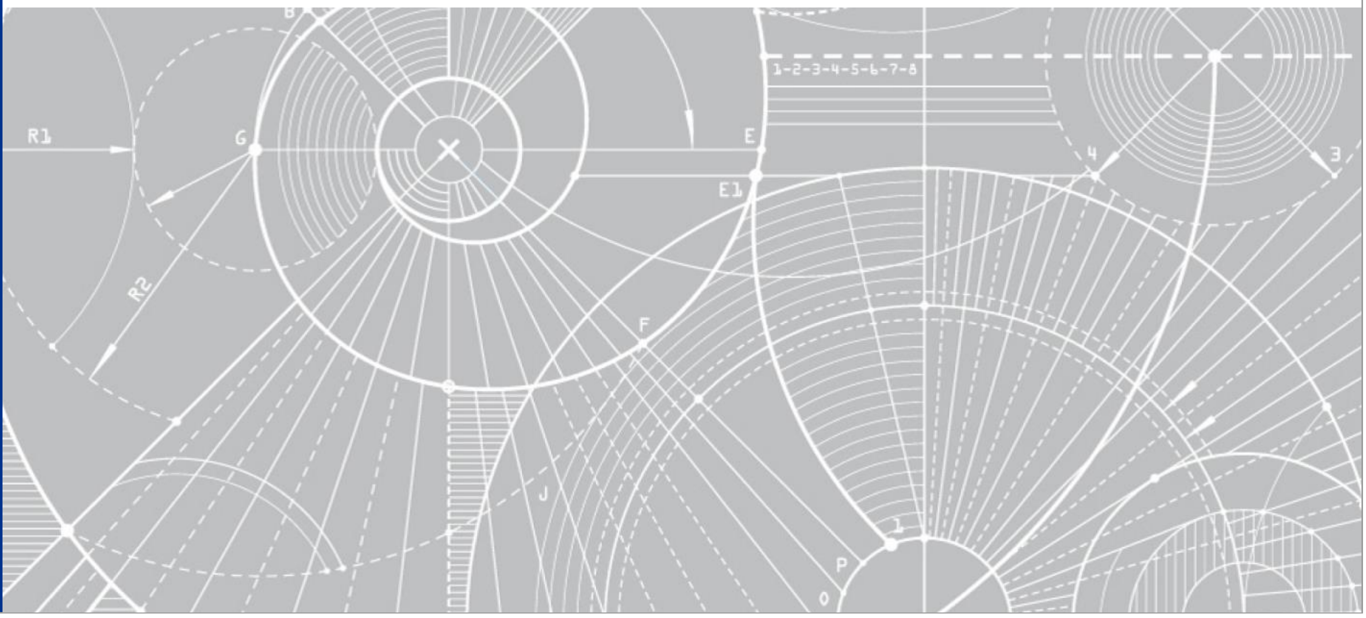
2018-19 Margin Peak and Margin Off-peak Review

AUSTRALIAN ENERGY MARKET OPERATOR

Draft assumptions report - PUBLIC

1.2

26 September 2017



JACOBS®

2018-19 Margin Peak and Margin Off-peak Review

Project no:	RO095900
Document title:	Draft assumptions report – PUBLIC
Document no:	1.2
Date:	26 September 2017
Client name:	Australian Energy Market Operator
Client no:	
Project manager:	Paul Nidras
Author:	Paul Nidras
File name:	I:\MMA\Projects\RO095900 AEMO MVR\Report\Draft assumptions report - PUBLIC.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	11/09/2017	Initial draft	P Nidras		P Nidras
1.1	22/09/2017	Incorporated feedback from AEMO	P Nidras		P Nidras
1.2	26/09/2017	Incorporated feedback from ERA	S Hyland	P Nidras	P Nidras

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.

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 an 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 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:

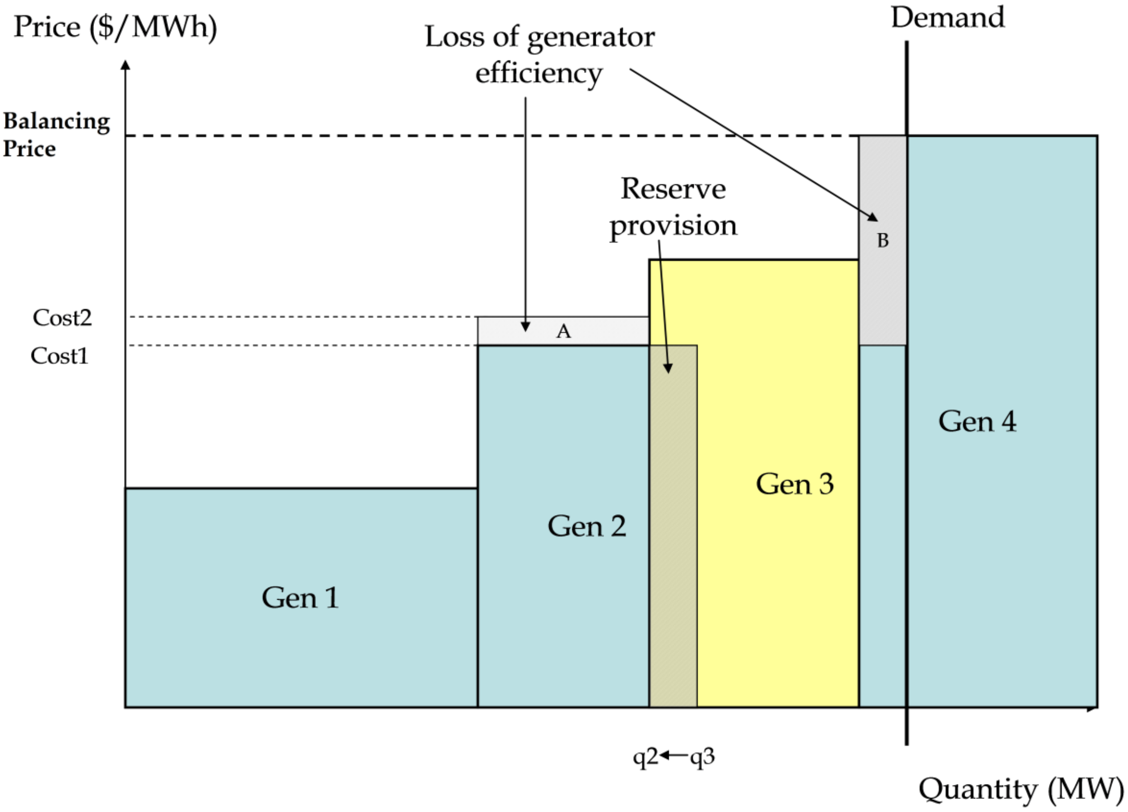
- movement to a less efficient point on a unit's heat rate curve;
- an increase in production from higher cost Synergy plant to counteract lower cost generation backed off to provide reserve;
- additional start-up costs that may be incurred due to commitment of additional units that would otherwise not 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 (i.e. with SR being provided) and comparing those outcomes to a counterfactual case (i.e. where SR is not provided). 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 SR 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

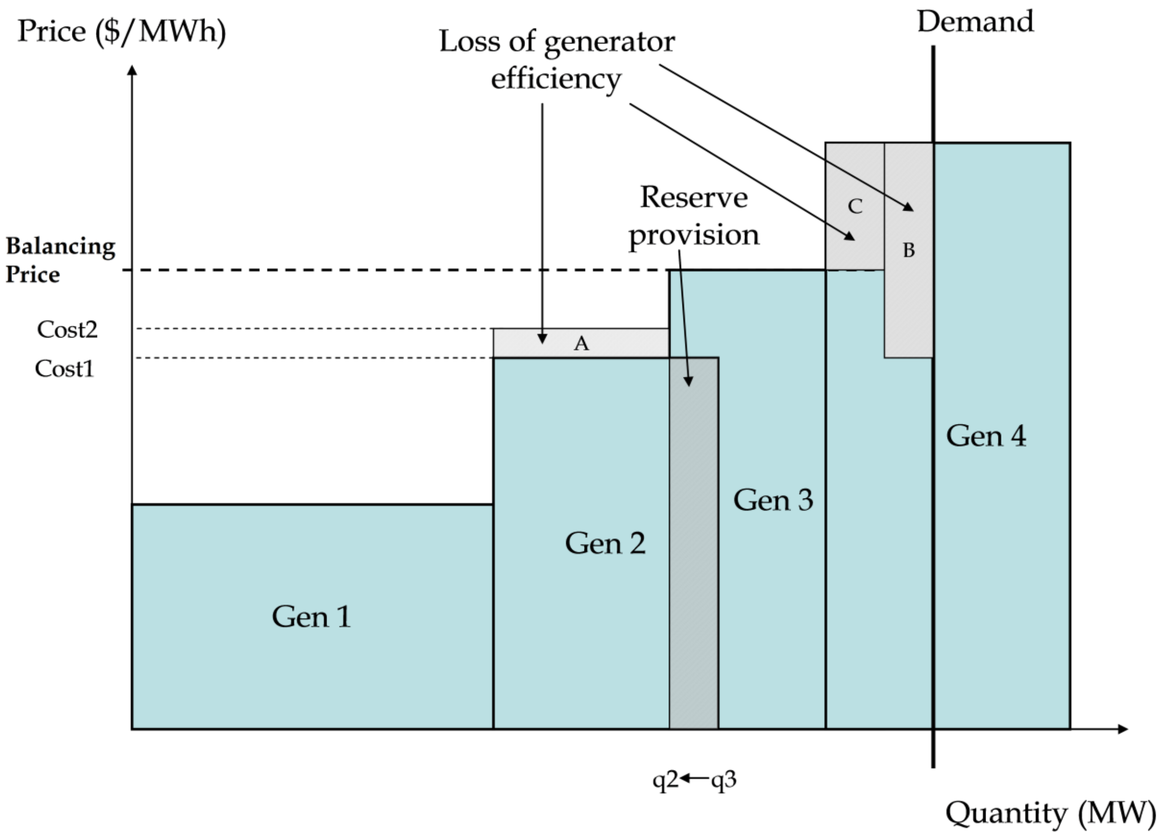
During the off-peak, some units may be constrained on at minimum generation level to meet the reserve requirements but a lower cost generator may be the marginal generator setting the price. Therefore, the availability cost could be quite high relative to the Balancing Price.

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[1]

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 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 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

[1] Load Following Ancillary Services

Base SR availability cost[2] 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)*

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 7.1.4.

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[3] in the period t:

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

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 the above formula includes LFAS raise (LFR) from all facilities, regardless of whether the LFR is eligible to

[2] That is, the availability cost of providing SR only, with no provision of LRR.
[3] In this model the Balancing Price cannot be a negative number – if it is negative then it is adjusted upwards to zero.

contribute to SR[4] (see section 8.2) 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:

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

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:

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

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 AEMO under clause 3.22.1(e) and (f). These clauses define the Ancillary Service Requirement for SR as being equal to the requirement assumed in calculating the margin values, with a different value used for peak and off-peak trading periods (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). These quantities now include an adjustment for the LFR provision of facilities that are not eligible to also contribute to SR (see section 8.2), 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 8.2.

3. Modelling the wholesale electricity market

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

- 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, 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 SWIS 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.

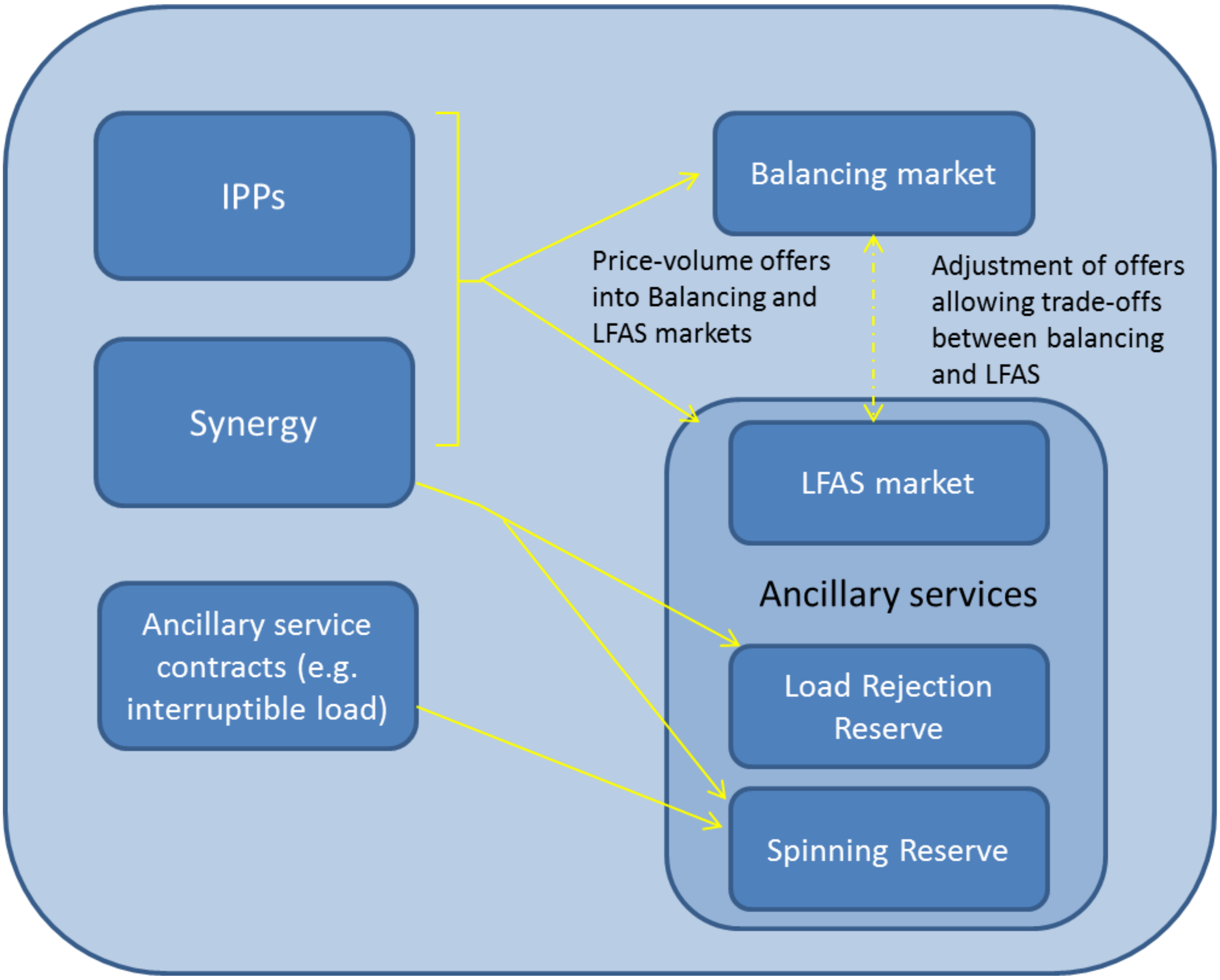
Market participants (both generators and retailers) can submit offers to sell energy to the STEM, or bids to buy energy from the STEM. Market generators may wish to buy energy from the market if the STEM price is lower than its marginal cost of generation. Alternatively, the generator may wish to sell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

AEMO is responsible for clearing the offers and bids in the STEM. The STEM price is set at the point where the STEM offer curve intersects the STEM bid curve. 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.

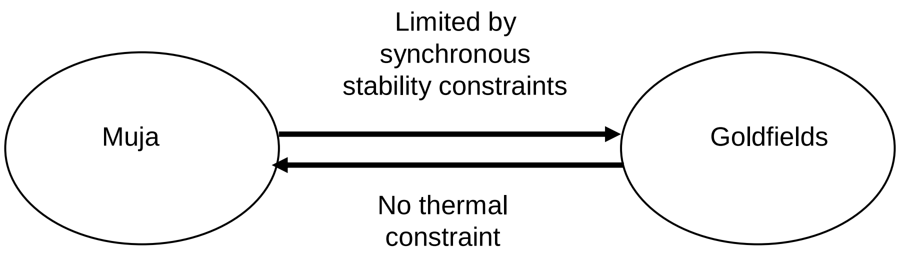
Figure 3 Balancing Market and Ancillary Service Provision



4. 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.

5. Demand assumptions

5.1 Regional demand forecasts

Table 1 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 0.3% lower than the projected 2018-19 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.

Table 1 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 1, the regional peaks are not coincident (i.e. they occur at different times). Therefore the sum of the individual peak demands is slightly higher than the total SWIS demand. Coincidence factors are derived from the 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 1. The energy and peak demand forecasts provided in Table 1 are net of AEMO assumptions on small-scale solar PV uptake. For the 2016-17 financial year[5], AEMO estimated that small-scale solar PV contributed 265 MW during the summer peak demand[6]. 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%[7]), 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 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

[5] We have presented the 2016-17 impact of rooftop PV on peak demand because this is based on actual data, not projections.
[6] AEMO, 2017 Electricity Statement of Opportunities for the Wholesale Electricity Market, June 2017, p.2.
[7] CEC, Consumer Guide to Solar PV, 19 December 2012, http://www.cleanenergycouncil.org.au/cec/resourcecentre/Consumer-Info/solarPV-guide

(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.

5.2 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.

6. Fuel assumptions

The following fuels are represented in the modelling:

- Coal: used by Muja C and D and Collie
- Vinalco coal: used by Muja A and Muja B
- 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 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.

6.1 Fuel costs

Table 2 shows our assumptions on fuel prices (exclusive of transport charges):

Table 2 Fuel prices (real June 17 dollars)

Name	Price ($/GJ)
Coal	2.90
Vinalco Coal	Confidential
Griffin Coal	Confidential
Cogeneration contract gas	2.88
Synergy contract gas	Confidential
NewGen contract gas	Confidential
NewGen contract peak gas	Confidential
Parkeston contract gas	Confidential
Goldfields Contract gas	Confidential
Perth Energy contract gas	Confidential

Name	Price ($/GJ)
New gas	5.91
Landfill gas	Confidential
Distillate	16.23

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[8], 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).[9] The estimated nominal transport cost to the Perth region is estimated to be $0.35/GJ in June 2017 dollars.[10]

6.1.1 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[11] 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.

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

[9] 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%).

[10] *Ibid.*

[11] According to Goldman Sachs in the 2016 Review

6.2 Fuel constraints

Based on our understanding of the market and historical data, we have included gas constraints limiting the contract gas daily availability.

We also included some constraints on the total gas available in different locations. Where possible, these figures have been obtained from the capacities standing data listed in the Western Australia Gas Bulletin Board[12]. Otherwise, the figures correspond to estimates from historical dispatch data and fine-tuned in our PLEXOS model during previous SWIS back-casting exercises.

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

7. General assumptions

7.1 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. 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 3: Proposed generator retirements

Time period	Generator(s)
30 September 2017	Muja A & B 2 units out of 4 (120 MW)[13]
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)[14]

7.1.1 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[15].

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

[13] 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.

[14] 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.

[15] 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.

7.1.2 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.

7.1.3 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[16].

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

[16] 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 example for the 2013 review Vinalco provided updated heat rate, fuel price and VO&M cost values for its facilities.

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 2014-14 data is not available.

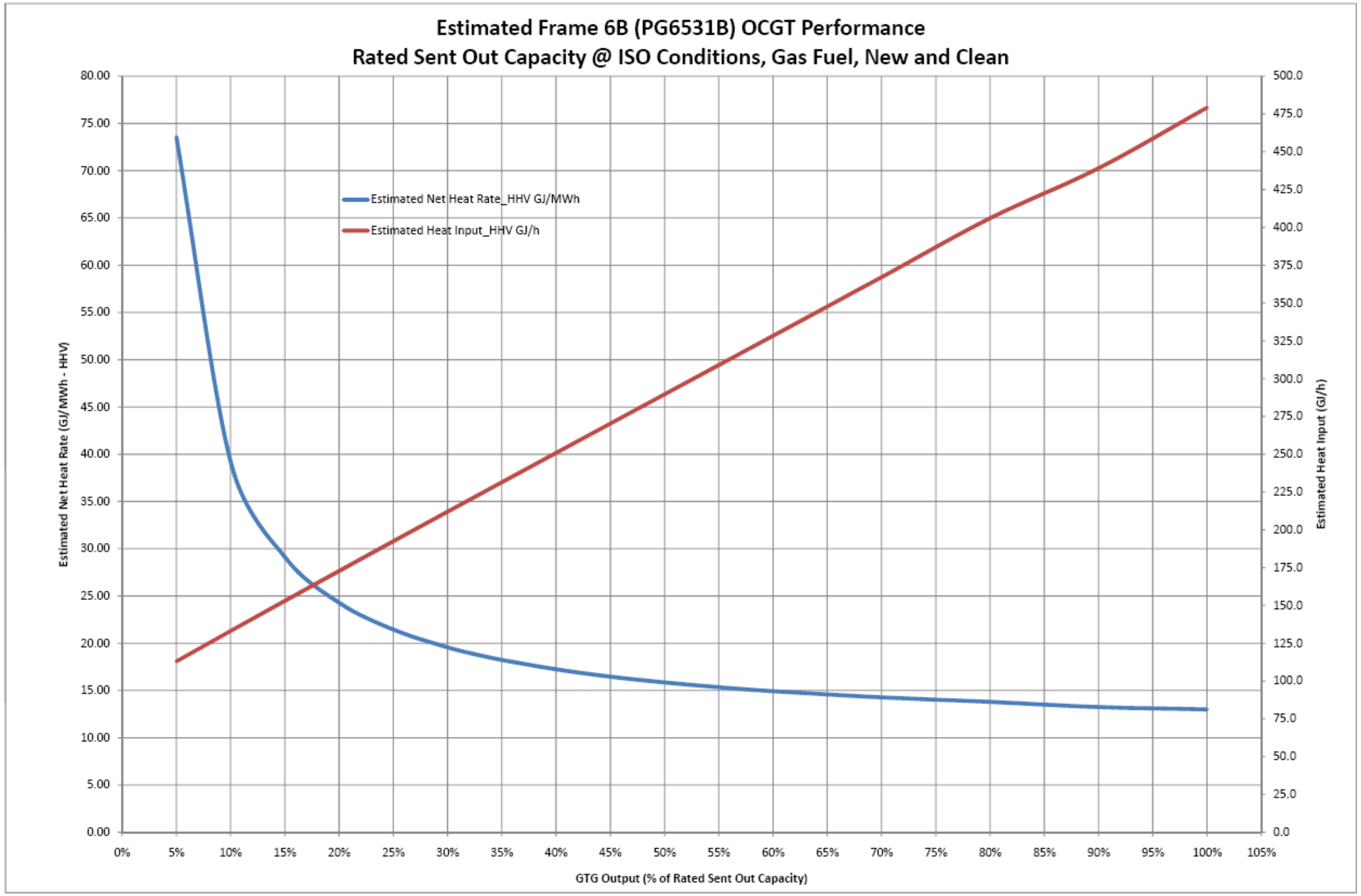
7.1.4 Heat rates

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[17]. 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.

[17] 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.

7.1.5 Kwinana NewGen

The Kwinana NewGen 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.

7.2 Future generators

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

8. 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.

8.1 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.

8.2 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 is therefore reduced by the amount of LFAS that is being provided. The exceptions to this include any LFAS that is provided by Cockburn CCGT[18] and NewGen Kwinana CCGT[19]. Both facilities have been granted primary frequency control exemption under the Technical Rules and have been confirmed by System Management as ineligible to provide spinning reserve service. This has resulted in Cockburn CCGT's and NewGen Kwinana CCGT's control system configuration being unable to automatically respond to changes in system frequency other than to LFAS quantities.

Based on the estimate of the LFAS requirement provided in System Management's Ancillary Service Report for 2016[20], for the 2017-18 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.

8.3 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 can also be available for LRR, with the exception of Cockburn CCGT and NewGen Kwinana CCGT.

Only Synergy units are able to provide LRR directly, although LFAS lower contributes to meeting the LRR requirement. The amount of LRR required in any time period t is as follows:

[18] Primary frequency control exemption under clause 1.9.4(a) of the Technical Rules as at December 2016 - https://www.erawa.com.au/cproot/14411/2/EDM%2040518689%20-%20TECHNICAL%20RULES%201ST%20AUGUST%202016%20PUBLISH%20VERSION%20-%20FRI%20-%20R....pdf

[19] Primary frequency control exemption granted by Western Power - https://www.erawa.com.au/cproot/14495/2/WPs%20Technical%20Rules%20Exemption%20from%201%20July%20to%2030%20September%202016.PDF

[20] https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Data/-/media/9B95C6BE952746FCACDAA686A6427303.ashx.

LRR = 120MW – (72MW – Cockburn_LFAS_provision_t– NewGen CCGT_LFAS_provision_t[21])

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[22] parameter covers the payment to a market generator for the costs of providing the LRR Service and System Restart Service.

8.4 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. It is understood that one long-term contract and two short-term contracts will be in place for FY 2018-19. The long-term contract is for the provision of 42 MW of interruptible load. One short-term contract is for an additional 13 MW of interruptible load, and the other is a 13 MW contract with one of the IPPs.

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.

[21] If a contract is in place with System Management to ensure that provision of LRR services from NewGen Kwinana CCGT meets system standards then this term will be zero.
[22] https://www.erawa.com.au/electricity/wholesale-electricity-market/determinations/ancillary-services-parameters/load-rejection-cost_lr

8.5 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*[23]).

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 8.2). 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.

8.6 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.

[23] If a contract is in place with System Management to ensure that provision of SR services from NewGen Kwinana CCGT meets system standards then this term will be zero.

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)[24] 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[25]. 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[26] 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

[24] The Perth Consumer Price Index (All Groups) published by the Australian Bureau of Statistics is referred to in this report as Perth CPI.
[25] 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.
[26] 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[27] 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 4.

Table 4 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

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

- 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[28].

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 5.

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 5 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[29]
Cockburn	DBNGP T1		0.15	1.79	1.05
Perth Energy	DBNGP T1		0.15	1.79	1.05

[28] 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.

[29] 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[30]
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

[30] NewGen Kwinana CCGT provided its actual transport charge for the 2016 review.