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2019-20 Energy Price Limits Review – Final Report (Public)

A Report for the Australian Energy Market Operator

A Marsden Jacob Report

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Prepared for Client

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Marsden Jacob Associates

ABN 66 663 324 657

ACN 072 233 204

economists@marsdenjacob.com.au

Authors

Grant Draper – Marsden Jacob Associates

Peter McKenzie – Marsden Jacob Associates

Philip Jones – Marsden Jacob Associates

Hana Ramli – Marsden Jacob Associates

About Us

Established in 1996, Marsden Jacob Associates has grown to be Australia's leading dedicated natural resource economics, policy and strategy advisory. We employ talented economists and policy advisors who specialise in solving practical, real world problems relating to water, energy, environment, natural resources, agriculture, earth resources, public policy and transport. We work with a wide range of cross-disciplinary partner firms to deliver best project outcomes for our clients.

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Acronyms and abbreviations

AEMO	Australian Energy Market Operator
ACPL	Australian Cents Per Litre
DBNGP	Dampier to Bunbury Natural Gas Pipeline
ERA	Economic Regulation Authority
GGP	Goldfields Gas Pipeline
GJ	gigajoule
GST	Goods and Services Tax
MW	megawatt
MWh	megawatt hour
NCS	Network Control Service
NPV	net present value
O&M	operating and maintenance
OCGT	open cycle gas turbine
PDF	probability density function
STEM	Short Term Energy Market
TGP	Terminal Gate Price
WEM	Wholesale Electricity Market

Definitions

Term	Explanation
Balancing Market	Accounts for imbalances between a market participant's net contract position (after STEM nominations) on the scheduling day (day before trading) and their actual position on the trading day. Trading in the Balancing Market can result from incorrect demand forecasts and/or plant outages, or deliberate trading strategies by retailers to take some balancing market exposure (can lower purchase costs in particular circumstances).
Capacity Factor	The ratio of the average output of a generator (in MW) for a given period to the rated capacity of that generator. The formula for capacity factor is Total Output (in MWh) / Period (in Hours) / Rated Capacity (in MW). A ratio of 0.5 implies that the generation plant is running at 50 per cent of its rated capacity for that period.
Dispatch Cycle	The process of starting a generating plant, synchronising it to the electricity system, ramping it up to minimum generation as quickly as possible, changing its generation between minimum and maximum levels to meet system demand requirements, ramping it down to minimum generation and then to zero for shut-down.
Dispatch Cycle Cost	Total costs incurred in the start-up and shut-down (Dispatch Cycle) of a peaking gas turbine divided by the amount of electrical energy (in MWh) generated during a Dispatch Cycle.
Energy Price Limits (or Price Caps)	The Maximum STEM Price (applies to non-liquid fuelled facilities), the Alternative Maximum STEM Price (applies to liquid fuelled facilities), and the Minimum STEM Price expressed in $ per MWh[1]. The Maximum and Alternative Maximum STEM Prices are reviewed annually by AEMO and approved by the Economic Regulation Authority[2]. The Minimum STEM Price is -$1,000 per MWh[3].
Fixed O&M	Fixed operating and maintenance costs that do not change with variations in generation output. Can include some labour costs, overheads and time related maintenance costs. Usually expressed in $ per MW per annum.
Heat Rate	A measure of the efficiency of a generation plant that converts fuel into electricity. Usually measured in GJ per MWh and is a function of the utilisation of the generation plant (i.e. lower heat rate at higher plant utilisation).
Loss Factor (or Marginal Loss Factor)	Transmission loss factors that are used to determine how much sent out electricity is delivered to the regional reference node (Muja)[4]. A Loss Factor less than unity implies that less energy is delivered to the node than what is injected into the transmission network and vice versa if the Loss Factor is greater than unity.
Margin	The difference between the maximum Energy Price Limits and the expected value of the highest short run costs of a peaking generation plant.
Mungarra Units	Collectively means the two gas turbine units at the Mungarra Power Station formerly registered in the WEM as individual facilities MUNGARRA_GT1 and MUNGARRA_GT3.
O&M	Operating and maintenance costs. These are the non-fuel expenses incurred in running a generation plant (e.g. water, lubricants, labour and equipment).
Parkeston Units	Collectively means the 3 aero-derivative units at the Parkeston Power Station registered in the WEM as a single facility PRK_AG.

[1] Chapter 11 of the WEM Rules
[2] Sections 6.20 and 2.26 of the WEM Rules
[3] Chapter 11 of the WEM Rules
[4] Chapter 11 of the WEM Rules

Pinjar Units	Collectively means the 6 Pinjar 40MW gas turbine units registered in the WEM as individual facilities PINJAR_GT1, PINJAR_GT2, PINJAR_GT3, PINJAR_GT4, PINJAR_GT5 and PINJAR_GT7.
Risk Margin	A measure of uncertainty in the assessment of the mean short run marginal cost for a generation plant, expressed as a fraction.[5]
Short Run Marginal Cost	The additional cost of producing one more unit of output from an existing generation 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 $ per MWh.
Short Term Energy Market	A day ahead forward market that is operated by AEMO to allow wholesale market participants to buy and sell electricity to adjust their net bilateral contractual positions for the next trading day.
Variable O&M	Variable operating and maintenance costs that change with variations in generation output. Includes but is not limited to start-up related costs. Usually expressed in $ per MWh of generation (generated or sent out).
WEM Rules	The Western Australian Wholesale Electricity Market Rules.

[5] Clause 6.20.7(b) of the WEM Rules

Executive Summary

The Australian Energy Market Operator (AEMO) is required under section 6.20 of the Wholesale Electricity Market Rules (WEM Rules) to review the Energy Price Limits that apply to the Wholesale Electricity Market (WEM) for the 2019-20 financial year. The Energy Price Limits represent the upper and lower price limits for offers submitted into the Short Term Energy Market (STEM) and the Balancing Market. Marsden Jacob Associates (Marsden Jacob) has been appointed by AEMO to assist in the review of the upper price limits for 2019-20.[6]

The Energy Price Limits are set with reference to the costs of running a 40 MW Open Cycle Gas Turbine (OCGT)[7]. The Maximum STEM Price applies to generation facilities that are running on non-liquid fuels (e.g. coal, gas), while the Alternative Maximum STEM Price applies to generation facilities running on liquid fuels (i.e. distillate). The candidate generation units to be used in the review of the Energy Price Limits included the Pinjar 40 MW gas turbines (6 units) and the Parkeston aero-derivative gas turbines (3 units). The candidate generation units are selected based on unit size (40 MW) and the likely running cost of the plant; the latter is a function of historical dispatch patterns and plant heat rates amongst other factors (listed below). The Mungarra gas turbines were considered candidate generation units in previous Energy Price Limit reviews but have been excluded from setting upper price limits in this review given that they are not actively participating in the energy market and are providing a Network Control Service in the North Country Region.

To derive the costs of running (referred to as *dispatch cost*) of the candidate OCGT units, Marsden Jacob has consulted with relevant Market Participants, and collated and analysed data that will impact the dispatch cost of the units. That includes the following:

- Fuel prices (i.e. gas and distillate);
- Unit heat rates (GJ per MWh);
- Variable operating and maintenance costs (or Variable O&M);
- Loss Factor.

Fuel costs are a function of fuel prices and the heat rate (GJ per MWh) of an OCGT unit. The heat rate is in turn a function of the loading of the generator (in MW). Fuel costs are also impacted by the frequency of unit start-ups, since additional fuel is required to start the unit (can adjust unit heat rate to cater for start-up energy use). Non-fuel (Variable O&M) costs are a function of the frequency of unit start-ups, average duration of each dispatch event (in hours) and loading of the generator (in MW). Five-year historical data for unit start-up frequency, average duration of each dispatch event and loading of the generator, for both the Pinjar and Parkeston units, were used in the derivation of the upper Energy Price Limits.

Based on analysis by Marsden Jacob, the most expensive 40 MW OCGT units are the Pinjar Units. The value of variables that influence the unit dispatch cost and ultimately the assessed Maximum STEM Price are summarised in ES Table 1. The analysis indicates that the Maximum STEM Price should be $234.57 per MWh for the 2019-20 year.

ES Table 1: Calculation of Maximum STEM Price with Pinjar Units

Component	Units	Values
Mean Variable O&M Cost	$/MWh	104.98
Mean Heat Rate	GJ/MWh	20.62
Mean Fuel Cost (heat rate adjusted)	$/MWh	113.02
Loss Factor		1.0369
Before Risk Margin	$/MWh	210.24
Risk Margin Added	$/MWh	24.33
Risk Margin Value	%	11.57
Assessed Maximum STEM Price	$/MWh	234.57

Source: Marsden Jacob analysis 2019

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[6] The Minimum STEM Price is fixed at -$1,000 per MWh (Chapter 11 of the WEM Rules) and is not being reviewed in this study.
[7] Clause 6.20.7 of the WEM Rules

The components of the Alternative Maximum STEM Price that are derived from an assessment of the dispatch costs of the Pinjar Units are provided in ES Table 2. The average distillate price used in the derivation of Mean Fuel Cost was based on $21.10 per GJ (or 81.3 cents per Litre) for the Pinjar Units.

ES Table 2: Calculation of Alternative Maximum STEM Price with Pinjar Units

Component	Units	Values
Mean Variable O&M Cost	$/MWh	104.98
Mean Heat Rate	GJ/MWh	20.62
Mean Fuel Cost (heat rate adjusted)	$/MWh	437.11
Loss Factor		1.0369
Before Risk Margin	$/MWh	522.79
Risk Margin Added	$/MWh	44.63
Risk Margin Value	%	8.54
Assessed Alternative Maximum STEM Price	$/MWh	567.42

Source: Marsden Jacob analysis 2019

The Alternative Maximum STEM Price is varied each month according to changes in the price of distillate, based on historical Perth Diesel Terminal Gate Prices. It is therefore necessary to separate out the cost components that depend on fuel cost and those which are independent of fuel cost.

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

$120.72 per MWh + 21.2297 multiplied by the Delivered Distillate Price ($ per GJ)

A comparison of the assessed Maximum STEM Price for 2019-20 with the previous year's price limit is provided in ES Table 3 along with a waterfall chart in Figure ES Figure 1.

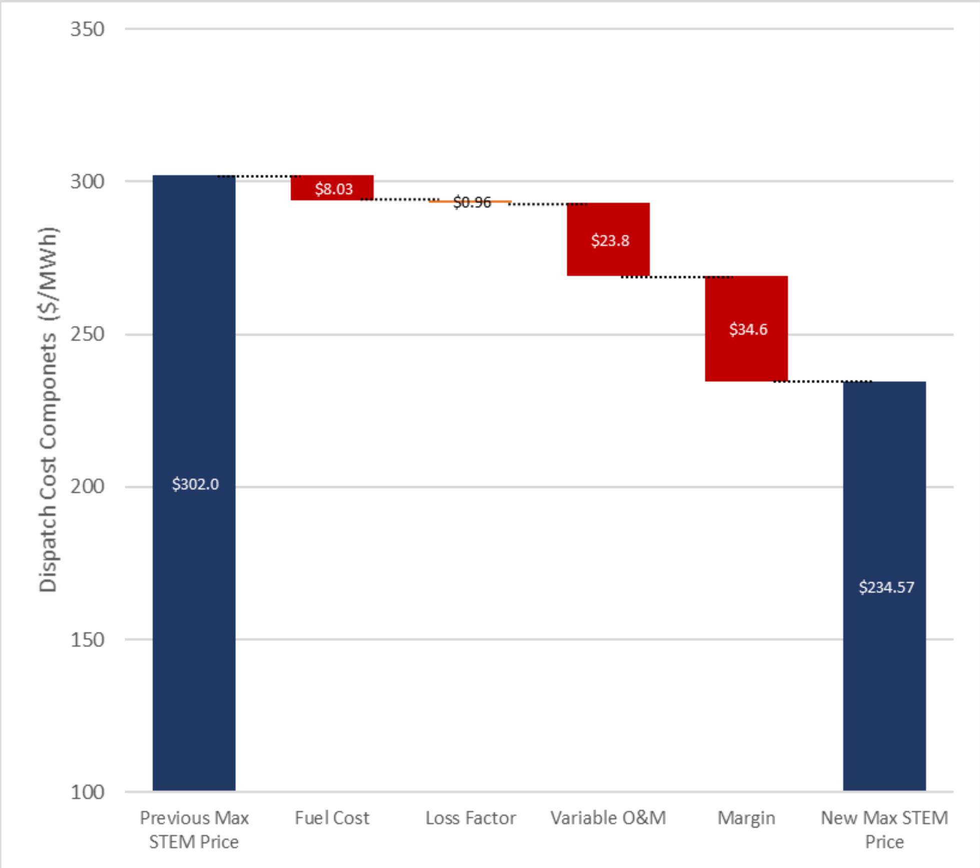
ES Table 3: Comparison of Maximum STEM Price – multiple years

Component	Units	2019-20	2018-19	Change
Mean Variable O&M Cost (a)	$/MWh	104.98	129.59	-24.61
Mean Heat Rate	GJ/MWh	20.62	19.23	1.40
Mean Fuel Cost (heat rate adjusted) (a)	$/MWh	113.02	121.31	-8.29
Loss Factor		1.0369	1.0322	0.005
Before Risk Margin	$/MWh	210.24	243.07	-32.83
Risk Margin Added	$/MWh	24.33	58.93	-34.60
Risk Margin Value	%	11.57	24.20	-12.63
Assessed Maximum STEM Price	$/MWh	234.57	302.00	-67.43

Source: Marsden Jacob analysis 2019, Jacobs Group (Australia) Pty Ltd 2018

Notes: (a) Mean Fuel Cost and Mean Variable O&M Cost are not loss factor adjusted.

ES Figure 1: Factors causing change in the Maximum STEM Price from 2018-19



Source: Marsden Jacob analysis 2019, Jacobs Group (Australia) Pty Ltd 2018

Notes: (a) The changes in Mean Fuel Cost and Mean Variable O&M have been loss factor adjusted. That is why the change is lower when compared to ES Table 3.

The major reasons for changes in the Maximum STEM Price since last year are explained in detail in Section 4.4 and are summarised below.

1. Lower *Mean Variable O&M Cost* ($104.98 per MWh compared to $129.59 per MWh last year). The Mean Variable O&M Cost per MWh is equal to average Variable O&M Costs per start (based on overhaul costs) divided by Dispatch Event MWh (for dispatch events of 6 hours or less duration) plus an additional $1.50 per MWh cost to cover water, labour and lubricants.

   a) *Average Variable O&M Cost* per start (based on overhaul costs) – as outlined in Section 3.2, Marsden Jacob has determined that the average Variable O&M Cost per start for the Pinjar Units is $3,984 for 2019-20, whereas the equivalent cost used in developing the 2018-19 Maximum STEM Price was $3,320 per start and was $4,279 per start in 2017-18. The significant reduction in the average Variable O&M Cost per start from 2017-18 to 2018-19 was due to a change in the methodology used to calculate this variable (e.g. excluding overhaul costs incurred in the last 3 years of the plant's life).

   b) Marsden Jacob calculated *Dispatch Event MWh* for events of 6 hours or less duration. This included data for all Pinjar Units over the period 2013-14 to 2018-19 (ending February 2019). It was found that across all Pinjar Units, the average generation output was 38.5 MWh per event. The equivalent amount calculated for last year's Energy Price Limits calculation was 26 MWh. Previous reviews have typically found that Dispatch Event MWh (6 hours or less) was around 26 MWh. The higher Dispatch Event MWh of 38.5 for the Pinjar Units contributes to a lower Mean Variable O&M Cost per MWh.

   c) Therefore, the *Mean Variable O&M Cost* for 2019-20 is calculated to be $104.98 per MWh (i.e. $3,984 per start / 38.5 MWh per start plus $1.50 per MWh to cover additional O&M costs).[8] The

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[8] That is, water, labour and lubricants.

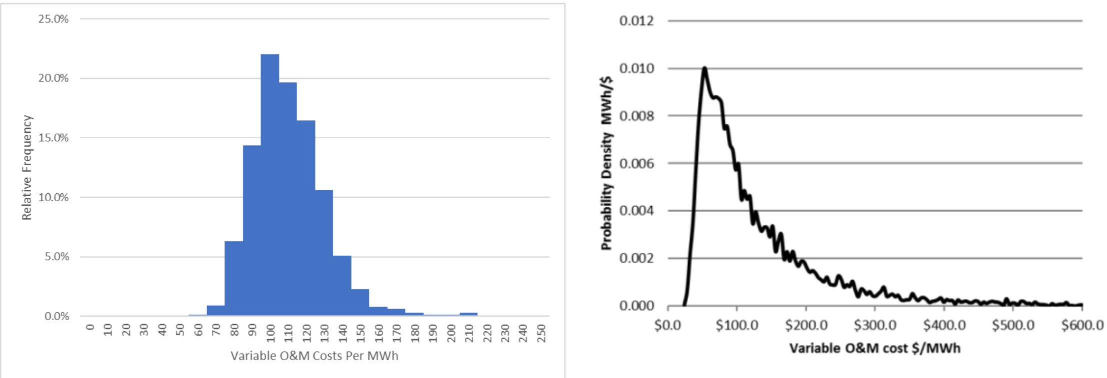
Variable O&M Cost for 2018-19 was calculated to be $129.59 per MWh (i.e. $3,320 per start / 26 MWh per start).

It should be pointed out the calculation of the Mean Variable O&M Cost for the Pinjar Units has been highly volatile. The 2018-19 cost was $129.59 per MWh, was $158.93 per MWh in 2017-18, and was as low as $57.18 MWh in 2016-17 (all above Variable O&M Costs listed are before application of the loss factor). To a large extent this has resulted from changes in underlying modelling methodologies and has not reflected actual costs of maintaining the Pinjar Units.

2. Lower *Mean Fuel Cost* ($8.29 per MWh lower in 2019-20) resulting from lower gas commodity prices. The delivered cost of (spot) gas is forecast to be $5.445 per GJ for 2019-20. The mean delivered spot gas cost was forecast to be $6.31 per GJ in 2018-19. The lower delivered spot price for gas has resulted from the continued over supply of gas in the domestic market, which resulted in average spot gas price forecasts reducing to $3.41 per GJ in 2019-20, compared to average spot prices of $4.00 per GJ for 2018-19. The underlying spot gas price forecast used in the 2018-19 review was $4.02 per GJ.
3. Reduced *Risk Margin Value* due to a smaller variance in the distribution of Maximum STEM Prices, which is mainly a function of the reduced variance in Variable O&M Costs and delivered (spot) gas prices.

As outlined in Point (1) above, modelled mean Variable O&M Costs ($ per MWh) have fallen. In addition, the modelling of Variable O&M Costs in 2019-20 has a significantly narrower probability distribution function when compared to the modelling undertaken to support Energy Price Limits in 2018-19. The probability density function (PDF) for Variable O&M Costs for this year is compared with the PDF for last year in ES Figure 2.

ES Figure 2: Comparison of PDF for Variable O&M Costs ($ per MWh) – Pinjar Units 2019-20 (left) and 2018-19 (right)



Source: Marsden Jacob analysis 2019, Jacobs Group (Australia) Pty Ltd 2018

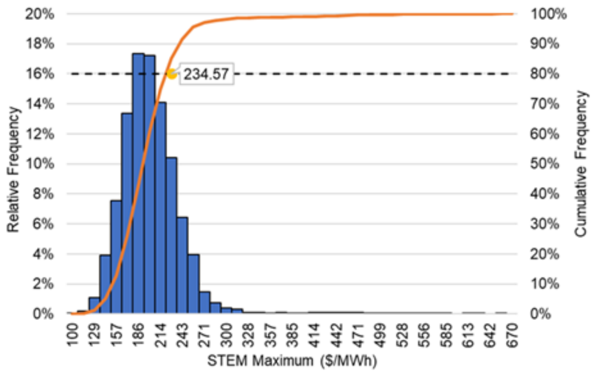
This highlights the considerable range of Variable O&M Costs that could occur under the modelling undertaken in the 2018-19 review. Variable O&M Costs could be as high as $600 per MWh in last year's modelling, whereas modelling for setting the 2019-20 Energy Price Limits indicates that the maximum Variable O&M Costs are only likely to be around $203 per MWh for the Pinjar Units. As a result of the significantly higher range of values modelled in previous reviews, Mean Variable O&M Costs ($129.59 per MWh) are substantially above the median cost ($96 per MWh), and the standard deviation of costs is $99.15 per MWh. The estimated standard deviation of Variable O&M Costs calculated for the 2019-20 review is $19.125 per MWh, with a mean of $104.98 per MWh. The 80th percentile of Variable O&M Costs is around $120 per MWh.

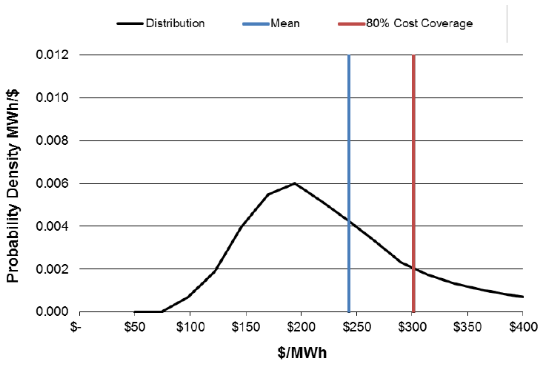
Contributing to the smaller variance in the Variable O&M Costs for the Pinjar Units is the planned retirement date of December 2031 for all units. (based on 40 year plant lives). While the exact maintenance cycle for all units (e.g. when a major overhaul was undertaken for a specific unit) is unknown, the number of potential maintenance cycle possibilities is reduced because the units only require a further 10 years of maintenance. The plants have a further 12 years of life, and it is assumed that no major maintenance is undertaken in the last 2 years of the Pinjar 40 MW Units' lives. Knowing the end date for the Pinjar Units reduces the number of potential maintenance cycle possibilities and hence reduces the variance for Variable O&M Costs.

The distribution of delivered gas prices for 2019-20 also has a significant influence on the distribution of Maximum STEM Prices. This is discussed further in Section 4.4.

The distribution of Variable O&M Costs and gas costs has a direct influence on the probability density function for Maximum STEM Prices, and hence the 80th percentile price which determines the Risk Margin Value. The PDFs for the 2018-19 and 2019-20 Maximum STEM Prices are provided in ES Figure 3.

ES Figure 3: Comparison of PDF for Maximum STEM Prices ($ per MWh) – Pinjar Units 2019-20 (left) and 2018-19 (right)

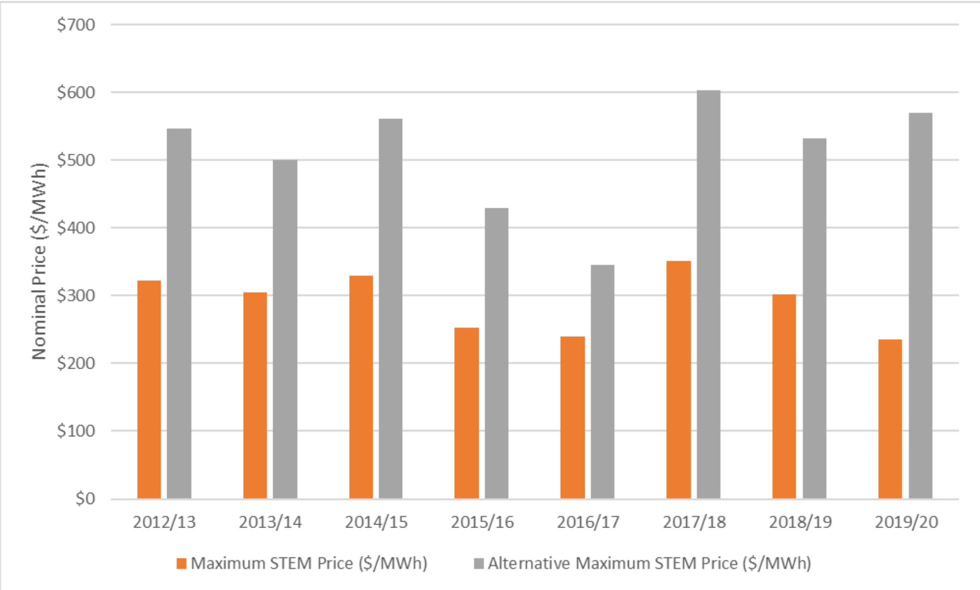




Source: Marsden Jacob analysis 2019, Jacobs Group (Australia) Pty Ltd 2018

Provided in ES Figure 4 is a comparison of the assessed upper Energy Price Limits with previous upper Energy Price Limits. What this shows is that the assessed Maximum STEM Price is the lowest price (in nominal dollars) since 2012-13. This is broadly consistent with lower commodity gas prices that are projected for 2019-20. However, the reductions in Variable O&M Cost and Risk Margin in 2019-20 are also significant factors (see Section 4.4). On the other hand, the Alternative Maximum STEM Price has increased from last year as a result of higher distillate prices that have increased in response to projected increases in crude oil prices in 2019 and 2020.

ES Figure 4: Comparison of assessed and historical upper Energy Price Limits



Source: Marsden Jacob analysis 2019

1. Background and Scope of Work

1.1 Purpose of this Report

AEMO is required under section 6.20 of the Wholesale Electricity Market Rules (WEM Rules) to review the Energy Price Limits for the 2019-20 financial year. The Energy Price Limits represent the upper and lower price limits for offers submitted into the Short Term Energy Market (STEM) and the Balancing Market. The three price limits[9] are:

- Maximum STEM Price (which applies if a Facility is running on non-liquid fuel);
- Alternative Maximum STEM Price (which applies if a Facility is running on liquid fuel); and
- Minimum STEM Price (which is set at negative $1,000 per MWh).

Only a review of the Maximum and Alternative Maximum STEM Price is required for the 2019-20 review. Revised values must then be submitted to the Economic Regulation Authority (ERA) for approval[10].

Marsden Jacob Associates (Marsden Jacob) has been appointed by AEMO to assist in the review of the Energy Price Limits for 2019-20.

1.2 Scope of Work

Marsden Jacob is required to determine the upper Energy Price Limits, as prescribed in clause 6.20.7 of the WEM Rules. This requires Marsden Jacob to undertake the following tasks:

a) assess the methodology used in the 2018-19 review and clearly articulate and justify any changes to the methodology (ensuring that the methodology is consistent with the requirements in clause 6.20.7 of the WEM Rules), including consideration of:

   i. the ERA's recommendations captured in its previous Energy Price Limits determinations, specifically:

      A. potential inclusion of the Mungarra Units in this year's review (section 5.2 of the 2017 Energy Price Limits Decision);

      B. fully capturing the variability of future maintenance expenditures in estimating the distribution of Variable O&M costs, such as:

         – using a weighted average cost of capital (instead of a risk-free rate) to derive a distribution for the present value of maintenance expenditures and subsequent annuity amounts; and

         – using the entire present value distribution to derive the Variable O&M cost and average variable cost distributions, rather than a single sample (i.e. the 80th percentile) of the present value of future maintenance expenditures;

      C. obtaining information from asset owners about the actual maintenance status of the facilities and their expected retirement time;

      D. estimation of the risk margin, in particular the use of an 80th percentile, rather than an average of the distribution could lead to overly conservative energy price caps; and

      E. review the application of Monte Carlo analysis to ensure that samples drawn from underlying distributions (for heat rate, gas price, and Variable O&M) are drawn and combined randomly to produce the average variable cost distribution;

b) provide independent modelling, analysis and justification for the cost assumptions and input data prescribed in clause 6.20.7 of the WEM Rules and used for determining the proposed price limits, including a specific focus on the determination of, and impact on, proposed price limits of:

   i. gas price distributions; and

   ii. any other relevant issues that arise during the review; and

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9 Refer to Price Caps in Chapter 11 of the WEM Rules

10 Clause 6.20.10 of the WEM Rules

c) propose any revised price limits to be applied for the 2019-20 financial year.

1.3 Structure of the Report

The structure of the proposal is outlined below:

- Chapter 1: Background and Scope of Work;
- Chapter 2: Methodology Review;
- Chapter 3: Determination of Key Parameters;
- Chapter 4: Modelling Results;
- Appendix One: Determination of Key Parameters for the Parkeston Units

2. Methodology Review

This chapter discusses the methodology as it was applied in this review. Previous reports and stakeholder feedback on the Energy Price Limits have been incorporated into the methodology for 2019-20.

2.1 Determination of Maximum Prices in the WEM

Maximum prices serve several purposes in the WEM:

- Protect market customers from high prices that could result from generators exercising market power in the STEM and Balancing Market;
- Provide incentives for new generation investment (i.e. peaking generators);
- Enable existing generators to cover the costs incurred in providing these services so that they are encouraged to provide their capacity during high price periods in the WEM.

Market efficiency is maximised if wholesale market prices (including maximum prices) reflect efficient costs of supply. The purpose of this analysis is to determine efficient costs consistent with the role of Energy Price Limits in the WEM.

The Maximum and Alternative Maximum STEM Prices are set based on the average variable cost of the highest-cost generating facility in the South West Interconnected System (SWIS) using the following formula[11]:

$$\text{Dispatch Cost} = (1 + risk\ margin) \times (variable\ O\&M + (heat\ rate \times fuel\ cost))\ /\ loss\ factor \quad (1)$$

where:

- $risk\ margin$ 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;
- $variable\ O\&M$ is the mean variable operating and maintenance cost for a 40 MW open cycle gas turbine generating station, expressed in $ per MWh, and includes, but is not limited to, start-up related costs;
- $heat\ rate$ is the mean heat rate at minimum capacity for a 40 MW open cycle gas turbine generating station, expressed in GJ per MWh;
- $fuel\ cost$ is the mean unit fixed and variable fuel cost for a 40 MW open cycle gas turbine generating station, expressed in $ per GJ; and
- $loss\ factor$ is the marginal loss factor for a 40 MW open cycle gas turbine generating station relative to the reference node.

There is some uncertainty regarding all the variables that make up the formula for the Energy Price Limits, except for the Loss Factor that is published by the Network Operator (Western Power). This implies that probability distributions can be found for the following key variables: heat rate, Variable O&M Cost, and fuel cost. Using Monte Carlo analysis, Marsden Jacob can then generate distributions of likely maximum prices in the STEM/Balancing Market and then choose a percentile level (typically 80th percentile) to derive the maximum price limit.

Current price limits are set by reference to the following:

- Maximum STEM Price is chosen as the 80th percentile of the output price distribution;
- 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.

The Alternative Maximum STEM Price is based on the following: the 80th percentile cost of formula (1) (Dispatch Cost) 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-distillate price into the regression equation (2).

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[11] Clause 6.20.7(b) of the WEM Rules

Alternative Maximum STEM Price = constant + α × Distillate Price (2)

2.2 Selection of the Candidate Peaking Generators

The above input variables will vary depending on which 40 MW generation plant is used to establish the dispatch cost used to set Energy Price Limits. In previous studies, Energy Price Limits have been based on the Pinjar 40 MW gas turbines (6 units). Other candidate generators include the Parkeston aero-derivative gas turbines (3 units) located in the Goldfields region, and the Mungarra gas turbines (3 units) located in the North Country region.

In May 2017, Synergy announced it would retire four generation assets in order to meet the terms of the direction handed down by the state government to reduce its generation cap to a total of 2,275 MW. This included the Mungarra Units, which were scheduled to retire on 30 September 2018.

In May 2018, the Network Operator (Western Power) determined that reliability obligations under the Technical Rules would not be met unless the Mungarra Units provided a Network Control Service for the North Country region (as well as the West Kalgoorlie units providing an equivalent service in the Eastern Goldfields region, however these units are not being considered as candidate peaking generators). A Network Control Service (NCS) is a service provided in accordance with Chapter 5 of the WEM Rules. Specifically, an NCS is a *"service provided by generation or demand side management that can be a substitute for transmission or distribution network upgrades"*[12]. It is a contractual arrangement between Western Power and a Market Participant who owns the relevant generation plant. Western Power may call upon an NCS contract for network reliability purposes or to maintain voltage security in a region (e.g. when the electrical systems in those regions are effectively islanded, or there are other network outages). In addition, when the SWIS is in an emergency operating state, AEMO may issue directions under the WEM Rules with respect to any registered facilities, including facilities that are subject to NCS contracts, requiring them to be operated in specific ways.[13]

On 1 October 2018, Western Power and Synergy entered into an NCS contract in relation to the Mungarra Units. As required under clause 5.2A.1 of the WEM Rules the Mungarra Units are registered facilities in the WEM. However, the Mungarra Units do not have network access rights (i.e. DSOC) except to support the provision of NCS, or to comply with a generation direction issued by. AEMO when the SWIS is in an emergency operating state. A Market Participant providing an NCS is paid by Western Power in accordance with the contract (except where the NCS facility is required to generate in response to a direction from AEMO when the SWIS is in an emergency operating state, in which case the Balancing Price is paid for energy provided under the normal WEM Rules settlement process).

In conclusion, since the Mungarra Units will not be dispatched in the WEM except under the terms of the NCS contract, or potentially under an emergency operating state scenario, it is considered that they are *not* a candidate facility for the "highest cost generating works" in the SWIS as required under clause 6.20.7(a) of the WEM Rules. The facilities will not set prices in the STEM or the Balancing Market. When an NCS is provided, the facilities will be compensated under the terms of the NCS contract by Western Power.

Table 1 shows the capacity and the technology of the candidate units for setting Energy Price Limits in 2019-20. The WEM Rules stipulate that the candidate units must be 40 MW OCGT units. The heat rate is a dominant factor in the determination of generation dispatch costs and is higher for smaller OCGTs. The Pinjar and Parkeston units are the smallest gas turbine units connected to the SWIS (excluding the Mungarra Units) which implies that they will have higher heat rates when compared to other gas turbines connected to the SWIS.

Table 1: Candidate OCGT units for setting Energy Price Limits

Unit	Maximum Capacity (MW)	Technology
PINJAR_GT1	38.5	Industrial GT
PINJAR_GT2	38.5	Industrial GT
PINJAR_GT3	39.3	Industrial GT
PINJAR_GT4	39.3	Industrial GT

[12] Clause 5.1.1 of the WEM Rules
[13] Clauses 3.5.5(d) and 3.5.8(a) of the WEM Rules

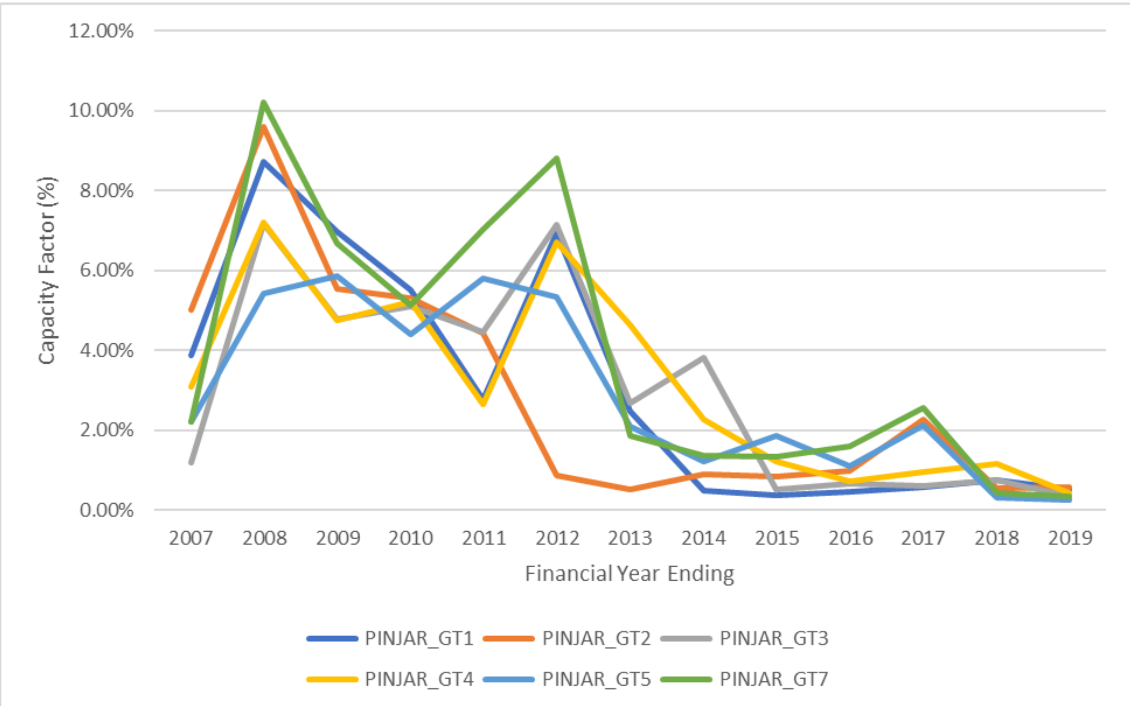
PINJAR_GT5	39.3	Industrial GT
PINJAR_GT7	39.3	Industrial GT
PRK_AG unit 1	37	Aero-derivative
PRK_AG unit 2	37	Aero-derivative
PRK_AG unit 3	37	Aero-derivative

Source: AEMO Facilities Data, Marsden Jacob analysis 2019

The choice of the benchmark OCGT unit is dependent on the operational model of the unit. If the unit is mainly used as a peaking unit, then the unit will be dispatched infrequently and only for a few hours per start. In addition, the unit will most likely operate below its maximum rated output, which implies a high heat rate (GJ/MWh). A higher heat rate implies a higher fuel cost, while a low dispatch MWh per start implies a higher Variable O&M Cost per start. Combining a high heat rate with a higher Variable O&M Cost per start implies that the plant will have a high Dispatch Cost relative to other plants in the SWIS and is likely to set the highest prices in the STEM/Balancing Market. This highlights that OCGT unit operation can be important in determining the unit which is used to set upper Energy Price Limits.

The Pinjar Units (GT 1 to 5 and 7) are owned and operated by Synergy and are used to provide peaking power in the SWIS. The units were fully operational by October 1990 and have typically had capacity factors of around 3 per cent on average, although the capacity factor can vary significantly between units and across years. The capacity factor of the Pinjar Units has declined over time as other less expensive generator units have entered the SWIS (e.g. Alinta Wagerup, Kemerton, Perth Energy Kwinana GT1 etc). The average capacity factor of the units was around 1.2 per cent in the last three years. This increases the dispatch costs of the plant since the generators will typically operate at low output levels which increases the heat rate for the respective units.

Figure 1: Capacity factor of Pinjar Units



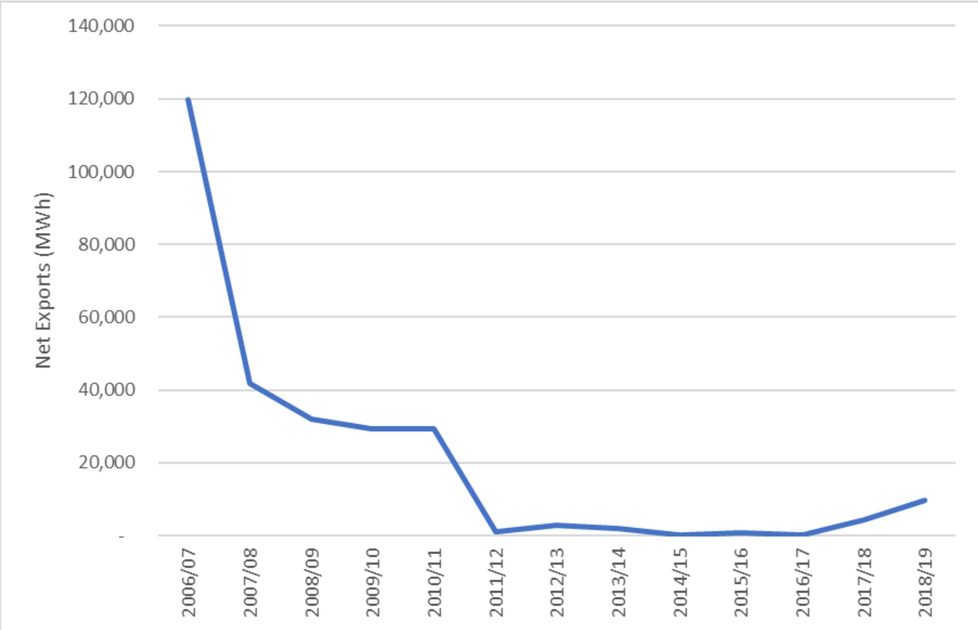
Notes: 2007 financial year ending data only includes data commencing September 2006, while 2019 financial year ending data only includes data up to and including February 2019.

Source: AEMO Facility Scada Data, Marsden Jacob analysis 2019

While the Pinjar Units have a definitive role as peaking units, the Parkeston Units provide electricity to a major mining customer in the Goldfields region. The mining customer load is usually met by a single generation unit (GT1 in 2018) and imports from the SWIS (especially overnight when balancing prices are low). GT2 and GT3 do not generate much relative to GT1 and are typically used to provide backup to GT1 and participate in the Balancing Market. Net exports from the Parkeston Power Station typically occur if two units are operating simultaneously. This implies that GT2 and GT3 are possible candidates for setting upper Energy Price Limits in the SWIS since they are operating less frequently than GT1, are usually operating below maximum output of the units (higher heat rate), and when operating, are only dispatched for a few hours (low Dispatch MWh per start).

The net exports for the Parkeston Power Station are shown for several years in Figure 2, which highlights that net exports are significantly lower in the last 8 years.

Figure 2: Net exports from the Parkeston Units



Source: AEMO Facility Scada Data, Marsden Jacob analysis 2019

The operating data for the Parkeston Units (net exports only) and Pinjar Units are in Table 2.

Table 2: Operating data for candidate OCGT units in the SWIS 2018

Unit	PRK_ AG	PINJAR_ GT1	PINJAR_ GT2	PINJAR_ GT3	PINJAR_ GT4	PINJAR_ GT5	PINJAR_ GT7
No. of Starts	185	38	43	27	35	21	41
Hours Operating	645.5	137	203	107.5	120.5	100.5	109.5
Average Generation Per Trading Interval (MWh)	9.91	5.51	4.33	6.31	5.73	5.59	5.55
Average Output (MW)	19.82	11.02	8.65	12.63	11.47	11.18	11.11
Annual Generation (MWh)	12,795	1,510	1,756	1,358	1,382	1,124	1,216
Capacity Factor (%)	2.1	0.4	0.5	0.4	0.4	0.3	0.4
Hours Per Start	3.49	3.61	4.72	3.98	3.44	4.79	2.67

Source: Marsden Jacob analysis 2019

What this shows is that the Pinjar Units had between 21 and 43 starts in 2018 and did not operate much (100 to 200 hours in a year). This suggests that estimating start-up costs correctly will be critical in determining Energy Price Limits, since the units do not operate for long periods (2.67 to 4.72 hours per start on average).

It should be noted that the operation of the Pinjar Units is appreciably down compared to 2017. Milder summer temperatures (i.e. cooling degree days) has reduced air conditioning use and lowered average demand in the SWIS compared to previous years. On average, generation from the Pinjar Units in 2018 is 53 per cent lower compared to the previous 12-month period.

On the other hand, exports from the Parkeston Units has increased appreciably in 2018 (12,795 MWh) compared to 2017 (482 MWh).

Table 3 shows the average and maximum prices captured by the Parkeston and Pinjar 40 MW Units.This is important since it can highlight if the units are having a role in determining the cleared price in both markets and hence are units that should be used to set upper Energy Price Limits.

Table 3 highlights that only the Parkeston Units were able to capture the Maximum STEM Price in 2018. It should be noted that the Maximum STEM Price only occurred three times in the Balancing Market in 2018 and not at all in the STEM ($302 per MWh). The Maximum STEM Price has not previously cleared in the STEM, while the Maximum STEM Price cleared in the Balancing Market on 26 trading intervals in 2016-17 but did not clear in 2015-16 or 2017-18.

Table 3: Captured Balancing and STEM Prices ($/MWh, nominal) 2018

Unit	PRK_AG	PINJAR_GT1	PINJAR_GT2	PINJAR_GT3	PINJAR_GT4	PINJAR_GT5	PINJAR_GT7
Average STEM Price When Running ($/MWh)	77.4	66.1	62.3	68.2	70.8	68.3	68.9
Average Balancing Price When Running ($/MWh)	80.1	85.8	66.4	66.0	67.1	68.8	88.2
Max STEM Price Captured ($/MWh)	167.8	139.7	142.3	142.3	176.7	176.7	137.3
Max Balancing Price Captured ($/MWh)	302.0	269.4	269.4	151.3	201.0	269.3	269.4

Note: "Captured" means the unit was operating when various prices were set in the Balancing Market and STEM.

Source: Marsden Jacob analysis 2019

Table 4 illustrates the volatility of the occurrence of Maximum STEM Prices in the Balancing Market.

Table 4: Occurrence of Maximum STEM Price in the Balancing Market

Financial Year	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18
Occurrence of Maximum STEM Price	23	5	22	0	26	0

Source: AEMO Balancing Summary Data, Marsden Jacob analysis 2019

It is likely that the energy market will be subject to increasing price volatility due to the increased penetration of both small and large-scale renewable generation in the SWIS. During periods of high intermittent non-scheduled generation (e.g. solar photovoltaic and wind facilities), prices could go below zero for longer periods, while prices may be higher when scheduled generation is required to ramp up rapidly to meet the load when solar generation levels fall in the evening period (in both winter and summer).

2.3 Determining the Risk Margin

The Risk Margin is intended to allow for the uncertainty in assessing the short run average cost for a candidate generation plant[14], including its fuel and non-fuel price components. It represents the difference between the upper Energy Price Limits and the function of the expected values of Variable O&M Costs, heat rate and fuel cost.

The Risk Margin is established by inputting the mean values of each variable into the following equation.

$$\text{Risk Margin} = \text{Derived Energy Price Limit} / \text{Dispatch Cost} - 1 \quad (3)$$

Where the Dispatch Cost ($/MWh) is a function of the four input variables, i.e.

[14] Clause 6.20.7(b)(i) of the WEM Rules

Dispatch Cost = (Variable O&M + (Heat Rate x Fuel Cost)) / Loss Factor) (4)

The methodologies for determining the values for input variables are discussed below.

2.3.1 Variable O&M Costs

Variable O&M Costs are those costs that vary with electricity generation. This includes:

- Variable operating labour costs;
- Usage-related maintenance costs (i.e. labour and materials);
- Non-fuel inputs such as lubricants and water.

Usage related maintenance costs can be accelerated due to the frequency of start-ups and the duration of dispatch. Increasing the number of start-ups can also bring forward maintenance expenditure since additional wear and tear is incurred in frequently going from cold start to minimum (stable) generation levels.

Longer dispatch cycles will also require that maintenance cycles are brought forward to ensure that the generating unit is operating reliably and efficiently.

There are issues with factoring start-up costs (i.e. accelerated maintenance) into the determination of Variable O&M Costs. These costs can be factored into the first half hour of dispatch on the basis that an OCGT is only guaranteed to be dispatched for the first trading interval that it operates, or these costs can be smoothed over several trading intervals based on its expectation of the number of trading intervals that it will operate for a given start (say 4.5 hours). In the latter case, there is no guarantee that the plant will recover its start-up costs if it operates fewer hours (i.e. dispatch forecasts were wrong). In the former case, including all start-up costs in the generation offer for the first half hour of trading may result in the plant not operating often and forgoing profitable opportunities to operate in the market.

Standard practice would be to amortise the start-up costs over the expected number of hours of operation of the plant in a year (i.e. they have a probability distribution). However, Monte Carlo analysis will be required since there is uncertainty about the number of starts in a year and the average number of hours that a plant will be dispatched.

Variable O&M Costs for OCGT plant in the WEM are based on cost and engineering data available to Marsden Jacob. This includes reports used to set upper Energy Price Limits in previous years, as well as data from Synergy (owner of Pinjar Units) and Goldfields Power Pty Ltd (owner of Parkeston Power Station).

Marsden Jacob estimates of Variable O&M Costs for both the Pinjar and Parkeston Units, and the triggers for this expenditure, are provided in Section 3.2.

2.3.2 Heat Rate

Heat rate curves for the benchmark OCGT units have been sourced from Synergy (Pinjar) and Goldfields Power Pty Ltd (Parkeston) as owners of the respective units. The heat rate curves show how unit heat rates vary with generation output (no temperature adjustments since there is less than a one per cent impact on the heat rate between high and low temperatures).

Fuel start-up costs have been factored into the plant heat rates. This includes fuel use associated with starting up the unit (from cold start), idling, and ramping up the unit to minimum (stable) generation levels.

A more detailed discussion on the Heat Rates is provided in Section 3.4.

2.3.3 Fuel Costs

Estimates of dispatch costs are highly dependent upon fuel price assumptions. As most OCGT plant operate at a thermal efficacy less than 32 per cent, a $1 per GJ change in fuel price results in a $11.25 per MWh change in dispatch costs in a trading interval.

The Maximum STEM Price is calculated based on the dispatch costs of a 40 MW unit using natural gas, while the Alternative Maximum STEM Price is calculated based on the dispatch costs of a unit using distillate[15]. In this section, the methodology for determining delivered gas and distillate prices is outlined.

[15] Chapter 11 of the WEM Rules

Commodity Gas Costs

The wholesale gas market in Western Australia is based on bilateral trading between gas producers and major buyers. Many of these transactions take the form of long-term gas sales agreements (5 to 20-year contracts) that include annual and daily maximum quantities and annual minimum quantities (i.e. “take-or-pay” (ToP) volumes).

Gas shippers (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.

Shorter-term gas trading arises when market participants want to vary their offtake volumes above contracted maximum levels or below ToP levels. While there is no centralised spot gas market in WA, there are currently three third party exchanges that can trade gas on a short-term basis:

- The Inlet Trading market operated by DBNGP (WA) Transmission Pty Ltd 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.
- The gas trading platform operated by Energy Access Services since 2010. Energy Access has nine members, but usage of the platform is unknown.

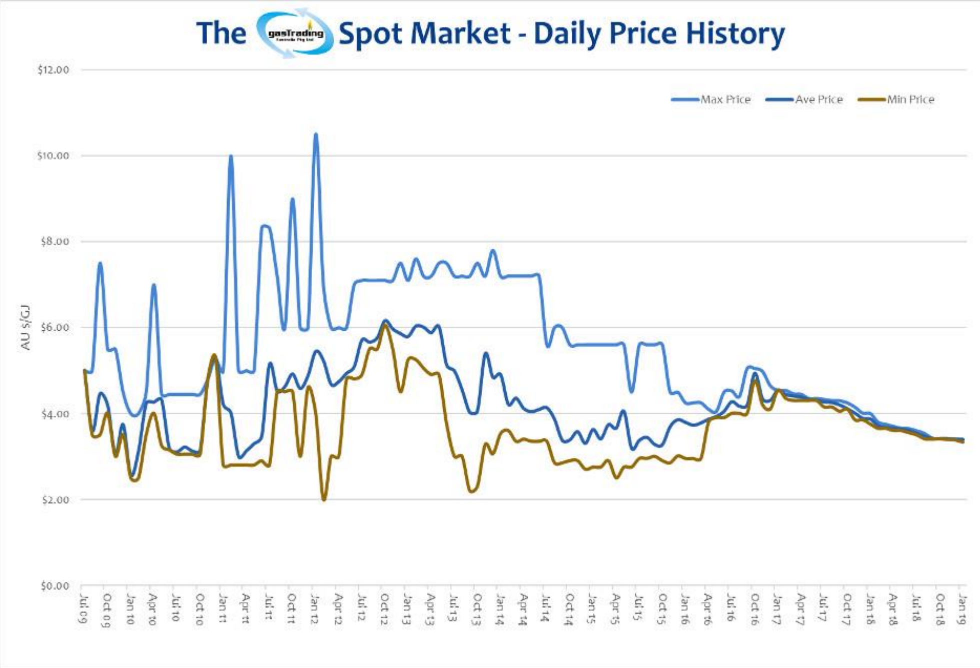
It should also be pointed out that most gas is traded informally between the major gas buyers and sellers in Western Australia. There is a high concentration of both major buyers and sellers which implies that each party can simply enter into bilateral spot transactions on a daily, weekly or monthly basis.

Data from gasTrading’s website is publicly available. For the past three years, typical volumes traded range from 5 to 25 TJ per day (0.5 to 2.0 per cent of WA domestic gas volumes) and prices paid range from $2.00 to $10.40 per GJ. The market does not settle at a single daily price but a range of prices reflecting a series of bilateral transactions.

Past consultants used the historical price data from gasTrading to develop a spot gas price that could be used to derive a Maximum STEM Price in previous studies. Daily spot gas prices are shown in Figure 3 and indicate that maximum, minimum and average prices have converged in recent years, reflecting the oversupply of domestic gas capacity and reserves.

Despite the limitations of only using gas price data from a single source with relatively low trading volumes (gasTrading), the average gas prices have been reflective of the underlying value of gas to major participants in the market.

Figure 3: Daily spot gas prices in Western Australia ($/GJ, nominal)



Source: gasTrading website[16]

The forecasts of gas commodity prices using the gasTrading data are provided in Section 3.3.1.

Gas Transport Cost

Gas transportation is usually incorporated into the fuel cost ($ per GJ) of supply offers from generators. However, gas haulage fees can usually be classified into two components: a reservation component charged on capacity reserved and a commodity component charged on volumes shipped. In the case of the Dampier to Bunbury Natural Gas Pipeline (DBNGP), the capacity reservation charge represents 80 per cent of the total haulage fee.

Given that most parties enter into long term haulage agreements with pipeline operators, it can be argued that the capacity component of the haulage charge is a fixed cost for most proponents and hence the commodity component of the charge is only relevant to determining the fuel cost of an OCGT plant. This implies that a gas transport charge of only $0.32 per GJ, compared to total gas transport charge of $1.605 per GJ (assuming 100 per cent load factor) on the DBNGP for 2018-19.

However, given that an OCGT operates at low capacity factors, it may choose to only utilise gas when transport and commodity gas is available, and distillate at other times. If it purchases gas in this way, then the full transport charge (both the reservation charge and commodity charge) are relevant in the determination of Energy Price Limits in the WEM.

The DBNGP offers capacity on a spot basis[17] to shippers via a bidding process. No data is available on price outcomes but typically the clearing price is set at a premium (15 per cent) above the T1 tariff rate. The DBNGP trading site shows that there is spare capacity on the pipeline (approximately 60 TJ per day on average in 2017-18).[18]

In this case, it can be argued that for a merchant OCGT plant (single unit), the relevant gas transport charge would include the full haulage charge ($1.395 per GJ)[19] on the DBNGP plus 15 per cent. This implies a unit gas transmission tariff of $1.605 per GJ in 2018-19 (inclusive of gas reservation and commodity charges). Allowing for some inflation of costs on 1 January 2020, the estimated unit tariff for 2019-20 for the Pinjar Units is $1.624 per GJ (assuming they operate at 100 per cent capacity factor). This price establishes a

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[16] http://www.gastrading.com.au/spot-market/historical-prices-and-volume, downloaded 24 February 2019.
[17] Details can be found in DBNGP P1 Standard Shipping Contract (March 2015), available at http://www.dbp.net.au/wp-content/uploads/2015/03/20150325-Standard-Shipper-Contract-P1.pdf.
[18] https://www.dbp.net.au/wp-content/uploads/2018/07/Spot-Capacity-Market-Rules.pdf
[19] DBNGP (WA) Nominees Pty Limited, *DBNGP Access Arrangement – Scheduled Tariff Variation 1 January 2018*, letter to Economic Regulation Authority, 30 November 2017.

benchmark rate for determining gas transport to Pinjar but is increased to reflect the fact that the plant will not be operating at a 100 per cent capacity factor. This adjustment is outlined in Section 3.3.2.

It is understood that the Goldfields Gas Pipeline (GGP) does not systematically offer capacity on a spot basis. In previous studies, it has been assumed that when excess capacity is available, then the GGP would offer transport on a spot basis (premium to Covered Tariff published rates) to a generator, which would imply that all charges (i.e. commodity and capacity reservation) are relevant to the determination of Energy Price Limits. In addition, the published rates have been increased by 10 per cent to reflect the premium value of transport on the GGP[20] and have also added in part haul costs on the DBNGP for shipping gas from gas production facilities to the inlet point on the GGP (estimated to be $0.1624 per GJ). The estimated gas transmission charge for the Parkeston Units is estimated to be $1.5051 per GJ. For this study, it is assumed that an OCGT plant could negotiate spot commodity and transport on the GGP, which implies that the $1.5051 per GJ gas transport charge will be applied in the determination of delivered gas prices for the Parkeston Units (assuming a 100 per cent capacity factor). Further adjustments to this benchmark price are made given that the plant does not run at a 100 per cent capacity factor and are outlined in Section 3.3.2.

Distillate Prices

The Alternative Maximum STEM Price is based on distillate prices (i.e. diesel)[21]. Diesel is typically imported from Singapore, which makes the delivered cost of Singapore diesel (0.5 per cent sulphur) the relevant benchmark for determining Energy Price Limits in the WEM. The Perth Terminal Gate Price (net of GST and excise) is the relevant benchmark for this study. Road transport costs from the BP refinery and port (ex-terminal) to both the Pinjar and Parkeston Units have been factored into the delivered distillate price for both candidate plants.

The WEM Rules require the Alternative Maximum STEM Price to be updated monthly to enable changes in oil prices to be passed through (with a lag) into wholesale electricity prices[22]. This reduces the level of uncertainty for establishing Alternative Maximum STEM Prices.

In theory, the Maximum STEM Price could go above the Alternative Maximum STEM Price if the delivered gas price went above the distillate price for an OCGT. This situation is highly unlikely in practice, which implies that the Alternative Maximum STEM Price acts as price ceiling for the Maximum STEM Price. This truncation of the distribution of prices for the Maximum STEM Price has been considered in the determination of Energy Price Limits.

Forecasts of world oil prices (e.g. Brent Crude) are available from a range of sources (e.g. World Bank, US Energy Information Administration etc) and have been used to develop ex-terminal Singapore diesel based on known relationships between world oil prices and landed diesel prices in Australia.

The distillate price forecasts are provided in Section 3.3.3.

2.4 Statistical Modelling Methodology

As outlined earlier, there is considerable uncertainty regarding many of the variables that make up the formula for the Energy Price Limits. This includes the operation of the plant (i.e. frequency of starts, dispatch duration), Variable O&M Cost, and fuel cost (i.e. gas and distillate prices). Using statistical methods, Marsden Jacob has generated probability distributions for each of the key input variables that are uncertain (see Chapter 3).

During a Monte Carlo simulation, values are sampled at random from the input probability distributions. Each set of samples is called an iteration, and the resulting outcome from that sample is recorded. Marsden Jacob has undertaken 10,000 iterations of the model to generate the probability distribution of possible Maximum STEM Price outcomes.

Once the distributions of likely maximum prices in the STEM/Balancing Market are determined, using the 80th percentile threshold, the Maximum STEM Prices that covers 80 per cent of occurrences in the WEM can be set. The Risk Margin is also determined since it is simply the difference between the mean and the 80th percentile (see Figure 4).

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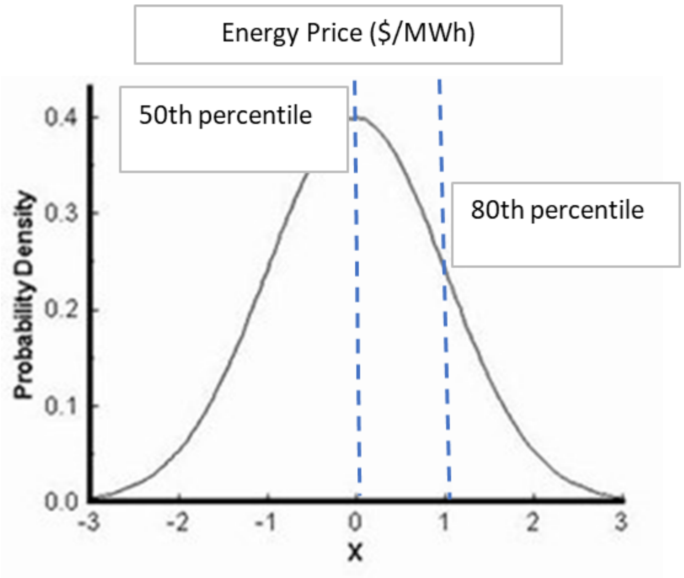
[20] Jacobs Group (Australia) Pty Ltd, *Energy Price Limits for the Wholesale Electricity Market in Western Australia*, Final report 1.1, 8 June 2018, p.59 and confirmed in discussions with *Gas Trading*.
[21] Chapter 11 of the WEM Rules
[22] Clause 6.20.3(b) of the WEM Rules

Figure 4: Decision rule for determining Maximum STEM Price (80th percentile) and Risk Margin



2.5 Addressing Feedback from Previous Reviews

The ERA and Perth Energy provided feedback to AEMO on the approach taken to estimate Variable O&M Costs in the previous 2017-18 review and the ERA has raised some of these issues in its 2018-19 Decision on the Energy Price Limits. The issues raised are discussed below.

2.5.1 Maintenance Cycle Length

The 2018-19 review considered that the remaining life of the Pinjar Units was 44 years (was 29 years in the 2017-18 review). Consequently, a maintenance program would need to be put in place to ensure that the plant can operate for another 44 years.

In Marsden Jacob's view, all the smaller and high operating cost Pinjar Units (GT1 to GT5 and GT7) are likely to remain in service until around 2031, at which time they will be 40 years old and at the end of their useful lives. This implies that the maintenance program will only need to ensure that the smaller Pinjar Units remain operational until 2031. This has been factored into the determination of the maintenance cycle for the Pinjar Units.

The Parkeston Units are also likely to have around a 40-year life, which implies that the units will be in service until at least 2036. A maintenance cycle for the Parkeston Units has been developed based on this expected plant life.

If the maintenance cycle requires a major overhaul two years prior to the retirement of the unit, this cost will not be included in the overall O&M costs, as noted by the ERA.

Estimates of maintenance costs have been obtained from both Goldfields Power Pty Ltd (Parkeston Units) and Synergy (Pinjar Units).

2.5.2 Average Number of Starts per Year

The Variable O&M Costs (including start-up costs) are based on a high heat rate because the unit is assumed to be operating at low output levels. The 2018-19 review calculated the cost per start as $3,320 (2018-19) down from $4,279 in 2017-18. Perth Energy indicated that the General Electric (GE) manual "Heavy-Duty Gas Turbine Operating and Maintenance Considerations GER-3620M" states that if the machine is started and then run at low load, below 60 per cent of output, the factored start value for a GE Frame 6 is only one-half of a start than where the machine then runs to full power. The cost for a start during which the machine is only run at low load would then be only $2,140.[23] This is a significant difference in start-up costs and has a major impact on Energy Price Limits in the WEM.

For this study, Marsden Jacob has investigated this issue and adjusted the estimated number of starts with low loads only contributing 0.5 for a normal start. The estimated starts for both the Pinjar and Parkeston Units are provided in Section 3.2 and in Appendix One respectively.

2.5.3 Discount Rate

Based on the current method, future maintenance expenditures are discounted back to present value based on an appropriate real discount rate. Two approaches were recommended by the ERA in previous reviews:

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 are determined by the variability of future maintenance expenditures. In the next step, the present value of drawn cash flows is 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.

The previous reviews moved from Method 1 in 2017-18 to Method 2 in 2018-19. In the view of Marsden Jacob, both methodologies are sound, although the Monte Carlo method will yield a more rigorous and likely more accurate estimate of maintenance expenditure costs.

However, for this study Method 1 has been utilised since the actual estimates of maintenance expenditures are based on data provided by both Synergy (Pinjar) and Goldfields Power Pty Ltd (Parkeston) and there is a high degree of confidence in the determination of maintenance costs per start (see Section 3.2). Future maintenance expenditures have been discounted using a real pre-tax WACC of 6.3 per cent, which is based on estimates provided by the Independent Pricing and Regulatory Tribunal (in New South Wales) in regulatory price determinations (February 2019).[24]

2.5.4 Other Issues

Other issues that have been addressed in this review of the methodology for setting Energy Price Limits include the following:

1. Estimation of the Risk Margin, in particular the use of an 80th percentile, rather than an average of the distribution could lead to overly conservative energy price caps (section 4.7 of the ERA's 2018-19 Energy Price Limits Decision).

   Depending on the underlying distribution, the 80th percentile can produce more reliable results than using mean values of a distribution. As the mean is a function of all values in a distribution, it can fluctuate greatly with distributions that have long tails (i.e. high/low values with low probabilities of occurring). For example, several extremely high price events can move the mean value further away from the "true" central value (as measured by the median value). However, the 80th percentile is also very stable as it would take many simulation values (say 2,000 simulation results out of 10,000 simulations) to significantly change the 80th percentile. This provides an argument for using the 80th percentile in the determination of the Risk Margin. For this study, Marsden Jacob have continued to use the 80th percentile when calculating the Risk Margin.

2. Review the application of Monte Carlo analysis to ensure that samples drawn from underlying distributions (for heat rate, gas price, and Variable O&M) are drawn and combined randomly to produce the average variable cost distribution (section 4.8 of the ERA's 2018-19 Energy Price Limits Decision).

   Some of the input distributions (e.g. gas price) used in the Monte Carlo simulations were truncated. If a normal curve is used to produce an input distribution, then this can result in negative values (depending on mean and standard deviation of the distribution) which may be impossible for input variables (e.g. gas price, MWh per start etc). In these cases, the truncation of the input variable distribution may be required to yield sensitive results. Some truncation of the gas commodity and

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[23] Perth Energy, Submission in respect to the 2017 Energy Price Limits Review, 28 August 2017.

[24] Sourced from the Independent Pricing and Regulatory Tribunal, "Spreadsheet-WACC-model-February-2019.xls". Source: https://www.ipart.nsw.gov.au/Home/Industries/Special-Reviews/Regulatory-policy/WACC/Market-Update/Spreadsheet-WACC-model-February-2019

transport price distributions was required in this study to avoid negative (and extremely) low price outcomes.

For each simulation, the Monte Carlo model uses the Microsoft Excel RAND() function to produce 1 random number for each distribution between 0 and 1. If the function was truly random, these numbers would be independent. However, all computers use a “Pseudorandom” generator. Excel uses a Mersenne Twister algorithm which is standard in many applications.

The option of seed numbers was included in the model so the same string of random numbers could be produced if required. With 10,000 simulations, the 80th percentile value converged regardless of seed number.

3. Determination of Key Parameters

3.1 Introduction

This chapter summarises the derivation of the key input values for setting the 2019-20 Energy Price Limits using their probability distributions and mean values.

3.2 O&M Costs

To calculate O&M costs, it has been assumed that the Pinjar and Parkeston Units have 40 year lives. This implies that O&M costs were calculated on the basis that the Pinjar Units are retired by 31 December 2031 and that the Parkeston Units are retired by 31 December 2036.

O&M costs for the units have been derived using the following six steps.

Firstly, determine a point estimate of maintenance costs per start based on confidential data provided by both Synergy and Goldfields Power Pty Ltd. The estimated costs per start are confidential and not provided in this public report however the costs range from $2,500 to $3,300 per start. This data is used to help verify the mean calculations of Variable O&M Costs per start that have been developed by Marsden Jacob using the methodology outlined in this section.

While these point estimates of start costs are useful reference points, to calculate the mean Variable O&M Cost per start and risk margin (based on the 80th percentile of Maximum STEM Prices), a distribution of maintenance costs per start needs to be calculated. In the process of developing probability density functions for the number of starts, Dispatch Event MWh and Variable O&M Cost per MWh, the resulting Mean Variable O&M Cost per start may differ from the point estimates.

Secondly, create a distribution of start costs ($ per start) given that the number of starts can vary which will change the overhaul maintenance cycle and hence the Variable O&M Costs per start. This is estimated for the Pinjar Units and shown in Figure 5 based on the dispatch profile of all six units over the period 2013-14 to 2018-19.[25] A probability density function was developed for the number of starts by fitting a gamma distribution to the historical distribution of starts per year.

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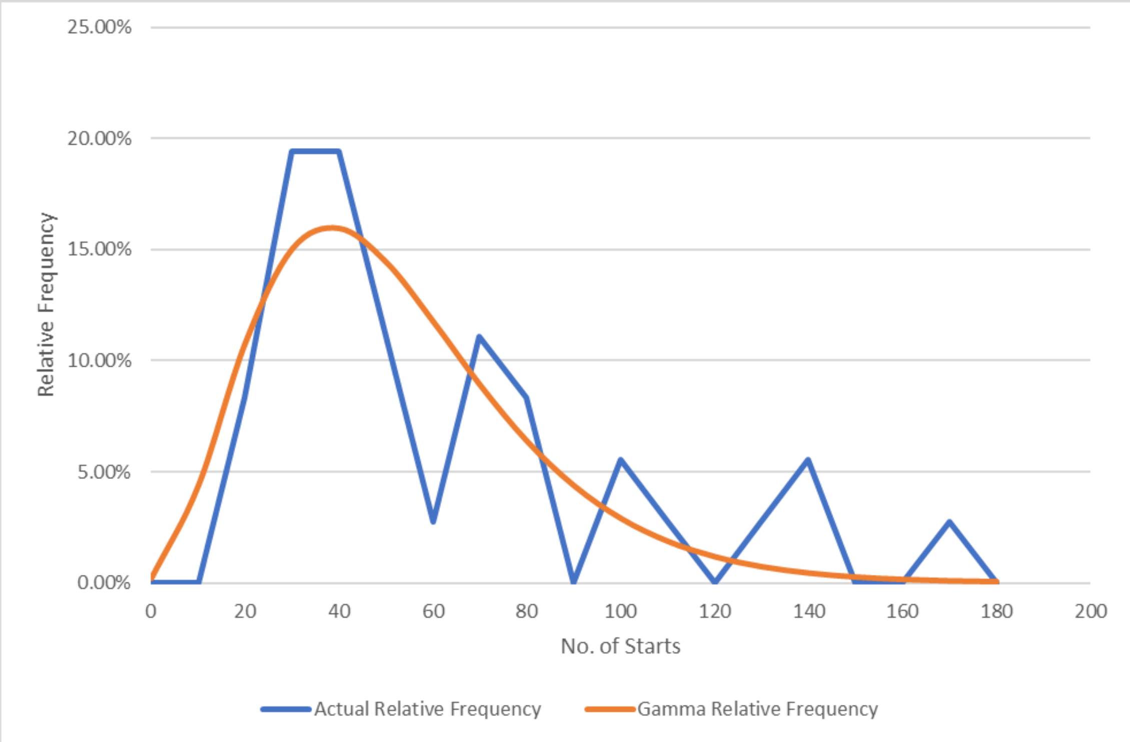
[25] 2018-19 only includes dispatch information ending February 2019.

Figure 5: Distribution of the number of starts – Pinjar Units



Source: Marsden Jacob analysis 2019

Thirdly, determine the relationship between the number of starts, which is the driver for maintenance overhaul of the Pinjar Units, and overhaul costs. The overhaul costs and unit start costs are shown in Table 5Table 5 for Pinjar only. This was based on costs in previous reviews but has been updated for exchange rate movements (impacts cost of imported parts) and local inflation (local labour and recycled parts). The results are shown for 58 actual starts per annum (average number of starts calculated from historical data).

Table 5: Overhaul costs and levelised cost per start for Pinjar Units – 10 Year Life

Overhaul type	Number of starts trigger point for overhaul	Cost per overhaul	Number in an overhaul cycle	Cost	Average of NPV of Overhaul Costs
A	600	$1,268,704	1	$1,268,704	
B	1200	$3,353,841	1	$3,353,841	
A	1800	$1,268,704	1	$1,268,704	
C	2400	$4,843,906	1	$4,843,906	
Total Cost		$10,735,154		$10,735,154	$2,485,233
Cost Per Start (a)		$4,472.98	Levelised Cost Per Start (b)		$4,133.13
Actual Starts / Year		58.0	NPV of Actual Starts		505

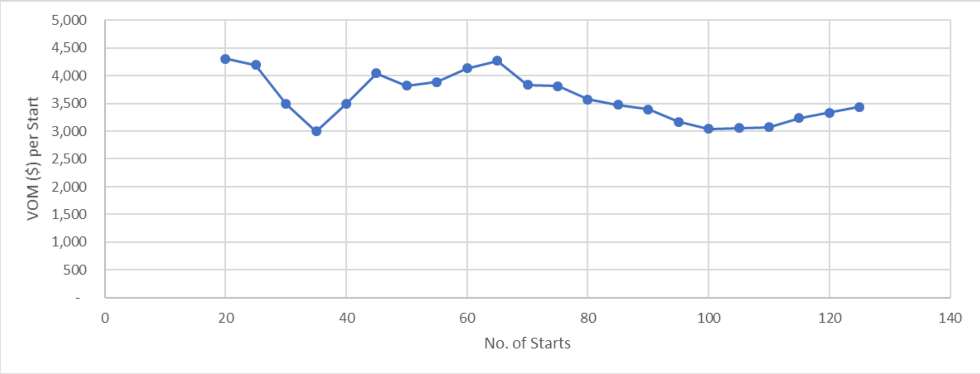
Notes: (a) Total Cost divided by 2,400 starts (consistent with previous reviews) and (b) NPV of Overhaul Costs divided by NPV of Starts

Source: Marsden Jacob analysis 2019, Jacobs Group (Australia) Pty Ltd 2018

While Overhaul Type C is a function of actual starts, Overhaul Type A and B are a function of factored starts. Factored starts are estimated based on the following: low loads (less than 60 per cent of maximum capacity of a unit) represent 0.5 for a normal start; whereas all other starts represent 1.2 actual starts. Based on historical operations, 69 per cent of actual starts for the Pinjar Units are low load starts. This implies that factored starts are 40.2 when actual starts are 58 for the Pinjar Units. Factored starts are used to determine Type A and B Overhauls, while actual starts are used to determine Type C Overhauls.

Using these costs, a relationship between start costs (Variable O&M Cost in $ per start) and the number of starts has been created. The start costs are shown in Figure 6 and are calculated by dividing the net present value (NPV) of overhaul costs by the net present value of future starts (based on a 10-year plant life). The net present value is determined using a weighted average cost of capital (WACC) of 6.3 per cent (real pre-tax).[26] .

Figure 6: Relationship between Variable O&M Costs per start and number of starts – Pinjar Units



Source: Marsden Jacob analysis 2019

Fourthly, determine the distribution of Dispatch Event MWh (generation) equal to or less than 6 hours. In previous reviews of Energy Price Limits, it was considered that the Maximum STEM Price needs to cover short dispatch periods (less than 6 hours) with high prices, rather than considering longer dispatch intervals with lower prices.

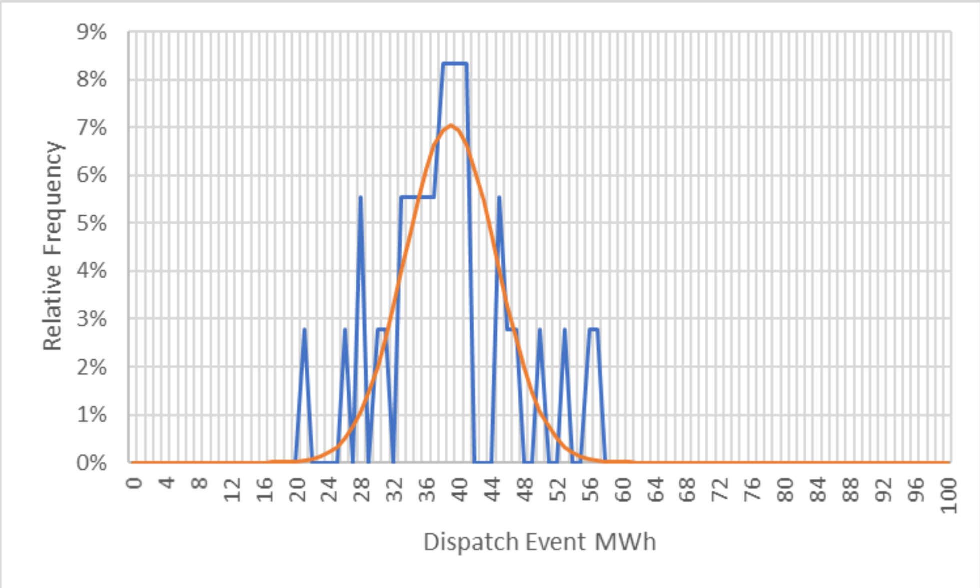
The methodology employed in this review follows the previous methodology for determining Variable O&M Costs on the basis that a change in the methodology will result in significant variations in future Maximum STEM Prices (up to $80 per MWh reduction in prices in one year if dispatch output is based on all dispatch events). However, it should be noted that truncating the duration of dispatch events means that the Maximum STEM Price will now cover more than 80 per cent of all potential STEM price outcomes. It is more likely that Maximum STEM Prices will cover between 85 to 90 per cent of all potential STEM price outcomes under this approach.

The estimates of Dispatch Event MWh for the Pinjar Units is based on the dispatch profile of all six units over the period 2013-14 to 2018-19.[27] Dispatch Event MWh has a normal distribution as shown in Figure 7 and the modelled normal distribution is used in the development of Variable O&M Costs per MWh.

[26] Sourced from the Independent Pricing and Regulatory Tribunal. "Spreadsheet-WACC-model-February-2019.xls". Available at: https://www.ipart.nsw.gov.au/Home/Industries/Special-Reviews/Regulatory-policy/WACC/Market-Update/Spreadsheet-WACC-model-February-2019

[27] 2018-19 only includes dispatch information ending February 2019.

Figure 7: Distribution of Dispatch Event MWh (6 hours or less) – Pinjar Units



Source: Marsden Jacob analysis 2019

Provided in Table 6 is a summary of the starts and operating hours for the Pinjar Units which is used in the modelling of the O&M overhaul cycle (all dispatch events), which showed that the average number of operating hours was around 4 to 5 hours per start across all dispatch events. This reduced to 2.75 hours if only dispatch events less than or equal to 6 hours were considered.

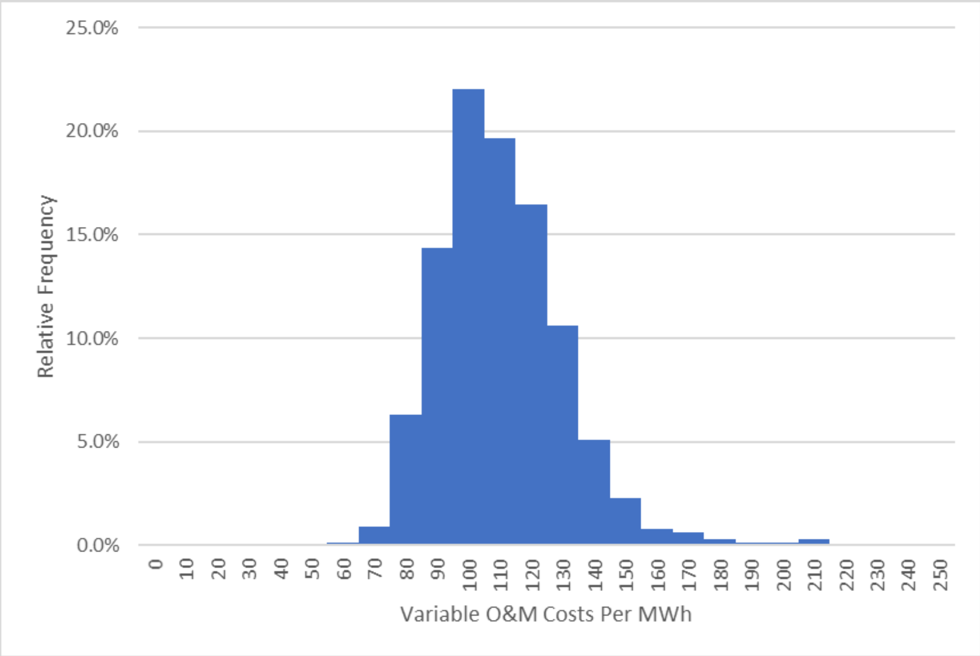
Table 6: Summary of Pinjar Units O&M cycle determination

Measure	Unit	All Dispatch Events	Only Dispatch Events Less Than or Equal to 6 hours duration
Mean	Starts/year	58	31
Standard deviation	Starts/year	36	20
Minimum	Starts/year	12	5
Maximum	Starts/year	153	86
Operating Hours	Hours/Start	4.5	2.75

Source: Marsden Jacob analysis 2019

Fifthly, using the distribution of start costs (Figure 6) and the distribution of Dispatch Event MWh (Figure 7), a Monte Carlo simulation was undertaken to develop a distribution of Variable O&M Costs ($ per MWh) as shown in Figure 8. The distribution of start costs for the Parkeston Units was derived using the above process and is shown in Appendix One.

Figure 8: Distribution of Variable O&M Costs ($/MWh) – Pinjar Units



Source: Marsden Jacob analysis 2019

The distribution of Variable O&M Costs for the Pinjar Units is then used in the Monte Carlo simulation to determine the distribution of Maximum STEM Prices.

Based on this distribution, the Mean Variable O&M cost was calculated to be $103.48 per MWh. This is equivalent to a start cost of $3,984 per start and Dispatch Event MWh of 38.5 (i.e. $3,984 per start / 38.5 MWh per start) and is higher than the four year estimates provided by Synergy.[28] The Variable O&M Cost per start of $3,984 was the mean value calculated by Marsden Jacob, while the Dispatch Event MWh of 38.5 was calculated from historical data for the Pinjar Units.

This is significantly lower than the Variable O&M Cost derived in the 2018-19 review ($129.59 per MWh). This is due to the lower Dispatch Event MWh calculated in the 2018-19 review for the Pinjar Units (26 MWh) for dispatch events less than or equal to 6 hours. Estimated maintenance costs were $3,320 per start for the Pinjar Units in 2018-19, however this lower maintenance cost was offset by a lower Dispatch Event MWh (i.e. $3,320 per start / 26 MWh per dispatch event which results in a Variable O&M of $129.59 per MWh).

Sixthly, the above analysis estimated only the maintenance overhaul component of Variable O&M Cost. Previous studies have based Variable O&M Cost on overhaul costs only (which is typically most of the cost) however Variable O&M Cost also includes other inputs such as water, labour and lubricants. Accordingly, the Mean Variable O&M Cost has been increased by $1.50 per MWh to ensure that Variable O&M Cost includes all cost components. This is based on Marsden Jacob's assessment of these costs for an OCGT plant. This increases the Mean Variable O&M costs to $104.98 per MWh.

3.3 Fuel Prices

3.3.1 Commodity Gas Prices

Under the approach developed in previous reviews of Energy Price Limits, short-run projections of maximum gas prices were developed using an Auto Regressive Integrated Moving Average (ARIMA) model of historical maximum monthly prices. The projections were then used as the central estimate for each month with historical variation in prices used to generate the standard deviation. A normal distribution was assumed to exist for projected prices.

For this analysis Marsden Jacob has adopted a similar approach. Variations from the approach are noted below.

—

[28] Variable O&M Costs per MWh had to be estimated given that the dispatch profile for the Pinjar Units is not known with certainty.

The analysis considered different forms of an ARIMA model allowing for up to:

- two levels of differences;
- 4 auto-regressive lagged errors;
- 4 moving average lagged errors.

The analysis also considered a constant term. This would reflect either an average level (no differencing), a growth factor (first differences) or an acceleration factor (second differences).

The analysis found that a model with slight negative growth (constant with first differences) produced the model of "best statistical fit".[29] However, analysis of the gas market indicated that price declines over recent years have reflected significant new gas supply capacity coming online. This has had two effects:

- first, price levels have declined (see Figure 9). Marsden Jacob considers that the declines observed over recent years have incorporated the impact of the increase in gas capacity. It is not considered that there is significant scope for further price declines, particularly as prices approach the $2 per GJ floor;
- secondly, there has been a significant reduction in volatility of maximum prices over the past few years. The significant volatility before 2012 is unlikely to be replicated.

For these reasons, Marsden Jacob has used an ARIMA model with no constant term. Reflecting the significant reduction in price volatility in recent years, statistical measures have only been calculated based on data commencing July 2012.

The full period of data examined by Marsden Jacob for this 2019-20 review comprised August 2009 to February 2019. For the reasons outlined above, Marsden Jacob estimated short run projections of maximum gas prices using a shorter period from 2012. The preferred period for the 2019-20 review is July 2012 to February 2019. Table 7 provides summary distribution statistics for the full period and the preferred period for the 2019-20 review. It also compares these with summary statistics from the 2018-19 review. As is shown, the most recent period demonstrates tighter upper and lower bounds of gas prices.

Table 7: Comparison of forecast gas distribution statistics

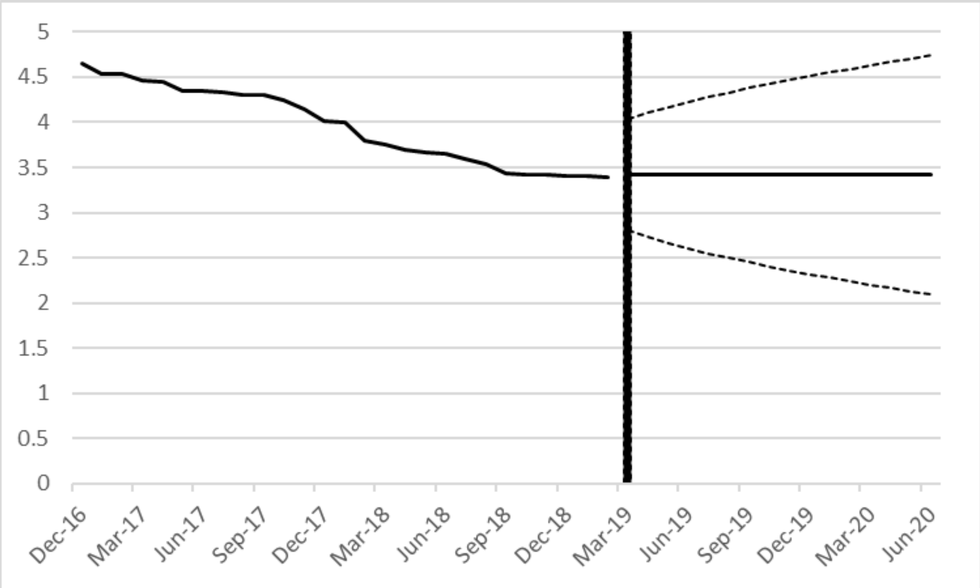
Parameter	2018-19 review	2019-20 review preferred	2019-20 review full period
Average	$4.02	$3.41	$3.44
Median	$4.02	$3.41	$3.44
80% lower bound (10th percentile)	$1.82	$2.55	$1.98
80% upper bound (90th percentile)	$6.23	$4.27	$4.91

Source: Marsden Jacob analysis 2019, Jacobs Group (Australia) Pty Ltd 2018

While the analysis suggests that the mean gas price remains constant over the period 2019 to 2020, consistent with statistical projections the range of gas outcomes has been increased progressively over time to reflect greater uncertainty (Figure 9). Separate to the statistical analysis summarised in Table 7, there may be some doubt about future gas prices remaining at such historically low levels for another 15 months (1 April 2019 to 30 June 2020). Expected growth in mining and mineral processing (e.g. iron ore) in Western Australia could increase demand for gas and consequently domestic gas prices. Conversely, new gas supplies in the domestic market could lower spot gas prices further. To cater for this uncertainty, the standard deviation for commodity gas prices has been increased beyond historical levels to account for this possibility (i.e. wider bounds shown in Figure 9 than those shown in Table 7 – 2019-20 review preferred).

[29] In terms of adjusted R-square, statistical significance of estimated parameters, and a lack of serial correlation or heteroscedasticity

Figure 9: Historical gasTrading monthly maximum prices and ARIMA forecast



Source: Marsden Jacob analysis 2019

3.3.2 Gas Transport Charges

As outlined in Section 2.3.3, the mean value for gas transport charges for gas delivered to both the Pinjar and Parkeston Units has been calculated (assuming a 100 per cent capacity factor):

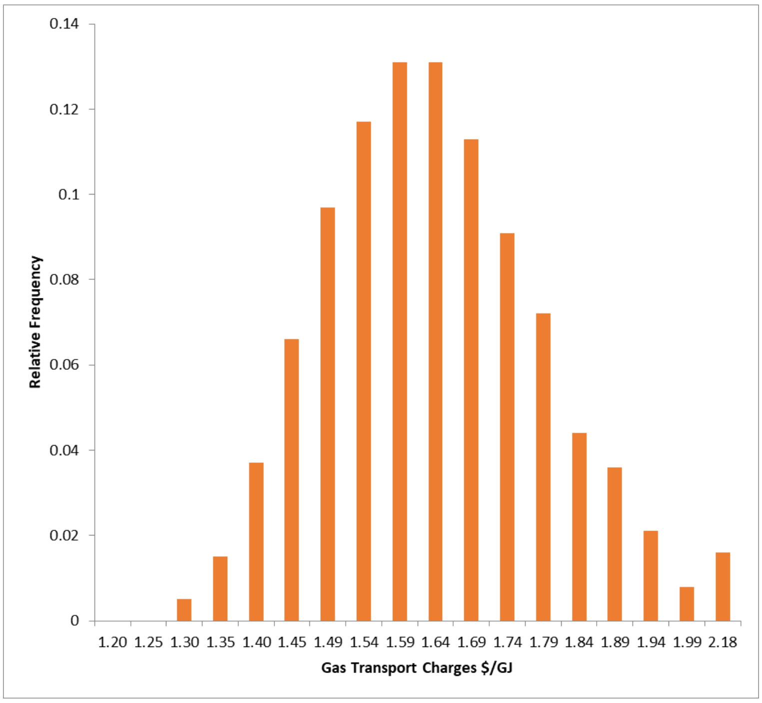
- Pinjar – $1.624 per GJ (based on a 15 per cent premium above the T1 Reference Tariff[30] applicable on the DBNGP). Assuming a standard deviation of $0.15 per GJ.
- Parkeston – $1.5051 per GJ (based on the purchase of spot transport for covered services on the GGP) with a standard deviation of $0.14 per GJ.

The probability density functions were derived for gas transport charges applicable to the Pinjar Units and the Parkeston Units.

The distribution of DBNGP gas transport is based on a log-normal distribution (which helps eliminate the occurrence of negative gas transport costs in statistical analysis). This has then been converted from the log-normal distribution back to a normal distribution for DBNGP transport charges which is shown in Figure 10. The probability density function for GGP transport charges (not shown here) has also been estimated.

[30] https://www.erawa.com.au/gas/gas-access/dampier-to-bunbury-natural-gas-pipeline/tariff-variations

Figure 10: Distribution of Gas Transport Charges ($/GJ) for the Pinjar Units (100% capacity factor)



Source: Marsden Jacob analysis 2019

The gas transport charges in Figure 10 assume the generator is operating at a 100 per cent capacity factor daily. However, it is likely that peaking gas generators will not be operating at this level and gas transport charges have been adjusted on the basis that the daily capacity factor is closer to 80 per cent for gas turbines[31]. At this level, gas transport charges would be $1.989 per GJ on the DBNGP instead of $1.624 per GJ, and $1.581 on the GGP instead of $1.5051 per GJ. These higher transport charges (and associated distribution of charges) has been incorporated into the Monte Carlo simulation analysis.

The distribution of gas transport charges is then combined with gas commodity charges to derive a delivered gas price for the Pinjar and Parkeston Units.

3.3.3 Distillate Prices

The WEM 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 per cent sulphur) or another suitable published price as determined by AEMO[32]. AEMO uses the Perth Terminal Gate Price (net of GST and excise) for this purpose, as the Singapore gas oil price (0.5 per cent sulphur) is no longer widely used. Moreover, the Perth Terminal Gate Price includes shipping costs and as such considers 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.

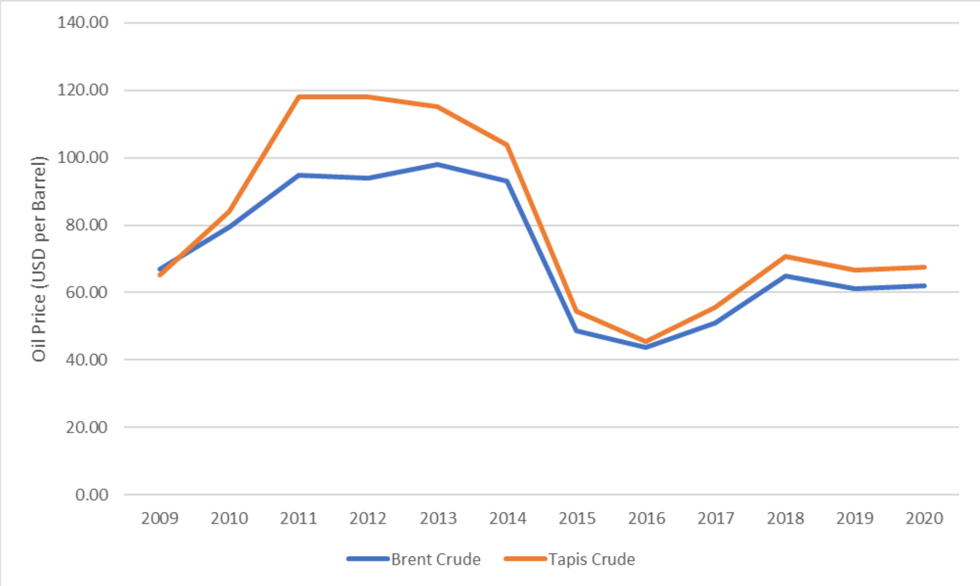
For this purpose, the uncertainty in the distillate price is not statistically important because the Alternative Maximum STEM Price is updated monthly. However, in modelling the gas price for the Maximum STEM Price, the uncertainty and level of the distillate price is relevant to the extent that it is 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. The following discussion describes the expected level and uncertainty in the distillate price for capping the gas price.

Figure 11 shows annual average crude oil prices. After the low prices of 2016, prices climbed in 2017 and 2018. The US Energy Information Administration[33] has forecast that Brent Crude, after averaging USD 59 per barrel in January, will average USD 61 per barrel in 2019 and USD 62 per barrel in 2020, after averaging

[31] Daily capacity factor is based on Synergy's portfolio of gas turbines and not the daily capacity factor of the Pinjar Units alone. This incorporates the benefit of Synergy's gas portfolio in reducing gas transport charges for all gas turbines.
[32] Clause 6.20.3(b) of the WEM Rules
[33] EIA March 2019 outlook: https://www.eia.gov/outlooks/steo/

USD 71 per barrel in 2018. The lower oil price outlook is due to the impact of increased oil production in the US and consequently less imports, and the US becoming a net exporter of oil in the 4th quarter of 2020.

Figure 11: Crude oil prices (USD per barrel) – annual average prices



Source: Marsden Jacob analysis 2019

Tapis Crude is imported into Australia from Singapore and directly impacts the terminal gate price of petroleum products and diesel in Australia. While independent forecasts of Tapis Crude were not available, there is a relationship between Brent Crude and Tapis Crude prices. In recent times, Tapis Crude trades at around a 9 per cent premium to Brent Crude. Using this relationship, Tapis Crude prices will average USD 67.10 per barrel in 2019-20.

To derive a distillate price forecast that reflects the above movements in crude oil prices, the following measures were calculated:

- Using the above forecast of Tapis Crude, derive the USD 2019 and 2020 Perth Terminal Gate Price. Convert into AUD using an exchange rate of AUD 1 = USD 0.71 (current exchange rate).
- Remove GST and the Diesel Excise to derive a Terminal Gate Price that would be paid by local generators.
- Add in the cost of transport (e.g. road, rail) from the Kwinana refinery to the generation plant.
- Convert the delivered cost of distillate into a price in $ per GJ.

The outputs are shown in Table 8. In effect, gas prices used to set the Maximum STEM Price should not exceed $21.1 per GJ (Pinjar delivered distillate cost). The standard deviation of distillate prices is estimated to be $1.31 per GJ.

Table 8: Reference distillate prices for Pinjar and Parkeston Units 2019-20

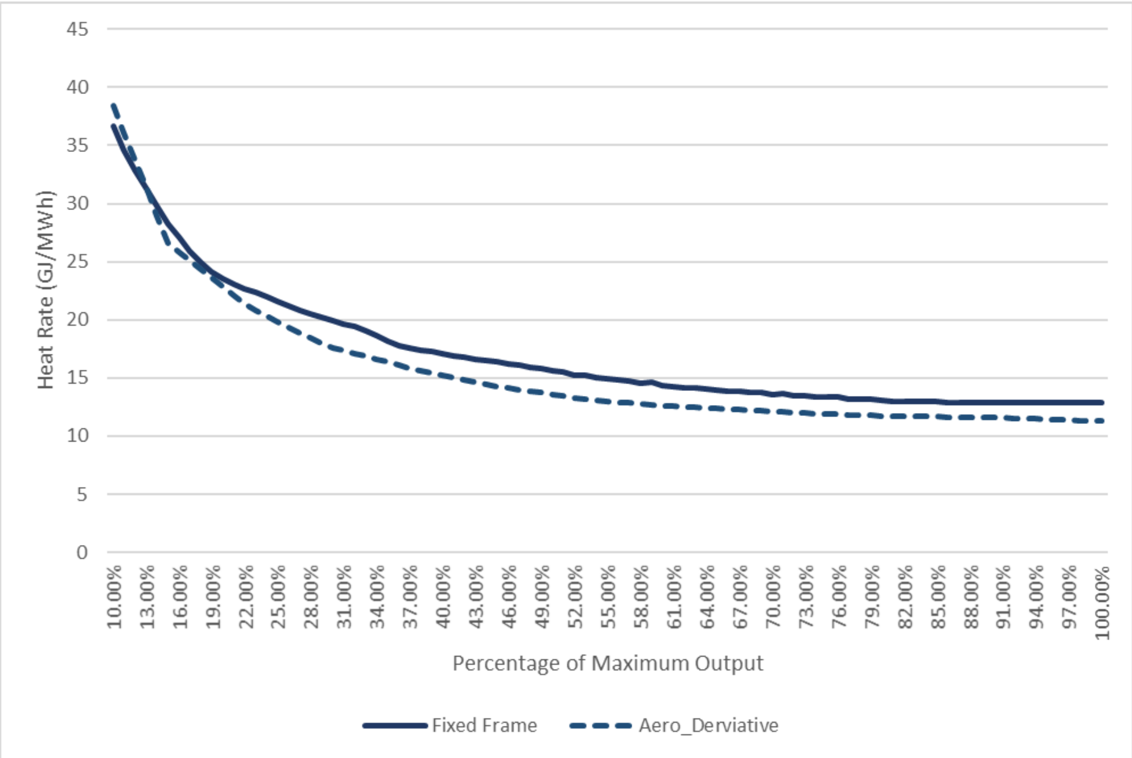
Prices and Taxes	Australian Cents per Litre (ACPL)	AUD/GJ
Diesel TGP	134.5	
Excise	42.2	
GST	12.2	
Diesel TGP	80.1	20.7
Delivery Cost to Pinjar (road)	1.22	
Delivery Cost to Parkeston (rail)	1.05	
Delivered Cost to Pinjar	81.3	21.1
Delivered Cost to Parkeston	81.1	21.0

Source: Marsden Jacob analysis 2019 and confidential information provided by Synergy and Goldfields Power Pty Ltd

3.4 OCGT Heat Rates

Heat rates of the Pinjar and Parkeston Units were derived using information provided by Synergy and Goldfields Power Pty Ltd respectively. Figure 12 shows the typical heat rate of both 40 MW OCGT fixed frame units (similar to the Pinjar Units) and 40 MW OCGT aero-derivative units (similar to the Parkeston Units) based upon the percentage loading (MW) of the generator (compared to nameplate capacity of the plant).

Figure 12: Typical heat rate of 40 MW OCGT units – Fixed Frame and Aero-Derivative Units



Source: Marsden Jacob analysis 2019

In the range above 15 per cent utilisation, the 40 MW aero-derivative units are much more efficient than the heavy frame units.

3.4.1 Start-Up Energy Consumption

Start-up heat energy was assumed to average 3.5 GJ per start for each turbine. Start-up energy consumption is aggregated across all generation for that start. For a Pinjar Unit operating at 75 per cent capacity utilisation, the 3.5 GJ used to start the turbine is equivalent to an additional 15 minutes of operation for a single MW. For most simulated starts, this cost accounts for less than $0.50 per MWh of the Maximum STEM Price.

3.5 Loss Factors

Transmission loss factors are used to determine how much sent out electricity is delivered to the regional reference node (Muja)[34]. A loss factor less than unity implies that less energy is delivered to the node than what is injected into the transmission network and vice versa if the loss factor is greater than unity.

Table 9 lists the loss factors for the 2019-20 financial year for the Pinjar and Parkeston Units[35]. Parkeston's loss factor is significantly higher than that for Pinjar and has the fourth-highest transmission loss factor in the SWIS. Pinjar's loss factor is close to the average SWIS loss factor value of 1.0339 for 2019-20.

Table 9: Loss factors for Pinjar and Parkeston Units

Loss Factor Area Code	Description	Loss Factor	StartDate
WPJR	Pinjar	1.0369	1-Jul-19
WPKS	Parkeston	1.1633	1-Jul-19

Source: Western Power 2019

[34] Chapter 11 of the WEM Rules
[35] Western Power. 2019/20 Loss Factor Report. Available at: http://aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Data/Loss-factors

4. Modelling Results

4.1 Maximum STEM Price

Modelling results presented in this chapter are the outcome of 10,000 simulations. Each unit is run independently and the potential generation outcomes for the Pinjar Units have no impact on the operation of the Parkeston Units and vice versa.

- Five random variables are created for each simulation;
  - Fuel commodity cost ($ per GJ);
  - Fuel transport cost ($ per GJ);
  - Variable O&M ($ per MWh);
  - Average generation (MW) when dispatched;
  - Run hours (h);
- Mean heat rate is a function of the average dispatch generation which is based on historic generation from 2014-2018 for Pinjar and 2018 for Parkeston;
- Fixed start-up costs are aggregated over all generation (MWh) for that start (Average Generation (MW) x Run Hours (h)).

There are large differences in the Maximum STEM Price between the use of Parkeston and Pinjar Units in establishing the Energy Price Limits. The lower average dispatch of the Pinjar Units (38.5 MWh per dispatch event) results in the plant operating at higher points on the heat rate curve when compared to the Parkeston Units (49 MWh per dispatch event).

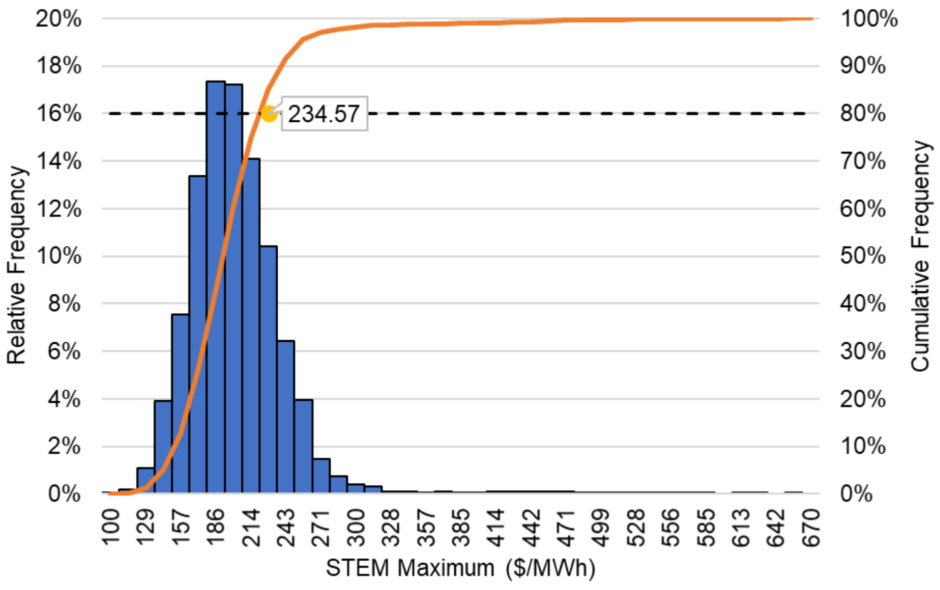
Table 10: Calculation of Maximum STEM Price with Pinjar Units

Component	Units	Values
Mean Variable O&M Cost	$/MWh	104.98
Mean Heat Rate	GJ/MWh	20.62
Mean Fuel Cost (heat rate adjusted)	$/MWh	113.02
Loss Factor		1.0369
Before Risk Margin	$/MWh	210.24
Risk Margin Added	$/MWh	24.33
Risk Margin Value	%	11.57
Assessed Maximum STEM Price	$/MWh	234.57

Source: Marsden Jacob analysis 2019

The probability density function for the Maximum STEM Price based on the Pinjar Units is provided in Figure 13. It also shows the 80th percentile of Maximum STEM Price outcomes.

Figure 13: Maximum STEM Price probability density function – Pinjar Units



Source: Marsden Jacob analysis 2019

The Maximum STEM Price based on the Parkeston Units is shown in Table 11.

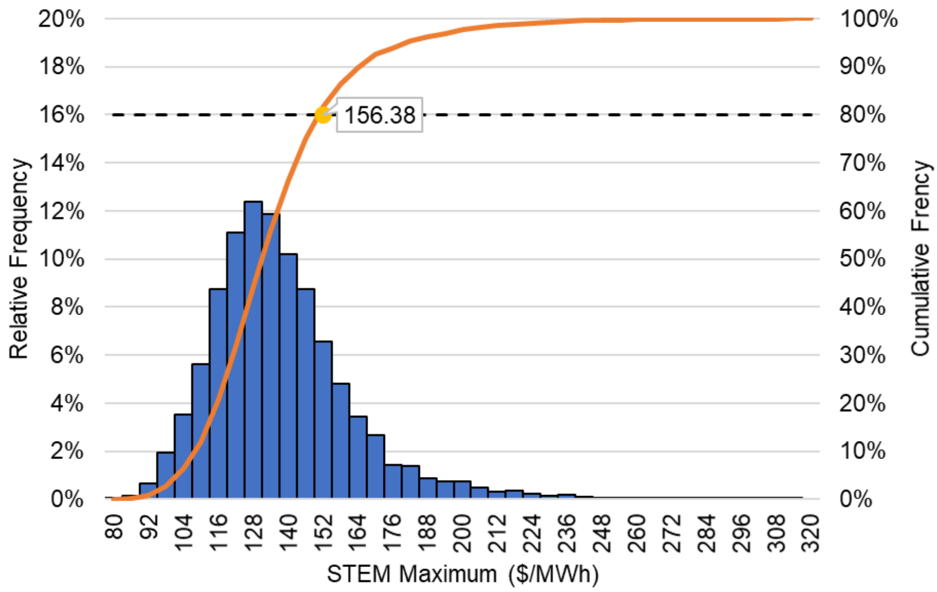
Table 11: Calculation of Maximum STEM Price with Parkeston Units

Component	Units	Values
Mean Variable O&M Cost	$/MWh	89.70
Mean Heat Rate	GJ/MWh	13.85
Mean Fuel Cost (heat rate adjusted)	$/MWh	73.97
Loss Factor		1.1633
Before Risk Margin	$/MWh	140.69
Risk Margin Added	$/MWh	15.69
Risk Margin Value	%	11.15
Assessed Maximum STEM Price	$/MWh	156.38

Source: Marsden Jacob analysis 2019

The probability density function for the Maximum STEM Price based on the Parkeston Units is provided in Figure 14. It also shows the 80th percentile of Maximum STEM Price outcomes.

Figure 14: Maximum STEM Price probability density function – Parkeston



Source: Marsden Jacob Analysis 2019

The calculated Risk Margin, which is the difference between the mean and 80th percentile, is provided in Table 12.

Table 12: Risk Margin

Generating Units	Mean	80% Cost Coverage	Risk Margin
Pinjar	210.24	234.57	11.57%
Parkeston	140.69	156.38	11.15%

Source: Marsden Jacob Analysis 2019

4.2 Alternative Maximum STEM Price

The assessed Alternative Maximum STEM Price (using distillate) for both the Pinjar and Parkeston Units are shown in Table 13 and respectively.

Table 13: Calculation of the Alternative Maximum STEM Price with Pinjar Units

Component	Units	Values
Mean Variable O&M Cost	$/MWh	104.98
Mean Heat Rate	GJ/MWh	20.62
Mean Fuel Cost (heat rate adjusted)	$/MWh	437.11
Loss Factor		1.0369
Before Risk Margin	$/MWh	522.79
Risk Margin Added	$/MWh	44.63
Risk Margin Value	%	8.54
Assessed Alternative Maximum STEM Price	$/MWh	567.42

Source: Marsden Jacob analysis 2019

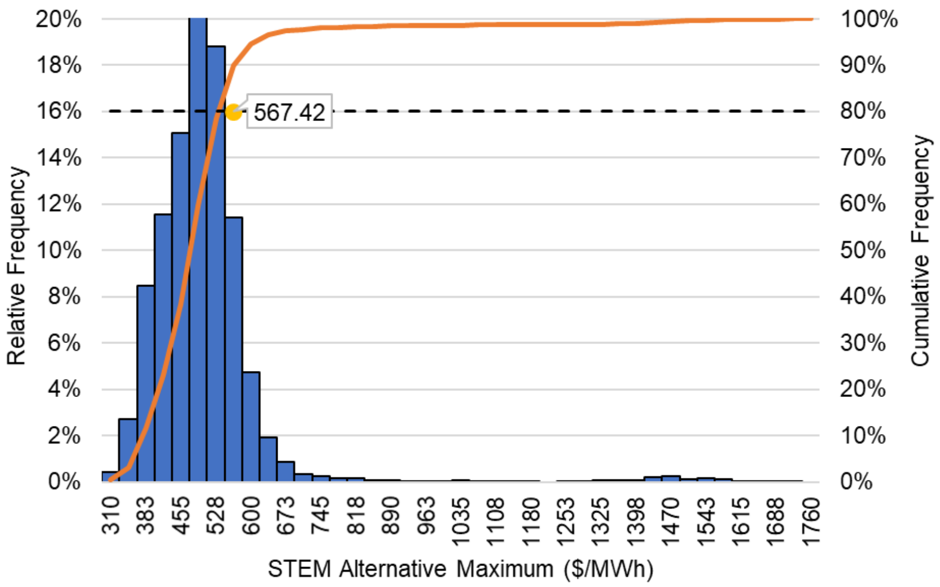
Table 14: Calculation of the Alternative Maximum STEM Price with Parkeston Units

Component	Units	Values
Mean Variable O&M Cost	$/MWh	89.70
Mean Heat Rate	GJ/MWh	13.85
Mean Fuel Cost (heat rate adjusted)	$/MWh	293.41
Loss Factor		1.1633
Before Risk Margin	$/MWh	329.33
Risk Margin Added	$/MWh	19.37
Risk Margin Value	%	5.88
Assessed Alternative Maximum STEM Price	$/MWh	348.70

Source: Marsden Jacob analysis 2019

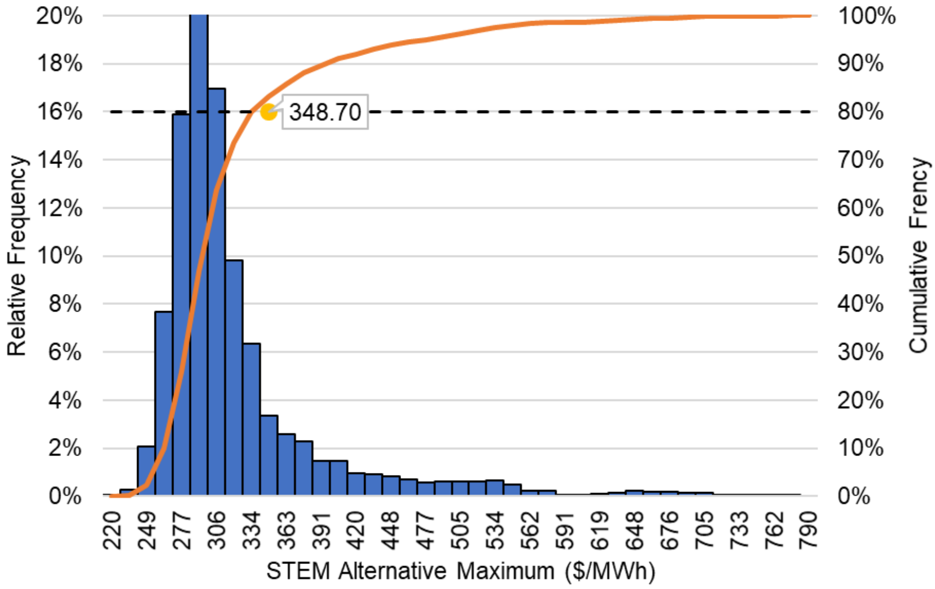
The probability density function for the Alternative Maximum STEM Price based on the Pinjar Units is shown in Figure 15 and in Figure 16 for the Parkeston Units. These figures also show the 80th percentile of Alternative Maximum STEM Price outcomes for each generation unit.

Figure 15: Alternative Maximum STEM Price probability density function – Pinjar Units



Source: Marsden Jacob analysis 2019

Figure 16: Alternative Maximum STEM Price probability density function – Parkeston Units



Source: Marsden Jacob analysis 2019

4.3 Regression of Alternative Maximum STEM Price

The Alternative Maximum STEM Price is varied each month according to changes in the price of distillate[36]. It is therefore necessary to separate out the cost components that depend on fuel cost and those which are independent of fuel cost.

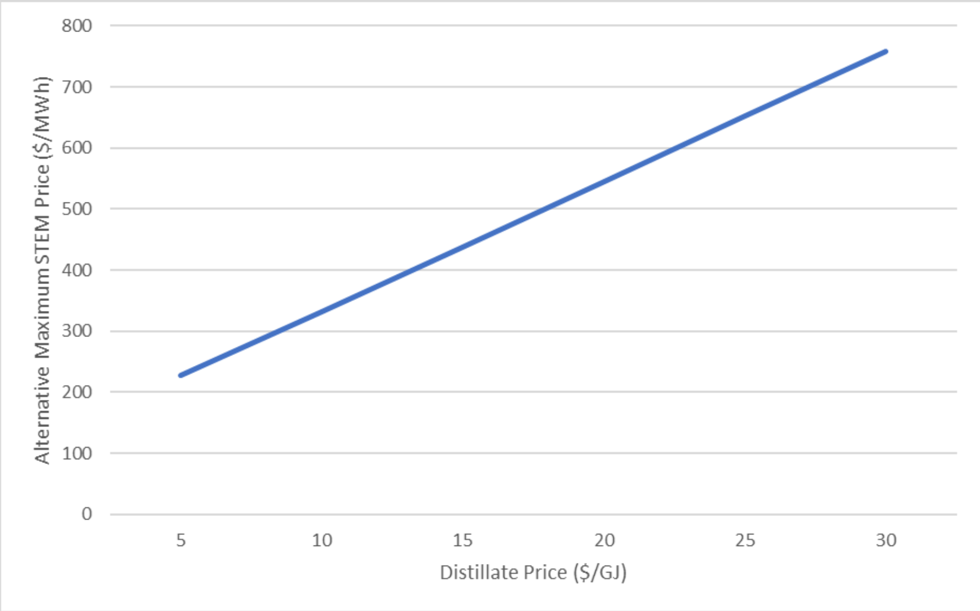
The price components for the Alternative Maximum STEM Price that provide the 80 per cent cumulative probability price are:

$120.72 per MWh + 21.2297 multiplied by the Delivered Distillate Price ($ per GJ) (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 $5 and $30 per GJ, to assess the 80 per cent probability level of cost for each fuel price. Rather than taking the 80 per cent probability values of the cost terms themselves, the two cost factors were derived from the linear regression fit of the 80 per cent price versus distillate price. The relationship using the function in equation (5) is shown in Figure 17.

[36] Clause 6.20.3(b) of the WEM Rules

Figure 17: Assessed Alternative Maximum STEM Price vs delivered distillate price – Pinjar



Source: Marsden Jacob analysis 2019

4.4 Changes in Energy Price Limits Compared to Previous Years

A comparison of the assessed Maximum STEM Price for 2019-20 with the previous year's price is provided in Table 15 and Figure 18.

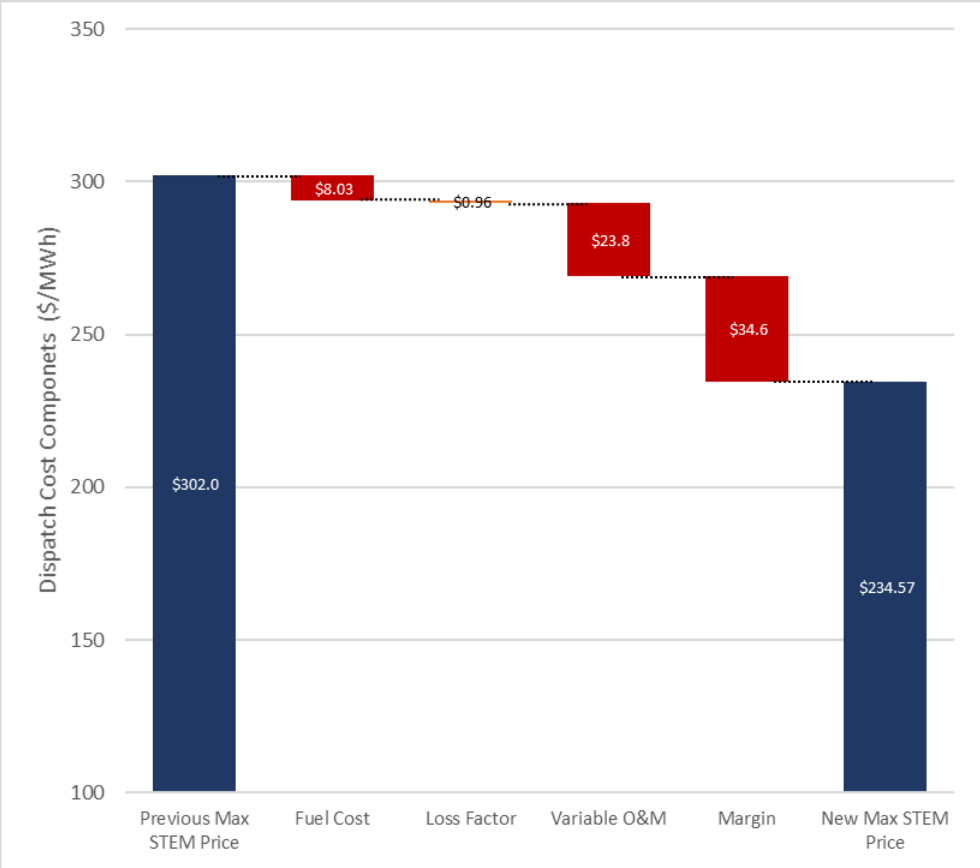
Table 15: Comparison of Maximum STEM Price – multiple years

Component	Units	2019-20	2018-19	Change
Mean Variable O&M Cost (a)	$/MWh	104.98	129.59	-24.61
Mean Heat Rate	GJ/MWh	20.62	19.23	1.40
Mean Fuel Cost (heat rate adjusted) (a)	$/MWh	113.02	121.31	-8.29
Loss Factor		1.0369	1.0322	0.005
Before Risk Margin	$/MWh	210.24	243.07	-32.83
Risk Margin Added	$/MWh	24.33	58.93	-34.60
Risk Margin Value	%	11.57	24.20	-12.63
Assessed Maximum STEM Price	$/MWh	234.57	302.00	-67.43

Source: Marsden Jacob analysis 2019, Jacobs Group (Australia) Pty Ltd 2018

Notes: (a) Mean Fuel Cost and Mean Variable O&M Cost are not loss factor adjusted.

Figure 18: Factors causing change in the Maximum STEM Price from 2018-19 (a)



Source: Marsden Jacob analysis 2019, Jacobs Group (Australia) Pty Ltd 2018

Notes: (a) The changes in Mean Fuel Cost and Mean Variable O&M Cost have been loss factor adjusted. That is why the change is lower when compared to Table 15.

The major reasons for changes in the Maximum STEM Price since last year are explained below.

1. Lower *Mean Variable O&M Cost* ($104.98 per MWh compared to $129.59 per MWh last year). The Mean Variable O&M Cost per MWh is equal to average Variable O&M Costs per start (based on overhaul costs) divided by Dispatch Event MWh (for dispatch events of 6 hours or less duration) plus an additional $1.50 per MWh cost to cover water, labour and lubricants.

    a) *Average Variable O&M Cost* per start (based on overhaul costs) – as outlined in Section 3.2, Marsden Jacob has determined that the average Variable O&M Cost per start for the Pinjar Units is $3,984 for 2019-20, whereas the equivalent cost used in developing the 2018-19 Maximum STEM Price was $3,320 per start and was $4,279 per start in 2017-18. The significant reduction in the average Variable O&M Cost per start from 2017-18 to 2018-19 was due to a change in the methodology used to calculate this variable (e.g. excluding overhaul costs incurred in the last 3 years of the plant's life).

    b) Marsden Jacob calculated *Dispatch Event MWh* for events of 6 hours or less duration. This included data for all Pinjar Units over the period 2013-14 to 2018-19 (ending February 2019). It was found that across all Pinjar Units, the average generation output was 38.5 MWh per event. The equivalent amount calculated for last year's Energy Price Limits calculation was 26 MWh. Previous reviews have typically found that Dispatch Event MWh (6 hours or less) was around 26 MWh.

    c) Therefore, the *Mean Variable O&M Cost* for 2019-20 is calculated to be $104.98 per MWh (i.e. $3,984 per start / 38.5 MWh per start plus $1.50 per MWh to cover additional O&M costs). The Variable O&M Cost for 2018-19 was calculated to be $129.59 per MWh (i.e. $3,320 per start / 26 MWh per start).

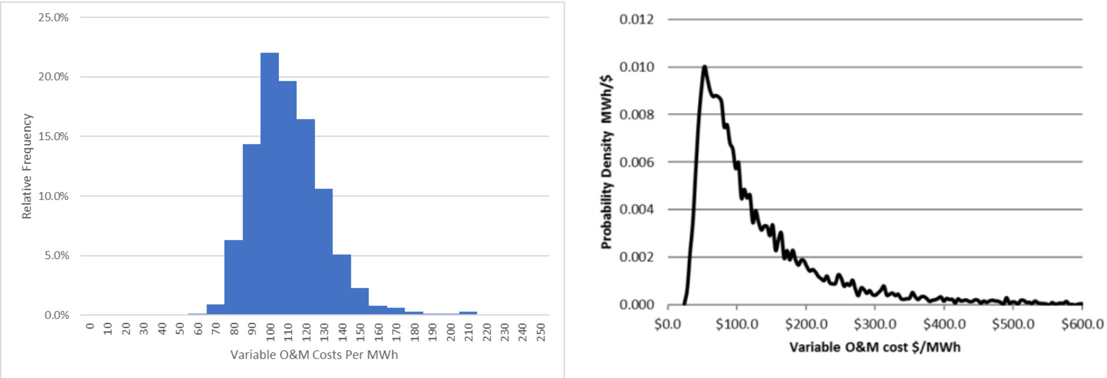
    It should be pointed out the calculation of the Mean Variable O&M Cost for the Pinjar Units has been highly volatile. The 2018-19 cost was $129.59 per MWh, was $158.93 per MWh in 2017-18, and was as low as $57.18 MWh in 2016-17 (all above Variable O&M Costs listed are before application of the loss factor). To a large extent this has resulted from changes in underlying modelling methodologies and has not reflected actual costs of maintaining the Pinjar Units.

2. Lower *Mean Fuel Cost* ($8.29 per MWh lower in 2019-20) resulting from lower gas commodity prices. The delivered cost of (spot) gas is forecast to be $5.445 per GJ for 2019-20. The mean delivered spot gas cost was forecast to be $6.31 per GJ in 2018-19. The lower delivered spot price for gas has resulted due to the continued over supply of gas in the domestic market, which resulted in average spot gas price forecasts reducing to $3.41 per GJ in 2019-20, compared to average spot prices of $4.00 per GJ for 2018-19. The underlying spot gas price forecast used in the 2018-19 review was $4.02 per GJ.

3. Reduced *Risk Margin Value* due to a smaller variance in the distribution of Maximum STEM Prices, which is mainly a function of the reduced variance in Variable O&M Costs and delivered (spot) gas prices.

As outlined in Point (1) above, modelled mean Variable O&M Costs ($ per MWh) have fallen. In addition, the modelling of Variable O&M Costs in 2019-20 has a significantly narrower probability distribution function when compared to the modelling undertaken to support Energy Price Limits in 2018-19. The probability density functions for Variable O&M Cost for this year is compared with the PDF for last year in Figure 19.

Figure 19: Comparison of PDF for Variable O&M Costs ($ per MWh) – Pinjar Units 2019-20 (left) and 2018-19 (right)



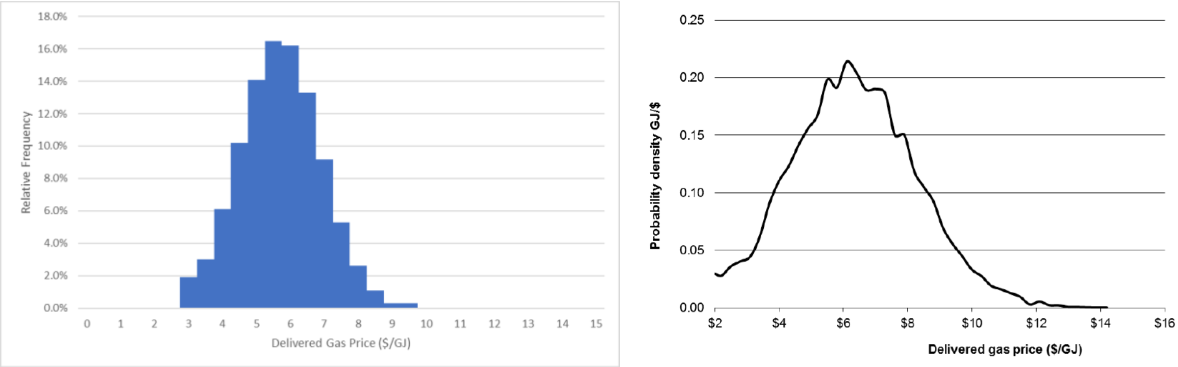
Source: Marsden Jacob analysis 2019, Jacobs Group (Australia) Pty Ltd 2018

This highlights the considerable range of Variable O&M costs that could occur under the modelling undertaken in the 2018-19 review. Variable O&M Costs can be as high as $600 per MWh in last year's modelling, whereas modelling for setting the 2019-20 Energy Price Limits indicates that the maximum Variable O&M Costs are only likely to be around $208 per MWh for the Pinjar Units. As a result of the significantly higher range of values modelled in previous reviews, Mean Variable O&M Costs ($129.59 per MWh) are substantially above the median cost ($96 per MWh), and the standard deviation of costs is $99.15 per MWh. The estimated standard deviation of Variable O&M Costs calculated for the 2019-20 review is $19.12 per MWh, with a mean of $104.98 per MWh. The 80th percentile of Variable O&M Costs is around $120.1 per MWh.

Contributing to the smaller variance in the Variable O&M Costs for the Pinjar Units is the planned retirement date of December 2031 for all units. While the exact maintenance cycle for all units (e.g. when a major overhaul was undertaken for a specific unit) is unknown, the number of potential maintenance cycle possibilities is reduced because the units only require a further 10 years of maintenance. The plants have a further 12 years of life, and it is assumed that no major maintenance is undertaken in the last 2 years of the Pinjar Units' lives. Knowing the end date for the Pinjar Units reduces the number of potential maintenance cycle possibilities and hence reduces the variance for Variable O&M Costs.

The distribution of delivered gas prices also has a significant influence on the distribution of Maximum STEM Prices. The significantly wider distribution of delivered gas prices in the 2018-19 review contributed to increasing the 80th percentile for the Maximum STEM Prices in 2018-19. The PDFs for delivered gas prices for 2019-20 and 2018-19 setting of Energy Price Limits are shown in Figure 20.

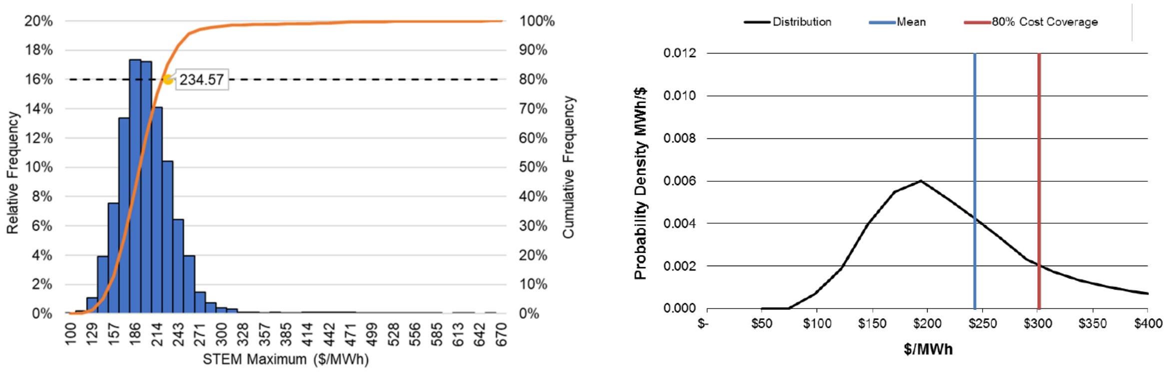
Figure 20: Comparison of PDF for Delivered Gas Costs ($ per GJ) – Pinjar Units 2019-20 (left) and 2018-19 (right)



Source: Marsden Jacob analysis 2019, Jacobs Group (Australia) Pty Ltd 2018

The distribution of Variable O&M Costs and gas costs has a direct influence on the probability density function for Maximum STEM Prices, and hence the 80th percentile price which determines the Risk Margin value. The PDFs for 2018-19 and 2019-20 Maximum STEM Prices are provided in Figure 21.

Figure 21: Comparison of PDF for Maximum STEM Prices ($ per MWh) – Pinjar Units 2019-20 (left) and 2018-19 (right)



Source: Marsden Jacob analysis 2019, Jacobs Group (Australia) Pty Ltd 2018

While the Maximum STEM Price has reduced, the Alternative Maximum STEM Price has increased compared to last year. The lower Mean Variable O&M Cost has been offset by a higher Mean Fuel Cost due to higher distillate prices. The Risk Margin is also lower due to the reduced variance in the distribution of Alternative Maximum STEM price outcomes.

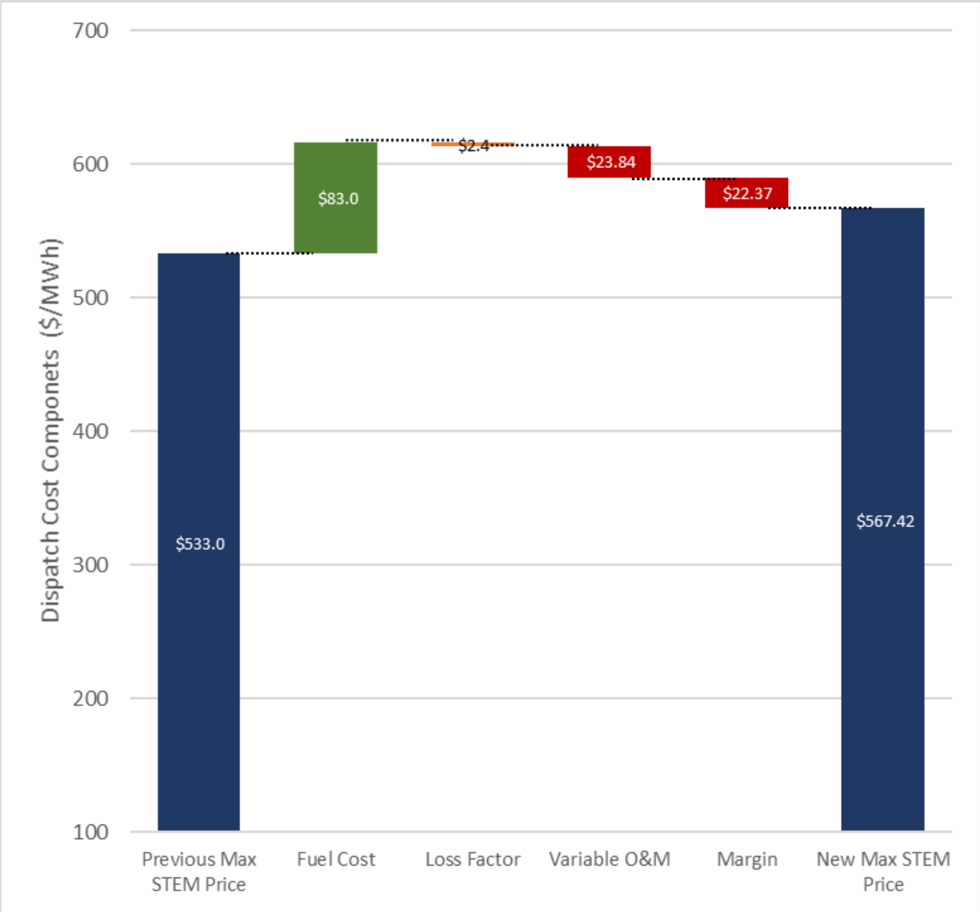
Table 16: Comparison of Alternative Maximum STEM Price – multiple years

Component	Units	2019-20	2018-19	Change
Mean Variable O&M Cost (a)	$/MWh	104.98	129.6	-24.61
Mean Heat Rate	GJ/MWh	20.62	19.277	1.35
Mean Fuel Cost (heat rate adjusted) (a)	$/MWh	437.11	351.4	85.69
Loss Factor		1.0369	1.0322	0.005
Before Risk Margin	$/MWh	522.79	466.0	56.79
Risk Margin Added	$/MWh	44.63	67.0	-22.37
Risk Margin Value	%	8.54	14.4	-5.86
Assessed Alternative Maximum STEM Price	$/MWh	567.42	533.0	34.42

Source: Marsden Jacob analysis 2019, Jacobs Group (Australia) Pty Ltd 2018

Notes: (a) Mean Fuel Cost and Mean Variable O&M Cost are not loss factor adjusted.

Figure 22: Factors causing change in the Alternative Maximum STEM Price from 2018-19 (a)



Source: Marsden Jacob analysis 2019, Jacobs Group (Australia) Pty Ltd 2018

Notes: (a) The changes in Mean Fuel Cost and Mean Variable O&M Cost has been loss factor adjusted. That is why the change is lower when compared to Table 16.

A comparison of assessed upper prices with historical outcomes is provided in Figure 23. What this shows is that the assessed Maximum STEM Price is the lowest price (in nominal dollars) since 2012-13. This is broadly consistent with lower commodity gas prices that are projected for 2019-20. However, the reduction in Variable O&M Cost and Risk Margin in 2019-20 are also significant factors (the latter is also a function of the reduced variance in both Variable O&M Costs and commodity gas prices). On the other hand, the Alternative Maximum STEM Price is slightly higher than last year, resulting from higher distillate prices that have increased in response to rising forecast crude oil prices, which has easily offset lower Variable O&M Costs.

Figure 23: Comparison of assessed upper Energy Price Limits with historical prices

Source: Marsden Jacob analysis 2019, Jacobs Group (Australia) Pty Ltd 2018

5. Appendix One: Determination of Key Parameters for the Parkeston Units

As outlined in Section 2.2, the Parkeston Units provide electricity to a major mining customer in the Goldfields region, while also providing peaking energy in the STEM and Balancing Market. Usually, Unit 1 (GT1) provides energy to the baseload mine, while Units 2 and 3 are providing back-up to Unit 1 and participating in the Balancing Market. This makes it problematic when using the Parkeston Units as a benchmark for establishing Energy Price Limits, since the maintenance overhaul cycle for Unit 1 will be driven by operating hours, while the overhaul cycle for Units 2 and 3 will be largely dictated by their participation in the Balancing Market.

For this study, we have based the calculation of overhaul costs on the dispatch profile of Units 2 and 3 participating in the Balancing Market. The calculation of levelised overhaul costs is $4,087 per start for the mean number of starts of 66.5 (based on the latest two years of starts) and is shown in Table 17 along with the overhaul cycle costs.

Table 17: Overhaul costs and levelised cost per start for Parkeston Units – 66.5 starts per annum

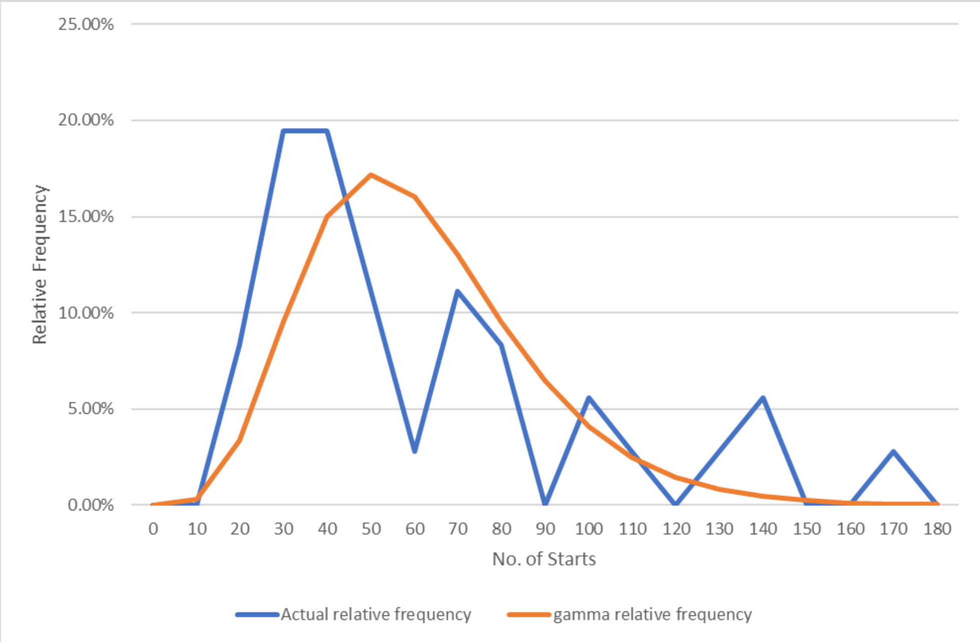
Overhaul type	Number of starts trigger point for overhaul	Cost per overhaul	Number in an overhaul cycle	Cost	Average of NPV of Overhaul Costs
A	600	$1,268,704	1	$1,268,704	
B	1200	$3,353,841	1	$3,353,841	
A	1800	$1,268,704	1	$1,268,704	
C	2400	$4,843,906	1	$4,843,906	
Total Cost		$10,735,154		$10,735,154	$2,764,763
Cost Per Start (a)		$4,472.98	Levelised Cost Per Start (b)		$4,087.49
Actual Starts / Year		66.5	NPV of Actual Starts		682

Notes: (a) Total Cost divided by 2,400 starts (consistent with previous reviews); (b) NPV of Overhaul Costs divided by NPV of Starts; and Overhaul costs calculated over remaining lives of Units 2 and 3 which is assumed to be period ending December 2036.

Source: Marsden Jacob analysis 2019

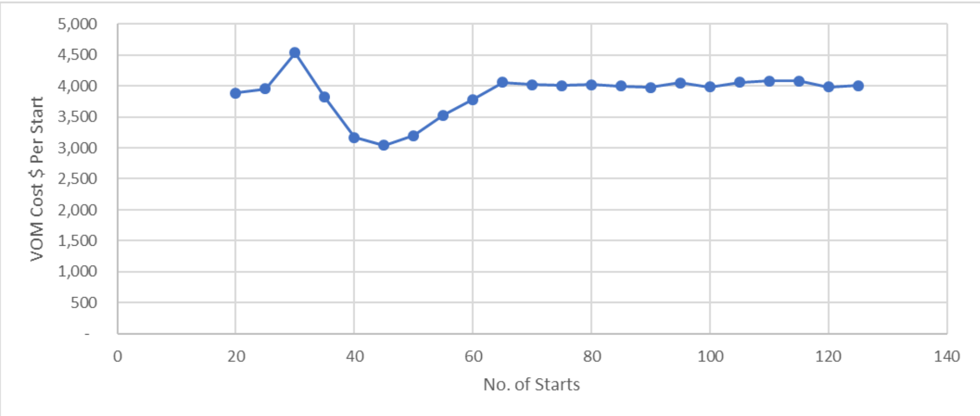
The calculation of Parkeston O&M Costs follows the six-step methodology outlined in Section 3.2 for the Pinjar Units. Shown in Figure 24 to 27 are the distribution of the number of starts (which is based on the same distribution of the number of starts for the Pinjar Units), and the relationship between starts and Variable O&M Cost, distribution of dispatch events of 6 hours duration or less and the distribution of Variable O&M Cost per MWh for the Parkeston Units. The distribution of Variable O&M Cost per MWh is used in the Monte Carlo analysis to determine the Maximum and Alternative Maximum STEM Prices. The distribution of starts in Figure 24 is based on the distribution for the Pinjar Units because the sample size for the number of starts for the Parkeston Units was insufficient to derive a reasonable probability density function.

Figure 24: Distribution of the number of starts – Parkeston Units (2 and 3 only)



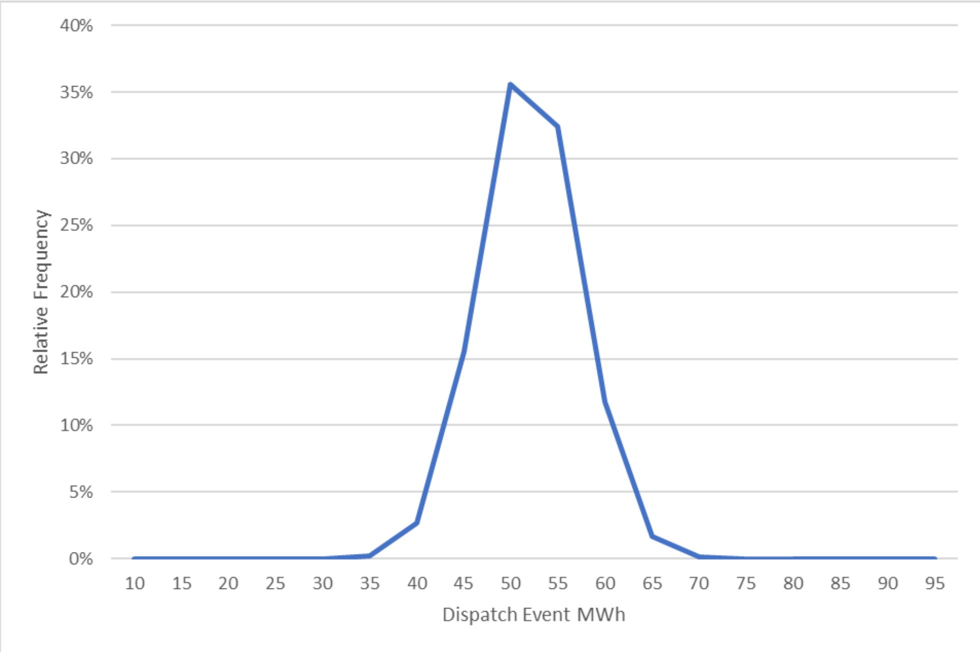
Source: Marsden Jacob analysis 2019

Figure 25: Relationship between Variable O&M Costs per start and number of starts – Parkeston Units (2 and 3 only)



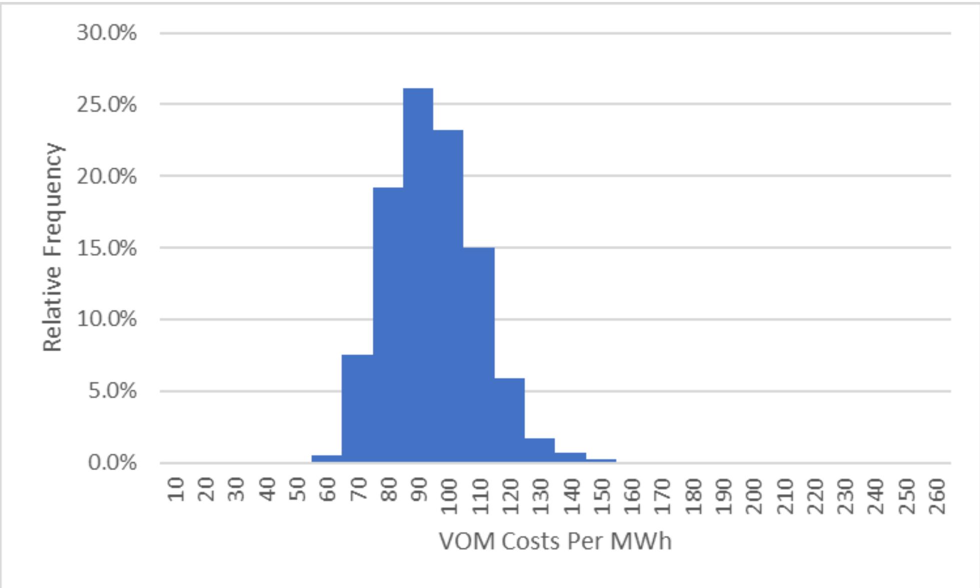
Source: Marsden Jacob analysis 2019

Figure 26: Distribution of Dispatch Event MWh (6 hours or less) – Parkeston Units (2 and 3 only)



Source: Marsden Jacob analysis 2019

Figure 27: Distribution of Variable O&M Costs ($/MWh) from overhaul costs – Parkeston Units (2 and 3 only)



Source: Marsden Jacob analysis 2019