MARSDEN JACOB ASSOCIATES

economics
public policy
markets
strategy

2020-21 Energy Price Limits Review – Final Report (Public)

A report for the Australian Energy Market Operator

A Marsden Jacob Report 20 Jul 2020

I

Prepared for Client
20 Jul 2020

Marsden Jacob Associates
ABN 66 663 324 657
ACN 072 233 204

economists@marsdenjacob.com.au

Authors

Andrew Campbell – 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.

www.marsdenjacob.com.au

Contents

Figures

Tables

Acronyms and abbreviations

AEMO	Australian Energy Market Operator
ACPL	Australian Cents Per Litre
ARIMA	AutoRegressive Integrated Moving Average
BM	Balancing Market
CCGT	combined cycle gas turbine
DBNGP	Dampier to Bunbury Natural Gas Pipeline
DMIRS	Department of Mines, Industry Regulation, and Safety
ERA	Economic Regulation Authority
FOM	fixed operating and maintenance
GGP	Goldfields Gas Pipeline
GJ	gigajoule
GST	Goods and Services Tax
GW	gigawatt
GWh	gigawatt hour
kW	kilowatt
kWh	kilowatt hour
LRET	Large-scale Renewable Energy Target
MLF	marginal loss factor
MW	megawatt
MWh	megawatt hour
NCS	Network Control Service
NPV	net present value
O&M	operating and maintenance
OCGT	open cycle gas turbine
PJ	petajoule
ppm	parts per million
PV	photovoltaic
RET	Renewable Energy Target
SRMC	short run marginal cost
STEM	Short Term Energy Market
TGP	Terminal Gate Price

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 $/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 -$1000/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 $/MW/annum.
Heat Rate	A measure of the efficiency of a generation plant that converts fuel into electricity. Usually measured in GJ/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 2 gas turbine units at the Mungarra Power Station 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).

—

[1] Chapter 11 of the WEM Rules
[2] Section 6.20 of the WEM Rules
[3] Chapter 11 of the WEM Rules
[4] Chapter 11 of the WEM Rules

Parkeston Units	Collectively means the PRK_AG Unit 2 and PRK_AG Unit 3 aero-derivative units at the Parkeston Power Station registered in the WEM as a single facility PRK_AG.
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 $/MWh.
Short Term Energy Market (STEM)	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 $/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

Marsden Jacob Associates (Marsden Jacob) was appointed and undertook the modelling for calculating revised values for the Maximum STEM Price and Alternative Maximum STEM Price (referred to as Energy Price Limits) to apply in the Wholesale Electricity Market (WEM) for the 2020-21 year. Marsden Jacob undertook this work for the 2019-20 review.

This annual review is required under clause 6.20.6 of the Wholesale Electricity Market Rules (WEM Rules).

Required Methodology

In accordance with clause 6.20.7 of the WEM Rules, the Maximum STEM Price and Alternative Maximum STEM Price must be set based on the estimate of the short run marginal cost of the highest cost generating facility in the South West Interconnected System (SWIS) fuelled by natural gas and distillate respectively.

For the selected generator, the determination of this generator's short run marginal cost requires:

- The following factors to be determined for that generator: Variable Operating and Maintenance costs ($/MWh), Heat Rate (GJ/MWh), Fuel Cost ($/GJ), Loss Factor at its connection location, and a Risk Margin (that is expressed as a fraction and represents the level of uncertainty);
- The factors are expressed as distributions as forecasts of these factors are uncertain;
- The Maximum STEM Price and Alternative Maximum STEM Price must be calculated using the following equation defined in clause 6.20.7(b) of the WEM Rules:

$$\frac{1 + Risk\ Margin}{Loss\ Factor} \times \left(Variable\ O\&M_{\$/MWh} + \left(Heat\ Rate_{GJ/MWh} \times Fuel\ Cost_{\$/MWh}\right)\right)$$

- The variable cost is to be calculated over combinations of the factor distributions, and selecting the value based on a defined percentile of the variable cost distribution;
- The Maximum STEM Price and Alternative Maximum STEM are treated differently in relation of Fuel Costs:
  - gas costs are developed as a distribution based on the outlook and uncertainty; while
  - as the Alternative Maximum STEM Price is updated monthly and is split into two components: a constant non-fuel component ($/MWh) and a fuel component (GJ/MWh).

Modelling Steps

The approach undertaken by Marsden Jacob was the same as was used for the 2019-20 review. This involved the following:

- Selecting the generator(s) to be the basis of the upper Energy Price Limits. Two generators were selected;
- Obtaining data on the factors noted above;
- Quantifying the amount of uncertainty in factors;
- Using natural gas costs for the Maximum STEM Price and distillate costs for the Alternative Maximum STEM Price;
- Undertaking simulations to develop the distributions of the selected generator variable costs based on the uncertainty in the relevant factors;
- From this, developing the Maximum STEM Price and Alternative Maximum STEM Price for the two selected generators as the 80th percentile of the variable cost distribution (the selection of the 80th percentile accounts for the Risk Margin factor);

- The generator that resulted in the highest Maximum STEM Price and Alternative Maximum STEM Price set these values;
- Comparing the calculated upper Energy Price Limits for 2020-21 to that calculated in the previous 2019-20 review.

Selection of the Highest Cost Generator(s)

The WEM Rules stipulate that the candidate units for setting of the Maximum STEM Price and Alternative Maximum STEM Price must be 40 MW open cycle gas turbine units[6]. Based on this requirement, Marsden Jacob analysis and the previous 2019-20 review, the generator units selected were:

- Pinjar Units: the 6 Pinjar 40 MW gas turbine units registered in the WEM as individual facilities PINJAR_GT1, PINJAR_GT2, PINJAR_GT3, PINJAR_GT4, PINJAR_GT5 and PINJAR_GT7 (these are located on the outskirts of Perth); and
- Parkeston Units: the PRK_AG Unit 2 and PRK_AG Unit 3 aero-derivative units at the Parkeston Power Station registered in the WEM as a single facility PRK_AG (these are located in the Goldfields Region).

These were the same generator units used in the 2019-20 review.

The Mungarra Units (the 2 gas turbine units at the Mungarra Power Station) were considered, but these units will not be dispatched in the WEM except under the terms of the Network Control Services arrangement. This made them not suitable for selection.

Determination of the Factor Distributions

Marsden Jacob was provided with data through AEMO by contacting the generator operators to aid in the development of the factors for distribution. The assessment of the factors was as follows:

- Variable O&M costs (those costs that vary with electricity generation) depend on variable operating labour costs, usage-related maintenance costs (i.e. labour and materials) and non-fuel inputs such as lubricants and water. A key determinant is the number and costs of generator unit starts and how this impacts maintenance costs. From the distribution of the number of events where Balancing Prices continually exceeded $100/MWh, distributions of Variable O&M costs for the selected generators was developed.
- Heat Rate varies with generator output. The modelling had start-up heat energy between 9 to 15 GJ/start for each turbine. Start-up energy consumption was aggregated across all generation for that start.
- The Loss Factors were based on the 2019-20 year. These were Pinjar 1.0369 and Parkeston 1.1633.
- Gas prices required both gas commodity costs and gas transport costs to be determined. Gas data included the gasTrading data in the development of average and gas price uncertainty, where the average of the past year was considered the best estimate of the expected value for the coming year. Marsden Jacob used the "best" ARIMA model to generate estimates of gas price volatility.
- Distillate prices reflected movements in crude oil prices.

After the development of the first Draft Report, the impact of COVID-19 on gas and distillate prices required Marsden Jacob to review the outlooks of these commodities. These commodities can vary greatly over short time periods with changing demands. The projections contained in the second Draft Report and this Final Report incorporate the impact of COVID-19:

- The distillate price outlook was substantially reduced (reflecting prices as of 7 May 2020) from that contained in the first Draft Report.
- The spot gas price was unchanged from the first Draft Report which incorporated a low spot gas price outlook (reflecting oversupply conditions).

---

[6] Clause 6.20.7(b)(i)-(v) of the WEM Rules

Annual gas prices published by the Department of Mines, Industry Regulation and Safety (DMIRS) are based on a weighted average of flows on the DBNGP. By using a weighted average price which includes long term contracts before the any impact of COVID-19 on contracts will be mitigated and delayed.

Further details are presented in Chapter 7 of this Final Report.

Stakeholder Submissions

AEMO received three formal submissions[7] during the public consultation period.

In summary, all three submissions suggested that the gas spot prices used in the Draft Report did not adequately represent the fuel cost of generators, and suggested that AEMO should use the annual gas price published by the Department of Mines, Industry Regulation and Safety (DMIRS) in place of gas spot prices.

One submission raised the matter that gas transport costs for the Parkeston Units may be understated because there is no spot capacity on the Goldfields Gas Pipeline, and that the facility would be required to pay part haul rates on the DBNGP also.

Marsden Jacob has addressed the issues raised by stakeholders in Chapter 7 of this Final Report.

Statistical Monte Carlo Modelling

With the distributions determined, Monte Carlo simulation were performed. This involved sampling at random from input probability distributions of the Variable O&M, Fuel Cost and Heat Rate.

Each set of samples, called an iteration, provided an outcome of the variable cost, and was recorded.

Marsden Jacob undertook 10,000 iterations of the model to generate the probability distribution of possible Maximum STEM Price outcomes. The Risk Margin was determined as the difference between the mean and the 80th percentile.

Modelling Results: 2020-21

Table ES1 presents the calculated Maximum STEM Price and Alternative Maximum STEM Price for the Pinjar and Parkeston Units.

Table ES1: Calculated Maximum STEM Price and Alternative Maximum STEM Price 2020-21

	Pinjar Units	Parkeston Units
Maximum STEM Price	267.14	148.34
Alternative Maximum STEM Price	383.28	238.24

Source: Marsden Jacob analysis 2020

The upper Energy Price Limits for 2020-21 have been calculated as follows:

- **Maximum STEM Price** of $267.14/MWh; and
- **Alternative Maximum STEM Price** of $383.28/MWh.

As observed from Table ES1, the Pinjar Units had both the highest Maximum STEM Price and Alternative Maximum STEM Price. This meant that the Pinjar Units were used to set the upper Energy Price Limits.

Table ES2 and Table ES3 presents the component values determined from the modelling that make-up the Maximum STEM Price and Alternative Maximum STEM Price for the Pinjar Units.

Table ES2: Calculation of Maximum STEM Price – Pinjar Units

Component	Units	2020-21	2019-20	Change

[7] Available at https://aemo.com.au/consultations/current-and-closed-consultations/2020-energy-price-limits

Mean Variable O&M Cost	$/MWh	110.48	104.98	5.50
Mean Heat Rate	GJ/MWh	19.19	20.62	-1.43
Mean Fuel Cost (heat rate adjusted)	$/MWh	134.98	113.02	21.96
Loss Factor		1.0274	1.0369	-0.01
Before Risk Margin	$/MWh	238.91	210.24	28.67
Risk Margin Added	$/MWh	28.23	24.33	3.90
Risk Margin Value	%	11.82	11.57	0.25
Assessed Maximum STEM Price	$/MWh	267.14	234.57	32.57

Source: Marsden Jacob analysis 2020

Table ES3: Calculation of the Alternative Maximum STEM Price – Pinjar Units

Component	Units	2020-21	2019-20	Change
Mean Variable O&M Cost	$/MWh	110.48	104.98	5.50
Mean Heat Rate	GJ/MWh	19.07	20.62	-1.55
Mean Fuel Cost (heat rate adjusted)	$/MWh	235.42	437.11	-201.69
Loss Factor		1.0274	1.0369	-0.01
Before Risk Margin	$/MWh	336.67	522.79	-186.12
Risk Margin Added	$/MWh	46.61	44.63	1.98
Risk Margin Value	%	13.84	8.54	5.30
Assessed Alternative Maximum STEM Price	$/MWh	383.28	567.42	-184.14

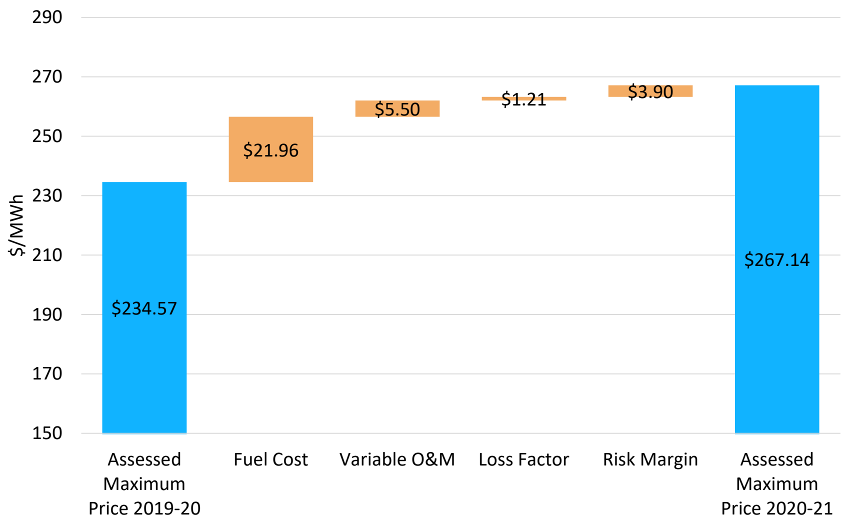
Source: Marsden Jacob analysis 2020

Change in upper Energy Price Limits from 2019-20 Review

Figure ES1 and Figure ES2 presents for the Pinjar units:

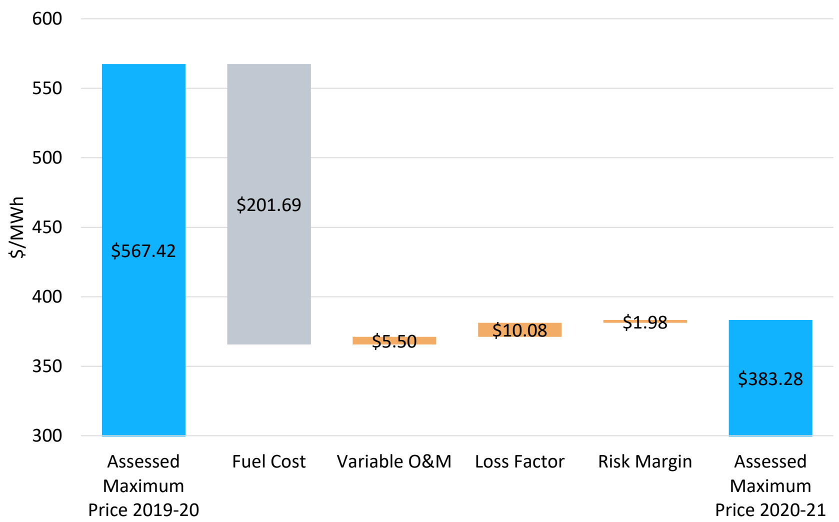
- The calculated Maximum STEM Price and Alternative Maximum STEM Price for 2019-20;
- The increase in the cost components from 2019-20 to 2020-21;
- The calculated Maximum STEM Price and Alternative Maximum STEM Price for 2021-21.

Figure ES1: Change in the Maximum STEM Price from 2019-20



	2019-20	Fuel Cost	VOM Cost	Loss Factor	Risk Margin	2020-21
Maximum STEM Price	234.57	21.96	5.50	1.21	3.90	267.14

Figure ES2: Change in the Alternative Maximum STEM Price from 2019-20



	2019-20	Fuel Cost	VOM Cost	Loss Factor	Risk Margin	2020-21
Alternative Maximum STEM Price	567.42	-201.69	5.50	10.08	1.98	383.28

Figure ES1 and Figure ES2 shows that except for fuel costs of the Alternative STEM Price all components saw an increase.

The major reasons for changes in the upper Energy Price Limits since last year are explained in detail in Chapter 10 and are summarised below.

- Changes in Fuel Cost:
  - The impact of COVID-19 has lowered the spot gas commodity price, the low gas spot prices assessed in the first Draft Report that reflected gas oversupply dampened the impact of COVID-19 and were considered to remain valid.
  - The 2019-20 review used gas commodity projections using gasTrading spot prices for the ARIMA modelling. The 2020-21 has considered DMIRS data for gas commodity projections which has resulted in a higher mean gas Fuel Cost. Reasons for this change are detailed in sections 7.2 and 7.3.
  - The distillate Fuel Costs are lower than existed in 2019 due to COVID-19. This results in a 35% reduction for the Alternative Maximum STEM Price.
- Increased Variable O&M: Confidential data on the expected Variable O&M costs per year showed a slightly higher mean cost per start (increases Variable O&M) and more variability in cost per start (increases Risk Margin).
- Increased Risk Margin: The Risk Margin reflects higher volatility in the distribution obtained for Variable O&M costs.
- The dispatch of Pinjar Units for 2019 showed an increase capacity factor to 2% from less than 1% in the previous year. The impact of this change is lower mean Heat Rates (reduces Fuel Costs), higher dispatch per start (reduces Variable O&M) and a wider range of operating capacities (increases Risk Margin).
- Increased Loss Factor: The slight decrease in Loss Factor in the 2020-21 review compared to the 2019-20 review resulted in an increase to costs for both the Maximum STEM Price and Alternative Maximum STEM Price as these are dependent on the inverse of the Loss factor as described in Equation 1. As the Loss Factor is a scaler quantity its impact on the Maximum STEM Price and Alternative Maximum STEM Price is influenced by changes in the other components, Fuel Cost and Variable O&M Cost. This effect can be seen in the Loss factor components for the Alternative Maximum STEM Price which increased by $10.08/MWh due to the large reduction in fuel costs.

1. Background and Scope of Work

1.1 Purpose of this report

AEMO is responsible for operating the Wholesale Electricity Market (WEM) in Western Australia and is required to undertake certain reviews in accordance with the WEM Rules.

Section 6.20 of the WEM Rules provides information with respect to the Energy Price Limits, which 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 are[8]:

- 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 $1000/MWh under the WEM Rules).

Under clause 6.20.6 of the WEM Rules, AEMO must annually review the appropriateness of the value of the Maximum STEM Price and the Alternative Maximum STEM Price. Those revised values must then be submitted to the Economic Regulation Authority (ERA) for approval[9].

Marsden Jacob Associates (Marsden Jacob) has been appointed by AEMO to assist in the review of the upper Energy Price Limits for the 2020-21 year.

1.2 Scope of Work

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

a) assess the methodology used in the previous 2019-20 Energy Price Limits Review and clearly articulate and justify any changes that Marsden Jacob recommends to the methodology (ensuring that the methodology is consistent with the requirements in clause 6.20.7 of the WEM Rules), including consideration of:

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

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

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

            1. 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

            2. 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;

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

—

[8] Refer to Price Caps in Chapter 11 of the WEM Rules

[9] Clause 6.20.10 of the WEM Rules

iv. 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

v. 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:

   a. gas price distributions; and

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

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

1.3 Note to the Scope of Work

Marsden Jacob undertook this review for the 2019-20 year. The learning and model developments that were associated with that review were brought to this assignment.

1.4 Impact of COVID-19

After the development of the first Draft Report, the impact of COVID-19 on gas and distillate prices required Marsden Jacob to review the outlooks of these commodities. These commodities can vary greatly over short time periods with changing demands. The projections contained in the second Draft Report and Final Report incorporated the impact of COVID-19:

- The distillate price outlook was substantially reduced (reflecting prices as of 7 May 2020) from that contained in the first Draft Report.
- The spot gas price was unchanged from the first Draft Report which incorporated a low spot gas price outlook (reflecting oversupply conditions).

Annual gas prices published by the Department of Mines, Industry Regulation and Safety (DMIRS) are based on a weighted average of flows on DBGP. By using a weighted average price which includes long term contracts before the any impact of COVID-19 on contracts will be mitigated and delayed.

Further details are presented in Chapter 7.

1.5 Stakeholder Submissions

AEMO received three formal submissions[10] during the public consultation period.

In summary, all three submissions suggested that the gas spot prices used in the Draft Report did not adequately represent the fuel cost of generators, and suggested that AEMO should use the annual gas price published by the Department of Mines, Industry Regulation and Safety (DMIRS) in place of gas spot prices.

One submission raised the mater that gas transport costs for the Parkeston Units may be understated because there is no spot capacity on the Goldfields Gas Pipeline, and that the facility would be required to pay part haul rates on the DBNGP also.

Marsden Jacob has addressed the issues raised by stakeholders in Chapter 7.

---

[10] Available at https://aemo.com.au/consultations/current-and-closed-consultations/2020-energy-price-limits

1.6 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: Selection of the Candidate Peaking Generator;
- Chapter 4: Variable O&M Costs;
- Chapter 5: Heat Rates;
- Chapter 6: Loss Factors;
- Chapter 7: Gas and Distillate Costs;
- Chapter 8: Statistical Modelling and Risk Margin;
- Chapter 9: Modelling Results;
- Chapter 10: Changes in Energy Price Limits Compared to Previous Years.

2. Methodology Review

This chapter discusses the methodology as it was applied in this review. Previous reports and stakeholder feedback on the upper Energy Price Limits have been incorporated into the methodology for period 2020-21.

The chapter presents:

- An overview of the methodology; and
- A description of the factors to be determined.

2.1 Overview of Approach to the Calculation of Maximum Prices

Basis of Calculation

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 peaking generation so that they are encouraged to provide their capacity during high price periods.

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

In accordance with clause 6.20.7 of the WEM Rules, the Maximum STEM Price and Alternative Maximum STEM Price must be set based on the estimate of the short run marginal cost of the highest cost generating facility in the South West Interconnected System (SWIS) fuelled by natural gas and distillate respectively.

The Maximum STEM Price and Alternative Maximum STEM Price must be calculated using the following equation defined in clause 6.20.7(b) of the WEM Rules:

Equation 1

$$\frac{1 + Risk\ Margin}{Loss\ Factor} \times \left(Variable\ O\&M_{\$/MWh} + \left(Heat\ Rate_{GJ/MWh} \times Fuel\ Cost_{\$/MWh}\right)\right)$$

where:

- $Risk\ Margin$ is a measure of uncertainty in the assessment of the mean short-run average cost of a 40 MW open cycle gas turbine generating station, expressed as a fraction;
- $Variable\ O\&M$ is the mean variable operating and maintenance cost of a 40 MW open cycle gas turbine generating station, expressed in $/MWh, and includes, but is not limited to, start-up costs;
- $Heat\ Rate$ is the mean heat rate at minimum capacity of a 40 MW open cycle gas turbine generating station, expressed in GJ/MWh;
- $Fuel\ Cost$ is the mean unit fixed and variable fuel cost of a 40 MW open cycle gas turbine generating station, expressed in $/GJ; and
- $Loss\ Factor$ is the marginal loss factor of 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 upper 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, and Fuel Cost.

Using Monte Carlo analysis, Marsden Jacob can 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.

Based on the above, the methodology for the Maximum STEM Price and the Alternative Maximum STEM Price are presented below.

Maximum STEM Price

The Maximum STEM Price is based on the 80th percentile cost of the formula given by Equation 1.

In applying this formula, the Dispatch Cost is calculated using a gas price distribution (refer to Chapter 5) over all Monte Carlo samples.

Alternative Maximum STEM Price

The Alternative Maximum STEM Price is based on the 80th percentile cost of the formula given by Equation 1.

In applying this formula, the 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 dependent component that is proportional to the net ex terminal distillate price.

Each month the Alternative Maximum STEM Price is calculated by substituting the current net ex terminal distillate price into the following regression equation:

Equation 2

$$Alternative\ Maximum\ STEM\ Price_{\$/MWh} = Constant_{\$/MWh} + \alpha_{GJ/MWh} \times Distilate\ Price_{\$/GJ}$$

Risk margin

The Risk Margin is intended to allow for the uncertainty in assessing the short run marginal cost of a candidate generation plant[11], 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:

Equation 3

$$Risk\ Margin = \frac{Derived\ Energy\ Price\ Limit_{\$/MWh}}{Mean\ Dispatch\ Cost_{\$/MWh}} - 1$$

2.2 Factors to be determined

Noting the variables to be determined from equations 1 and 2 above, and the application of the Risk Margin specified by equation 3, the methodology required the following to be determined:

- Selection of the Candidate Peaking Generators;
- Variable O&M for the Candidate Peaking Generators;

---

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

- Gas and Distillate price distributions;
- Heat Rate curve for Candidate Peaking Generators
- Loss Factors for Candidate Peaking Generators
- Statistical Modelling Methodology to Determining the Risk Margin.

These factors are discussed in detail in Chapter 3 to Chapter 8 of this report.

2.3 Other issues

2.3.1 Truncated Normal Distribution and Gamma Distributions

Some of the input distributions (e.g. gas price) used in the Monte Carlo simulations were truncated. The Monte Carlo modelling uses Gaussian/Normal distributions to incorporate uncertainty. These functions are continuous and depending on the distribution there is a chance that they can produce values that are inconsistent with physical constraints. For example, use of a Normal curve may result in negative values (depending on mean and standard deviation of the distribution) which may not be possible for input variables (e.g. gas price, MWh/start etc).

In these cases, the truncation of the input variable distribution may be required to yield sensitive results. Some truncation of the spot gas commodity price distributions was required in this study to avoid negative (and extremely) low price outcomes. The truncation worked by setting any value below a floor to the floor and any value above a ceiling to the ceiling value.

As a normal distribution is symmetric around the mean of the distribution, the normal distribution has the property that the mode and mean value are identical. However, with the distribution truncated, the symmetry is broken due to the upper and lower limits, and the mean value will no longer be the same as the mode. Gamma distribution can be asymmetric but with different modes and means.

2.3.2 Pseudorandom number generator

For each simulation, the Monte Carlo model uses the Microsoft Excel RAND() function to produce one 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. With a very high number of simulations this could lead to repeating pattern. However, with the 10,000 simulations used in the review this number is small enough that this will not be an issue.

3. Selection of the Candidate Peaking Generator

This chapter addresses the selection of the marginal gas generator. This is relevant to the input variables of Heat Rate, Variable O&M and Loss Factor which is generator unit dependent.

3.1 Review of Gas Generators

In previous studies, the upper Energy Price Limits have been based on the Pinjar 40 MW gas turbines (6 units). Other candidate generators included the Parkeston aero-derivative gas turbines (3 units) located in the Goldfields Region, and the Mungarra gas turbines (2 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 2275 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[12]. These units are not being considered as candidate peaking generators.

> Box - Network Control Services
>
> 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" (Clause 5.1.1).* 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).

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.

This is the same conclusion as in the 2019-20 review by Marsden Jacob, and we maintain the view that this conclusion remains appropriate for the current 2020-21 review.

---

[12] Energy Policy WA, September 2018, Information Paper: Arrangements for continued power supply reliability in the North Country and Eastern Goldfields regions, https://www.wa.gov.au/sites/default/files/2019-08/Arrangements-for-continued-power-supply-reliability-in-the-North-Country-and-Eastern-Goldfields-regions.pdf

3.2 Candidate gas Generators

The WEM Rules stipulate that the candidate units must be 40 MW OCGT units[13]. 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 as outlined in Section 3.1) which implies that they will have higher Heat Rates when compared to other gas turbines connected to the SWIS. These units are listed in Table 1 below. They are then reviewed in turn below.

The selection of the candidate generators is based on factors that are different between the generators such as Heat Rate and maintenance costs. As all gas generators share the same gas and distillate prices, COVID-19 was not a factor in the selection of the candidate generators.

Table 1: Candidate OCGT units for setting upper 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
PINJAR_GT5	39.3	Industrial GT
PINJAR_GT7	39.3	Industrial GT
PRK_AG Unit 2	37	Aero-derivative
PRK_AG Unit 3	37	Aero-derivative

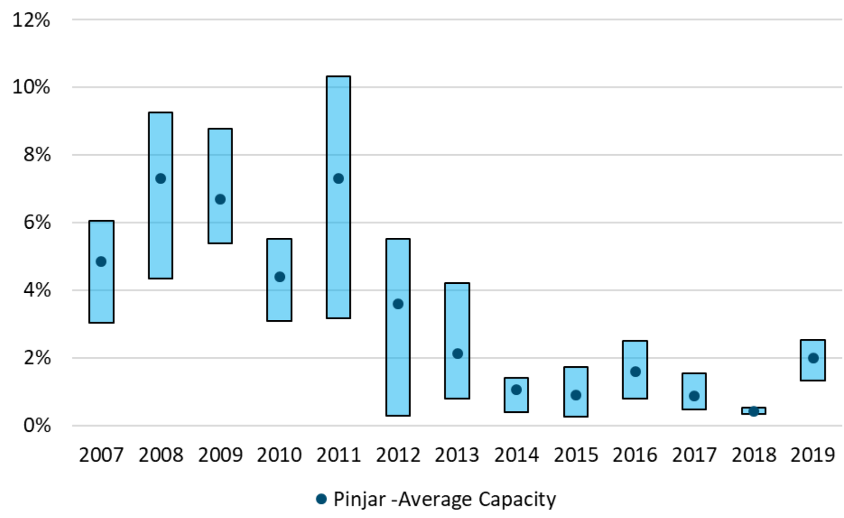
Source: AEMO Facilities Data, Marsden Jacob analysis 2020

3.3 Pinjar Gas Generators

The Pinjar Units are owned and operated by Synergy and are used to provide peaking power in the SWIS. These units were fully operational by October 1990 and typically have had capacity factors of around 3%, 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 below 2% between 2014 and 2018 but has increased in 2019 to be above 2%. These low capacity factors will increase 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.

[13] Clause 6.20.7(b)(i)-(v) of the WEM Rules

Figure 1: Capacity factor range of Pinjar Units



Notes: 2007 financial year ending data only includes data commencing September 2006.

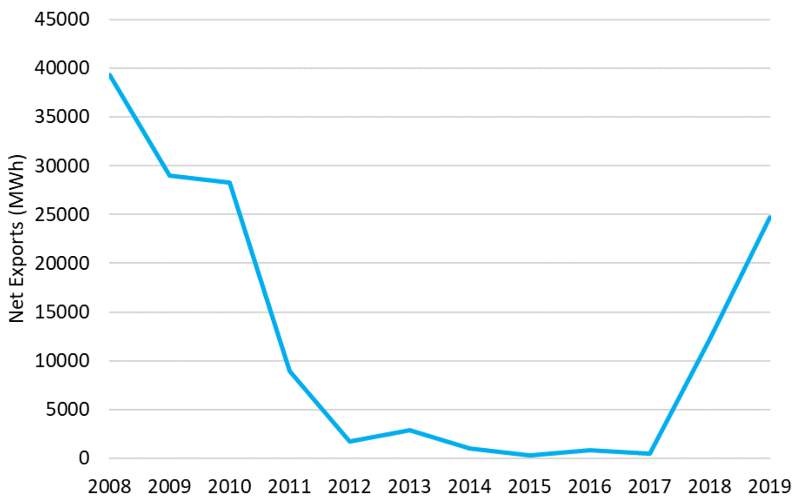
Source: AEMO Facility Scada Data, AEMO Facility Standing Data, Marsden Jacob analysis 2020

3.4 Parkeston Gas Generators

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 typically has an average energy requirement of around 40 MW baseload. This requirement is usually met by a single generation unit (PRK_AG Unit 1 in 2019) and imports from the SWIS.

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 presented in Table 2.

Table 2: Operating data for candidate OCGT units in the SWIS 2019

Unit	PRK_AG	PINJAR_GT1	PINJAR_GT2	PINJAR_GT3	PINJAR_GT4	PINJAR_GT5	PINJAR_GT7
No. of Starts	296	44	33	36	38	31	44
Hours Operating	1392.5	524	435.5	369.5	480	409	413
Average Output (MW)	17.7	16.0	13.8	14.9	16.3	17.0	16.6
Annual Generation (MWh)	24682	8384	6009	5500	7804	6948	6843
Capacity Factor (%)	2.41%	2.5%	1.8%	1.6%	2.3%	2.0%	2.0%

Source: Marsden Jacob analysis 2020

3.5 Assessment of Selected Gas Generators

The analysis above shows that the Pinjar Units had between 31 and 44 starts in 2019 and operated for 438 hours a year on average. Compared to 2018 the operation of the Pinjar Units is appreciably up with the average length of generation per start increasing from 3 to 5 hours in 2018 to 9 to 12 hours in 2019. This increased generation per start is likely to have the effect of lowering variable costs on a per MWh basis.

Exports from the Parkeston Units have also increased in 2019 (24,682 MWh) compared to 2018 (12,795 MWh).

Table 3 highlights that only the Parkeston Units were able to capture on average, a higher Balancing Price than the Pinjar Units. The average Balancing Price for the Pinjar Units when operating decreased from 2018 which is expected due to the increased hours of operation.

Table 4 illustrates the volatility of the occurrence of maximum prices in the Balancing Market.

Table 3: Captured Balancing and STEM Prices ($/MWh, nominal) 2019

Unit	PRK_AG	PINJAR_ GT1	PINJAR_ GT2	PINJAR_ GT3	PINJAR_ GT4	PINJAR_ GT5	PINJAR_ GT7
Average STEM Price When Running ($/MWh)	59.8	44.2	42.5	43.6	41.9	43.0	46.1
Average Balancing Price When Running ($/MWh)	72.5	47.5	48.3	40.4	44.7	50.4	57.4
Maximum Price Captured in STEM ($/MWh)	165.6	138.7	138.7	126.7	140.5	138.7	138.7
Maximum Price Captured in Balancing Market ($/MWh)	257.6	227.8	232.8	218.7	192.7	209.6	232.8

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

Source: Marsden Jacob analysis 2020

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	2018-19
Occurrences	23	5	22	0	26	0	3

Source: AEMO Balancing Summary Data, Marsden Jacob analysis 2020

Table 5 shows the average generation of the candidate OCGTs by ranges of Balancing Prices.

Table 5 Candidate OCGT average MW by price bands FY 2018-19

Balancing Price Range	Periods	PRK_AG	PINJAR_GT 1	PINJAR_GT 2	PINJAR_GT 3	PINJAR_GT 4	PINJAR_GT 5	PINJAR_GT 7
>300	3	24.49	0.00	0.00	0.00	0.00	0.00	0.00
250 - 300	8	8.21	0.00	0.00	0.00	0.00	0.00	0.00
200 - 250	6	8.32	0.00	2.24	0.00	2.23	2.53	7.84
150 - 200	123	6.82	0.97	0.81	0.17	0.69	0.00	1.04
100 - 150	670	7.49	0.97	1.50	0.45	0.73	0.25	0.78
50 - 100	3518	4.30	0.39	0.51	0.34	0.26	0.28	0.22
0 - 50	12624	0.32	0.13	0.26	0.12	0.11	0.07	0.08
<0	568	0.16	0.02	0.06	0.00	0.19	0.00	0.00

3.6 The Selected Gas Generators

In relation to the selection of the generator or generators we note the following:

- Of the candidate gas generators, the Parkeston Units were the only unit generating during the time of Maximum STEM Price. The Pinjar Units did not capture any price over $250/MWh in 2018-19.
- It is likely that the STEM and Balancing 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 and wind facilities), Balancing Prices could go below zero for longer periods. Prices may be higher when scheduled generation is required to ramp up rapidly to meet demand when solar generation levels fall in the evening period (in both winter and summer). This is a change in generating patterns for fast response peaking plant that have traditionally been run to respond to extreme demands and planned outages. The additional generator starts and increases in operating hours will increase maintenance costs over the plant lifetime. In 2019 this behaviour was not observed in the selected generators, although with a large amount of wind capacity entering the system over the next 2 years will be significant in future reviews.
- In the past reviews, the combined commodity and transport costs for gas have been below that of distillate. COVID-19 has resulted in about a 40% decline in the distillate cost excluding excise (Section 7.5). It is Marsden Jacob's view that distillate costs falling below gas is extremely unlikely due to the current large gap in costs between distillate and gas, an outlook which has distillate prices not decreasing further, and the current oversupply of gas (Section 7.2).
- However, if distillate prices were to reach similar levels to gas, distillate may become the preferred fuel for the following reasons:
  - Lower transport costs per GJ than gas.
  - Distillate is less volatile than gas making onsite storage possible with less specialised equipment.

The above analysis illustrates that both the Parkeston Units and the Pinjar Units are suitable as the candidate generators to use in this study. This was the conclusion in the 2019-20 review.

As per the 2019-20 review, the generator units selected are:

- Parkeston Units: PRK_AG Unit 2 and PRK_AG Unit 3 aero-derivative units at the Parkeston Power Station registered in the WEM as a single facility PRK_AG; and
- Pinjar Units: 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.

4. Variable O&M Costs

This chapter presents the derivation of the Variable O&M costs for the Parkeston Units and Pinjar Units (i.e. for the selected generator units). This is done using their probability distributions and mean values.

4.1 Review of Variable O&M Costs

Variable O&M 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 for 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 sufficiently and foregoing 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 is based on engineering data available to Marsden Jacob, and includes:

- The Electric Power Research Institute (EPRI) study into power generation costs in Australia[14];
- Data that has been collected, analysed and benchmarked while undertaking market studies in the NEM, Northern Territory and WEM for numerous market participants and investors;
- Reports used to set upper Energy Price Limits in previous years; and
- Data from Synergy (owner of Pinjar Units) and Goldfields Power Pty Ltd (owner of Parkeston Units).

Marsden Jacob estimates of Variable O&M for both the Pinjar and Parkeston Units, and the triggers for this expenditure, are provided in Section 4.3.

[14] Electric Power Research Institute, Australian Power Generation Technology Report, 2015

4.2 Maintenance Cycle

4.2.1 Maintenance cycle length

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 2031, at which time they will be 40 years old and at the end of their useful lives. This end of service date for Pinjar Units is unchanged from the 2019-20 review. This implies that the maintenance program will need to ensure that the Pinjar Units remain operational until 2031. This has been factored into the determination of the maintenance cycle for the Pinjar Units.

In addition, the Parkeston Units are also likely to have 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.

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

4.2.2 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.

In the 2018-19 review, 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, this being below 60% of full 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.

For this study, Marsden Jacob has estimated number of starts with low loads only contributes 0.5 of a normal start, and this is consistent with the view from the 2019-20 review.

4.2.3 Future maintenance Costs

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

Method 1: This involves the use of a risk-adjusted discount rate based on the perceived riskiness of the future expenditures.

Method 2: This involves the use of Monte Carlo simulation. 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. The present value of drawn cash flows is then 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.

In line with the approach for the previous 2019-20 review, for this study used Method 2. Future maintenance expenditures have been discounted using a real pre-tax WACC of 5.8%, which is based on estimates provided by the Independent Pricing and Regulatory Tribunal (in New South Wales) in regulatory price determinations (February 2020).[15]

—

[15] Sourced from the Independent Pricing and Regulatory Tribunal, "Spreadsheet-WACC-model-February-2020.xls".

4.3 O&M Cost Determination

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.

4.3.1 Approach

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

Step 1: determine a point estimate of maintenance costs per start based on (confidential) data provided by both Synergy and Goldfields Power Pty Ltd[16]. The relevant costs range from $2,500 to $5,000 per start and are summarised below:

- Pinjar Units: $[redacted] per start
- Parkeston Units: $[redacted] per start

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 per MWh, the resulting mean Variable O&M cost per start may differ from the above point estimates.

Step 2: create a distribution of start costs ($/Start) given that the number of starts can vary which will change the overhaul maintenance cycle and hence the VOM costs per start. The probability density function for the number of starts was developed by fitting a gamma distribution to the historical distribution of starts per year.

Step 3: determine the relationship between the number of starts, which is the driver for maintenance overhaul costs, and maintenance costs. These maintenance overhaul costs are annualised across the remaining operating years of the plant.

- For the Parkeston Units, the annualised costs were based on overhaul costs in previous reviews which have been updated for exchange rate movements (impacts cost of imported parts) and local inflation (local labour and recycled parts)[17].
- For the Pinjar Units, Synergy provided maintenance costs as an annual cost per unit this year, rather than as a cost per start as were provided in the 2019-20 review. These annualised costs from Synergy were compared with Marsden Jacobs own calculations of the overhaul and repair costs for the remaining life of the plant. Both methods produced a similar mean cost per start with the Synergy annualised cost having a slightly wider range of costs per start values. As the numbers provided by Synergy align with our analysis, these were used for the annualised costs in Step 3 for the Pinjar Units.

Step 4: determine the distribution of dispatch event MWh (generation) equal to or less than 6 hours. The rationale behind the 6 hour limit is explained in section 4.3.2. In previous reviews of Energy Price Limits, it was argued 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.

Variable O&M also includes other inputs such as water, labour and lubricants these costs have been estimated by increased by Marsden Jacobs to be $1.50/MWh for an OCGT plant.

The methodology for calculating Variable O&M this year is similar to the 2019-20 review (used Synergy prices for Step 3 directly instead of calculating) and annualised costs are also similar on a $/MW/Year basis. The dispatch profiles of plant have changed from the previous year and this is likely to change the Variable O&M cost on $/MWh. The wider range of cost per start values will have an impact on the risk margin as the 80th percentile will incorporate more simulations with a higher O&M cost.

—

[16] The WEM Rules place no obligation on Rule Participants to provide AEMO with data in order to undertake the calculations in clause 6.20.7. Any information provided for this purpose is voluntary and may not be in the format requested by AEMO and its consultant.
[17] Annualised maintenance costs were not provided as part of the data submission from Goldfields Power Pty Ltd.

As described above, the steps in deriving the O&M costs between Pinjar and Parkeston are identical with the exception of the annualised costs. This supports our view that the O&M costs between the candidate units is undertaken on the same basis for each.

4.3.2 Number of Events where Balancing Price continually exceeded $100/MWh in 2019

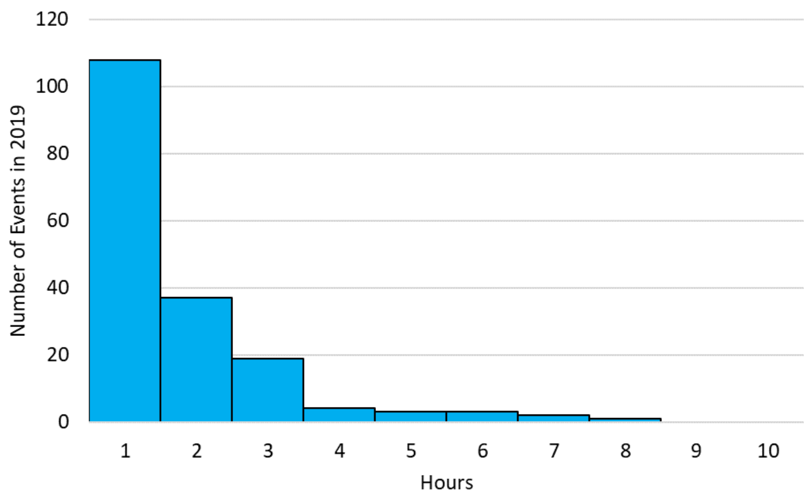
As noted in section 4.3.2, the length of high Balancing Price events is relevant to the amortisation of start-up costs to a generator unit.

For the calculation of O&M costs to go from $/start to $/MWh, a distribution of MWh/start is required. The length of time that a peaking unit is operating plays a large role in the total MWh/start (i.e. dispatch capacity MW multiplied by time).

Figure 3 presents the number of occurrences of Balancing Prices exceeded $100/MWh in 2019 and for how many hours this lasted. Many of the events that last for less than 3 hours occur on the same day with a small lower price period in between. A 6 hour period of operation is capable of covering a multiple of these short events without restarting the unit.

Analysis of continuous prices exceeding $100/MWh showed that periods longer than 6 hours were very rare. This was used to support a cut off point for the hours per start as the generators were not operating in a peaking capacity. This analysis of high balancing prices formed the basis for setting the number of hours in Step 4 of the O&M cost approach.

Figure 3 Number of events where Balancing Price continually exceeded $100/MWh in 2019



Source: *Marsden Jacob analysis 2020*

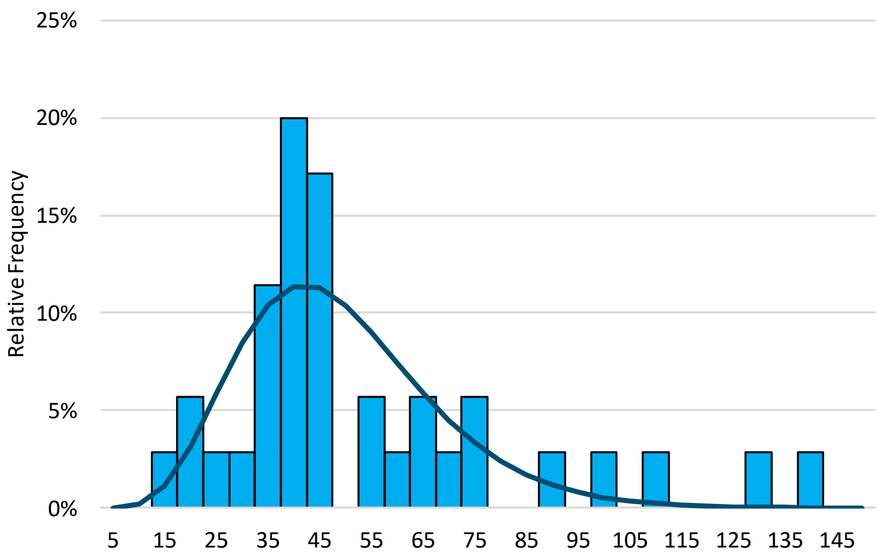
4.3.3 Pinjar Units O&M Costs

The estimates of dispatch event (per MWh) for the Pinjar Units is based on the dispatch profile of all six units over the period 1 January 2014 to 31 December 2019.

Dispatch event MWhs have a gamma distribution fitted and used in the development of Variable O&M costs per MWh. The use of a gamma distribution is a change from the 2019-20 review which previously used a normal distribution. Analysis of the results showed that the higher operation of Pinjar Units in 2019 fit better with the a less symmetrical gamma function that allows for a higher occurrence of high generation levels.

Table 6 presents a summary of Pinjar Units O&M Starts. Based on this, Figure 4 below shows the distribution of the number of starts between 1 January 2014 and 31 December 2019 and a fitted gamma profile for all Pinjar Units.

Figure 4: Distribution of the number of starts – Pinjar Units



Source: Marsden Jacob analysis 2020

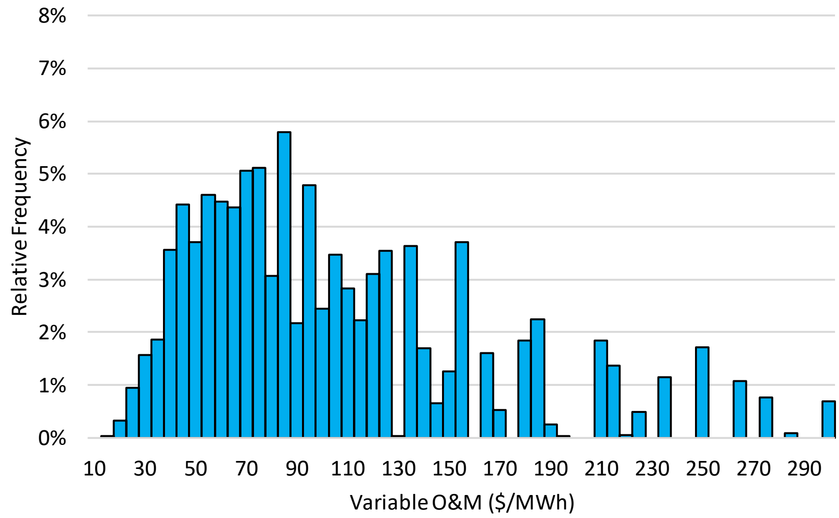
Table 6: Summary of O&M starts – Pinjar Units

Measure	Unit	Dispatch Events
Mean	Starts/year	54
Minimum	Starts/year	12
Maximum	Starts/year	153
Operating Hours	Hours/Start	3.6

The Variable O&M per Start distribution has changed from the 2019-20 review. As part of the 2020-21 review, Synergy has provided an annual estimate of maintenance cost per unit for the Pinjar Units. This annual cost is fixed independent of the number of starts so higher starts results in lower cost as there are more starts to distribute the fixed value across. In the 2019-20 review a high number of starts would bring forward scheduled maintenance increasing costs per start.

Figure 5 below displays the distribution of Variable O&M costs for the Pinjar Units used in the Monte Carlo modelling.

Figure 5: Distribution of Variable O&M Costs ($/MWh) – Pinjar Units



Source MJA analysis 2020

4.3.4 Parkeston Units O&M Costs

Table 8 presents a summary of Parkeston Units O&M Starts.

The benchmark overhaul costs and unit start costs are shown in Table 7 for Parkeston Units. The overhaul costs are the same as used in the 2019-20 review adjusted for local and international inflation costs and changes to the WACC. The NPV of starts is based on calendar year 2019 operation of Parkeston Units.

Table 7: Overhaul costs and levelised cost per start for Parkeston Units – 15 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	$1,324,213	1	$1,324,213	
B	1200	$3,500,579	1	$3,500,579	
A	1800	$1,324,213	1	$1,324,213	
C	2400	$5,055,839	1	$5,055,839	
Total Cost		$11,204,843		$11,204,843	$4,726,853
Cost Per Start (a)		$4,668.68	Levelised Cost Per Start (b)		$3,244.24
Starts / Year		137	NPV of Starts		1457

Notes: (a) Total Cost divided by 2400 starts (consistent with previous reviews)
(b) NPV of Overhaul Costs divided by NPV of Starts

Source: Marsden Jacob analysis 2020, Jacobs Group (Australia) Pty Ltd 2018

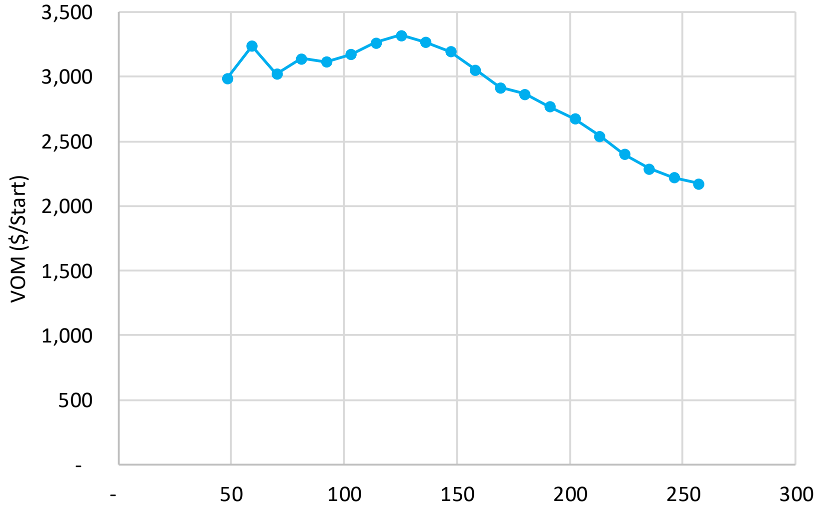
Figure 6 below displays the average Variable O&M costs per start for the Parkeston Units.

Figure 7 presents the resulting distribution of Variable O&M costs for the Parkeston Units.

Table 8: Summary of O&M Starts – Parkeston Units

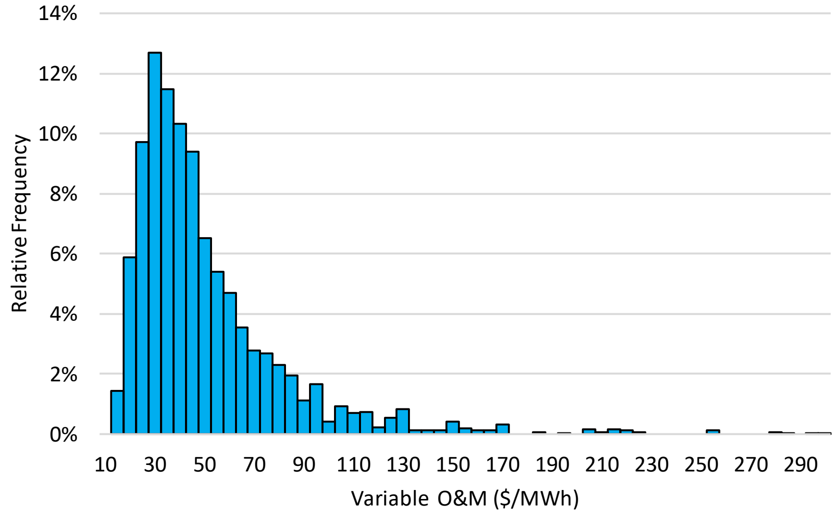
Measure	Unit	All Dispatch Events
Mean	Starts/year	216
Minimum	Starts/year	15
Maximum	Starts/year	275
Operating Hours	Hours/Start	3.76

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



Source: Marsden Jacob analysis 2020

Figure 7: Distribution of Variable O&M costs ($/MWh) – Parkeston Units



Source: Marsden Jacob analysis 2020

5. Heat Rates

This chapter presents the Heat Rates used for the Pinjar and Parkeston Units.

5.1.1 OCGT Heat Rates

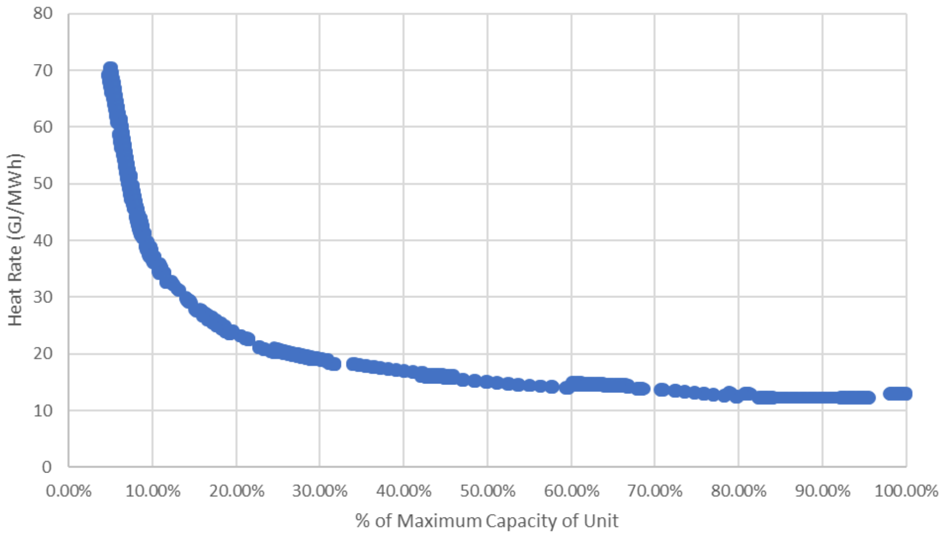
Heat Rate curves for these units have been sourced from Synergy (Pinjar Units) and Goldfields Power Pty Ltd (Parkeston Units) as owners of the respective units.

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.

The Heat Rate curves show how unit heat rates vary with generation output (no temperature adjustments since there is less than a 1% impact on the heat rate between high and low temperatures).

Figure 8 shows the typical Heat Rate of a 40 MW OCGT units (similar to the Pinjar Units) based upon the percentage loading (MW) of the generator (compared to nameplate capacity of the plant).

Figure 8: Typical Heat Rate of 40 MW OCGT units – 15°C/ 30% humidity



Source: Marsden Jacob analysis 2019

5.1.2 Start-Up Energy Consumption

Start-up heat energy was assumed to average between 10 to 15 GJ/Start for each turbine. Start-up energy consumption is aggregated across all generation for that start.

For a Pinjar Unit operating at 75% capacity utilisation, the fuel used to start the turbine was less than the operation for a single MWh. Aggregated over a complete simulated cycle of operation (start up, run time and decommit), this cost accounts for less than $2/MWh of the Maximum STEM Price.

6. Loss Factors

Loss Factors are used to determine the quantity of sent out electricity that is delivered from a generator to a reference node. The SWIS has only one reference node, which is defined as the Muja 330 bus-bar[18].

A Loss Factor less than unity implies that less electricity is delivered to the node than what is injected into the transmission network and vice versa if the Loss Factor is greater than unity. The Loss Factor at the reference node is 1.

Table 9 below lists the Loss Factors for the 2020-21 financial year for the Pinjar and Parkeston Units.

Parkeston loss factor is significantly higher than that for Pinjar and has the fourth highest Transmission Loss Factor (TLF) in the SWIS.

Table 9: Loss Factors for Pinjar and Parkeston Units

Loss Factor Area Code	Description	Loss Factor	Start Date
WPJR	Pinjar Units	1.0274	1-Jul-20
WPKS	Parkeston Units	1.1234	1-Jul-20

Source: Western Power, 2020-21 Transmission Loss Factors provided 5 June 2020

[18] Chapter 11 of the WEM Rules

7. Gas and Distillate Costs

This chapter presents the costs of gas and distillate used on the modelling.

Gas costs are important as dispatch costs are highly dependent upon fuel price assumptions. As most OCGT plant operate at a thermal efficacy less than 32%, a $1/GJ change in fuel price results in a $11.25/MWh change in dispatch costs in a trading interval.

The Maximum STEM Price is calculated based on the dispatch costs of a 40 MW OCGT using natural gas, while the Alternative Maximum STEM Price is calculated based on the dispatch costs of a 40 MW OCGT using distillate[19]. In this section, the methodology for determining delivered gas and distillate prices is outlined.

Presented in turn below are the following:

- Gas:
  - Commodity Costs
  - Determination of Gas Cost Distribution
  - Gas - Transport Costs;
- Distillate Prices
  - Distillate Prices Distribution.

7.1 COVID-19 Impact on Fuel Prices

Gas prices are influenced by both oil prices and the demand and supply of LNG.

Over the past 6 months oil prices have been influenced by two matters. The increase in oil production by Russia in early 2020 (that resulted in substantial oversupply) and the subsequent impact of COVID-19 which has reduced the global demand for oil by over 45%. The reduction in oil demand occurred over a short period (due to the "overnight" shutdown of many businesses). The resulting oil oversupply (and oil with no immediate use) resulted in oil prices collapsing. In April 2020, an agreement was reached for a reduction in oil production which has seen a recovery in oil prices. The outlook for oil prices will be largely determined by the recovery in oil demand, in terms of both recovery time and demand level. While this is not known, on the basis that economies commence to reopen in July 2020 and business do recover over a period of several years, we would expect a return to pre 2019 oil prices by 2023.

While lessons can be learnt from recent oil price reductions, the oil collapse due to COVID-19 is different than the most recent oil price collapse in 2014 to 2016. The difference in the 2014 to 2016 oil price collapse was that this involved both a shift in demand and a shift in supply. The demand side related to global demand for oil flattening (due to lower economic outcomes in countries that included Japan and China) while the supply side related to the development of shale oil production in the United States of America. Shale oil also had a lower breakeven cost compared to conventional oil production. Prices recovered post 2016 due to action by OPEC to reduce supply. However, oil prices have been lower than they were pre 2014 reflecting the new demand and supply conditions. The difference with the current reduction is that this is demand side related only (unlike in 2014 to 2016).

LNG has been in a state of oversupply as supply has increased over the last six years, with the Asia Pacific region the largest export region. In the longer term the outlook is for supply projects to be delayed or cancelled and a resulting tightening of the market. Over the next 12 months oil and LNG prices are expected to remain low, but with a continuing recovery as the level of oversupply reduces and the economic impacts of COVID-19 reduce.

—

[19] Chapter 11 of the WEM Rules

Figure 9 10 year daily crude oil price USD$/BBL

Source: https://www.macrotrends.net/2516/wti-crude-oil-prices-10-year-daily-chart

7.2 Gas – Commodity 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 gas market participants want to vary their offtake volumes above contracted maximum levels or below ToP levels. While there is no centralised gas spot market in Western Australia, 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. The gasTrading platform 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.

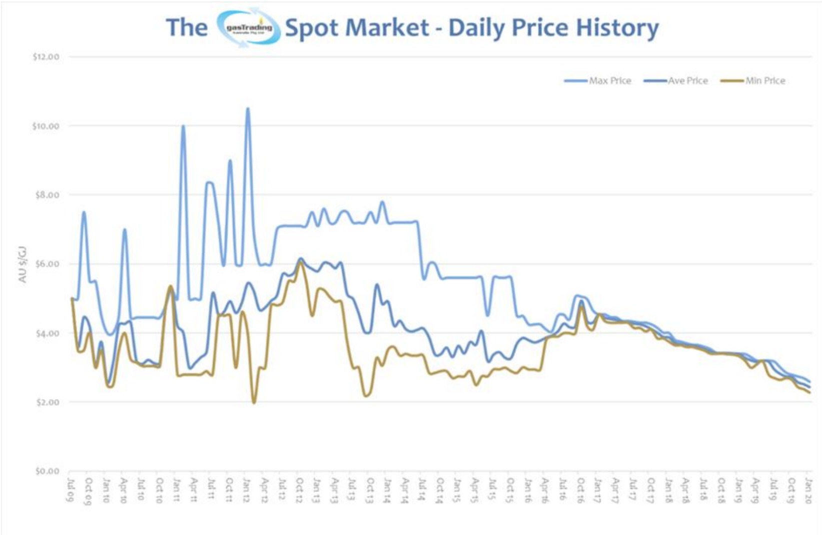
Most gas is contracted, then if required, gas is informally traded between the major gas buyers and sellers in Western Australia rather than by using third party exchange platforms. There is a high concentration of both major buyers and sellers which implies that each party can simply enter into bilateral spot transactions on a daily, weekly or monthly basis.

7.2.1 Third Party Exchanges

Data from gasTrading's website is publicly available. For the past two years, typical volumes traded range from 5 to 25 TJ/day (0.5 to 2.0% of Western Australian domestic gas volumes) and prices paid range from $2.50 to $4.15/GJ. The market does not settle at a single daily price but a range of prices reflecting a series of bilateral transactions.

Daily spot gas prices from the gasTrading's website are shown in Figure 10. This shows that there has been a downward trend for gas traded via the gasTrading platform since 2017 and that the maximum, minimum and average prices are very closely aligned. This is consistent with the oversupply of domestic gas capacity and reserves over this period.

Figure 10: Daily spot gas prices in Western Australia ($/GJ, nominal)



Source: gasTrading website[20]

Past reviews used the historical price data from gasTrading in the development of a spot gas price that could be used in the determination of the Maximum STEM Price. This data was used as it represented a source of data of the prices that gas generators could obtain gas.

7.2.2 Contracted

During the 2020-21 review of the Energy Price Limits, several stakeholders suggested that spot gas prices do not adequately represent the fuel cost of generators. Marsden Jacob has reviewed the available data and agrees that the price data from the gasTrading platform is no longer representative of the prices that the gas generators have been able to obtain gas. This divergence in the gas prices of the gasTrading platform and what the gas generators can obtain is due to the small volumes traded via this platform and the level of gas firmness required by the gas generators.

Step 5.3.4 of the Market Procedure for Certification of Reserve Capacity (Market Procedure)[21] states "AEMO considers that a fuel supply or fuel transportation (including gas pipeline capacity) that has a Non-Firm component may indicate a restriction on fuel availability that could prevent the Facility operating at its full capacity for Peak Trading Intervals on Business Days". It is a requirement of the Market Procedure that a Facility applying for Capacity Credits must provide evidence of the extent of its firm fuel supply or transportation in order to demonstrate any restrictions on its availability for Peak Trading Intervals on Business Days.

The gas prices published by the Department of Mines Industry Regulation and Safety (DMIRS) present the prices of gas obtained in the contract market and are shown in Figure 11 below. Up until 2018, there was reasonable alignment between these gas prices and the gas prices traded on the gasTrading platform. From 2018 the prices published by gasTrading have decreased relative to those published by DMIRS.

---

[20] http://www.gastrading.com.au/spot-market/historical-prices-and-volume, downloaded March 2020.
[21] https://aemo.com.au/energy-systems/electricity/wholesale-electricity-market-wem/procedures-policies-and-guides/procedures

The reason for the divergence is assessed to be the impact of the gas oversupply on small quantities of gas (represented by gas prices published by gasTrading) as opposed to larger quantities of firm gas supply (represented by gas prices published by DMIRS).

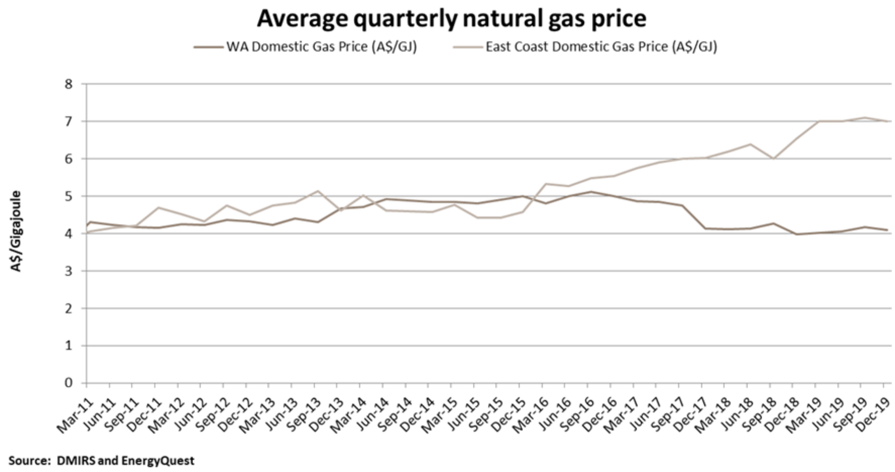
The changed gas market dynamic and the separate influences this had on the different gas purchase products, was not evident under conditions of a tighter gas market. This meant that low opportunity value gas was not traded and that gas prices published by gasTrading were then representative of the gas products required by the gas generators.

This is no longer case, meaning that gas prices published by gasTrading are no not representative of the gas products required by the gas generators in the outlook year.

As a result, the DMIRS gas data was also used in the projection of gas prices.

The forecasts of gas commodity prices are provided in section 7.3 below.

Figure 11 Average Domestic Gas Price



Source DMIRS [22]

7.3 Determination of Gas Cost Distribution

This section presents the model and data used to develop the distribution of gas prices. The gas price trends and comparison to the 2019 outlook is first presented. This is followed by a description of the model and results of the model using data from gasTrading and DMIRS.

7.3.1 Gas Price Trends

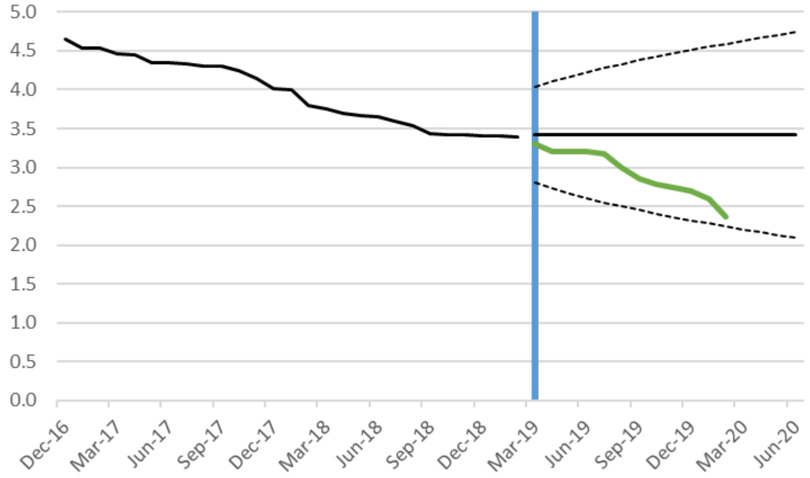
At the time of the 2019 analysis, Marsden Jacob's analysis of the gas market indicated that declines in gas price over recent years have reflected significant capacity coming online. This has resulted in two effects:

- Firstly, levels have declined. Marsden Jacob considers that the declines observed over recent years have incorporated the impact of the increase in capacity. We do not consider there is significant scope for further declines, particularly as prices approach the $2/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 considered to be unlikely to be replicated.

Figure 12 shows our projections from 2019 and the actual course of maximum prices during the year. While within the bounds provided, it suggests that a $2/GJ price floor may be tested.

[22] 2019 Major Commodities resource data, https://www.dmp.wa.gov.au/About-Us-Careers/Latest-Statistics-Release-4081.aspx, downloaded June 2020

Figure 12: 2019 analysis of historical gasTrading monthly maximum prices, ARIMA forecast and actuals ($/GJ)



Source: gasTrading and Marsden Jacob analysis

7.3.2 Gas Distribution Model

Under earlier approaches[23], short-run projections of maximum gas prices were developed using an 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 explained below.

The analysis considered different forms of an ARIMA[24] 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).

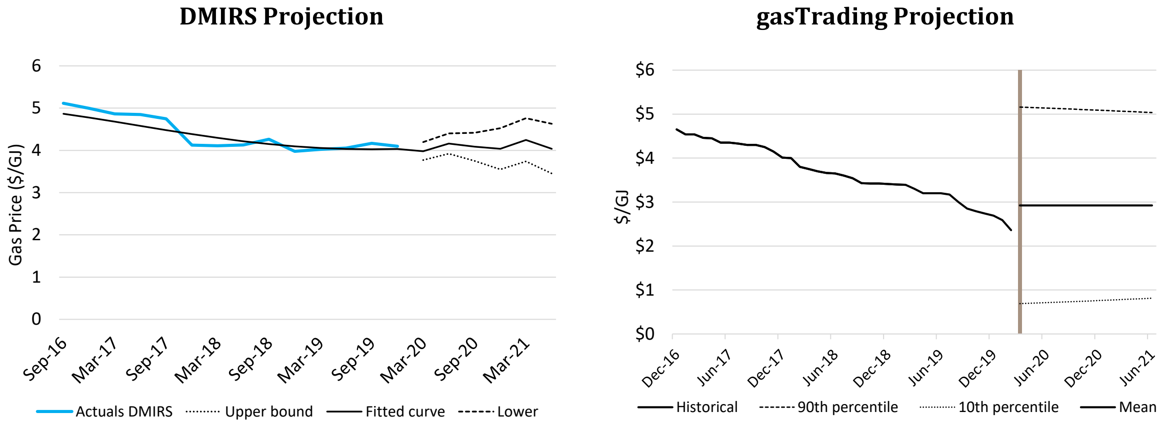
The 2019 analysis suggested a single lag moving average model with one level of differencing (consistent with a slowly constantly declining price.

Marsden Jacob used the "best" ARIMA to generate estimates of volatility. This was used to generate standard errors for the estimates. For the purposes of projections for 2020-21, we consider the average of the past year to provide the best estimate of the expected value for the coming year. This ARIMA model was applied to both the gasTrading spot market dataset and the DMIRS average domestic price.

Figure 13 shows these projections and the upper and lower bounds.

[23] Jacobs (2018)
[24] Auto Regressive Integrated Moving Average

Figure 13: Projections of gas prices 2020-21



Source: DMIRS and Marsden Jacob analysis

Source: gasTrading and Marsden Jacob analysis

Table 10 shows a comparison of the statistic for the gas forecasts for the 2019-20 and 2020-21 Energy Price Limit Review. These statistics are before the application of a floor price.

Table 10 Comparison of forecast gas distribution statistics excluding floor price

Parameter	2019-20 Review (**Error! Reference source not found.**)	2020-21 Review DMIRS	2020-21 Review GasTrading
Average	$3.41	$4.09	$2.92
Median	$3.42	$4.08	$2.92
80% lower bound (10th percentile)	$2.55	$3.70	$0.72
80% upper bound (90th percentile)	$4.28	$4.49	$5.13

Source: Marsden Jacob analysis 2020

Marsden Jacob considered the DMIRS projection to be used as the gas commodity charge for generators for the following reasons:

- Gas oversupply has had a larger impact on the smaller volumes reported by gasTrading and are not representative of the gas products required by generators.
- DMIRS uses the total trades on the DBNGP and Goldfields Gas Pipeline which are used for haulage of Pinjar and part haulage for Parkeston.
- DMIRS prices have been used recently for benchmark gas price for *Ancillary service parameters: spinning reserve margins, load rejection reserve and system restart costs for 2020/21*[25] Determination.

Marsden Jacob considered how COVID-19 would alter these projections of gas commodity prices, and believe that with average prices in April 2020 approaching $2/GJ the floor price selected is valid and that these projections are able to account for change in the market. The floor price of $2/GJ is incorporated into the normal distribution of gas commodity prices in the modelling with any point on the projection below this value in the distribution being set to the $2/GJ floor.

[25] http://www.erawa.com.au/cproot/21126/2/Determination-Report-Margin-Values-and-Cost_LR-Ancillary-Service-parameters-for-2020-21.pdf

7.4 Gas – Transport Costs

The mean value for gas transport charges for gas delivered to both the Pinjar and Parkeston Units has been calculated:

- Pinjar – $1.557/GJ (based on a 15% premium above the T1 Reference Tariff[26] applicable on the Dampier to Bunbury Natural Gas Pipeline). Assuming a standard deviation of $0.15/GJ.
- Parkeston – $1.45/GJ (based on the purchase of spot transport for covered services on the Goldfields Gas Pipeline) with a standard deviation of $0.15/GJ.

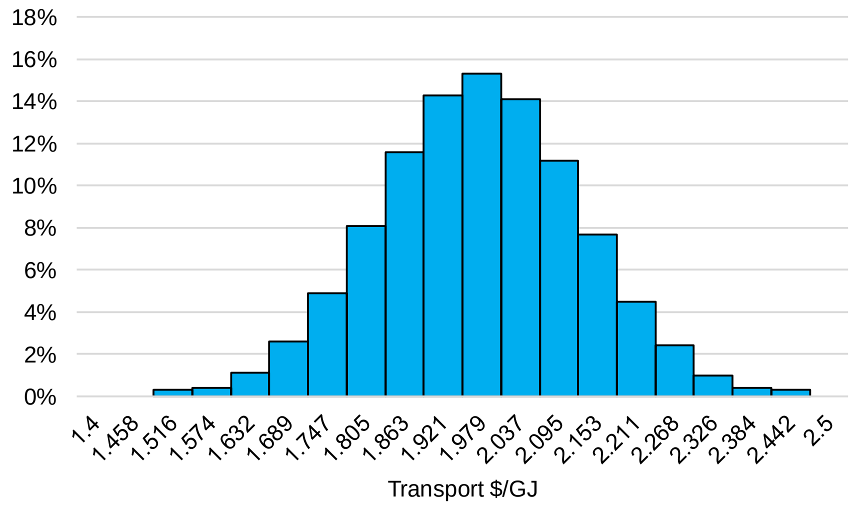
The above gas transport charges assume the generator is operating at a 100% capacity factor daily.

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% for gas turbines. At this level, gas transport charges would be $1.95/GJ on the Dampier to Bunbury Natural Gas Pipeline instead of $1.557/GJ, and $1.81/GJ on the Goldfields Gas Pipeline instead of $1.45/GJ.

Transport costs on the Goldfields Gas Pipeline above are based on the covered capacity tariff which is cheaper than the uncovered capacity tariff[27] of approximately $4.40/GJ to Parkeston. At an average Heat Rate of 15.3 GJ/MWh the additional cost of using the uncovered tariff for Parkeston would result in an increase of around $37/MWh.

In response to stakeholder feedback, Marsden Jacob has modelled the Maximum STEM Price using both the covered and uncovered capacity tariffs for gas transport to Parkeston (see Chapter 9).

Figure 14 Distribution of gas transport costs



Source *ERA and Marsden Jacob analysis*

7.5 Distillate Prices

The Alternative Maximum STEM Price is based on distillate prices (i.e. diesel)[28].

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

[26] https://www.erawa.com.au/gas/gas-access/dampier-to-bunbury-natural-gas-pipeline/tariff-variations
[27] https://www.apa.com.au/our-services/gas-transmission/current-tariffs-and-terms/current-tariffs-and-terms/
[28] Chapter 11 of the WEM Rules

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 permit 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[29]. This reduces the level of uncertainty for establishing Alternative Maximum STEM Prices.

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.

7.6 Distillate Prices Distribution

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% sulphur) or another suitable published price as determined by AEMO[30]. AEMO uses the Perth Terminal Gate Price (net of GST and excise) for this purpose, as the Singapore gas oil price (0.5% sulphur) is no longer widely used. Moreover, the Perth Terminal Gate Price includes shipping costs and 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.

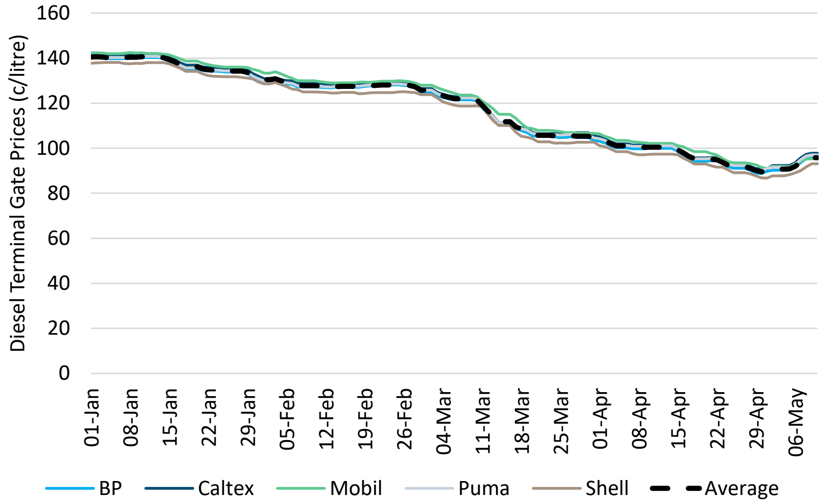
For this purpose, the uncertainty in the distillate price is not statistically important because the Alternative Maximum STEM Price is updated monthly. However, in modelling the gas price for the Maximum STEM Price, the uncertainty and level of the distillate price is relevant to the extent that it is 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 15 shows the Diesel terminal gas price for Kwinana Beach from 1 Jan 2020 to 7 May 2020. During January and February 2020 there was a gradual decline in price from 140c/litre to 125c/litre, a 15c reduction. The effect of COVID-19 on distillate prices can be seen from the start of March 2020 onwards. Over the two month period of March to April 2020 the prices dropped from 125c/litre to 90c/litre, a reduction of 35c/litre, more than twice the decline in the previous 2 months of 2020.

—

[29] Clause 6.20.3(b) of the WEM Rules
[30] Clause 6.20.3(b) of the WEM Rules

Figure 15: Kwinana Beach Diesel Terminal Gate Price 2020



Source: FuelWatch[31]

To derive a distillate price that reflects the recent movements in Terminal Gate Price and the cost for local generators, the following measures were calculated:

- 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 from the Kwinana refinery to the generation plant;
- Convert the delivered cost of distillate into a price in $/GJ.

The outputs are shown in Table 11. In effect, gas prices used to set the Maximum STEM Price should not exceed $12.02/GJ (Pinjar delivered distillate cost). The standard deviation of distillate prices is estimated to be $0.68/GJ.

Table 11: Reference distillate prices for Pinjar and Parkeston Units 2020-21

Prices and Taxes	AUD cents per litre (ACPL)	AUD/GJ
Diesel TGP	92.52	
Excise	42.30	
GST	5.02	
Diesel TGP	45.20	11.71
Delivery Cost to Pinjar	1.20	
Delivery Cost to Parkeston	1.10	
Delivered Cost to Pinjar	46.40	12.02
Delivered Cost to Parkeston	46.30	11.99

Source: Marsden Jacob analysis 2020

[31] FuelWatch Industry Prices May 2020: https://www.fuelwatch.wa.gov.au/fuelwatch/pages/public/terminal_gate_pricing.jspx

8. Statistical Modelling and Risk Margin

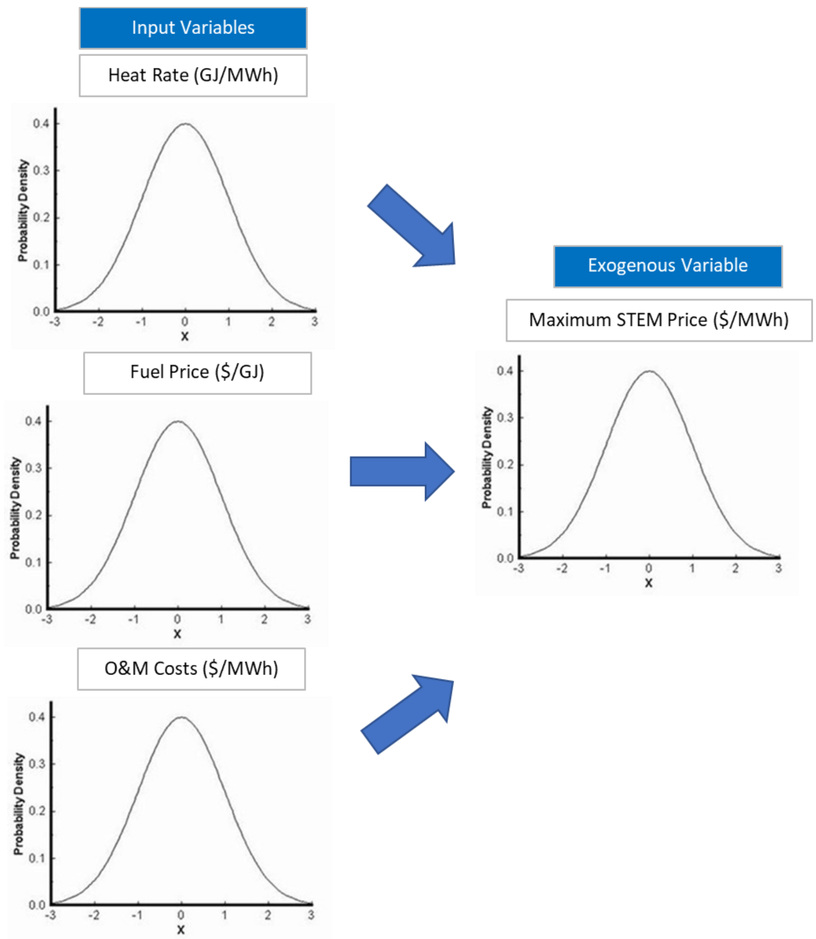
This chapter presents the statistical modelling undertaken.

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 heat rate of the benchmark unit, Variable O&M, and fuel cost (i.e. gas and distillate prices).

Using statistical methods, Marsden Jacob have generated probability distributions for each of the key input variables that are uncertain (see Chapter 3). Figure 16 shows that the input variables have normal distributions, but this is not necessarily the case. Input variables could have normal, log-normal, uniform or triangular distributions, and in some cases could be truncated (i.e. input values cannot take certain values).

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.

Figure 16: Monte Carlo simulations used to generate Maximum STEM Price probability density function

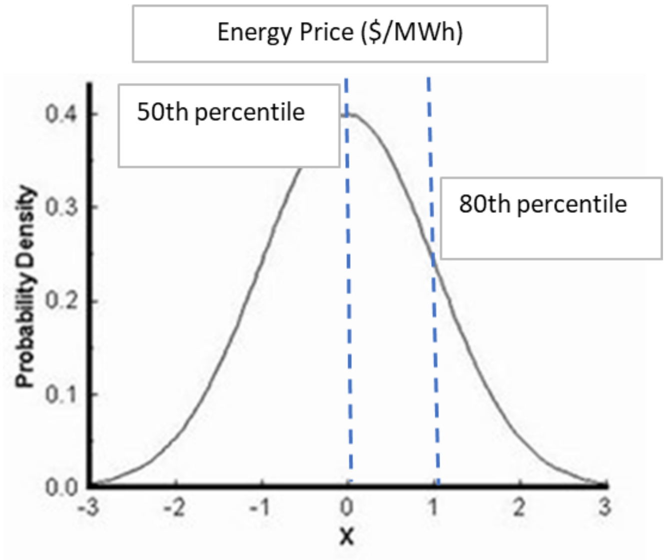


Source Marsden Jacob 2019

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% 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 17 below).

Figure 17: Decision rule for determining Maximum STEM Price (80th percentile) and Risk Margin



Source Marsden Jacob 2019

9. Modelling Results

This chapter presents the modelling results for determining the Maximum STEM Price and Alternative Maximum STEM Price when based on the Parkeston Units and Pinjar Units.

In relation to the modelling:

- The results are based on 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;
- Six random variables are created for each simulation;
  - Fuel commodity cost ($/GJ)
  - Fuel transport cost ($/GJ)
  - Start up Fuel (GJ/Start)
  - Variable O&M ($/MWh)
  - Average generation (MW) when dispatched
  - Run hours (h);
- Mean heat rate is a function of the average dispatch generation which is based on historical generation from 2014-2019 for Pinjar Units and 2019 for Parkeston Units;
- Fixed start-up costs are aggregated over all generation (MWh) for that start (Average Generation (MW) x Run Hours (h)).

9.1 Maximum STEM Price

The modelling results for the Maximum STEM Price for the Pinjar Units and Parkeston Units are presented in turn as follows:

Pinjar Units

- Table 12 presents the calculation of Maximum STEM Price;
- Figure 18 presents the Maximum STEM Price probability density function (this show the 80th percentile of Alternative Maximum STEM Price outcomes).

Parkeston Units

- Table 13 presents the calculation of Maximum STEM Price with covered tariff on the GGP;
- Figure 19 presents the Maximum STEM Price probability density function with covered tariff on the GGP. (this show the 80th percentile of Alternative Maximum STEM Price outcomes).
- Table 14 presents the calculation of Maximum STEM Price with uncovered tariff on the GGP;
- Figure 20 presents the Maximum STEM Price probability density function with uncovered tariff on the GGP. (this show the 80th percentile of Alternative Maximum STEM Price outcomes).

From the above results, the calculated Risk Margin, which is the difference between the mean and 80th percentile, is provided in Table 15.

A comparison of the results shows that there are large differences in the Maximum STEM Price between the use of Parkeston and Pinjar Units in establishing the Energy Price Limits.

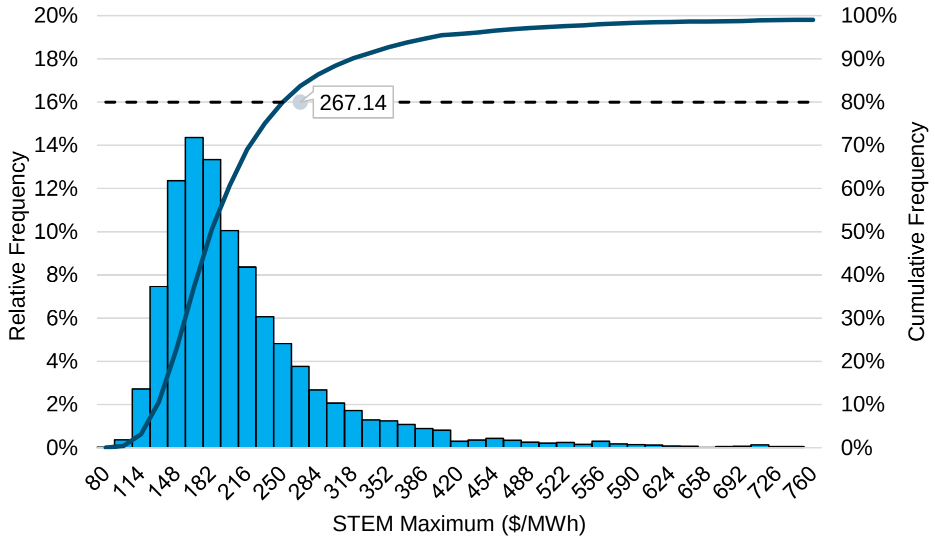
The lower average dispatch of the Pinjar Units (49.1 MWh per dispatch event) results in the plant operating at higher points on the heat rate curve when compared to the Parkeston Units (93 MWh per dispatch event).

Table 12: Calculation of Maximum STEM Price – Pinjar Units

Component	Units	Values
Mean Variable O&M Cost	$/MWh	110.48
Mean Heat Rate	GJ/MWh	19.19
Mean Fuel Cost (heat rate adjusted)	$/MWh	134.98
Mean Unit Fuel Cost (Transport included)	$/GJ	7.03
Loss Factor		1.0274
Before Risk Margin	$/MWh	238.91
Risk Margin Added	$/MWh	28.23
Risk Margin Value	%	11.82
Assessed Maximum STEM Price	$/MWh	267.14

Source: Marsden Jacob analysis 2020

Figure 18: Maximum STEM Price probability density function – Pinjar Units



Source: Marsden Jacob analysis 2020

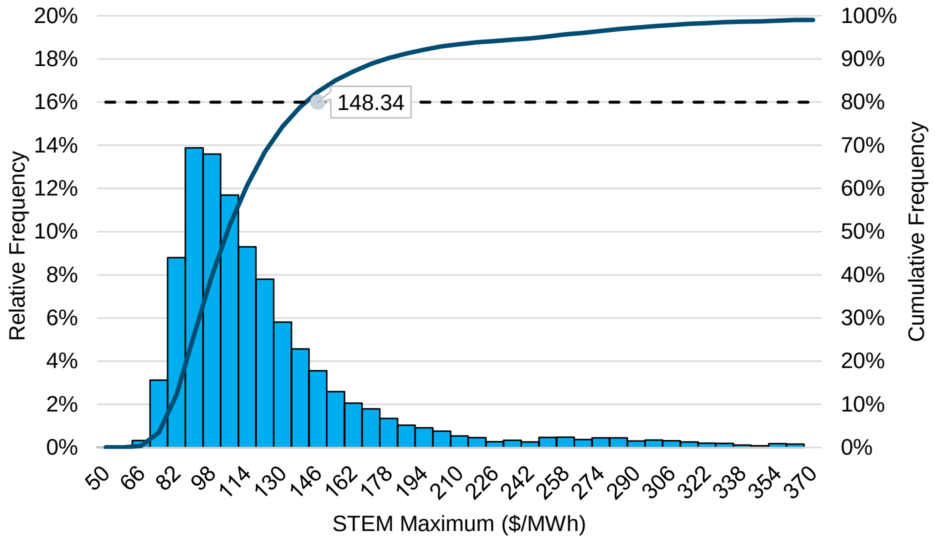
Table 13: Calculation of Maximum STEM Price – Parkeston Units Covered

Component	Units	Values
Mean Variable O&M Cost	$/MWh	50.55
Mean Heat Rate	GJ/MWh	15.31
Mean Fuel Cost (heat rate adjusted)	$/MWh	95.50
Mean Unit Fuel Cost (Transport included)	$/GJ	6.23
Loss Factor		1.1234
Before Risk Margin	$/MWh	130.01

Risk Margin Added	$/MWh	18.32
Risk Margin Value	%	14.09
Assessed Maximum STEM Price	$/MWh	148.34

Source: Marsden Jacob analysis 2020

Figure 19: Maximum STEM Price probability density function – Parkeston Units Covered



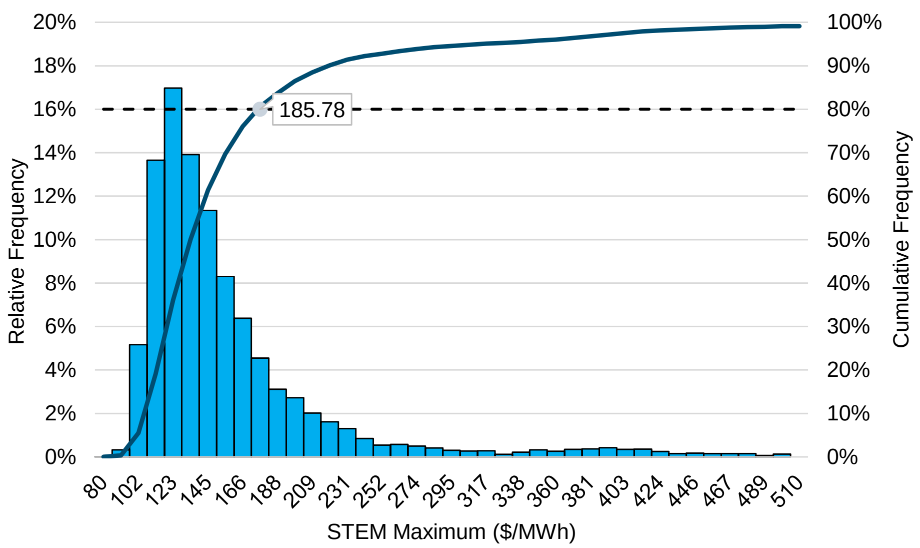
Source: Marsden Jacob Analysis 2020

Table 14: Calculation of Maximum STEM Price – Parkeston Units Uncovered

Component	Units	Values
Mean Variable O&M Cost	$/MWh	50.55
Mean Heat Rate	GJ/MWh	15.31
Mean Fuel Cost (heat rate adjusted)	$/MWh	137.25
Mean Unit Fuel Cost (Transport included)	$/GJ	8.96
Loss Factor		1.1234
Before Risk Margin	$/MWh	167.17
Risk Margin Added	$/MWh	18.60
Risk Margin Value	%	11.13
Assessed Maximum STEM Price	$/MWh	185.78

Source: Marsden Jacob analysis 2020

Figure 20: Maximum STEM Price probability density function – Parkeston Units Uncovered



Source: Marsden Jacob Analysis 2020

Table 15: Risk Margin

Generating Units	Mean ($/MWh)	80% Cost Coverage ($/MWh)	Risk Margin (%)
Pinjar Units	238.91	267.14	11.82
Parkeston Units Covered	130.01	148.34	14.09
Parkeston Units Uncovered	167.17	185.78	11.13

Source: Marsden Jacob Analysis 2020

9.2 Alternative Maximum STEM Price

The modelling results for the Alternative Maximum STEM Price for the Pinjar and Parkeston units are presented in turn as follows:

Pinjar Units

- Table 16 presents the calculation of the Alternative Maximum STEM Price;
- Figure 21 presents the Alternative Maximum STEM Price probability density function (this shows the 80th percentile of Alternative Maximum STEM Price outcomes).

Parkeston Units

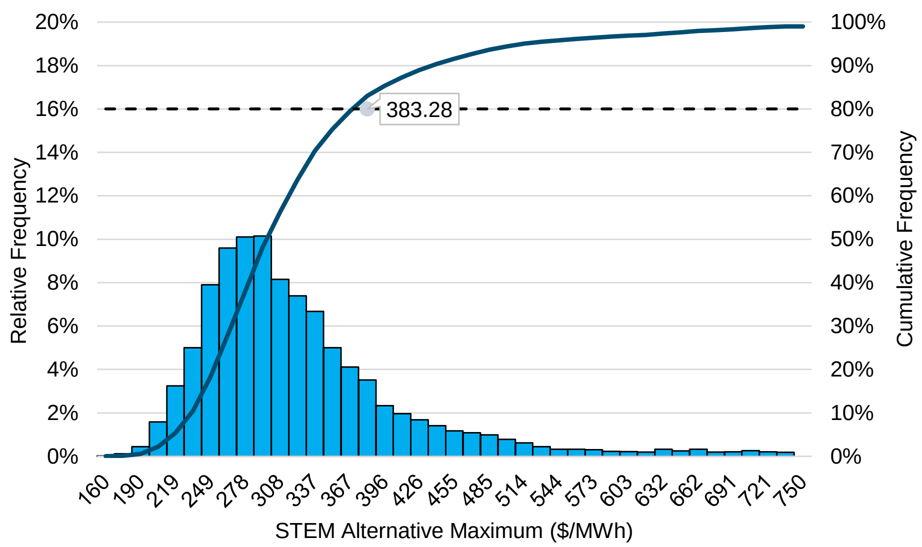
- Table 17 presents the calculation of the Alternative Maximum STEM Price;
- Figure 22 presents the Alternative Maximum STEM Price probability density function (this show the 80th percentile of Alternative Maximum STEM Price outcomes).

Table 16: Calculation of the Alternative Maximum STEM Price – Pinjar Units

Component	Units	Values
Mean Variable O&M Cost	$/MWh	110.48
Mean Heat Rate	GJ/MWh	19.07
Mean Fuel Cost (heat rate adjusted)	$/MWh	235.42
Mean Unit Fuel Cost (Transport included)	$/GJ	12.35
Loss Factor		1.0274
Before Risk Margin	$/MWh	336.67
Risk Margin Added	$/MWh	46.61
Risk Margin Value	%	13.84
Assessed Alternative Maximum STEM Price	$/MWh	383.28

Source: Marsden Jacob analysis 2020

Figure 21: Alternative Maximum STEM Price probability density function – Pinjar Units



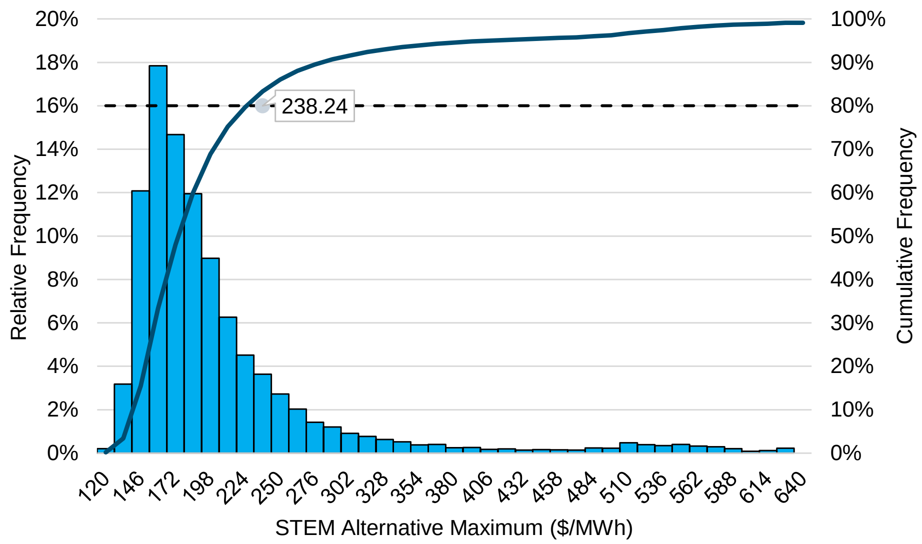
Source: Marsden Jacob analysis 2020

Table 17: Calculation of the Alternative Maximum STEM Price – Parkeston Units

Component	Units	Values
Mean Variable O&M Cost	$/MWh	50.55
Mean Heat Rate	GJ/MWh	15.31
Mean Fuel Cost (heat rate adjusted)	$/MWh	192.18
Mean Unit Fuel Cost (Transport included)	$/GJ	12.55
Loss Factor		1.1234
Before Risk Margin	$/MWh	216.07
Risk Margin Added	$/MWh	22.18
Risk Margin Value	%	10.26
Assessed Alternative Maximum STEM Price	$/MWh	238.24

Source: Marsden Jacob analysis 2020

Figure 22: Alternative Maximum STEM Price probability density function – Parkeston Units



Source: Marsden Jacob analysis 2020

9.2.1 Regression of Alternative Maximum STEM Price

The Alternative Maximum STEM Price is varied each month according to changes in the price of distillate[32]. 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% cumulative probability price are:

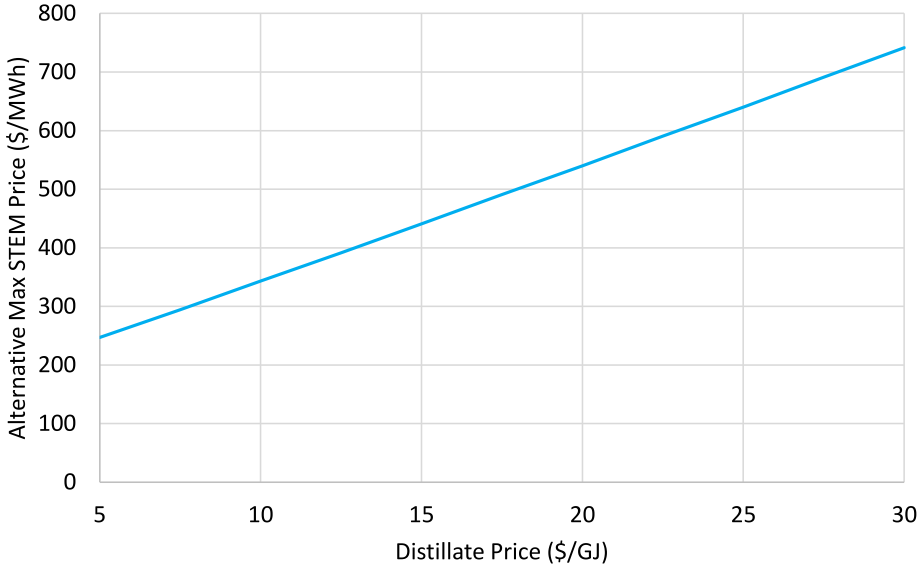
Equation 4

$$145.28_{\$/MWh} + (19.808_{GJ/MWh} \times Delivered\ Distillate\ Price_{\$/GJ})$$

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/GJ, to assess the 80% probability level of cost for each fuel price. Rather than taking the 80% probability values of the cost terms themselves, the two cost factors were derived from the linear regression fit of the 80% price versus distillate price. The relationship using the function in Equation 4 is shown in Figure 23.

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

Figure 23: Assessed Alternative Maximum STEM Price vs delivered distillate price – Pinjar Units



Source: Marsden Jacob analysis 2020

10. Changes in Energy Price Limits Compared to Previous Years

This chapter compares the results presented in the previous chapter to the results of the 2019-20 year. As the analysis shows that Pinjar was the more expensive unit in both the current and previous review this chapter focuses on the results of the Pinjar Units.

As Pinjar has both a higher mean Heat Rate and mean Variable O&M costs it will remain more expensive unit to run despite fluctuations in fuel prices as it will consume a higher amount of fuel on average to produce a MWh than Parkeston. This means that COVID-19 has not affected Pinjar being the more expensive unit.

10.1.1 Maximum STEM Price

A comparison of the assessed Maximum STEM Price for 2020-21 with the previous year's price is provided in Table 18. Figure 24 presents the factors that resulted in the change.

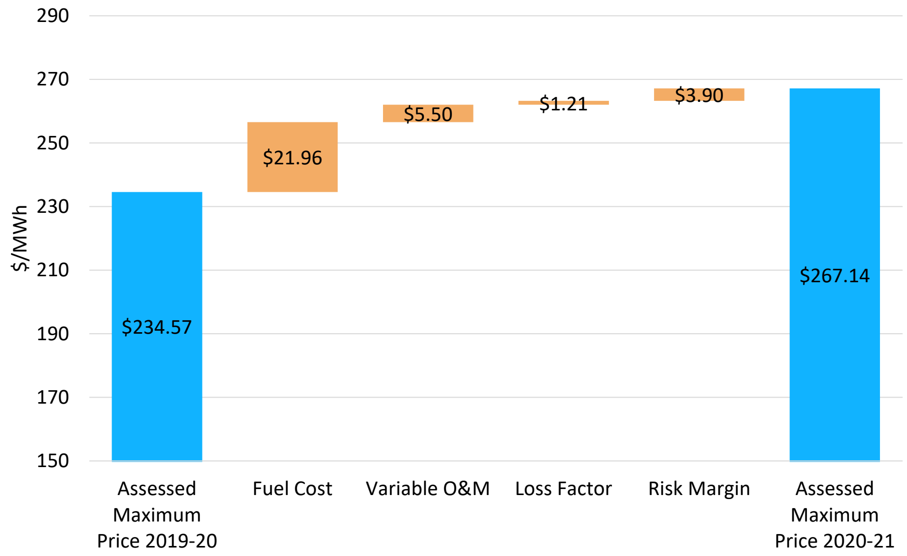
Table 18: Comparison of Maximum STEM Price to 2019-20

Component	Units	2020-21	2019-20	Change
Mean Variable O&M Cost (a)	$/MWh	110.48	104.98	5.50
Mean Heat Rate	GJ/MWh	19.19	20.62	-1.43
Mean Fuel Cost (heat rate adjusted) (a)	$/MWh	134.98	113.02	21.96
Loss Factor		1.0274	1.0369	-0.01
Before Risk Margin	$/MWh	238.91	210.24	28.67
Risk Margin Added	$/MWh	28.23	24.33	3.90
Risk Margin Value	%	11.82	11.57	0.25
Assessed Maximum STEM Price	$/MWh	267.14	234.57	32.57

Source: Marsden Jacob analysis 2019-2020

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

Figure 24: Factors causing change in the Maximum STEM Price from 2019-20 (a)



Source: Marsden Jacob analysis 2019-2020

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 18.

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

Variable O&M

Generation for both the Pinjar Units and Parkeston Units was higher in 2019 than 2018 and this data was not available as part of the 2019-20 review. The addition of an extra year of high generation results in a higher average generation per start increase for Pinjar from 38.5 to 49.1 MWh.

The use of a fixed annual cost for Pinjar Units in this year's review resulted in a significant change to the distribution of Variable O&M costs. The fixed costs resulted in a higher mean cost per start and a larger spread of cost per start compared to the 2019-20 review.

The combination of these two factors kept the Variable O&M costs for Pinjar similar to the 2019-20 review.

The distribution had more variance as years with both higher and lower number of starts used the same fixed cost. Previously for Pinjar the number of starts directly impacted the Variable O&M distribution and this factor results in a reduction to the variance of the distribution.

Had generation not been limited to 6 hours, the Variable O&M costs would be much lower due to an average generation per dispatch of 71 MWh.

Fuel Costs

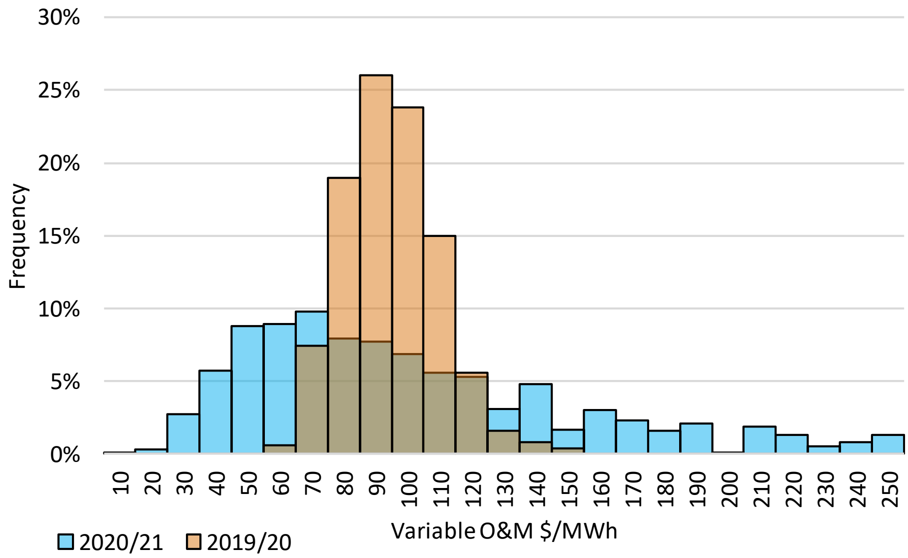
Compared to the 2019-20 review the unit cost ($/GJ) for delivered gas has increased by 28.3%. Lower average Heat Rate due to the higher capacity factor resulted in the $/MWh cost of fuel increasing by a lower percentage (19.4%).

Risk Margin

Risk Margin value increased as a result of the inclusion of generation data for calendar year 2019.

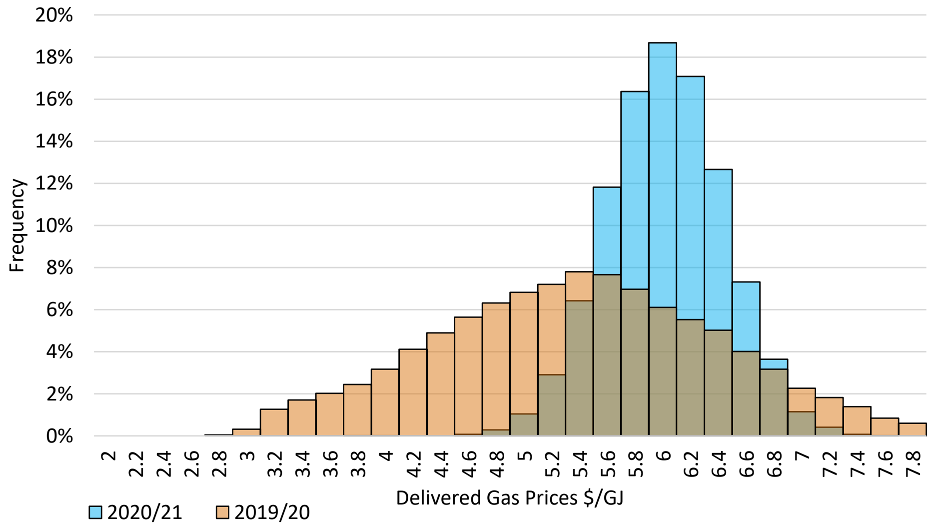
The inclusion of 2019 with higher generation acted to lower the mean value of Variable O&M. However, the low levels of generation seen in 2018 and earlier years are still included in the data sets used for distribution. As a result, there are still many higher priced tail simulations. These tail simulations have more impact on the 80th percentile, and when compared to the lower mean value of Variable O&M, the Risk Margin increases.

Figure 25: Comparison of probability density function for Variable O&M Costs ($/MWh)



Source: Marsden Jacob analysis 2019 & 2020

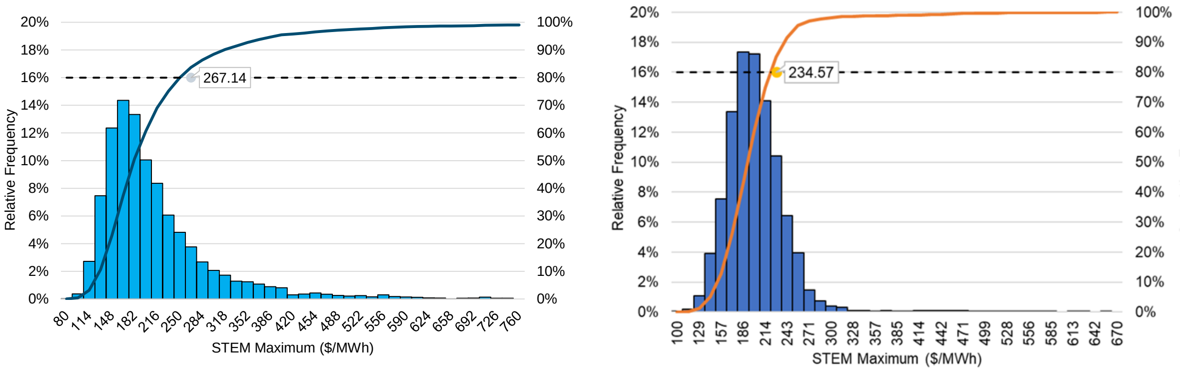
Figure 26: Comparison of probability density function for Delivered Gas Costs ($/GJ)



Source: Marsden Jacob analysis 2019 & 2020

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 probability density functions for 2019-20 and 2020-21 Maximum STEM Prices are provided in Figure 27.

Figure 27: Comparison of probability density functions for Maximum STEM Prices ($/MWh) – Pinjar Units 2020-21 (left) and 2019-20 (right)



Source: Marsden Jacob analysis 2019,2020

10.1.2 Alternative Maximum STEM Price

The Alternative Maximum STEM Price is slightly higher than last year, resulting mostly from a change in the Risk Margin.

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

Variable O&M

The Alternative Maximum STEM Price uses the same distribution of Variable O&M as the Maximum STEM Price, as maintenance costs are independent of fuel type. Section 10.1.1 above describes changes to the Variable O&M costs.

Fuel Costs

The main cause of the decrease is the large drop in mean Fuel Costs. The drop in Mean Fuel Costs is a result of the current low diesel price, which has occurred as a result of COVID-19 reducing demand. The lower Heat Rate (resulting from higher average dispatch capacity) than in the 2019-20 review also contributed to the mean Fuel Cost decrease.

Risk Margin

The Risk Margin in $/MWh terms only increased slightly, up $1.98/MWh, however in percentage terms the increase was 5.3%, this being due to a greater uncertainty in both the Variable O&M and Fuel Costs.

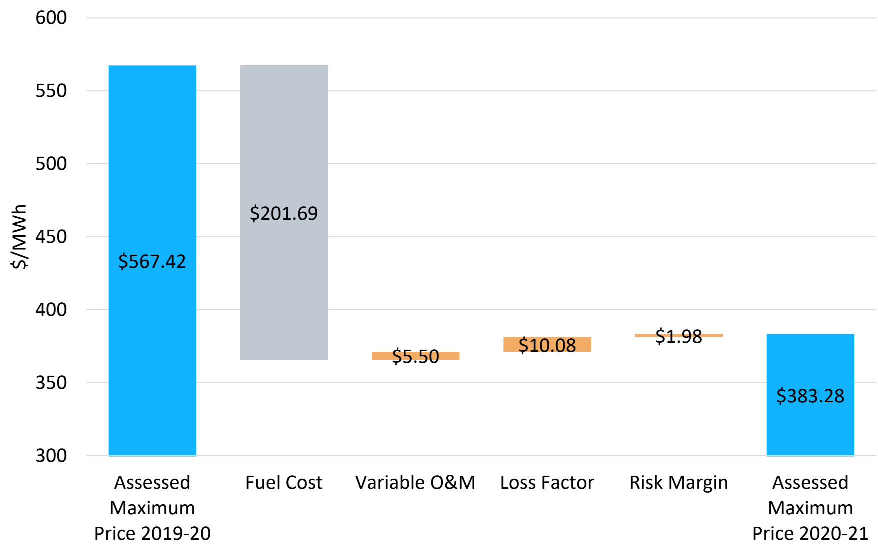
Table 19: Comparison of Alternative Maximum STEM Price to 2019-20

Component	Units	2020-21	2019-20	Change
Mean Variable O&M Cost (a)	$/MWh	110.48	104.98	5.50
Mean Heat Rate	GJ/MWh	19.07	20.62	-1.55
Mean Fuel Cost (heat rate adjusted) (a)	$/MWh	235.42	437.11	-201.69
Loss Factor		1.0274	1.0369	-0.01
Before Risk Margin	$/MWh	336.67	522.79	-186.12
Risk Margin Added	$/MWh	46.61	44.63	1.98
Risk Margin Value	%	13.84	8.54	5.30
Assessed Alternative Maximum STEM Price	$/MWh	383.28	567.42	-184.14

Source: Marsden Jacob analysis 2019 -2020

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

Figure 28: Factors causing change in the Alternative Maximum STEM Price from 2019-20 (a)



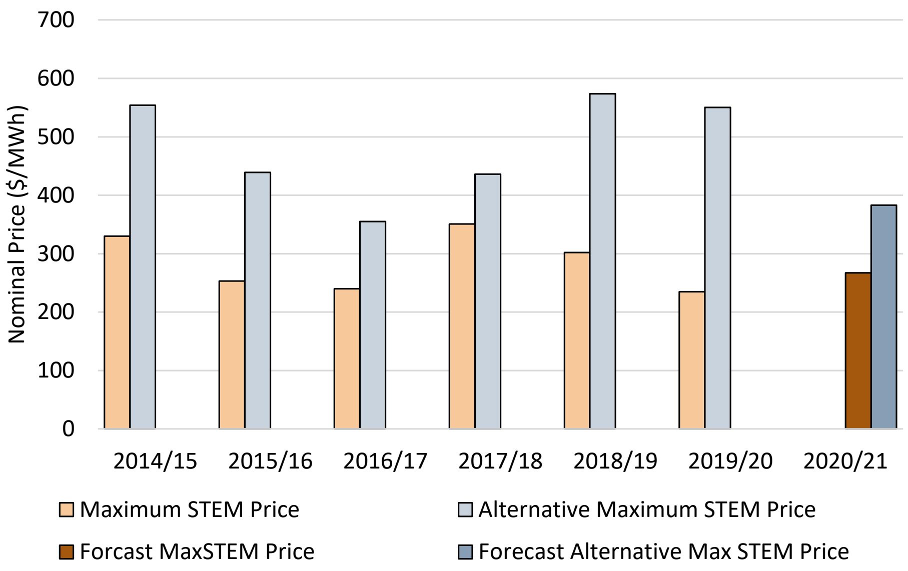
Source: Marsden Jacob analysis 2019-2020,

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 19.

10.1.3 Historical Prices

A comparison of assessed upper prices with historical outcomes in nominal dollars since 2014-15 is provided in Figure 29.

Figure 29: Comparison of assessed upper Energy Price Limits with historical prices



Source: Marsden Jacob analysis 2020, AEMO