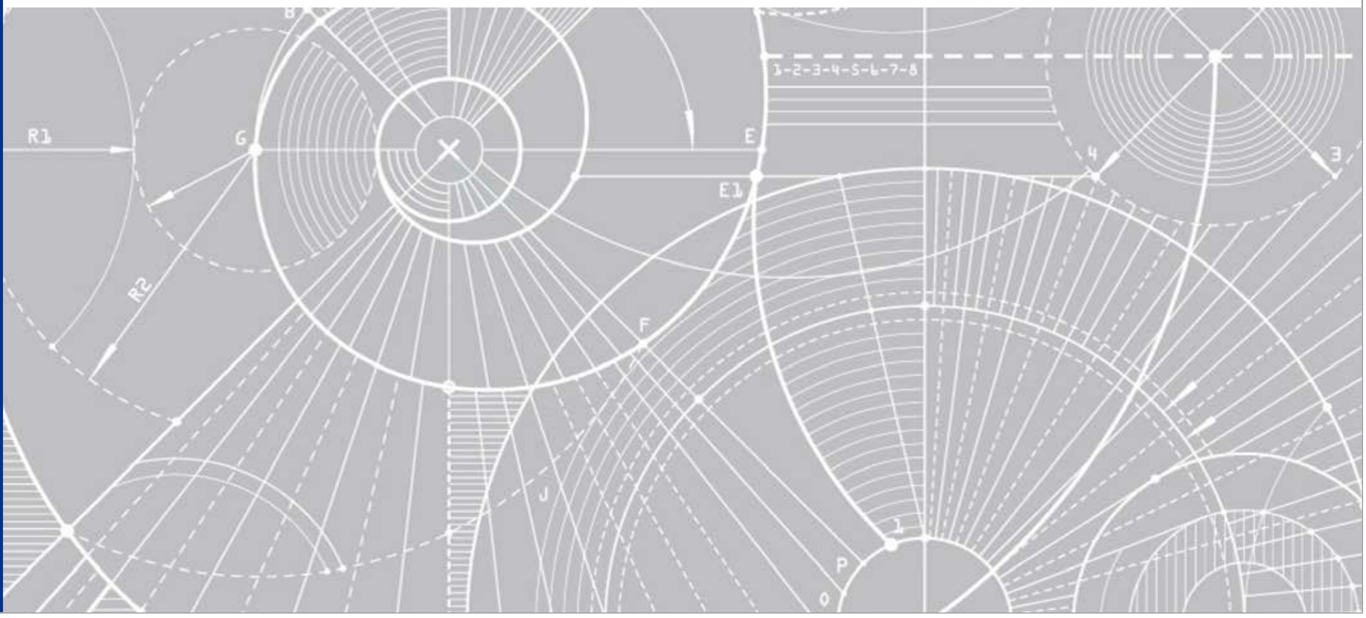
Energy Price Limits for the Wholesale Electricity Market in Western Australia

AUSTRALIAN ENERGY MARKET OPERATOR

Final report

1.1

8 June 2018



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Project no:	RO115800
Document title:	Final report
Document no:	1.1
Date:	8 June 2018
Client name:	Australian Energy Market Operator
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File name:	RO115800 Jacobs 2018 Energy Price Limits Review Final v1.1

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Executive Summary

Energy Price Limits are the price ceilings of the Wholesale Electricity Market (WEM) for offers submitted by Market Generators into the Short Term Energy Market (STEM) and the Balancing Market. There are three types of Energy Price Limits called the Maximum STEM Price, the Alternative Maximum STEM Price and the Minimum STEM Price. The Maximum STEM Price applies to Facilities that are not running on liquid-fuel, and as such it is determined by assessing the cost of gas-fired generation. The Alternative Maximum STEM Price is higher[1] than the Maximum STEM Price because it applies to Facilities running on liquid fuel and is determined by assessing the cost of distillate-fired generation. The Minimum STEM Price is fixed at -$1,000/MWh and is not being reviewed in this study.

Once a year, the Australian Energy Market Operator (AEMO) is required to review the Energy Price Limits in the WEM. The formula for calculating the Energy Price Limits is stated in the Market Rules as:

(1 + Risk Margin) x (Variable O&M + (Heat Rate x Fuel Cost))/Loss Factor

Where:

i. Risk Margin is a measure of uncertainty in the assessment of the mean short run average cost for a 40 MW open cycle gas turbine (OCGT) generating station, expressed as a fraction;

ii. Variable O&M is the mean variable operating and maintenance cost for a 40 MW OCGT generating station expressed in $/MWh, and includes, but is not limited to, start-up related costs[2];

iii. Heat Rate is the mean heat rate at minimum capacity for a 40 MW OCGT generating station, expressed in GJ/MWh;

iv. Fuel Cost is the mean unit fixed and variable fuel cost for a 40 MW OCGT generating station, expressed in $/GJ; and

v. Loss Factor is the marginal loss factor for a 40 MW OCGT generating station relative to the Reference Node.

The Market Rules state that the above variables should be determined for "a 40 MW open cycle gas turbine generating station". Previous analysis of Energy Price Limits has shown that the Pinjar[3] 40 MW gas turbines (GTs) have the highest cost for short dispatch periods and the Parkeston aero-derivative gas turbines are the next most costly to run for peaking purposes.

In May 2017, Synergy announced[4] it would retire four generation assets in order to meet the terms of the direction handed down last year by the state government to reduce its generation cap to a total of 2275 MW. The announcement noted that the Mungarra gas turbine units 1, 2 & 3 (113 MW) would retire on 30 September 2018. Jacobs has modelled the cost of Mungarra operating in peaking mode and has found that it would have set the price if it was in consideration. However, Mungarra will be operating in peaking duty for only part of the 2018-19 financial year and will not be operating over the Hot Season (December to March) when peaking operation is most likely to occur. Accordingly, this report has considered Pinjar and Parkeston setting the 2018-19 Energy Price Limits.

Jacobs was engaged by AEMO to assist with the 2018 review of the Energy Price Limits. This assignment was conducted in a similar fashion to that conducted by Jacobs in 2017. Jacobs' methodology in assessing the above formula hinges on the fact that uncertainty surrounds all of the variables in the above Energy Price Limits formula, with the exception of the Loss Factor, which is a fixed number that is known in advance. Jacobs's approach is to represent the uncertainty around each variable with an appropriate probability distribution, and then perform Monte Carlo simulations which yield a distribution of output prices.

[1] Historically the price of gas has always been lower than the price of distillate – this could theoretically change if there is a shortage of gas in the WA market, although such a scenario would most likely be short-term in nature.
[2] Note that according to the Economic Regulation Authority's (ERA's) definition, the short-run marginal cost (SRMC) of a plant does not include start-up costs: https://www.erawa.com.au/cproot/6316/2/20080111%20Short%20Run%20Marginal%20Cost%20-%20Discussion%20Paper.pdf. However, we are including a start-up cost component in calculating the Energy Price Limits because an explicit provision for this is included in clause 6.20.7(b) (ii) in its definition of the VO&M cost.
[3] In this report, unless otherwise stated, a reference to the Pinjar units or to Pinjar is referring to Pinjar units 1 to 5 and Pinjar 7 as these are the units satisfying the 40 MW requirement as stated in clause 6.20.7(b). The larger Pinjar machines (units 9, 10 and 11), which are about 120 MW in size, are excluded from this reference.
[4] https://www.synergy.net.au/About-us/News-and-announcements/Media-releases/Synergy-to-Reduce-Generation-Capacity-by-380-MW

The Energy Price Limit for the Maximum STEM price is chosen as the 80th percentile of the output price distribution, where an appropriate gas price distribution has been used to represent the fuel cost. The Risk Margin is an output of this assessment and is chosen to be the difference between the mean and the 80th percentile of the output price distribution.

A slightly different approach is used to determine the Alternative Maximum STEM price compared to the determination of the Maximum STEM price. The 80th percentile cost of the above formula is calculated for a fixed distillate price over all Monte Carlo samples, and this calculation is repeated over an appropriate range of distillate prices. This enables a regression equation to be determined with a fuel independent (“non-fuel”) component plus a “fuel” cost component that is proportional to the net ex terminal distillate price. Each month the Alternative Maximum STEM price is determined by substituting the current net ex terminal distillate price into the regression equation.

For the 2018 review, Jacobs has:

- Continued with the basis for setting the Energy Price Limits as applied in 2017;
- Reviewed and addressed the ERA’s recommendations captured in its 2017/18 Energy Price Limits decision[5] (more detail provided in section 3.4).
- Reviewed and addressed recommendations made by the Secretariat of the ERA (more detailed provided in section 3.4).
- Revised the previous treatment of start-up cost methodology and cost uncertainty to better reflect the time value of money with respect to start-up costs.
- Revised the effective annual starts distribution used for the Pinjar machines, taking better account of the impact of low-load starts on the maintenance cycle.
- Updated the O&M costs for operating 40 MW gas turbines for both the industrial and aero-derivative types by accounting for movements in the cost of parts for both turbine types, foreign exchange rates and applying CPI cost escalation;
- Retained assumptions on average heat rates at maximum and minimum capacity from the 2017 review;
- Used the same approach in projecting the gas price distribution relative to last year’s review;
  - The gas price projection was based on the historical maximum monthly spot gas price time series, but was not adjusted to account for any other price factors;
- Used the following gas pricing parameters deemed applicable to the spot purchase and transport of gas for peaking purposes:
  - Defined the daily load factor to have an 80% confidence range between 80% and 98% using a truncated lognormal distribution, with a mean value of 89.9%, and a most likely value of 95.0%;
  - Sampled from the gas commodity cost distribution between $2/GJ and $19.6/GJ[6] with an 80% confidence range of $1.80/GJ to $6.20/GJ, a mean value of $3.99/GJ and a most probable value of $4.00/GJ;
  - Used a lognormal distribution of spot gas transport cost to the Perth area between $1.00/GJ and $3.00/GJ with an 80% confidence range between $1.51/GJ and $2.22/GJ, a mean value of $1.848/GJ and a mode of $1.805/GJ;
- Used historical market observations from the 2013 to the 2017 calendar years to estimate distributions for starting frequency, average run time, generation per Dispatch Cycle and minimum capacity for Pinjar and Parkeston;
- Used the standard deviation of daily Perth ex Terminal price (rather than daily Singapore gas oil prices) to assess the variation in distillate price. The uncertainty and level of the distillate price is relevant to the extent that it is used to cap the extreme spot gas prices at the level where the Dispatch Cycle cost would be equal for gas and for distillate firing for the nominated gas turbine technology and location. Hence

[5] Available at https://www.erawa.com.au/cproot/18283/2/2017%20Energy%20Price%20Limits%20Decision.pdf

[6] Note that the maximum gas price was simulated up to a break-even price with the use of distillate in the generation plant assuming dual fuel capability.

variation in distillate price is used in determining the Maximum STEM Price, not the Alternative Maximum STEM Price.

- Continued basing the analysis on 10,000 Monte Carlo samples, as this yields a narrower standard error of estimated quantities by a factor of 3.16 relative to the analyses performed prior to 2016.

Exec Table 1 shows the calculation of the Energy Price Limits in accordance with the formula defined in clause 6.20.7(b) of the Market Rules.

Exec Table 1 Summary 2018 Parameters defined in Clause 6.20.7 (b)

Component	Units	Maximum STEM Price	Alternative Maximum STEM Price
Mean Variable O&M	$/MWh	$129.59	$129.59
Mean Heat Rate	GJ/MWh	19.225	19.277
Mean Fuel Cost	$/GJ	$6.31	$18.23
Loss Factor		1.0322	1.0322
Before Risk Margin 6.20.7(b) [7]	$/MWh	$243.07	$466.00
Risk Margin added	$/MWh	$58.93	$67.00
Risk Margin Value	%	24.2%	14.4%
Assessed Maximum Price	$/MWh	$302	$533

Exec Table 2 summarises the prices that have applied since July 2012 and the subsequent results obtained by using the various methods. New values are rounded to the nearest dollar which is consistent with previous practice.

Exec Table 2 Summary of price cap analysis

No.	History of proposed and published prices	Maximum STEM Price ($/MWh)	Alternative Maximum STEM Price ($/MWh)	Comment
1	Published Prices from 1 July 2012	$323	$547	From AEMO website.
2	Published Prices from 1 July 2013	$305	$500	From AEMO website
3	Published Prices from 1 July 2014	$330	$562	From AEMO website
4	Published Price from 1 July 2015	$253	$429	From AEMO website
6	Published Price from 1 July 2016	$240	$346	From AEMO website
7	Published Price from: • 1 October 2017 for Maximum STEM Price • 1 June 2018 Alternative Maximum STEM Price	$351	$604	From AEMO website[8]
8	Proposed price to apply from 1 July, 2018	$302	$533	Based on $17.88/GJ for distillate, ex terminal.
9	Probability level as Risk Margin basis	80%	80%	

Notes: (1) In row 8, as required in clause 6.20.7(b) these are the proposed price caps to apply from 1 July 2018 based on a projected Net Ex Terminal wholesale distillate price of $1.104/litre excluding GST ($17.88/GJ).
(2) In row 9, the probability levels that are proposed to be applied to determine the Risk Margin for setting the price caps in accordance with the Market Rules.

[7] Mean values have been rounded to the values shown in the Table for the purpose of this calculation.
[8] https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Data/Price-limits, last accessed 23 May 2018.

The recommended values are $302/MWh for the Maximum STEM Price and $533/MWh for the Alternative Maximum STEM Price at $17.88/GJ Net Ex Terminal distillate price (i.e. net of excise rebate and excluding GST).

The price components for the Alternative Maximum STEM Price are:

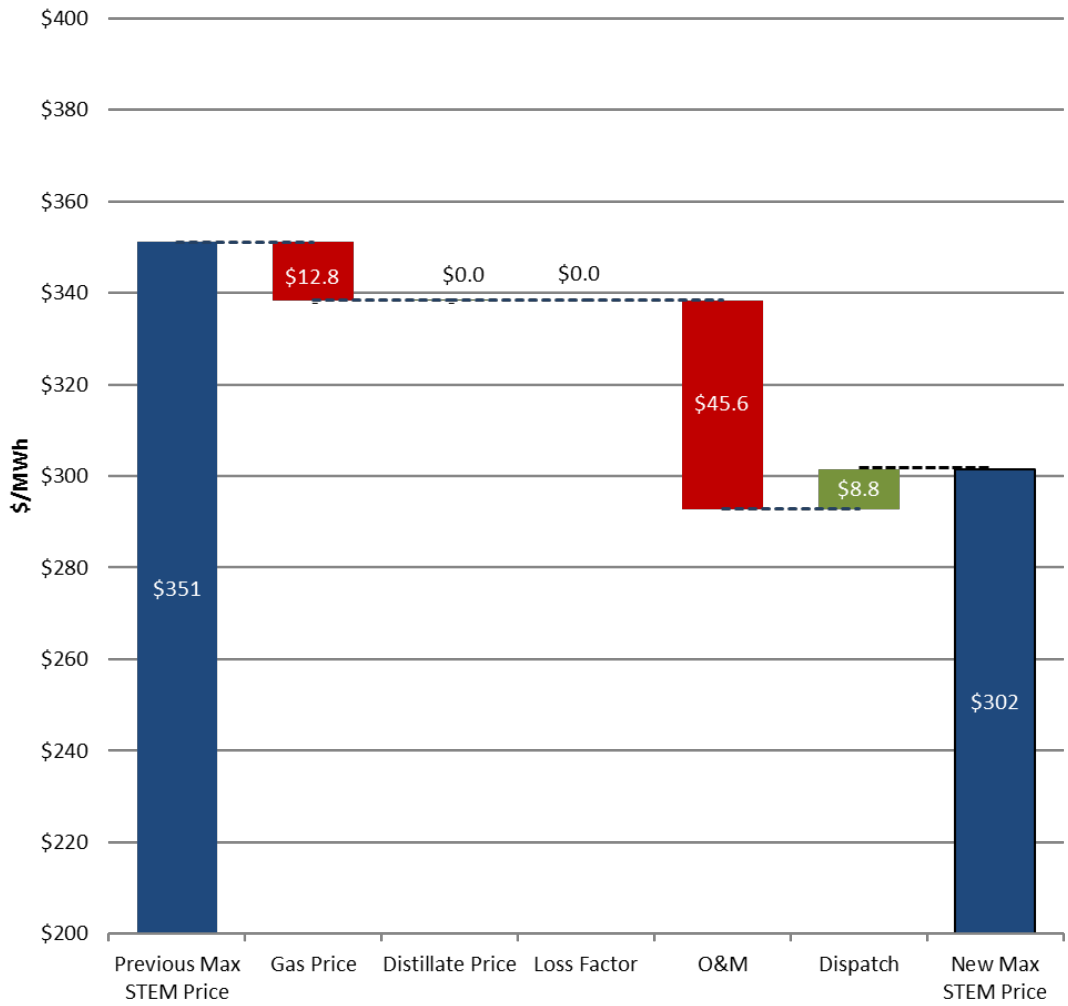
> $189.27/MWh + 19.211 multiplied by the Net Ex Terminal distillate fuel cost in $/GJ.

The largest factor accounting for the movement in the Maximum STEM Price since last year's assessment is the downward change in the O&M cost. The decrease in the O&M cost is primarily driven by a change in the calculation methodology for the start cost. One of the contributing factors to the lower start cost is that major maintenance items are assumed not to be incurred if they occur in the last two to three years of the plant's life. The other factor is that average factored starts have been calculated to be 0.84 starts per market start for Pinjar, whereas in last year's analysis 1.2 starts were used. The lower average factored start rate reduces the start cost because it defers maintenance.

In addition to the change in the O&M cost, there are two secondary factors that explain the change in the Maximum STEM Price. These factors move in different directions and almost cancel themselves out. The factor with the next largest impact is the change in the average gas price, which also has a negative cost impact. The forecast gas price has decreased from $4.66/GJ in last year's review to $4.02/GJ in this year's review due to a state of oversupply in global LNG markets and oversupply in the WA gas market. The next largest difference in magnitude is the change in the dispatch characteristics of the Pinjar plant over the 2017 calendar year. This has a positive impact on the price because Pinjar's dispatch reduced over the 2017 calendar year, and therefore the start cost needs to be recovered over a smaller volume of energy.

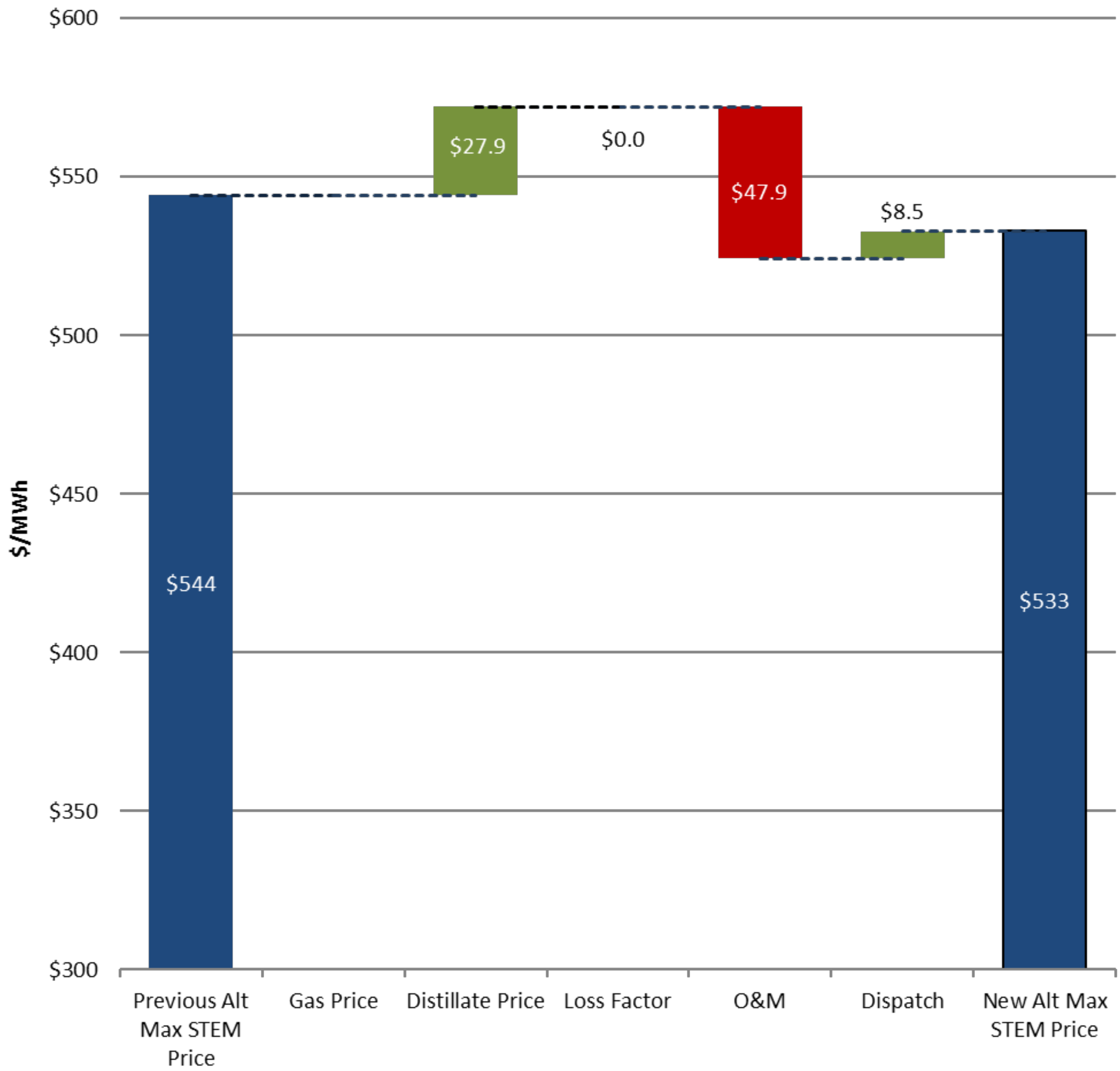
The contributions to the change in the Maximum STEM Price relative to last year's analysis are illustrated in the waterfall diagram in Exec Figure 1.

Exec Figure 1 Impact of factors on the change in the Maximum STEM Price since 2017



The decrease in the Alternative Maximum STEM Price is primarily due to the change in the calculation methodology for the start cost which reduces the O&M cost, as described above, and the increase in the distillate price, which reduces the impact of the reduction in the O&M cost. The change in the dispatch characteristics of Pinjar have a second order impact, which is similar in magnitude to their impact on the Maximum STEM Price. The contributions to the change in the Alternative Maximum STEM Price relative to last year's analysis are illustrated in the waterfall diagram in Exec Figure 2.

Exec Figure 2 Impact of factors on the change in the Alternative Maximum STEM Price since 2017



Definitions

To assist the reader this section explains some of the terminology used in this Report.

Term	Explanation
Dispatch Cycle cost	This term is used to describe the parameter calculated to determine the Energy Price Limits. It is the total cost of dispatch of a start-up and shut-down cycle of a peaking gas turbine divided by the amount of electrical energy in MWh generated during the Dispatch Cycle.
Break-even gas price	In simulating the gas price distribution, the delivered gas price was reduced if necessary to make the sampled value of the Dispatch Cycle cost equal to the Dispatch Cycle cost for running on distillate, allowing for the impact on relative operating costs and thermal efficiency on both fuels. It was not based on the equivalent heat content of distillate alone.
Carbon price	The previous federal government legislated a carbon pricing mechanism from 1 July 2012 with an initial carbon price of \$23/t CO_2e, a price from 1 July 2013 of \$24.15/ t CO_2e and a price from 1 July 2014 of \$25.40/ t CO_2e. The current federal government repealed this legislated carbon price effective from 1 July 2014.
Dispatch Cycle	The process of starting a generating plant, synchronising it to the electricity system, loading it up to minimum load as quickly as possible, changing its loading between minimum and maximum levels to meet system loading requirements, running it down to minimum load and then to zero for shut-down.
Energy Price Limits	The Maximum STEM Price and the Alternative Maximum STEM Price as specified in the Market Rules.
Heat Rate	Is a measure of the efficiency of a power plant that converts fuel into electricity. In this report, heat rate measures how many gigajoules (GJ) of fuel (expressed in terms of higher heating value) is required to produce one megawatt-hour (MWh) of electricity. The heat rate of a power plant is usually a function of the plant's power output.
Loss Factor	Loss factors in this report refer to transmission loss factors that are calculated each year by AEMO for each power station in the WEM. These loss factors are fixed for any given year and quantify the average marginal losses for power injected by the power station into the transmission network relative to the regional reference node, which in the case of the WEM is the Muja node.
Margin	The difference between the price caps as set by AEMO and the expected value of the highest short run costs of peaking power.
Market Dispatch Cycle Cost Method	A method for calculating the fuel consumption over a dispatch period of a peaking gas turbine that represents various levels of loading consistent with a specified capacity factor. This is an alternative method to specifying a particular heat rate basis irrespective of dispatch conditions.
Market Rules	The Western Australian Wholesale Electricity Market Rules (WEM).
Net Ex Terminal Price	Wholesale price for distillate in Perth, Western Australia, after deduction of excise rebate and excluding GST. This price does not include road freight costs.
O&M	Operating and maintenance costs encompass both non-fuel expenses incurred for the ongoing operation of the plant, and also expenses relating to ongoing maintenance of a power station. These costs are typically categorised as fixed costs and variable costs.
O&M Variable	Variable operating and maintenance costs are the variable cost component of the operating and maintenance costs of a power station. These costs increase as the amount of electricity produced increases, and in this report they also include start costs, as specified in clause 6.20.7(b) ii of the Market Rules.
Risk Margin	The difference between the price caps as set by AEMO and a function of the expected values of variable O&M costs, heat rate and fuel cost as specified in clause 6.20.7(b) of the Market Rules. The Risk Margin is intended to allow for the uncertainty faced by AEMO in setting the price caps, or (in the case of the Alternative Maximum STEM price) its fuel and non-fuel price components.
Short run marginal cost (SRMC)	The additional cost of producing one more unit of output from existing plant. In the context of this report it refers to the increase in the total production cost arising from the production of one extra unit of electricity and is measured in dollars per megawatt hour (\$/MWh).

Term	Explanation
Short run (average) cost	The cost of starting a generating unit, running it to produce electricity for a short period of time (usually less than 6 hours) and then shutting it down divided by the amount of electricity produced during that period of operation. This is measured in $/MWh.
Short Term Energy Market (STEM)	A day ahead contract market that is operated by AEMO, to allow buyers and sellers of electricity to adjust their contract positions on a day to day basis to allow for variations in demand and plant performance and to reduce exposure to the Balancing Market arising from mismatch between supply (for generators) or demand (for retailers) and their contract position.
Synchronisation	Refers to the point in time when a generating unit is connected to the electricity network so that it can be subsequently loaded up to supply power to the electricity system.
Type A gas turbine maintenance	Frequent annual preventative maintenance which may only take a few days and does not require major part replacement. Such maintenance is typically undertaken after 12,000 running hours or some 600 unit starts.
Type B gas turbine maintenance	Hot section refurbishment / intermediate overhaul – typically carried out at around 24,000 running hours or 1200 starts. Major thermally stressed operating parts are often replaced.
Type C gas turbine maintenance	Major overhaul of thermally stressed and rotating parts of the gas turbine. Typically undertaken after 48,000 running hours or 2400 unit starts.
WEM	Wholesale Electricity Market as operated by AEMO.

Important note about this report

The sole purpose of this report and the associated services performed by Jacobs is to assist with the review of the Energy Price Limits to apply in the Wholesale Electricity Market for the year commencing 1 July 2018 in accordance with the scope of services set out in the contract between Jacobs and AEMO.

In preparing this report, Jacobs has relied upon, and presumed accurate, any information (or confirmation of the absence thereof) provided by AEMO 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 AEMO (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.

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1. Introduction

1.1 Review of maximum prices

As part of the market power mitigation strategy for the WEM, there are price caps which limit the prices that may be paid in the STEM and Balancing Market. The maximum price depends on whether gas or liquid fuelled generation is required to meet the electricity demand when the maximum price applies. The Alternative Maximum STEM Price is applied when gas fired generation is fully committed and liquid fuelled generation is required.

The prices that currently apply are shown below in Table 1. Further details are also available on the AEMO website: http://wa.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Data/Price-limits.

Table 1 Maximum Prices in the WEM

Variable	Value	From
Maximum STEM price	$351.00 / MWh	1 October 2017
Alternative Maximum STEM Price	$604.00 / MWh	1 June 2018

Note that the Alternative Maximum STEM Price is adjusted monthly according to changes in the three-monthly average Perth Terminal Gate Price for distillate (less excise and GST)[9].

1.2 Engagement of Jacobs

Jacobs was engaged by AEMO to assist in:

- reviewing the appropriateness of the Maximum STEM Price and the Alternative Maximum STEM Price, as required under clause 6.20.6 of the Market Rules; and
- proposing values for the Maximum STEM Price and Alternative Maximum STEM Price to apply for the year commencing 1 July 2018.

The Final 2018 Report will be derived from this Final Draft 2018 Report, now that the public consultation process has concluded[10].

1.3 Basis for review

The basis for the review of Maximum STEM prices is set out in the Market Rules as shown in Appendix A. The key elements of the process are to:

- review the cost basis for the Maximum STEM Price and the Alternative Maximum STEM Price;
- prepare a draft report for public consultation; and
- finalise the report based upon the public consultation.

The Market Rules specify a methodology in clause 6.20.7(b) related to the costs of a 40 MW gas turbine generator without specifying the type of gas turbine technology – for example aero-derivative or industrial gas turbine. The key factor is that the costs should represent the short run marginal cost of “the highest cost generating works in the South West Interconnected System (SWIS)” as per clause 6.20.7(a) of the Market Rules. The aero-derivative turbines are more flexible in operation, have lower starting costs and generally have higher thermal efficiency. The aero-derivative turbines better serve a load following regime and very short peaking duty. The industrial gas turbines are not as well suited to extreme peaking operation and therefore

[9] The Market Rules clause 6.20.3(b)i require AEMO to use the 0.5% sulphur gas oil price as quoted in Singapore, or another suitable price as determined by AEMO.
[10] No submissions were received from the public consultation.

would be expected to be the last units loaded for this purpose, if they were not already running for higher load duty.

The analysis in this report calculates the Energy Price Limits for selected actual industrial gas turbines and aero-derivative turbines and selects the highest cost unit as the reference unit.

The formula for calculating the Energy Price Limits is stated as:

(1 + Risk Margin) x (Variable O&M + (Heat Rate x Fuel Cost))/Loss Factor

Where:

i. Risk Margin is a measure of uncertainty in the assessment of the mean short run average cost for a 40 MW open cycle gas turbine (OCGT) generating station, expressed as a fraction;

ii. Variable O&M is the mean variable operating and maintenance cost for a 40 MW OCGT generating station expressed in $/MWh, and includes, but is not limited to, start-up related costs;

iii. Heat Rate is the mean heat rate at minimum capacity for a 40 MW OCGT generating station, expressed in GJ/MWh;

iv. Fuel Cost is the mean unit fixed and variable fuel cost for a 40 MW OCGT generating station, expressed in $/GJ; and

v. Loss Factor is the marginal loss factor for a 40 MW OCGT generating station relative to the Reference Node.

AEMO must determine appropriate values for the factors described in paragraphs (i) to (v) as applicable to the Maximum STEM Price and Alternative Maximum STEM Price.

1.3.1 Analysis in this report

The methodology outlined in clause 6.20.7(b) makes explicit allowance for the fact that the applicable costs that make up the estimated SRMC of the highest cost generating works are difficult to estimate. There is no single value for all operating conditions. The Maximum STEM Price, being fixed, must be set so that it provides sufficient incentive for peaking plants to provide energy to the STEM and the Balancing Market in the presence of highly variable market conditions.

In the equation in clause 6.20.7(b) Variable O&M, Heat Rate, Fuel Cost and Loss Factor are all deterministic values for which an average value can be provided; the uncertainty in the calculation of an appropriate Maximum STEM Price or Alternative Maximum STEM Price is intended to be dealt with through the concept of the Risk Margin.

The analysis in this report seeks to apply industry best practice to establish an appropriate Risk Margin.

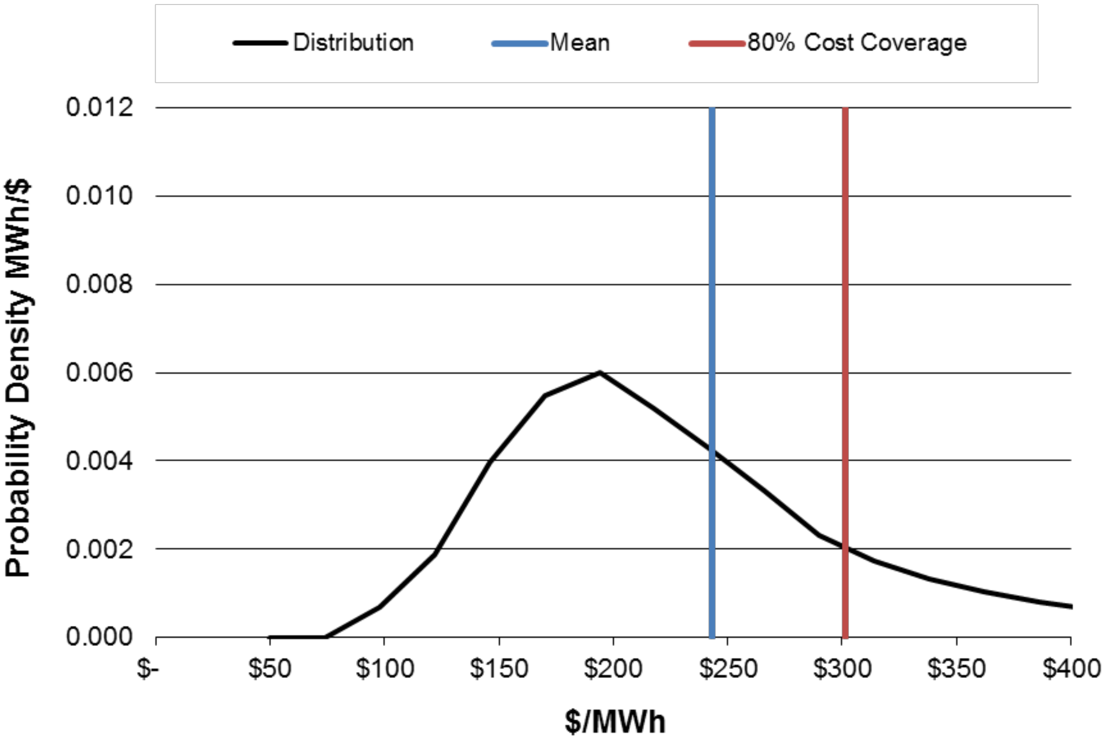
The approach taken to calculate the Risk Margin in this report (as with previous years) is to identify the likely variability in key inputs to the calculation of Energy Price Limits and model the impact that the variability in the key inputs would have on the Dispatch Cycle cost. This method results in a probability distribution of possible costs from which the recommended price limit is selected to cover 80% of the possible outcomes (representing a 20% probability that the price may be exceeded). The Risk Margin is then the percentage difference between the cost outcome that covers 80% of possible outcomes and the cost derived from the mean inputs according to the formula in clause 6.20.7(b).

This is provided diagrammatically in Figure 1 for the operating cost of the Pinjar gas turbines and based on the historical dispatch pattern of Pinjar from January 2013 to December 2017 inclusive. The charts show the density distribution as a black line, the product of the mean of the formulae inputs as the blue vertical line, and the value exceeded 20% of the time as the red line, which are the proposed Maximum STEM Prices in this instance.

Jacobs notes the probability curve used to calculate the Risk Margin is a subset of all of the possible Dispatch Cycle cost outcomes. That is, the Risk Margin is based on the 80th percentile outcome for the generation described by clause 6.20.7(b) and does not represent all of the generation that participates in the STEM. It only considers Dispatch Cycles of between 0.5 and 6 hours' duration.

Jacobs believes this approach most appropriately reflects the intent of setting Energy Price Limits for extreme peaking operation and the concept of the Risk Margin as detailed in clause 6.20.7(b).

Figure 1 Probability density for price cap calculation for highest cost generator



Further, Jacobs also notes that in using this methodology to calculate the Risk Margin, the relevant Energy Price Limits are calculated before the Risk Margin. This makes the concept of the Risk Margin an output of the calculation methodology rather than an input determining the Energy Price Limits.

JACOBS

2. Methodology

2.1 Overview

This chapter discusses the price cap methodology as it was applied in this review. Previous reports on the Energy Price Limits have thoroughly discussed the evolution of these methods.

2.2 Concepts for Maximum STEM Prices

2.2.1 Basis for magnitude of price

The estimation of the Maximum STEM Price depends on the consideration of a number of factors. There are a number of conflicting objectives in setting the Maximum STEM Price, which should be:

- low enough to mitigate market power;
- high enough so as to ensure that new entrants are not discouraged in the peaking end of the market; and
- high enough that generators with dual fuel capability (gas and liquid) do not regularly switch to liquid fuel as a result of short term gas market prices exceeding the basis of the Maximum STEM Price.

However, it is not possible to predict the particular circumstances that would define the highest cost peak loading conditions in any particular period of time. Therefore, the value that would be high enough to allow the market to operate cannot be accurately determined. A number of factors influence this calculation including plant cost and market factors. The following section discusses how this uncertainty is managed in setting the price caps.

2.2.2 Managing uncertainty

From the viewpoint of AEMO, it does not have perfect knowledge of all the possible conditions that determine the cost of generation at any particular time. Therefore, some margin for uncertainty is needed when applying the expected costs to set a price limit.

The Market Rules allow for the uncertainty of the short run average cost of peaking power to be assessed and a value to be determined that results in a price cap that exceeds the majority of potential circumstances with an acceptable probability, say 80% to 90%. This range is typical of risk margins observed in electricity markets where traders cannot accurately predict future market conditions and yet must strike a fixed price for trading purposes to manage uncertainty. The margin is applied to the expected cost to ensure that the imposition of a capped price does not impede participation of high cost generators in the market under high demand or low reserve supply conditions.

In the event that future market conditions prove that the Maximum STEM Price is constraining economic operation of peaking plant, AEMO is able to review the price settings to reflect prevailing market conditions and recommend an adjustment to the probabilities. Thus the risk that generators would be financially disadvantaged by the price cap is very low.

2.2.3 Selection of the candidate OCGT for analysis

The previous analysis of Energy Price Limits has shown that the Pinjar 40 MW gas turbines (units 1-5 and unit 7) have the highest cost for short dispatch periods and the Parkeston aero-derivative gas turbines (units 1 to 3) are the next most costly to run for peaking purposes. In this report, unless otherwise stated, a reference to the Pinjar units or to Pinjar is referring to Pinjar units 1 to 5 and Pinjar 7 as these are the units satisfying the 40 MW requirement as stated in clause 6.20.7(b). The larger Pinjar machines (units 9, 10 and 11), which are about 120 MW in size, are excluded from this reference. In the case of Parkeston all 3 of its units satisfy the requirements of clause 6.20.7(b) and therefore references to Parkeston are not ambiguous.

Pinjar and Parkeston have consistently had the highest cost for short dispatch periods since the Energy Price Limits were first determined. In the 2011 review, the Kwinana twin sets were included in the analysis and it was shown that they are very unlikely to have higher dispatch costs than the Pinjar gas turbines, and that they do not need to be considered further. There is no reason to suggest that this would change in the foreseeable future.

In this year's review the three Mungarra GTs (MUNGARRA_GT1, MUNGARRA_GT2 and MUGARRA_GT3) were flagged as possible candidates to be considered in the Energy Price Limits review. Jacobs' understanding is that these machines have the same characteristics as the Pinjar machines, however they have been excluded from previous reviews because they had in the past been operated quite frequently to provide voltage support to the Geraldton region of the grid. The commissioning of the Mid-West Energy Project, Southern Section in August 2016 has relieved network congestion between Muja and Geraldton and has also alleviated the need to operate Mungarra for voltage support. As a result, Mungarra has been operating less frequently and is now a suitable candidate to be included in the Energy Price Limits review and has been considered in this year's analysis.

Despite this, Jacobs has excluded Mungarra from this review for setting the Energy Price Limits. In May 2017, Synergy announced[11] it would retire four generation assets in order to meet the terms of the direction handed down last year by the state government to reduce its generation cap to a total of 2275 MW. The announcement noted that the Mungarra gas turbine units 1, 2 & 3 (113 MW) would retire on 30 September 2018. Jacobs has modelled the cost of Mungarra operating in peaking mode and has found that it would have set the price if it was in consideration. However, Mungarra will be operating in peaking duty for only part of the 2018-19 financial year and will not be operating over the Hot Season (December to March) when peaking operation is most likely to occur. Accordingly, this report has considered Pinjar and Parkeston setting the 2018-19 Energy Price Limits.

Jacobs has presented the analysis relating to Mungarra in Appendix E. We sought stakeholder feedback on the approach proposed for the 2018-19 Energy Price Limits during the public consultation process. AEMO did not receive any submissions in response to the draft report. Jacobs has therefore prepared the Final Energy Price Limits Report based on the information contained in the draft report. Jacobs notes that Mungarra is not presently configured for burning distillate and is only considered for the purposes of the Maximum STEM Price in this analysis.

For the reasons described above, the Pinjar 40 MW machines and the Parkeston aero-derivative gas turbines are the two candidate machines selected for analysis in this report. Mungarra's cost will also be calculated for setting the Maximum STEM Price, and the assumptions underlying the Mungarra analysis will also be explained in the body of the report. The determination of the highest cost machine is discussed further in section 2.4.

2.3 Determining the Risk Margin

The methodology in this report seeks to model the uncertainty in the calculation of the Risk Margin in a manner that appropriately covers variability in the key inputs detailed in clause 6.20.7(b) of the Market Rules. These inputs are:

- Variable O&M (Section 2.3.1)
- Heat Rate (Section 2.3.2)
- Fuel Cost (Section 2.3.3)
- Loss Factor (Section 2.3.4)

The following details the methodology by which the variability in each of these inputs is determined and the process by which these parameters are combined to determine the Energy Price Limits.

Throughout this section the text in square brackets is provided to link the methodology discussion to the variables of the operational formulae in Appendix B.

2.3.1 Variable O&M

The determination of Variable O&M costs for the candidate machines is based on engineering data available to Jacobs. These values were last reviewed in detail in the 2015 review. For this year's study, Jacobs contacted

[11] https://www.synergy.net.au/About-us/News-and-announcements/Media-releases/Synergy-to-Reduce-Generation-Capacity-by-380-MW

the manufacturers of the machines to determine the appropriate price escalation for the parts component that should be applied to last year's O&M costs. For the Pinjar industrial machines, the cost of new parts has increased by 7% over the year in nominal terms, whereas for Parkeston there has been no appreciable cost increase. In addition, Jacobs also reviewed the O&M market in the Western Australian context to determine appropriate price escalation for the labour cost component of the O&M cost.

Taking the above into consideration Jacobs has updated base maintenance costs with a correction for forex movements since then and has also applied a standard CPI cost escalation, which is appropriate for the industry. As with last year's review, Jacobs has applied the forex movement to the new parts component of the O&M cost[12], and the remainder of the O&M cost escalation has been treated as labour cost, which has been escalated by CPI.

O&M costs are incurred in the following manner:

- Type 1: Annually whether the unit is operated or not.
- Type 2: On a per start basis independent of the time the unit operates for, or loading level. [SUC]
- Type 3: On a per hour of operation basis independent of machine loading. [VHC]
- Type 4: On a per MWh basis (variable basis).

Type 1 costs above are not included in the Energy Price Limit determination as they are not considered short run costs. It is expected that such costs would be captured in the Capacity Credit payment mechanism within the market for fixed operating costs such as facility inspections, etc.

Types 2 through 4 above must be stated on a per MWh basis to meet the requirements of clause 6.20.7(b) of the Market Rules. As a result, Types 2 and 3 require conversion to a per MWh basis. This conversion is achieved by estimating how much generation is associated with each start (Type 2) or hour of operation (Type 3) as applicable. These items are dependent on the duration for which the machine is operational and how heavily loaded the machine is while it is being dispatched. These components change dramatically from machine to machine and are a key source of uncertainty in the development of the Variable O&M. To determine these items Jacobs uses the concept of the Dispatch Cycle.

As in previous years, the characteristics of Dispatch Cycles experienced by the Pinjar and Parkeston machines were determined through the analysis of historic dispatch data obtained from AEMO. This approach has also been extended to the Mungarra machines, although only the last 12 months of their operation is relevant, since before this time frame the operating characteristics of Mungarra did not primarily reflect peaking operation. This sampled dispatch data is expressed through the following variables:

- The sampled number of starts per year. [SPY]
- The sampled run time between 0.5 and 6 hours. [RH]
- The sampled Dispatch Cycle capacity factor as a function of run time. [CF]
- The sampled maximum capacity. [CAP]

The latter three variables are multiplied to determine the MWh delivered per start [MPR] which divides the start-up operating cost to give the variable O&M. This is shown in detail in Appendix B.

The number of starts per year for Pinjar and Parkeston are based on analysis of historical data from January 2013 to December 2017. For Mungarra we are using historical data from January 2017 to December 2017. The analysis of the recent dispatch patterns of these units is summarised in section 3.4.1.

[12] The total parts component of the O&M cost was estimated to be 70% of the O&M cost in last year's review. However, in this year's review we have recognised that labour cost is also a component of the repair cost of recycled parts. We have used the actual assumed parts and labour build-up of the O&M cost for the Pinjar and Mungarra machines. It was found that 45% of the O&M cost is comprised of new parts, and forex movement is therefore only applied to this component of the cost. We have applied the same factor to Parkeston since we don't have as detailed a cost breakdown for the Parkeston units.

2.3.2 Heat rate

The heat rate of the reference machines is based on data provided by the manufacturer as available in heat rate modelling software GT Pro. The heat rate characteristics for run-up and for continuous operation were reviewed and refined in the 2012 review. This data was again reviewed in the 2015 study but remains unchanged as it is identical to the information used in the 2012 review. For Mungarra, we are using identical heat rate characteristics to the Pinjar machines, since they share the same characteristics. The manufacturer data reflects that the actual heat rate of the machine varies with the following:

- Machine load
- Temperature
- Humidity
- Atmospheric pressure.

For the purpose of this report, heat rates are considered with atmospheric pressure defined at 15 m above sea level and over the range between two conditions:

- Temperature of 41°C, humidity 30%
- Temperature of 15°C, humidity 60%

The peaking dispatch of the reference machines occurs throughout the year, and therefore the variation of heat rates attributable to temperature variation has been added to the underlying uncertainty. This underlying uncertainty is modelled as having a deviation of 3%[13]. The mean heat rates were interpolated between the above reference temperature values for 25°C corresponding to the mean daily maximum temperature in Perth.

The Market Rules clause 6.20.7 (b) iii state that the Heat Rate should be determined at “minimum capacity”. The concept of minimum capacity itself has a range of associated uncertainties. From an engineering perspective a machine can for short periods be run to almost zero load. However, the associated heat rate and increased maintenance burden make this unsustainable over extended durations. Thus, to identify the appropriate minimum capacity reference Jacobs reviewed historic machine operation to determine an appropriate minimum load for the reference machines. A heat rate was then extracted from the manufacturer’s data for that loading level, as well as the sensitivity of the average heat rate to the variation in output, for modelling the uncertainty in the minimum capacity level. [AHRM]

In addition to the above, the Pinjar and Mungarra machines use material quantities of fuel during the start-up process that must be considered in the analysis. The start-up fuel is added to the total cost and included as part of the Fuel Cost term. Through this process the start-up fuel cost is converted from a fixed fuel consumption to a per MWh consumption using the Dispatch Cycle concept discussed in section 2.3.1 above. [SUFC]

The “heat rate at minimum capacity approach” is cross checked against a second methodology that establishes the heat rate of the Pinjar and Mungarra machines across the Dispatch Cycle of the particular machine and then calculates the aggregate fuel consumption to determine an average heat rate. This approach includes the fuel consumed in start-up and the modelled heat rate for the various load levels as the machine moves through the Dispatch Cycle, from start-up to shut-down. This approach is undertaken with reference to the Dispatch Cycle method discussed further in section 4.5 of this report. This method is not used to determine the recommended Energy Price Limits. Rather, it is used to confirm that the method for determining the Energy Price Limits as specified in the Market Rules is consistent with the observed pattern of dispatch, and consequently the appropriate heat rate levels.

2.3.3 Fuel cost

This report considers a modelled distribution of likely gas prices to determine the Maximum STEM Price.

[13] 3% of the heat rate at 25°C obtained by interpolating with the values at 41°C and 15°C.

Gas cost

The modelling of gas cost is based on additional analysis undertaken by Jacobs and summarised in Appendix C. Jacobs has used an ARIMA time series model for forecasting the gas price this year, which is based on historical maximum monthly gas prices. The resulting forecast distribution is normal, and its mean and standard deviation were derived from the output of the ARIMA forecast. The variance of the distribution was similar to that of last year's distribution, reflecting a similar level of uncertainty around future spot gas price movements.

Of critical importance to the setting of the Maximum STEM Price is the definition of the upper bounds of this distribution. In this report the upper bound of this distribution is defined by the gas cost that would give the same Dispatch Cycle cost as if distillate were used. This is because it is considered unlikely that the spot gas price would exceed the value of gas in displacing distillate usage in OCGTs. This situation reflects the significant capacity for dual fuelled gas turbines in the SWIS, including Pinjar. In defining this upper bound, a position must be taken on the delivered price of distillate and the quantity of distillate required to deliver the same energy as a unit of gas. The latter item is dependent on the generation technology adopted (industrial machines versus aero-derivatives) when comparing the results to determine the highest cost OCGT. [VFC] and [FSR]

Transport cost

The gas transport costs are based on analysis undertaken by Jacobs. These costs have been generally modelled as variable costs [VFTC]. For the Parkeston machines, parts of the costs had been treated as fixed costs [FT], but we have revised this approach in this year's review based on the latest review on the Goldfields Gas Pipeline (GGP). The spot gas transport cost distribution for the Dampier to Bunbury Natural Gas Pipeline (DBNGP) has increased slightly from the 2017 review due to CPI escalation (see section C.7.1.1 in Appendix C).

Daily load factor

The impact of variation in daily forecast volume error is modelled through the inclusion of a daily gas load factor [VFTCF]. This daily gas load factor is applied to the fixed transport cost [FT] and the gas cost [VFC].

2.3.4 Loss factor

The loss factor is extracted from the published loss factors for the candidate OCGTs. As this is a published figure no variability is modelled for this input; that is a single data point is used. [LF]

2.3.5 Determining the impact of input cost variability on the Energy Price Limit

For each candidate machine and for each of the variables detailed in sections 2.3.1 to 2.3.4 a range and a distribution are applied from one of the following options:

- Assume the variable is normally distributed and assign a standard deviation with the base value representing the mean, and then apply maximum and minimum limits if appropriate.
- When specific information is available from the WEM or other sources, Jacobs has analysed the information and derived a suitable probability distribution to represent the uncertainty. This method has been used to analyse run times, generation available capacity and generation capacity factors related to the Dispatch Cycle.

For each candidate machine, these distributions are used to develop a set of 10,000 input combinations to the equation detailed in Appendix B. Based on the distribution of the inputs, this equation is processed for each of this set of inputs to provide a profile of possible costs determining the Energy Price Limits. From this profile a potential Energy Price Limit is selected that covers 80% of the outcomes for that generator.

2.3.6 Risk Margin

To determine the Risk Margin associated with the Energy Price Limit the following process is adopted. The mean values of the relevant probability distributions described above are used to calculate the term

(Variable O&M + (Heat Rate x Fuel Cost))/Loss Factor

in clause 6.20.7(b) from which the Risk Margin is determined to match the Energy Price Limit. Hence the Risk Margin is calculated as:

$$\text{Risk Margin} = \frac{\text{Energy Price Limit as determined in section 2.3.5}}{\text{(Variable O\&M + (Heat Rate x Fuel Cost))/Loss Factor}} - 1.0$$

This method is consistent with the construction of the Energy Price Limits as currently defined in the Market Rules whilst providing for an objective method for defining the Risk Margin having regard to an analytical construction of the market risk as perceived by AEMO using public data.

Jacobs notes that the start-up fuel consumption [SUFC] is included in the Heat Rate input. That is the heat rate for the purposes of clause 6.20.7 (b) includes both the steady state heat rate at minimum capacity [AHRM] and a component that covers the start-up fuel consumption [SUFC]. In previous reviews, the option of presenting the start-up fuel cost in the Variable O&M input was considered; however Jacobs decided as this component was part of the fuel consumption of the machine it was best presented in the heat rate.

2.4 Determination of the highest cost OCGT

Based on the analysis outlined in section 2.3 for Parkeston and Pinjar the unit with the highest Maximum STEM Price is selected. In this year's review Pinjar was found to have the highest cost of the two candidate machines, although Mungarra's cost was found to be higher than Pinjar's. The cost of Mungarra in this year's analysis is over 50% higher than that of Pinjar, and the main driver of this outcome is its operating characteristics, which require it to spread its start cost over a smaller volume of energy.

For the reasons outlined in section 2.2.3, Jacobs has excluded Mungarra from this review for setting the Energy Price Limits. To simplify the report the calculations for Pinjar are presented in Chapter 3. The corresponding analyses for Parkeston and Mungarra are provided in Appendix D and Appendix E respectively.

2.5 Alternative Maximum STEM Price

Although the Alternative Maximum STEM Price is calculated consistently with the requirements of clause 6.20.7(b) detailed above it is recalculated monthly based on changes in the monthly distillate price. This defines the delivery of the Alternative Maximum STEM Price in this report as a function of distillate price in Australian dollars per GJ, ex terminal. It also removes uncertainty in the cost of distillate from consideration in determining the Risk Margin discussed above. In the reviews from 2014 to 2017, the road freight cost was not included in the variable fuel component of the Alternative Maximum STEM Price as this freight cost was considered to be relatively constant over a one-year period. This approach remains appropriate for the current review as the freight cost is still considered to be constant over one year.

The Lower Heating Value heat rates for industrial gas turbines and aero-derivative machines are increased by 5% for the calculation of the Alternative Maximum STEM Price to represent the operating conditions when fired on distillate. When adjusted for the ratio of lower to Higher Heating Value on the two fuels, the effective increase in Higher Heating Value is 0.27%. This factor was also applied to the start-up fuel consumption.

The Risk Margin for the Alternative Maximum STEM Price is determined by calculating the Dispatch Cycle cost that is exceeded in 80% of Dispatch Cycles of less than 6 hours for a fixed distillate price. This enables an equation to be determined with a fuel independent ("non-fuel") component plus a "fuel" cost component that is proportional to the Net Ex Terminal distillate price. This is presented in section 4.2.

The method for the selection of the non-fuel and the fuel cost factor in the formula for the Alternative Maximum STEM Price was based upon 10,000 samples of each of the two cost factors combined with a range of fixed distillate prices between $6/GJ and $36/GJ, to assess the 80% probability level of cost for each fuel price. Rather than taking the 80% probability values of the cost terms themselves, the two cost factors were derived from the linear regression fit of the 80% price versus distillate price. This function is shown with the results in Figure 8. This method ensures that the resulting cost is at the 80% probability level over this fuel cost range, given the cost and dispatch related uncertainties.

The elements which make up the non-fuel cost components for the Alternative Maximum STEM Price are shown in Appendix B.

3. Determination of key parameters

This chapter discusses the analysis of the various cost elements and how they are proposed to be used to set proposed revised values for the Energy Price Limits using their probability distributions and mean values. This section is structured to follow the cost elements as defined in clause 6.20.7(b) of the Market Rules. A summary of the operational distributions of the input variables is provided in Appendix B. More detailed information on gas prices is provided in Appendix C. Other probability distributions are described in a confidential Appendix provided to AEMO and the ERA. The calculations for Parkeston and Mungarra are presented in summary form in Appendix D and Appendix E respectively.

3.1 Factors considered in the review

In the course of this price cap review, the following items concerning the methodology have been identified. Items identified and addressed in previous years' reports have not been detailed in this report.

3.1.1 Review of operating and maintenance costs of aero-derivative and industrial gas turbines

The last detailed review of operating and maintenance costs of the Pinjar and Parkeston units was carried out in the 2015 review. An incremental review of the current market was conducted for this year's study. The first component of the review involved contacting the manufacturers for both the industrial and aero-derivative GTs to ascertain the appropriate cost escalation to be applied to new parts for these units. The manufacturers advised a 7% escalation is applicable for the Pinjar and Mungarra machines, whereas no cost escalation applied to the Parkeston units.

The second component of the review involved assessing the O&M labour market in the Western Australian context. The review found that activity in this market has been relatively muted, and as such CPI escalation for labour costs is appropriate.

Jacobs has also reviewed how it has applied forex and CPI escalation to the O&M costs. In last year's review it was assumed that 70% of the O&M cost relates to the cost of parts and 30% related to the cost of labour. However, we do have a parts and labour cost breakdown for the Pinjar and Mungarra machines[14], and in this year's review we have derived the parts/labour cost split directly from these assumptions, but also recognising that the cost of repairing parts also includes a labour cost component. For Pinjar and Mungarra it was found that 45% of the O&M cost in one full maintenance cycle is comprised of new parts, and forex movement is therefore only applied to this component of the cost. For Parkeston we have applied the same 45% assumption for the cost of new parts.

3.1.2 Review of O&M cost calculation for Pinjar and Mungarra

In this year's review a more comprehensive methodology has been used to calculate the variable O&M cost of the Pinjar and Mungarra machines, which is exclusively driven by the machines' number of starts. This method has better taken into account future cost risk associated with the maintenance of these generators and has also accounted for factored starts, based on the operation of the machines. The revised method is presented in section 3.4.2.1.

3.2 Fuel prices

3.2.1 Gas price trends

The analysis of gas prices has been based on the aforementioned additional Jacobs analysis. The recommended approach was to set gas price and transport cost on projected spot gas trading from 1 July 2018. The value of gas was based on the opportunities in the spot gas market for gas that would be used by a 40 MW peaking plant at Pinjar. The price of gas delivered to a 40 MW power station has two components: the price at the gas producer's plant gate and the cost of transmission from the plant gate to the delivery point at the power

[14] For the Parkeston units the only cost information we have available is at the aggregate level, and is based on the manufacturer's quote.

station. In this study the gas price has been estimated on the basis that the gas is sourced from the Carnarvon Basin and transported to generators in the South West via the DBNGP.

The spot market gas price, which excludes the transport component, has been based upon alternative uses, either in:

- displacing contracted gas which is not subject to take-or-pay inflexibility,
- changes in industrial processes, or
- displacing liquid fuel in power generation or mineral processing.

These alternative uses have a range of values and Jacobs has assessed a range from $1.80/GJ to $6.20/GJ as representing 80% of the range of uncertainty for the gas price forecast.

A time series forecasting approach was used to derive this distribution, which was based on the maximum monthly spot gas price. This was the same approach used in last year's modelling. Our review of the gas market in the Western Australian context (as presented in Appendix C) concluded that no other foreseeable factor is expected to have an impact on the price beyond what is encompassed by the time series forecast. Similarly to last year's review, AEMO's 2017 *Gas Statement of Opportunities* (GSOO)[15] has revised its medium term contract price forecast downwards relative to the 2016 GSOO[16] by $0.60/GJ for the 2018/19 year. While this revised forecast is assumed to take account of the commencement of Wheatstone domestic gas production facility and Woodside production from Pluto in the second half of 2018, there is a possibility that the spot price might reduce further; but there is no current evidence to substantiate this.

Gas prices are represented as a normal distribution with a mean of $4.02/GJ and a standard deviation of $1.72/GJ. A more detailed description of the methodology and assumptions underpinning the gas price forecast is discussed in Appendix C.

As described in section 2.3.3, a gas price range up to $19.6/GJ has been modelled with the gas price capped by the comparative value relative to the distillate price[17]. Jacobs has calculated a breakeven gas price for each of the 10,000 simulated Dispatch Cycles given its particular characteristics, including a cost penalty for liquid firing where applicable for industrial gas turbines[18]. The breakeven price was estimated to equalise the Dispatch Cycle average energy cost. This is preferable to capping the gas price distribution at a single level when estimating the Energy Price Limits.

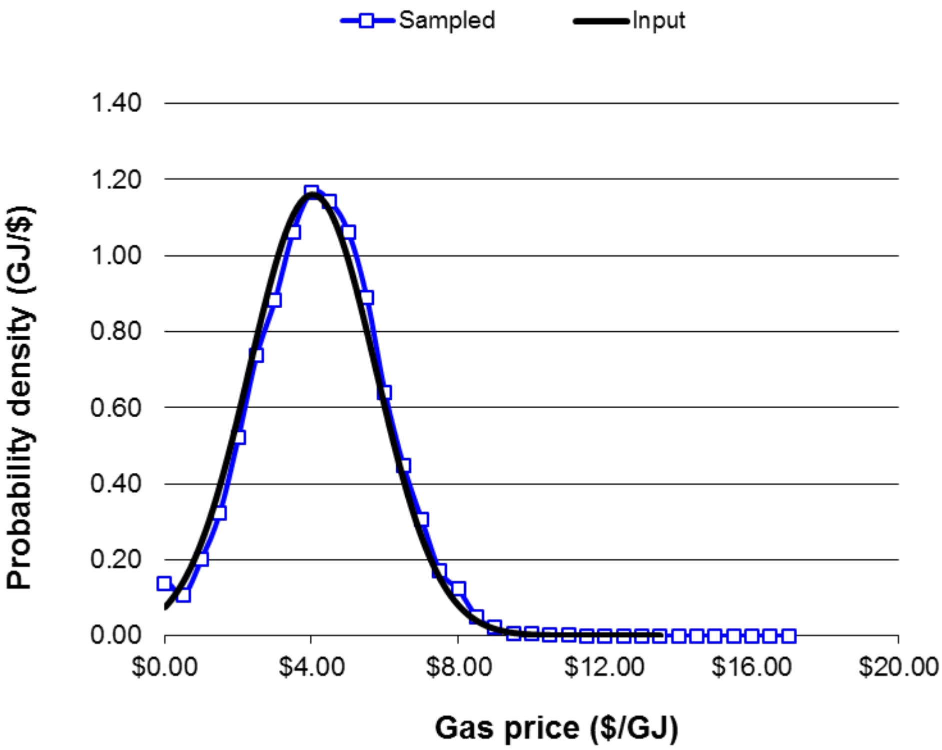
Jacobs has chosen to represent the gas price as a normal distribution up to $19.6/GJ, as shown in Figure C- 5 in Appendix C. A normal distribution was the appropriate choice as it represents the error distribution associated with the ARIMA forecast. The final normal distribution used had a mean of $4.02/GJ and a standard deviation of $1.72/GJ.

The resulting gas price distribution as sampled is as shown in Figure 2. The smooth black line represents the density function of the normal distribution for the gas price from which 10,000 samples were drawn. Some small distortions are evident in the sampled data compared to the input distribution. These are the effect of the distillate price serving as a cap on the gas price.

The sampled gas price did not exceed $10.80/GJ for the industrial gas turbine once capped by the breakeven gas price. Thus modelling the gas price initially to $19.6/GJ was sufficient. The maximum delivered gas price was $14.42/GJ to the industrial gas turbines.

[15] AEMO, Gas Statement of Opportunities for Western Australia, Dec 2017 p.65. https://www.aemo.com.au/-/media/Files/Gas/National_Planning_and_Forecasting/WA_GSOO/2017/2017-WA-GSOO.pdf
[16] AEMO, Gas Statement of Opportunities for Western Australia, Dec 2016, p.67. https://www.aemo.com.au/-/media/Files/Gas/National_Planning_and_Forecasting/WA_GSOO/2016/2016-WA-Gas-Statement-of-Opportunities.pdf
[17] The distillate price cap is discussed further in section 3.2.5 of this report.
[18] No liquid firing operating cost penalty was applicable to aero-derivative gas turbines which are designed to use liquid fuel.

Figure 2 Gas price distribution as modelled with upper price limited to the distillate equivalent



3.2.2 Gas daily load factor

Consistent with the approach adopted for last year's review, it has been assumed that, when applied to spot trading on a daily basis, the daily gas load factor is only important to the extent that it represents daily forecast volume error. For that purpose, it is modelled as having an 80% confidence range between 80% and 98% with a 95% most likely value (the mode). The continuous distribution had a mean of 97.0%, but when the maximum value of 1.0 was used to truncate the distribution, the mean value was 89.91%. Jacobs developed the lognormal distribution of Spot Gas Daily Load Factor shown in Figure C- 7. The distribution was truncated and redistributed so that there was no discrete probability of a value of 100%. This was in accordance with the methodology applied in last year's review. There is a 0.005% probability of a value at the minimum value 60%.

The effective spot price was calculated by dividing the spot price sampled from the capped distribution in Figure C- 5 by the daily load factor sampled from the capped distribution in Figure C- 7.

In the past, assessed changes to this distribution have been quite small. When the Balancing Market was introduced in 2012 this distribution did not change materially and ACIL Tasman (who carried out this assessment for the 2013 review) noted that the re-bidding process introduced by the Balancing Market did not eliminate the risk of a peaking generator over-estimating its spot gas requirement for the next day. Jacobs is not aware of any material change in spot gas arrangements relating to peaking generators in the WEM and has proceeded on the basis of the recommendation in last year's review.

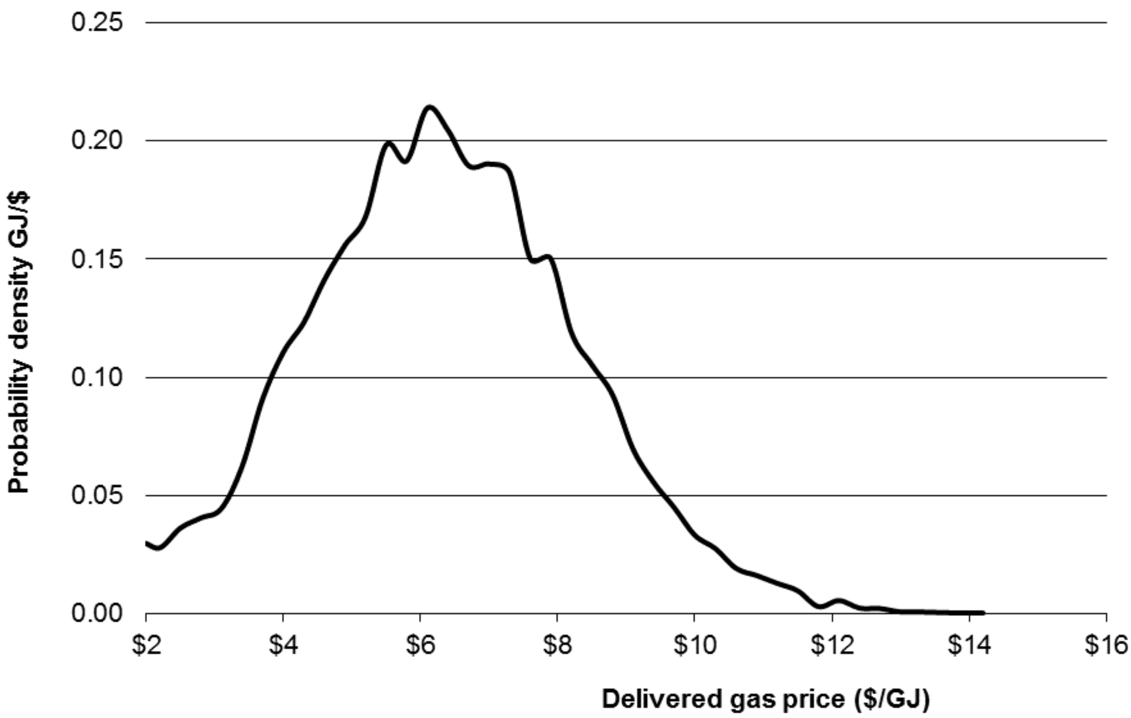
3.2.3 Gas transmission charges

In previous reviews, ACIL Tasman has recommended basing the gas transport cost on spot market conditions. This same approach was adopted for the last five reviews and for this year's review. For the transport to Perth, a lognormal distribution is recommended with the 80% confidence range being between $1.51/GJ and $2.22/GJ with a most likely value (mode) of $1.805/GJ. The mean value of the transmission charge is $1.848/GJ. Jacobs developed the distribution shown in Figure C- 6 in Appendix C to represent this uncertainty in the gas transport cost. The gas cost range was taken between $1/GJ and $3/GJ which is consistent with previous reviews.

3.2.4 Distribution of delivered gas price

The composite of the variation in the gas supply price, the gas transport price and the daily load factor applied to the gas commodity price results in the probability density for delivered gas price shown in Figure 3. The effect of this skewed distribution is to spread the effect of the capped prices and to result in a range of sampled prices as shown in Table 2 for the gas price forecast.

Figure 3 Sampled probability density of delivered gas price to Pinjar for peaking purposes



The modelled delivered gas price for the Perth region had an 80% confidence range of $3.82/GJ to $8.82/GJ with a mode of $6.10/GJ and a mean of $6.31/GJ.

Table 2 Modelled delivered base gas price distribution to Pinjar

Delivered Gas Prices as Modelled	
	Pinjar
Min	$1.29
5%	$3.05
10%	$3.82
50%	$6.28
Mean	$6.31
Mode	$6.10
80%	$7.93
90%	$8.82
95%	$9.61
Max	$13.57

3.2.5 Distillate prices

The Market Rules provide for a monthly re-calculation of the Alternative Maximum STEM Price based on assessment of changes in the Singapore gas oil price (0.5% sulphur) or another suitable published price as determined by AEMO. AEMO uses the Perth Terminal Gate Price (net of GST and excise) for this purpose, as the Singapore gas oil price (0.5% sulphur) is no longer widely used. Moreover, the Perth Terminal Gate Price includes shipping costs and so takes into account variations in these costs due to factors such as exchange rate changes. Therefore, in this analysis a reference distillate price based upon the Perth Terminal Gate Price is assessed to define a benchmark Alternative Maximum STEM Price component that depends on the underlying distillate price.

For this purpose, the uncertainty in the distillate price is not important because the Alternative Maximum STEM Price is updated monthly. However, in modelling the gas price for the Maximum STEM Price, the uncertainty and level of the distillate price is relevant to the extent that it is used to cap the extreme spot gas prices at the level where the Dispatch Cycle cost would be equal for gas and for distillate firing for the nominated gas turbine technology and location, Pinjar in this case. The following discussion describes the expected level and uncertainty in distillate price for capping the gas price.

After spending over 3 years in the $US100-120/barrel (b) range, Brent crude prices tumbled through the back end of 2014 due to global oversupply of crude (see Figure 4). In January 2016 Brent crude prices fell to just under US$32/b, the lowest monthly average price since February 2004. Prices have subsequently recovered and the average price in 2017 was US$54/b. Front-month futures prices in 2017 ranged from US56/b to $63/b and at March 1 2018 were US$63.8/b down US$5.8/b from the price at 1 February.

In the latest Short Term Outlook released in March 2018, the Energy Information Administration (EIA) has assessed that global oil inventories, declined by 0.6 million barrels a day in 2017 but are expected to grow by about 0.4 millions of barrels per day in 2018 and another 0.3 million barrels a day in 2019. The global picture appears comfortable for the next three years but supply growth slows considerably after that, according to Oil 2017, the IEA's market analysis and forecast report previously known as the Medium-Term Oil Market Report. The demand and supply trends point to a tight global oil market, with spare production capacity in 2022 falling to a 14-year low.

Last year the EIA predicted a Brent crude price of US$57/b in 2018. The March 2018 forecast is US$62/b for both 2018 and 2019. This is similar to the base price of US$60/b for modelling undertaken by the IEA in Oil2017. By contrast the oil price forecasts in the December 2017 GSOO are significantly lower at below US$45/b in 2018 and 2019 which are at below current price.

Here we refer to the crack spread as the difference between the price of ultra-low sulphur diesel (a good proxy for gas oil as specified in the Market Rules) and Brent crude. This varies with a year depending on seasonal inventories caused by (amongst other factors) heating demand. In 2017 there was a small increase but prices have subsequently fallen, and at the beginning of March 2018 were at US$0.37/gallon. While there is no explicit forward estimate of the crack spread for the purposes of this assessment it is assumed that for FY2019 there is no change from the FY2018 level.

As with past forecasts, the above forecasts are based on the assumption that there are no significant geopolitical events throughout the subject period.

Figure 4 Brent Crude price: 2007 to start of 2018

The following approach was taken to derive the reference distillate price:

- Take the average 2017 Perth Terminal Gate Price and adjust this for excise and GST to determine the underlying price
- Assume the 2017 price reflects the average global oil price of US$54/b and determine the FY19 price based on US$62/b, assuming an exchange rate of 1$AU = $US0.77
- Assume no change in crack spread
- Add in the cost of transport from the Kwinana refinery to the power stations, using the approach used in the previous review.

The outputs are shown in Table 3.

Table 3 Reference distillate prices for Pinjar and Parkeston

2019 Reference Prices	Acpl	$/GJ (at 38.6 GJ/l)
Ex Terminal price	121.4	
Ex Terminal price less excise and GST	69.0	17.88
Road transport to Pinjar	1.4	
FIS at Pinjar (ex excise and GST)	70.4	18.24
Rail transport to Parkeston	3.2	
FIS at Parkeston (ex excise and GST)	72.3	18.72

Assuming road transport from Kwinana would increase the transport charge from 3.3 Acpl to 5.39 Acpl exclusive of GST.

Over the period relevant to the Maximum STEM Price the price of distillate will vary due to fluctuations in world oil prices and refining margins. Based on the 2017 volatility in daily Perth gas oil prices (assuming prices exclusive of GST), the distillate price is assumed to have a standard deviation of about 4.2 Acpl. This translates to $1.10/GJ. This standard deviation is lower than was applied in previous 2013 and 2017 reviews ($1.36/GJ and $2.88/GJ in 2013 and 2017 respectively). It is considered this is due to a lower volatility in Perth prices compared to Singapore.

For this review, in capping the gas price the distillate price has been modelled as a normal distribution with a standard deviation of $1.10/GJ. A mean price of $18.2/GJ has been applied in the Perth region for Pinjar. The standard deviation in the distillate price indicates that the sampling range for the price of distillate used to cap the gas price will be narrower than that of the 2017 review. The higher price of distillate, relative to last year's review, will tend to increase the cap on the gas price.

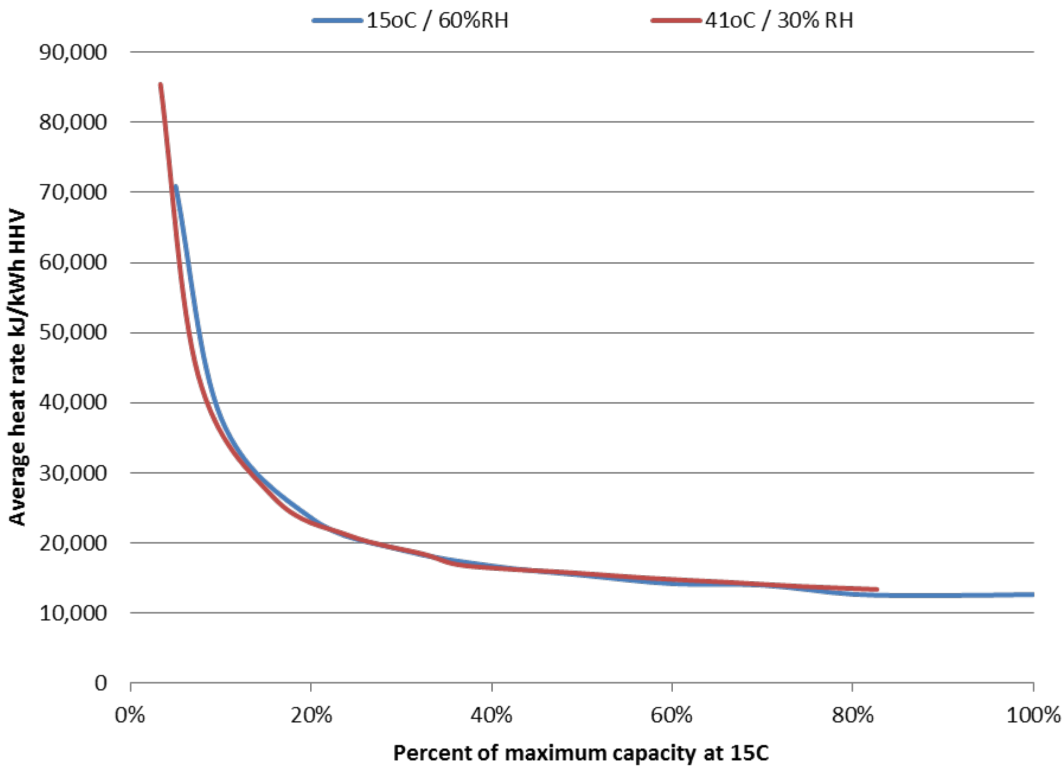
3.3 Heat rate

3.3.1 Start-up heat consumption

The start-up heat consumption was estimated by Jacobs as 3.50 GJ for the industrial gas turbine based on the Pinjar facility characteristics. An additional 5% of heat energy was allowed for start-up on distillate at Lower Heating Value which equates to 0.27% at Higher Heating Value. A 10% standard deviation was applied to these values with a normal distribution limited to 3.2 standard deviations.

Figure 5 shows the run-up heat rate curve applied for the industrial gas turbine to calculate the energy used to start the machine.

Figure 5 Run-up Heat rate curve for industrial gas turbine (new and clean)



3.3.2 Variable heat rate curve for dispatch

Table 4 shows the steady state heat rates that were applied for the industrial gas turbine. They were increased by 1.5% to represent typical degradation from new conditions. The temperature sensitivity of the heat rates was estimated from the run-up heat rate curves, and was less than 1% over the range 15°C to 41°C.

Table 4 Steady state heat rates for new and clean industrial gas turbines (GJ/MWh HHV)

		% site rating			
Temp	**Humidity**	**100%**	**50%**	**33%**	**25%**
15°C	30%	12.990	15.843	18.711	21.438

The minimum load position has been extracted from the sampled data and the corresponding heat rate at minimum determined from Table 4. This heat rate at this minimum, including the temperature variability, results in a normal distribution with a mean of 19.088 GJ/MWh sent out and a standard deviation of 1.335 GJ/ MWh sent out. The mean and the standard deviation have decreased slightly from the 2017 review, reflecting changes in the actual operation of the Pinjar units at the lower end of its operating range over the observation period (calendar years 2013 – 2017) relative to last year's observation period (calendar years 2013-2016). The change in the assessed minimum operating level changes the average heat rate modelled even though the heat rate characteristics have not been changed since the 2017 review.

3.4 Variable O&M

This section describes the structure of the variable O&M costs for the Pinjar gas turbines. The equivalent data for the aero-derivatives is discussed in Appendix D. In addition, this information is presented for Mungarra in Appendix E using Mungarra's actual dispatch characteristics.

The variable O&M cost for the Pinjar gas turbines in $/MWh is influenced by Type 2 and Type 3 maintenance costs discussed in section 2.3.1 above. Jacobs has not identified any significant component of operating cost which depends directly on the amount of energy dispatched. Therefore, there is no specific $/MWh component other than that derived from the above costs.

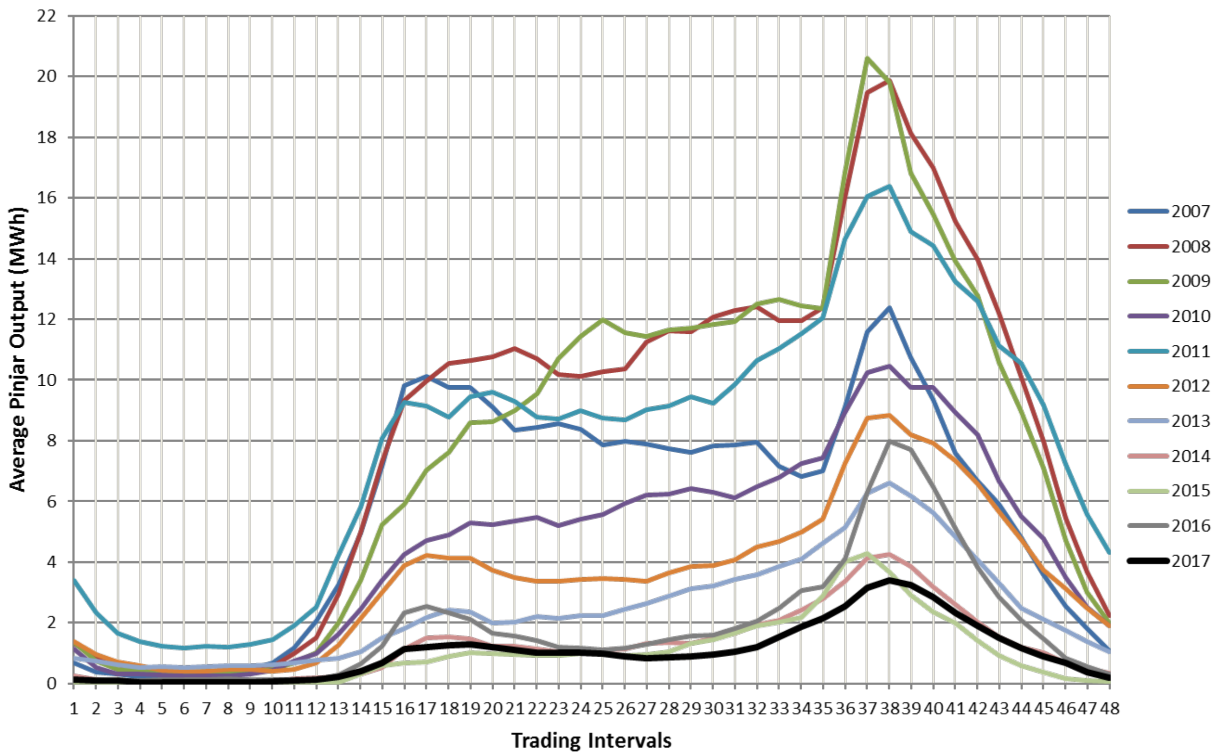
3.4.1 Dispatch cycle parameters

An examination of the Pinjar dispatch data from 2007 had shown a steady decrease in both the number of starts per month from 2011 until 2015 as well as the total dispatch of the plant. The daily profile of Pinjar's total output is shown below in Figure 6. This shows a distinct downtrend in Pinjar's total output from 2011 until 2017. The trend reversed in 2016 when Pinjar's average output increased across most of the daily profile, but Pinjar's 2017 daily output profile was similar to that of 2014 and 2015.

The change from 2012 onwards indicates a change in the role of Pinjar, and this can be traced back to the commencement and continuing operation of HEGTs in the WEM from September 2012. The HEGTs at Kwinana have a lower SRMC relative to Pinjar and therefore the impact of their commissioning on the dispatch of Pinjar will be ongoing.

The entire distribution of historical Dispatch Cycles (including cycles lasting more than 12 trading intervals) is used when calculating the impact of the average number of starts per annum on the O&M cost. There is considerable variation in the average number of starts for the Pinjar units over the last five years, ranging from 50 in 2015 up to 97 in 2016. Jacobs therefore considers it appropriate to include the last five years in assessing the average number of starts of the Pinjar units, as the downward trend in the number of starts was broken, with the most average number of starts being recorded in 2016.

Figure 6 Pinjar average daily generation profile (2007 – 2017)



NOTE: Trading intervals here are not based on the WEM's Trading Day. That is, trading interval 1 represents 12:00 AM to 12:30 AM, not 8:00 AM to 8:30 AM.

Jacobs considers that it is reasonable to include the last five years of dispatch information to form the 2018/19 Dispatch Cycle distributions for Pinjar since Pinjar's operation in 2013 was similar to that of 2016. As such, Jacobs has included the 2013 Pinjar dispatch data in the analysis, using all data points from January 2013 until December 2017 to determine the distribution of Pinjar's starts and the length of the Dispatch Cycle. By using five complete calendar years of data the approach avoids introduction of seasonal bias.

An analysis of the Pinjar dispatch patterns since January 2013 has shown that:

- Pinjar run times have averaged around 9 trading intervals per Dispatch Cycle, which is the same as the 2017 average. The average power generation per Dispatch Cycle has decreased slightly when compared against last year's review, which reflects Pinjar's lower output in 2017 relative to 2016.
- Overall the incidence of short run times below 6 hours have been reducing slowly in the Pinjar dispatch since the distributions were first formulated in 2007 and in the updates for the 2009 to 2013 reviews. However, since September 2012, the incidence of short run times below 6 hours has increased. For the 2013 to 2017 calendar years, approximately 80% of all Pinjar run times were below 6 hours, compared to 70.5% in 2013 and 51.5% observed over the four-year period from January 2009 until December 2012.

Frequency of starts

From the operating characteristics of the Pinjar gas turbine machines between January 2013 and December 2017, they have been required to start between 12 and 153 times per year on an individual unit basis, 64.9 starts per year on average, with average run times of between 3.8 and 5.7 hours on a unit basis. This means that the number of starts per year is the primary cost driver, rather than the operating hours.

The number of starts for the six units has a standard deviation of 20.37 starts in a period of one year. This has been represented by a normal distribution up to 3.2 standard deviations from the mean with a minimum number of starts of 10.

The parameters for the modelling of unit start frequency were:

Mean value	64.9 starts/year
Standard deviation	20.37 starts/year
Minimum value	10 starts/year

The values of the actual distributions used were decreased by 16%, because in the course of reviewing the start cost methodology it was found that the maintenance cycle is driven by factored starts rather than actual market starts. This is described below.

In last year's review we had applied a 20% uplift on the number of annual starts to account for a gas turbine operating in peaking mode. This 20% factor is to allow for the relationship between "Factored Starts" that the Original Equipment Manufacturer (OEM) applies to estimate the timing of maintenance outages as opposed to actual starts that the gas turbine might experience. The OEMs (and specifically GE in the case of the Frame 6B units at Pinjar) calculate Factored Starts based on how severe the starts and trips experienced by the machine are relative to a "normal start". As such, it is appropriate to consider this factor in the starting cost evaluation.

Jacobs reviewed the appropriateness of the 20% uplift for factored starts relative to market starts, and concluded that the main drivers for factored starts in Pinjar's context are trips or fail-to-start restarts, which are similar to trips. However, as part of last year's stakeholder consultation, Perth Energy also noted that low-load starts (<60% loading) are also relevant in this analysis. Jacobs interrogated the historical data for Pinjar and found that low-load starts do make a material contribution to the average level of factored starts incurred by a market start. Over the 2013 to 2017 calendar years, Jacobs found that 69% of Pinjar's starts fell into the low-load start category, each of which only incur an equivalent of an 0.5 start.

Both trips and fail-to-start restarts are known to inherently occur in gas turbines. Jacobs does not have the statistics of these types of events specifically for the Pinjar or other WA units but we do have relevant data from units in another power system. For these units, which also date back to the 1980s, over their lives the factored starts attributable to trips have been a number that is similar enough to 20% to give us confidence that a 20% uplift to the factored start is a reasonable number to apply.

Jacobs combined the above two start factors in a simple start model for Pinjar and this indicated that each market start was on average equivalent to 0.84 factored starts.

The resulting parameters for the factored start distribution are as follows:

Mean value	54.5 factored starts/year
Standard deviation	17.1 factored starts/year
Minimum value	8.4 factored starts/year

Run times

Run times are used to convert start-up costs for maintenance and fuel into an average operating cost per MWh of a Dispatch Cycle.

The run times of the peaking units have been analysed from the market data from 1 January 2013 to 31 December 2017. A probability density function has been derived which represents the variation in run times. Whilst it would be possible to set a minimum run time of say 1 or 2 trading intervals, this condition occurs infrequently, about 1 in 16 starts for the industrial gas turbines since January 2013[19]. Since other market factors have also been varied, it is preferred to assess the variation of run time as just another uncertain factor rather than treat it as a deterministic variable.

Maximum capacity

The maximum capacity of the Pinjar machines varies during the year due to temperature and humidity variation. The maximum capacity was derived from historical dispatch information taking into account the seasonal time of year using a sinusoidal fitting function. In this way, the variation of the maximum output during the year is included in the uncertainty analysis. A sinusoidal curve was used to estimate the maximum dispatch and the error around this curve was added back to give an overall distribution of maximum capacity. The applicable distributions are provided in a confidential Appendix to AEMO and the ERA.

Dispatch Cycle capacity factor versus run time

The Market Rules specify the use of the average heat rate at minimum capacity. As previously, the available loading data was analysed to assess what actual loading levels have been achieved, especially with shorter run times. A capacity factor for the Dispatch Cycle was defined from the historical dispatch data by the following equation:

$$\text{Capacity Factor} = \frac{\text{Energy Generated in Dispatch Cycle}}{\text{Maximum Capacity x Run Time}}$$

The capacity factor varied quite markedly even for similar run times. The relationship between these variables was defined as follows. The capacity factor has a mean equal to a linear function of the run time up to a certain threshold and then a different linear relationship above the threshold. The standard deviation of the capacity factor was assessed with the same value above and below the threshold. The details were provided in a confidential Appendix to AEMO and the ERA.

The standard deviation of the variation was 11.84% for all run times employed (i.e. up to 12 trading intervals). These values were used to formulate the capacity factor which was then clipped between the practical maximum and minimum values having regard to ramp rates and minimum stable operating capacity levels.

The formulation of the capacity, run times and capacity factors is shown in Appendix B.

3.4.2 Maintenance costs

3.4.2.1 Items investigated for the 2018 review

AEMO received feedback on the approach taken to estimate the variable O&M costs in the 2017/18 Energy Price Limits review from stakeholders, including the ERA and the Secretariat of the ERA. AEMO has reviewed the feedback and addressed as follows:

- **Maintenance Cycle Length:** It was recommended by the ERA that AEMO undertake an investigation into the maintenance status of the highest-cost generator and actual position of relevant units within their maintenance cycle by seeking information from the asset owner. It was expected this would inform whether the units might be near the end of their life and whether no further expensive maintenance operations would be undertaken, independent of the occurrence of an incremental start.
  - AEMO has contacted the asset owner of the impacted facilities and has been advised no additional information on maintenance status can be provided at this time.
  - Jacobs has undertaken a comprehensive analysis on the maintenance requirements and cycle of the impacted units and presented this in Appendix F.

[19] While the aero-derivative gas turbine has higher frequency of shorter runs it should also be pointed out that it has longer average run time per start than the industrial type gas turbine. This probably reflects bilateral energy contract obligations and higher efficiency than for the industrial turbines.

- In the absence of information from the asset owner, Jacobs will make an allowance for the influence of Factored Starts on the likely maintenance cycle. Jacobs has considered some other units of similar age, technology and duty to the Pinjar units and determined that for those units the Factored Starts are approximately 1.2 times the actual starts for all starting conditions, except low-load starts. Since 2013, 69% of Pinjar's starts have been low load starts, and combining this with the 1.2 factored starts factor for all other starts yields an average service factor of 0.84 for the Pinjar machines. Similarly, 70% of Mungarra's starts in calendar 2017 were low-load starts, and this yields a service factor of 0.83.

- **Average number of starts per year:** The number of effective starts is calculated based on the value of factored starts. In its submission to the review of the 2017 Energy Price Limits, Perth Energy noted that the value of factored starts has to be 60 per cent for low load starts. The ERA recommended that AEMO more accurately account for the impact of low load starts in calculating the average number of effective starts per annum.
  - To address this point, Jacobs has undertaken an investigation as to whether the number of low load starts experienced by Pinjar due to its particular service might result in a lower Service Factor.
  - Jacobs interrogated the operating history and has estimated the impact of starts to low load (this is described above in section 3.4.1).
- **Choice of discount rate:** The discount rate is applied to factor in the time-effects of the maintenance cycle on the effective cost of a current start. It was recommended by the Secretariat of the ERA that AEMO consider alternate approaches to determining the discount rate (as opposed to the method applied in the 2017 review). Two approaches were recommended:
  1. Use a risk-adjusted discount rate based on the perceived riskiness of the future expenditures
  2. A Monte Carlo simulation can be run by drawing samples from distributions assigned to future maintenance expenditures. The characteristics of the assigned distribution is determined by the variability of future maintenance expenditures. In the next step, the present value of drawn cash flows are calculated based on a risk-free rate of interest. This yields a distribution for the present value of the future cash flows. A percentile of the distribution can be taken as the risk-adjusted present value of future maintenance expenditures.

  Once the present value of future maintenance expenditures is calculated (by either Approach 1 or 2 above), an annuity payment may be calculated based on the weighted average cost of capital of the asset owner. Note that the asset owner must finance the future maintenance expenditures in the form of an annuity at its marginal cost of capital. The annuity payment yields a maintenance-cost-per-annum amount. Dividing the per-annum amount by the average number of starts per year yields a cost-per-start value.
  - Jacobs has applied Approach 2 with some minor adjustments. The rationale for this is described below.
  - Regarding Approach 1:
    - This requires selection of a discount rate based on the perceived riskiness of the future expenditures, Jacobs considers this is not the best option as it requires the derivation of a suitable risk-adjusted discount rate. Observable discount rates determined using methods such as the Capital Asset Pricing Model (CAPM) are based on observations of returns of companies (rather than specific assets) as a function of the relationship between variations in the company's returns and variations in the overall market returns of risky assets. In making evaluations it is common to seek companies for comparison that are a fair "pure-play" proxy for the asset in question. The observed returns of a company are based on items such as share price changes and dividends. These are functions of the company's net earnings or cashflow (i.e. revenue minus expenses) rather than separate consideration of the variations in revenues or expenses let alone variations in individual expenditure items such as maintenance costs. There is no model known for determining a separate discount rate to apply to an individual expense item (such as maintenance) separate to a discount rate for a complete asset comprising both revenues and expenses. This is notwithstanding that it could be argued that a future revenue or expense item that is entirely determinate as to its timing and value would be considered less risky than a highly uncertain revenue or expense item and, over the totality of the company, may support a higher

level of debt funding and hence lower cost of capital (discount rate). Also relevant to the evaluation is the issue of determining whether the extent of correlation between the uncertainty of the revenue or expense item is correlated to the overall market return (i.e. its beta) as opposed to absolute uncertainty.

- While in the CAPM theory it is only correlated returns that are compensated by the (external) market, it could be argued that at the corporate level, the larger the uncertainty in net cashflow becomes in an absolute sense relative to the size of the firm, the more it will dominate the accessible gearing level and hence cost of capital for the firm.
- Because revenues and expenses are of similar magnitudes in most companies and net cashflow is the difference between revenues and (cash) expenses, small changes in either (relative to the size of either) tend to be magnified in their effect on net cashflow.
- It is hard to see this as materially improved on the method employed in 2017. The 2017 method is very similar to the method used to assess levelised costs (similar to LRMC) for components of an asset's overall life-cycle costs in such a way that the sum of the levelised cost components (fuel, O&M, capital, etc.) equals the overall levelised cost (i.e. the constant real price for the output of the plant that results in a zero NPV in the overall cashflow analysis of the project). Practically, in undertaking a comparison of the overall levelised cost with the sum of the discounted-weighted averages of the components the same overall commercial discount rate is applied to each. No method is known to estimate a robust discount rate for individual components of cost (or revenue).

- Regarding Approach 2:
  - In order to apply a risk-free rate to the expenditures in finding a present value we would need to be satisfied that the distribution of possible expenditures evaluated was accurate and encapsulated all the uncertainty elements within the distribution. Any uncertainty in the selection of the distribution of expenditures would invalidate the use of the risk-free rate.
  - The uncertainty in the timing of the various overhauls can be drawn from sampling the simulations that are drawn from the modelling. However, it is also appropriate to consider the uncertainty in the cost of each overhaul into the analysis as well. Jacobs is not aware of a statistical dataset for this but our judgment is that asserting that the estimated costs are ±20% accurate at 70% confidence is generally consistent with the nature of such estimates. Such a distribution can be incorporated into the (Monte Carlo type) simulations.
  - In the recommended approach, the future uncertain timings/costs are brought to a present value (PV) using the risk free rate (on the grounds that the summation process is made over all potential outcomes using valid distributions for those outcomes). The approach then suggests converting this to an annual equivalent using an annuity at the commercial discount rate of the owner.
  - Jacobs' view is that this process is appropriate however in the last step we have used the risk-free rate to create the annual equivalent cost rather than the owner's commercial discount rate. Although the asset owner would finance its overall business at its commercial WACC, if it were the case that individual line-items of expense and revenue were financed separately (a hypothetical analysis) it would be the risks of those individual cash-flows being financed that would dictate the discount rate that should be applied to each.
  - This should be the risk-free discount rate in this case as the present-value-equivalent-to-the-maintenance-costs was itself derived using a risk free rate in summing across all possible outcomes and hence the present value is itself "riskless" in the same sense that the maintenance costs are riskless. Following the Modigliani and Miller (MM) approach it is the nature of what is being financed that sets the discount rate rather than the nature of the firm raising the finance. In the present case we suggest that what is being financed has been made "riskless" and hence the risk free rate should be applied at the annuity step.
  - To apply the commercial WACC at this step would in effect be a doubling up of the risk allowance. In bringing the future cashflows to a present value using the risk free rate, the asset

owner has “paid” extra to make that a “riskless” amount. It would not make sense for the asset owner to pay “extra” again to finance that present value using a risked discount rate.

- The resulting method applied, that appears more consistent with the process used elsewhere to select values at (say) the 80th percentile is to:
  - Generate a number of simulations, N, of the annual starts over the remaining life of the relevant unit
  - For each simulation, consider the timing of CIs, HGPI and MO in the simulation
  - Assume in each simulation that if a high cost overhaul (HGPI or MO) would occur in the last three years of the simulation that it would not be undertaken and the life would be assumed to end at that time
  - Sample the cost of each service in each simulation drawing from the estimated cost ±20% at 70% confidence (assuming a Normal distribution)
  - Discount each simulation to a present value equivalent using the risk free rate (since the steps below are effectively summing over all possible outcomes)
  - Using the distribution of the N resulting PVs from the previous step, take the 80th percentile. This is the risk adjusted value/cost of maintenance.
  - Calculate an annuity amount for the 80th percentile PV in the previous step using the risk-free rate.
  - Divide the annuity amount calculated in the previous step by the number of starts expected for next year.
  - The resulting estimate is the start cost to be used in the Energy Price Limit calculation

3.4.2.2 Lifecycle O&M costs

Jacobs refreshed the maintenance costs for the 2017 review from the previous review by adjusting the base maintenance cost to better reflect industry practice with respect to the maintenance of ageing generation assets. Jacobs then applied appropriate forex and CPI adjustments to the adjusted base maintenance costs (the rationale for this approach is explained in section 2.3.1). The costs are shown in Table 5 in December 2018 dollars for General Electric Frame 6 gas turbines with the maintenance stage occurring after the stated number of running hours or the stated number of starts, whichever comes first. December 2018 dollars are required in this analysis because this represents the mid-point of the 2018/19 year which is the time frame in which this analysis is applied, and the Energy Price Limits have to be expressed in nominal dollars. In the maintenance cycle there are two Type A overhauls, one of Type B and one Type C at the end. The maintenance costs were originally provided in nominal $US in February 2015. They have been converted to Australian dollars at the rate 1$AU = $US0.78, which was the February 2015 conversion rate. The parts component of the maintenance costs (estimated to be 70%) has been adjusted for movements in the forex rate since February 2015, assumed to be 1$AU=$US0.77 in December 2018. The total maintenance cost with the forex adjustment has been escalated from February 2015 dollars to December 2017 dollars using known historical CPI values, and then escalated to December 2017 dollars with an assumed future CPI rate of 2.0% per annum.

An overall increase in the cost of O&M for aero-derivative turbines has been observed, based on advice from the Original Equipment Manufacturer, considering the cost of the overhauls themselves and in some of the underlying assumptions regarding the cost of spare parts, labour etc. (costs which are generally included in the cost quoted for the overhauls).

We assume that maintenance costs for both plants being studied (Pinjar and Parkeston) remain the same in real terms over the remaining life of the plants.

Table 5 Overhaul costs for industrial gas turbines (December 2018 dollars)

Overhaul Type	Number of hours trigger point for overhaul	Number of starts trigger point for overhaul	2017 Cost per overhaul	Number in each overhaul cycle	Cost
A	12000	600	1,195,775	2	2,391,551
B	24000	1200	3,161,052	1	3,161,052
C	48000	2400	4,565,464	1	4,565,464
Total cost per overhaul cycle					10,118,067

No adjustment is applied for any future changes in foreign exchange rates. Each maintenance cycle of 2400 units starts and ends with a Type C overhaul. Further details of the maintenance regime relevant to this determination are provided in Appendix H.

Where each generating unit has progressed in the maintenance cycle is not public knowledge. In simple terms:

- the average running hour cost is $10,118,067/ 48,000 = $210.79/hour = $5.54/MWh at full rated output (38.081 MW)[20]
- the average start cost is $10,118,067 / 2400 = $4,216/start
- one start is equivalent to 20 running hours, but (in the G.E. methodology) they are not interchangeable, as an overhaul is indicated either by the starts criterion or the hours-run criterion, rather than a mixture of the two.

However, these costs are spread over several years and it is not appropriate to divide these costs by the number of starts or number of running hours to derive an equivalent cost accrual. Our description of the modelling of appropriate costs per start, taking into account the time value of money is described below in the next section.

3.4.2.3 Modelling start costs of industrial gas turbines

Jacobs performed Monte Carlo simulations to calculate an appropriate start cost for each of the 10,000 samples used to build up the cost distribution. The method employed to do this is described above at the end of section 3.4.2.1. This methodology requires the calculation of a risk free rate, which is presented below.

Risk free rate

Jacobs derived a real risk free rate to appropriately evaluate costs per start for the industrial gas turbines. The derivation follows the processes adopted by the ERA and AER being:

- Determine the nominal risk free rate using the average of the last 20 business days' 10y CGS published by the RBA. This is 2.738%[21].
- Determine the expected inflation rate using the method adopted by the AER[22] being the average of: the next two years of (market economist) expected inflation (2.3% and 2.4%[23]) followed by 8 years of the midpoint of the Reserve Bank's target range for inflation (2.5%), being 2.47%.
- Determine the real risk free rate using the Fisher formula

This yields a real risk free rate of 0.261%.

[20] Calculation based on rate of output for a new machine at 15ºC, 60% relative humidity. The O&M cost is calculated based on a sampled capacity derived from market dispatch data in the Energy Price Limits cost model.
[21] http://www.rba.gov.au/statistics/tables/xls/f02d.xls?v=2018-03-28-15-04-08. Accessed 28.3.2018. Date for 28.2.2018 to 27.3.2018 inclusive, series FCMYGBAG10D
[22] https://www.aer.gov.au/system/files/AER%20-%20Final%20position%20paper%20-%20Regulatory%20treatment%20of%20inflation%20-%20December%202017%20-%20Web%20upload.PDF
[23] http://www.rba.gov.au/statistics/tables/xls/g03hist.xls?v=2018-03-28-15-04-08 accessed 28/3/2018

Start cost distribution

Table 6 shows the statistics of the start cost distribution for Pinjar using the method described at the end of section 3.4.2.1. The average discounted start cost is $3,320, which is substantially lower than last year's average start cost of $4,279.

Table 6 Modelled start cost distribution for Pinjar

Start costs as Modelled	
	Pinjar
Min	$2,105
10%	$2,629
50%	$3,506
Mean	$3,320
Mode	$3,567
80%	$3,633
90%	$3,701
Max	$3,913

For the calendar years 2013 to 2017 the average historical MWh production per start (including Dispatch Cycles greater than 6 hours) was 68.0 MWh. The equivalent variable (non-fuel) O&M cost derived from the discounted start cost of $3,320 is $48.82/MWh compared to $61.13/MWh in the 2017 review.

In the simulation of variable O&M cost Jacobs has taken the start-up cost based on the average number of factored starts per year, that is with 54.5 factored starts per year with a standard deviation of 31.4% of that value (17.1 starts/year on an annual basis) based on the observed variability of the number of starts per year across the units.

3.4.3 Resulting average variable O&M for less than 6-hour dispatch

For the sampled generation levels up to 6 hours based on the historical dispatch, the average variable O&M value is $129.59/MWh before the application of the loss factor. The resulting distribution which provides this mean value is shown in Figure 7.

Based on the start cost of $3,320, the average variable O&M of $129.59/MWh corresponds to an equivalent generation volume per cycle of 25.62 MWh, equivalent to about one hour running at 67% load factor or 2 to 3 hours at minimum load. It is these short Dispatch Cycles which are covered by the resulting Energy Price Limits.

Table 7 shows the characteristics of these distributions before the loss factor is applied.

Figure 7 Probability density of variable O&M for industrial gas turbine (excluding impact of loss factor)

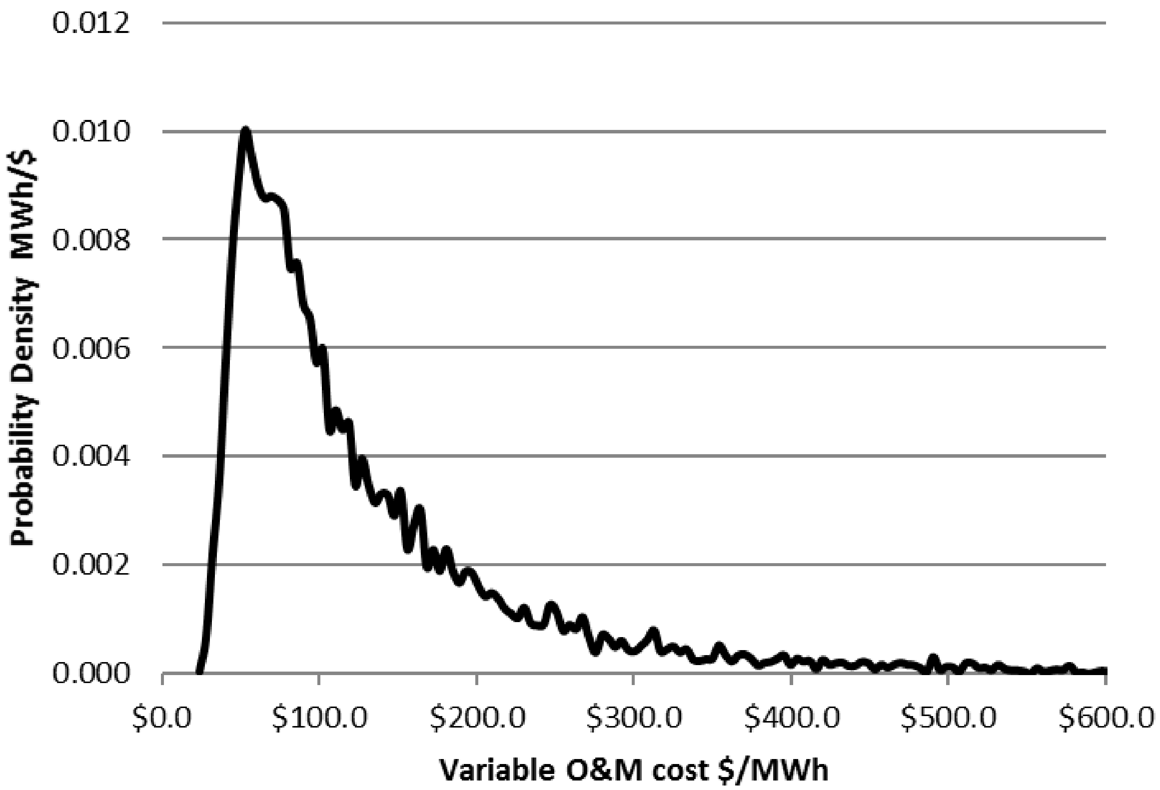


Table 7 Parameters of variable O&M cost distributions (before loss factor adjustment)

Pinjar variable O&M	$/MWh
90% POE	$48.41
Mean	$129.59
10% POE	$253.24
Minimum	$23.15
Median	$96.06
Maximum	$827.07
Standard Deviation	$99.15

The analysis detailed above for the historical dispatch results in an average variable O&M cost of $129.59/MWh with an 80% confidence range as sampled between $48.41/MWh and $253.24/MWh, excluding the impact of loss factors.

3.5 Transmission marginal loss factors

The transmission loss factors applied were as published for the 2017/18 financial year for sites where aero-derivative gas turbines and industrial gas turbines of 40 MW capacity are installed. The loss factor for Pinjar for the 2017/18 financial year is 1.0322, which is identical to Pinjar's 2016/17 loss factor.

3.6 Carbon price

Effective from 1 July 2014, the carbon price was repealed by the current Federal Government and therefore emissions from the peaking plants do not have a cost impact.

4. Results

4.1 Maximum STEM Price

The Dispatch Cycle costs of the dispatch of the industrial gas turbines are projected as shown in Table 8 using the average heat rate at minimum operating capacity and the base gas price distribution.

Table 8 Analysis of industrial gas turbine Dispatch Cycle cost using average heat rate at minimum capacity

	Pinjar Gas Turbines	
	Gas	**Distillate**
Mean	$243.06	$465.90
80% Percentile	$301.52	$525.69
90% Percentile	$374.69	$596.08
10% Percentile	$144.01	$368.38
Median	$217.98	$438.35
Maximum	$1,021.19	$1,259.48
Minimum	$59.36	$293.45
Standard Deviation	$104.94	$104.39
Non-fuel component $/MWh		
Mean		$136.95
80% Percentile		$189.27
Fuel component GJ/MWh		
Mean		18.696
80% Percentile		19.211
Equivalent fuel cost for % value ($/GJ)		
Mean		17.595
80% Percentile		17.512

The Maximum STEM Price is based on 80% probability that the assessed cost would not be exceeded for run time events of 6 hours or less. Using the average heat rate at the minimum capacity the Maximum STEM Price would yield a value of $302/MWh[24].

4.1.1 Coverage

It must be recognised that only short run times from 0.5 to 6 hours have been applied in formulating the distributions. This arrangement therefore covers a high proportion of Dispatch Cycles represented in the analysis, as shown in Table 9 which shows the results of a calculation which estimates the proportion of dispatch events that would be expected to be covered by the Maximum STEM Price.

Taking into account the distribution of run times, it is estimated that 82.6% of gas fired run time events would have a Dispatch Cycle cost less than the proposed Maximum STEM Price, based on the mathematical representation of uncertainties included in this analysis and using historical dispatch characteristics.

[24] In the discussion in this section, the values have been rounded to the nearest $1/MWh

Table 9 Coverage of Maximum STEM Price for Pinjar

Dispatch	Historical from Jan 2013 to Dec 2017 (80th percentile)
Proportion of Dispatch Cycles less than 6 hours	80.3%
Proportion of 6 hourly Dispatch Cycles covered by Maximum STEM Price (by simulation)	78.4%
Proportion of Dispatch Cycles covered by Maximum STEM Price	82.6%

4.2 Alternative Maximum STEM Price

The Alternative Maximum STEM Price is varied each month according to changes in the price of distillate. It is therefore necessary to separate out the cost components that depend on fuel cost and those which are independent of fuel cost. Accordingly, the lower half of Table 8 presents the non-fuel and fuel components of the Alternative Maximum STEM Price for the distillate firing of the gas turbines, as well as parameters of the fuel price as simulated[25]. The road freight cost of distillate is not included in the fuel component as it is considered that this price is largely independent of the price of distillate. This is the same assumption that was used in last year's review.

The price components for the Alternative Maximum STEM Price that provide the 80% cumulative probability price are:

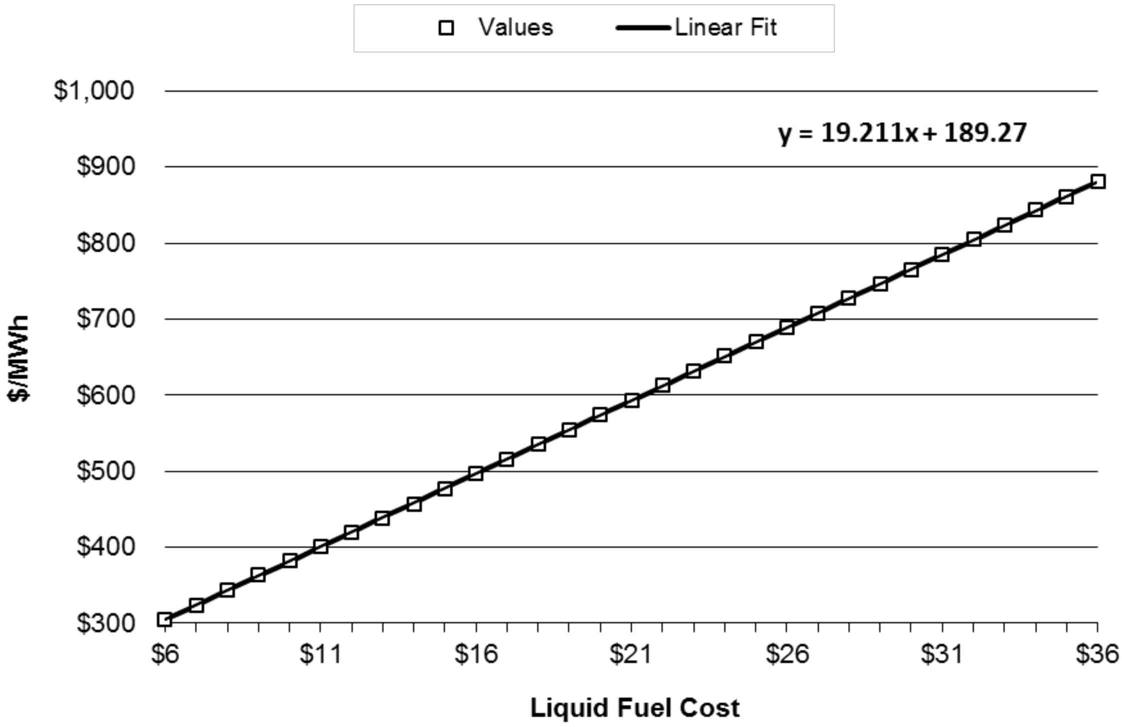
$189.27/MWh + 19.211 multiplied by the Net Ex Terminal distillate fuel cost in $/GJ.

As discussed in section 2.5, the method for selection of the non-fuel and fuel cost factors in the above formula was based upon 10,000 samples of each of the two cost factors combined with a range of fixed distillate prices between $6/GJ and $36/GJ, to assess the 80% probability level of cost for each fuel price. Rather than taking the 80% probability values of the cost terms themselves, the two cost factors were derived from the linear regression fit of the 80% price versus distillate price. This function is shown in Figure 8.

Assuming a Net Ex Terminal distillate price of $17.88/GJ, we calculate a cap price of $533/MWh using the Alternative Maximum STEM Price equation above. This value is based on 80% probability that the assessed cost would not be exceeded for run time events of 6 hours or less and is based on the industrial type gas turbine. The 80% simulated value in Table 8 of $525.69 has been calculated by modelling the uncertainty in distillate price in the simulations. This value is lower than the value obtained with a fixed fuel price.

[25] The percentile values of the fuel and non-fuel components shown in Table 8 are provided for calculating the Alternative Maximum STEM Price. They are not the percentile values of the sampled parameters themselves. For example the 80% value of the non-fuel component in the 10,000 samples was $181.04/MWh and the fuel component 80% value was 20.210 GJ/MWh for the industrial gas turbine. These are not the same values shown in Table 8 ($189.27/MWh and 19.211 GJ/MWh respectively) which used together calculate the 80% value of the Alternative Maximum STEM Price.

Figure 8 80% Probability generation cost with liquid fuel versus fuel cost (using average heat rate at minimum capacity)



4.3 Price components

The Market Rules specify the components that are used to calculate the Energy Price Limits and these have been applied in a statistical simulation. Table 10 summarises the expected values of the various components and the Risk Margin that are required under paragraphs (i) to (v) of clause 6.20.7(b) so that the resulting calculation will provide the assessed proposed revised values for the 2018 Energy Price Limits.

It shows:

- the expected values of each of the cost components that were represented in the cost simulations
- the value of the dispatch cost that would be derived from the mean values of each component and the implied Risk Margin between that average value based calculation and the proposed Energy Price Limits.

It should be noted that the mean and 80th percentile values for the Energy Price Limits cannot be calculated by using the corresponding mean and percentile values for the individual components due to the asymmetry of the probability distributions of the cost components. It may be noted that the “Before Risk Margin” in Table 10 is significantly higher than the expected value of the Dispatch Cycle cost due to these asymmetries.

4.4 Sources of change in the Energy Price Limits

To illustrate the sources of change in the Energy Price Limits since last year’s 2017 review, a series of studies was developed with progressive changes in the input parameters from the current parameters to those which were applied in the 2017 review of Energy Price Limits. The value of the Dispatch Cycle cost was taken which exceeded 8,000 (80%) of the 10,000 samples. Changes in the key variables driving the differences in this year’s Energy Price Limits review relative to the 2017 review are summarised in Appendix G.

Table 10 Illustration of components of Energy Price Limits based on mean values

Component	Units	Maximum STEM Price	Alternative Maximum STEM Price	Source
Mean Variable O&M	$/MWh	$129.59	$129.59	Mean of Figure 7
Mean Heat Rate	GJ/MWh	19.225	19.277	Mean AHRM plus start-up fuel consumption.[26]
Mean Fuel Cost	$/GJ	$6.31	$18.23	Mean of Figure 3 for delivered gas price distribution
Loss Factor		1.0322	1.0322	Western Power Networks
Before Risk Margin 6.20.7(b)	$/MWh	$243.07	$466.00	Method 6.20.7(b)
Risk Margin	$/MWh	$58.93	$67.00	Difference between the 80th percentile price and the mean price
	%	24.2%	14.4%	By ratio
Assessed Maximum Price	$/MWh	$302.00	$533.00	Energy Price Limit calculation

Not all combinations of old and new inputs were evaluated. The sequence from new parameters back to old parameter values was developed in the order of:

1) The 2017 review case
2) Previous dispatch patterns restored
3) Previous operating and maintenance costs restored
4) Previous loss factor applied
5) Previous distillate cost and standard deviation applied
6) Previous gas commodity cost distribution applied
7) The calculation of the 2017 Maximum STEM Price based on the 80% probability of coverage of the Dispatch Cycle cost.

4.4.1 Change in the Maximum STEM Price

Table 11 provides an analysis of the specific changes to show the changes in the Maximum STEM Price and the parameters affected as described in Appendix B. The table describes the successive changes made to the 2018 analysis to convert it back to the 2017 analysis.

Table 11 Analysis of changes to form the waterfall diagram for the Maximum STEM Price

Step	Label in chart	Changes	Parameters affected (Appendix B)
1	Previous Max STEM Price	The calculation of the Maximum STEM Price based on the 2017 parameters.	
2	Gas Price	The 2017 spot gas commodity cost distribution was updated with the distribution that applied in this year’s review.	VFC (gas)
3	Distillate Price	Distillate price was changed from $16.43/GJ to $17.88/GJ, and the 2017/18 standard deviation was also used	VFC for distillate (gas price cap altered for Maximum STEM Price)
4	Loss factor (No effect)	The loss factor is still the 2017/18 loss factor	LF

[26] The slight difference in mean heat rates (0.27%) is influenced by the 0.27% difference in operating heat rates (refer section 2.5).

Step	Label in chart	Changes	Parameters affected (Appendix B)
5	O&M Parameters	The O&M costs for the industrial gas turbines, including number of starts, were updated with the 2018 values	VHC, SUC
6	New Historical Dispatch Patterns	Capacity, run times and Dispatch Cycle capacity factor based on the data from 1 January 2013 to 31 December 2017, replaces the data from 1 January 2013 to 31 December 2016	CAP, CF, RH, and hence MPR
7	New Max STEM Price	The basis for the 2018 Energy Price Limits	

Figure 9 and Table 12 show the relative contribution of the various changes to the Maximum STEM Price since the 2017 review. The greatest difference is in the change in the O&M cost, which is primarily driven by the decrease in the start cost from $4,279/start to $3,320/start. The decrease in start costs reflects the change in the underlying methodology used to calculate it. One of the contributing factors to the lower start cost is that major maintenance items are assumed not to be incurred if they occur in the last two to three years of the plant's life. The other factor is that average factored starts have been calculated to be 0.84 starts per market start, whereas in last year's analysis 1.2 starts were used. The lower average factored start rate reduces the start cost because it defers maintenance.

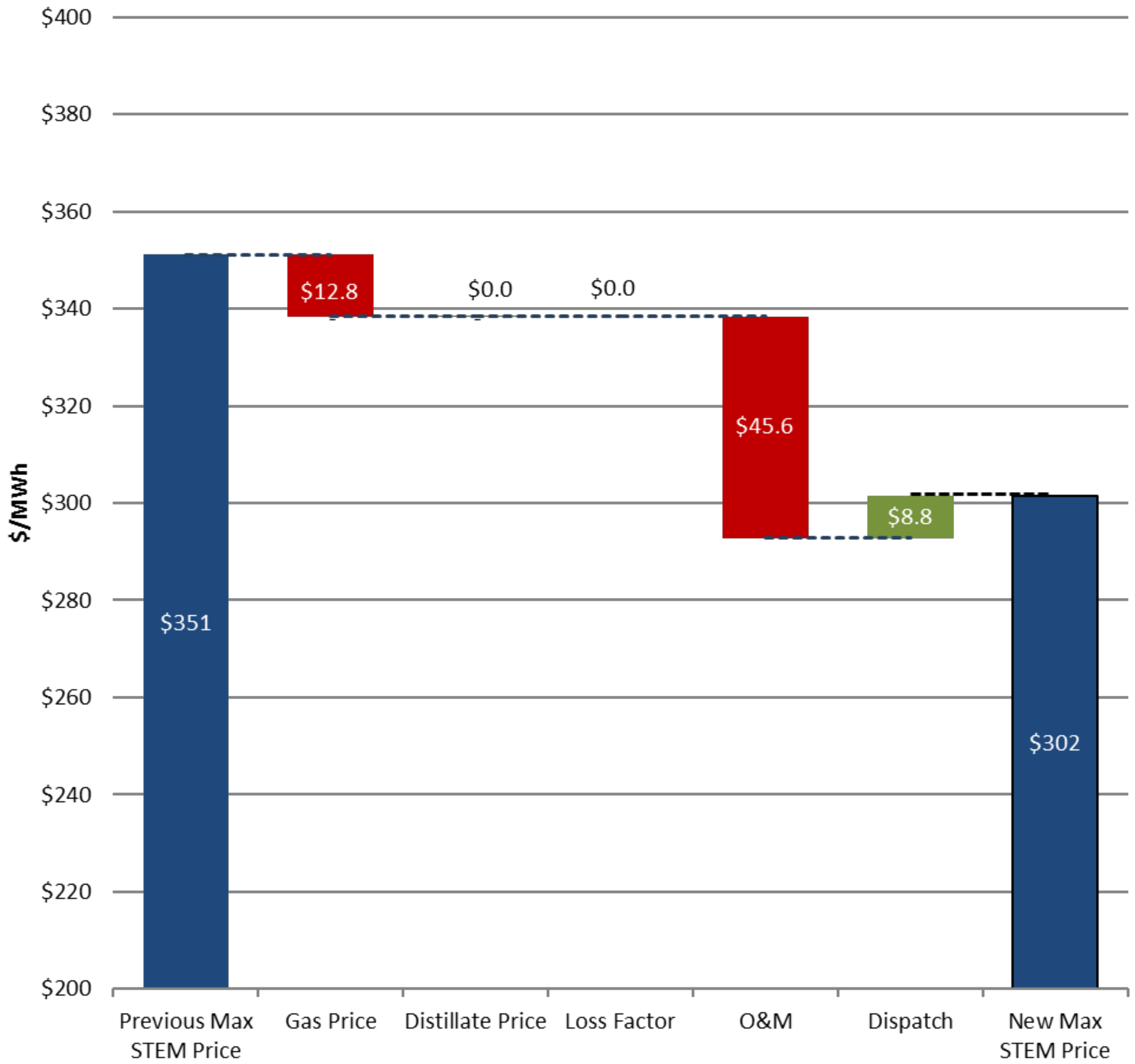
In addition to the change in the O&M cost, there are two secondary factors that explain the change in the Maximum STEM Price, also these factors move in different directions and almost cancel themselves out. The factor with the next largest impact is the change in the average gas price, which also has a negative cost impact. The forecast gas price has decreased from $4.66/GJ in last year's review to $4.02/GJ in this year's review due to a state of oversupply in global LNG markets and oversupply in the WA gas market. The next largest difference in magnitude is the change in the dispatch characteristics of the Pinjar plant over the 2017 calendar year. This has a positive impact on the price because Pinjar's dispatch reduced over the 2017 calendar year, and therefore the start cost needs to be recovered over a smaller volume of energy.

The relative contributions to the change in the Maximum STEM Price are illustrated in the waterfall diagram in Figure 9.

Table 12 Impact of factors on the change in the Maximum STEM Price

Factor	Impact $/MWh
Dispatch	$8.80
O&M	-$45.65
Loss Factor	$0.00
Distillate Price	$0.01
Gas Price	-$12.78

Figure 9 Impact of factors on the change in the Maximum STEM Price since 2017



4.4.2 Change in Alternative Maximum STEM Price

Table 13 provides an analysis of the changes to the Alternative Maximum STEM Price and the parameters affected as described in Appendix B. The table describes the successive changes made to the 2018 analysis to convert it back to the 2017 analysis.

Figure 10 and Table 14 show the relative contribution of the various changes to the Alternative Maximum STEM Price since the 2017 review. The largest contributing factor to the change has been caused by the decrease in the O&M cost mainly due to the change in calculation methodology, disregarding large maintenance expenditure at the end of the plant's life and the reduction in the average number of factored starts per market start from 1.2 to 0.84. The other key contributing factor, which cancels some of the impact of the change in the O&M cost is the increase in the distillate price from $16.43/GJ to $17.88/GJ. The change in the dispatch characteristics of Pinjar have a second order impact, which is similar in magnitude to their impact on the Maximum STEM Price.

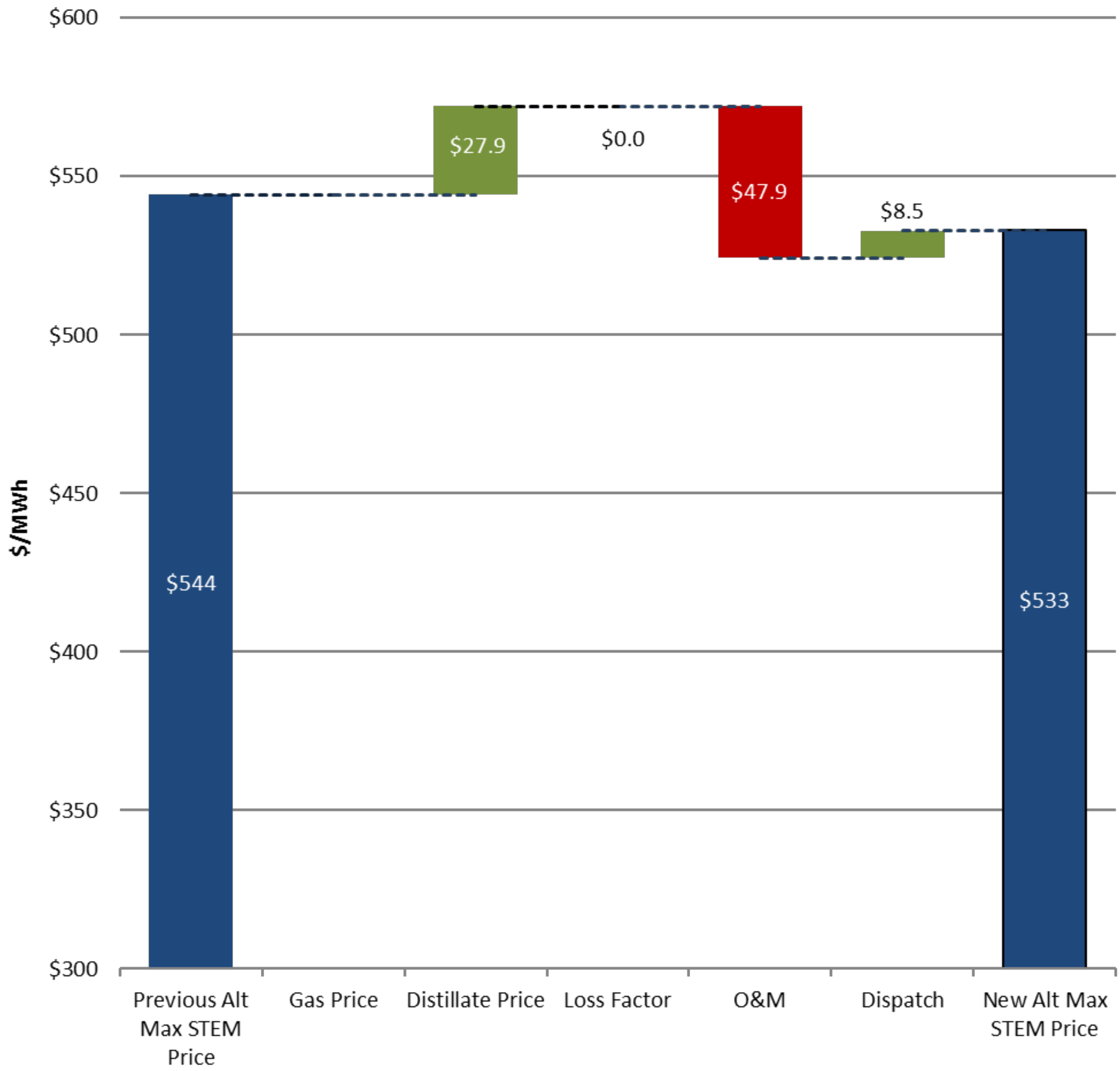
Table 13 Analysis of changes to form the waterfall diagram for the Alternative Maximum STEM Price

Step	Label in chart	Changes	Parameters affected (Appendix B)
1	Previous Max STEM Price	The calculation of the Maximum STEM Price based on the 2017 parameters.	
2	Gas Price (No effect)	The 2017 spot gas commodity cost distribution was updated with the distribution that applied in this year's review.	VFC (gas)
3	Distillate Price	Distillate price was changed from $16.43/GJ to $17.88/GJ, and the 2017/18 standard deviation was used	VFC (distillate)
4	Loss Factor (No effect)	The loss factor is still the 2017/18 loss factor	LF
5	O&M Parameters	The O&M costs for the industrial gas turbines, including number of starts, were updated with the 2018 values	VHC, SUC
6	New Historical Dispatch Patterns	Capacity, run times and Dispatch Cycle capacity factor based on the data from 1 January 2013 to 31 December 2017, replaces the data from 1 January 2013 to 31 December 2016	CAP, CF, RH, and hence MPR
7	New Max STEM Price	The basis for the 2018 Energy Price Limits	

Table 14 Impact of factors on the change in the Alternative Maximum STEM Price

Factor	Impact $/MWh
Dispatch	$8.51
O&M	-$47.93
Loss Factor	$0.00
Distillate Price	$27.92
Gas Price	$0.00

Figure 10 Impact of factors on the change in the Alternative Maximum STEM Price since 2017



4.5 Cross checking Dispatch Cycle costs with heat rate based on market dispatch

Since Rule Change RC_2008_07, the Market Rules refer to the use of the average heat rate at minimum capacity. This approach ensures that the Energy Price Limits would not restrict the most inefficient practical operation of the gas turbines - that is with loading at the minimum generation level. This has the effect of providing additional margin above the likely actual costs of peaking operation. In this study and previously, Jacobs has also calculated the expected costs using minimum and maximum capacities and associated heat rates and typical dispatch profiles to assess the variation of average heat rate for Dispatch Cycles of different duration and capacity factor. This process is described as the “Market Dispatch Cycle Cost Method” and the method and results are presented in Appendix F. This may be used to assess the probability that the Energy Price Limits will exceed actual Dispatch Cycle costs.

Table 15 shows a tabulation of the mean values of the Dispatch Cycle cost using the average heat rate at minimum capacity as well as the Market Dispatch Cycle Cost method. The results are quite similar, with only a very slight over-estimation of the Maximum and Alternative Maximum STEM Prices by using the heat rate at minimum value. For both the Maximum STEM Price and the Alternative Maximum STEM Price the value is $1/MWh lower after rounding using the Market Dispatch Cycle Cost Method.

Table 15 Energy Price Limits using average heat rate at minimum capacity or Market Dispatch Cycle Cost Method

	Maximum STEM Price		Alternative Maximum STEM Price	
	Average heat rate at minimum capacity	Market Dispatch Cycle Cost method	Average heat rate at minimum capacity	Market Dispatch Cycle Cost method
Mean value	$243.06	$242.24	$465.90	$464.04
80th percentile	$302.00	$301.00	$533.00	$532.00
Margin over expected value	24.7%	24.3%	14.9%	14.6%

The difference between the proposed Energy Price Limits and the Dispatch Cycle costs based on the Market Dispatch Cycle Cost Method for Pinjar is about 14.6% of the expected costs for distillate firing and about 24.3% for gas firing[27]. That the values are similar for the Maximum STEM Price reflects a higher number of short Dispatch Cycles in the historical data. Thus the Market Dispatch Cycle Cost Method is calculating an effective heat rate commensurate with the average heat rate at minimum capacity at the 80% probability of coverage.

[27] Table 15 compares the proposed price caps with the expected average Dispatch Cycle cost and shows the margins as a ratio of the expected average Dispatch Cycle cost, rather than the cost calculated by clause 6.20.7(b). The use of the average heat rate at minimum produces a slightly higher Maximum STEM Price due to the assumption about operation at minimum stable capacity which is not fully reflected in historical dispatch. The difference is immaterial.

5. Conclusions

The cost analysis of the short term running of gas turbines in the SWIS has confirmed the need to decrease the Energy Price Limit values on 1 July 2018 from those that apply currently. From 1 July 2018 it is proposed that:

- The Maximum STEM Price should be $302/MWh; and
- The Alternative Maximum STEM Price should be $189.27/MWh + 19.211 multiplied by the Net Ex Terminal distillate fuel cost in $/GJ.

At $17.88/GJ Net Ex Terminal Price the proposed Alternative Maximum STEM Price is $533/MWh.

The most significant influences on the Alternative Maximum STEM Price have been the decrease in start costs due to the new calculation methodology and the decrease in the assumed average factored starts per market start and the increase in the fuel price, driven by the recovery in the world oil price since early 2016.

The decrease in the Maximum STEM Price since last year's assessment has also primarily been driven by the decrease in the start cost as described above, and the decrease in the forecast spot gas price has also had a negative price impact. These impacts are also summarised in Appendix G.

Table 16 summarises the prices that have applied since July 2012 and the subsequent results obtained by using the various methods. New values are rounded to the nearest dollar amount.

Table 16 Summary of price caps

No.	History of proposed and published prices	Maximum STEM Price ($/MWh)	Alternative Maximum STEM Price ($/MWh)	Comment
1	Published Prices from 1 July 2012	$323	$547	From AEMO website.
2	Published Prices from 1 July 2013	$305	$500	From AEMO website
3	Published Prices from 1 July 2014	$330	$562	From AEMO website
4	Published Price from 1 July 2015	$253	$429	From AEMO website
6	Published Price from 1 July 2016	$240	$346	From AEMO website
7	Published Price from: • 1 October 2017 for Maximum STEM Price • 1 June 2018 Alternative Maximum STEM Price	$351	$604	From AEMO website[28]
8	Proposed price to apply from 1 July, 2018	$302	$533	Based on $17.88/GJ for distillate, ex terminal.
9	Probability level as Risk Margin basis	80%	80%	

Notes: (1) In row 8, as required in clause 6.20.7(b) these are the proposed price caps to apply from 1 July 2018 based on a projected Net Ex Terminal wholesale distillate price of $1.104/litre excluding GST ($17.88/GJ).
(2) In row 9, the probability levels that are proposed to be applied to determine the Risk Margin for setting the price caps in accordance with the Market Rules.

[28] https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Data/Price-limits, last accessed 23 May 2018.

Appendix A. Market Rules related to maximum price review

This appendix lists the Market Rules that determine the review of maximum prices in the WEM. The relevant Market Rule clauses are provided below:

6.20.6. AEMO must annually review the appropriateness of the value of the Maximum STEM Price and Alternative Maximum STEM Price.

6.20.7. In conducting the review required by clause 6.20.6 AEMO:

a) may propose revised values for the following:

i. the Maximum STEM Price, where this is to be based on AEMO's estimate of the short run marginal cost of the highest cost generating works in the SWIS fuelled by natural gas and is to be calculated using the formula in paragraph (b); and

ii. the Alternative Maximum STEM Price, where this is to be based on AEMO's estimate of the short run marginal cost of the highest cost generating works in the SWIS fuelled by distillate and is to be calculated using the formula in paragraph (b);

b) must calculate the Maximum STEM Price or Alternative Maximum STEM Price using the following formula:

(1 + Risk Margin) x (Variable O&M + (Heat Rate x Fuel Cost))/Loss Factor

Where:

i. Risk Margin is a measure of uncertainty in the assessment of the mean short run average cost for a 40 MW open cycle gas turbine generating station, expressed as a fraction;

ii. Variable O&M is the mean variable operating and maintenance cost for a 40 MW open cycle gas turbine generating station, expressed in $/MWh, and includes, but is not limited to, start-up related costs;

iii. Heat Rate is the mean heat rate at minimum capacity for a 40 MW open cycle gas turbine generating station, expressed in GJ/MWh;

iv. Fuel Cost is the mean unit fixed and variable fuel cost for a 40 MW open cycle gas turbine generating station, expressed in $/GJ; and

v. Loss Factor is the marginal loss factor for a 40 MW open cycle gas turbine generating station relative to the Reference Node.

Where AEMO must determine appropriate values for the factors described in paragraphs (i) to (v) as applicable to the Maximum STEM Price and Alternative Maximum STEM Price.

6.20.9. In conducting the review required by clause 6.20.6 AEMO must prepare a draft report describing how it has arrived at a proposed revised value of an Energy Price Limit. The draft report must also include details of how AEMO determined the appropriate values to apply for the factors described in clause 6.20.7(b)(i) to (v). AEMO must publish the draft report on the Market Web Site and advertise the report in newspapers widely published in Western Australia and request submissions from all sectors of the Western Australia energy industry, including end-users, within six weeks of the date of publication.

6.20.9A. Prior to proposing a final revised value to an Energy Price Limit in accordance with clause 6.20.10, AEMO may publish a request for further submissions on the Market Web Site. Where AEMO publishes a request for further submissions in accordance with this clause, it must request submissions from all sectors of the Western Australia energy industry, including end-users.

6.20.10. After considering the submissions on the draft report described in clause 6.20.9, and any submissions received under clause 6.20.9A, AEMO must propose a final revised value for any proposed change to an Energy Price Limit and submit those values and its final report, including any submissions received, to the Economic Regulation Authority for approval.

6.20.11. A proposed revised value for any Energy Price Limit replaces the previous value after:

a) the Economic Regulation Authority has approved that value in accordance with clause 2.26; and

b) AEMO has posted a notice on the Market Web Site of the new value of the applicable Energy Price Limit,

with effect from the time specified in AEMO's notice.

Appendix B. Formulation of the Maximum STEM Price

B.1 Formulation of the Energy Price Limits

The following represents the formulae used to model the formula in clause 6.20.7(b) of the Market Rules, excluding the Risk Margin factor, broken down into the full set of sub components. It is the formulae below that are used to calculate the 10,000 plus samples used to create the probability curve for the Energy Price Limits. The primary formula below includes the start-up fuel cost, the start operating cost and the fuel cost components.

Cost = (VHC * RH / MPR + AHRM * (VFTC+ (FT + VFC * FSR)/VFTCF)
+(SUC + SUFC * (VFTC + (FT + VFC * FSR)/VFTCF))/MPR)/ LF

Where:

Cost is the sampled estimate of the average marginal cost of a Dispatch Cycle including the start-up costs on the basis that the start-up costs are part of the cost associated with the decision to start operating a unit.

VHC is the variable hourly running cost when maintenance costs are based on running hours;

RH is the running hours per Dispatch Cycle based on a sampled distribution derived from market observations of dispatch. This distribution is confidential and is not included in this report, apart from the average of 66.7 hours for Parkeston shown in Table D- 4;

MPR is the MWh generated per run based on a sampled distribution derived from market observations and derived as a function of run time. This distribution is confidential and is not included in this report, apart from the average value of 1,401 MWh for Parkeston shown in Table D- 4;

MPR = CAP * RH * CF

AHRM is the average heat rate at minimum capacity in GJ/MWh sent out (or a dispatch based calculation of average heat rate when that alternative method was applied);

VFTC is the variable fuel transport cost in $/GJ;

FT is the fixed fuel transport cost in $/GJ;

VFC is the variable fuel cost in $/GJ in the range $2/GJ to $19.6/GJ or lower if the break-even price with distillate is lower;

FSR is the reference spot gas supply capacity factor (taken as 100%);

VFTCF is the spot gas supply daily capacity factor as modelled as a probability distribution between 60% and 100%;/

SUC is the cost per start ($/start) and is calculated using Monte Carlo simulations, as described in section 3.4.2.

SUFC is the start-up fuel consumption to get the plant up to minimum stable generation in GJ;

CAP is the plant sent-out capacity in MW. The capacity is derived from a distribution of maximum output of the generator units which is derived from market data.

CF is the capacity factor of the Dispatch Cycle derived from the capacity factor versus run time based on a regression function derived from historical operating data from January 2013 to December 2017 inclusive.

LF is the loss factor.

The variable fuel cost of gas (VFC) was capped to the price which would give the same Dispatch Cycle cost as the prevailing price of distillate sampled from the distillate price distribution.

The primary formula above may be split into the two components (fuel and non-fuel dependent) for the calculation of the Alternative Maximum STEM Price as follows.

The non-fuel component is based on non-fuel start-up costs, distillate road freight, and the variable O&M cost as applicable:

AMSP Non-fuel Component = ((VHC * RH / MPR + SUC)/MPR + (AHRM + SUFC/MPR) * VFTC)/LF

The fuel dependent component for the Alternative Maximum STEM Price cost is derived from the following components:

AMSP Fuel Component = (AHRM * (FT + VFC * FSR)/VFTCF + SUFC * (FT + VFC * FSR)/VFTCF/MPR)/ LF

After removing the zero and unity terms applicable to distillate, the fuel component is:

AMSP Fuel Component = (AHRM * VFC + SUFC * VFC /MPR)/ LF

The effective Fuel Cost Coefficient may be derived by dividing by the Net Ex Terminal fuel cost (VFC):

AMSP Fuel Cost Coefficient = (AHRM + SUFC/MPR)/LF

Note that the percentile value of these coefficients is derived from these sampled values so that the 80% value is obtained as discussed in section 4.2.

The treatment of these variables as stochastic variables is summarised in Table B.1. The means, minima and maxima and standard deviations for the heat rate (AHRM) were as derived from the Dispatch Cycle parameters based on the minimum capacity level. Over the 10,000 samples, the normal variables were typically between ±4 standard deviations unless clipped to a smaller range around the mean. The sampled number of starts per year was given a minimum value of 10. The start-up cost SUC, MPR, run times RH and plant sent-out capacity CAP and Dispatch Cycle capacity factor CF were derived from confidential market data. The start-up cost SUC depends on the distribution of the number of starts per year for the industrial gas turbines. The loss factor LF was as published by Western Power Networks for 2017/18. The start-up fuel consumption was based on the estimates developed by Jacobs.

Table B.1 Structure of the stochastic model of cost

Variable	Mean/Mode	Sampled Minimum	Sampled Maximum	Standard Deviation	Distribution Type	Comment
VHC	211.00	$129	$297	10%	Normal	Aero-derivative - Goldfields
AHRM	13.849 GJ/MWh	10.208	39.447	2.946 *	Normal	Aero-derivative – Goldfields (including variation due to minimum capacity uncertainty)
AHRM	19.088 GJ/MWh	15.52	29.51	1.335 *	Normal	Industrial – Pinjar (parameters obtained from the sampled distribution including variation due to minimum capacity uncertainty)
VFTC	$1.587	$1.464	$3.448	$0.280 *	Truncated lognormal	Aero-derivative - Goldfields
VFTC	$1.848	$1.017	$3.000	$0.280 *	Truncated lognormal	Industrial
FT	$0.00	$0.00	$0.00		None	Aero-derivative
FT	$0.00	$0.00	$0.00		None	Industrial

Variable	Mean/Mode	Sampled Minimum	Sampled Maximum	Standard Deviation	Distribution Type	Comment
VFC	$4.02	$0.00	$10.80	$1.702 *	Truncated normal	Gas supply after break-even price capping
FSR	100%	100%	100%		Fixed	
VFTCF	89.9%	61%	100%	6.86% *	Truncated lognormal	VFTCF = 1 for distillate
SUFC	3.53 GJ	2.142	4.752	10%	Normal	Aero-derivative
SUFC	3.50 GJ	2.121	4.704	10%	Normal	Industrial
SUFC	3.54 GJ	2.148	4.765	10%	Normal	Aero-derivative (liquid fuel)
SUFC	3.51 GJ	2.126	4.717	10%	Normal	Industrial (liquid fuel)

Note: * These standard deviation values refer to the values as sampled within the limited range.

Appendix C. Gas prices in Western Australia in 2018-19

C.1 Introduction

Jacobs considers the spot gas price to be the relevant price for use in the calculation of the Maximum STEM Price as it represents the opportunity cost of gas used by the marginal gas fired peaking unit. If surplus to requirements, the spot gas price represents the value that could be extracted through sale of gas in this market. This is consistent with the approach adopted in previous Energy Price Limit reviews.

This section presents Jacobs's assessment of the appropriate spot gas price range to apply in the derivation of the Maximum STEM Price. The assessment is based on publicly available information regarding gas prices in WA. Jacobs has estimated the 2018-19 gas price distributions using its own statistical approach.

C.2 The WA gas market

In WA gas is bought and sold predominantly on a term contract basis, with terms ranging from under one year to over 15 years. Contracts provide for annual and daily maximum quantities and annual minimum quantities also known as take-or-pay volumes. Contract details are confidential but for many contracts quantities and/or prices can be estimated from company press releases and other sources.

Buyers nominate daily quantities to be injected into pipelines on their behalf (up to the maximum limit) based on what they intend to withdraw and imbalances are managed by adjusting subsequent nominations up or down. If cumulative imbalances exceed a threshold, the pipeline may charge a penalty – on the major WA pipeline, the Dampier to Bunbury Natural Gas Pipeline (DBNGP), the thresholds are relatively generous.

Shorter-term trades arise when parties want to vary their offtake volumes above maxima or below minima or avoid penalty payments. This can be done through over-the-counter trades or through exchanges, of which there are currently three third party exchanges in WA[29]:

- The Inlet Trading market operated by DBNGP at the inlet to the pipeline, which enables pipeline shippers to trade equal quantities of imbalances.
- The gasTrading platform, which enables prospective buyers and sellers to make offers to purchase and bids to sell gas on a month-ahead basis at any gas injection point. gasTrading matches offers and bids and the gas is then scheduled, with subsequent daily adjustments.

  gasTrading's website provides information regarding volumes and prices of trades. For the past three years, typical volumes traded range from 5TJ/d to 20TJ/d (0.5% to 2.0% of WA domestic gas volumes) and prices paid range from $2.50/GJ to $7.50/GJ. The market does not settle at a single daily price but a range of prices reflecting a series of bilateral transactions.
- The gas trading platform operated by Energy Access Services since 2010. Energy Access has nine members but usage of the platform is unknown.
- Quadrant hosts a web-based system utilised for nominations management for existing customers of its domestic gas production facilities.

The reasons parties may choose to participate in each of the above alternatives may include preferences to deal directly with counterparties, their scale of trading, preferred periods of trades (e.g. daily, monthly). There is anecdotal evidence that the bulk of spot trading is completed bilaterally via master spot agreements. Stakeholders indicate that these trades are done below the gasTrading average price but there is no public data.

C.3 Estimating future gas spot market prices

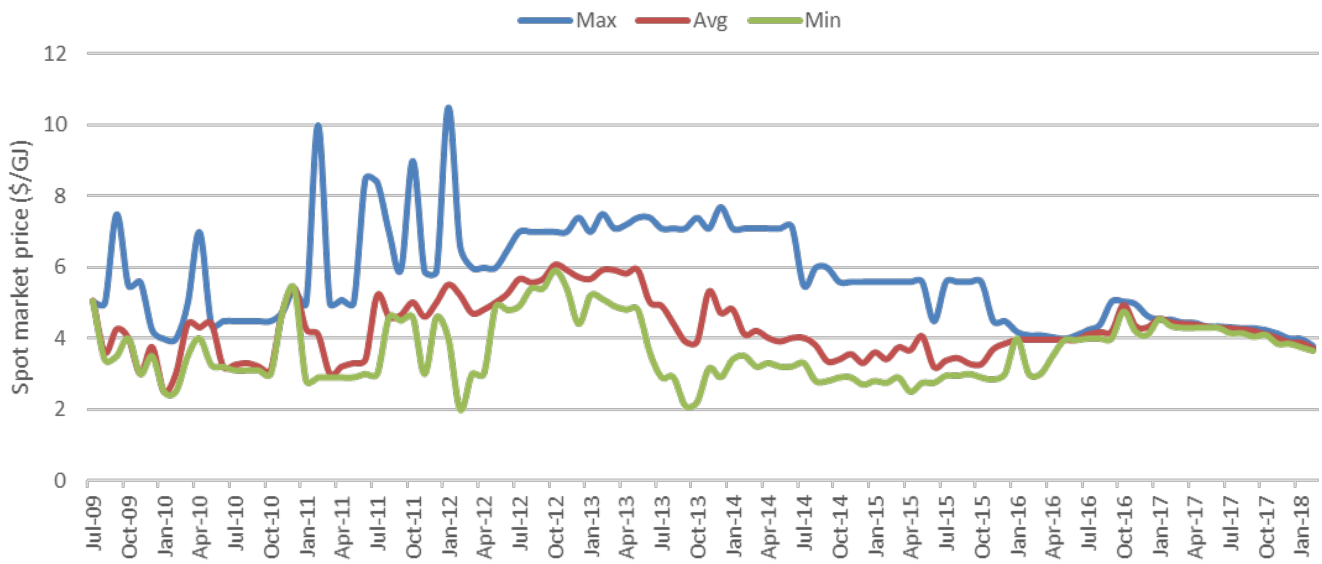
Jacobs believes that the most appropriate approach to projecting future spot prices for use in setting the Maximum STEM Price is to consider the recent spot market data available, as well as the measure by which

[29] There are also a number of privately run exchanges for which data is not available.

further developments are likely to influence this market. Ideally, spot prices would include estimates of all spot prices discussed above, including those which are not published. For the non-published prices this would involve a rigorous survey of market participants, to avoid using potentially unreliable anecdotal information. However, this has not been possible within the time frame of this review. Consequently, Jacobs has used gasTrading's spot prices as representative of the spot market as a whole.

During the 2015 review, Jacobs updated the methodology by which the distributions of future gas spot market prices are estimated as the previous method produced forecast price distributions that did not appear to align with market outcomes. Jacobs has based this year's modelling on the 'alternative' forecast methodology developed during the 2015 review, which predicts the gas price distribution as a function of the historical maximum monthly spot gas prices.

Figure C- 1 gasTrading spot market monthly price history



Source: gasTrading website

As evidenced from the data in Figure C- 1, average and minimum gas market prices have seen a gradual decrease from their peak in October 2012. In addition, the maximum price for gas exchanges through this market has become much more stable since October 2012, with much less volatility than previously. Between then and July 2014, the maximum price was seemingly capped at $7/GJ, which decreased on July 2014 to $5.60/GJ in 2015 and to $4.6/GW in the three years to February 2018. In the last 6 months the maximum price was $4.1/GJ and it fell to $3.8 in February 2018.

Jacobs has reviewed the December 2017 Gas Statement of Opportunities produced by AEMO and carried out analysis to understand the drivers behind the spot market exchanges.

The GSOO noted that *'WA spot gas prices traded via the gasTrading platform have averaged $4.32/GJ in 2017. Volumes traded are around 1% of total WA gas consumption through the gas transmission system. Since the start of 2017, the volatility of these prices has decreased considerably. There was no discernible spike in April 2017 during an outage at KGP.*'

In addition, using consumption and transmission data, a number of market dynamics have been identified which are likely to underpin the gas spot market in WA in the short term.

C.4 Factors affecting gas spot market trades and prices

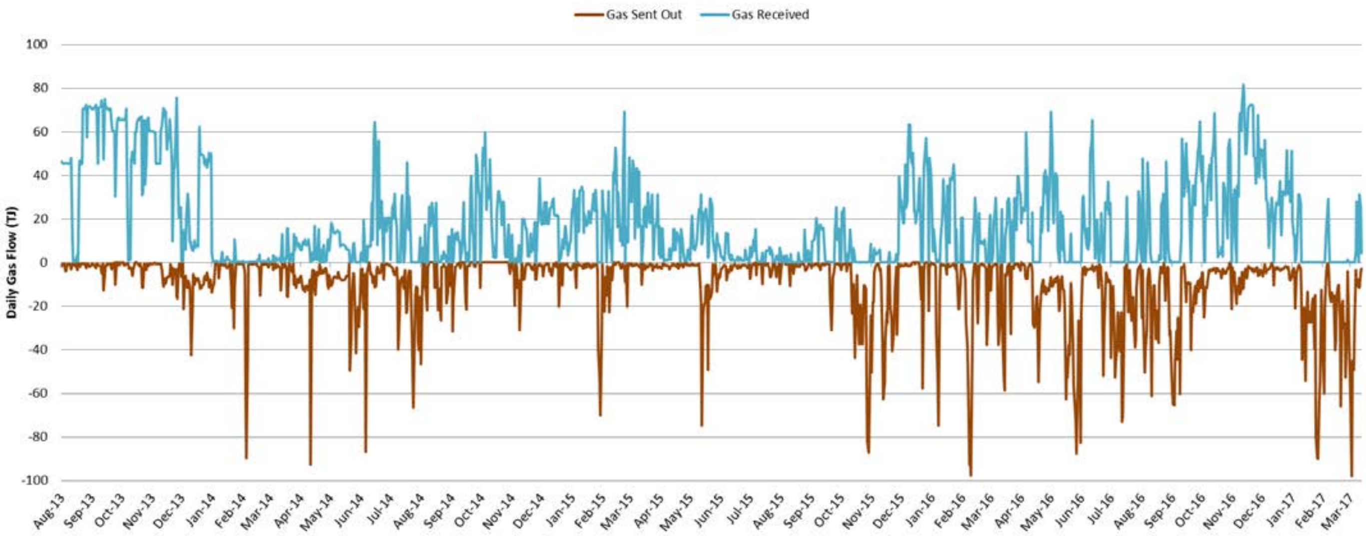
Electricity demand

In the 2015 study, Jacobs examined the relationship between peak electrical demand and high spot gas prices, on the basis that the higher demand for gas from peaking plant may have a significant impact on the spot gas price. However, only a weak correlation between the two was observed, indicating that other short-term factors dominate the spot market price.

Mondarra storage

The Mondarra storage operated by the APA Group (APA) commenced operations in 2013 and has an upgraded storage capacity of 15 PJ. Gas storages serve two functions: emergency supply when production or pipeline capacity is accidentally lost, and provision of additional peak or seasonal supply subject to availability of pipeline capacity from the storage to end-users. The latter function also involves price arbitrage, because gas is stored during lower price periods and re-used during higher price periods, assuming low/high prices correlate with low/high demand or high/low supply. At a time of generally rising prices lower cost gas can also be stored for future use in a longer timeframe. Figure C- 2 shows the changes in operation of the Mondarra storage plant since August 2013. It can be observed that the first period of operation consisted of drawing gas from the market to build up its gas storage. Closer inspection of the data suggests that there is no contract in place as the injection and withdrawal of gas by the facility may be displaying an opportunistic pattern.

Figure C- 2 Mondarra Gas Storage Facility Operations, Aug 2013 to Feb 2017



Source: AEMO Gas Bulletin Board

In September 2017 the Tubridgi gas storage facility began commercial operation. This is larger than Mondarra and quadruples WA's total gas storage capacity of 60 petajoules (PJ).

The impact of Mondarra and Tubridgi should be a reduced cost of gas supply, including gas spot prices. In particular, we would expect price volatility to be reduced with the introduction of the storage facility, as extreme prices present an arbitrage opportunity. The recent reduction in gas prices and volatility of price is consistent with this view.

New gas plant, LNG oversupply, and future exploration

Since the inception of the WA gas bulletin board and the first WA GSOO in 2013 two new export plants, Gorgon and Wheatstone have been constructed contributing to a doubling of existing liquefaction export capacity. LNG projects in WA (but not offshore projects) have an obligation under the WA domestic gas policy to set aside reserves equivalent to 15% of their LNG production for the WA domestic market. Commercial terms of supply, including price and timing, are left to the market to negotiate.

Two new domestic gas production facilities, Gorgon and Xyris have commenced operations adding 31% to production capacity bringing the total to 1,659 TJ/day.

The Wheatstone domestic gas facility and Woodside via compression from Pluto are expected to commence operations in 2018. The commissioning of these projects is expected to increase potential gas supply from 2018 and reduced price volatility in the domestic market. There is the possibility that this will lead to downside pressure on the spot price but there is no current evidence to substantiate this.

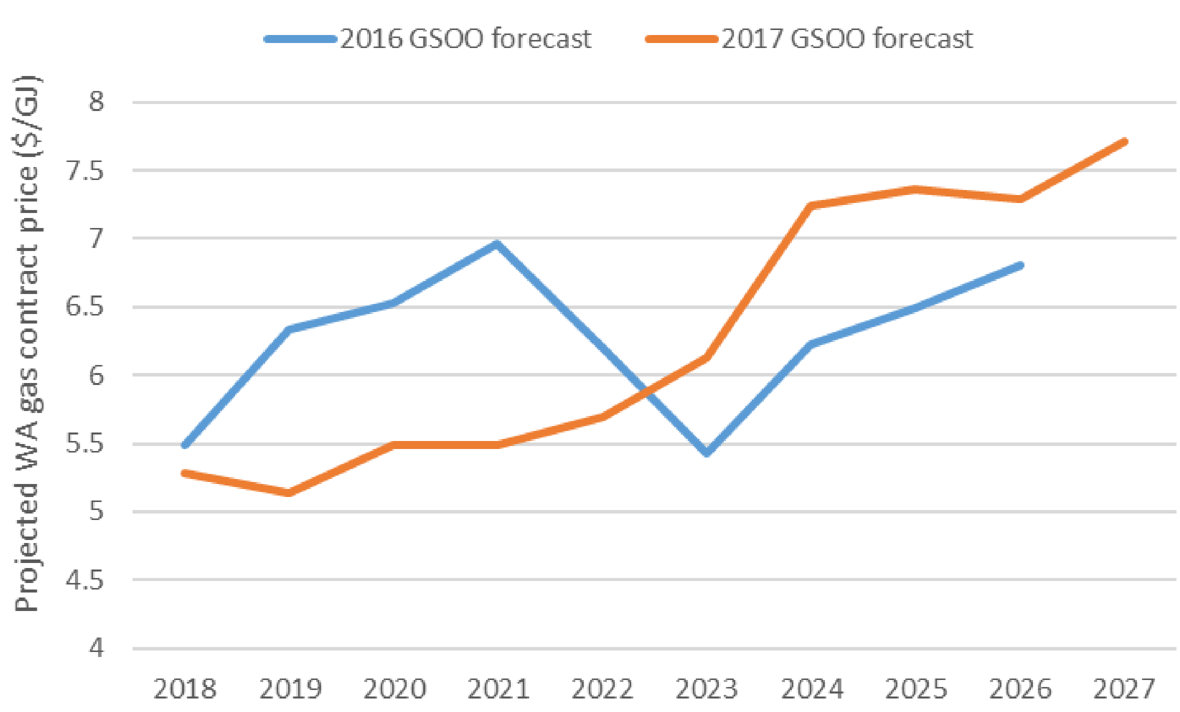
The December 2017 GSOO forecasts domestic gas prices to remain above production costs and it is assumed there will be continued investment to develop gas reserves to replace natural decline. The GSOO Base scenario shows potential gas supply exceeds demand by at least 132TJ/day each year until 2020. There is only a small increase in gas price until 2022 after which a rise in gas price is expected to incentivise development of new reserves. Presently, exploration activity continues to decline since the 2008 peak, in line with over-supply in the global oil and gas markets keeping prices low. Only nine wells have been drilled to date in 2017 (assumed to be end of August 2017), which is a quarter of those drilled in 2016. This compares to 194 wells drilled in 2008.

Future gas prices

The WA domestic gas price has been forecast as a value that is between a minimum (the production cost of gas plus and a 10% rate of return) and a maximum (the LNG netback price). This range reflects the considerable level of competition in the WA domestic gas supply market.

The average new medium- to long-term contract gas price forecasts developed for the Base scenario for the 2016 WA GSOO and those developed for the 2017 report are compared in Figure C- 3 below. The main driver for a sharp decrease in forecast domestic gas prices since the previous WA GSOO is that international oil prices are now projected to remain weak until 2022, and excess WA domestic gas supply capacity is projected to keep WA domestic gas prices in the $5 to $8/GJ range.

Figure C- 3 Forecast medium-term average (ex-plant) new domestic contract gas prices ($/GJ real)



C.5 Forecasting maximum monthly spot market prices

For the forecast of the gas price distribution for the period 2018/19 Jacobs has modelled the forecast prices using a standard ARIMA time-series model, which is widely considered reliable for short term projections. The historical spot market maximum price is used as the basis of the model, which produces a range of prices that future maximum spot gas prices are likely to fall within. Once this forecast range is calculated, a normal distribution has been fitted to the prediction series, which best represents the expected probability density curve of spot prices based on the market forces considered in this study.

For the ARIMA model, the historical data has been obtained from the gasTrading market website. The spot market experienced a high level of volatility from 2009 to early 2012. After this period the maximum price settled down and has maintained low variability. The maximum prices show a downward trend in pattern, although over the last two years prices have levelled off. Based on these trends, the forecast suggests stable price outcomes, with the maximum spot price being flat throughout the year. The level of uncertainty around the forecast has been used to derive the standard deviation of the spot gas price distribution. The projection shows increasing uncertainty over time, which is typical of an ARIMA forecast. The level of uncertainty is slightly lower than was forecast in last year's review.

Figure C- 4 gasTrading spot market daily price history and ARIMA forecast

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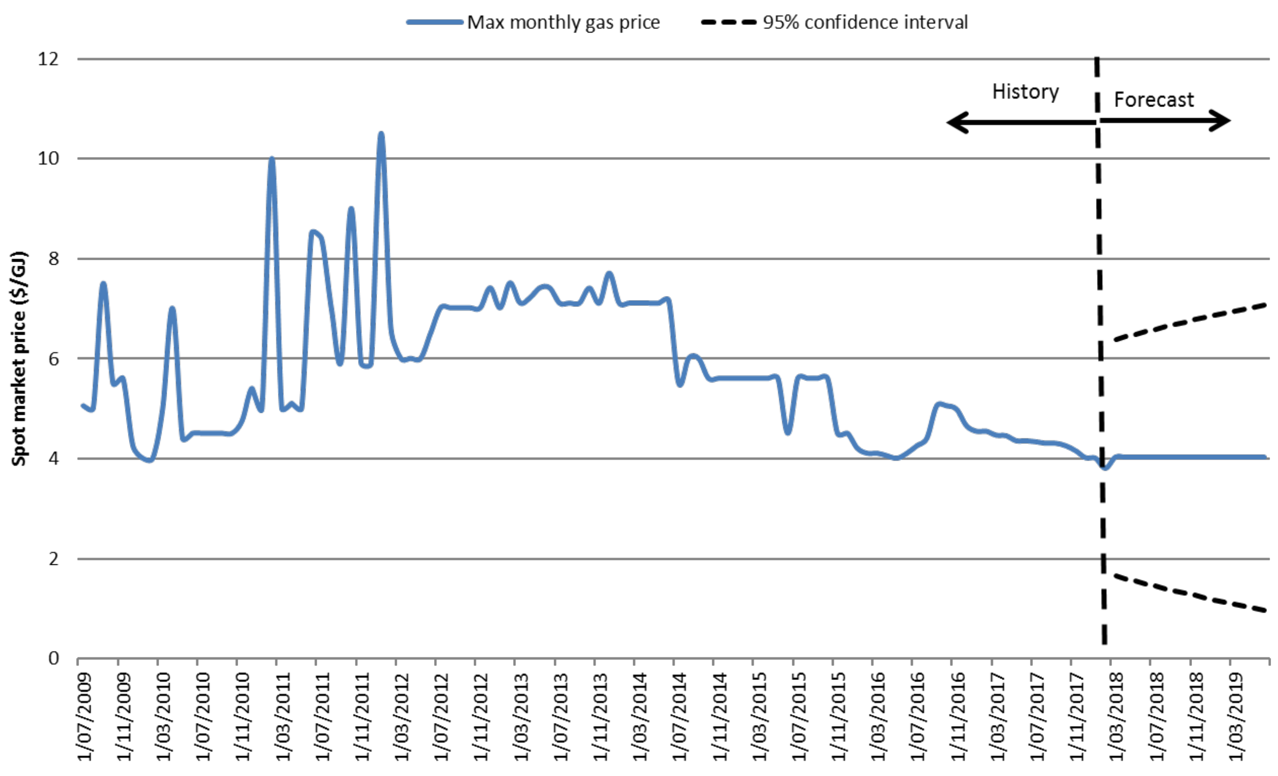


Source: gasTrading website; Jacobs's analysis.

C.6 Forecast of WA gas spot market price distribution

The gas price distribution was derived by using the maximum monthly prices and monthly standard deviations obtained from the ARIMA model described in section C.5. The historical maximum prices from July 2009 to February 2018 and the forecast maximum prices for the 2018/19 financial year from the ARIMA model are illustrated in Figure C- 4 together with the upper and lower 95% confidence intervals.

These monthly parameters (monthly maximum prices and monthly standard deviations) were used to derive a normal distribution of gas prices for each month. A composite normal distribution was then derived for financial year 2018/19 from the 12 monthly distributions. The composite distribution was also normal, having a mean price of $4.02/GJ and a standard deviation of $1.72/GJ.

A limitation of the ARIMA modelling is that it can only project future price trends based on the information contained in the historical price time series. It is not able to represent other factors, such as expected movements in the gas contract price or the oil price, or foreseeable shifts in the supply/demand balance, that may also have an impact on future spot prices. Our review presented in section C.4 did not reveal any external factors that would have a foreseeable impact on domestic prices, and as a result we propose to use the unmodified ARIMA maximum monthly spot gas price forecast to represent the expected distribution of maximum spot gas prices in 2018/19. Jacobs believes this approach is appropriate as all indications are that the global LNG market is currently oversupplied and will remain so for at least two years, and the domestic WA gas market also appears to be oversupplied.

The composite gas price distribution is shown in Figure C- 5, which shows that some gas prices under this distribution fall below the $2/GJ gas floor price adopted for this analysis. In these cases the $2/GJ floor has not been applied in the modelling because this part of the distribution will not contribute to the 80th percentile anyway. A refinement could be to model a $2/GJ gas price floor, but its impact will only be to have a slight impact on the mean of the sampled distribution.

Figure C- 5 Forecast of WA gas spot market distribution

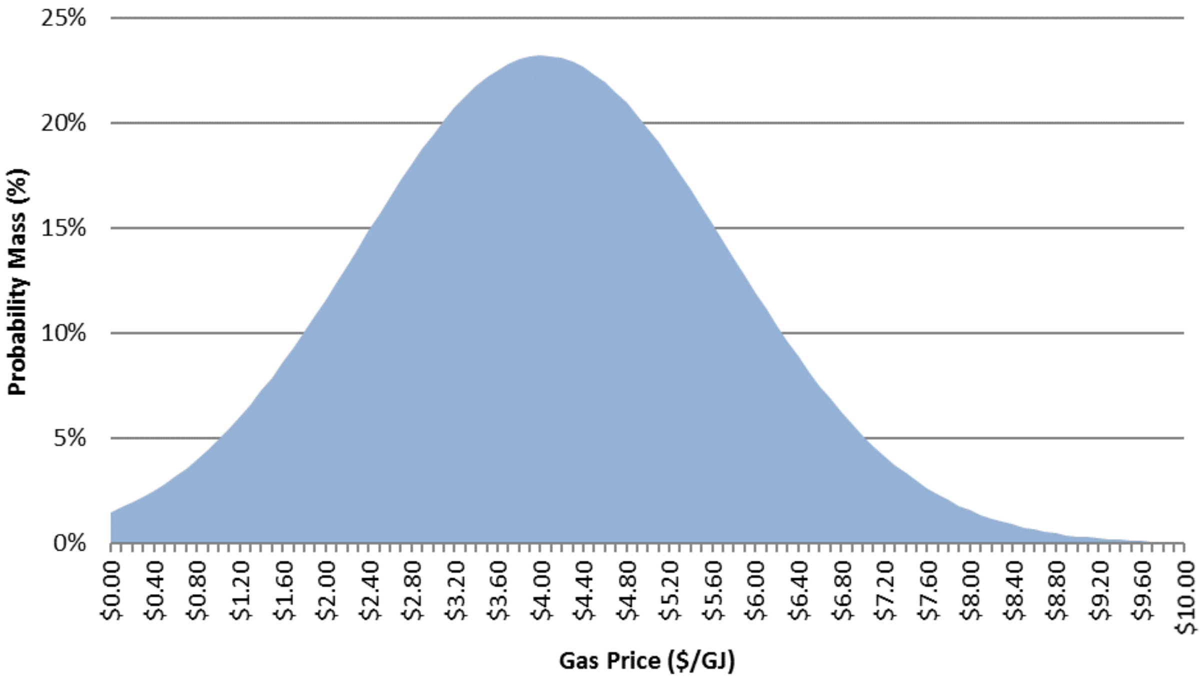


Table C- 1 compares the gas price forecast with last year’s gas price forecast.

Table C- 1 Comparison of forecast gas distribution statistics

Parameter	Jacobs 2017/18	Jacobs 2018/19	Change 2017/18 to 2018/19
Average	$4.66	$4.02	-$0.64
Median (50th percentile)	$4.66	$4.02	-$0.64
80% lower bound (10th percentile)	$2.36	$1.82	-$0.54
80% upper bound (90th percentile)	$6.96	$6.23	-$0.73

C.7 Gas transmission costs

C.7.1 Transmission tariffs

Transmission costs on the two pipelines considered in this Energy Price Limit review are set by a combination of regulation by the Economic Regulation Authority under the National Gas Regulations (NGR) and negotiation between the pipeline operators and gas shippers. A review of both pipelines led to new prices being established in 2015 and 2016.

C.7.1.1 Dampier to Bunbury Natural Gas Pipeline

The DBNGP is a Covered (regulated) pipeline and tariffs were set by the ERA in 2016 to cover the base tariff and recent capacity increases. The standard full haul (T1) tariff is applicable to delivery into the Perth region downstream of compressor station CS9 and the part haul tariff (P1) is for deliveries to the north of CS9. The P1 tariff also provides rules for spot trading.

The T1 and P1 tariffs are comprised of two components, a reservation component charged on capacity reserved and set at 80% of the aggregate, and a commodity component charged on volumes shipped, set at 20% of the aggregate. For the P1 tariff the T1 tariff is adjusted by a distance factor: for each outlet point at which the shipper receives gas, the distance factor is the distance in kilometres between the inlet point I1-01 (domgas) and the relevant outlet point divided by 1400 kilometres.

Spot capacity is defined as gas transmission capacity on a gas day that is available for purchase. A shipper has to bid for spot capacity by 15.00 hours the day before and will be notified by 16.00 hours whether the bid has been accepted. Capacity is allocated to the highest bid, then the next highest until the capacity is sold or all bids are satisfied.

The shipper must pay the daily spot bid price bid by it for that spot capacity whether or not it uses the spot capacity.

The operator may set a minimum bid price for daily bids and is not obliged to schedule spot capacity to any shipper bidding a daily spot bid price which is less than the minimum bid price. The minimum bid price for daily bids cannot be greater than 115% of the base T1 tariff applying on the relevant gas day.

Up to January 2021, the base T1 tariff is adjusted, on 1 January in each year (beginning with 1 January 2015), in accordance with CPI on the following basis:

$Base\ Tariff_n = New$ 2014 $Tariff \times (CPI_n CPI_{2013})$; where the New 2014 Tariff is $1.403000.

Jacobs is not aware of any scheduled new capacity to the DBNGP and this has not occurred since the price reset there are no additional tariff factors. There is potential for an increased tariff of 200% of the T1 tariff for gas that falls outside the outer imbalance limit of 20% of the shipper’s capacity and outside the accumulated imbalance limit of 8% that has not been rectified as per the request of the operator. It is expected that a prudent shipper will not pay for either of these increased tariffs.

Based on this, we assume that the T1 tariff will have an average value of $1.607/GJ over the 2018/2019 financial year, which is the average of the estimated 2018 and 2019 tariffs, assuming future CPI escalation of 2.0%, which is in line with Western Australia’s Treasury’s forecast.

No data is available on price outcomes for spot transport but in the current climate of capacity being in excess of transport requirements we would expect limited demand for spot capacity and correspondingly low prices.

C.7.1.2 Goldfields Gas Pipeline

Capacity on the GGP is partly covered and partly uncovered. Covered capacity amounts to 109 TJ/d with the current delivery configuration, of which 3.8 TJ/d was uncontracted as at 1 January 2010. Uncovered capacity, which relates to recent expansions, is estimated to be approximately 91 TJ/d following an expansion in 2013.

The regulated tariffs for the covered capacity are shown in Table C- 2 for the base year together with the total charge in Kalgoorlie (distance 1380km). The capacity reservation capacity relates to the maximum daily capacity (MDC).

Inflation is applied quarterly according to the following formula.

$C_t = C_{t-1} * 1/(1+K) * (CPI_{t-2} / CPI_{t-3})$

Where:

C_t is the relevant charge in the quarter t in which the adjustment occurs.
C_{t-1}s the charge for the quarter commencing three months prior to the commencement of quarter t. For the quarter commencing 1 September 2016, C_{t-1} is the relevant charge shown above for 1 July 2016.

K is $(1+Z)^{0.25}$ -1

Z is 0.0146 (1.46% being the forecast annual percentage inflation rate used in the final decision).

CPI_{t-2} is the CPI all groups, weighted average of eight capital cities for the quarter commencing six months prior to the commencement of quarter t.

CPI_{t-3} is the CPI for the quarter commencing nine months prior to the commencement of quarter t.

Applying this formula, and assuming a CPI increase of 0.496% per quarter (2.0% pa) gives an average cost in 2018/2019 of gas transmission to Kalgoorlie of $1.297/GJ.

Table C- 2 GGP tariffs

	Toll Tariff $/GJ	Capacity Reservation Tariff $/GJ MDC km	Throughput Tariff $/GJ km	2018/19 cost at 100% load factor in Kalgoorlie (1380 km) $/GJ
Covered capacity, Base tariff	0.116369	0.000620	0.000228	1.296689

To the best of our knowledge GGP does not systematically offer capacity on a spot basis. For previous Energy Price Limit reviews, ACIL Tasman has suggested that "it would be possible for an existing shipper to gain access to limited volumes of spot capacity for a small premium above the existing indicative tariffs"[30]. It is therefore reasonable to believe both APA and existing shippers would only offer spare capacity above the covered capacity price level. GGP data suggests there is at least 25 TJ/d unused capacity which supports the assumption that access to small volumes of spot capacity would be possible.

C.7.2 Transmission costs

The accepted practice in previous Energy Price Limit reviews has been to use the following transmission costs:

- For DBNGP full haul, the estimated minimum spot price converted into a range by adding a lognormal distribution with a standard deviation of $0.15/GJ.
- For GGP, a 10% premium on the covered estimate at 100% load factor, that is, $1.43/GJ for 2018/19.

For the gas transport to Perth on DBNGP, the lognormal distribution assumed has an 80% confidence range being between $1.51/GJ and $2.21/GJ with a most likely value (mode) of $1.805/GJ. The mean value of the transmission charge is $1.848/GJ. The distribution shown in Figure C- 6 represents this uncertainty in the gas

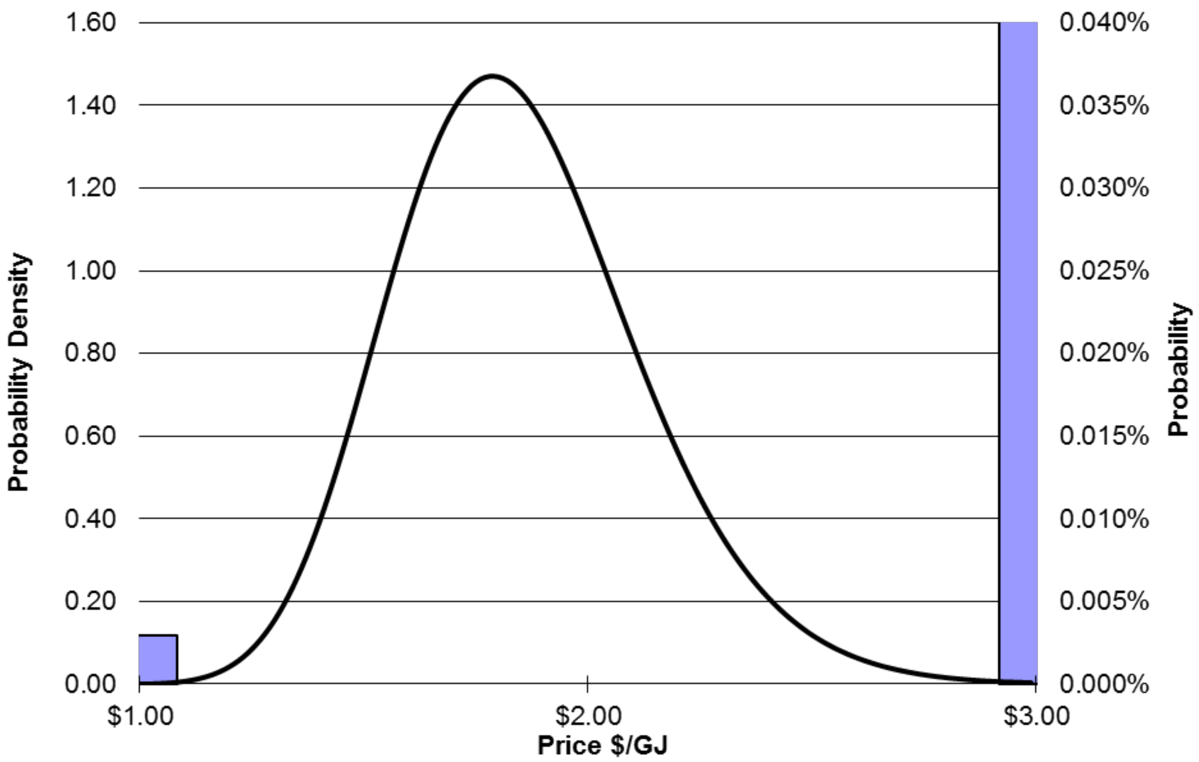
[30] ACIL Tasman, *Gas Prices in Western Australia: 2013-14 Review of inputs to the Wholesale Energy Market*, February 2013, p.10.

transport cost. The gas cost range was taken between $1/GJ and $3/GJ which is consistent with the assumptions adopted in the past four reviews.

For Mungarra, gas is supplied by DBNGP at delivery point O81-02. This is 999km from Dampier, so the P1 tariff applies with a distance factor of 0.71. This factor has been applied to the cost distribution assumed for Mungarra.

For Parkeston, gas delivered via the GGP is sourced from production plants that inject gas into the DBNGP and directly into the GGP. Gas injected into the DBNGP is backhauled or part-hauled to the inlet of the GGP. As the distance travelled in the DBNGP pipeline is small, a nominal 10% of the DBNGP full spot price is added to the cost of delivering gas to Kalgoorlie. Note that this simplistic assumption is different to last year's update that assumed the total cost of spot transport to Perth. There is uncertainty since it is not known what proportion of gas to the power station is injected directly into the GGP and/or into the DBNGP. Given that the Parkeston aero-derivative units do not currently set the Maximum STEM Price, this assumption is considered reasonable for this analysis, but may need to be reconsidered should the Parkeston units become genuine candidates for setting the Maximum STEM Price in the future.

Figure C- 6 Capped lognormal distribution for Dampier to Bunbury Pipeline spot gas transport cost

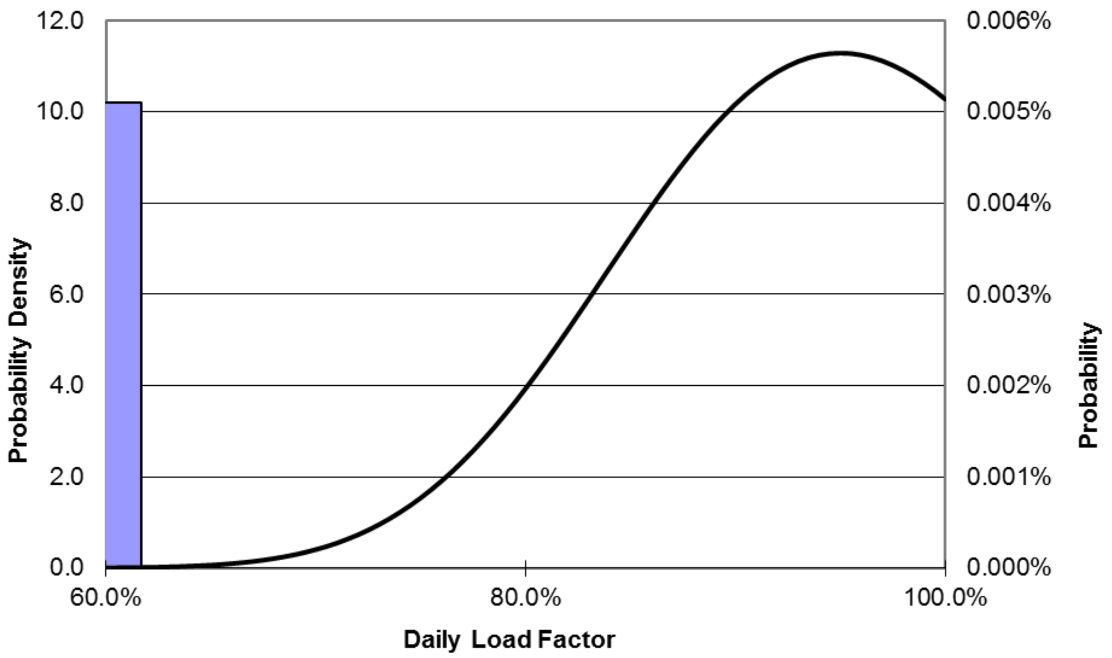


C.8 Daily gas load factor

The probability distribution used to represent the uncertainty of the daily gas supply load factor is shown in Figure C- 7. The mode of the continuous distribution is at 95% with an 80% confidence range between 80% and 98%. There is a 0.005% probability of a value at 60%. The mean of the composite daily load factor distribution is 89.91%. This is consistent with the model provided by ACIL Tasman for the 2013 review and has been used in all reviews by Jacobs since then.

In the past, assessed changes to this distribution have been quite small. When the Balancing market was introduced in 2013 this distribution did not change materially and ACIL Tasman (who carried out this assessment for the 2013 review) noted that the re-bidding process introduced by the Balancing Market did not eliminate the risk of a peaking generator over-estimating its spot gas requirement for the next day. In light of this, Jacobs recommends that the daily load factor distribution be locked in for future reviews unless there is a change in spot gas arrangements relating to peaking generators in the WEM.

Figure C- 7 Capped lognormal distribution for modelling spot gas daily load factor uncertainty



Appendix D. Energy Price Limits based on aero-derivative gas turbines

This appendix presents the analysis for the Parkeston gas turbines and compares it with the base calculations for Pinjar gas turbines shown in Chapters 3 and 4.

The calculations were substantially the same as for the industrial gas turbines except that:

- The gas transportation cost is supplemented by the Gas to the Goldfields Pipeline (GGP)
- The distillate freight cost is greater given the larger distance travelled (3.2 Acpl excluding GST and excise compared to 1.4 Acpl for Pinjar)
- The O&M cost is determined by running hours instead of starts
- There is a 47% cost penalty on the variable O&M cost for liquid firing because the aero-derivatives require more frequent maintenance when liquid fired. This arises from the Hot Rotable exchange which is required every 12,500 hours for liquid firing instead of 25,000 for gas firing.
- The transmission loss factor differs for Parkeston (1.1686)
- The assumed heat rate and start-up fuel consumption differs for Parkeston as described in Section D.4 below

The following sections discuss these differences in input data where not already commented on.

D.1 Run times

The frequency of starts and run times for Parkeston have changed appreciably over the 2017 calendar year. Units 2 and 3 in particular are operating more frequently, but for much shorter cycles relative to their operation in calendar 2013 to 2016. The evidence is presented in the confidential Appendix for AEMO.

The run times of the peaking units have been analysed from the market data from 1 January 2013 to 31 December 2017. A probability density function has been derived which represents the variation in run times until 31 December 2017.

D.2 Gas transmission to the Goldfields

Having assessed the likely conditions for spot trading of gas transmission capacity, Jacobs have concluded that the appropriate prices for delivery to the Goldfields from 1 July 2018 should be $1.59/GJ (this includes 10% of the DBNGP transport price) distributed lognormally with a standard deviation of $0.15/GJ. This results in a distribution with mean of $1.60/GJ with an 80% confidence range between $1.31/GJ to $1.94/GJ.

The resulting modelled delivered gas price as compared with the equivalent delivered price for the industrial gas turbines at Pinjar is shown in Figure D- 1. The modelled delivered gas price for the Goldfields region had an 80% confidence range of $3.58/GJ to $8.61/GJ with a mode of $6.10/GJ and a mean of $6.08/GJ. The key features of the delivered gas price for Parkeston are provided in Table D- 1. The distribution is very similar to that of the industrial gas turbines at Pinjar.

Figure D- 1 Sampled probability density of delivered gas price for peaking purposes

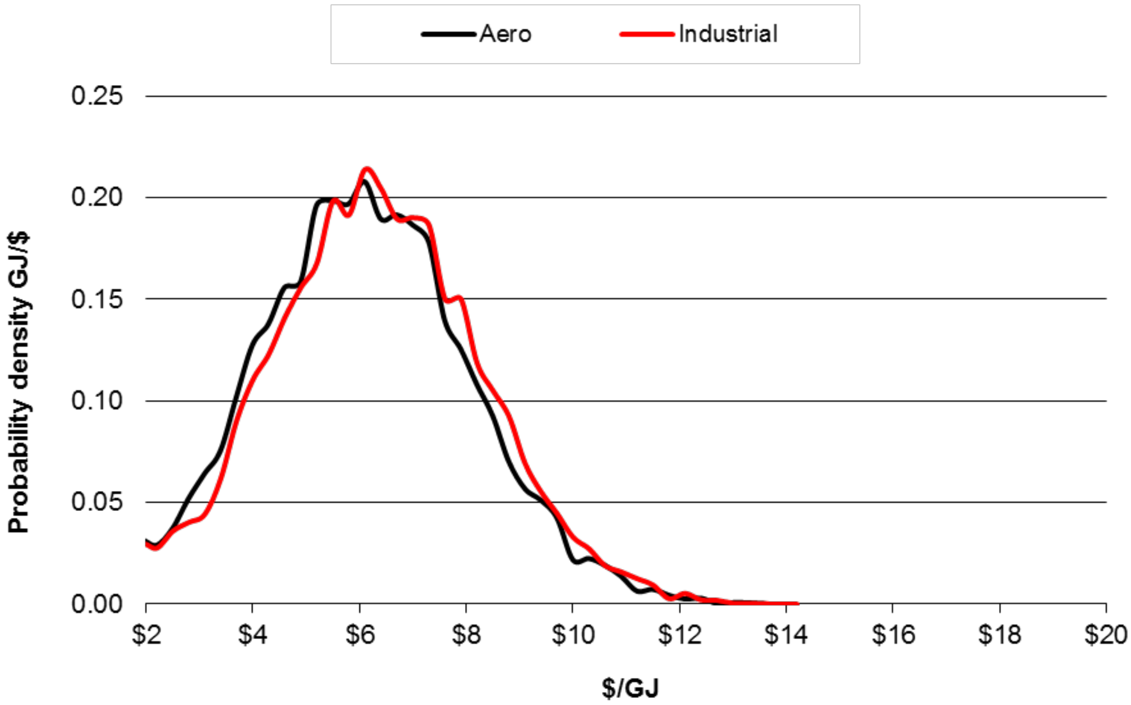


Table D- 1 Delivered gas price for Parkeston gas turbines

Delivered Gas Prices as Modelled	
	Parkeston
Min	$1.07
5%	$2.84
10%	$3.58
50%	$6.05
Mean	$6.08
Mode	$6.10
80%	$7.69
90%	$8.61
95%	$9.40
Max	$13.21

D.3 Distillate for the Goldfields

The Net Ex Terminal distillate price is assumed to be $17.88/GJ, as shown in Table 3. After applying a rail freight cost of 3.23 Acpl to Parkeston this equates to a diesel price of $18.72/GJ for Parkeston.

D.4 Fuel consumption

The start-up fuel consumption for the aero-derivative gas turbines was estimated as 3.53 GJ. For liquid firing, it is 3.54 GJ. An additional 5% of heat energy was allowed for start-up on distillate at Lower Heating Value which equates to 0.27% at Higher Heating Value. A 10% standard deviation was applied to these values with a normal distribution limited to 3.2 standard deviations.

Table D- 2 shows the steady state heat rates that were applied for the aero-derivative gas turbines. They were increased by 1.5% to represent typical degradation from new conditions. The temperature sensitivity of the heat rates was estimated from the run-up heat rate curves, and was less than 1% over the range 15°C to 41°C.

Table D- 2 Steady state heat rates for new and clean aero-derivative gas turbines (GJ/MWh HHV)

		% site rating			
Temp	**Humidity**	**100%**	**50%**	**33%**	**25%**
15°C	30%	10.584	11.776	13.066	14.100

The minimum load position has been extracted from the sampled data and the corresponding heat rate at minimum determined from Table D- 2. This heat rate at this minimum, including the temperature variability, results in a normal distribution with a mean of 13.849 GJ/MWh and a standard deviation of 2.946 GJ/ MWh. Both the mean and the standard deviation have increased markedly since last year's review, where both are based on the analysis of actual dispatch for the Parkeston units over the 2013 to 2017 calendar years. This reflects the change in operation evident in the Parkeston units over calendar 2017.

D.5 Aero-derivative gas turbines – LM6000

The maximum capacity of the Parkeston machines varies during the year due to temperature and humidity variation. The maximum capacity was derived from historical dispatch information taking into account the seasonal time of year using a sinusoidal fitting function. In this way, the variation of the maximum output during the year is included in the uncertainty analysis. A sinusoidal curve was used to estimate the maximum dispatch and the error around this curve was added back to give an overall distribution of maximum capacity. The applicable distributions are provided in a confidential Appendix to AEMO and the ERA.

The variable O&M cost for aero-derivative gas turbines is based upon a maintenance contract price of $307.07/hour in December 2018 dollars as estimated and shown in the second column from the right in Table D- 3. These costs have been established after new price data from GE were provided and the $US exchange rate was applied to the parts component of the cost. Jacobs has applied economic time based discounting for the major overhaul components and the logistics costs split between scheduled and unscheduled maintenance to calculate a discounted cost of $207.83/hour in December 2018 dollars.

Table D- 3 Basis for running cost of aero-derivative gas turbines, gas firing —LM6000 (December 2018 dollars)

Overhaul Type	Number of hours trigger point for overhauls	Cost per Overhaul	Number in Overhaul Cycle	Cost per cycle	Cost per fired hour	Discounted Cost per fired hour
Preventative Maintenance	4,000 hrs, 450 cycles or annually, whichever first		14.227	$252,049	$5.04	$5.04
Hot Section Rotable Exchange	25000	$4,228,488	1	$4,228,488	$84.57	$48.74
Major Overhaul	50000	$7,047,480	1	$7,047,480	$140.95	$81.23
Shipping of Parts, Travel, Living Expenses of Maintenance Personnel, Extra				$545,965	$10.92	$7.23

JACOBS

Overhaul Type	Number of hours trigger point for overhauls	Cost per Overhaul	Number in Overhaul Cycle	Cost per cycle	Cost per fired hour	Discounted Cost per fired hour
Unscheduled Maintenance				$2,863,043	$57.26	$57.26
Consumable Day-to-Day Maintenance (lube oil, air filters, etc.)				$416,711	$8.33	$8.33
			Total:	$15,353,736	$307.07	$207.83

Source: Jacobs data sourced from manufacturers and analysis of discounted value based on 52.7 starts/year

Aero-derivatives have a minimum start-up cost equivalent to about one running hour. However, under this pricing structure, this additional impost may be ignored as immaterial.

Table D- 4 shows the assessed variable O&M cost based on the historical operating regime for the aero-derivative gas turbine since January 2013. The weighted average is $7.11/MWh. The variable O&M cost is more stable, so Jacobs has not added uncertainty due to changes in starts per year or running hours.

Table D- 4 Assessed variable O&M cost for aero-derivative gas turbine – LM6000

Aero-Derivative Unit	Average Running Hours	Number of Starts / Year	Cost / Run	Average MWh per Run	Variable O&M Cost $/MWh
1	16.7	70.8	$3,787	449.9	$8.42
2	125.6	30.4	$28,522	3,309.0	$8.62
3	57.7	57.0	$13,100	1,564.8	$8.37
ALL UNITS	66.7	52.7	$11,896	1,401.0	$8.49

It is considered that liquid firing of aero-derivative gas turbines doubles the frequency of the Hot Section Rotable Exchange every 12,500 hours. This increases the assessed discounted operating cost from $208/hour to $305/hour, which is a 47% increase.

D.6 Results

Table D- 5 compares the results for the aero-derivative gas turbines with the results shown above for the industrial gas turbines. It is evident that the costs remain substantially lower for the aero-derivative gas turbines.

Table D- 5 Analysis of Dispatch Cycle cost using average heat rate at minimum capacity

Sample	Aero-Derivative – LM6000		Industrial Gas Turbine	
	Gas	Distillate	Gas	Distillate
Mean	$79.66	$240.98	$243.06	$465.90
80% Percentile	$99.31	$262.47	$301.52	$525.69
90% Percentile	$113.88	$289.50	$374.69	$596.08
10% Percentile	$47.27	$199.69	$144.01	$368.38
Median	$76.82	$228.52	$217.98	$438.35
Maximum	$390.95	$714.15	$1,021.19	$1,259.48

Sample	Aero-Derivative – LM6000		Industrial Gas Turbine	
	Gas	Distillate	Gas	Distillate
Minimum	$17.49	$162.38	$59.36	$293.45
Standard Deviation	$28.76	$50.93	$104.94	$104.39
Non-Fuel Component $/MWh				
Mean	$24.77		$136.95	
80th Percentile	$28.42		$189.27	
Fuel Component GJ/MWh				
Mean	10.804		18.696	
80th Percentile	13.099		19.211	
Equivalent Fuel Cost for % Value $/GJ				
Mean	19.742		17.595	
80th Percentile	17.628		17.512	

Appendix E. Energy Price Limits based on the Mungarra industrial gas turbines

This appendix presents the analysis for the Mungarra gas turbines and compares it with the base calculations for Pinjar gas turbines shown in Chapters 3 and 4.

The calculations were substantially the same as for the Pinjar gas turbines except that:

- The P1 tariff applies for gas transportation with a distance factor of 0.71 relative to Pinjar.
- The transmission loss factor differs for Mungarra (0.9957)
- The dispatch characteristics for Mungarra were sourced from the historical operation of the plant from January 2017 until December 2017. This represents one full year over which the plant has been operating in peaking mode.
- Mungarra has had 70% low-load starts over this time period, resulting in an applicable factored starts factor of 0.83 starts per market start.

The following sections discuss these differences in input data where not already commented on.

E.1 Run times and number of starts

The frequency of starts and run times for Mungarra in calendar 2017 are quite different to Mungarra's historical operation and are also different to Pinjar's characteristics. The evidence is presented in the confidential Appendix for AEMO.

The run times of the peaking units have been analysed from the market data from 1 January 2017 to 31 December 2017. A probability density function has been derived which represents the variation in run times until 31 December 2017.

The average number of starts assessed for the Mungarra units over calendar year 2017 was 27.7, compared with 64.9 for Pinjar, which is less than half the number of starts. Applying 0.83 factored starts per market start reduces this to 23.0 factored starts per annum, compared with 54.5 factored starts for Pinjar.

The same methodology that was applied to Pinjar was also used to calculate Mungarra's start cost. This resulted in a distribution with the characteristics shown in Table E- 1. The first and second quartiles of the start cost distribution for Mungarra are similar to that of Pinjar, but the Mungarra distribution is clearly skewed to the upside relative to Pinjar, and this contributes to Mungarra's high cost as a peaking plant.

Table E- 1 Modelled start cost distribution for Mungarra

Start costs as Modelled	
	Mungarra
Min	$2,247
10%	$2,352
50%	$3,406
Mean	$3,350
Mode	$3,624
80%	$3,930
90%	$4,278
Max	$4,496

E.2 Gas transmission to Mungarra

Having assessed the likely conditions for spot trading of gas transmission capacity, Jacobs have concluded that the appropriate prices for delivery to Mungarra from 1 July 2018 should be $1.319/GJ distributed lognormally with a standard deviation of $0.15/GJ. In addition, the minimum and maximum values of the distribution range from $0.5/GJ to $2.5/GJ, which is $0.5/GJ lower relative to the Pinjar gas transmission distribution, reflecting the lower expected gas transmission charges at Mungarra. This results in a distribution with mode of $1.282/GJ with an 80% confidence range between $1.08/GJ to $1.58/GJ.

The resulting modelled delivered gas price as compared with the equivalent delivered price for the industrial gas turbines at Pinjar is shown in Figure E- 1. The modelled delivered gas price for the Mungarra region had an 80% confidence range of $3.28/GJ to $8.31/GJ with a mode of $5.10/GJ and a mean of $5.79/GJ. The key features of the delivered gas price for Mungarra are provided in Table D- 1. The distribution is shifted slightly to the left relative to that of the industrial gas turbines at Pinjar.

Figure E- 1 Sampled probability density of delivered gas price for peaking purposes

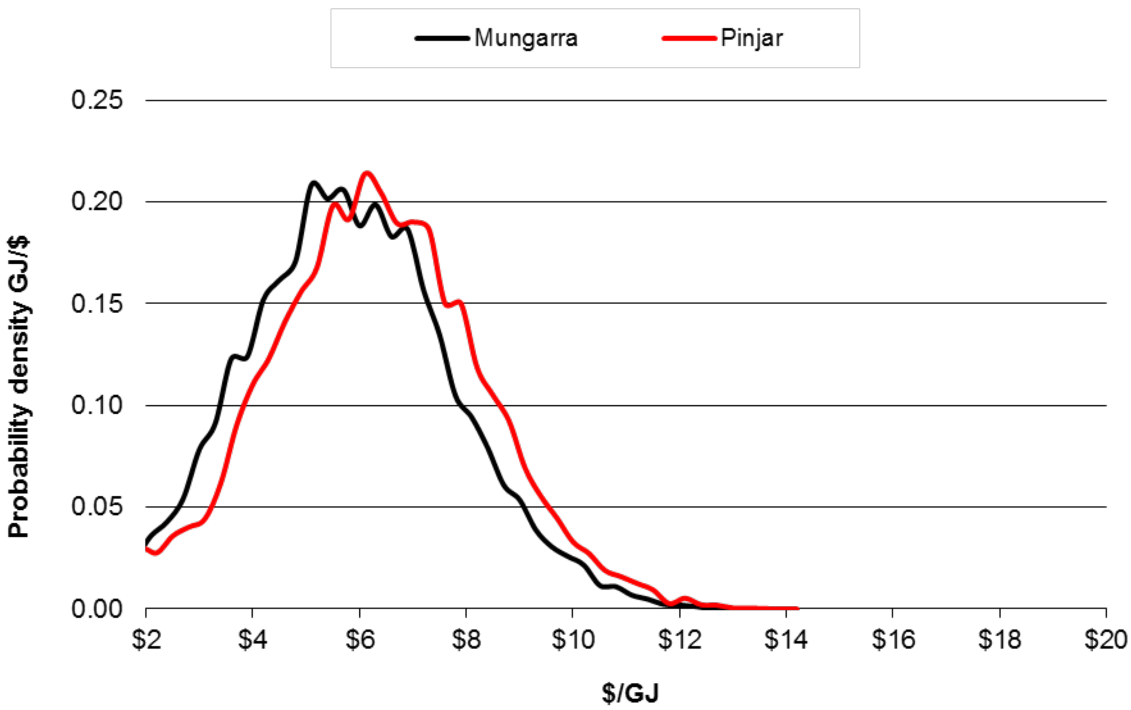


Table E- 2 Delivered gas price for Mungarra gas turbines

Delivered Gas Prices as Modelled	
	Mungarra
Min	$0.94
5%	$2.58
10%	$3.28
50%	$5.75
Mean	$5.79
Mode	$5.10

Delivered Gas Prices as Modelled	
80%	$7.39
90%	$8.31
95%	$9.10
Max	$13.29

E.3 Results

Table E- 3 compares the results for the Mungarra gas turbines with the results shown above for the Pinjar gas turbines. It is evident that the costs for Mungarra exceed those of Pinjar despite the lower delivered price of gas at Mungarra. The key drivers for this outcome are: (i) Mungarra's start cost distribution, which is skewed to the upside relative to that of Pinjar; and (ii) Mungarra's dispatch cycle characteristics, which result in Mungarra effectively recovering its start cost over a smaller volume of energy, hence increasing its unit energy cost relative to Pinjar.

Table E- 3 also shows that the 80th percentile of the Pinjar cost distribution corresponds to the 60th percentile of the Mungarra cost distribution.

Table E- 3 Analysis of Dispatch Cycle cost using average heat rate at minimum capacity

Sample	Mungarra – Gas	Pinjar – Gas
Mean	$335.04	$243.06
80% Percentile	$465.45	$301.52
90% Percentile	$645.50	$374.69
10% Percentile	$159.43	$144.01
Median	$264.77	$217.98
Maximum	$1,333.21	$1,021.19
Minimum	$62.39	$59.36
Standard Deviation	$200.26	$104.94
Mungarra cost percentile @ $301.52	60% percentile	

Appendix F. Calculation of maximum prices using market dispatch to estimate heat rate impact

In selecting the appropriate Maximum STEM Price, an alternative approach is to consider revising the pricing model to take account of observed dispatch patterns instead of using the average heat rate at minimum operating capacity. That would require a change to the Market Rules. However, for cross-checking purposes, we have analysed the positon if the Market Dispatch Cycle Cost Method had been applied.

F.1 Methodology for Market Dispatch Cycle Cost Method

The Market Dispatch Cycle Cost Method was based on the following principles for output level during the Dispatch Cycle:

- The gas turbine unit would be loaded at maximum allowable rate to minimum generation level after synchronisation.
- The gas turbine would generate at no less than minimum capacity level until required to run down to zero just prior to disconnection. This would define the basis for a minimum allowable capacity factor for the Dispatch Cycle.
- If additional generation is required, the unit would ramp up to an intermediate level, hold that level and then run down to minimum and zero levels. The rate at which the generation would increase would be the rate that would get the unit to maximum output and then back again.
- For higher generation levels the gas turbine would ramp up to maximum output, hold at that level, and then ramp down to minimum generation.

The use of the heat rate at minimum capacity is slightly conservative relative to results that would be expected from more detailed analysis based on typical operations. However, the impact on the Maximum STEM Price assessment in this review is minimal at $1/MWh rounding to the nearest integer, which is less than 1% of the price.

F.2 Treatment of heat rates

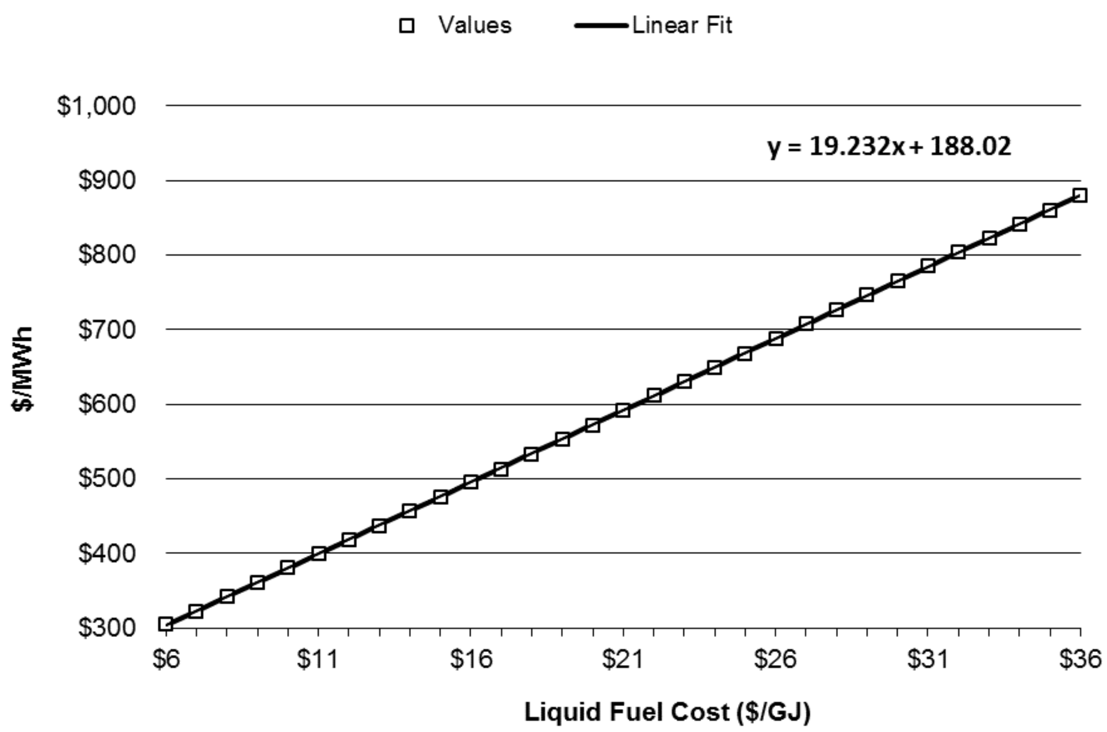
If we repeat the analysis of the Energy Price Limits, but develop the heat rates by using detailed dispatch modelling based on heat rate curves and probability distributions of capacity factor and maximum capacity derived from market data over the period from 1 January 2013 to 31 December 2017, with the same adjustment to frequency of unit starts, then we obtain the results shown in Table F- 1. This Market Dispatch Cycle Cost Method gives slightly lower heat rates at the 80% level for both Pinjar and the aero-derivative gas turbines.

Table F- 1 also shows the decomposition of the costs for distillate firing. The non-fuel and equivalent heat rate terms for distillate firing were derived from the 80% cumulative probability values of cost versus distillate price over the range between $6/GJ and $36/GJ as explained in Section 2.5 for the 10,000 simulated values corresponding to each individual sample of cost. Again the relationship between the sampled values and the linear regression function was strong as shown in Figure F- 1.

Table F- 1 Analysis of Dispatch Cycle cost using Market Dispatch Cycle Cost Method

Sample	Aero-Derivative – LM6000		Industrial Gas Turbine	
	Gas	Distillate	Gas	Distillate
Mean	$77.40	$233.95	$242.24	$464.04
80% Percentile	$96.30	$250.98	$301.47	$523.29
90% Percentile	$108.60	$265.66	$374.69	$599.36
10% Percentile	$47.04	$203.13	$142.87	$366.17
Median	$75.86	$229.12	$216.64	$435.43
Maximum	$358.02	$862.10	$1,027.31	$1,275.06
Minimum	$17.69	$120.50	$59.49	$294.82
Standard Deviation	$25.56	$35.51	$105.74	$106.65
Non-Fuel Component $/MWh				
Mean	$25.24		$137.28	
80% Percentile	$28.99		$188.02	
Fuel Component GJ/MWh				
Mean	10.948		18.623	
80% Percentile	13.286		19.232	
Equivalent Fuel Cost for % Value $/GJ				
Mean	20.034		17.546	
80% Percentile	17.772		17.433	

Figure F- 1 80% probability generation cost with liquid fuel versus fuel cost (using Market Dispatch Cycle Cost Method)



F.3 Implications for margin with use of Market Dispatch Cycle Cost Method

If we adopt these lower values, then the margin of the price cap over the expected cost is 24.4% for the Maximum STEM Price and 14.7% for the Alternative Maximum STEM Price if based on $17.88/GJ Net Ex Terminal distillate price, as shown in Table F- 2 using rounded values. These margins reflect the current market and cost uncertainties[31].

Thus if we compare the assessed cost using the average heat rate at minimum capacity with the expected cost allowing for the Dispatch Cycles, then we obtain the comparison shown in Table F- 3. This would provide an effective margin of up to 24.8% over the expected cost, which is higher than the required heat rate assumption (accounting for rounding error). The margin for the Alternative Maximum STEM Price is 14.9% over the expected Dispatch Cycle cost, which is again higher than the required heat rate assumption.

Table F- 2 Margin analysis (Market Dispatch Cycle Cost Method) [32]

	Maximum STEM Price	Alternative Maximum STEM Price at $17.88/GJ[33]
Expected Cost	$242.00	$464.00
Market Dispatch Cycle Cost Based Price Cap	$301.00	$532.00
At Probability Level of	80%	80%
Margin	$59.00	$68.00
% Margin	24.4%	14.7%

Table F- 3 Margin analysis with use of average heat rate at minimum capacity using Market Dispatch Cycle Cost for the expected cost

	Maximum STEM Price	Alternative Maximum STEM Price at $17.88/GJ
Expected Cost (Market Dispatch Cycle Cost)	$242.00	$464.00
Proposed Price Cap (Min Heat Rate)	$302.00	$533.00
At Probability Level of	80%	80%
Margin	$60.00	$69.00
% Margin	24.8%	14.9%

[31] Note that the expected value of $532/MWh for the Alternative STEM Price allows for the modelled uncertainty in the distillate price.
[32] Rounded to the nearest $/MWh.
[33] Net Ex Terminal.

Appendix G. Key factors impacting 2018 Energy Price Limits

Table G- 1 Summary of changes to key factors impacting 2018 Energy Price Limits

Factor	Units	2017 value	2018 value	% change	Reason for change
Input factors					
Gas price	$/GJ	4.66	4.02	-13.7%	Softer GSOO gas price forecast
Distillate price	$/GJ	16.43	17.88	8.8%	Higher crude oil price
Standard deviation of distillate price	$/GJ	2.88	1.10	-61.8%	Lower oil price volatility and use of Perth Terminal prices rather than Singapore prices
Factored starts	-	82.2	54.5	-33.7%	Reduced frequency of Pinjar starts in 2017 and have taken low-load starts into account
Start cost	$/start	4279	3320	-22.4%	The new calculation methodology for start cost accounts for some of the increase. The decrease in Pinjar starts lengthens the maintenance cycle, deferring costs and making it less costly
Maintenance cost per cycle	$	10,034,372	10,118,067	0.8%	Includes escalation for changes in part costs, CPI and forex impact on cost of parts
Output factors					
VO&M cost	$/MWh	158.93	129.59	-18.5%	Decrease in start cost
Heat rate	GJ/MWh	19.237	19.225	-0.1%	Reflects change in operation of Pinjar at minimum capacity over the CY 2013-2017 reference time period relative to the previous reference time period of CY 2013-2016
Total fuel price	$/GJ	6.97	6.31	-9.5%	Lower input gas price
Loss factor	-	1.0322	1.0322	0%	Loss factor for 2018/19 is unchanged from 2017/18 loss factor

Appendix H. Gas turbine maintenance cycle costs

H.1 Introduction

The relevant gas turbines at Pinjar are Frame 6B gas turbines. While these gas turbine units have historically been available from several manufacturers, generally under licence, the prime manufacturer and designer of this gas turbine model is General Electric (GE). Jacobs understands that Synergy adopts the GE recommended maintenance schedule for these units. These units are "industrial" gas turbines (as opposed to "aeroderivative" gas turbines), which are called "heavy duty" in GE's nomenclature.

GE's maintenance recommendations for these gas turbines are generally described in GE's "Heavy-Duty Gas Turbine Operating and Maintenance Considerations" document[34]. The following descriptions are based on this document.

H.2 Factors influencing gas turbine life (and maintenance)

GE identifies that the factors that tend to influence the life of a peaking gas turbine are fatigue related factors driven by the number of starts. For a base-load gas turbine the factors that tend to influence gas turbine and component life are oxidation, creep, corrosion and wear and these factors are driven by the fired operating hours of the unit. A mid-range unit will be limited by (predominantly) one or other of the mechanisms. In GE's model the starts and hours-run failure modes are substantially independent and the life, and maintenance, model is based on when the unit achieves either the starts or the hour's criteria. This is somewhat in contrast to some other manufacturers who combine the two factors into an "equivalent operating hours" formula.

GE (and other manufacturers) recognise that some operating conditions can accelerate the damage mechanisms that occur relative to a "standard" operating condition that might be broadly describes as a "normal" start on low-impurity natural gas fuel. These types of factors are recognised within Service Factors that are applied to the actual hours run or starts experienced and include (Table H- 1):

Table H- 1 Service Factor elements

Hours based factors	Starts based factor
Fuel type	Start type (whether the selected starting time is faster than a "normal" start time
Peak load (operating at a higher load than the unit's base load rating)	Start load (i.e. whether the selected load at the end of the start is less than or higher than the unit's base load rating)
Water or steam injection into the combustors for emissions control or output enhancement	Unit trips[35]

As these factors are more detrimental than a normal operating hour or start, the actual hours and starts are multiplied by service factors (for each hour and start) where these apply and the maintenance/life cycle is effectively shortened when these apply.

The Service Factors applied are not necessarily the same for all gas turbine units as different units are better or worse at coping with some conditions due (for example) to their size, operating temperatures and pressures, or materials technologies employed.

The hours and starts of each type are accumulated within the gas turbine control system to inform the owner (and OEM) of the expected condition of the unit relative to the baseline cycle. It should be noted that in practice

[34] GE Power and Water document GER-3620M (02/15)

[35] Because trips can occur immediately from a high load without the opportunity to "ramp down" the unit, a trip has a high fatigue impact on a gas turbine unit

gas turbine operation and maintenance is planned on an ongoing basis incorporating information from the unit's sensors, reliability experienced and the results revealed at previous inspection outages. The cycles are thus best described as guidelines subject to "on condition" experience rather than hard-and-fast rules.

The observable hours and starts based on market data are only the actual hours and starts of each unit rather than the Factored Hours and Starts.

The baseline regime for a Frame 6B with conventional combustors (per Pinjar) are (Table H- 2):

Table H- 2 Frame 6B baseline program

	Factored or Actual	Hours	Starts
Combustion inspection (CI)	Factored	12,000	600
Hot Gas Path Inspection (HGPI)	Factored	24,000	1,200
Major inspection/overhaul (MO)	Actual	48,000	2,400
Rotor			5,000 starts + trips

As a guide, a peaking fast start for a Frame 6B could be counted as 4 normal starts for a CI and 3.5 normal starts for a HGPI. For starting to loads above base-load and for trips an exponential formula is applied based on the load. Conversely a start to a low load (<60%) only incurs a 0.5 factor. A start using distillate has a 1.25 factor for CI but not for a HGPI.

It is noted that the MO uses actual rather than factored starts. In practice the owner would potentially need to make a decision as to whether to incur an additional HGPI in the cycle or to do the MO early.

With regards to rotor inspections the experience is that gas turbines have tended to not reach these limits or are only just beginning to do so. The nature of any repairs required, or whether a replacement is necessary, are highly unit-specific and indeterminate. Where an owner had a rotor that was no longer serviceable then since this would usually be encountered "late" in the unit's life the first option for consideration would usually be to find a second-hand rotor from a retired unit that ran in a less peaking mode (i.e. such that the rotor has remaining starts). The cost of this service is not able to be determined on a general basis.

The actual accrued hours and starts of the key units in the SWIS (Pinjar and Mungarra) have not been able to be sourced from the asset owners at the present time.

In order to make an allowance for the influence of Factored Starts on the likely maintenance cycle Jacobs has considered some other units of similar age, technology and duty to the Pinjar units and determined that for those units the Factored Starts are approximately 1.2 times the actual starts for all starting conditions, except low-load starts. Since 2013, 69% of Pinjar's starts have been low load starts, and combining this with the 1.2 factored starts factor for all other starts yields an average service factor of 0.84 for the Pinjar machines. Similarly, 70% of Mungarra's starts in calendar 2017 were low-load starts, and this yields a service factor of 0.83. In the absence of more specific information Jacobs has allowed for these factors in the analysis.