Consultation/Consultations/2017-Energy-Price-Limits-Review, accessed 8 September 2017

[13] Prices in Jacobs "Energy Price Limits for the Wholesale Electricity Market in Western Australia" 2017 report are nominal for the 2017-18 financial year. In order to convert them to real June 2017 dollars, we assumed they are from December 2017 (mid-point of the 2017-18 financial year) and then scaled them back to June 2017 dollars assuming a Perth annual out-year inflation rate of 2.5%).

[14] *Ibid.*

[15] According to Goldman Sachs in the 2016 Review

constrained to offtake a minimum amount of contract gas on a daily basis. The second constraint is a maximum daily limit, representing the maximum amount of contract gas available to Synergy each day.

We also included some constraints on the total gas available in different locations. Where possible, these figures have been obtained from the capacities standing data listed in the Western Australia Gas Bulletin Board[16]. Otherwise, the figures correspond to estimates from historical dispatch data and fine-tuned in our PLEXOS model during previous SWIS back-casting exercises.

16 https://gbbwa.aemo.com.au/#capacities

8. General assumptions

8.1 Existing generators

The modelling of the existing generation system includes the larger private power stations owned by Alcoa and the Goldfields miners.

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

On 5 May 2017, Synergy announced the closure of 436 MW of existing coal and gas-fired capacity to address the overcapacity that currently exists in the WEM[17]. The capacity to be retired is as follows:

- Muja A&B units 1-4 (240 MW);
- Mungarra units 1-3 (113 MW);
- West Kalgoorlie units 2 & 3 (62 MW); and
- Kwinana GT unit 1 (21 MW).

It is intended that this capacity will be progressively retired until September 2018. Jacobs has used the latest available information for the retirement dates of these units as follows:

Table 4: Proposed generator retirements

Time period	Generator(s)
30 September 2017	Muja A & B 2 units out of 4 (120 MW)[18]
30 September 2018	West Kalgoorlie units 2 & 3 (62 MW), Kwinana gas turbine unit 1 (21 MW), Mungarra units 1, 2 & 3 (113 MW)
30 April 2018	Muja A & B remaining 2 units (120 MW)[19]

8.1.1 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 Jacobs' 2017 Energy Price Limits report[20].

Start-up costs for some other facilities will be updated in accordance with confidential advice provided as part of this year's public consultation. Start-up costs for other Synergy and non-Synergy facilities are based on a Perth

[17] https://www.synergy.net.au/About-us/News-and-announcements/Media-releases/Synergy-to-Reduce-Generation-Capacity-by-380-MW
[18] As these units are not expected to be operational over the modelling timeframe (1 July 2018 to 30 June 2019), they have been removed from the model.
[19] As these units are not expected to be operational over the modelling timeframe (1 July 2018 to 30 June 2019), they have been removed from the model.
[20] https://www.aemo.com.au/Stakeholder-Consultation/Consultations/2017-Energy-Price-Limits-Review, accessed 8 September 2017

CPI escalation of the values used in the 2017-18 financial year Margin Value Review, which were provided by the former IMO.

For some units that typically operate as “must-run”, unit commitment is imposed on the model. Specifically, the Bluewaters units, Muja 7 and 8, Collie, Kwinana NewGen, cogeneration units and other generators meeting private loads are treated as units that must generate whenever they are available. The status of “must-run” units will be reviewed in this year’s back-casting study.

8.1.2 Planned maintenance and forced outages

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

Forced outages are unplanned, and can occur at any time. These are randomly determined in PLEXOS and differ in each Monte Carlo simulation. Ten Monte Carlo simulations are to be conducted for this analysis. In each simulation, the frequency with which forced outages occur is determined by the forced outage rate and mean-time-to-repair parameters in the model. The outage rates were provided by AEMO, based on three years of historical full and partial outage data and consideration of major outages planned for 2017-18. During FY 2016/17 the second unit of Bluewaters power station experienced an extended forced outage lasting about 6 months due to equipment failure. These types of outages are beyond the scope of the modelling as they are completely unforeseeable. They can be indirectly incorporated into the modelling by factoring them in when calculating the long-term average forced outage rates of the generating units.

An exception in the use of historical unplanned outage rates was for plants with outages rates less than 0.1%. This level of reliability is unusual for a generation unit, and it normally comes about if the unit has had very infrequent use or no use at all over the historical period. For this reason, we applied a floor of 0.1% for forced outage rates. This affected the four Tesla distillate units and the Neerabup peaking units.

Another exception to the use of historical data applied to the planned outage rates that were retained from last year’s analysis. The reason for this is that calculating planned outages from historical data requires at least six years of data, which is the length of a typical maintenance cycle for a thermal generator. Using only three years of maintenance data can skew the results to either too much maintenance, if a major overhaul has been carried out within the last three years, or too little maintenance, if a major overhaul has not been carried out in the three years. No outage rates are included for wind farms since the historical generation profiles of these units will already include outages.

8.1.3 Short run marginal cost calculations

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

*SRMC = marginal heat rate * (fuel price + variable transport charge) + VO&M 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 AEMO’s website for 2017-18[21].

The SRMC values for all generators are estimated for 2018-19, based on the primary fuel only and considering the average heat rate at maximum capacity. Most of the input values were obtained from publicly available information (SOO, planning reviews, AEMO website, and companies’ websites). AEMO approaches all generators to provide updated assumptions, including fuel costs and start-up costs on a confidential basis. If

[21] https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Data/Loss-factors

confidential data is provided, these cost assumptions can be used, otherwise an adjustment of the previous financial year's cost assumptions are used.

For the wind farms, solar PV plants and landfill gas plants, the assumed value of large-scale generation certificates (LGC) has been subtracted from the variable operating and maintenance costs of each plant type, 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 $85/MWh in real June 2017 dollars, based on LGC certificates currently being traded in the forward market. The government agreement on the Renewable Energy Target (RET) has resulted in elevated LGC prices since March 2015, and this figure is based on certificates traded during this calendar year. Assumed VO&M costs for wind farms are $25/MWh, which is based on Jacobs' independent assessments of these plants. The exception to this is the VO&M cost for Collgar wind farm, which was provided by the plant owner. For large-scale solar PV in WA we assume a VO&M cost of $24/MWh, which is based on the VO&M cost quoted by ARENA applicants for WA projects. For landfill plants the assumed VO&M cost is based on the implied VO&M cost from previous Margin Value Review studies.

Generation profiles for all winds farms and large-scale solar PV plant are using 2014-15 historical profiles where possible, or the closest matching year whenever 2014-15 data is not available.

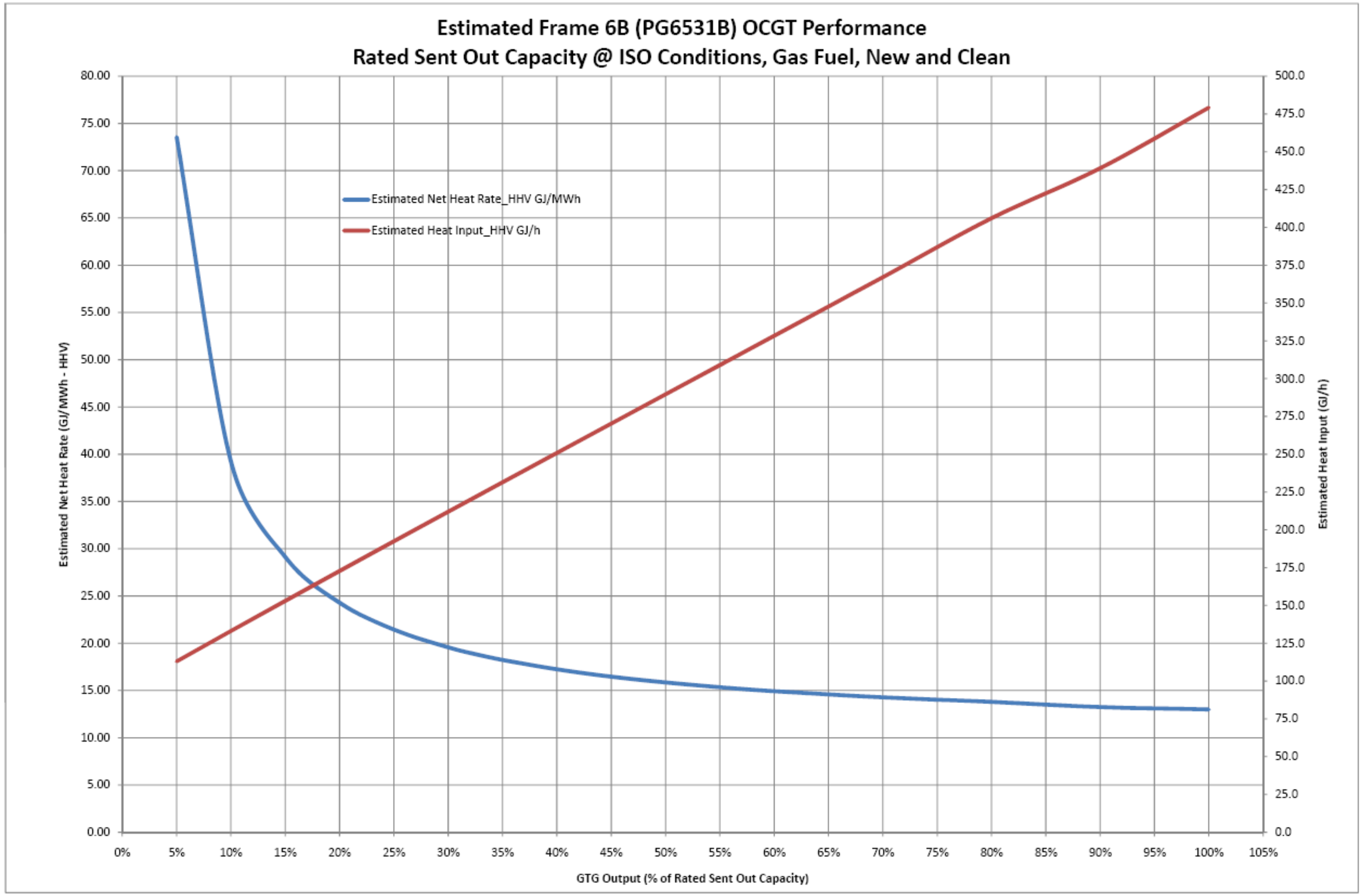
8.1.4 Heat rates

Heat rates are usually quoted by gas turbine manufacturers on a lower heating value (LHV) basis. However, fuels such as natural gas are usually sold on a $/GJ HHV basis, and therefore gas turbine performance needs to be adjusted using the HHV/LHV ratio for any economic or financial evaluation. It should be noted that the HHV/LHV ratio is fuel-specific[22]. For example, for natural gas it is approximately 1.108, whereas for distillate the factor is about 1.06.

The sent out heat rates used in the modelling are based on available published or calculated values, using engineering judgement, for the rated plant capacities at ISO conditions, expressed on a HHV basis. In some instances, generators have provided more accurate information on a confidential basis following a request for details made by the former IMO and/or AEMO as part of the consultation process for previous and/or the current Margin Value Review. 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.

[22] The HHV / LHV ratio relates to the state of the water in the exhaust. For the HHV it is assumed that the water is condensed to liquid form and for the LHV it is assumed the water is in vapour form. The HHV value is higher than the LHV value by the latent heat of evaporation of the water. Fuels that have relatively higher hydrogen contents (to other combustible elements such as carbon) have higher HHV / LHV ratios as the hydrogen combusts to form water in the exhaust and carbon combusts to form carbon dioxide instead of water. Therefore the HHV/LHV ratio inherently accounts for combustion moisture.

Figure 5 Example of performance curve for a typical GTG unit, at ISO conditions



An example heat input function and resulting average heat rate curve are provided in Figure 5. 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.

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.

8.1.5 NewGen Kwinana

The NewGen Kwinana CCGT consists of a 167.8 MW open cycle gas turbine, and a 160 MW steam turbine. In base load operation, 247.8 MW of power may be provided, with an additional 80 MW 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.

8.2 Future generators

No new generators are being modelled in the 2018/19 year.

9. Reserve modelling assumptions

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

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

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.

9.2 Load following Ancillary Service

LFAS is required to meet fluctuations in supply and demand in real time. There are two LFAS products in the WEM: raise and lower. LFAS raise 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 can be reduced by the amount of LFAS raise that is being provided.

AEMO has reviewed Spinning Reserve provided by LFAS raise and for modelling purposes has recommended to only reduce the Spinning Reserve requirement by the amount of LFAS that is being provided by Synergy Facilities, with the exception of Cockburn CCGT, and non-Synergy facilities that currently have a Spinning Reserve contract.

NewGen Kwinana CCGT does not currently have a Spinning Reserve contract, consequently LFAS enablement of this facility will not be modelled as providing Spinning Reserve.

Based on the estimate of the LFAS requirement provided in System Management's Ancillary Service Report for 2017[23], for the 2018-19 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.

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.

While the dispatch of an LFAS 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, an LFAS generator is not providing any LFAS. That is, intra-half-hour load following fluctuations in their generation average out.

9.3 Load Rejection Reserve

Load Rejection Reserve (LRR) is required to provide system stability in the event of sudden, unplanned load disconnection. LRR is modelled in PLEXOS as a lower reserve. The generators providing LRR must be able to lower their generation in response to load rejection. Spare lowering capacity in a generator that provides LFAS lower may also be available for LRR. AEMO has reviewed the LRR and for modelling purposes has recommended to only reduce the LRR requirement by the amount of LFAS lower that is being provided by Synergy Facilities, with the exception of Cockburn CCGT, and non-Synergy facilities that currently have a Load Rejection Reserve contract.

Due to exclusion of Cockburn CCGT and because NewGen Kwinana CCGT does not have a LRR contract, the amount of LRR required in any time period t is as follows:

[23] https://www.aemo.com.au/-/media/Files/Electricity/WEM/Data/System-Management-Reports/2017/2017-Ancillary-Services-Report.pdf

LRR = 120MW – (72MW – Cockburn_LFAS_provision_t– NewGen CCGT_LFAS_provision_t[24])

where the 72MW represents the current LFAS requirement, Cockburn_LFAS_provision_t is the amount of LFAS lower provided by Cockburn CCGT and NewGen CCGT_LFAS provision_t is the amount of LFAS lower provided by NewGen Kwinana CCGT.

Although we model the availability costs for Synergy to provide LRR, a separate determination is made by the ERA in accordance with clause 3.13.3B and a different settlement mechanism is utilised for the recovery of LRR costs. In this separate determination the value of the Ancillary Service Cost_LR[25] parameter covers the payment to a market generator for the costs of providing the LRR Service and System Restart Service.

9.4 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 Synergy and IPPs are able to provide LFAS subject to meeting technical requirements (i.e. being connected to AGC). At present NewGen Kwinana and Tiwest Cogeneration plant are the only IPP facilities capable of providing LFAS. Tiwest has indicated that it is uncertain if it will participate in the LFAS markets. As a result, NewGen Kwinana remains the only IPP modelled to provide LFAS during this period. SR is provided by Synergy or through ancillary service contracts with an IPP.

As AEMO has not finalised all the Spinning Reserve contracts for FY 2018-19, the previous Spinning Reserve contracts for FY2017-18 will be used for modelling the Spinning Reserve contracts for the current review period.

Spinning Reserve contracts to be modelled include the provision of 42 MW of interruptible load from a long-term contract. One short-term contract is for an additional 13 MW of interruptible load, and the other is a contract with an IPP.

For all generators specified as being able to provide reserve, PLEXOS is set up to assume by default that, if a unit is generating, all spare capacity could contribute to providing reserve. This is not always possible, so PLEXOS allows users to specify the maximum reserve provision for each generator that can provide reserve. The amount of reserve provided by the generator will therefore be limited by the minimum of its spare capacity or its maximum reserve provision capability.

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, LFAS and LRR. 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 and LRR, additional restrictions are imposed on some units, as suggested by System Management.

[24] If an AEMO LRR contract is in place for NewGen Kwinana CCGT then this term will be zero.
[25] https://www.erawa.com.au/electricity/wholesale-electricity-market/determinations/ancillary-services/load-rejection-cost_lr

9.5 Ancillary service contracts

Some reserve may be provided by reducing load through interruptible load ancillary service contracts. System Management's latest advice is that 55 MW of interruptible load is assumed to be available. This interruptible load can be used at all times to provide SR. The other SR contract that will be active over FY 2018-19 is understood to be with one of the IPPs.

For the purposes of modelling, the SR requirement to be provided by Synergy in period *t* for the 2018-19 financial year is therefore equal to:

70% largest generating unit–55 MW interruptible load – IPP_SR_provision –* (*72 MW LFAS – Cockburn_LFAS_provision_t–NewGen CCGT_LFAS_provision_t*[26]).

Cockburn's and NewGen Kwinana's provision of LFAS are subtracted off the modelled 72MW of LFAS provided each period because Cockburn's and NewGen Kwinana's LFAS are not a suitable substitute for SR (see section 9.2). For the purposes of settlement, there is a subsequent adjustment for Cockburn's and NewGen Kwinana's provision of LFAS as outlined section 2.3.

9.6 Value of reserve shortage

Clause 3.10.2 (d) of the Market Rules states that the SR requirement may be relaxed following activation (subject to a requirement that it be fully restored as soon as practicable) 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.

[26] If an AEMO SR contract is in place with NewGen Kwinana CCGT then this term will be zero.

10. 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) of the Market Rules.

The components of the SR availability cost calculation (that is, the last equation in section 2.3) are provided by sample for peak and off-peak periods in Table 6 and Table 7 respectively.

The margin values, availability cost and system marginal prices are presented in Table 5 averaged over 10 random outage samples, described in further detail in Table 8. The table also provides a comparison with the 2017-18 parameter estimates.

The terms SR_Capacity_Peak and SR_Capacity_Off-Peak are defined in section 2.4, and they represent the average SR_Capacity(t) variable in peak and off-peak periods which represents the capacity necessary to cover the Ancillary Service Requirement for SR, which meets the requirements of clause 3.22.1(e) and (f) of the Market Rules. These quantities are now adjusted by the LFR provision of Cockburn CCGT and NewGen Kwinana CCGT, which have not been modelled to contribute to SR (see section 9.2), and therefore also needs to be supplied by Synergy. The reason for making this adjustment is that the LF_Up_Capacity(t) term in the equations of section 2.4 is a flat 72 MW in AEMO's settlement system, and does not differentiate which facility provides the LFR.

Table 5 Parameter estimates

Parameter	Proposed (2018-19)	Standard error[27] (2018-19)	Approved (2017-18)	Standard error (2017-18)
Margin_Off-Peak	71%	1.1%	64%	1.8%
Margin_Peak	34%	0.8%	36%	0.7%
SR_Capacity_Off-Peak (MW)	189.0	0.34	190.2	0.23
SR_Capacity_Peak (MW)	224.1	0.29	221.8	0.17
Availability cost ($M)	13.15	0.23	13.29	0.27
Off-peak price ($/MWh)	39.52	0.06	39.56	0.07
Peak price ($/MWh)	54.44	0.12	56.27	0.17

On average, a Margin_Off-Peak value of 71% is proposed, based on an average system marginal off-peak price of $39.52/MWh. For Margin_Peak, an average value of 34% has been estimated, based on an average system marginal peak price of $54.44/MWh. The Margin_Off-Peak parameter is higher than what was recommended for the 2017-18 financial year, whereas the Margin_Peak parameter is lower. The 11% relative increase[28] in the

[27] The standard error is a measure of the statistical accuracy of an estimated quantity. If the errors associated with the samples are normally distributed, then the true value of the quantity is with 68% confidence likely to lie within 1 standard error of the estimated value, and with 95% confidence likely to lie within 2 standard errors of the estimated value.

[28] It is more useful to consider the relative increase rather than the absolute increase in the margin values (which is 7%) because the relative changes in the margin values can be understood in terms of the relative changes of the components of the margin values, which are the availability cost, the price and the SR quantity provided by Synergy.

Margin_Off-Peak value is primarily explained by the 9% increase in the off-peak availability cost. The off-peak price is only 0.1% lower relative to last year's value, but the volume of SR required to be supplied by Synergy in the off-peak has decreased by 2%, which puts upward pressure on the Margin_Off-Peak value as there is less volume over which to spread the off-peak availability cost. In contrast, the Margin_Peak parameter is lower than last year's recommended value by 6% on a relative basis[29]. This decrease is primarily explained by the 7% decrease in the availability cost during peak periods. The other two factors contributing to the movement in the Margin_Peak value are the peak price[30], which is 3% lower than last year's price, and an increase of 3% in average SR provision by Synergy during peak periods.

The key driver leading to the higher availability cost in off-peak periods ($5.16M compared with $4.72M in last year's modelling) is the increased dispatch of Alinta Pinjarra cogeneration power station and NewGen Kwinana CCGT in off-peak periods. The dispatch of these facilities was increased in this year's modelling compared to 2017-18, based on the backcasting exercise. A comparison of the back-cast modelled outcomes to actual outcomes can be found for both plants in Figure 24 and Figure 28. Neither the Alinta Pinjarra facilities nor NewGen Kwinana CCGT are modelled to provide spinning reserve, and both these generators are assumed to operate as must run. The increased dispatch of these units in the off-peak increases the availability cost to Synergy because it more frequently puts the system in a state where some Synergy units – primarily the Kwinana and Kemerton GTs – are only online because of the ancillary services requirements. When these units are switched on to provide reserve the availability cost is incurred in the increased number of starts of the GTs, as well as the cost of foregoing cheaper generation to bring GTs online and to their minimum operating levels.

The key drivers leading to the lower availability cost in the peak ($8.00M compared with $8.57M in last year's modelling) include the lower marginal cost of fuel for the Synergy peakers, the introduction of the constraint on Synergy coal in peak periods which results in more Synergy gas-fired generation in the no SR cases[31], the increase in the SR and LRR provision capabilities of the Muja C and D coal-fired generators (7.4 MW additional provision capability, which represents a 9% increase), and the increase in the LFAS provision capabilities of the Kwinana high efficiency GTs (HEGTs) (50% increase in capability), Pinjar GTs (125% increase) and Mungarra GTs (119% increase). The last two factors represent an increase in SR supply capacity, which naturally puts downward pressure on the SR cost.

The increased dispatch of the Alinta Pinjarra units and NewGen Kwinana CCGT in the peak is mitigated by the maximum generation constraint imposed on Synergy's coal plant in peak periods. This explains why this factor has a greater impact during off-peak periods, but a lesser impact in peak periods.

On a plant level the key dynamics explaining the availability cost are as follows:

- Cockburn CCGT runs harder in the no SR case because of its relatively low SRMC. When SR is required Cockburn backs off generation because it has no capability of providing SR. It therefore has to allow headroom for the SR capable peaking gas turbines to dispatch at their minimum generation level. Cockburn's behaviour is also sensitive to the system's LRR requirement. When the system requires LRR the cost-effectiveness of dispatching Cockburn is degraded, despite its relatively low SRMC, because it has no LRR capability. In this case it runs at about 40% of the capacity factor relative to the cases where LRR is not required. Therefore, in the simulation without SR with LRR Cockburn is forced to back off its generation more than the corresponding case where LRR is not required. When SR is also required, Cockburn has already backed off its dispatch in the LRR case, and therefore it does not need to back off as much to create the required headroom for SR.

- The key peaking plants that increase their dispatch to provide SR - relative to the no SR cases - are Kemerton, Kwinana HEGTs and Pinjar. In the cases where LRR is required Kemerton and Pinjar incur the most availability cost (for sample 1[32] their contributions under the LRR case are $8.9M and $5.2M respectively out of a total availability cost of $11.8M[33]), whereas when LRR is not required all three

[29] As per footnote 36, noting that the absolute decrease in the peak Margin Value is 2%.

[30] A decrease in the price results in an increase in the Margin Value. The reason is that the Margin Values are expressed as a percentage of the system price, and decreasing the price means that the Margin Value should be raised to recover the same availability cost.

[31] This decreases this year's availability cost because in the no SR case the gas-fired generators that provide SR tend to be already generating. This results in the avoidance of start costs, and possibly smaller differences in generation costs.

[32] Sample 1 was used to assess plant-level contributions to the availability cost as its availability cost was closest to the median. Three other samples were also examined, and this confirmed that the key plant behaviours in Sample 1 were representative across the other samples.

[33] The sum of these contributions exceeds the total availability cost, but plants that are backed off, such as Cockburn CCGT, reduce the availability cost as their generation costs are lower.

plants incur most of the availability cost (Kemerton contributes $8.6M, Kwinana contributes $14.4M and Pinjar contributes $6.1M under the no LRR case[34]). In total, these plants contribute $20.1M to sample 1's total availability cost of $13.2M[35].

- The behaviour of the Kwinana HEGTs changes depending on whether LRR is required or not. When LRR is required, the HEGTs make very little contribution to the availability cost because both units tend to be operating to provide LRR in the no SR case (average of 32% capacity factor in sample 1), and both units can also provide SR as they are already switched on. However, when LRR is not required the Kwinana HEGTs contribute to the availability cost because the units tend to be switched off in the no SR case (average of 11% capacity factor in sample 1), and therefore they generate more and start more often when SR is required.
- Collie backs off dispatch in both peak and off-peak periods when SR is required in order to minimise the demand for SR, since it typically sets the SR requirement for the system. As a result, it tends to contribute to the availability cost by forgoing profit, with its total contribution under sample 1 being $0.3M.

A notable difference in this year's modelling is that the profit foregone component of the availability cost calculation is negative, as shown in Table 6 and Table 7 below. In the previous years' modelling this component was positive. A negative profit foregone means that Synergy units are actually earning more revenue in the SR case, than in the No SR case. This is a counter-intuitive result, but is due to the fact that GTs are actually being brought online to minimum generation levels to provide SR, whereas otherwise they would be offline. This has two impacts:

- When higher cost GTs come online to provide SR they have to at least operate at their minimum stable level, so other units in the system must be backed off to enable this to occur. When this happens the change in dispatch can be significant. Lower cost plant like Cockburn that can't provide reserve actually have to be backed off more than the SR requirement so the GTs can operate at their minimum level. This year's modelling indicates that this requirement is causing some non-Synergy plant such as NewGen Kwinana to be backed off as well because they have not been modelled to provide SR. This means that in the case when SR is required, Synergy is generating more rather than less[36], and so is actually earning more revenue overall.
- Although Synergy earns more revenue in the SR case, its availability cost is still positive. This is because although its revenue increases, its generation costs increase even more. The gas GTs that provide SR are more expensive to run than the CCGT generation they replace, so the fact that the Synergy portfolio generates more overall, and earns more revenue, is more than offset by the fact that much of that generation is higher cost. This effect can be seen in the results. Compared to last year's modelling the 'profit foregone' component of the calculation has decreased by $9.3M on average (indicating more revenue), whereas generation costs and start-up costs have increased by $9.2M. This $0.1M differential explains the slight decrease in this year's availability cost.

As with last year's result, the interaction cost is negative across most of the samples for peak and off-peak periods. Based on the definition of the interaction cost (see section 2.3), this implies that the availability cost for the SR Only case is greater than the availability cost for the SR case given provision of LRR. Therefore, there is a negative cost benefit from the perspective of providing SR when LRR is already operating. The behaviour of the system with and without LRR is as follows:

- Under the LRR case, Cockburn is not utilised much in the no SR case as it cannot provide LRR (25% capacity factor for sample 1). Both the Kwinana HEGTs and Pinjar are utilised more in no SR case as they can provide LRR. Under the SR case Cockburn does not back off as much because the Kwinana HEGTs are already on to provide LRR, and their output increases by about 20% under the SR case. Kwinana HEGTs and Kemerton are already on for LRR provision in the no SR case, but in the SR case Pinjar also needs to come online to supplement the shortfall in SR provision. The aggregate increase in the generation for the SR case of Kwinana HEGTs, Pinjar and Kemerton for sample 1 is 343 GWh relative to the no SR case.

[34] See footnote 42.
[35] See footnote 42.
[36] It is possible for Synergy to have to generate less in order to provide SR. For example, if its peaking plant is generating at close to full capacity in the no SR case, it is possible that in the SR case this plant would have to back-off to create the headroom required to provide SR. If an IPP plant switches on to cover the generation that Synergy backed off, then Synergy would be generating a lower amount and foregoing revenue in the SR case.

- Under the no LRR case, Cockburn runs much harder in the no SR case to provide energy (61% capacity factor), and Pinjar and the HEGTs (and to a lesser extent Kemerton) are not running as hard relative to the with LRR case. Under the SR case the Kwinana HEGTs, Pinjar and Kemerton all run harder to provide SR, with the aggregate increase for sample 1 being 506 GWh relative to the no SR case.

In summary, the contribution of generation cost component of the availability cost is higher when LRR is not required, notwithstanding Cockburn backing off much more. The contribution of the start cost component of the availability cost is also higher for the no LRR case, with the biggest contributors to this being Kemerton and Cockburn.

Among the Synergy portfolio, the majority of the availability cost is accounted for by changes in the dispatch of Cockburn, and the Kemerton and Pinjar GTs and the Kwinana HEGTs. Other units that contribute are Collie – which generally backs off in the off-peak and the Muja generators generally increase output in both peak and off-peak periods when SR is required. The cost components of the availability cost are shown in the tables below.

Table 6 and Table 7 show a breakdown of the availability cost for peak and off-peak periods for all samples.

Table 8 shows the estimates of the margin value, availability cost and other parameters by sample.

Table 6 SR availability cost calculation - peak

Sample	S1	S2	S3	S4	S5	S6	S7	S8	S9	S10	Average[37]
Cost of SR only ($M)	**9.6**	**10.2**	**10.1**	**11.1**	**10.4**	**10.0**	**9.7**	**10.6**	**10.3**	**9.4**	**10.14**
Gen cost ($M)	15.2	14.7	15.3	16.2	14.3	14.8	14.1	15.2	16.4	14.8	15.10
Start-up cost ($M)	0.8	1.3	1.1	1.6	1.6	1.2	1.4	1.4	1.0	1.1	1.26
Profit forgone ($M)	-6.4	-5.9	-6.3	-6.7	-5.5	-6.0	-5.8	-6.0	-7.2	-6.5	-6.22
Cost of SR given provision of LRR ($M)	**7.1**	**7.4**	**5.4**	**6.6**	**7.3**	**6.2**	**6.7**	**7.0**	**6.4**	**8.4**	**6.85**
Gen cost ($M)	14.6	14.7	13.6	13.0	14.0	13.5	13.8	14.5	13.3	15.3	14.02
Start-up cost ($M)	0.4	0.7	-0.4	0.6	1.0	0.6	0.0	0.7	-0.1	1.2	0.45
Profit forgone ($M)	-7.9	-8.0	-7.8	-6.9	-7.6	-7.8	-7.1	-8.2	-6.8	-8.1	-7.63
Interaction cost ($M)	-2.5	-2.8	-4.7	-4.5	-3.1	-3.8	-3.0	-3.6	-3.9	-1.1	-3.29
SR apportioning factor	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.651
SR only contribution	3.35	3.55	3.51	3.85	3.63	3.48	3.39	3.70	3.60	3.30	3.54
SR given LRR contribution	4.62	4.80	3.51	4.32	4.75	4.06	4.37	4.58	4.15	5.45	4.46
SR availability cost ($M)	**7.97**	**8.35**	**7.03**	**8.17**	**8.38**	**7.54**	**7.75**	**8.28**	**7.74**	**8.76**	**8.00**

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

Table 7 SR availability cost calculation – off-peak

Sample	S1	S2	S3	S4	S5	S6	S7	S8	S9	S10	Average[38]
Cost of SR only ($M)	**6.06**	**5.53**	**6.00**	**5.85**	**5.70**	**5.86**	**6.02**	**6.63**	**6.12**	**5.97**	**5.97**
Gen cost ($M)	3.87	3.48	3.51	4.14	3.68	3.28	4.22	4.43	3.69	4.08	3.84
Start-up cost ($M)	3.06	2.60	2.94	2.49	2.78	2.86	2.65	3.01	2.98	2.65	2.80
Profit forgone ($M)	-0.86	-0.55	-0.45	-0.78	-0.76	-0.28	-0.85	-0.81	-0.54	-0.76	-0.66
Cost of SR given provision of LRR ($M)	**4.68**	**4.69**	**4.21**	**4.74**	**4.71**	**4.44**	**4.14**	**4.36**	**4.55**	**5.84**	**4.64**
Gen cost ($M)	4.12	3.84	3.47	3.04	3.74	3.03	3.49	3.63	3.56	4.57	3.65
Start-up cost ($M)	1.57	1.64	1.65	2.29	2.03	2.08	1.49	1.72	1.60	2.16	1.82
Profit forgone ($M)	-1.00	-0.80	-0.91	-0.59	-1.05	-0.66	-0.84	-1.00	-0.60	-0.90	-0.84
Interaction cost ($M)	-1.38	-0.84	-1.80	-1.11	-0.99	-1.42	-1.88	-2.27	-1.57	-0.14	-1.34
SR apportioning factor	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.612
SR only contribution	2.35	2.15	2.34	2.27	2.21	2.28	2.34	2.56	2.39	2.32	2.32
SR given LRR contribution	2.87	2.86	2.57	2.90	2.88	2.71	2.53	2.67	2.77	3.57	2.84
SR availability cost ($M)	**5.22**	**5.01**	**4.91**	**5.17**	**5.10**	**4.99**	**4.87**	**5.23**	**5.17**	**5.89**	**5.16**

Table 8 Parameter estimates by sample

Sample	S1	S2	S3	S4	S5	S6	S7	S8	S9	S10	Average
Margin off-peak	70%	71%	69%	70%	70%	71%	67%	70%	74%	80%	71%
Margin peak	33%	36%	29%	34%	36%	32%	33%	35%	33%	38%	34%
Availability cost ($M)	13.19	13.37	11.94	13.34	13.47	12.53	12.62	13.51	12.91	14.65	13.15
OP availability cost ($M)	5.22	5.01	4.91	5.17	5.10	4.99	4.87	5.23	5.17	5.89	5.16
P availability cost ($M)	7.97	8.35	7.03	8.17	8.38	7.54	7.75	8.28	7.74	8.76	8.00

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

Sample	S1	S2	S3	S4	S5	S6	S7	S8	S9	S10	Average
Off-peak price ($/MWh)	39.50	39.16	39.54	39.84	39.75	39.31	39.51	39.44	39.49	39.71	39.52
Peak price ($/MWh)	54.31	54.33	55.13	55.07	54.35	54.16	54.12	54.35	54.66	53.94	54.44
SR_Capacity Peak (MW)	224.6	223.2	224.6	225.5	222.9	224.3	223.9	225.2	223.7	223.0	224.1
SR_Capacity_ Off-Peak (MW)	190.3	188.5	188.0	189.5	188.8	188.5	188.8	190.8	187.2	189.3	189.0

The breakdown in the availability cost between peak and off-peak periods is shown for sample 1 (the most representative sample) in Table 9 both with and without LRR. We observe the following:

- The relativities of peak/off-peak availability costs are very similar for the No LRR and With LRR cases. This shows there is no significant change in peak/off-peak dynamics between the two cases.
- In the generation and start cost categories for both peak and off-peak the No LRR cost is higher than the with LRR cost, with the exception of the off-peak generation cost. In the profit foregone category for both peak and off-peak the no LRR cost is lower than the with LRR cost.
- The generation cost is about 4 times higher in the peak ($14.6M and $15.2M for with LRR and no LRR cases respectively) relative to the off-peak ($4.1M and $3.9M for with LRR and no LRR cases respectively). This partly reflects the higher number of peak trading intervals in the year (28 intervals per day, as opposed to 20 off-peak intervals). However, it also reflects the fact that more SR is required in the peak, and the peaking generators switching on to provide this are higher cost.
- Start costs are higher in off-peak periods ($1.6M and $3.1M for with LRR and no LRR cases respectively compared to $0.4M and $0.8M). This reflects more plant starts required to provide reserve in the off-peak when demand is low and peaking plant tend to be off in the no SR case.
- Profit foregone is 8 to 9 times higher in the peak (-$7.9M and -$6.3M for with LRR and no LRR cases respectively) relative to the off-peak (-$1.0M and -$0.7M for with LRR and no LRR cases respectively). This reflects a combination of higher generation levels of peaking plant in the peak (c.f. generation cost relativities) and also higher prices in the peak, which lead to higher profits.

Table 9 Peak/Off-peak breakdown of availability cost for sample 1 with and without LRR ($M)

	Generation cost	Start cost	Profit foregone	Total
With LRR				
Peak	14.6	0.4	-7.9	7.1
Off-peak	4.1	1.6	-1.0	4.7
Total	18.7	2.0	-8.9	**11.8**
No LRR				
Peak	15.2	0.8	-6.3	9.7
Off-peak	3.9	3.1	-0.7	6.2
Total	19.1	3.9	-7.1	**15.9**

10.1 Cockburn CCGT and NewGen Kwinana CCGT LFR provision

Table 10 shows a breakdown of LFR provision by Cockburn CCGT and NewGen Kwinana CCGT in peak and off-peak periods. This LFR provision does not contribute to SR for the reasons mentioned in section 9.5. Since Cockburn and NewGen Kwinana are the only LFAS facilities that have not been modelled to provide SR, and Synergy is paid based on a fixed quantity of SR in the peak and the off-peak, the correct quantity of SR to be paid to Synergy can be calculated by adding back the average LFR provision of Cockburn CCGT and NewGen Kwinana CCGT. Therefore, the quantities in Table 10 are included in the SR_Capacity_Peak and SR_Capacity_Off-Peak values reported in Table 5. This is required as Synergy's net SR provision determined in clause 9.9.2(f) of the Market Rules does not exclude the LFR provision which is SR ineligible.

Table 10 shows that NewGen Kwinana CCGT provides more of its LFR in off-peak periods, whereas Cockburn provides more in peak periods.

Table 10 Average LFR provision by Cockburn CCGT and NewGen Kwinana CCGT that is ineligible to contribute to SR

		S1	S2	S3	S4	S5	S6	S7	S8	S9	S10	Average
Cockburn CCGT	Peak (MW)	5.0	4.6	5.3	5.6	4.6	5.5	5.2	6.5	4.9	4.8	5.2
	Off-peak (MW)	3.8	3.5	2.6	3.1	2.9	3.7	4.0	4.0	2.2	3.5	3.3
NewGen Kwinana CCGT	Peak (MW)	9.1	8.6	8.5	8.7	8.8	9.8	9.5	9.7	8.7	8.6	9.0
	Off-peak (MW)	15.4	14.7	14.6	15.6	15.0	15.2	14.7	16.4	14.9	14.7	15.1
Total	Peak (MW)	14.1	13.1	13.8	14.3	13.3	15.3	14.7	16.1	13.5	13.4	14.2
	Off-Peak (MW)	19.2	18.2	17.2	18.7	17.9	18.9	18.7	20.4	17.1	18.2	18.5

Appendix A. Pipeline tariffs

A.1 DBNGP tariffs

A.1.1 Tariff components

Dampier to Bunbury Natural Gas Pipeline (DBNGP) tariffs have been obtained from the 2016-20 Access Arrangement and otherwise calculated using the same approach used for the 2017-18 Margin Value Review.

The DBNGP 2016-20 Access Arrangement published by the ERA on 30 June 2016 allows for, as at 1 July 2016:

- the T1 Capacity Reservation Tariff is $1.165954/GJ ($2016); and
- the T1 Commodity Tariff is $0.128597/GJ ($2016);
- making a T1 Tariff of $1.294551/GJ ($2016).

This Base T1 Tariff does not take into account tariff adjustments for capacity expansions. When account is taken of this, ACIL Tasman referred to a Standard Shipper Contract (SSC) T1 tariff at 1 January 2010 of $1.4942 which, when escalated at the Perth Consumer Price Index (All Groups)[39] 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 new SSC negotiated in 2014 for 1 July 2014 to 31 December 2020, Base T1 tariffs and Aggregate Tariff Adjustment Factor (ATAF) escalate at Perth CPI.

Thus, we have calculated tariffs in two parts:

- A Base T1 Tariff of $1.294551/GJ at 30 June 2016;
- An ATAF adjustment of $0.192/GJ at 1 January 2011 (calculated by difference from the $1.5411) which escalates at Perth CPI[40]. It has also been escalated based on the new real pre-tax discount rate of return calculated by the ERA in the 2016-20 Access Arrangement and referred to in the SSC.

A.1.2 CPI numbers and estimates

The Perth CPI growth for 2015-16 was 0.5%. The Western Australian 2016-17 budget forecasts for Perth CPI growth were[41] 1.75% for 2016-17, 2.25% for 2017-18, and 2.5% p.a. for 2018-19 and 2019-20.

In its calculations, Jacobs 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
- 2.6% for Sept 2012 to Sept 2013 actual, which determined the price for calendar year 2014
- 2.6% for Sept 2013 to Sept 2014 actual, which determined the price for calendar year 2015
- 1.1% for Sept 2014 to Sept 2015 actual, which determined the ATAF price for calendar year 2016 (the Base T1 Tariff is based on the 2016-20 Access Arrangement)
- 0.5% for Sept 2015 to Sept 2016 assumed, which will set the price for calendar year 2017

[39] The Perth Consumer Price Index (All Groups) published by the Australian Bureau of Statistics is referred to in this report as Perth CPI.
[40] 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.
[41] CPI forecasts were not reported in the 2017-18 budget, so we have used the 2016-17 budget forecasts

- 1.4% for Sept 2016 to Sept 2017 assumed, which will set the price for calendar year 2018
- 2.3% for Sept 2017 to Sept 2018 assumed, which will set the price for calendar year 2019

Where relevant, Jacobs has assumed that Australia CPI[42] will be 2.5% p.a. in each year.

A.1.3 Full-haul tariff calculations in nominal dollars

The Perth CPI assumptions and tariffs calculated are provided in Table 11.

Table 11 Actual and forecast CPI and tariffs for the DBNGP, nominal dollars

	Calendar 2016 (actual)	Calendar 2017 (actual)	Calendar 2018 (forecast)	Calendar 2019 (forecast)
Perth CPI increase*	0.5%	0.9%	2.3%	2.5%
Base Tariff	$1.29	$1.30	$1.31	$1.34
ATAF	$0.26	$0.26	$0.26	$0.27
Total	$1.55	$1.56	$1.58	$1.61

* From September to September. Calendar 2017 is based on Sept 2016 to forecast Sept 2017 Perth CPI and Calendar 2018 and 2019 tariffs are based on forecast 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 2017

Based on our calculations and assumptions we have estimated that the tariffs will be $1.58/GJ for calendar year 2018 and $1.62 for calendar year 2019 in nominal terms.

Assuming equal quantities off-taken in each of the four quarters and using the Perth CPI Index of 109.0 in June 2017 as the base and assuming Perth CPI growth based on WA 2016-17 budget forecasts, we have estimated the average tariff in 2018-19 in real June 2017 dollars to be $1.53/GJ at 100% load factor.

A.1.5 Commodity and capacity components

In the Access Arrangement, the Base Tariff has a capacity reservation to commodity ratio of approximately 90% to 10%. As a result, we have assessed:

- The capacity reservation tariff to be $1.381/GJ of capacity reserved
- The commodity component to be $0.152/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 2017 are:

- A capacity reservation tariff of $0.000987/GJ of capacity reserved multiplied by the distance transported

[42] 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.

- A commodity tariff of $0.000109/GJ transported multiplied by the distance transported.

A.2 Goldfields Gas Pipeline

A.2.1 Tariffs for transport through uncovered expansions

GGP reference tariffs have been obtained from the 2015-19 Access Arrangement:

- Toll charge: $0.116369/GJ
- Capacity reservation charge: $0.000620/GJ MDQ/km
- Throughput charge $0.000228/GJ/km.

These rates are at 1 July 2016 with quarterly indexation using the Australia All Groups CPI, for which the June 2016 index value is 108.6 and the June 2017 index value is 110.7.

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 $1.31/GJ in June 2017 dollars, for a 100% load factor customer in Kalgoorlie (1380 km) in 2017[43].

A.3 Transport costs for SWIS generators in 2018-19

Based on the above analysis, the transport costs for individual generators in the SWIS are set out below in Table 12.

The calculations show the variable and fixed components in $/GJ, assuming a 77% load factor of which only 50% is included in the calculation and take account of distances specified by ACIL Tasman where relevant.

Table 12 Transport costs for SWIS generators in 2018-19 in $June 2017/GJ

Generator	Tariff Used	Distance	Variable transport charge	Fixed Transport Charge, 77% LF, $June 2017	Total transport Charge (50% of fixed component) $June 2017
Alinta Pinjarra	DBNGP T1		0.15	1.79	1.05
Alcoa Wagerup	DBNGP T1		0.15	1.79	1.05
PPP_KCP_EG1	DBNGP T1		0.15	1.79	1.05
SWCJV Worsley	DBNGP T1		0.15	1.79	1.05
Tiwest	DBNGP T1		0.15	1.79	Confidential[44]
Cockburn	DBNGP T1		0.15	1.79	1.05
Perth Energy	DBNGP T1		0.15	1.79	1.05

[43] 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 ($0.119 x 365) plus a capacity reservation charge of ($0.0063 x 365 x 1380) plus a throughput charge of ($0.000232 x 365 x 1380) all divided by the throughput (365 GJ) = $1.31/GJ in July 2017. Assuming a 77% load factor, the toll Charge and capacity reservation charge are divided by 0.77 resulting in a transportation charge of $1.61/GJ.

[44] TiWest provided its actual transport charge for the 2016 review.

Generator	Tariff Used	Distance	Variable transport charge	Fixed Transport Charge, 77% LF, $June 2017	Total transport Charge (50% of fixed component) $June 2017
Kwinana	DBNGP T1		0.15	1.79	1.05
Mungarra	DBNGP P1	1020	0.11	1.31	0.76
Pinjar	DBNGP T1		0.15	1.79	1.05
NewGen Neerabup	DBNGP T1		0.15	1.79	1.05
NewGen Kwinana	DBNGP T1		Confidential	Confidential	Confidential[45]
Southern Cross Energy	GGP	1388	0.32	1.29	0.97
Goldfields Power Parkeston	GGP	1380	0.32	1.29	0.96
Kemerton	DBNGP T1		0.15	1.79	1.05
Alinta Wagerup	DBNGP T1		0.15	1.79	1.05

Jacobs estimates of tariffs. ACIL Tasman distances

[45] NewGen Kwinana CCGT provided its actual transport charge for the 2017 review.

Appendix B. Backcasting Study

Part of this year's scope for the Margin Values Review was to conduct a back-cast study using PLEXOS with the goal of better tuning the market model to achieve more accurate market outcomes. Jacobs therefore has conducted a back-cast study for the 2016/17 financial year, which is the latest full year for which actual market outcomes are available. Jacobs used actual market data provided by AEMO, against which it has compared its modelled PLEXOS outcomes. In making the comparisons, Jacobs calculates "duration curves" by sorting the data series from the largest to the smallest value. This is useful in comparing multiple data series because the period by period variability is removed and the "overall" data can be compared in a clear manner.

To facilitate this comparison, the back-cast was set up as follows:

- Actual reported outages for the 2016/17 year were used
- Actual system operational demand was used, with the limitation that the split between Muja and Goldfields was based on the 2012/13 historical profile rather than the 2016/17 historical profile
- Initially we used last year's fuel prices

The initial run of the back-cast model resulted in the following key discrepancies between modelled and actual outcomes:

- Synergy's modelled coal output was higher than actual, with dispatch for Collie and Muja C and D all being higher than actuals, especially in peak periods
- Non-Synergy gas generation was lower than actual
- The modelled off-peak price was lower than actual
- The modelled peak price, and the annual average price were lower than actual

By changing fuel prices to reflect this year's fuel prices reported by some Market Participants we were able to achieve slightly better price outcomes in peak periods, with the main source of difference being the increase of Synergy's price. Off-peak prices were also improved by increasing the coal price to this year's assumed price, which resulted in matching of the average off-peak price.

The key difference occurring in the model was too much coal dispatch from Synergy's portfolio relative to actual output (in the order of 2,000 GWh too much, which is about 30% above actual dispatch). Of particular interest is the dispatch from Collie as this tends to be the largest operating unit in the WEM and therefore it tends to set the Spinning Reserve (SR) requirement (70% of largest outputting unit). The dispatch of NewGen Kwinana CCGT is also important in this respect as it too tends to set the SR requirement, although not as frequently as Collie.

Given the marginal cost differential between coal and gas-fired generation in the WEM, there is no obvious explanation to account for the large difference between modelled and actual coal dispatch. One explanation we had posited was a fuel constraint on Synergy coal-fired generation, but AEMO investigated whether this was a possible explanation, but concluded that it was not.

In the absence of any explanation, we dealt with this issue by constraining annual coal output for Synergy. The method adopted was to examine its historical output over the last five years, which revealed no trend. We therefore chose to constrain Synergy coal output to the maximum level over the last five years, which happened to be 2016/17 output (about 6,500 GWh). Applying this constraint achieved better alignment for total coal and total gas output, but it did dramatically shift the price duration curve up in the off-peak as the model chose to constrain coal-fired generation in off-peak periods. In terms of coal dispatch the model off-loaded Muja C to below its historical output, achieved very good dispatch for Collie, and favoured Muja D, achieving more output for Muja D than actual.

The next step was to constrain Synergy coal-fired dispatch only in peak periods. Historically, annual Synergy peak period coal-fired dispatch had a similar pattern to annual Synergy coal-fired dispatch, and so peak-period coal-fired dispatch was constrained to the 2016/17 value, which is about 4,500 GWh. This restored the modelled price duration curve to lower levels, although the modelled off-peak price is slightly higher than the actual off-peak price. However, it did bring better alignment in the generation duration curves (GDCs) of many generators:

- This setting achieved the best alignment for both Collie and NewGen Kwinana
- Muja C modelled output was still below actual output, but it was closer aligned than the previous iteration
- Muja D modelled output was still above actual output, but it was closer aligned than the previous iteration
- Cockburn CCGT output is now better aligned with actuals

The most significant misalignments with the current modelling run are that Kemerton GT is tending to take the place of the Pinjar GTs, as it is running in the mid-merit role, and Pinjar is running in purely a peaking role. This is a case of two plants with similar costs and generation characteristics being switched by the model. It should not have a material impact on the margin value analysis since the generation costs of the two plants are very similar.

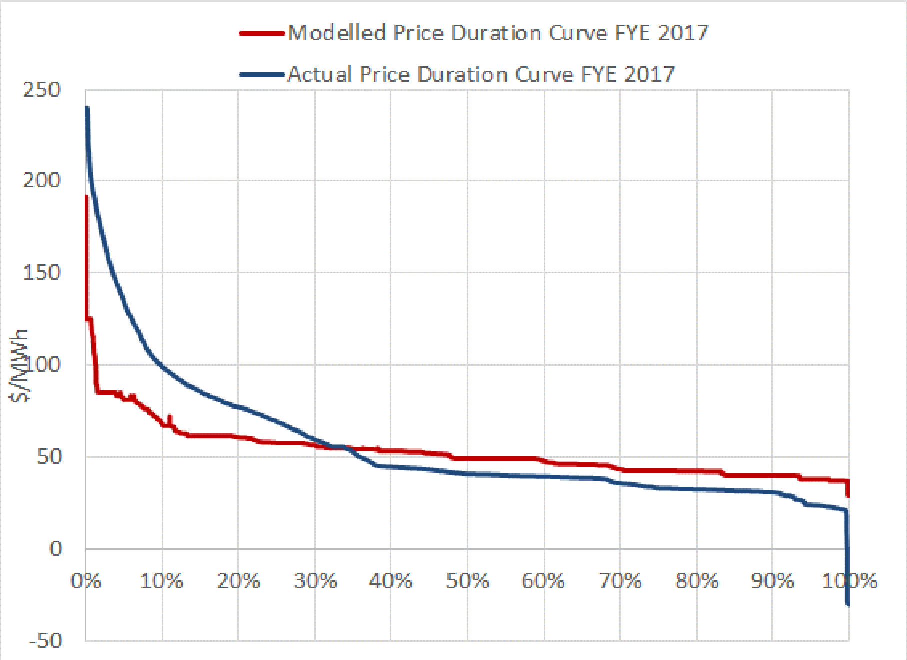
NewGen Neerabup is also running harder in the model than in actuality. The Market Participant had advised a fairly low fuel price relative to the Synergy portfolio in particular, and increasing this marginal cost would bring it back into better alignment.

Jacobs notes that peak prices in 2016/17 have increased markedly relative to peak prices in 2015/16. Jacobs' modelled outcomes are closer to the 2015/16 outcomes, but the model still falls short of prices at the top end of the duration curve (top 10%), even compared with the 2015/16 price outcomes. Higher price outcomes are likely to be caused by constraints in the transmission system (the Jacobs model have very few constraints in it), and generation de-ration at high temperatures would also be a contributing factor.

We note that PLEXOS is an optimisation model whereas System dispatch is not based on full co optimisation. This difference in approach explains some of the differentials between the modelled outcome and actuals.

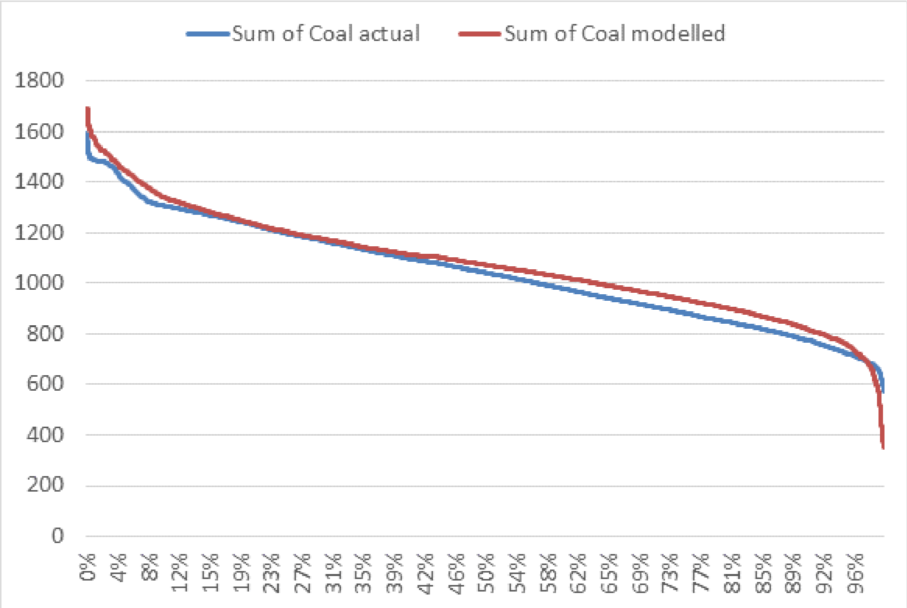
B.1 Prices

Figure 6 shows the price duration curves for both actual and modelled outputs. The actual pricing outcomes in the WEM for FY2016/17 is aligned well during off peak however the actual pricing is higher during peak.



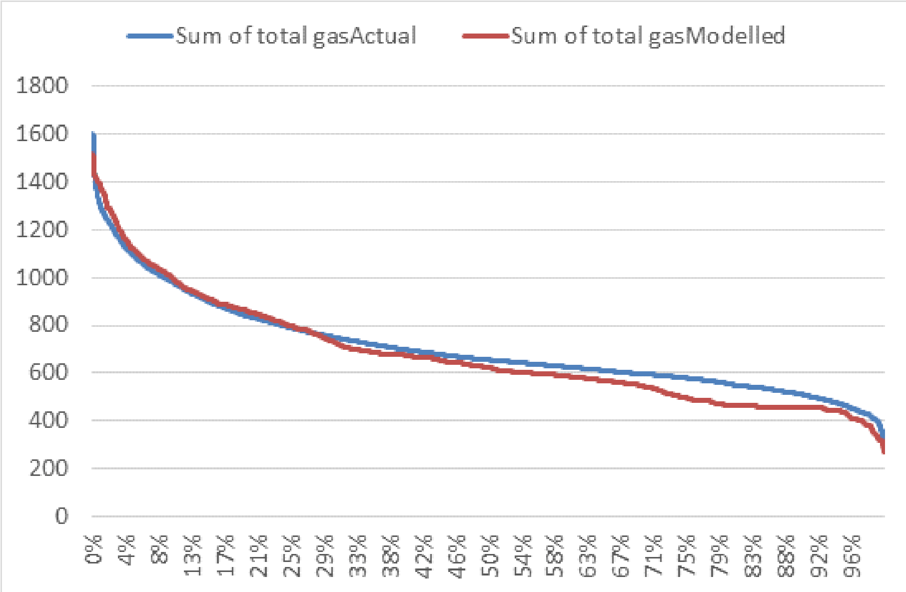
B.2 Coal

Figure 7 shows total coal generation duration curve for actual and modelled in the WEM. The modelled coal generation is slightly over compared to the actual coal generation during both peak and offpeak. This should mean that there should be slightly lower gas generation compared to actuals which is shown in Figure 9.



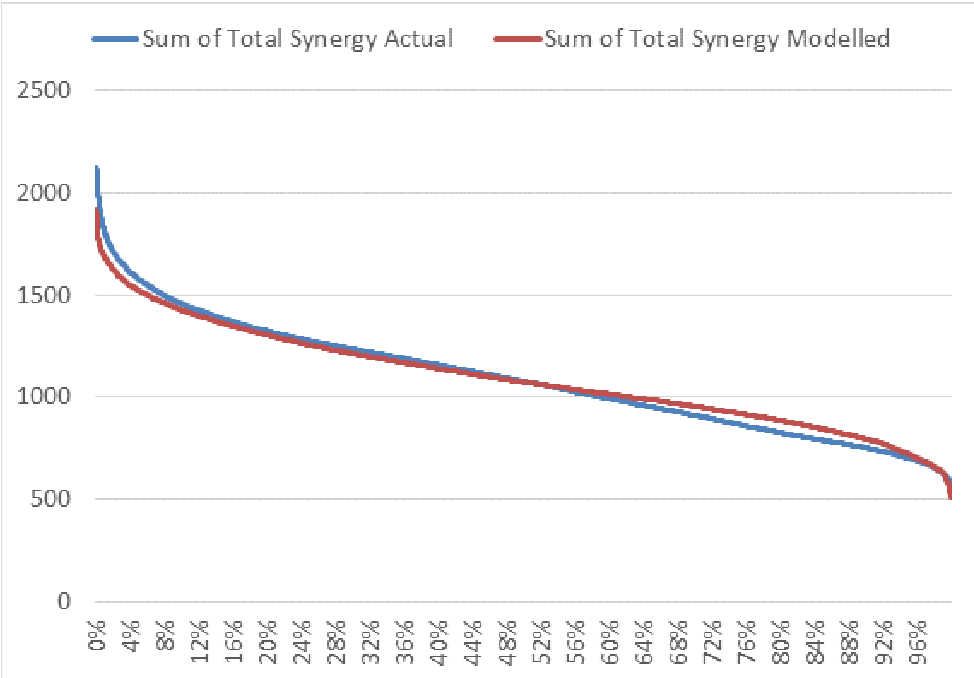
B.3 Gas

Figure 8 shows total gas generation duration curve for actual and modelled in the WEM.



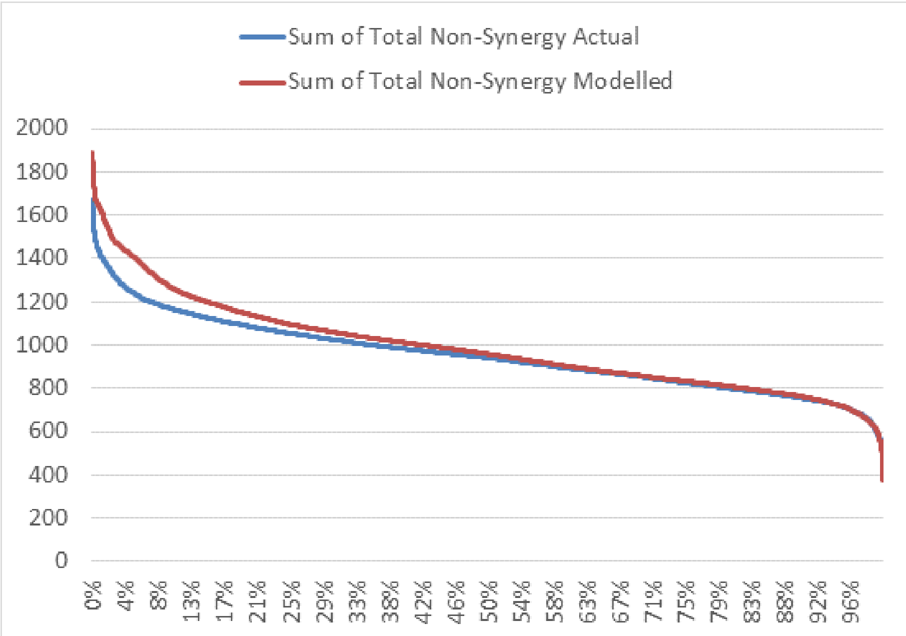
B.4 Synergy (MW)

Figure 9 shows actual and modelled total Synergy output. The modelled output is very close to the actual for Synergy generators. The deviation is quite small compared to actual with slightly low during peak and slightly low during off peak. The coal constraint that has been implemented during peak of 4,500 GWh based on last 5 years of actual generation has put the output in alignment with the actuals.



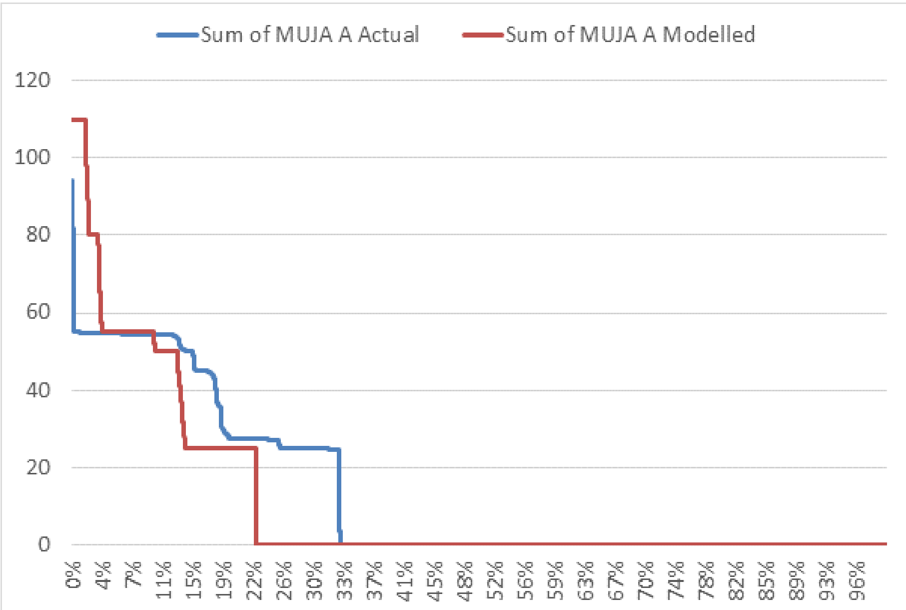
B.5 Non-Synergy (MW)

Figure 10 shows generation duration curves for Non-Synergy generators. The actual generation from non-Synergy generators during peak is slightly lower than the modelled generators.



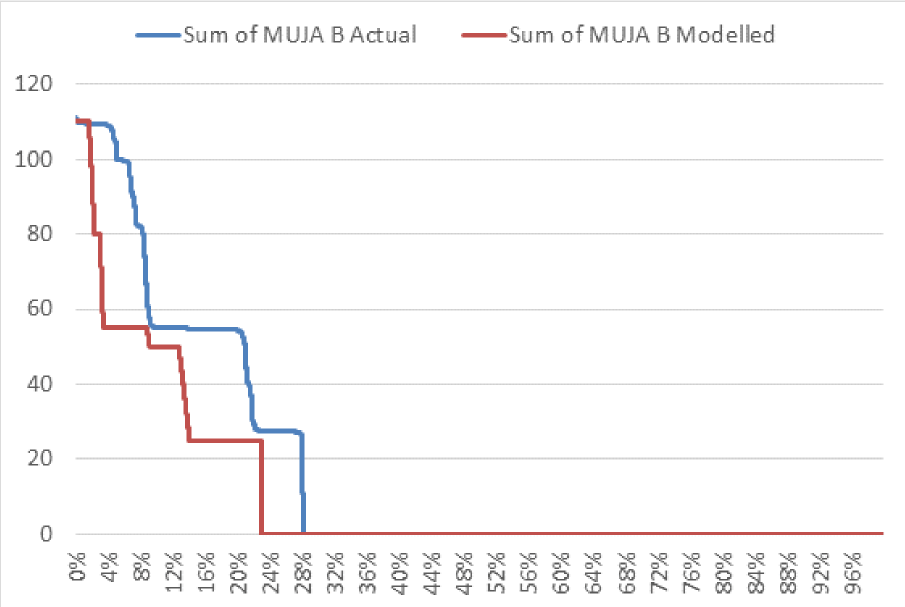
B.6 MUJA A

Figure 11 shows dispatch of MUJA A and this dispatches very similar to the actual dispatch.



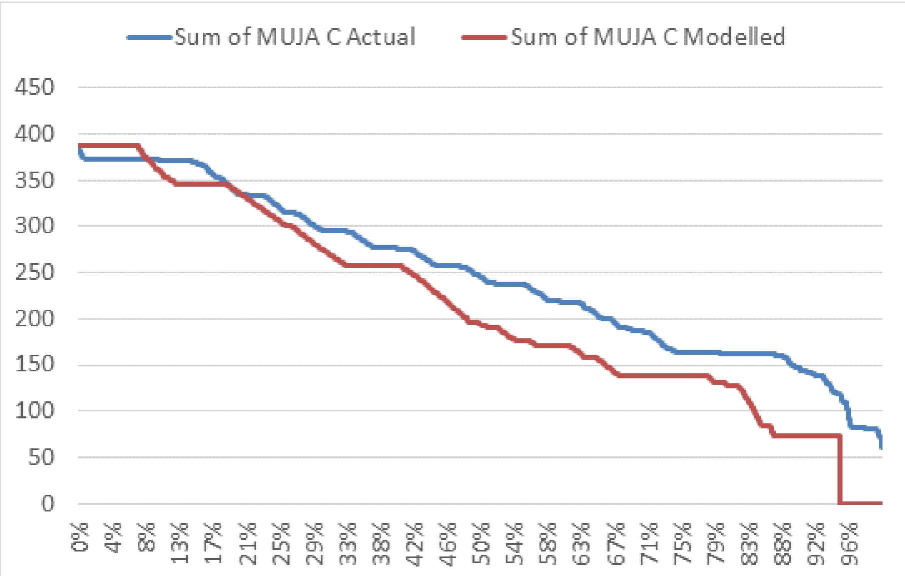
B.7 MUJA B

Figure 12 shows duration curves for MUJA B, which track very close to the actuals. Note that both MUJA A & B are retiring soon and will not be part of the study for 2018/19



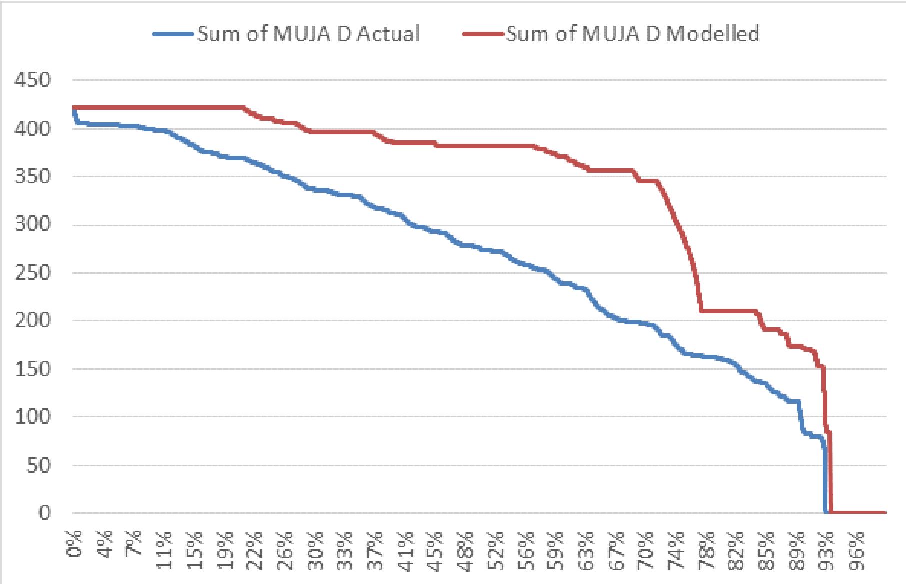
B.8 MUJA C (MW)

Figure 13 shows that MUJA C dispatches in line with actual mainly due to the coal constraint in place.



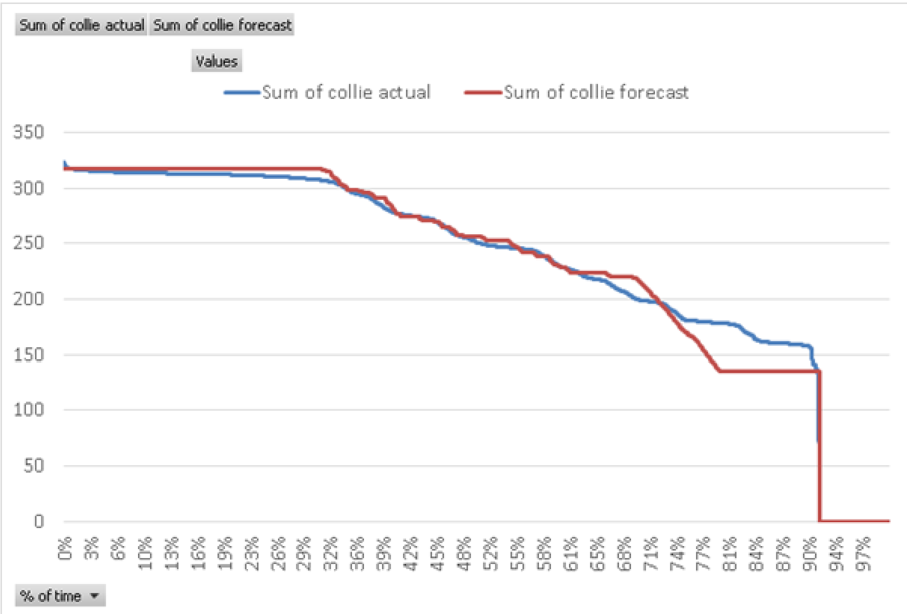
B.9 MUJA D (MW)

Figure 14 shows that MUJA D operating at max capacity more frequently than actual. MUJA D has a much lower marginal cost and hence is seen being dispatched more in the model.



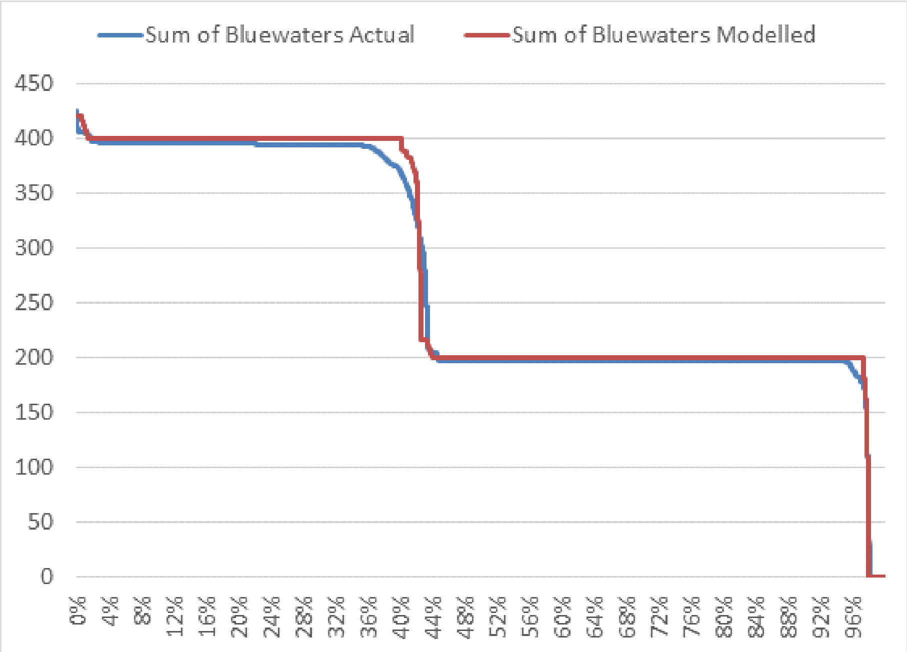
B.10 COLLIE (MW)

Figure 15 shows COLLIE'S modelled output compared to actual output is very similar. COLLIE is often the largest generating unit in the system, which will determine the amount of spinning reserve required in the market.



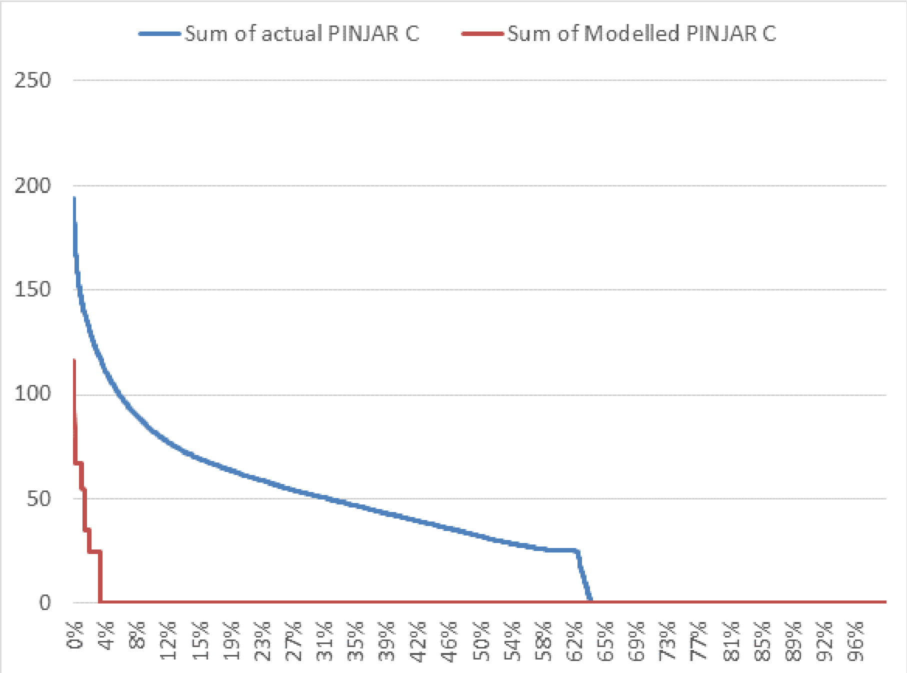
B.11 Bluewaters (MW)

Figure 16 shows modelled total generation from the two BLUEWATERS units is very much in line with the actual generation. BLUEWATERS had an outage on one of its units for 6 months which is reflected below.



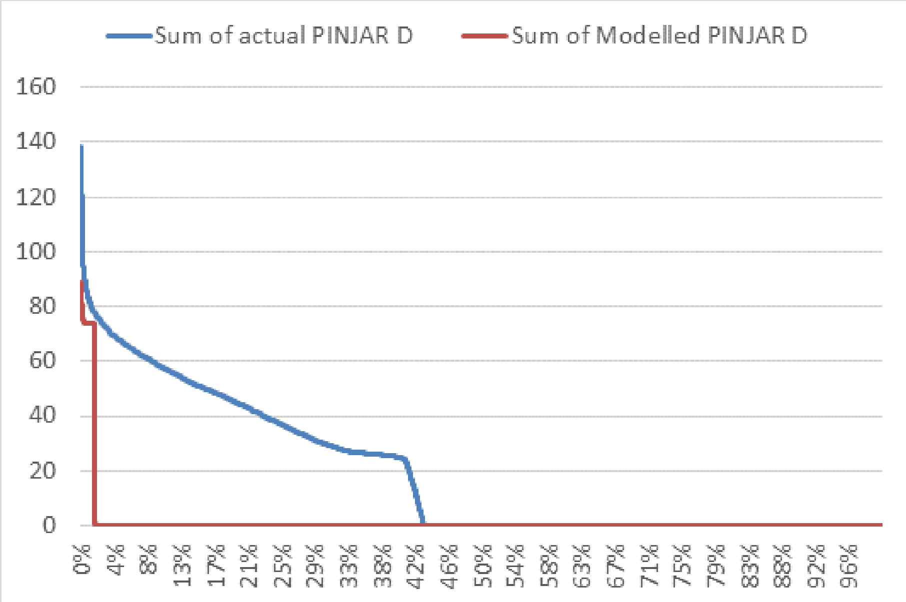
B.12 PINJAR C (MW)

Figure 17 shows PINJAR C (PINJAR GT9 & GT10) operates mainly as a peaking unit in the modelling; however, the actual generation duration curve suggests that it also operated as a mid-merit plant.



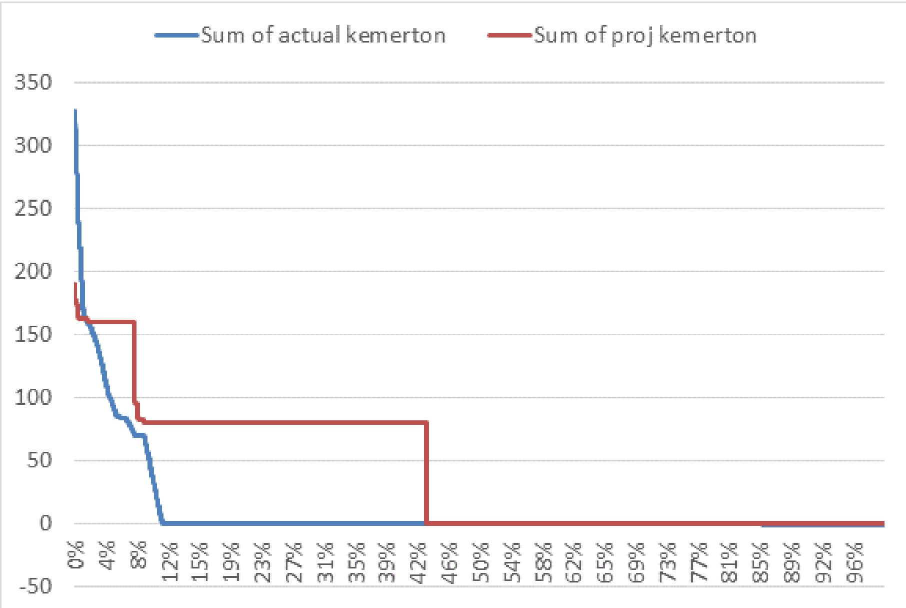
B.13 PINJAR D (MW)

Figure 18 shows the comparison for PINJAR GT11, which was restricted in the model to peaking duty.



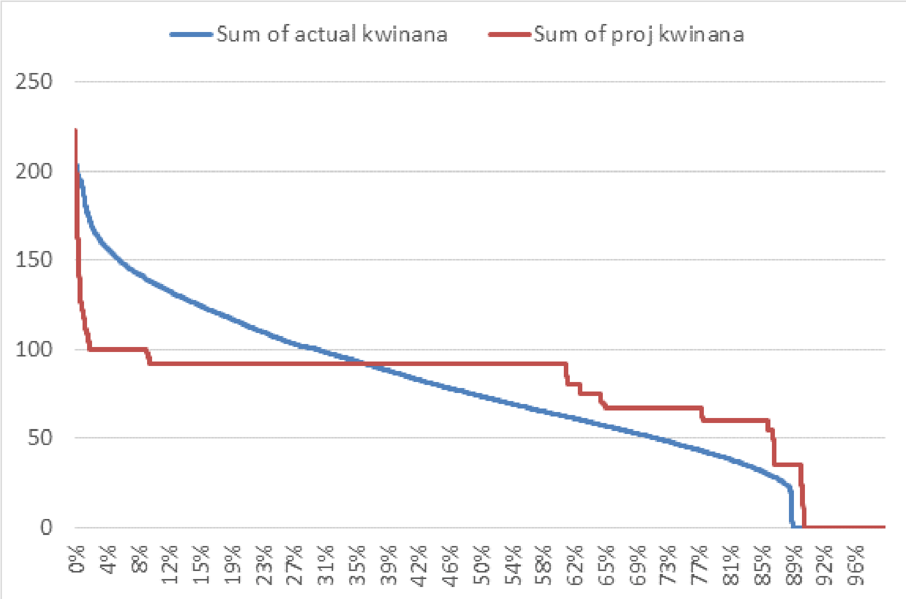
B.14 KEMERTON (MW)

Figure 19 shows KEMERTON GT ran harder in the model than in actuality. This is likely explained by its access to a separate low cost gas contract in the model, making the plant more competitive at the peaking end of the market. In modelling Pinjar C/D as shown above runs more mid-merit while in modelling we have Kemerton doing that.



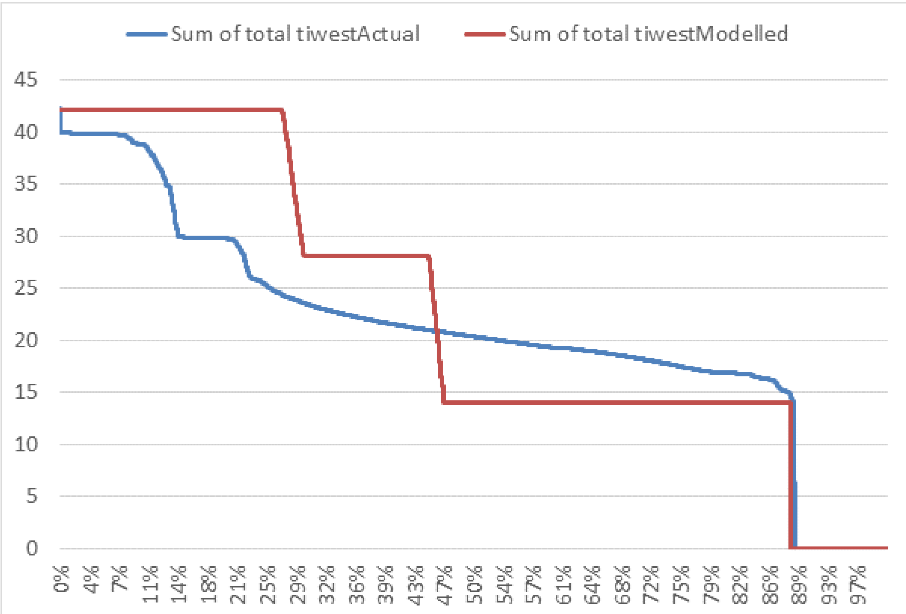
B.15 KWINANA (MW)

Figure 20 shows the sum of generation from three Kwinana gas units (KWINANA GT1, KWINANA GT2 and KWINANA GT3.



B.16 TIWEST (MW)

Figure 21 shows generation profile for TIWEST. Tiwest is generating at max capacity a bit more than actual.

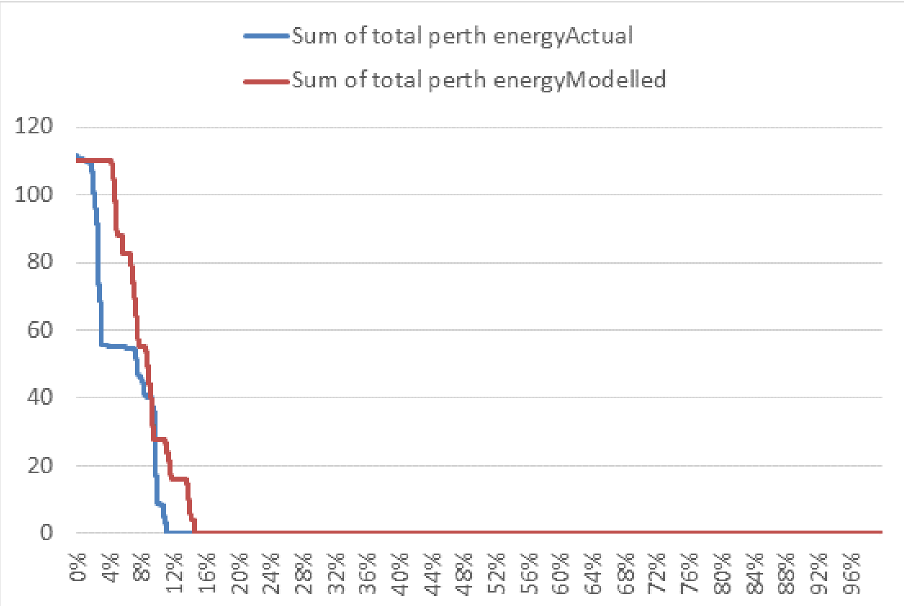


B.17 PPP_KCP (MW)

Figure 22 shows output from PPP_KCP. The modelled generator operates very similar in off peak however, ran a lot harder in reality in FY17.

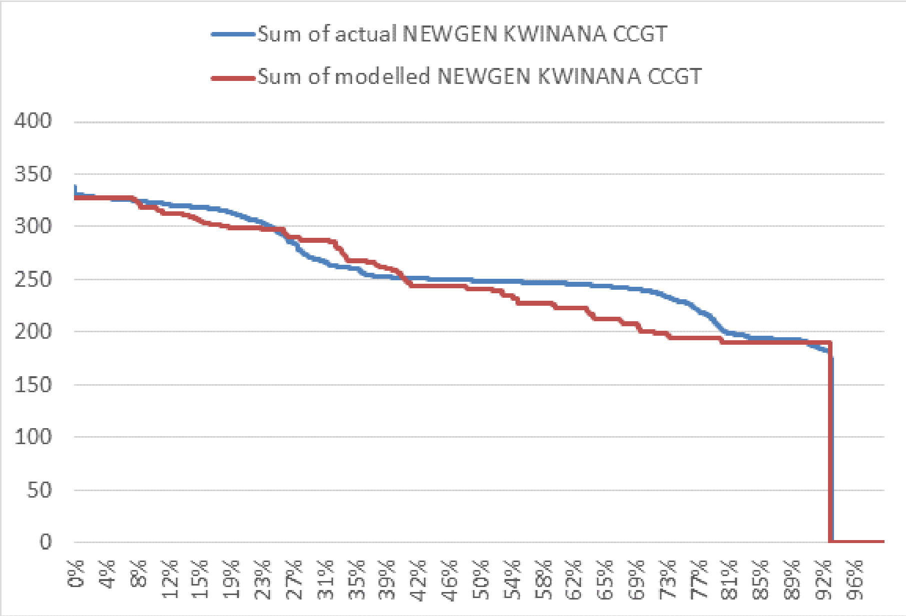
B.18 Perth Energy (MW)

Figure 23 shows output from Perth Energy which is consistent with actual.



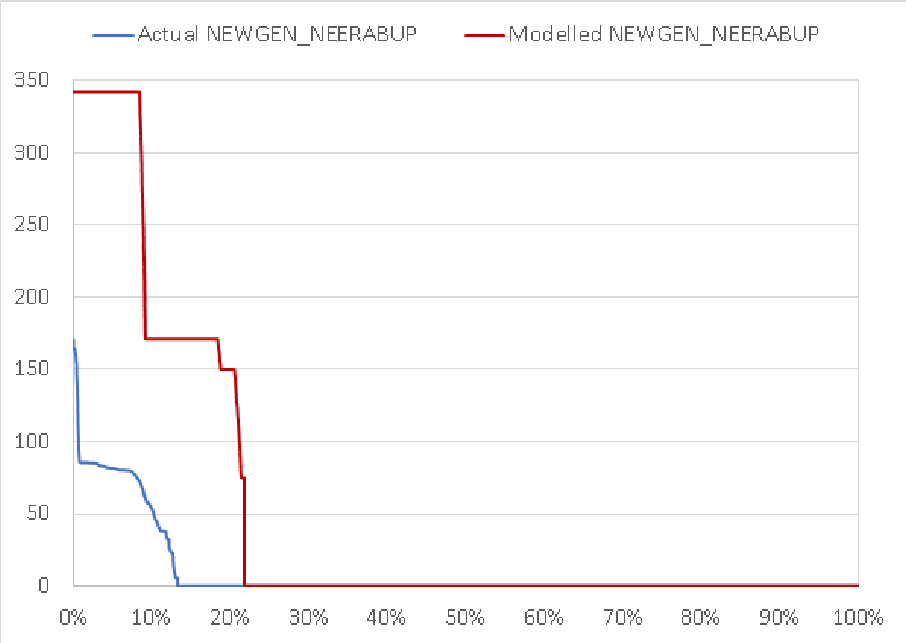
B.19 NEWGEN KWINANA CCGT (MW)

Figure 24 shows the generation of NEWGEN KWINANA CCGT, which 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.



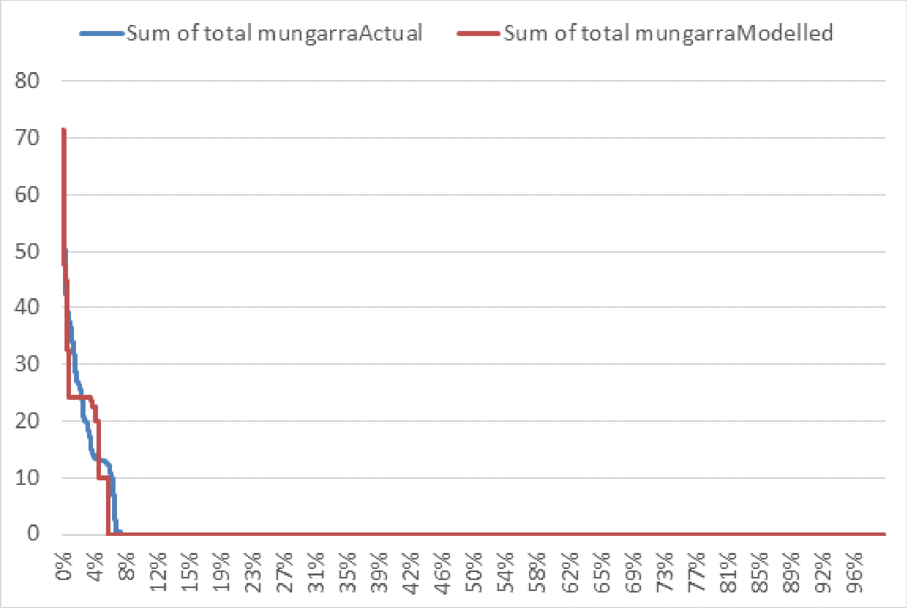
B.20 NEWGEN NEERABUP (MW)

Figure 25 shows that the NEWGEN NEERABUP operates at a higher capacity factor than actual due to access to lower gas prices in the model. NEERABUP running harder in the model displacing Pinjar C & D plants.



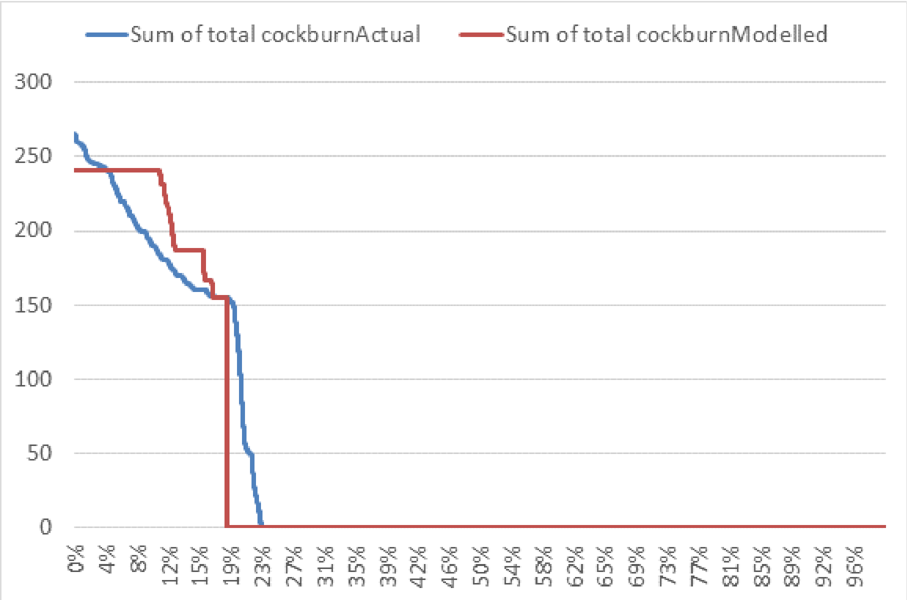
B.21 MUNGARRA (MW)

Figure 26 shows MUNGARRA GT emulating actual dispatch quite closely.



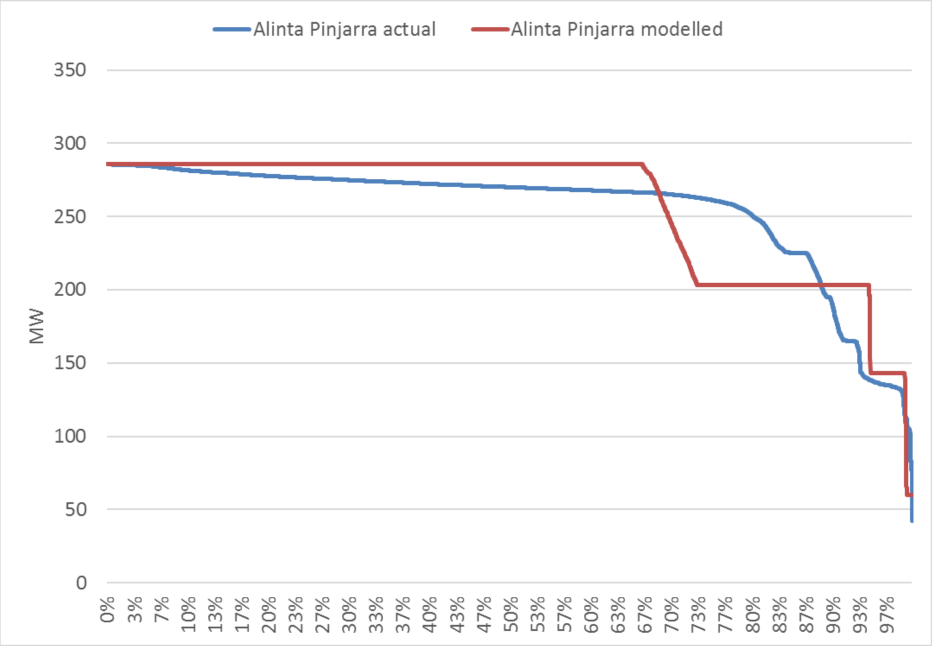
B.22 COCKBURN (MW)

Figure 27 shows that the modelled generation is very similar to the actual and confirms the higher Synergy gas price assumption.



B.23 ALINTA PINJARRA (MW)

Figure 28 shows that the modelled generation for the cogeneration plant has been adjusted until it is very similar to the actual.



Appendix C. Derivation of the Interaction cost

Jacobs models four cases to differentiate the cost of providing SR from the cost of also providing LRR:

- Scenario A: no LRR, no SR
- Scenario B: no LRR, with SR
- Scenario C: with LRR, no SR
- Scenario D: with LRR, with SR

The availability cost of the provision of a reserve service for any given trading interval is defined as follows:

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

where:

GenCost_Res = Synergy's total generation costs, including start-up costs, with reserve provision

GenCost_NRP = Synergy's total generation costs, including start-up costs, without any reserve provision apart from LFAS

GenQ_Res = Synergy's total generation volume, with reserve provision

GenQ_NRP = Synergy's total generation volume, without any reserve provision apart from LFAS

Balancing Price = The modelled system marginal price for dispatch with both SR and LRR reserve provision

The availability cost of Synergy providing SR needs to be differentiated from the cost of providing LRR. Simulation of SR costs in the previous study revealed that there is often an interaction cost effect between the cost of providing SR, and the cost of providing LRR. That is, the cost of providing both forms of reserve is generally not the same as the sum of providing each reserve separately. The difference between these two quantities is labelled as the Interaction Cost. Following consultation with AEMO, it was determined that the availability cost of providing SR should be the Base SR availability cost[46] plus the Interaction cost of providing both SR and LRR, allocated proportionally to the average level of SR required across the study horizon relative to the sum of the SR and LRR requirements.

That is:

Availability Cost(SR) = Availability Cost(SR only) + [Interaction Cost * SR_Proportion]

where the Interaction Cost is defined according to the following relationship:

Availability Cost(Both SR & LRR) = Availability Cost(SR only) + Availability Cost(LRR only) + Interaction Cost

and therefore

Interaction Cost = Availability Cost(Both SR & LRR) – Availability Cost(SR only) – Availability Cost(LRR only)

[46] That is, the availability cost of providing SR only, with no provision of LRR.

and

SR_Proportion = *Average SR provision / (Average SR provision + Average LRR provision)*

The calculation of the interaction cost can be simplified. Using the above definition of the availability cost, we can define the following availability costs for a given trading interval:

LRR only: $C_C - C_A + (G_A - G_C) \times P_D$

SR only: $C_B - C_A + (G_A - G_B) \times P_D$

Both SR & LRR: $C_D - C_A + (G_A - G_D) \times P_D$

SR given LRR: $C_D - C_C + (G_C - G_D) \times P_D$

where

C_x = generation cost + start cost of scenario *x*

G_x = Synergy's total generation under scenario *x*

P_D = price of scenario *D*, which is the only relevant price as both SR and LRR are provided in this scenario

Substituing the above into the interaction cost formula gives the following:

Interaction cost $= C_D - C_A + (G_A - G_D) \times P_D - [\, C_B - C_A + (G_A - G_B) \times P_D \,] - [\, C_C - C_A + (G_A - G_C) \times P_D \,]$

$= C_D - C_C + (G_C - G_D) \times P_D - [\, C_B - C_A + (G_A - G_B) \times P_D \,]$

= *Availability cost (SR given LRR) – Availability cost (SR only)*